Request IR-1:

General Inquiries and Follow-Up pages 7 to 30

Page 8 notes that the targeted reliability projects include vegetation management, storm hardening and upgrades, device replacements and grid modernization. Please identify the projects that would fall under these categories from the Routines in section 10 and those in the individual Capital Investments (Generation, Transmission, Distribution and General Plant).

Response IR-1:

Please refer to Attachment 1.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

CI#	Project Title	2026 ACE Forecast Spend	Combined Category - 2026	Reliability Enhancement	Asset Class
C0068718	IT - DERMS Solution Project	857,294	Advanced Grid Modernization	DERs	General Plant
C0068719	IT - Distributed Intelligence Apps	1,312,110	Advanced Grid Modernization	Downline Connectivity	General Plant
C0070907	MDR-8000 Microwave Radio Replacement	526,010	Advanced Grid Modernization	Downline Connectivity	General Plant
C0080623	Network Manager Replacement	493,651	Advanced Grid Modernization	Downline Connectivity	General Plant
C0070868	LEDR Radio Link Replacement	164,874	Advanced Grid Modernization	Downline Connectivity	General Plant
C0071528	FLISR Implementation	3,445,667	Advanced Grid Modernization	FLISR	Distribution
38243	Telecom Spare Routine	208,261	Advanced Grid Modernization	General	General Plant
C0051815	2025 RTU Replacement Program	1,669,606	Advanced Grid Modernization	RTU	General Plant
C0080111	2026 RTU Deployment Project	901,513	Advanced Grid Modernization	RTU	General Plant
16550	Telecom Systems Routine	852,510	Advanced Grid Modernization	Upgrades and Replacements	General Plant
16551	TELECOMMUNICATION RADIO AND FIBRE OPTIC BLDG UPGRADE	222,400	Advanced Grid Modernization	Upgrades and Replacements	General Plant
T030-000	Transmission Tower Refurbishment / Life Extension	2,266,774	Equipment Upgrades	Asset Life Extension	Transmission
C0069238	2025/2026 Steel Tower Refurbishment	1,391,030	Equipment Upgrades	Asset Life Extension	Transmission
C0061387	2024/2025 Wood Pole Retreatment Program	847,264	Equipment Upgrades	Asset Life Extension	Transmission
C0052299	2023/2024 Steel Tower Life Extension	469,206	Equipment Upgrades	Asset Life Extension	Transmission
C0061403	2024/2025 Sacrifical Anode Installation	142,517	Equipment Upgrades	Asset Life Extension	Transmission
C0080234	57C-426H Country Harbour Cell Tower BTR	431,461	Equipment Upgrades	Build to Roadside	Distribution
C0060757	4C-432G Loch Katrine Build to Roadside	191,769	Equipment Upgrades	Build to Roadside	Distribution
C0042927	103C-314-Grand etang Water Crossing	106,353	Equipment Upgrades	Build to Roadside	Distribution
C0052798	10C-211 Fleur De Lis Trail Conversion	700,168	Equipment Upgrades	Conversion	Distribution
C0053076	14C-211 Boudreauville Rd Conversion	513,673	Equipment Upgrades	Conversion	Distribution
C0080247	Halifax Conversion of Undersized Secondary Buses	505,261	Equipment Upgrades	Conversion	Distribution
C0080613	9H-224 Chebucto Road Conversion	500,000	Equipment Upgrades	Conversion	Distribution
C0061103	South Rawdon Rd Conversion	467,802	Equipment Upgrades	Conversion	Distribution
C0080605	19C Canso Conversion Phase 1 (Union and Water)	444,005	Equipment Upgrades	Conversion	Distribution
C0053517	9H-221 University Ave and Morris St Conversion	36,643	Equipment Upgrades	Conversion	Distribution
C0080252	ECC Intelligent Asset Data Capture & Integration Platform	251,719	Equipment Upgrades	General	General Plant
C0080244	85S-401 Cape Smokey BTR Removals	221,970	Equipment Upgrades	General	Distribution
23511	Primary Equipment Spares - Distribution	162,391	Equipment Upgrades	General	Distribution
C0080102	92H-331 Double Circuit Peggys Cove Rd	1,704,973	Equipment Upgrades	Line Addition	Distribution
C0070827	99V-314G Lake George Line Extension	672,694	Equipment Upgrades	Line Addition	Distribution
C0080612	57C-426 Melrose Reconductor and Line Extension Phase 1	629,268	Equipment Upgrades	Line Addition	Distribution
C0080249	Aerotech Connector Part 2 of 2	559,765	Equipment Upgrades	Line Addition	Distribution
C0031117	2H-411-Prospect Rd Phase Extension	75,857	Equipment Upgrades	Line Addition	Distribution
C0041804	2022 Line Retirement Program	340,094	Equipment Upgrades	Line Retirement	Transmission
23120	Provincial - Trans Substation Primary	3,122,388	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0080107	L5532 Reliability Upgrade - 91W Middle Field Substation	2,537,039	Equipment Upgrades	Misc. Sustaining Capital	Transmission
T020-000	2026 Transmission Switch & Breaker Replacements	2,326,441	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0070586	L6536 Switch Replacements	1,626,611	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0068961	2025 PCB Substation Sampling and Replacement	1,224,293	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0056240	2024 Transmission Switch & Breaker Replacements	1,049,910	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0057882	2024 Pennsylvania Breaker Replacements	990,156	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0061883	129-H Kearney Lake Substation Rebuild	946,245	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0059483	83V L5017 and L5046 Rebuild Tap	927,126	Equipment Upgrades	Misc. Sustaining Capital	Transmission
23121	Provincial - Substation Additions and Replacements	902,743	Equipment Upgrades	Misc. Sustaining Capital	Transmission
14841	Protection Modification and Replacement	862,088	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0055796	2023 EHV Breaker Replacements	733,370	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0080254	2026 Substation Fence Upgrades	710,229	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0080255	2026 Substation Theft Prevention	694,077	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0068966	2026 Merlin Gerin Breaker Replacements	688,347	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0050842	2024 Bulk Oil (KSO) Breaker Replacements	635,204	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0050834	Spare EHV Breaker	511,097	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0067866	2024 Substation Recloser Replacements	425,799	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0061046	2024 Merlin Gerin Breaker Replacements	423,012	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0068969	2026 Pennsylvania Breaker Replacements	398,876	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0080259	67N Onslow Spare Reactors	215,427	Equipment Upgrades	Misc. Sustaining Capital	Transmission
14973	Primary Equipment Spares	192,433	Equipment Upgrades	Misc. Sustaining Capital	Transmission
C0021140	138KV-25KV Substation Stellarton	5,084,736	Equipment Upgrades	New Substation	Transmission
C0071888	New Tidewater Substation	4,119,741	Equipment Upgrades	New Substation	Transmission
C0062123	143H - Mt Uniacke Substation	1,000,000	Equipment Upgrades	New Substation	Transmission
C0032382	142H - Susie Lake Substation	624,824	Equipment Upgrades	New Substation	Transmission
C0070787	91W-411 Labelle Road Phase Extension	1,051,545	Equipment Upgrades	Phase Addition	Distribution
C0071410	25W-301 Welshtown Phase Additions	770,654	Equipment Upgrades	Phase Addition	Distribution
C0080238	11S-301J Barrachois Phase Extension	277,020	Equipment Upgrades	Phase Extension	Distribution
C0080243	62H-304 Woodland Ave Extend 3 Phase to Feeder Tie	234,399	Equipment Upgrades	Phase Extension	Distribution

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

CI#	Project Title	2026 ACE Forecast Spend	Combined Category - 2026	Reliability Enhancement	Asset Class
C0061550	L5031 Hubbards to East Chester Phase 2	1,898,274	Equipment Upgrades	Rebuild	Transmission
C0080104	36V-303 Baxter's Harbour Rd Reconductor Phase 1	979,830	Equipment Upgrades	Reconductor	Distribution
C0080245	88W-312 Albert St Reconductor	673,576	Equipment Upgrades	Reconductor	Distribution
C0080246	99H-311 Windmill Rd Wyse Rd Reconductor	264,409	Equipment Upgrades	Reconductor	Distribution
C0080242	4S-332 George St Single Circuit Reconductor	207,686	Equipment Upgrades	Reconductor	Distribution
52184	37N-412-Glooscap Trail Rebuild PH2	49,303	Equipment Upgrades	Reconductor	Distribution
23118	Provincial Planned Transmission Line Replacements	5,680,154	Equipment Upgrades	Replace and Upgrade	Transmission
23115	Provincial Transmission Line Replacements	3,322,385	Equipment Upgrades	Replace and Upgrade	Transmission
C0031122	L6539 2021 Replacements and Upgrades	2,780,796	Equipment Upgrades	Replace and Upgrade	Transmission
C0080110	L7012 Replacements and Upgrades Phase 1	2,195,905	Equipment Upgrades	Replace and Upgrade	Transmission
C0070048	L5027B Replacements and Upgrades Phase 1	2,130,943	Equipment Upgrades	Replace and Upgrade	Transmission
C0069232	L6021 Replacements and Upgrades	1,953,732	Equipment Upgrades	Replace and Upgrade	Transmission
C0069231	L8002 Replacements and Upgrades	1,812,896	Equipment Upgrades	Replace and Upgrade	Transmission
C0061552	L6043 Replacements and Upgrades	1,626,537	Equipment Upgrades	Replace and Upgrade	Transmission
C0061551	L7009 Replacements and Upgrades	1,472,353	Equipment Upgrades	Replace and Upgrade	Transmission
C0069227	L6516 Replacements and Upgrades Phase 3	1,125,133	Equipment Upgrades	Replace and Upgrade	Transmission
C0080109	L7001 Replacements and Upgrades Phase 1	1,019,910	Equipment Upgrades	Replace and Upgrade	Transmission
C0080108	L5532 Replacements and Upgrades Phase 1	908,755	Equipment Upgrades	Replace and Upgrade	Transmission
C0061547	L7022 Replacements and Upgrades	896,998	Equipment Upgrades	Replace and Upgrade	Transmission
C0041812	L6040 Replacements and Upgrades	688,563	Equipment Upgrades	Replace and Upgrade	Transmission
C0061546	L6514 Replacements and Upgrades	484,426	Equipment Upgrades	Replace and Upgrade	Transmission
C0061544	L6536 Replacements and Upgrades	423,807	Equipment Upgrades	Replace and Upgrade	Transmission
C0041807	L5534 Replacements and Upgrades	274,987	Equipment Upgrades	Replace and Upgrade	Transmission
C0041791	L6551 Replacements and Upgrades	241,491	Equipment Upgrades	Replace and Upgrade	Transmission
C0061545	L6006 Replacements and Upgrades	206,436	Equipment Upgrades	Replace and upgrade	Transmission
C0070909	70W-T52 Transformer Addition	3,474,286	Equipment Upgrades	Substation Transformer Addition	Transmission
C0022247	1N Onslow Transformer Addition (1N-T66)	2,055,587	Equipment Upgrades	Substation Transformer Addition	Transmission
C0071889	77V-T1 Transformer Replacement	3,486,796	Equipment Upgrades	Substation Transformer Replacement	Transmission
C0055539	10H-T1 Transformer Replacement	2,794,480	Equipment Upgrades	Substation Transformer Replacement	Transmission
C0070086	10H-T2 Transformer Replacement	2,508,966	Equipment Upgrades	Substation Transformer Replacement	Transmission
C0031048	91H-T11 Transformer Replacement	2,329,053	Equipment Upgrades	Substation Transformer Replacement	Transmission
C0053234	96H-T1 Transformer Replacement	1,794,354	Equipment Upgrades	Substation Transformer Replacement	Transmission
C0053214	76W-T1 Transformer Replacement	614,732	Equipment Upgrades	Substation Transformer Replacement	Transmission
C0074130	Robie Street Underground	2,798,771	Equipment Upgrades	Upgrades and Replacement	Distribution
D020-000	2026 Padmount Replacement Program	2,278,256	Equipment Upgrades	Upgrades and Replacement	Distribution
C0080101	539N-210 Big Island Sub-Sea Cable Replacement	1,112,927	Equipment Upgrades	Upgrades and Replacement	Distribution
C0008638	D- Cogswell HRM Redevelopment Program	537,430	Equipment Upgrades	Upgrades and Replacement	Distribution
C0080248	Kentville UG Cable replacement	517,917	Equipment Upgrades	Upgrades and Replacement	Distribution
C0080240	2026 Underground Switchgear replacement	513,918	Equipment Upgrades	Upgrades and Replacement	Distribution
C0080236	Subsea Cable Asset Management	494,282	Equipment Upgrades	Upgrades and Replacement	Distribution
C0080611	2026 Vault Upgrade Program	474,451	Equipment Upgrades	Upgrades and Replacement	Distribution
C0080251	84W-302 Subsea Cable Removal	383,897	Equipment Upgrades	Upgrades and Replacement	Distribution
C0070506	2025 Vault Replacements	349,585	Equipment Upgrades	Upgrades and Replacement	Distribution
C0080609	2026 Manhole Cover Replacements	207,587	Equipment Upgrades	Upgrades and Replacement	Distribution
C0080608	2026 Manhole Automatic Pumps	173,671	Equipment Upgrades	Upgrades and Replacement	Distribution
C0070508	2025 Manhole Automatic Pumps	154,527	Equipment Upgrades	Upgrades and Replacement	Distribution
C0080607	2026 Feeder Exit Replacements	146,448	Equipment Upgrades	Upgrades and Replacement	Distribution
C0080237	2026 Padmount Switch Replacement	74,195	Equipment Upgrades	Upgrades and Replacement	Distribution
23158	Unplanned Replace Deteriorated	22,418,590	Equipment Upgrades	Upgrades and Replacements	Distribution
23137	Planned Routine Upgrade	15,000,016	Equipment Upgrades	Upgrades and Replacements	Distribution
23361	Provincial Storm	6,927,211	Equipment Upgrades	Upgrades and Replacements	Distribution
23135	Regulatory Replacements	4,118,292	Equipment Upgrades	Upgrades and Replacements	Distribution
23136	Contractual Replacements - Joint Use	3,723,004	Equipment Upgrades	Upgrades and Replacements	Distribution
C0068952	2025 PCB Poletop Sampling and Replacement	2,777,749	Equipment Upgrades	Upgrades and Replacements	Distribution
C0068954	2025 PCB Downline Device Sampling and Replacement	1,100,618	Equipment Upgrades	Upgrades and Replacements	Distribution
29038	System Performance Improvement Routine	1,099,867	Equipment Upgrades	Upgrades and Replacements	Distribution
C0068956	2025 PCB Program - Reclosers	926,007	Equipment Upgrades	Upgrades and Replacements	Distribution
C0082275	Single Phase Quick Cycle Reliability 2026	800,048	Equipment Upgrades	Upgrades and Replacements	Distribution
C0080235	74N-412 Sutherlands Lake Reconfiguration	620,054	Equipment Upgrades	Upgrades and Replacements	Distribution
C0080241	2026 Voltage Regulator Replacements	147,822	Equipment Upgrades	Upgrades and Replacements	Distribution
C0070268	2025 Voltage Regulator Replacements	547,973	Equipment Upgrades	Upgrades and Replacements	Distribution
C0071954	87W-312 Dauphiness Mill Lake Rebuild	500,000	Equipment Upgrades	Upgrades and Replacements	Distribution
C0070426	2025 Downline Recloser Additions	147,822	Equipment Upgrades	Upgrades and Replacements	Distribution
C0070347	2025 Hydraulic Recloser Replacements	52,773	Equipment Upgrades	Upgrades and Replacements	Distribution
51098	L-6014 Shannon Park Transmission Towers	4,532,569	Equipment Upgrades	Water Crossing Upgrade	Transmission

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

CI#	Project Title	2026 ACE Forecast Spend	Combined Category - 2026	Reliability Enhancement	Asset Class
C0053295	L5004 Kearney Lake Structure Replacement	1,090,202	Equipment Upgrades	Water Crossing Upgrade	Transmission
C0023802	L6515 Canso Causeway Rebuild	477,049	Equipment Upgrades	Water Crossing Upgrade	Transmission
C0052654	L5541 Water Crossing Upgrades	305,788	Equipment Upgrades	Water Crossing Upgrade	Transmission
C0080266	New Distribution Right of Way Phase 11	18,551,713	Vegetation Management	Distribution Vegetation Management	Distribution
23127	D010 Provincial Distribution ROW	13,223,181	Vegetation Management	Distribution Vegetation Management	Distribution
43827	Transmission Right of Way Widening	3,314,050	Vegetation Management	Transmission Vegetation Management	Transmission

Request IR-2:

General Inquiries and Follow-Up pages 7 to 30

Figure 1 Nova Scotia Power (NS Power) Total Capital Investment: Historical, Budget and Forecast.

(a) In the 2025 Annual Capital Expenditure (ACE Plan) M12012, Figure 1 in the application shows a total expected capital expenditure of $4,134.4M from 2025 to 2029 inclusive. Figure 1 in the 2026 ACE Plan application shows a total expected capital expenditure of $3,610.8M from 2025 to 2029 inclusive. Please describe the reasons for the $523.6M decrease in expected capital expenditures over these years between the two ACE Plans, particularly in the context of getting off coal fired generation by 2030.

(b) Please describe the reasons for the expected decline in capital expenditures beyond 2028.

(c) Please explain what explicit constraints (financial, operational, regulatory, system reliability, and customer affordability) were applied in developing the 2026 to 2030 capital forecasts shown in Figure 1 and confirm whether the forecast reflects a top-down capital limit or is the aggregation of bottom-up project submissions.

(d) Please confirm whether the forecast capital levels shown beyond 2026 assume continuation of existing depreciation rates, continued recovery of all capital investments in rate base and no material changes in planning responsibility arising from the transition to the Nova Scotia Independent Energy System Operator (IESO Nova Scotia).

(e) Please provide an updated version of Figure 1 that incorporates high level estimates of the expected funding to be received clearly showing how much NS Power will fund

and amounts expected to be funded by external sources. Please identify the degree of certainty associated with these funding assumptions.

(f) Please confirm whether the capital investment trajectory shown in Figure 1 would remain unchanged if assumed external funding is delayed, reduced, or does not materialize.

Response IR-2:

(a) The decrease in total forecast for 2025-2029 from the 2025 ACE Plan to the 2026 ACE Plan is due to the removal of the NS-NB Reliability Tie project from the 2026 ACE Plan forecast as this project is no longer a NS Power project, rather, it is a Wasoqonatl Transmission Line (WTI) project.

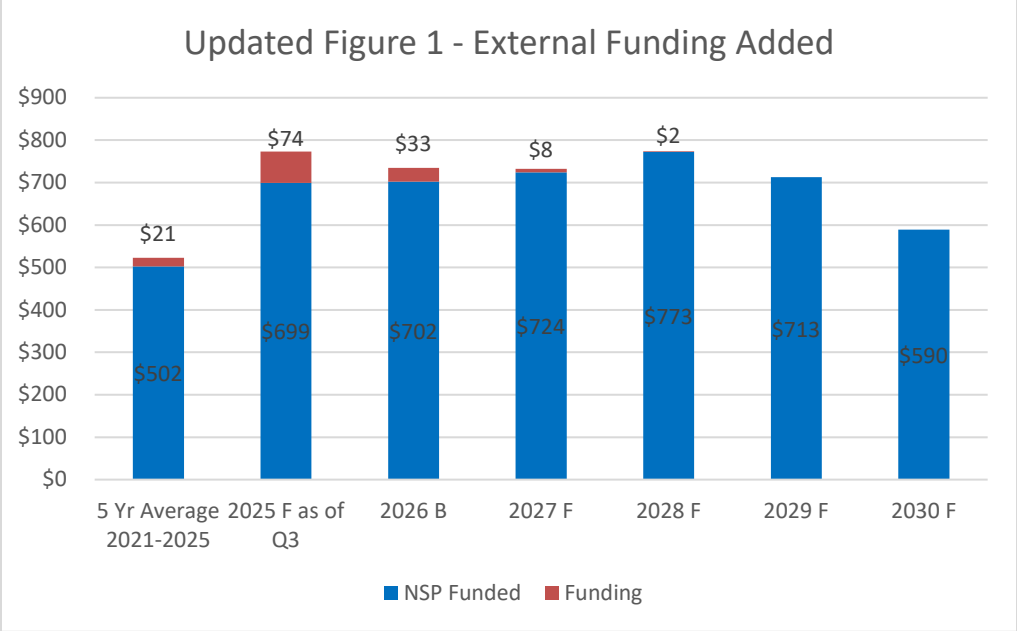
(b) The forecast beyond 2028 begins to decrease as transformative projects are completed; for example, the Synchronous Condenser project is forecast to be completed in 2029 (and therefore has lower investment compared to 2028). Additionally, forecasted investment in the legacy thermal generating stations is reduced post-2028 as units that no longer operate as they do today may require less capital investment.

(c) The multi-year forecast was developed, similar to all current year forecasts, utilizing a bottom up approach, based on the asset management mechanism. The future forecasts are not entirely developed at the project level, as all of the precise requirements for future forecast years cannot be known at this time. An example of NS Power's approach is on the thermal assets, where the current asset mission (unit utilization and asset end-life) determines an expected level of investment for lower criticality assets that does not break it out into specific projects, while more critical assets (turbines, for example) will have explicit investment intervals defined in the multi-year forecast, therefore a specific project can be included. No constraints are put on this process during the development of the plan to ensure NS Power is solely focusing on a risk based approach to asset investment. Once all of these risks are considered and a forecast is developed, certain constraints such as

thermal unit outage scheduling, are factored in, as a single year can only include a certain number of major outages at NS Power's thermal facilities, which could result in shifting timelines for forecast investment, specifically for higher criticality assets like Turbines which require much longer unit outages to complete work. System reliability and customer affordability are also factors considered, as have been discussed in the Five-Year Reliability Plan.

(d) The capital forecast beyond 2026 is not dependant on potential changes to depreciation rates or rate base inclusion, therefore they are not a consideration when developing the multi-year forecast. This multi-year forecast is developed based on asset risk and the requirements of the generation, transmission and distribution systems. It does factor in the transition to the Nova Scotia Independent Energy System Operator (IESO Nova Scotia) in the sense that it does not include investment (for example, in new generation) that NS Power knows will be procured through the IESO Nova Scotia.

(e) When currently expected federal funding is added to Figure 1, the amounts currently included in Figure 1 remain the same and represent the portion that NS Power will fund. All federal funding received to date, and expected in future years shows as an additive to the forecast capital investment totals and is the orange section of the bar chart below. Updated Figure 1 is below. NS Power has a high degree of certainty on this funding as approval has already been received for all forecasted funding.



(f) The trajectory of Figure 1 would only change in the numbers in the 5-year average, 2025 F as of Q3 and 2026B would increase. The projects brought forward that include federal funding (Energy Storage, ECC - Wind Integration, ECC – Dynamic Line Ratings, and ECC - Intelligent Asset Data Capture & Integration Platform) would simply have higher total project costs. However, as discussed above, all of the funding included in Figure 1 has been approved, therefore no risk of delay or not materializing is present.

Request IR-3:

General Inquiries and Follow-Up pages 7 to 30

In reference to Figure 2 – Total Annual Capital Expenditures by Function, on page 15.

(a) Please describe the reasons for the significant increase in forecast generation spending in 2027 to 2029 compared to compared to the 2026 ACE Plan generation budget.

(b) Please describe the reasons for the significant decrease in forecast transmission spending from 2028 to 2029.

(c) Please describe the reasons for the significant increase in forecast general plant spending from 2027 to 2028.

(d) In which "Function" category are "synchronous condensers" included?

(e) In which "Function" category is "energy storage" included?

(f) Please provide an excel version of Figure 2 providing a breakdown of the spending by ACE Category, Functional Class (Hydro, steam etc.) and Major Location.

Response IR-3:

(a) The increase in generation investment in 2027-2029 compared to 2026 is driven by investment in NS Power's Hydro infrastructure, specifically Hydro Dam infrastructure. A number of Hydro Dam projects were able to be safely deferred in 2026 to allow for continued project planning and engineering to occur which led to a smaller investment in

2026 Hydro investment in 2026 is $35 million, but is forecast to be approximately $77 million, $79 million and $97 million in 2027, 2028 and 2029 respectively.

(b) The decrease in transmission spending from 2028 to 2029 is due to the Synchronous Condenser project being forecasted to complete in 2029, therefore having significantly higher construction charges in 2028 ($91 million) compared to 2029 ($47 million).

(c) The increase in general plant investment from 2027 to 2028 is primarily driven by an increase in the CIS Replacement project in 2028 as well as investment related to NS Power's Customer Care & Billing infrastructure that is forecast to begin in 2028.

(d) Synchronous condensers are included in the Transmission function.

(e) Energy storage is included in the Transmission function for the purposes of capital tracking. However, from a Cost of Service perspective, these assets have been proposed to be re-functionalized to Generation.

(f) Please refer to Attachment 1 for a breakdown of the spending by Functional Class and Major Location. Please note that ACE Category in Figure 2 means the same as Functional Class.

2026 ACE Plan NSEB IR-3 Attachment 1 has been filed electronically.

Request IR-4:

General Inquiries and Follow-Up pages 7 to 30

Figure 2: Total Annual Capital Expenditures by Function on page 15 budget for 2026 is lower for Generation and Transmission but higher for Distribution and General Plant in comparison to Figure 2 Total Annual Capital Expenditures by Function for 2026 from the 2025 ACE Plan in matter M12012. Please briefly discuss the changes in the 2026 budget for Generation and Transmission and please detail if there were changes to specific projects driving these reductions.

Response IR-4:

The decrease in 2026 investment in those two functions from the 2025 ACE Plan to the 2026 ACE Plan are as follows:

- Generation – The reduction from $258 million to $178 million is driven by a reduction in Hydro investment of $61 million as a result of multiple dam safety projects and Wreck Cove tunnel work being safely deferred to future years, and a reduction in Steam investment of $20 million primarily due to significant boiler work planned for Tufts Cove that has been deferred to 2027-2028.

- Transmission – The reduction from $468 million to $241 million is driven by the removal of the NS – NB Reliability Tie project that is no longer being completed by NS Power.

Request IR-5:

General Inquiries and Follow-Up pages 7 to 30

Figures 3 and 4 Breakdown of Capital Forecast by Investment Type on pages 16 and 17.

(a) The 2025 ACE Plan application included capital spending in 2026 to 2029 for the NS-NB reliability tie. Please explain why this spending is no longer shown in Figures 3 and 4 in the 2026 ACE Plan.

(i) What are the forecast capital spending amounts for the reliability tie project in each year from 2026 to 2030?

(b) With regards to the estimated Sustaining Capital spending for 2026 to 2030, please identify how much of each year's spending is estimated to be spent on NS Power's existing coal fired generation fleet.

(c) With regards to the estimated Generation Reliability Capital spending for 2026 to 2030, please identify how much of each year's spending is estimated to be spent on NS Power's existing coal fired generation fleet.

(d) Please explain why the forecast capital spending for regulatory/compliance from 2026 to 2029 has decreased by roughly 50% to 58% compared to forecasts in the 2025 ACE Plan.

Response IR-5:

(a) Investment in the NS-NB Reliability Tie is not included in the 2026 ACE Plan as this project is not a NS Power project, and is being completed by Wasoqonatl Transmission Incorporated (WTI).

(i) The spend profile for 2026 to 2029 for this project is as follows (please note, there is no investment forecast for 2030):

- 2026 - $177.9M
- 2027 - $221.1M
- 2028 - $218.9M
- 2029 - $7.2M

(b) The sustaining capital spending on the existing coal fired generation fleet is listed in the table below. This includes investment (2028 and 2029 only) that is required to allow for Lingan 1, 3, and 4 to operate fully on heavy fuel oil and for Pt. Tupper to operate on natural gas. These costs are still considered sustaining as they are required to allow the unit to continue operation.

Year	**Sustaining Capital ($M)**
2026	67.8
2027	62.0
2028	71.2
2029	25.4
2030	15.6

(c) The amount included under Generation Reliability related to the existing coal fired generating facilities is as follows:

Year	**Generation Reliability ($M)**
2026	69.9

2027	64.2
2028	73.5
2029	28.0
2030	16.7

(d) The Regulatory / Compliance forecast listed in the 2026 ACE Plan is reduced as it does not include a number of future significant Hydro dam projects that moved to the Sustaining Capital category, as while these investments do meet both definitions, they are based on condition data and intended to sustain the current asset in a safe and reliable manner.

Request IR-6:

General Inquiries and Follow-Up pages 7 to 30

Figure 4: Breakdown of Capital Forecast by Investment Type on page 17 presents the budget estimates for investment in the Eastern Clean Energy Initiative (ECEI) – Synchronous Condenser for 2026 to 2029. The values presented in the application are lower for 2026, 2028 and 2029, albeit higher for 2027 compared to the budget estimates presented in the 2025 ACE Plan in M12012.

(a) In its 2025 ACE Plan application, NS Power had estimated capital spending of $243.8M in 2025 to 2027 for ECEI – Synchronous Condenser. Figures 3 and 4 of the 2026 ACE Plan application show total forecast capital spending of $338M from 2026 to 2029. Please explain why forecast spending on the ECEI – Synchronous Condenser has been extended from 2027 to 2029.

(i) Please explain why the estimated capital spending on the ECEI – Synchronous Condenser has increased compared to the projections shown in the 2025 ACE Plan.

(b) How much was spent on the ECEI – Synchronous Condenser in 2025?

(c) What is the current estimated total cost for the ECEI Synchronous Condenser project?

(d) Recognizing that the estimates presented in the 2026 ACE Plan application are more current/accurate, please explain the budget changes forecasted for the ECEI Synchronous Condenser.

Response IR-6:

(a) Forecast spending has been extended out to 2029 as the project scope now includes installing synchronous condensers for future wind farms included within the Green Choice Program.

(i) The budget forecast cost for the Synchronous Condenser project provided in the 2025 ACE Plan was developed for the four synchronous condensers required to serve the four Rate Base Procurement wind projects. The budget forecast cost for the Project provided in the 2026 ACE Plan includes four additional synchronous condensers to serve both the two wind projects in the Green Choice Program with executed Power Purchase Agreements and the Port Hawkesbury Paper (PHP) Goose Harbour Lake wind projects. Wind farms with a larger capacity output may require two units.

(b) In 2025, $635,211 was spent on the ECEI – Synchronous Condenser project. Costs incurred were related to preliminary engineering activities such as developing the technical specification for the project's request for proposals.

(c) The current estimated total cost for the ECEI Synchronous Condenser project is $365 million, as noted in Section 5.3 of the 2026 ACE Plan (PDF page 35).

(d) Please refer to part (a).

Request IR-7:

General Inquiries and Follow-Up pages 7 to 30

(a) Please identify, within the 2026 ACE spending forecast, all projects related to Information Technology (IT). For each IT project, please specify whether the project represents a natural lifecycle replacement or upgrade, or whether it was initiated in response to the cybersecurity incident.

(b) For cybersecurity related projects, please further clarify whether the scope involves the replacement of existing infrastructure or the addition of new assets intended to enhance system resiliency and robustness.

Response IR-7:

(a) Please refer to Attachment 1. In addition to lifecycle replacement or upgrades, projects can be driven by the need to implement new capabilities and would not fall under those two options. The attachment classifies projects that do not fit those two options as New Implementation. There are no projects in the 2026 ACE Plan that were initiated in response to the cybersecurity incident.

(b) The projects listed below require the addition of new assets to enhance system resilience and robustness:

- IT - OT Cyber Security Control Implementation Phase 1
- IT - Enterprise GRC
- IT - Identity & Access Management

The project listed below involves the replacement of assets:

- IT - Managed Detect & Respond

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

CI#	Project #	Project Long Title	Invesment Trigger
29114-P03	P031	IT - NSPI Infrastructure Routine	Lifecycle / Upgrade
C0021835		IT - CIS Replacement	Lifecycle / Upgrade
C0022002		IT - Storm Centre Upgrade	Lifecycle / Upgrade
C0030991	P031	IT- PC Refresh	Lifecycle / Upgrade
C0042163	P031	IT - iPhone/iPad Refresh	Lifecycle / Upgrade
C0047214		IT - CIS HW Replacement/OS Upgrade	Lifecycle / Upgrade
C0047277		IT - GIS Utility Network Migration	Lifecycle / Upgrade
C0047278		IT - Oracle MDM Upgrade	Lifecycle / Upgrade
C0047296		IT - Microsoft SQL Consolidation	Lifecycle / Upgrade
C0047301		IT - Cloud Integration Platform	Lifecycle / Upgrade
C0049614		IT - Network Video Recorders	Lifecycle / Upgrade
C0054755		IT - Connect My Data (Green Button)	New Implementation
C0056461		IT - Contact Centre Cloud Migration	Lifecycle / Upgrade
C0061284		IT - OT Cyber Security Control Implementation Phase 1	New Implementation
C0061285		IT - Enterprise GRC	New Implementation
C0061347		IT - Wireless Video Solution	New Implementation
C0061443		IT - WAM Maintenance Release Routine	Lifecycle / Upgrade
C0062043		IT - SharePoint Technical Migration	Lifecycle / Upgrade
C0062624		IT - Mobile Field Connectivity Enhancements	New Implementation
C0067703		IT - Prov Community Solar	New Implementation
C0067863		IT - Managed Detect & Respond	Lifecycle / Upgrade
C0068714		IT - Identity & Access Management	New Implementation
C0068718		IT - DERMS Solution Project	New Implementation
C0068719		IT - Distributed Intelligence Apps	New Implementation
C0068721		IT - ADMS Upgrade 2026	Lifecycle / Upgrade
C0068724		IT - Safety IRD Replacement	Lifecycle / Upgrade
C0068726		IT - BlueCross Integration with PeopleSoft	New Implementation
C0072648		IT - Customer Enrollment Automation	New Implementation
C0073777		IT - Complex Customer Projects	New Implementation
C0080618		IT - Lifecycle: DR Hardware Refresh	Lifecycle / Upgrade
C0080619		IT - Lifecycle: Network Devices 2026	Lifecycle / Upgrade
C0080620		IT - Responsible AI foundations	New Implementation
C0082129		IT - Customer Self-Serve Enhancements	Lifecycle / Upgrade
C0082131		IT - Customer Billing Enhancements	Lifecycle / Upgrade
C0082133		IT - Renew Microsoft Enterprise Agreement	Lifecycle / Upgrade
C0082134		IT - Test Automation Tool Implementation	New Implementation
C0082135		IT - Virtual Wiring Inspection Portal	New Implementation
C0082197		IT - Phone Recording for Compliance	Lifecycle / Upgrade
C0082198		IT - Plant Phone System Upgrade	Lifecycle / Upgrade
C0082274		Storm Management Software Implementation	New Implementation
16073	P010	SCADA Improvements Routine	Lifecycle / Upgrade
C0068346		Oracle to DL Interface	New Implementation

Request IR-8:

General Inquiries and Follow-Up pages 7 to 30

Section 4.2 2025 ACE Plan Capital Items Deferred/Cancelled, please identify those projects that were deferred or cancelled with a criticality rating of 16 or higher.

(a) For those projects with a criticality rate of 16 or higher, how many were cancelled?

(i) What does NS Power intend to do with these projects?

(b) For those projects with a criticality rate of 16 or higher and with a budget greater than $1M, how many projects were deferred.

(i) Briefly describe the mitigation measures NS Power has taken to sustain each asset.

Response IR-8:

Please refer to Attachment 1 for identification of projects deferred or cancelled with a risk rating of 16 or higher.

(a) Nine projects with a risk rating of 16 or higher were cancelled.

(i) There are currently no plans to proceed with these projects. The projects were cancelled due to work being captured in another project, the risk no longer requiring mitigation, or the risk being mitigated through a method that did not require capital investment.

(b) Twelve projects with a budget greater than $1 million and a risk rating of 16 or higher were deferred.

(ii) Not all projects that are deferred require mitigating measures to sustain the asset. All 12 of the projects that were greater than $1 million and had a risk rating of greater than 16 were listed as subsequent submittals, as not enough was known about the project to develop a fulsome application.

- Five projects were IT projects that could not be filed due to resource constraints driven from the cyber incident.

(iii) One project was a multi-year grid modernization initiative that required additional work to fully define the project scope. This is to install net new grid modernization tools; therefore, no mitigating measures were required.

- Two projects are new multi-year substation addition projects that required more time to develop the filing, which is not expected to negatively impact the actual construction timeline.

- One project is the Synchronous Condenser project originally planned for a late 2025 filing, now expected for Q2 2026. No change in completion date is expected due to this delay.

- One project is the Sydney T&D Depot project, where temporary arrangements have been made to allow the Energy Delivery team to utilize the space and defer this capital investment.

- One project is the ANN Facility Isolation project. This was deferred as the scope was not clearly defined enough to file an application. The current mitigation in place for this unit is sufficient until this project is complete.

- One project is for a transformer replacement project that needed additional engineering to finalize scope; continued condition monitoring of this transformer is considered sufficient until this project is completed in 2026.

As with all aspects of a project on the subsequent submittal list, the risk rating may not be as complete and precise as a risk rating for a project submitted for approval. A project can be included on the subsequent submittal list knowing that further condition assessment is required prior to filing; therefore, that updated condition assessment can lead to the determination that the risk does not require immediate mitigation.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

CI	Project Title	2025 ACE Amount	2025 ACE Project Total	Cancelled / Deferred	Deferred To	2025 ACE Plan Reference	Commentary	Rating
C0061366	TRE6 - Caustic Heater Heat Exchanger	84,017	91,767	Cancelled		Less than $1M	This project has been cancelled. Leak test on existing heat exchange bundle and gasket replacements mitigated risk and need for project.	16
C0068660	TRE5 - Boiler Refurbishment 2025	825,182	896,932	Cancelled		Less than $1M	This project has been cancelled as the scope of work will not be completed under C0073965 TRE5 U&U Burner Nest Waterwall Tube Replacement	16
C0068894	TUC1 Gas Block Valve Upgrades	607,737	607,737	Cancelled		Less than $1M	This project has been cancelled, as the risk can be managed through 2026 and will also be completed as part of a major boiler upgrade on TUC1 which will begin in 2027.	16
C0069567	TUC1 - Boiler Cyclone Tube Replacements	859,647	859,647	Cancelled		Less than $1M	This project has been cancelled, as the risk can be managed through 2026 and will also be completed as part of a major boiler upgrade on TUC1 which will begin in 2027.	16
40023	TRE - Sewage Lift Station Upgrades	158,493	158,493	Cancelled		Less than $1M	This project has been cancelled, as updated condition assessment revealed the risk does not need immediate mitigation.	16
C0068624	TRE - Overhead / Person Door Refurbishments	92,756	100,556	Cancelled		Less than $1M	This project is cancelled as the necessary scope to mitigate these risks will be completed through CI C0061356 TRE Overhead/Person Door Refurbishments.	16
C0060610	TUC Cable Spreading Room Fire Protection	250,108	250,108	Cancelled		Less than $1M	This project has been cancelled. Project scope will be completed as part of CI C0069829 TUC - Relay Room Fire Suppression System.	16
C0061340	LIN12 Diesel Generator Room Refurbishment	336,843	365,589	Cancelled		Less than $1M	This project has been cancelled, as updated condition assessment revealed the risk does not need immediate mitigation.	20
C0071652	IT - ZTN Security and Restrictive Network Controls	725,124	869,124	Cancelled		Less than $1M	Scope of this project included in C0061289 - IT - Network Next Generation Security Design.	20
C0020331	TRE5 Air Heater Expansion Joint Replacement	354,575	385,222	Deferred	2026	Less than $1M	Through further scoping it was determined the risk could be mitigated in 2025 with additional monitoring and detection.	16
C0069047	TUC2 FD Fan Duct Refurbishment	99,940	99,940	Deferred	2027	Less than $1M	Further scoping showed that engineering was required to determine the final project requirements and that the risks could be managed through to 2027.	25
C0068236	LIN4 North Water Wall Replacement 2025	446,612	526,275	Deferred	2026	Less than $1M	This project is being deferred to the 2026 outage. The existing approach to management of this asset is expected to address near-term risks.	16
C0068691	TRE6 - Boiler Main Stop Valve	148,839	162,539	Deferred	2026	Less than $1M	Deferred due to U&U capital work utilizing available resources. The existing approach to management of this asset is expected to address near-term risks.	16
C0068692	TRE6 - 6A BFP Discharge Valve Refurbishment	149,279	159,779	Deferred	2026	Less than $1M	Deferred due to U&U capital work utilizing available resources. The existing approach to management of this asset is expected to address near-term risks.	16
C0070850	TRE Shaker House Hoist Replacement	83,854	91,354	Deferred	2026	Less than $1M	Deferred to better define project scope. The exisiting approach to management of this asset is expected to address near-term risks.	16
C0057361	HYD - ANN Facility Isolation	210,689	2,899,094	Deferred	2026	Subsequent Submittal	Deferred to better define project scope. The exisiting approach to management of this asset is expected to address near-term risks.	20
C0051932	HYD - Avon 2 Penstock Recoating	152,346	688,897	Deferred	2027	Less than $1M	Deferred due to reprioritization. The existing approach to management of this asset is expected to address near-term risks.	16
C0068687	TRE6 "A" and "B" CW Screens Refurb	177,892	192,892	Deferred	2026	Less than $1M	Deferred due to U&U capital work utilizing available resources. The existing approach to management of this asset is expected to address near-term risks.	16
C0059533	WIN - DIG Gearbox Replacement WTG19	716,489	761,741	Deferred	2026	Less than $1M	Deferred due to reprioritization. The existing approach to asset management of this asset is expected to address near-term risks.	16
C0059602	WIN - DIG Gearbox Replacement WTG10	714,917	782,510	Deferred	2026	Less than $1M	Deferred due to reprioritization. The existing approach to asset management of this asset is expected to address near-term risks.	16
C0041822	WRC Spare Cable Replacement & Storage System	50,000	189,342	Deferred	2027	Less than $1M	Additional engineering is required before project can progress to construction.	25
C0011358	New Bridgewater Substation	1,385,538	18,173,047	Deferred	2027	Subsequent Submittal	Additional engineering is required before project can progress to construction.	20
C0032382	Susie Lake Substation Addition	5,149,415	13,954,518	Deferred	2026	Subsequent Submittal	Additional engineering is required before project can progress to construction.	20
C0053214	76W-T1 Transformer Replacement	1,938,848	2,279,295	Deferred	2026	Subsequent Submittal	Project now forecasted for 2026 ACE request approval. Project had been deferred as additional engineering was required before project could progress to construction.	20
C0072808	Synchronous Condensers (ECEI)	27,197,774	243,807,241	Deferred	2026	Subsequent Submittal	Project now forecasted for filing in 2026, as preliminary engineering and planning work continues throughout 2025 and is required prior to submission.	25
C0071410	25W-301 Welshtown Phase Addition	322,774	594,945	Deferred	2026	Less than $1M	Deferred due to reprioritization of projects in the West. The existing approach to asset management of this asset is expected to address near-term risks.	20
C0032202	Sydney T&D Depot Consolidation	1,578,174	1,879,855	Deferred	2026	Subsequent Submittal	Deferred to better define project scope.	20
C0021835	IT - CIS Replacement	2,243,592	77,890,771	Deferred	2026	Subsequent Submittal	This project is delayed due to the cyber event. Resources were required for priority restoration.	25
C0047278	IT - Oracle MDM Upgrade	912,789	3,010,689	Deferred	2026	Subsequent Submittal	This project is delayed due to the cyber event. Resources were required for priority restoration.	20
C0061285	IT - Enterprise Governance, Risk, and Compliance	664,056	1,179,857	Deferred	2026	Subsequent Submittal	This project is delayed due to the cyber event. Resources were required for priority restoration.	20
C0061347	IT - Wireless Video Solution	56,424	72,924	Deferred	2026	Less than $1M	This project is delayed due to the cyber event. Resources were required for priority restoration.	25
C0068719	IT - Distributed Intelligence Apps	2,086,440	4,353,461	Deferred	2026	Subsequent Submittal	This project is delayed due to the cyber event. Resources were required for priority restoration.	25
C0068718	IT - DERMS Solution Project	1,950,047	2,993,200	Deferred	2026	Subsequent Submittal	Deferred to better define project scope through the Distributed Energy Resource Integration Roadmap.	25
C0067863	IT - Managed Detect & Respond	668,280	1,126,413	Deferred	2026	Subsequent Submittal	This project is delayed due to the cyber event. Resources were required for priority restoration.	20

Request IR-9:

General Inquiries and Follow-Up pages 7 to 30

In reference to Figure 7 - Subsequent Submittal Project Status Update, pages 28-29. The Susie Lake Substation Addition project was included in the 2023 ACE Plan as a subsequent submittal item with a total estimated cost of $6.2M. The project was then shown as a 2024 ACE Plan subsequent submittal item. Figure 8 in the 2025 ACE Plan showed the project with an updated 2024 total estimated cost of $5,701,709, while Figure 11 showed an updated 2025 total estimated cost of $13,954,518. Figure 10 in the 2026 ACE Plan now shows and total estimated cost for the project of $8,256,386.

(a) Appendix C of the 2026 ACE Plan application notes that the project has been deferred to complete additional engineering before proceeding. Please explain why it has taken an additional year to complete additional engineering.

(b) Please describe the reasons for the significant decrease in the total estimated project cost between the 2025 and 2026 ACE Plans.

Response IR-9:

(a-b) The delay is the result of the land procurement process. The engineering and project management teams cannot finalize designs and estimates until the exact location of the substation is determined. Total costs for the project could fluctuate significantly based on the site conditions and land purchase costs and estimates provided in ACE Plan filings are expected to continue to fluctuate based on specific sites being considered.

Request IR-10:

General Inquiries and Follow-Up pages 7 to 30

In reference to Figure 10 – 2026 Capital Items Forecast for Subsequent Submittal, pages 34-38.

(a) To what AACE Class level have the cost estimates been developed for the 2026 Capital Items Forecast for Subsequent Submittal?

(i) What level of contingency has been included in these estimates and how was the level of contingency determined?

(ii) What is the expected accuracy of these cost estimates?

(b) With regards to the total project cost estimate for the C0064966 HYD – Tusket Powerhouse Tidal Pool Fish Passage project: How does the current estimate of $1,315495 compare to the estimate used in the Economic Analysis Model (EAM) for the Tusket Main Dam Refurbishment Authorization to Overspend (ATO) application, Matter M10197, comparing dam refurbishment to partial and full decommissioning?

(c) With regards to C0081985 – Michelin DVR Phase 2 project: In NS Power's application under Matter M11656 Michelin Waterville DVR, was there any mention of Phase 2 for the project?

(i) If not, why not?

(ii) What is the purpose of Phase 2 of the project?

Response IR-10:

(a) The estimates for the 2026 ACE Plan subsequent submittal items are directional in nature, are developed with the information available at time of the 2026 ACE Plan submission and are not developed to a specific class estimate. These projects estimates are generally AACE Class level 4 or 5; however, there is no minimum threshold for capital items to be included in the 2026 ACE Plan Subsequent Submittal list. The purpose of this list is to provide the Board and stakeholders with the best information that NS Power has at the time of filing on what investment is expected to occur in 2026. NS Power feels it beneficial to include a project with an estimate that has a likelihood of experiencing significant change than to not include that project at all.

(i) Contingency amounts are often not included as a separate line item in these estimates as that level of project development has yet to be completed. In cases where contingency is included, it would use the same methodology that submitted projects use and fall within the contingency guidelines based on the AACE Class of estimate present.

(ii) Generally, these estimates align with levels of accuracy for AACE Class 4 or 5 estimates (L: -20 percent to -50 percent H: +30 percent to +100 percent for Class 5, L:-15 percent to -30 percent H: +20 percent to +50 percent for Class 4),;however, as outlined above, in some instances could be included at an earlier stage of project development, and the range could exceed these percentages.

(b) NS Power did not include the Tusket Tidal Pool Fish Passage Project in the Tusket Main Dam EAM completed in July 2021 and submitted under Matter M10197, as the need for the project had not yet been established. The work at the tidal pool is unrelated to the future of the Tusket Hydro System and is required under all future scenarios. This capital work order is anticipated to be filed in Q1 2026 providing further details on project scope.

(c) No.

(i) Phase 2 was not identified as a requirement as part of the initial application; however, since then, the load consumed by the Michelin Waterville plant has grown to require an additional block of 5MW of protection.

(ii) Phase 2 of the Project is to add an additional 5MW of protected capacity to the existing 15MW currently installed at the plant.

Request IR-11:

Section 5.0 2026 Annual Capital Expenditure Plan pages 31 to 39
Less than $1M

Figure 12: Historical Number of Projects Less Than $1M indicates that there are 330 steam projects in 2026. Please identify the number of projects for each individual steam generation facility.

(a) In reference to Appendix B, tab Less than $1M investments for Trenton 5, please explain the difference between TRE5- Boiler Refurbishment 2026 and TRE5 Boiler South WW Panel at Lower Header and why they are separate projects.

(b) In reference to Appendix B, tab Less than $1M investments for Trenton 5, please explain the difference between 3 Mill Refurbishment, 1 Mill Refurbishment and Mill Platform and why they are separate projects.

(c) In reference to Appendix B, tab Less than $1M, investments for TUC3, please explain the difference between North Boiler Feed Pump Refurbishment, Boiler Safety Valves Replacement, Boiler Refurbishment 2026 and Steam Drum Refurbishment, and why they are separate projects.

(d) Please confirm or explain otherwise that there are no projects specifically for Lingan 2 that are less than $1M.

(e) In reference to Appendix B, tab Less than $1M, there are several capital projects for LIN1, LIN3 and LIN4 on the boiler, such as the Boiler Refurbishments 2026, Burner Front Refurbishments 2026, Boil Tube Replacements 2026, Boiler Erosion Reduction System 2026 and Valve Refurbishments. For each unit, please explain why these are separate capital investments rather than one all encompassing capital project.

Response IR-11:

NS Power breaks projects out by asset. When multiple significant assets have investment on them, and the efforts are not done as one effort, they should be separated into separate capital projects. This allows for improved asset tracking when looking at historical investment and also for better cost tracking ensuring that all appropriate costs are allocated to the proper asset. While projects in question here are all boiler related, breaking out projects within a broader asset class has been consistent over the years. Turbine projects are consistently separated into Turbine Blades and turbine valves, as an example.

Additionally, Boiler Refurbishment projects are to address risks found during the inspection of tubes and minor components that occurs during the outage when the project is being completed. These projects are estimated based on unit utilization and subject matter expert related to that boiler's past performance. If the boiler inspection in a given year determines that a significant component (waterwall, burner front, burner nest, etc) requires mitigation, then that project is treated as a separate capital investment due to the reasons stated above, and typically occurs in the subsequent year.

The differences between the projects / assets in question is as follows:

(a) The TRE5 – Boiler Refurbishment 2026 is for the inspection and refurbishment of defects and worn components as found from inspection. The TRE5 Boiler South Waterwall (WW) Panel at Lower Header is a project specifically for the replacement of the waterwall panel at the lower south waterwall header, as determined through previous inspection. Historically, NS Power has separated specific work like water wall panels as they are asset replacements outside the scope of the boiler refurbishment project.

(b) There are four solid fuel mills supplying the TRE5 boiler. The mills are labelled 1 to 4. The projects are for refurbishment of the 1 Mill and 3 Mill. The Mill Platform is for the installation of a platform to allow safe cleaning and adjusting the mills. Historically, NS

Power has treated each mill refurbishment as a separate initiative as they are distinct standalone assets and generally are completed at different times to preserve mill availability.

(c) As detailed above, these are all considered distinct assets within the broader boiler asset class. The North Boiler Feed Pump delivers high pressure water into the boiler and is not part of the boiler proper. The Boiler Safety Valves Replacement project is for replacement of the boiler pressure relief safety valves. The Boiler Refurbishment 2026 project is for the full boiler inspection and the refurbishment of worn boiler tubing and minor components found through the internal inspection of the boiler. The Steam Drum separates steam from water and is not part of the boiler proper. The Steam Drum Refurbishment project is specifically for the removal and inspection of all internal steam drum components, and refurbishment as required from inspection findings.

(d) Confirmed, per the NSEB's direction as part of the 2025 ACE Plan process, where Lingan 2 projects were separated by distinct asset, all investment related to Lingan 2 is combined into one project (C0082195 LIN2 2025/26 Capacity Requirement).

(e) The Boiler Refurbishment 2026 project is for the inspection of the boiler, and the refurbishment of worn boiler tubes and minor components found through the internal inspection of the boiler. The Burner Front is the outer wall of the boiler containing the fuel/air delivery and ignition system. The Burner Front Replacement projects are for the replacement of the worn burner fronts components which direct the pulverized fuel into the boiler, impacting boiler combustion and performance.

The Boiler Erosion Reduction System refurbishment is for the refurbishment of the ash velocity screens that reduce the ash velocity in the back section of the boiler preventing excessive ash erosion on the boiler tubes and premature failures.

The Valve Refurbishment projects are for refurbishment and/or replacement of valves on the various assets of the unit, and can include valves in the feed water system, cooling water, turbine, as well as the boiler.

Where these assets are all distinct, treating them as separate capital projects, as mentioned above, allows for better historical investment tracking, cleaner cost tracking to ensure that the appropriate costs are going to the appropriate projects, and greater visibility, both internally and externally on what assets are being invested in.

Request IR-12:

Section 5.0 2026 Annual Capital Expenditure Plan pages 31 to 39
Less than $1M

Please identify all projects with estimated total project costs of less than $1M in the 2026 ACE plan that relate to steam or other thermal generation assets.

(a) For each project identified, please confirm whether the associated asset is expected to be retired, decommissioned, or subject to material underutilization by 2030.

Response IR-12:

(a) Please refer to Attachment 1 for all less than $1M projects that relate to steam or other thermal generation assets for their status by 2030: Retired, Conversion/Utilization, or No Change.

Category	Unit	CI#	Functional Class	Project Long Title	Major Location	Project Total
Conversion/Utilization	LIN3	C0080638	Steam	LIN 34 GSCW Small Bore Piping Replacement 2026	Lingan Generating Station	212,436
Conversion/Utilization	LIN4	C0080639	Steam	LIN 4160 600V Breaker Refurbishment 2026	Lingan Generating Station	150,268
Conversion/Utilization	LIN4	C0082194	Steam	LIN 4160/600V Motor Refurbishment 2026	Lingan Generating Station	150,000
Conversion/Utilization	LINCP	C0040686	Steam	LIN 8th Stage Blade Replacement 2026	Lingan Generating Station	698,516
Conversion/Utilization	LINCP	C0081825	Steam	LIN Acid/Caustic Strength Meter Installation 2026	Lingan Generating Station	90,000
No Change	LINCP	C0080640	Steam	LIN Ash Site Winter Cover 2026	Lingan Generating Station	177,451
Conversion/Utilization	LINCP	C0080641	Steam	LIN BFP Cartridge Critical Spare	Lingan Generating Station	831,653
Conversion/Utilization	LINCP	C0080642	Steam	LIN BFP Refurbishment 2026	Lingan Generating Station	546,580
Conversion/Utilization	LINCP	C0080643	Steam	LIN Cinder Block Support Refurbishment	Lingan Generating Station	100,000
Retire by 2030	LINCP	C0080644	Steam	LIN Coal Crusher Refurbishment 2026	Lingan Generating Station	245,899
Retire by 2030	LINCP	C0080645	Steam	LIN Coal Plant Structural Refurbishment 2026	Lingan Generating Station	217,175
Retire by 2030	LINCP	C0082190	Steam	LIN D1 Conveyor Belt Replacement 2026	Lingan Generating Station	200,000
Conversion/Utilization	LINCP	C0080646	Steam	LIN Electric Actuator Refurbishment	Lingan Generating Station	168,903
Conversion/Utilization	LINCP	C0068165	Steam	LIN Electric Motor Refurbishment 2026	Lingan Generating Station	155,475
Conversion/Utilization	LINCP	C0080647	Steam	LIN Emergency Flyte Pump Replacement	Lingan Generating Station	182,728
Conversion/Utilization	LINCP	C0080648	Steam	LIN Facilities Upgrade 2026	Lingan Generating Station	152,908
Conversion/Utilization	LINCP	C0080649	Steam	LIN Flame Scanner Replacement 2026	Lingan Generating Station	130,430
Conversion/Utilization	LINCP	C0082191	Steam	LIN Fly Ash Baghouse Replacement 2026	Lingan Generating Station	300,000
Conversion/Utilization	LINCP	C0080650	Steam	LIN Fly Ash System Refurbishment	Lingan Generating Station	366,260
Conversion/Utilization	LINCP	C0080651	Steam	LIN Fly Ash Valve Replacement	Lingan Generating Station	150,618
Conversion/Utilization	LINCP	C0080652	Steam	LIN Grating Refurbishment 2026	Lingan Generating Station	161,183
Conversion/Utilization	LINCP	C0082189	Steam	LIN GSCW Pump Replacement 2026	Lingan Generating Station	184,500
Conversion/Utilization	LINCP	C0080653	Steam	LIN Guarding and Railing Upgrade 2026	Lingan Generating Station	126,315
Retire by 2030	LINCP	C0080654	Steam	LIN Mill Refurbishments 2026	Lingan Generating Station	913,231
Conversion/Utilization	LINCP	C0080656	Steam	LIN Plant Lighting Upgrade	Lingan Generating Station	247,805
Conversion/Utilization	LINCP	C0080657	Steam	LIN Precipitator Refurbishment 2026	Lingan Generating Station	257,967
Conversion/Utilization	LINCP	C0080658	Steam	LIN Roof Drain Replacement 2026	Lingan Generating Station	403,513
Conversion/Utilization	LINCP	C0080659	Steam	LIN Security Fencing Refurbishment 2026	Lingan Generating Station	96,949
Conversion/Utilization	LINCP	C0080660	Steam	LIN Siding Refurbishment 2026	Lingan Generating Station	239,002
Conversion/Utilization	LINCP	C0080661	Steam	LIN Sootblower Refurbishment 2026	Lingan Generating Station	334,471
Conversion/Utilization	LINCP	C0068195	Steam	LIN Substation Transformer Cable Refurbishment	Lingan Generating Station	175,736
Conversion/Utilization	LINCP	C0080662	Steam	LIN Turbine Lube Oil Dehydrator Replacement	Lingan Generating Station	294,834
Conversion/Utilization	LINCP	C0080663	Steam	LIN Wastewater Piping Replacement 2026	Lingan Generating Station	245,169
Conversion/Utilization	LINCP	C0080664	Steam	LIN WTP Polisher Caustic Skid Replacement	Lingan Generating Station	447,743
Conversion/Utilization	LIN1	C0080666	Steam	LIN1 Aux Air Upgrades 2026	Lingan Generating Station	595,474
Conversion/Utilization	LIN1	C0080667	Steam	LIN1 Boiler Erosion Reduction System 2026	Lingan Generating Station	376,134
Conversion/Utilization	LIN1	C0080668	Steam	LIN1 Boiler Refurbishment 2026	Lingan Generating Station	803,535
Conversion/Utilization	LIN1	C0080669	Steam	LIN1 Crossover Bellows Replacement 2026	Lingan Generating Station	352,858
Conversion/Utilization	LIN1	C0080670	Steam	LIN1 GSCW Small Bore Piping Replacement 2026	Lingan Generating Station	161,854
Conversion/Utilization	LIN1	C0080672	Steam	LIN1 Miscellaneous Valve Refurbishment 2026	Lingan Generating Station	221,797
Conversion/Utilization	LIN1	C0080673	Steam	LIN1 RH1 Boiler Tube Replacement 2026	Lingan Generating Station	411,001
Conversion/Utilization	LIN1	C0038806	Steam	LIN1 Snout Ring Refurbishment 2026	Lingan Generating Station	350,400
Conversion/Utilization	LIN1	C0080674	Steam	LIN1 Turbine Supervisory	Lingan Generating Station	201,059
Conversion/Utilization	LIN3	C0082186	Steam	LIN3 A Hydrolox CW Screen Replacement 2026	Lingan Generating Station	650,000
Conversion/Utilization	LIN3	C0068228	Steam	LIN3 Air Preheater Seal Refurbishment 2026	Lingan Generating Station	182,648
Conversion/Utilization	LIN3	C0080686	Steam	LIN3 Aux Air Upgrades 2026	Lingan Generating Station	380,720
Conversion/Utilization	LIN3	C0082188	Steam	LIN3 B Hydrolox CW Screen Replacement 2026	Lingan Generating Station	650,000
Conversion/Utilization	LIN3	C0080687	Steam	LIN3 Boiler Erosion Reduction	Lingan Generating Station	376,134
Conversion/Utilization	LIN3	C0080688	Steam	LIN3 Boiler Refurbishment 2026	Lingan Generating Station	803,535
Conversion/Utilization	LIN3	C0080689	Steam	LIN3 Burner Front Refurbishment 2026	Lingan Generating Station	460,080
Conversion/Utilization	LIN3	C0080690	Steam	LIN3 DC SealLube Oil Motor Cable Wrap	Lingan Generating Station	95,525
Conversion/Utilization	LIN3	C0068451	Steam	LIN3 Diesel Generator Fire Protection	Lingan Generating Station	93,273
Conversion/Utilization	LIN3	C0080692	Steam	LIN3 Fly Ash Hopper Vibration Replacement 2026	Lingan Generating Station	266,337
Conversion/Utilization	LIN3	C0080693	Steam	LIN3 Miscellaneous Valve Refurbishment 2026	Lingan Generating Station	220,164
Conversion/Utilization	LIN3	C0080694	Steam	LIN3 Oil Gun Replacement 2026	Lingan Generating Station	170,039
Retire by 2030	LIN3	C0080696	Steam	LIN3 SCC Drive Replacement	Lingan Generating Station	242,372
Conversion/Utilization	LIN3	C0080697	Steam	LIN3 South Waterwall Refurbishment 2026	Lingan Generating Station	454,772
Conversion/Utilization	LIN3	C0080698	Steam	LIN3 TG Bearing and Lagging Sprinkler Upgrade	Lingan Generating Station	97,999
Conversion/Utilization	LIN3	C0080699	Steam	LIN3 TG Column Protection 2026	Lingan Generating Station	152,365
Conversion/Utilization	LIN3	C0080700	Steam	LIN3 Turbine Valve Refurbishment 2026	Lingan Generating Station	596,011
Conversion/Utilization	LIN4	C0080701	Steam	LIN4 Air Preheater Seal Refurbishment 2026	Lingan Generating Station	183,109
Conversion/Utilization	LIN4	C0080702	Steam	LIN4 Aux Air Upgrades 2026	Lingan Generating Station	597,033
Conversion/Utilization	LIN4	C0080703	Steam	LIN4 Boiler Erosion Reduction System 2026	Lingan Generating Station	377,002
Conversion/Utilization	LIN4	C0080704	Steam	LIN4 Boiler Refurbishment 2026	Lingan Generating Station	805,340
Conversion/Utilization	LIN4	C0080705	Steam	LIN4 Burner Front Refurbishment 2026	Lingan Generating Station	461,161
Conversion/Utilization	LIN4	C0030122	Steam	LIN4 HIP Insulation Replacement 2026	Lingan Generating Station	152,083
Conversion/Utilization	LIN4	C0080706	Steam	LIN4 Miscellaneous Valve Refurbishment 2026	Lingan Generating Station	220,164
Conversion/Utilization	LIN4	C0068236	Steam	LIN4 North Waterwall Refurbishment 2026	Lingan Generating Station	455,811
Conversion/Utilization	LIN4	C0080707	Steam	LIN4 Oil Gun Replacement 2026	Lingan Generating Station	170,039
Conversion/Utilization	LIN4	C0080709	Steam	LIN4 RH1 Boiler Tube Replacement 2026	Lingan Generating Station	411,937
Conversion/Utilization	LIN4	C0080710	Steam	LIN4 West Waterwall Refurbishment 2026	Lingan Generating Station	694,156
Conversion/Utilization	POT	C0080762	Steam	POT - Asbestos Refurbishment 2026	Point Tupper Generating Station	363,373
Conversion/Utilization	POT	C0080763	Steam	POT - Boiler Refurbishment 2026	Point Tupper Generating Station	829,583
Conversion/Utilization	POT	C0080764	Steam	POT - Breaker Refurbishment 2026	Point Tupper Generating Station	264,529
Retire by 2030	POT	C0080765	Steam	POT - Coal Mill Refurbishment 2026	Point Tupper Generating Station	443,455
Retire by 2030	POT	C0080766	Steam	POT - Conveyor & Fuel Handling Refurbishment 2026	Point Tupper Generating Station	354,166
Conversion/Utilization	POT	C0080767	Steam	POT - Crane Motor & Controls Upgrade 2026	Point Tupper Generating Station	611,439
Conversion/Utilization	POT	C0080769	Steam	POT - CW Pump House Power Cable Replacement	Point Tupper Generating Station	525,753
Conversion/Utilization	POT	C0080770	Steam	POT - East CW Pump Refurbishment 2026	Point Tupper Generating Station	495,955
Conversion/Utilization	POT	C0080771	Steam	POT - Facility Upgrades	Point Tupper Generating Station	164,944
Conversion/Utilization	POT	C0080772	Steam	POT - Fire Protection Upgrades 2026	Point Tupper Generating Station	241,588
Conversion/Utilization	POT	C0080773	Steam	POT - Fuel Delivery Control & Instrumentation Refurbishment 2026	Point Tupper Generating Station	287,039
Conversion/Utilization	POT	C0080774	Steam	POT - Graver Carbon Filter Replacment 2026	Point Tupper Generating Station	325,093
Conversion/Utilization	POT	C0080775	Steam	POT - HFO Piping Insulation Refurbishment 2026	Point Tupper Generating Station	290,267
Conversion/Utilization	POT	C0080776	Steam	POT - HVAC Refurbishment 2026	Point Tupper Generating Station	111,746
Conversion/Utilization	POT	C0080777	Steam	POT - Miscellaneous Valve / Component	Point Tupper Generating Station	317,531
Conversion/Utilization	POT	C0080778	Steam	POT - New Skid Steer	Point Tupper Generating Station	124,339
Conversion/Utilization	POT	C0080779	Steam	POT - Overhead Doors Replacement	Point Tupper Generating Station	164,123
Conversion/Utilization	POT	C0080780	Steam	POT - PCB Lighting Replacement 2026	Point Tupper Generating Station	351,491
Conversion/Utilization	POT	C0080785	Steam	POT - Polisher Caustic Skid Replacement 2026	Point Tupper Generating Station	684,282
Conversion/Utilization	POT	C0080786	Steam	POT - Potable Water Carbon Sand Filter 2026	Point Tupper Generating Station	152,015
Conversion/Utilization	POT	C0080787	Steam	POT - Road Way Refurbishment 2026	Point Tupper Generating Station	348,219
Conversion/Utilization	POT	C0080788	Steam	POT - Seal Oil Cooler Replacement 2026	Point Tupper Generating Station	606,667
Conversion/Utilization	POT	C0080789	Steam	POT - SOFA Duct Attachment Refurbishment 2026	Point Tupper Generating Station	686,036
Conversion/Utilization	POT	C0080790	Steam	POT - Transmitter Refurbishment 2026	Point Tupper Generating Station	143,147
Conversion/Utilization	POT	C0080791	Steam	POT - WTP Graver PLC & HMI Upgrades	Point Tupper Generating Station	71,674
Conversion/Utilization	POT	C0041511	Steam	POT Enhanced Monitoring	Point Tupper Generating Station	191,959
Conversion/Utilization	POT	C0080792	Steam	POT -Lighting Upgrades 2026	Point Tupper Generating Station	158,122

Category	Unit	CI#	Functional Class	Project Long Title	Major Location	Project Total
No Change	PTMT	C0068871	Steam	Bear Head Erosion Management	Strait Marine Terminal	690,609
Retire by 2030	ICP	C0067783	Steam	ICP - RC Locomotive Refurb 2026	International Coal Pier	293,306
Retire by 2030	ICP	C0074110	Steam	ICP - RC TRMC Roof Structure Refurbishment	International Coal Pier	502,449
Retire by 2030	ICP	C0052615	Steam	ICP Locomotive Governor Refurb U&U	International Coal Pier	64,389
Retire by 2030	ICP	C0030943	Steam	ICP Pumphouse Refurbishment	International Coal Pier	391,280
Retire by 2030	ICP	C0074128	Steam	ICP Storm Culvert Pipe Refurb U&U	International Coal Pier	698,946
Retire by 2030	ICP	C0080637	Steam	ICP Walkways & Ladders Refurb	International Coal Pier	413,248
Retire by 2030	POA	C0080727	Steam	POA VFD Upgrades	Point Aconi Generating Station	277,054
Retire by 2030	POA	C0080728	Steam	POA 4KV 600V Breaker Refurbishment 2026	Point Aconi Generating Station	66,190
Retire by 2030	POA	C0080729	Steam	POA Access Improvement 2026	Point Aconi Generating Station	143,155
Retire by 2030	POA	C0080730	Steam	POA Acid Systems Polisher Upgrades	Point Aconi Generating Station	61,663
Retire by 2030	POA	C0080731	Steam	POA Arrowhead Refurbishment 2026	Point Aconi Generating Station	253,224
Retire by 2030	POA	C0080733	Steam	POA Ash Reinjection Refurbishments	Point Aconi Generating Station	313,782
Retire by 2030	POA	C0080734	Steam	POA Ash System Refurbishment 2026	Point Aconi Generating Station	304,137
Retire by 2030	POA	C0080735	Steam	POA Boiler Coal Chute Improvements	Point Aconi Generating Station	136,272
Retire by 2030	POA	C0080736	Steam	POA Building HVAC Refurbishments	Point Aconi Generating Station	156,505
Retire by 2030	POA	C0080737	Steam	POA Coal Feeder Refurbishments	Point Aconi Generating Station	202,662
Retire by 2030	POA	C0080738	Steam	POA Coal Gallery Refurbishments	Point Aconi Generating Station	591,666
Retire by 2030	POA	C0080739	Steam	POA Coal System Refurbishment 2026	Point Aconi Generating Station	304,137
Retire by 2030	POA	C0080740	Steam	POA CW Building Refurbishments	Point Aconi Generating Station	503,477
Retire by 2030	POA	C0080741	Steam	POA DCMS Upgrades 2026	Point Aconi Generating Station	202,662
Retire by 2030	POA	C0080742	Steam	POA Denim Tank Heater	Point Aconi Generating Station	85,103
Retire by 2030	POA	C0080743	Steam	POA Drag Chains Upgrades	Point Aconi Generating Station	202,375
Retire by 2030	POA	C0080744	Steam	POA Equipment/Emission Monitoring Upgrades	Point Aconi Generating Station	102,142
Retire by 2030	POA	C0080745	Steam	POA Expansion Joint Refurbishment 2026	Point Aconi Generating Station	219,356
Retire by 2030	POA	C0080746	Steam	POA Facilities Security Upgrades 2026	Point Aconi Generating Station	127,110
Retire by 2030	POA	C0080747	Steam	POA Fire System Upgrade 2026	Point Aconi Generating Station	76,244
Retire by 2030	POA	C0080748	Steam	POA Kubota RTV Replacement	Point Aconi Generating Station	42,384
Retire by 2030	POA	C0080749	Steam	POA Ladder Upgrades 2026	Point Aconi Generating Station	61,453
Retire by 2030	POA	C0080750	Steam	POA LS Cyclone Relining	Point Aconi Generating Station	451,780
Retire by 2030	POA	C0080751	Steam	POA LS Quarry Reclamation 2026	Point Aconi Generating Station	417,094
Retire by 2030	POA	C0080752	Steam	POA LS Quarry Refurbishments 2026	Point Aconi Generating Station	226,518
Retire by 2030	POA	C0080753	Steam	POA LS System Refurbishment 2026	Point Aconi Generating Station	304,137
Retire by 2030	POA	C0080754	Steam	POA Machinery Guarding 2026	Point Aconi Generating Station	92,720
Retire by 2030	POA	C0080755	Steam	POA Motor Overhauls	Point Aconi Generating Station	233,892
Retire by 2030	POA	C0080756	Steam	POA Plant Lighting Upgrades 2026	Point Aconi Generating Station	153,114
Retire by 2030	POA	C0080757	Steam	POA Sewage Lagoon Dredging	Point Aconi Generating Station	303,513
Retire by 2030	POA	C0080758	Steam	POA Turbine MSVs	Point Aconi Generating Station	201,704
Retire by 2030	POA	C0080759	Steam	POA Valve Component Replacement 2026	Point Aconi Generating Station	248,861
Retire by 2030	POA	C0080760	Steam	POA Water Treatment Trailer	Point Aconi Generating Station	725,737
Retire by 2030	POA	C0080761	Steam	POA Water Treatment Valve Overhaul	Point Aconi Generating Station	131,885
Retire by 2030	PTMT	C0080794	Steam	PTMT Hopper Wear Plate Refurb	Strait Marine Terminal	132,934
Retire by 2030	PTMT	C0080796	Steam	PTMT Shuttle Fire & Irrigation Refurb	Strait Marine Terminal	212,222
Retire by 2030	PTMT	C0080797	Steam	Rail Car & Truck Refurb 2026	International Coal Pier	90,190
Retire by 2030	PTMT	C0076351	Steam	SCR Track Refurbishment Phase 1	International Coal Pier	648,103
Retire by 2030	TRECP	C0080799	Steam	TRE - 4kV Breaker Replacements 2026	Trenton Generating Station	180,707
Retire by 2030	TRECP	C0080800	Steam	TRE - A Belt Structural Steel Refurbishment	Trenton Generating Station	317,309
Retire by 2030	TRECP	C0080801	Steam	TRE - Asbestos Abatement 2026	Trenton Generating Station	283,698
No Change	TRECP	C0080802	Steam	TRE - Ash Site Management	Trenton Generating Station	169,279
Retire by 2030	TRECP	C0080803	Steam	TRE - Chemical Unloading Drain	Trenton Generating Station	118,651
Retire by 2030	TRECP	C0080804	Steam	TRE - Lift Station Refurbishment	Trenton Generating Station	143,292
Retire by 2030	TRECP	C0080805	Steam	TRE - Overhead / Person Door Refurbishments	Trenton Generating Station	90,403
Retire by 2030	TRECP	C0080808	Steam	TRE - Roof Drain Replacements	Trenton Generating Station	168,035
Retire by 2030	TRECP	C0080809	Steam	TRE - Sootblower Refurbishment 2026	Trenton Generating Station	126,027
Retire by 2030	TRECP	C0080810	Steam	TRE - TAMS Offsetting 2025	Trenton Generating Station	23,066
Retire by 2030	TRECP	C0080811	Steam	TRE - Transmitters and Controls	Trenton Generating Station	125,238
Retire by 2030	TRECP	C0080812	Steam	TRE 4Kv Motor Refurbishments	Trenton Generating Station	224,427
No Change	TRECP	C0080813	Steam	TRE Ash Site Haul Road	Trenton Generating Station	194,669
Retire by 2030	TRECP	C0080814	Steam	TRE Common Water Replacement	Trenton Generating Station	100,822
Retire by 2030	TRECP	C0080815	Steam	TRE Electrical Panel Upgrades	Trenton Generating Station	118,243
Retire by 2030	TRECP	C0080816	Steam	TRE HVAC Replacement	Trenton Generating Station	232,592
Retire by 2030	TRECP	C0080817	Steam	TRE LED Upgrades 2026	Trenton Generating Station	123,187
Retire by 2030	TRECP	C0080818	Steam	TRE Multilin Upgrades	Trenton Generating Station	100,191
Retire by 2030	TRECP	C0080819	Steam	TRE PAC System Refurbishments	Trenton Generating Station	126,689
Retire by 2030	TRECP	C0070850	Steam	TRE Shaker House Hoist Replacement	Trenton Generating Station	468,971
Retire by 2030	TRECP	C0061331	Steam	TRE0 - 6A Service Air Compressor Replacement	Trenton Generating Station	152,758
Retire by 2030	TRE5	C0080820	Steam	TRE5 - 5-2 FD Fan Refurbishment	Trenton Generating Station	182,065
Retire by 2030	TRE5	C0080821	Steam	TRE5 - 5-4 Feedwater Heater Refurbishment	Trenton Generating Station	168,353
Retire by 2030	TRE5	C0080822	Steam	TRE5 - 5-5 Bled Steam Valve	Trenton Generating Station	59,776
Retire by 2030	TRE5	C0080823	Steam	TRE5 - Boiler Refurbishment 2026	Trenton Generating Station	896,954
Retire by 2030	TRE5	C0080824	Steam	TRE5 - Boiler Safety Valve Refurbishments 2026	Trenton Generating Station	76,267
Retire by 2030	TRE5	C0080825	Steam	TRE5 - Boiler South WW Panel at Lower Header.	Trenton Generating Station	892,848
Retire by 2030	TRE5	C0080826	Steam	TRE5 - Bottom Ash Refractory Replacement	Trenton Generating Station	235,265
Retire by 2030	TRE5	C0080827	Steam	TRE5 - Control Station Refurbishments	Trenton Generating Station	44,166
Retire by 2030	TRE5	C0080828	Steam	TRE5 - Conveyors Refurbishment 2026	Trenton Generating Station	115,811
Retire by 2030	TRE5	C0080829	Steam	TRE5 - ID Fan Expansion Joints	Trenton Generating Station	162,906
Retire by 2030	TRE5	C0080830	Steam	TRE5 - Mill Platform	Trenton Generating Station	197,537
Retire by 2030	TRE5	C0080831	Steam	TRE5 - Misc. Valves Refurbishment 2026	Trenton Generating Station	176,468
Retire by 2030	TRE5	C0080832	Steam	TRE5 - PF Elbow Replacement	Trenton Generating Station	385,903
Retire by 2030	TRE5	C0080833	Steam	TRE5 - Reclaim Refurbishment	Trenton Generating Station	111,973
Retire by 2030	TRE5	C0080834	Steam	TRE5 - UPS Inverter and Line Conditioner Replacement	Trenton Generating Station	201,791
Retire by 2030	TRE5	C0080835	Steam	TRE5 5-1/5-2 CW Screen	Trenton Generating Station	229,475
Retire by 2030	TRE5	C0080836	Steam	TRE5 5B Conveyor Belt Replacement	Trenton Generating Station	106,902
Retire by 2030	TRE5	C0082132	Steam	TRE5 FAC 2026	Trenton Generating Station	168,686
Retire by 2030	TRE5	C0080837	Steam	TRE5 Flamer scanner Upgrades	Trenton Generating Station	123,891
Retire by 2030	TRE5	C0080838	Steam	TRE5 Lube Oil Replacement	Trenton Generating Station	26,885
Retire by 2030	TRE5	C0080840	Steam	TRE5-1 Mill Refurbishment	Trenton Generating Station	467,496
Retire by 2030	TRE5	C0080841	Steam	TRE5-3 Mill Refurbishment	Trenton Generating Station	467,496
Retire by 2030	TRE6	C0080842	Steam	TRE6 - 6-6 Bled Steam Valve	Trenton Generating Station	59,638
Retire by 2030	TRE6	C0068692	Steam	TRE6 - 6A BFP Discharge Valve Refurbishment	Trenton Generating Station	148,141
Retire by 2030	TRE6	C0080843	Steam	TRE6 - 6A Seal Air Fan Replacement	Trenton Generating Station	92,093
Retire by 2030	TRE6	C0080844	Steam	TRE6 - A and B CW Screens Refurbishment	Trenton Generating Station	166,481
Retire by 2030	TRE6	C0080845	Steam	TRE6 - Air Heater Seal Replacement	Trenton Generating Station	376,296
Retire by 2030	TRE6	C0080846	Steam	TRE6 - Boiler Refurbishment	Trenton Generating Station	137,099
Retire by 2030	TRE6	C0080847	Steam	TRE6 - Boiler Safety Valve Refurbishments 2026	Trenton Generating Station	75,801
Retire by 2030	TRE6	C0080848	Steam	TRE6 - Bottom Ash Refurbishment	Trenton Generating Station	755,126
Retire by 2030	TRE6	C0080849	Steam	TRE6 - Conveyors Refurbishment 2026	Trenton Generating Station	115,011
Retire by 2030	TRE6	C0068691	Steam	TRE6 - Main Boiler Stop Valve	Trenton Generating Station	189,067

Category	Unit	CI#	Functional Class	Project Long Title	Major Location	Project Total
Retire by 2030	TRE6	C0080850	Steam	TRE6 - Misc. Valves Refurbishment 2026	Trenton Generating Station	175,346
Retire by 2030	TRE6	C0080851	Steam	TRE6 - Reclaim Refurbishment	Trenton Generating Station	317,309
Retire by 2030	TRE6	C0080852	Steam	TRE6 - Turbine Valves	Trenton Generating Station	567,201
Retire by 2030	TRE6	C0080853	Steam	TRE6 6 G Conveyor Belt Refurbishment	Trenton Generating Station	106,164
Retire by 2030	TRE6	C0080854	Steam	TRE6 600V Motor Starters	Trenton Generating Station	114,279
Retire by 2030	TRE6	C0080855	Steam	TRE6 6A BFP Refurbishment (volute)	Trenton Generating Station	211,460
Retire by 2030	TRE6	C0080856	Steam	TRE6 6B Mill Bullgear and Pinnion	Trenton Generating Station	671,040
Retire by 2030	TRE6	C0080857	Steam	TRE6 6D Conveyor Belt Refurbishment	Trenton Generating Station	132,704
Retire by 2030	TRE6	C0080858	Steam	TRE6 Aux Cooling Water Oil Analyzer	Trenton Generating Station	168,035
Retire by 2030	TRE6	C0080859	Steam	TRE6 Burner Impeller Replacement	Trenton Generating Station	191,704
Retire by 2030	TRE6	C0080860	Steam	TRE6 DCS Upgrade	Trenton Generating Station	423,497
Retire by 2030	TRE6	C0082146	Steam	TRE6 FAC 2026	Trenton Generating Station	168,686
Retire by 2030	TRE6	C0068693	Steam	TRE6 Instrument Air Dry Replacement	Trenton Generating Station	89,194
Retire by 2030	TRE6	C0068675	Steam	TRE6 Parallel Slide HP heater isolations	Trenton Generating Station	467,809
Retire by 2030	TRE6	C0080862	Steam	TRE6 Polisher Acid Skid	Trenton Generating Station	430,960
Retire by 2030	TRE6	C0080863	Steam	TRE6 WTP Silica Analyser	Trenton Generating Station	60,523
No Change	PHB	C0082196	Steam	PHB - Asbestos Abatement	Port Hawkesbury Biomass	225,000
No Change	PHB	C0080711	Steam	PHB - BAS Upgrade 2026	Port Hawkesbury Biomass	423,233
No Change	PHB	C0080712	Steam	PHB - Boiler Refurbishment 2026	Port Hawkesbury Biomass	850,535
No Change	PHB	C0080713	Steam	PHB - Conveyors & Fuel Handling 2026	Port Hawkesbury Biomass	293,867
No Change	PHB	C0080714	Steam	PHB – DCS Multivariable Transmitter Upgrade	Port Hawkesbury Biomass	251,683
No Change	PHB	C0080715	Steam	PHB - Dumpchute Replacement	Port Hawkesbury Biomass	495,233
No Change	PHB	C0080716	Steam	PHB - Fire Protection Upgrades 2026	Port Hawkesbury Biomass	496,008
No Change	PHB	C0080717	Steam	PHB - HVAC Refurbishment	Port Hawkesbury Biomass	174,306
No Change	PHB	C0080718	Steam	PHB – Lighting Upgrades 2026	Port Hawkesbury Biomass	170,771
No Change	PHB	C0080723	Steam	PHB - Powerflex 7000 VFD Drives	Port Hawkesbury Biomass	254,447
No Change	PHB	C0080724	Steam	PHB - Precipitator Refurbishment 2026	Port Hawkesbury Biomass	788,072
No Change	PHB	C0080725	Steam	PHB - Trancel Screw Refurbishment 2026	Port Hawkesbury Biomass	232,081
No Change	PHB	C0080726	Steam	PHB - Wennberg Screw Replacement	Port Hawkesbury Biomass	454,446
No Change	AMO	C0070306	Steam	PP FW Valve Critical Spare	Lingan Generating Station	453,486
No Change	TUCCP	C0080297	Steam	TUC 600v Local Disconnect Installations	Tufts Cove Generating Station	99,589
No Change	TUCCP	C0080296	Steam	TUC Auto Greaser Upgrade	Tufts Cove Generating Station	100,290
No Change	TUCCP	C0080298	Steam	TUC Aux Boiler Condensate Recovery	Tufts Cove Generating Station	149,814
No Change	TUCCP	C0080299	Steam	TUC Battery Bank Monitoring	Tufts Cove Generating Station	99,633
No Change	TUCCP	C0080300	Steam	TUC Concrete Floor Refurbishment	Tufts Cove Generating Station	100,382
No Change	TUCCP	C0080301	Steam	TUC Controls Shop Test Equipment	Tufts Cove Generating Station	99,000
No Change	TUCCP	C0060560	Steam	TUC Cooling Water Reduction	Tufts Cove Generating Station	250,442
No Change	TUCCP	C0080302	Steam	TUC DCS HMI Upgrade 2026	Tufts Cove Generating Station	149,839
No Change	TUCCP	C0080303	Steam	TUC Degas North & South	Tufts Cove Generating Station	499,517
No Change	TUCCP	C0080305	Steam	TUC Electrical Panel Replacements 2026	Tufts Cove Generating Station	100,127
No Change	TUCCP	C0080306	Steam	TUC Facilities Upgrades	Tufts Cove Generating Station	99,832
No Change	TUCCP	C0080307	Steam	TUC Fire Protection Routine	Tufts Cove Generating Station	50,003
No Change	TUCCP	C0080308	Steam	TUC Forklift Replacement	Tufts Cove Generating Station	90,499
No Change	TUCCP	C0080309	Steam	TUC Handrail Program 2026	Tufts Cove Generating Station	120,086
No Change	TUCCP	C0080310	Steam	TUC Lighting Program 2026	Tufts Cove Generating Station	120,400
No Change	TUCCP	C0080311	Steam	TUC Mechanical Storage Improvements	Tufts Cove Generating Station	199,932
No Change	TUCCP	C0080312	Steam	TUC NERC Replacements	Tufts Cove Generating Station	60,109
No Change	TUCCP	C0050892	Steam	TUC No1 Elevator Upgrade	Tufts Cove Generating Station	376,576
No Change	TUCCP	C0080313	Steam	TUC Obsolete Instrumentation	Tufts Cove Generating Station	98,954
No Change	TUCCP	C0080314	Steam	TUC Offloading Waste Oil Tank Replacement	Tufts Cove Generating Station	74,318
No Change	TUCCP	C0080315	Steam	TUC Oil Additive Injection	Tufts Cove Generating Station	49,870
No Change	TUCCP	C0080316	Steam	TUC Oil Analysis Improvements	Tufts Cove Generating Station	150,634
No Change	TUCCP	C0080317	Steam	TUC Plant Security Upgrades 2026	Tufts Cove Generating Station	98,954
No Change	TUCCP	C0080318	Steam	TUC Platform and Ladders 2026	Tufts Cove Generating Station	98,992
No Change	TUCCP	C0080319	Steam	TUC Roadway Refurbishment	Tufts Cove Generating Station	498,161
No Change	TUCCP	C0080320	Steam	TUC Roof Refurbishment	Tufts Cove Generating Station	549,770
No Change	TUCCP	C0080321	Steam	TUC Rotating Equipment Guards 2026	Tufts Cove Generating Station	98,992
No Change	TUCCP	C0080322	Steam	TUC SEL Generator Protection Relays	Tufts Cove Generating Station	99,555
No Change	TUCCP	C0080323	Steam	TUC SEL Motor Protection Relays	Tufts Cove Generating Station	99,555
No Change	TUCCP	C0080324	Steam	TUC Sensors and Alarms 2026	Tufts Cove Generating Station	124,567
No Change	TUCCP	C0080326	Steam	TUC Sprinkler Head Replacements	Tufts Cove Generating Station	49,604
No Change	TUCCP	C0080328	Steam	TUC Station Fuel Oil Upgrades Ph3	Tufts Cove Generating Station	99,621
No Change	TUCCP	C0080329	Steam	TUC Turbine Bay Louver Refurbishment	Tufts Cove Generating Station	99,555
No Change	TUCCP	C0080864	Steam	TUC WTP12 Train Valve Replacements	Tufts Cove Generating Station	70,481
No Change	TUCCP	C0080865	Steam	TUC WTP4 Replace DCS to PLC	Tufts Cove Generating Station	199,669
No Change	TUCCP	C0080331	Steam	TUC WTP4 RO Caustic Injection and Meter Replacements	Tufts Cove Generating Station	79,545
No Change	TUC2	C0080356	Steam	TUC 2 MCC Refurbishment 2026	Tufts Cove Generating Station	40,046
No Change	TUCCP	C0069050	Steam	TUC EST3 Fire Panel Protection	Tufts Cove Generating Station	81,456
No Change	TUCCP	C0080327	Steam	TUC Stack Lighting Ph 2	Tufts Cove Generating Station	124,567
No Change	TUC1	C0080348	Steam	TUC1 2 Wire Ni RTDs Replacements	Tufts Cove Generating Station	74,370
No Change	TUC1	C0080333	Steam	TUC1 4kV-600V Breaker Replacement 2026	Tufts Cove Generating Station	149,114
No Change	TUC1	C0080332	Steam	TUC1 Air Heater Internal Refurbishment	Tufts Cove Generating Station	49,468
No Change	TUC1	C0080334	Steam	TUC1 Boiler Refurbishment 2026	Tufts Cove Generating Station	446,287
No Change	TUC1	C0080335	Steam	TUC1 Control Valve Replacement 2026	Tufts Cove Generating Station	49,442
No Change	TUC1	C0080337	Steam	TUC1 DCS HMI Upgrades 2026	Tufts Cove Generating Station	148,846
No Change	TUC1	C0080338	Steam	TUC1 Electric Actuators 2026	Tufts Cove Generating Station	74,368
No Change	TUC1	C0080866	Steam	TUC1 Enhanced Monitoring	Tufts Cove Generating Station	204,443
No Change	TUC1	C0080339	Steam	TUC1 Feedwater MCC Replacement	Tufts Cove Generating Station	199,693
No Change	TUC1	C0082165	Steam	TUC1 Governor Valve Replacement	Tufts Cove Generating Station	527,492
No Change	TUC1	C0080867	Steam	TUC1 Iris Generator Monitor	Tufts Cove Generating Station	123,810
No Change	TUC1	C0060574	Steam	TUC1 Lube Oil Cooler Replacement	Tufts Cove Generating Station	925,518
No Change	TUC1	C0080340	Steam	TUC1 Main Stream Y Replacement	Tufts Cove Generating Station	498,045
No Change	TUC1	C0080341	Steam	TUC1 MCC Refurbishment 2026	Tufts Cove Generating Station	39,622
No Change	TUC1	C0080342	Steam	TUC1 Misc Valve Replacement 2026	Tufts Cove Generating Station	74,370
No Change	TUC1	C0080343	Steam	TUC1 Motor Refurbishments 2026	Tufts Cove Generating Station	50,189
No Change	TUC1	C0080344	Steam	TUC1 Natural Gas Valves Refurbishment 2026	Tufts Cove Generating Station	73,617
No Change	TUC1	C0080345	Steam	TUC1 Online Oil Analyser	Tufts Cove Generating Station	98,870
No Change	TUC1	C0080346	Steam	TUC1 Polisher Resin Replacement	Tufts Cove Generating Station	123,846
No Change	TUC1	C0080347	Steam	TUC1 Polisher Valve Upgrade 2026	Tufts Cove Generating Station	123,608
No Change	TUC1	C0080349	Steam	TUC1 South BFP Motor Refurbishment	Tufts Cove Generating Station	74,755
No Change	TUC1	C0080868	Steam	TUC1 South CW Pump Refurbishment	Tufts Cove Generating Station	298,427
No Change	TUC1	C0060563	Steam	TUC1 Steam Drum Refurbishment	Tufts Cove Generating Station	199,425
No Change	TUC2	C0080869	Steam	TUC2 4kV 600v Breaker Replacement 2026	Tufts Cove Generating Station	148,745
No Change	TUC2	C0080350	Steam	TUC2 Boiler Refurbishment 2026	Tufts Cove Generating Station	348,522
No Change	TUC2	C0080351	Steam	TUC2 Control Valve Replacement 2026	Tufts Cove Generating Station	50,130
No Change	TUC2	C0080353	Steam	TUC2 DCS HMI Upgrade 2026	Tufts Cove Generating Station	149,393
No Change	TUC2	C0080354	Steam	TUC2 Electric Actuators 2026	Tufts Cove Generating Station	74,180
No Change	TUC2	C0080355	Steam	TUC2 Flame Scanner Replacement	Tufts Cove Generating Station	99,122

Category	Unit	CI#	Functional Class	Project Long Title	Major Location	Project Total
No Change	TUC2	C0080357	Steam	TUC2 Miscellaneous Valve Replacement 2026	Tufts Cove Generating Station	74,370
No Change	TUC2	C0080358	Steam	TUC2 Motor Refurbishments 2026	Tufts Cove Generating Station	124,251
No Change	TUC2	C0080359	Steam	TUC2 Natural Gas Valves Refurbishments 2026	Tufts Cove Generating Station	73,617
No Change	TUC2	C0053594	Steam	TUC2 Replace BAS	Tufts Cove Generating Station	500,495
No Change	TUC3	C0080870	Steam	TUC3 4kV 600V Breaker Replacements 2026	Tufts Cove Generating Station	99,634
No Change	TUC3	C0080361	Steam	TUC3 BAS Upgrade	Tufts Cove Generating Station	74,951
No Change	TUC3	C0080379	Steam	TUC3 BFP Panel Upgrades	Tufts Cove Generating Station	99,860
No Change	TUC3	C0080363	Steam	TUC3 Boiler Refurbishment 2026	Tufts Cove Generating Station	375,100
No Change	TUC3	C0080364	Steam	TUC3 Boiler Safety Valves Replacement	Tufts Cove Generating Station	499,800
No Change	TUC3	C0080365	Steam	TUC3 Burner Valves Replacement 2026	Tufts Cove Generating Station	100,064
No Change	TUC3	C0060586	Steam	TUC3 Condenser Waterbox Refurbishment	Tufts Cove Generating Station	500,211
No Change	TUC3	C0080366	Steam	TUC3 Control Valve Replacement 2026	Tufts Cove Generating Station	49,944
No Change	TUC3	C0080368	Steam	TUC3 DCS HMI Upgrade 2026	Tufts Cove Generating Station	74,630
No Change	TUC3	C0080369	Steam	TUC3 DW Cooler Structure Refurbishment	Tufts Cove Generating Station	200,902
No Change	TUC3	C0080370	Steam	TUC3 Electric Actuators 2026	Tufts Cove Generating Station	74,921
No Change	TUC3	C0080380	Steam	TUC3 Furnace Camera	Tufts Cove Generating Station	100,032
No Change	TUC3	C0080371	Steam	TUC3 MCC Refurbishment 2026	Tufts Cove Generating Station	42,530
No Change	TUC3	C0080372	Steam	TUC3 Misccellaneous Valve Replacement 2026	Tufts Cove Generating Station	74,899
No Change	TUC3	C0080373	Steam	TUC3 Motor Refurbishment 2026	Tufts Cove Generating Station	59,530
No Change	TUC3	C0080374	Steam	TUC3 Natural Gas Valves Refurbishment 2026	Tufts Cove Generating Station	74,081
No Change	TUC3	C0080375	Steam	TUC3 North Boiler Feed Pump Refurbishment	Tufts Cove Generating Station	500,539
No Change	TUC3	C0080376	Steam	TUC3 North CW Pump and Motor	Tufts Cove Generating Station	400,000
No Change	TUC3	C0080377	Steam	TUC3 Polisher Valve Replacements	Tufts Cove Generating Station	124,811
No Change	TUC3	C0080381	Steam	TUC3 Replace Stack Flowmeters	Tufts Cove Generating Station	74,630
No Change	TUC3	C0080378	Steam	TUC3 Steam Drum Refurbishment	Tufts Cove Generating Station	150,058
No Change	TUC3	C0080871	Steam	TUC3 Turbine Valve Refurbishment	Tufts Cove Generating Station	349,905
No Change	TUC6	C0080382	Steam	TUC6 4160V/600V Motor Refurbishment 2026	Tufts Cove Generating Station	50,510
No Change	TUC6	C0080383	Steam	TUC6 4kV 600v Breaker Replacements	Tufts Cove Generating Station	99,345
No Change	TUC6	C0080385	Steam	TUC6 B&K TSE	Tufts Cove Generating Station	125,687
No Change	TUC6	C0068906	Steam	TUC6 Boiler Feed Pump Refurbishment	Tufts Cove Generating Station	300,629
No Change	TUC6	C0080386	Steam	TUC6 Breaker Refurbishments 2026	Tufts Cove Generating Station	50,913
No Change	TUC6	C0080387	Steam	TUC6 Bypass Valves Replacement	Tufts Cove Generating Station	25,136
No Change	TUC6	C0080388	Steam	TUC6 DCS HMI Upgrade 2026	Tufts Cove Generating Station	74,632
No Change	TUC6	C0080389	Steam	TUC6 Electric Actuators 2026	Tufts Cove Generating Station	74,923
No Change	TUC6	C0080390	Steam	TUC6 Generator Monitor (IRIS PD)	Tufts Cove Generating Station	125,687
No Change	TUC6	C0080384	Steam	TUC6A Polisher Element Replacement	Tufts Cove Generating Station	100,198

Request IR-13:

Section 5.0 2026 Annual Capital Expenditure Plan pages 31 to 39
Less than $1M

Does NS Power apply any internal aggregate cap or approval threshold to the total annual spending on projects with estimated total project costs of less than $1M?

Response IR-13:

No. All capital projects brought forward in the ACE Plan follow the same asset management mechanism, where the condition and criticality of that asset indicates that the risk requires capital investment. In all circumstances, the least cost alternative to mitigate that risk while still allowing the asset to meet its current asset mission (future utilization, end date, etc.) is chosen. As the asset mission of many of NS Power's generating facilities gets shorter as their forecasted retirement dates near, it is to be expected that smaller investments may be needed in many circumstances to mitigate the known risk over what is now a shorter period of time. NS Power is focused on managing the risks of the assets, and does not consider the number of projects as a factor when analyzing the overall capital plan.

Request IR-14:

Section 6.0 Generation pages 40 to 46

Board staff note that over the five-year period 2022-2026, NS Power's cumulative budgeted capital expenditure on generation projects with estimated total project costs of less than $1M total approximately $295M, of which approximately $246M relates to steam or other generation assets.

(a) Please provide actual spend for this category for 2020 – 2025.

(b) Please explain how this level of sub $1M capital investment is consistent with the path to 2030 plan.

(c) In your response, identify whether NS Power considers the expenditures to be:

(i) Life extension investments

(ii) Minimum safe operation investments, or

(iii) Investments necessary to meet regulatory or safety requirements only

Please indicate which category applies to each major class of expenditure.

Response IR-14:

(a) The following table details the annual spend on projects that are less than $1M.

Year	Annual Investment ($M)
2020	76.4
2021	89.3
2022	107.5
2023	98.3
2024	120.8
2025	96.3

(b) These projects are across 12 steam generating units, 8 of which will continue to operate beyond 2030 with natural gas or heavy fuel oil. The annual level of spending on these projects is consistent with the path to 2030 as the Generation projects that have been executed in this time period were required to mitigate the risks identified through the asset management mechanism. This mechanism factors in the asset mission (how the generating unit is to be operated, and when it is forecast to retire) in determining the level of risk. In all situations, the level of risk could not be left unmanaged for the remaining operational life of the asset and required mitigation in order to ensure that that unit could safely and reliably provide the necessary capacity to meet the system demands until the forecasted retirement date.

(c) All three of these categories would be represented within this spend. While not necessarily extending the life of the broader asset (generating unit), much of this investment does extend the life of the specific asset included in the project. Embedded within the asset management mechanism is the requirement to mitigate the risk in the most cost effective manner possible, therefore these projects are executed to only mitigate the risk for the assets' forecasted remaining life, or to meet regulatory or safety requirements (fire system upgrades, as an example).

Each major class of expenditure (Steam, Distribution, Transmission, etc.) would have projects that fall under each of the categories listed above.

Request IR-15:

Section 6.0 Generation pages 40 to 46

In reference to Figure 13 - Generation Investment on page 40.

(a) Please confirm that the dollar figure shown for 2028 in Figure 13 of the 2026 ACE Plan application includes the planned Gas Conversion project at Point Tupper No. 2.

(i) If not confirmed please explain.

(b) Please confirm that the dollar figure shown in 2029 in Figure 13 of the 2026 ACE Plan application includes the planned Heavy Fuel Oil Conversion project at Lingan 1/3/4.

(i) If not confirmed please explain.

(c) Please provide the forecast utilization rates for each of NS Power's generating units for the years 2026 to 2035 inclusive.

(d) Please provide a copy of the 2025 health and risk profiling for each of NS Power's generating facilities.

Response IR-15:

(a) Confirmed.

(b) Confirmed.

(c) The forecast utilization rates for NS Power's generating units from 2026 to 2035 are set out in the 2025 10-Year System Outlook (10YSO). The 10YSO includes annual capacity

factor forecasts for each thermal generating unit, as shown in Figure 9 of the 10YSO report. These values represent NS Power's current forecast of expected operating patterns for steam units, combined-cycle units, combustion turbines, and biomass generation. The Outlook also includes NS Power's utilization factor assessments in Figure 11 of the 10YSO report. Together, these figures provide the most up-to-date and comprehensive forecast of unit utilization available for the 2026–2035 period.

(d) Please refer to Figures 1, 2, and 3 below for the risk profiles of the Thermal, Hydro, and Combustion Turbine fleet, respectively. The colors in the figures align with NS Power's Asset Management Mechanism outlined in Figure 4.

Figure 1: 2025 Thermal Risk Profile

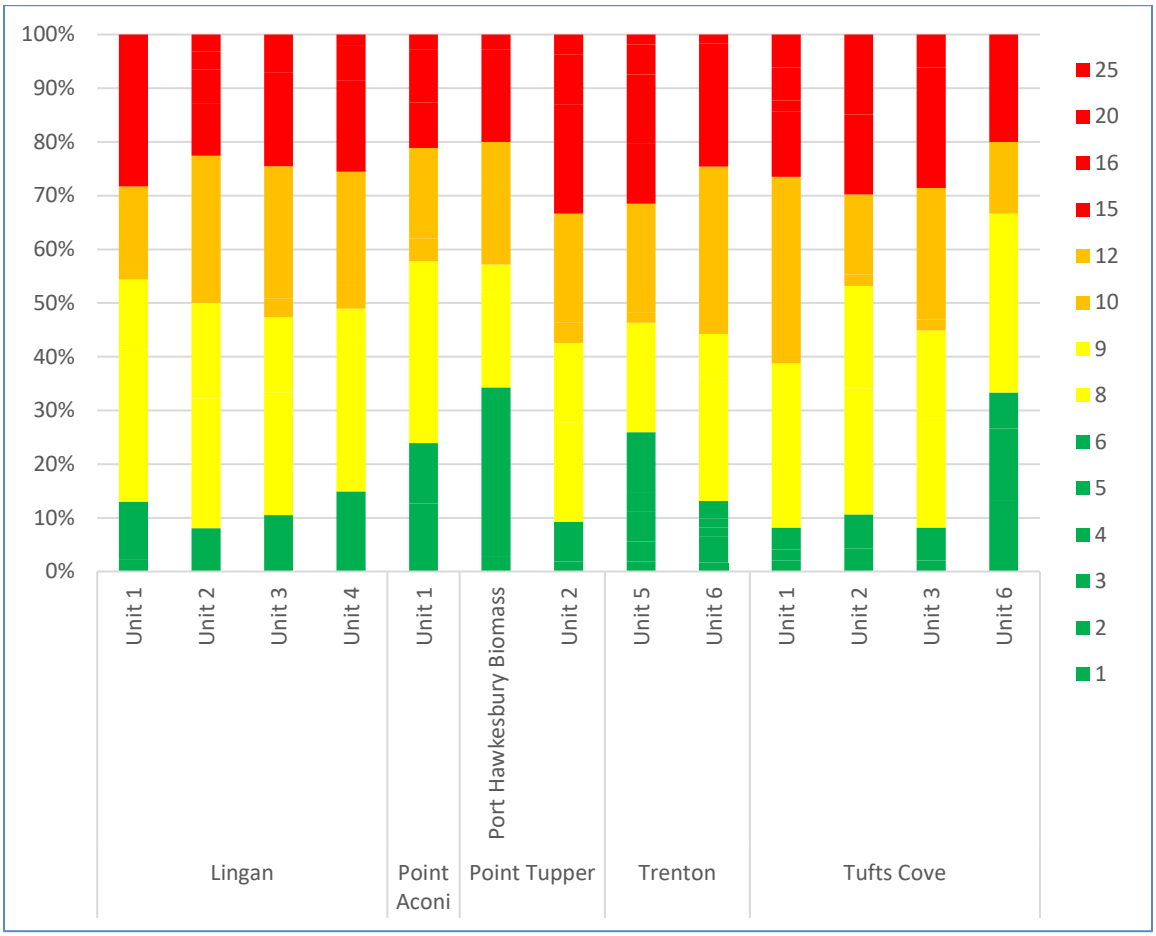


Figure 2: 2025 Hydro Risk Profile

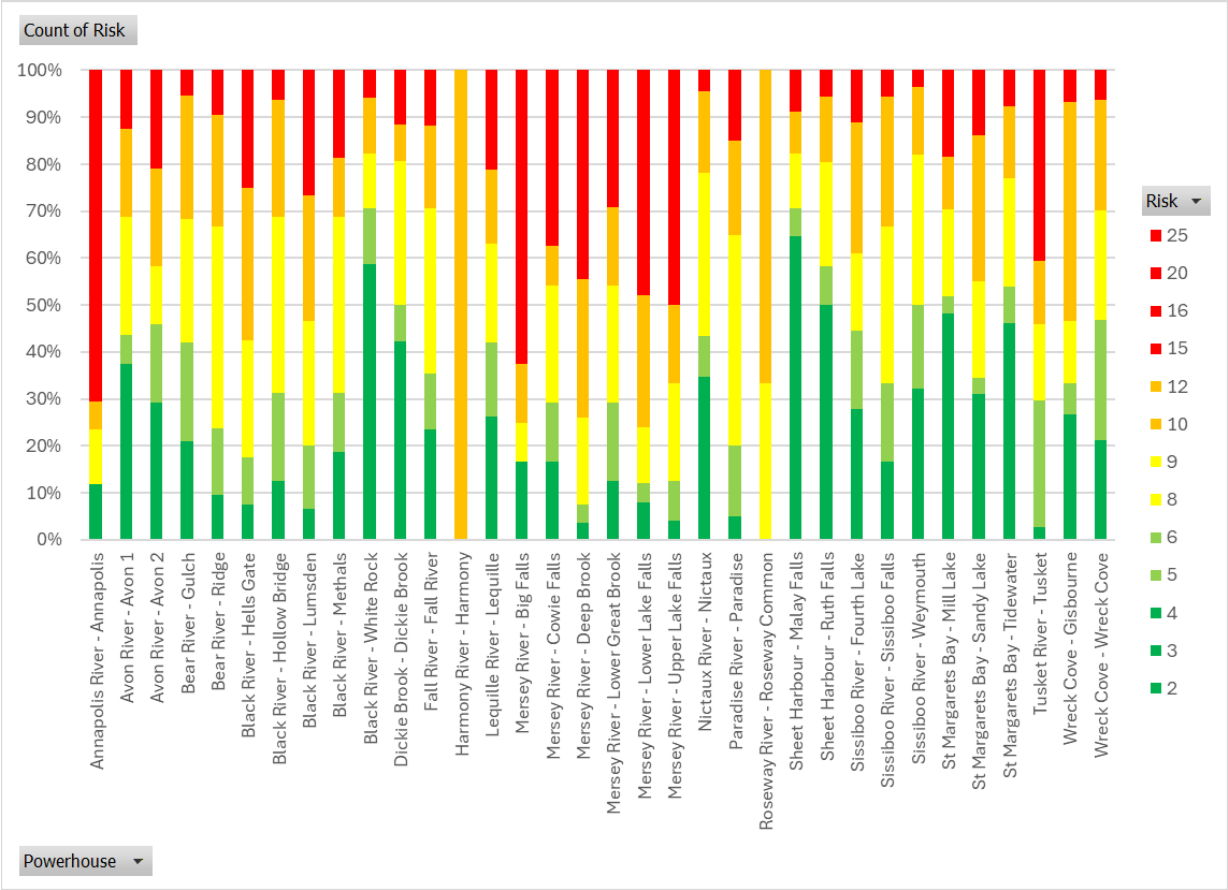
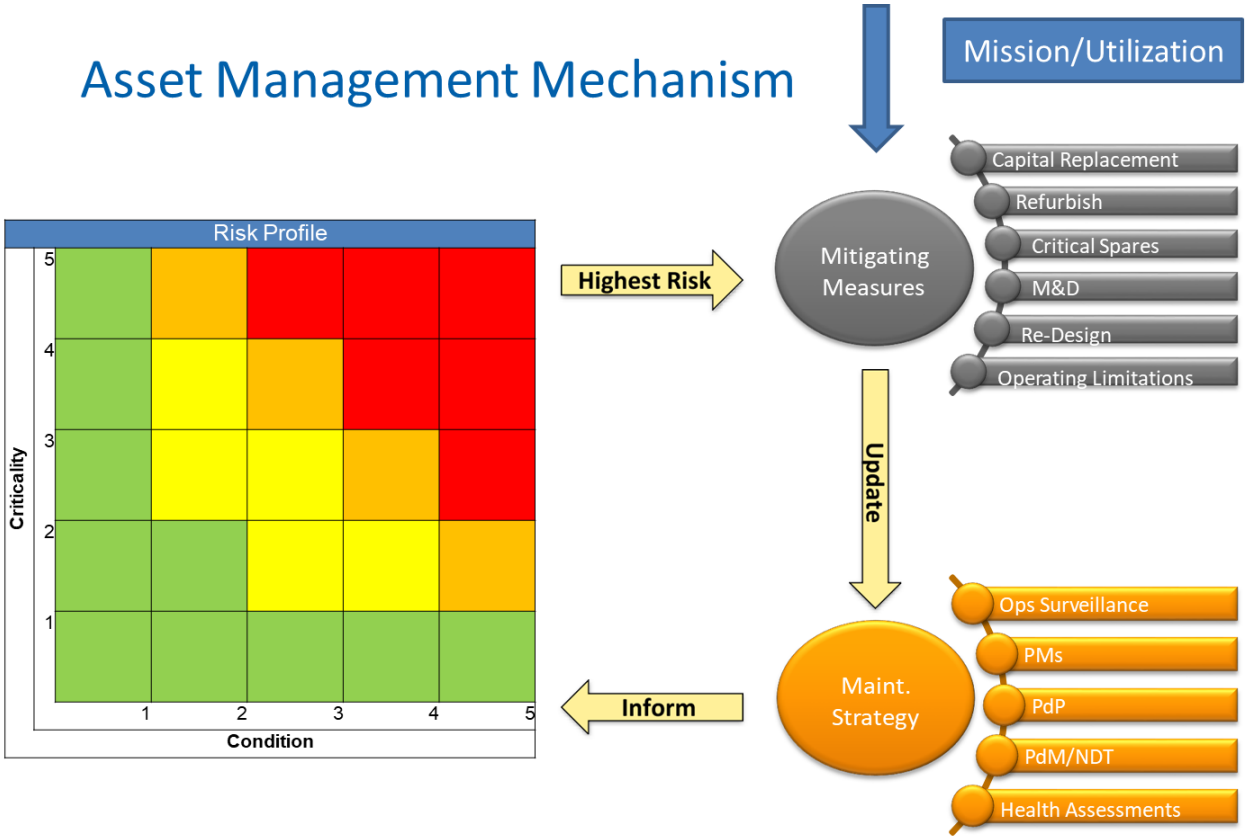


Figure 3: 2025 Combustion Turbine Fleet Risk Profile

Location	Engine	Free Turbine	Generator	Balance of Plant
Burnside Gas Turbine Unit 1 (BGT 1)				
Burnside Gas Turbine Unit 2 (BGT 2)				
Burnside Gas Turbine Unit 3 (BGT 3)				
Burnside Gas Turbine Unit 4 (BGT 4)				
Tusket Gas Turbine Unit 1 (TUS1)				
Victoria Junction Gas Turbine Unit 1 (VJ 1)				
Victoria Junction Gas Turbine Unit 2 (VJ 2)				
Tufts Cove Generating Station Unit 4 (TUC4 & Engine 191-332)				
Tufts Cove Generating Station Unit 5 (TUC5 & Engine 191-253)				
Spare Engine (191-443)				
Note: Updated as of Dec 2025				

Figure 4: Asset Management Mechanism



Request IR-16:

Section 6.0 Generation pages 40 to 46

Figure 17: Generation Carry-over Capital Spending Summary. Have there been any changes to the Final Date for any of the projects listed in Figure 17 since the 2026 ACE Plan has been filed?

(a) Please identify each of these carry-over projects that has a current total estimate amount that exceeds the Board approved amount by the ATO threshold, and identify the related dollar amount over the Board approved amount.

(b) Please provide a status update on the "WRC Tailrace Tunnel Rock Bolting Phase 2" project, complete with identification of spending to date and estimated project cost at completion.

(c) Figure 17 lists project C0080112 HYD Big Falls Unit 6 Rotor Reinsulation with a final date of 2026/10 and lists 2026 budget at $195,706 and subsequent spending of $137,902. Please explain the subsequent spending on this project given the listed final date is 2026/10.

(d) Please explain why the following projects do not list subsequent spending given that their final dates are after 2026: C0059783 HYD Upper Lake Falls 2 Overhaul; C0019025 HYD GUL Overhaul; C0068251 HYD WRC D11 Valve and Housing Replacement; and C0044030 WIN DIG Haights Brook Crossing Replacement.

(e) Please discuss the subsequent spending planned for C0073491 LM6000 191-443 Engine Replacement.

(i) Given the amount of subsequent spending on this project, what is the revised Final Date for this project?

(ii) Please discuss the delay in this project that was started 2024/08.

Response IR-16:

Yes. Project Final Dates are continuously being reviewed and revised as project progresses.

(a) Please refer to the Generation carry-over projects that have a current total estimate amount that exceeds the Board-approved amount by the ATO threshold below in the 2026 ACE Plan:

CI#	Project Title	Project Estimate ($)	NSEB Approved Amount (S)	Variance ($)
29807	Tusket Falls Main Dam	78,974,410	18,157,609	60,816,801
49756	HYD Marshall Falls Dam Refurbishment	13,850,456	5,452,794	8,397,663
C0060707*	CT BGT1 Generator Refurbishment	3,842,633	3,482,602	360,030

*Most recent forecast for this project is within $250,000 or 5% of the approved budget.

(b) CI C0006418 – HYD WRC Tailrace Rock Bolting Phase 2 is currently expected to be completed by December 2026. The rock bolting up to station 0+900 m was 100% completed and 70% of shotcrete scope was completed during the 2025 outage. The remaining shotcrete work is planned to be completed during the 2026 outage.

Spend to December 31, 2025	$12,993,787
Estimated project cost at completion	$15,720,860

(c) The Final Cost date of 2026/10 for this project is correct. The amount listed in subsequent spend is project contingency that was forecast as January 2027 spend, however, will be incurred (if needed) in 2026.

(d) The standard practice is a Final Cost Date six months after the in-service date which can lead to projects with a Final Date with no spend in the subsequent year.

- CI C0059783 HYD ULF 2 Overhaul lists a Final Date of 2027/04 and Subsequent Spend of $136K.

- C0019025 is not HYD GUL Overhaul as listed in the carry-over table. It is HYD – Sloane Dam Refurbishment as listed in 2026 ACE Plan Appendix B. The 2028 end date is due to ongoing archaeology and planning with construction potentially pushed to 2027. There will be investment in subsequent years once plan is finalized as path forward has changed from original plan.

- C0068251 HYD WRC D11 Valve and Housing Replacement has a Final Cost Date six months after in-service date.

- C0044030 WIN DIG Haights Brook Crossing Replacement has a Final Cost Date six months after in-service date.

(e) The subsequent spending planned for C0073491 are the remaining engine milestones, installation, testing, and commissioning activities.

The Start and Final dates listed in the table were transcribed incorrectly.

(i) The Final Date of this project is 06/2028 as per NS Power's filing on August 5, 2025 (M12416).

(ii) No delay. The Start Date for this project was 02/2025 as per NS Power's filing on August 5, 2025 (M12416).

Request IR-17:

Section 6.0 Generation pages 40 to 46

Please provide a copy of NS Power's 2026 Hydro Interval Plan.

(a) Please explain the reasons for any significant changes between the 2025 and 2026 Hydro Interval Plan.

(b) Has NS Power completed any updates to its 2018 Hydro Asset Study?

(i) If so, please submit a copy of the updated report.

(ii) If not, why not?

(c) Please provide a table listing the capital work NS Power plans to complete on its hydro generation assets in 2026 and beyond, similar to the one provided in the response to 2025 ACE Plan NSUARB IR-13.

Response IR-17:

Please refer to Attachment 1 for a copy of the 2026 Hydro Interval Plan (HIP).

(a) Variances between successive HIPs are expected due to the rolling 40-year horizon and rolling nature of the HIP, where each annual update removes the prior year (e.g., 2025), adds a new future year (e.g., 2065), and recurring investments (e.g., sustaining capital every 40+ years) re-emerge at the horizon's end.

Note 1: The Mersey Redevelopment HIP profile is not reproduced here, as it is already provided in Appendix E of the 2026 ACE Plan.

Note 2: The Mersey Sustaining HIP profile provided in Attachment 1 reflects the most current planning information. Because the sustaining capital plan for the HIP is continuously updated, minor timing and cost refinements may differ from the version included in Appendix E of the 2026 ACE Plan.

The most significant variances between the 2025 and 2026 HIPs are as follows:

- Annapolis Decommissioning – NPV +$10.0 million due to an increase in the estimate for CI 47650 – HYD ANN Decision (Options) Analysis.

- Black River Sustaining – NPV +13.3 million due to updated estimates for major dam refurbishments, unplanned Hollow Bridge stator refurbishment, and several fish and eel passage projects initiated to meet DFO requirements.

- Sissiboo Sustaining – NPV +30.9 million due to updated estimates for CI 50580 – HYD WEY Intake Refurbishment and CI 50574 – HYD Sissiboo Falls Main Dam Refurbishment.

- Tusket Sustaining – NPV +11.5 million due to increased estimate for CI 29807 – HYD TUS Falls Main Dam.

- Wreck Cove Redevelopment (LEM) – NPV –$66.8 million due to completion of significant scope of the LEM project, therefore no longer being included in the HIP timeframe.

- Wreck Cove Sustaining – NPV –$21.7 million due to favorable condition assessment results for tunnels T-1 and T-2, which reduced the estimated scope of future work and allowed this work to be deferred to later years..

(b) The key elements that inform the 2018 study—including sustaining capital requirements, decommissioning cost estimates, archaeological considerations, and other inputs that underpin long-term hydro system planning—have been updated, and these updated components have been filed with the Board in the 2025 ACE Plan proceeding (M12012) and NS Power's 2026-2027 General Rate Application (M12451).

(i) The updated studies are the updated Hydro Asset Archaeological Costing Study (2024) and the Hydro System Decommissioning Cost Estimate (Hatch 2024), which were both included in the 2026–2027 General Rate Application as Appendices 8C and 8B, respectively.[1] In addition, these hydro-related reports were filed in response to U-8 as part of the ACE 2025 Plan.[2]

These documents provide refreshed costing, archaeological considerations, and decommissioning estimates associated with hydro assets and serve as the most current updates relevant to the 2018 study.

(ii) N/A

(c) Please refer to Attachment 2 for a copy of NS Power's 5-Year Plan for Hydro

[1] M12451, NS Power 2026/2027 General Rate Application, Exhibit N-7, NS Power Depreciation Study, September 18, 2025.
[2] M12012, NS Power 2025 Annual Capital Expenditure Plan, Exhibit N-21, NS Power Responses to Undertakings, May 15, 2025.

NON-CONFIDENTIAL

2026 Hydro Interval Plan

WACC Rate	5.08%

System	TOTAL or NPV	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Annapolis																			
Decommissioning																			
Total Capital Investment	**$ 33,683,000**	$ 2,780,000	$ 1,209,000	$ 18,069,000	$ 11,625,000	$ -													
NPV	**$ 28,848,416**																		
Avon																			
Sustaining																			
Total Capital Investment	**$ 38,321,455**	$ 3,058,000	$ 2,532,000	$ 4,200,000	$ 1,000,000	$ -	$ 1,464,011	$ 114,869	$ 527,247	$ 119,509	$ 243,799	$ 124,337	$ 443,885	$ 129,361	$ 131,948	$ 134,587	$ 137,279	$ 140,024	$ 285,649
NPV	**$ 17,624,510**																		
Bear River																			
Sustaining																			
Total Capital Investment	**$ 44,295,769**	$ 858,000	$ 1,000,000	$ 2,625,000	$ -	$ -	$ 112,616	$ 1,378,423	$ 878,745	$ 119,509	$ 243,799	$ 124,337	$ 570,709	$ 776,164	$ 131,948	$ 1,581,395	$ 2,402,375	$ 700,121	$ 1,356,834
NPV	**$ 15,296,334**																		
Black River																			
Sustaining																			
Total Capital Investment	**$ 152,219,020**	$ 8,328,000	$ 14,152,000	$ 8,047,000	$ 38,423,000	$ 4,545,000	$ 788,314	$ 2,986,583	$ 5,155,301	$ 1,792,639	$ 1,218,994	$ 1,647,471	$ 317,060	$ 323,402	$ 461,818	$ 1,345,868	$ 1,372,786	$ 3,920,676	$ 2,070,957
NPV	**$ 88,334,993**																		
Dickie Brook																			
Sustaining																			
Total Capital Investment	**$ 17,758,022**	$ -	$ -	$ -	$ 950,000	$ 1,000,000	$ 56,308	$ 57,434	$ 58,583	$ 179,264	$ 60,950	$ 1,119,037	$ 63,412	$ 1,034,885	$ 65,974	$ 67,293	$ 68,639	$ 70,012	$ 71,412
NPV	**$ 6,440,047**																		
Fall River																			
Sustaining																			
Total Capital Investment	**$ 10,019,842**	$ 400,000	$ 4,200,000	$ -	$ -	$ -	$ 56,308	$ 57,434	$ 410,081	$ 59,755	$ 670,447	$ 62,169	$ 63,412	$ 64,680	$ 65,974	$ 67,293	$ 102,959	$ 70,012	$ 71,412
NPV	**$ 6,116,943**																		
Lequille																			
Sustaining																			
Total Capital Investment	**$ 27,616,429**	$ -	$ -	$ -	$ -	$ -	$ 506,773	$ 57,434	$ 58,583	$ 59,755	$ 60,950	$ 62,169	$ 63,412	$ 711,484	$ 65,974	$ 67,293	$ 755,032	$ 420,072	$ 4,641,800
NPV	**$ 7,372,176**																		
Mersey																			
Sustaining																			
Total Capital Investment	**$ 168,057,396**	$ 6,820,000	$ 12,775,000	$ 10,350,000	$ 6,400,000	$ 6,700,000	$ 3,997,877	$ 4,307,571	$ 4,159,391	$ 3,525,523	$ 1,950,391	$ 994,699	$ 887,769	$ 905,525	$ 923,635	$ 1,345,868	$ 960,950	$ 2,100,362	$ 999,772
NPV	**$ 75,512,812**																		
Nictaux																			
Sustaining																			
Total Capital Investment	**$ 23,343,802**	$ 240,000	$ -	$ 800,000	$ 1,750,000	$ -	$ 56,308	$ 344,606	$ 58,583	$ 537,792	$ 670,447	$ 559,518	$ 380,473	$ 1,940,410	$ 1,121,557	$ 67,293	$ 755,032	$ 70,012	$ 71,412
NPV	**$ 8,820,088**																		
Paradise																			
Sustaining																			
Total Capital Investment	**$ 16,325,526**	$ -	$ 85,000	$ 1,200,000	$ 950,000	$ -	$ 168,924	$ 631,777	$ 58,583	$ 358,528	$ 60,950	$ 559,518	$ 380,473	$ 64,680	$ 1,517,401	$ 2,018,803	$ 205,918	$ 70,012	$ 71,412
NPV	**$ 6,883,269**																		
Roseway																			
Decommissioning																			
Total Capital Investment	**$ 1,181,136**	$ 1,000,000	$ -	$ -	$ -	$ -													
NPV	**$ 1,086,206**																		
Sheet Harbour																			
Sustaining																			
Total Capital Investment	**$ 106,563,015**	$ 4,791,000	$ 3,100,000	$ 770,000	$ 9,500,000	$ 1,000,000	$ 337,849	$ 344,606	$ 351,498	$ 358,528	$ 487,598	$ 621,687	$ 1,585,302	$ 2,554,873	$ 527,792	$ 1,076,695	$ 3,981,079	$ 3,640,628	$ 428,474
NPV	**$ 38,930,398**																		
Sissiboo																			
Sustaining																			
Total Capital Investment	**$ 97,432,647**	$ 1,735,000	$ 2,445,000	$ 13,197,000	$ 18,450,000	$ 12,830,000	$ 1,520,319	$ 229,737	$ 234,332	$ 239,019	$ 365,698	$ 373,012	$ 253,648	$ 388,082	$ 5,607,785	$ 3,028,204	$ 1,921,900	$ 1,750,302	$ 3,534,909
NPV	**$ 56,568,630**																		
St Margaret's																			
Sustaining																			
Total Capital Investment	**$ 78,202,930**	$ -	$ 300,000	$ 4,250,000	$ 1,950,000	$ -	$ 675,697	$ 1,723,029	$ 1,757,489	$ 478,037	$ 1,676,117	$ 373,012	$ 507,297	$ 388,082	$ 3,529,606	$ 2,287,976	$ 549,114	$ 420,072	$ 428,474
NPV	**$ 26,685,949**																		
Tusket																			
Sustaining																			
Total Capital Investment	**$ 112,179,942**	$ 8,141,000	$ 27,151,000	$ 27,050,000	$ 9,750,000	$ 5,000,000	$ 168,924	$ 2,871,714	$ 3,104,897	$ 179,264	$ 182,849	$ 186,506	$ 317,060	$ 194,041	$ 3,562,593	$ 3,499,258	$ 205,918	$ 210,036	$ 214,237
NPV	**$ 80,345,728**																		
Wreck Cove LEM																			
Redevelopment																			
Total Capital Investment	**$ 36,843,000**	$ 11,218,000	$ 5,950,000	$ 14,500,000	$ 4,850,000	$ 325,000													
NPV	**$ 32,792,993**																		
Wreck Cove																			
Sustaining																			
Total Capital Investment	**$ 199,517,171**	$ 2,637,000	$ 1,110,000	$ 500,000	$ 5,850,000	$ -	$ 900,930	$ 287,171	$ 6,151,212	$ 657,301	$ 24,806,536	$ 1,492,049	$ 792,651	$ 323,402	$ 197,922	$ 20,389,905	$ 1,853,261	$ 350,060	$ 357,062
NPV	**$ 65,691,625**																		

NON-CONFIDENTIAL

2026 Hydro Interval Plan

WACC Rate	5.08%

System	TOTAL or NPV	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Annapolis																			
Decommissioning																			
Total Capital Investment	**$ 33,683,000**																		
NPV	**$ 28,848,416**																		
Avon																			
Sustaining																			
Total Capital Investment	**$ 38,321,455**	$ 145,681	$ 297,189	$ 757,833	$ 772,990	$ 157,690	$ 160,844	$ 492,182	$ 3,597,849	$ 2,560,330	$ 348,205	$ 1,021,111	$ 2,535,906	$ 3,325,660	$ 329,795	$ 3,075,570	$ 196,068	$ 199,989	$ 203,989
NPV	**$ 17,624,510**																		
Bear River																			
Sustaining																			
Total Capital Investment	**$ 44,295,769**	$ 145,681	$ 148,595	$ 151,567	$ 309,196	$ 788,450	$ 160,844	$ 2,132,788	$ 753,038	$ 170,689	$ 348,205	$ 177,584	$ 181,136	$ 831,415	$ 376,908	$ 5,093,913	$ 1,666,575	$ 11,927,341	$ 203,989
NPV	**$ 15,296,334**																		
Black River																			
Sustaining																			
Total Capital Investment	**$ 152,219,020**	$ 1,529,652	$ 2,897,597	$ 2,046,150	$ 3,034,758	$ 394,225	$ 1,367,172	$ 1,394,515	$ 2,259,114	$ 597,410	$ 2,524,485	$ 3,329,709	$ 2,671,758	$ 646,656	$ 2,732,584	$ 1,633,897	$ 1,470,507	$ 1,899,895	$ 2,243,876
NPV	**$ 88,334,993**																		
Dickie Brook																			
Sustaining																			
Total Capital Investment	**$ 17,758,022**	$ 327,783	$ 74,297	$ 227,350	$ 77,299	$ 1,340,364	$ 2,493,078	$ 1,845,682	$ 209,177	$ 85,344	$ 87,051	$ 266,377	$ 633,977	$ 277,138	$ 376,908	$ 2,210,566	$ 98,034	$ 99,994	$ 917,949
NPV	**$ 6,440,047**																		
Fall River																			
Sustaining																			
Total Capital Investment	**$ 10,019,842**	$ 72,841	$ 74,297	$ 530,483	$ 77,299	$ 78,845	$ 80,422	$ 82,030	$ 83,671	$ 85,344	$ 87,051	$ 88,792	$ 90,568	$ 508,087	$ 94,227	$ 672,781	$ 98,034	$ 99,994	$ 101,994
NPV	**$ 6,116,943**																		
Lequille																			
Sustaining																			
Total Capital Investment	**$ 27,616,429**	$ 72,841	$ 74,297	$ 75,783	$ 77,299	$ 78,845	$ 80,422	$ 82,030	$ 251,013	$ 85,344	$ 696,410	$ 88,792	$ 90,568	$ 3,233,280	$ 94,227	$ 9,515,045	$ 98,034	$ 99,994	$ 305,983
NPV	**$ 7,372,176**																		
Mersey																			
Sustaining																			
Total Capital Investment	**$ 168,057,396**	$ 2,622,260	$ 891,568	$ 3,637,599	$ 1,082,186	$ 1,103,829	$ 3,699,406	$ 984,364	$ 5,187,596	$ 7,339,612	$ 4,178,458	$ 7,893,630	$ 3,260,451	$ 8,129,391	$ 4,334,443	$ 1,730,008	$ 5,882,028	$ 1,199,934	$ 7,547,583
NPV	**$ 75,512,812**																		
Nictaux																			
Sustaining																			
Total Capital Investment	**$ 23,343,802**	$ 72,841	$ 74,297	$ 75,783	$ 77,299	$ 78,845	$ 80,422	$ 82,030	$ 251,013	$ 213,361	$ 87,051	$ 4,972,365	$ 1,267,953	$ 92,379	$ 282,681	$ 96,112	$ 1,078,372	$ 99,994	$ 305,983
NPV	**$ 8,820,088**																		
Paradise																			
Sustaining																			
Total Capital Investment	**$ 16,325,526**	$ 72,841	$ 668,676	$ 75,783	$ 77,299	$ 78,845	$ 201,055	$ 82,030	$ 251,013	$ 85,344	$ 87,051	$ 88,792	$ 2,400,054	$ 92,379	$ 94,227	$ 96,112	$ 98,034	$ 99,994	$ 305,983
NPV	**$ 6,883,269**																		
Roseway																			
Decommissioning																			
Total Capital Investment	**$ 1,181,136**												$ 181,136						
NPV	**$ 1,086,206**																		
Sheet Harbour																			
Sustaining																			
Total Capital Investment	**$ 106,563,015**	$ 2,767,941	$ 594,379	$ 757,833	$ 618,392	$ 2,365,349	$ 1,930,125	$ 656,242	$ 2,510,127	$ 810,771	$ 522,307	$ 2,663,767	$ 724,545	$ 2,401,865	$ 753,816	$ 576,669	$ 4,313,487	$ 799,956	$ 22,234,772
NPV	**$ 38,930,398**																		
Sissiboo																			
Sustaining																			
Total Capital Investment	**$ 97,432,647**	$ 291,362	$ 1,040,163	$ 1,667,233	$ 309,196	$ 473,070	$ 321,687	$ 492,182	$ 334,684	$ 341,377	$ 6,572,366	$ 1,065,507	$ 1,630,225	$ 831,415	$ 376,908	$ 1,345,562	$ 392,135	$ 599,967	$ 4,385,758
NPV	**$ 56,568,630**																		
St Margaret's																			
Sustaining																			
Total Capital Investment	**$ 78,202,930**	$ 582,724	$ 2,600,408	$ 3,561,816	$ 1,855,176	$ 2,365,349	$ 683,586	$ 492,182	$ 920,380	$ 640,082	$ 4,526,663	$ 710,338	$ 2,264,202	$ 4,434,213	$ 8,668,887	$ 2,883,347	$ 3,725,284	$ 1,299,928	$ 815,955
NPV	**$ 26,685,949**																		
Tusket																			
Sustaining																			
Total Capital Investment	**$ 112,179,942**	$ 218,522	$ 520,082	$ 227,350	$ 386,495	$ 236,535	$ 402,109	$ 902,333	$ 251,013	$ 2,304,297	$ 261,154	$ 266,377	$ 271,704	$ 2,494,245	$ 471,135	$ 288,335	$ 490,169	$ 3,199,823	$ 305,983
NPV	**$ 80,345,728**																		
Wreck Cove LEM																			
Redevelopment																			
Total Capital Investment	**$ 36,843,000**																		
NPV	**$ 32,792,993**																		
Wreck Cove																			
Sustaining																			
Total Capital Investment	**$ 199,517,171**	$ 218,522	$ 3,194,787	$ 4,395,432	$ 3,323,856	$ 394,225	$ 3,458,140	$ 2,871,060	$ 4,769,242	$ 1,109,476	$ 435,256	$ 532,753	$ 3,260,451	$ 4,249,454	$ 1,978,768	$ 6,247,252	$ 2,254,777	$ 299,983	$ 305,983
NPV	**$ 65,691,625**																		

NON-CONFIDENTIAL

2026 Hydro Interval Plan

WACC Rate	5.08%

System	TOTAL or NPV	2062	2063	2064	2065
Annapolis					
Decommissioning					
Total Capital Investment	**$ 33,683,000**				
NPV	**$ 28,848,416**				
Avon					
Sustaining					
Total Capital Investment	**$ 38,321,455**	$ 520,171	$ 212,230	$ 1,298,847	$ 1,324,824
NPV	**$ 17,624,510**				
Bear River					
Sustaining					
Total Capital Investment	**$ 44,295,769**	$ 1,040,343	$ 955,034	$ 216,474	$ 1,656,030
NPV	**$ 15,296,334**				
Black River					
Sustaining					
Total Capital Investment	**$ 152,219,020**	$ 4,473,473	$ 4,775,172	$ 4,113,015	$ 7,286,531
NPV	**$ 88,334,993**				
Dickie Brook					
Sustaining					
Total Capital Investment	**$ 17,758,022**	$ 104,034	$ 106,115	$ 865,898	$ 110,402
NPV	**$ 6,440,047**				
Fall River					
Sustaining					
Total Capital Investment	**$ 10,019,842**	$ 104,034	$ 106,115	$ 270,593	$ 110,402
NPV	**$ 6,116,943**				
Lequille					
Sustaining					
Total Capital Investment	**$ 27,616,429**	$ 416,137	$ 4,350,713	$ 108,237	$ 110,402
NPV	**$ 7,372,176**				
Mersey					
Sustaining					
Total Capital Investment	**$ 168,057,396**	$ 9,155,014	$ 1,910,069	$ 13,313,180	$ 2,870,452
NPV	**$ 75,512,812**				
Nictaux					
Sustaining					
Total Capital Investment	**$ 23,343,802**	$ 104,034	$ 2,652,873	$ 108,237	$ 1,766,432
NPV	**$ 8,820,088**				
Paradise					
Sustaining					
Total Capital Investment	**$ 16,325,526**	$ 104,034	$ 106,115	$ 108,237	$ 2,649,648
NPV	**$ 6,883,269**				
Roseway					
Decommissioning					
Total Capital Investment	**$ 1,181,136**				
NPV	**$ 1,086,206**				
Sheet Harbour					
Sustaining					
Total Capital Investment	**$ 106,563,015**	$ 13,836,556	$ 3,501,793	$ 4,329,490	$ 1,435,226
NPV	**$ 38,930,398**				
Sissiboo					
Sustaining					
Total Capital Investment	**$ 97,432,647**	$ 1,248,411	$ 1,591,724	$ 3,355,354	$ 662,412
NPV	**$ 56,568,630**				
St Margaret's					
Sustaining					
Total Capital Investment	**$ 78,202,930**	$ 624,206	$ 1,379,494	$ 7,955,437	$ 3,919,270
NPV	**$ 26,685,949**				
Tusket					
Sustaining					
Total Capital Investment	**$ 112,179,942**	$ 3,121,028	$ 318,345	$ 2,922,405	$ 331,206
NPV	**$ 80,345,728**				
Wreck Cove LEM					
Redevelopment					
Total Capital Investment	**$ 36,843,000**				
NPV	**$ 32,792,993**				
Wreck Cove					
Sustaining					
Total Capital Investment	**$ 199,517,171**	$ 520,171	$ 2,652,873	$ 42,104,286	$ 42,283,960
NPV	**$ 65,691,625**				

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2026 Hydro 5-Year Plan

Project Number	River System	Project Title	2026	2027	2028	2029	2030
C0057361	Annapolis	HYD ANN Facility Isolation	$ 1,000,000	$ -	$ -	$ -	$ -
C0047973	Annapolis	HYD ANN Sluice Gates and Check Refurbishment	$ 950,000	$ 343,000	$ 4,069,000	$ -	$ -
47650-H774	Annapolis	HYD ANN Decision (Options) Analysis	$ 830,000	$ 500,000	$ 14,000,000	$ 11,625,000	$ -
C0049456	Annapolis	HYD ANN Safety Boom Replacement	$ -	$ 366,000	$ -	$ -	$ -
	Annapolis Total		**$ 2,780,000**	**$ 1,209,000**	**$ 18,069,000**	**$ 11,625,000**	**$ -**
C0052514	Avon River	HYD MacDonald Dam Access Improvements	$ 963,000	$ 482,000	$ -	$ -	$ -
C0063803	Avon River	HYD AVO2 Access Road Stabilization	$ 750,000	$ 750,000	$ -	$ -	$ -
C0048990	Avon River	HYD AVO2 Switchgear Replacement	$ 550,000	$ -	$ -	$ -	$ -
49036-H766	Avon River	HYD AVO2 Controls Upgrade	$ 430,000		$ -	$ -	$ -
C0058062	Avon River	HYD AVO2 Station Service Upgrade	$ 365,000	$ -	$ -	$ -	$ -
C0048871	Avon River	HYD AVO1 Controls Upgrade	$ -	$ 650,000	$ 400,000	$ -	$ -
C0038127	Avon River	HYD AVO1 Overhaul	$ -	$ 500,000	$ 1,000,000	$ -	$ -
TBD	Avon River	HYD AVO2 Overhead Door Replacement	$ -	$ 100,000	$ -	$ -	$ -
TBD	Avon River	HYD AVO1 Powerhouse Refurbishment	$ -	$ 50,000	$ 700,000	$ 250,000	$ -
C0039067	Avon River	HYD AVO1 Generator Refurbishment	$ -	$ -	$ 900,000	$ -	$ -
C0039246	Avon River	HYD AVO1 Switchgear Replacement	$ -	$ -	$ 550,000	$ 500,000	$ -
C0051932	Avon River	HYD AVO2 Penstock Recoating	$ -	$ -	$ 650,000	$ -	$ -
TBD	Avon River	HYD AVO2 Crane Replacement	$ -	$ -	$ -	$ 250,000	$ -
	Avon River Total		**$ 3,058,000**	**$ 2,532,000**	**$ 4,200,000**	**$ 1,000,000**	**$ -**
C0049192	Bear River	HYD GUL Generator Refurbishment	$ 450,000	$ -	$ -	$ -	$ -
C0039266	Bear River	HYD GUL Overhaul	$ 408,000	$ -	$ -	$ -	$ -
49037-H767	Bear River	HYD RID Controls Upgrade	$ -	$ 500,000	$ 1,000,000	$ -	$ -
C0038629	Bear River	HYD RID Surge Tank Refurbishment	$ -	$ 500,000	$ 1,500,000	$ -	$ -
C0038326	Bear River	HYD BER Arc Flash Upgrades	$ -	$ -	$ 125,000	$ -	$ -
	Bear River Total		**$ 858,000**	**$ 1,000,000**	**$ 2,625,000**	**$ -**	**$ -**
16374-H517	Black River	HYD Gaspereau Dam Safety Remedial Works	$ 2,700,000	$ 2,500,000	$ 400,000	$ 9,600,000	$ -
C0080228	Black River	HYD HOB Stator Refurbishment	$ 1,870,000	$ -	$ -	$ -	$ -
C0054155	Black River	HYD HEG Dam Refurbishment	$ 689,000	$ 579,000	$ 678,000	$ 26,395,000	$ 45,000
C0080626	Black River	HYD WHR Bypass Modifications	$ 600,000	$ -	$ -	$ -	$ -
C0021342	Black River	HYD LUM Butterfly Valve Replacement	$ 562,000	$ 750,000	$ 1,100,000	$ 1,400,000	$ 4,500,000
47649	Black River	HYD Salmontail Dam Spillway Refurbishment	$ 460,000	$ 4,580,000	$ -	$ -	$ -
C0049011	Black River	HYD HEG Controls Upgrade	$ 412,000	$ 365,000	$ 35,000	$ -	$ -
C0049010	Black River	HYD HEG Switchgear Replacement	$ 340,000	$ 980,000	$ 240,000	$ -	$ -
C0067686	Black River	HYD LUM Rubber Dam Replacement	$ 250,000	$ 1,000,000	$ 10,000	$ -	$ -
C0038134	Black River	HYD LUM Crane Replacement	$ 150,000	$ -	$ -	$ -	$ -
C0080632	Black River	HYD WHR Eel Passage	$ 125,000	$ 450,000	$ -	$ -	$ -
C0080630	Black River	HYD Gaspereau Lake Telemetry	$ 120,000	$ -	$ -	$ -	$ -
C0039286	Black River	HYD HEG1 Surge Tank Refurbishment	$ 50,000	$ 500,000	$ 1,000,000	$ -	$ -
TBD	Black River	HYD LUM Controls Upgrade	$ -	$ 900,000	$ -	$ -	$ -
TBD	Black River	HYD WHR Controls Upgrade	$ -	$ 900,000	$ -	$ -	$ -
TBD	Black River	HYD HOB Crane Replacement	$ -	$ 250,000	$ -	$ -	$ -
TBD	Black River	HYD Aylesford Eel Passage	$ -	$ 157,000	$ 473,000	$ -	$ -
C0059802	Black River	HYD HEG Penstock Refurbishment	$ -	$ 60,000	$ 250,000	$ -	$ -
TBD	Black River	HYD HOB Controls Upgrade	$ -	$ 50,000	$ 900,000	$ -	$ -
TBD	Black River	HYD MET Controls Upgrade	$ -	$ 50,000	$ 900,000	$ -	$ -
TBD	Black River	HYD HOB Overhaul	$ -	$ 50,000	$ 850,000	$ -	$ -
C0059803	Black River	HYD HEG2 Surge Tank Refurbishment	$ -	$ 31,000	$ 411,000	$ 28,000	$ -
C0051314	Black River	HYD Black River Arc Flash Upgrades	$ -	$ -	$ 500,000	$ -	$ -
TBD	Black River	HYD WHR Overhaul	$ -	$ -	$ 50,000	$ 1,000,000	$ -
TBD	Black River	HYD WHR Crane Replacement	$ -	$ -	$ 250,000	$ -	$ -
	Black River Total		**$ 8,328,000**	**$ 14,152,000**	**$ 8,047,000**	**$ 38,423,000**	**$ 4,545,000**

2026 Hydro 5-Year Plan

Project Number	River System	Project Title	2026	2027	2028	2029	2030
47660	Dickie Brook	HYD DIB Controls Upgrade	$ -	$ -	$ -	$ 600,000	$ -
TBD	Dickie Brook	HYD DIB2 Overhaul	$ -	$ -	$ -	$ -	$ 1,000,000
TBD	Dickie Brook	HYD DIB Crane Replacement	$ -	$ -	$ -	$ 350,000	$ -
	Dickie Brook Total		**$ -**	**$ -**	**$ -**	**$ 950,000**	**$ 1,000,000**
49272-H776	Fall River	HYD Miller Lake Dam Refurbishment	$ 400,000	$ 4,200,000	$ -	$ -	$ -
	Fall River Total		**$ 400,000**	**$ 4,200,000**	**$ -**	**$ -**	**$ -**
11622-H001-405	Hydro General	HYD Routine Equipment Replacement	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000
C0053718	Hydro General	HYD Dam Safety Routine	$ 700,000	$ 700,000	$ 700,000	$ 700,000	$ 700,000
35583-H005-405	Hydro General	HYD Oil Release Risk Assessment Routine	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$ 450,000
20706-P012-405	Hydro General	HYD Security Improvement (PSAD)	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$ 450,000
27867-H004-405	Hydro General	HYD Roofing Routine	$ 220,000	$ 220,000	$ 220,000	$ 220,000	$ 220,000
C0041549	Hydro General	HYD HMS Rebabbitting Upgrade	$ 205,000	$ 150,000	$ -	$ -	$ -
35584-H006-405	Hydro General	HYD Gate Refurbishment Routine	$ 200,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000
C0038876	Hydro General	HYD HMS Vertical Boring Mill Refurbishment	$ 150,000	$ -	$ -	$ -	$ -
11611-P015-405	Hydro General	HYD Production Tools, Test Equip	$ 130,000	$ 130,000	$ 130,000	$ 130,000	$ 130,000
C0076111	Hydro General	HYD Bridge Inspections	$ 100,000	$ 100,000	$ -	$ -	$ -
C0080629	Hydro General	HYD Fish Safe Runner Assessment	$ -	$ 250,000	$ -	$ -	$ -
	Hydro General Total		**$ 3,605,000**	**$ 3,650,000**	**$ 3,150,000**	**$ 3,150,000**	**$ 3,150,000**
	Lequille River	No projects currently in the 5Yr Plan	$ -	$ -	$ -	$ -	$ -
	Lequille River Total		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
C0080219	Mersey River	HYD DEB Spillway Drawdown	$ 3,150,000	$ -	$ -	$ -	$ -
C0059783	Mersey River	HYD ULF2 Overhaul	$ 600,000	$ 700,000	$ 100,000	$ -	$ -
C0070206	Mersey River	HYD LLF Spillway Drawdown	$ 500,000	$ 1,500,000	$ -	$ -	$ -
C0070486	Mersey River	HYD LGB Stoplog Replacement	$ 466,000	$ -	$ -	$ -	$ -
C0080112	Mersey River	HYD BIF6 Rotor Reinsulation	$ 465,000	$ -	$ -		$ -
C0068283	Mersey River	HYD LGB Controls Upgrade	$ 440,000	$ 500,000	$ -	$ -	$ -
C0042526	Mersey River	HYD ULF2 Generator Refurbishment	$ 300,000	$ 600,000	$ -	$ -	$ -
C0058503	Mersey River	HYD LLF Crane Column Refurbishment	$ 292,000	$ -	$ -	$ -	$ -
C0064943	Mersey River	HYD BIF Hoist Replacement	$ 150,000	$ 1,000,000	$ 350,000	$ -	$ -
TBD	Mersey River	HYD LGB Eel Passage	$ 105,000	$ -	$ 1,000,000	$ -	$ -
C0080221	Mersey River	HYD BIF Powerhouse Leak Refurbishment	$ 79,000	$ -	$ -	$ -	$ -
C0060245	Mersey River	HYD Mersey Powerhouse Concrete Assessment	$ 73,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000
TBD	Mersey River	HYD DEB Eel Passage	$ 50,000	$ 1,000,000	$ -	$ -	$ -
TBD	Mersey River	HYD COW Eel Passage	$ 50,000	$ 800,000	$ -	$ -	$ -
TBD	Mersey River	HYD DEB Fishway Modifications	$ 50,000	$ 750,000	$ -	$ -	$ -
TBD	Mersey River	HYD LGB Fishway Modifications	$ 50,000	$ 50,000	$ 1,400,000	$ -	$ -
TBD	Mersey River	HYD DEB10 Overhaul	$ -	$ 1,500,000	$ -	$ -	$ -
TBD	Mersey River	HYD DEB10 Generator Refurbishment	$ -	$ 1,500,000	$ -	$ -	$ -
C0064945	Mersey River	HYD LLF Hoist Replacement	$ -	$ 1,000,000	$ 1,000,000	$ -	$ -
TBD	Mersey River	HYD LGB Sluiceway Refurbishment	$ -	$ 400,000	$ -	$ -	$ -
TBD	Mersey River	HYD LLF Powerhouse Roof Refurbishment	$ -	$ 400,000	$ -	$ -	$ -
TBD	Mersey River	HYD DEB Crane Replacement	$ -	$ 300,000	$ -	$ -	$ -
TBD	Mersey River	HYD LGB Crane Replacement	$ -	$ 300,000	$ -	$ -	$ -
TBD	Mersey River	HYD BIF Powerhouse Roof Refurbishment	$ -	$ 250,000	$ -	$ -	$ -
C0068703	Mersey River	HYD COW Battery Bank Replacement	$ -	$ 125,000	$ -	$ -	$ -
TBD	Mersey River	HYD LLF4 Overhaul	$ -	$ -	$ 1,500,000	$ -	$ -
TBD	Mersey River	HYD DEB9 Generator Refurbishment	$ -	$ -	$ -	$ 1,000,000	$ -
TBD	Mersey River	HYD LLF4 Generator Refurbishment	$ -	$ -	$ 1,000,000	$ -	$ -
TBD	Mersey River	HYD BIF Spillway Drawdown	$ -	$ -	$ -	$ 2,500,000	$ -
TBD	Mersey River	HYD ULF Spillway Drawdown	$ -	$ -	$ 2,000,000	$ -	$ -
TBD	Mersey River	HYD BIF Eel Passage	$ -	$ -	$ -	$ -	$ 1,000,000
TBD	Mersey River	HYD LLF3 Generator Refurbishment	$ -	$ -	$ -	$ -	$ 1,000,000
TBD	Mersey River	HYD DEB9 Overhaul	$ -	$ -	$ -	$ 1,500,000	$ -
TBD	Mersey River	HYD LGB8 Overhaul	$ -	$ -	$ 1,500,000	$ -	$ -
TBD	Mersey River	HYD LLF3 Overhaul	$ -	$ -	$ -	$ -	$ 1,500,000
TBD	Mersey River	HYD COW Powerhouse Roof Refurbishment	$ -	$ -	$ 250,000	$ -	$ -
TBD	Mersey River	HYD DEB Powerhouse Roof Refurbishment	$ -	$ -	$ -	$ 250,000	$ -
TBD	Mersey River	HYD LLF Eel Passage	$ -	$ -	$ -	$ -	$ 1,000,000
TBD	Mersey River	HYD ULF Eel Passage	$ -	$ -	$ -	$ -	$ 1,000,000
TBD	Mersey River	HYD COW Fishway Modifications	$ -	$ -	$ -	$ 50,000	$ 750,000
C0064944	Mersey River	HYD DEB Hoist Replacement	$ -	$ -	$ 150,000	$ 1,000,000	$ 350,000
	Mersey Total		**$ 6,820,000**	**$ 12,775,000**	**$ 10,350,000**	**$ 6,400,000**	**$ 6,700,000**

2026 Hydro 5-Year Plan

Project Number	River System	Project Title	2026	2027	2028	2029	2030
TBD	Nictaux	HYD NIC Eel Passage	$ 240,000	$ -	$ 800,000	$ 1,000,000	$ -
TBD	Nictaux	HYD NIC Main Dam Refurbishment	$ -	$ -	$ -	$ 750,000	$ -
	Nictaux Total		**$ 240,000**	**$ -**	**$ 800,000**	**$ 1,750,000**	**$ -**
C0019020	Paradise	HYD PAR System Arc Flash Upgrades	$ -	$ 85,000	$ 150,000	$ -	$ -
TBD	Paradise	HYD PAR Surge Tank Refurbishment	$ -	$ -	$ 50,000	$ 950,000	$ -
47655-H758	Paradise	HYD PAR Controls Upgrade	$ -	$ -	$ 1,000,000	$ -	$ -
	Paradise Total		**$ -**	**$ 85,000**	**$ 1,200,000**	**$ 950,000**	**$ -**
C0050414	Roseway	HYD Roseway	$ 1,000,000	**$ -**	**$ -**	**$ -**	**$ -**
	Roseway Total		**$ 1,000,000**	**$ -**	**$ -**	**$ -**	**$ -**
50518-H792	Sheet Harbour	HYD Ruth Falls Main Dam Refurbishment	$ 3,700,000	$ -	$ -	$ -	$ -
49756-H791	Sheet Harbour	HYD Marshall Falls Main Dam Refurbishment	$ 641,000	$ 650,000	$ 700,000	$ 9,500,000	$ 1,000,000
C0073368	Sheet Harbour	HYD MAL Falls Rubber Dam Replacement	$ 450,000	$ 1,600,000	$ 70,000	$ -	$ -
C0019025	Sheet Harbour	HYD Sloane Dam Refurbishment	$ -	$ 550,000	$ -	$ -	$ -
TBD	Sheet Harbour	HYD RUT Penstock Refurbishment	$ -	$ 300,000	$ -	$ -	$ -
	Sheet Harbour Total		**$ 4,791,000**	**$ 3,100,000**	**$ 770,000**	**$ 9,500,000**	**$ 1,000,000**
50580-H795	Sissiboo	HYD WEY Intake Refurbishment	$ 835,000	$ 1,575,000	$ 12,597,000	$ 6,600,000	$ -
50574-H794	Sissiboo	HYD Sissiboo Falls Main Dam Refurb	$ 430,000	$ 570,000	$ 600,000	$ 11,400,000	$ 12,500,000
C0072488	Sissiboo	HYD SIS Bridge Refurbishment	$ 370,000	$ 300,000	$ -	$ -	$ -
C0082128	Sissiboo	HYD FUN Smoke Detection	$ 100,000	$ -	$ -	$ -	$ -
49622	Sissiboo	HYD SIS Controls Upgrade	$ -	$ -	$ -	$ 450,000	$ 330,000
	Sissiboo Total		**$ 1,735,000**	**$ 2,445,000**	**$ 13,197,000**	**$ 18,450,000**	**$ 12,830,000**
TBD	St Margarets Bay	HYD SAL/MIL Controls Upgrade	$ -	$ 200,000	$ 1,500,000	$ 600,000	$ -
TBD	St Margarets Bay	HYD SAL Switchgear	$ -	$ 50,000	$ 1,000,000	$ 675,000	$ -
TBD	St Margarets Bay	HYD Mill Lake Switchgear	$ -	$ 50,000	$ 1,000,000	$ 675,000	$ -
C0039366	St Margarets Bay	HYD SAL Penstock Replacement	$ -	$ -	$ 750,000	$ -	$ -
	St Margarets Bay Total		**$ -**	**$ 300,000**	**$ 4,250,000**	**$ 1,950,000**	**$ -**
49595	Tusket	HYD TUS1 Overhaul	$ 3,412,000	$ 1,701,000	$ -	$ -	$ -
29807-H541	Tusket	HYD TUS Falls Main Dam	$ 1,950,000	$ 21,400,000	$ 25,700,000	$ 8,250,000	$ -
48913-H765	Tusket	HYD TUS Facility Refurbishment	$ 1,200,000	$ 4,000,000	$ 850,000	$ 1,500,000	$ 5,000,000
C0064966	Tusket	HYD TUS Tidal Pool	$ 1,000,000	$ -	$ -	$ -	$ -
C0080230	Tusket	HYD TUS3 Stator Refurbishment	$ 479,000	$ -	$ -	$ -	$ -
C0019199	Tusket	HYD TUS Crane Refurbishment	$ 100,000	$ -	$ -	$ -	$ -
TBD	Tusket	HYD TUS Headgate Replacement	$ -	$ 50,000	$ 500,000	$ -	$ -
	Tusket Total		**$ 8,141,000**	**$ 27,151,000**	**$ 27,050,000**	**$ 9,750,000**	**$ 5,000,000**
C0073348	Wreck Cove	HYD WRC Surge Lake Volume Optimization	$ 1,200,000	$ -	$ -	$ -	$ -
CI0039346	Wreck Cove	HYD GIS Civil Refurbishment	$ 500,000	$ 10,000	$ -	$ -	$ -
C0068251	Wreck Cove	HYD WRC D-11 Valve and Housing Replacement	$ 232,000	$ -	$ -	$ -	$ -
C0080635	Wreck Cove	HYD WRC South Lake Building Upgrade	$ 230,000	$ -	$ -	$ -	$ -
C0027882	Wreck Cove	HYD WRC Fire Protection Replacement	$ 225,000	$ -	$ -	$ -	$ -
C0080634	Wreck Cove	HYD WRC D6 D8 Riprap Replacement	$ 150,000	$ -	$ -	$ -	$ -
C0080633	Wreck Cove	HYD WRC D-1 Valve and Housing Replacement	$ 50,000	$ 500,000	$ -	$ -	$ -
C0064304	Wreck Cove	HYD WRC Gallery Tailrace Hoist	$ 50,000	$ 400,000	$ -	$ -	$ -
TBD	Wreck Cove	HYD WRC Sea Gate Refurbishment	$ -	$ 200,000	$ -	$ -	$ -
C0038627	Wreck Cove	HYD WRC Upper Warehouse Replacement	$ -	$ -	$ -	$ 600,000	$ -
C0031464	Wreck Cove	HYD WRC Garage Aux Storage	$ -	$ -	$ -	$ 250,000	$ -
TBD	Wreck Cove	HYD WRC D-6-1 McLeod Brook	$ -	$ -	$ 500,000	$ 5,000,000	$ -
	Wreck Cove Total		**$ 2,637,000**	**$ 1,110,000**	**$ 500,000**	**$ 5,850,000**	**$ -**
C0014218	Wreck Cove LEM	HYD WRC LEM Balance of Plant	$ 5,300,000	$ -	$ -	$ -	$ -
C0013838	Wreck Cove LEM	HYD WRC LEM Unit Rehabilitation	$ 2,900,000	$ -	$ -	$ -	$ -
C0006418	Wreck Cove LEM	HYD WRC Tailrace Rock Bolting Phase 2	$ 1,780,000	$ -	$ -	$ -	$ -
C0032746	Wreck Cove LEM	HYD WRC Tunnel T-1 Remediation	$ 550,000	$ 5,250,000	$ 9,500,000	$ 1,850,000	$ -
C0058543	Wreck Cove LEM	HYD WRC D-11 By-pass	$ 438,000	$ -	$ -	$ -	$ -
C0034486	Wreck Cove LEM	HYD WRC LEM Penstock Intake	$ 250,000	$ 700,000	$ 5,000,000	$ 3,000,000	$ 325,000
	Wreck Cove LEM Total		**$ 11,218,000**	**$ 5,950,000**	**$ 14,500,000**	**$ 4,850,000**	**$ 325,000**
	Hydro Total		**$ 55,611,000**	**$ 79,659,000**	**$ 108,708,000**	**$ 114,598,000**	**$ 34,550,000**

Request IR-18:

Section 7.0 Transmission pages 46 to 50

In reference to Figure 19 on page 46, please describe the reasons for the proposed significant decrease in transmission investment for 2026, 2027 and 2028 compared to the forecasts in the 2025 ACE Plan.

Response IR-18:

Please refer to NSEB IR-5.

Request IR-19:

Section 7.0 Transmission pages 46 to 50

On page 48 of the application, NS Power states: "The focus for transmission capital investments in 2026 is on sustaining and improving system reliability and transformational investment in Energy Storage and Synchronous Condensers" Similarly, on pdf page 52 of the application, NS Power states: "The focus for Distribution capital investments in 2026 continues to reflect localized customer load growth and customer reliability." And on pdf page 92 of the application, NS Power states: "All T&D projects in the 2026 ACE Plan that are included in the Five-Year Reliability Plan will contribute to having a net positive impact on the metrics tracked under performance standards."

(a) Which specific performance standards metrics are expected to improve with the completion of the proposed 2026 ACE Plan T&D projects?

(i) Please explain specifically how the proposed 2026 ACE Plan T&D projects are expected to improve each of these metrics.

(ii) What is the expected net positive impact (improvement) on the metric tracked by each of these performance standards?

(b) Are the 2026 distribution capital investments expected to produce any improvements in system reliability?

(i) If not, why not?

(ii) If so, please explain how.

Response IR-19:

(a-b) The investments proposed in the 2026 ACE Plan for NS Power's transmission and distribution system will have a positive impact on reliability as the assets (e.g. transmission lines, distribution feeders, transformers) are replaced and upgraded and vegetation will be moved away from lines.

The investments will address current reliability challenges on the targeted systems and contribute to avoidance of future outages throughout the province by executing corrective actions identified through inspection programs and other condition indicators. This work contributes to improving both Performance Standards SAIFI and SAIDI in these areas.

As outlined in the 5-Year Reliability Plan, the capital investments proposed for 2026 are not anticipated to result in a single, incremental, system-wide year-over-year improvement, but will support the longer-term system performance improvements of transmission and distribution assets by both correcting existing/emerging reliability issues and avoiding issues that have not caused reliability impacts to date. While each project is expected to have a positive, localized impact on performance and a corresponding impact on the overall system performance, the specific quantitative impacts on SAIFI and SAIDI (or CKAIFI and CKAIDI) of each investment are not possible to estimate due to the variability of factors such as system configuration and weather conditions. For example, The 5-Year Reliability Plan does include NS Power's long-term projections for Performance Standards SAIFI and SAIDI improvement over the 2025–2029 period.

Request IR-20:

Section 7.0 Transmission pages 46 to 50

Figure 22: Transmission Carry-over Capital Spending Summary. Have there been changes to the Final Date for any of the projects listed since the ACE Plan has been filed?

(a) Please identify each of these carry-over projects that has a current total estimate amount that exceeds the Board approved amount by the ATO threshold and identify the related dollar amount over the Board approved amount.

(b) Please explain why C0045132 ECEI Energy Storage has a negative subsequent spending of $3,291,005.

(c) Please explain why the following projects list subsequent spending given that their final dates are in 2026: C0021140 138KV-25KV Substation Stellarton; C0068961 2025 PCB Substation Sampling and Replacement; C0031122 L6539 2021 Replacements and Upgrades; C0061551 L7009 Replacements and Upgrades; C0050842 2024 Bulk Oil (KSO) Breaker Replacements; C0061547 L7022 Replacements and Upgrades; and C0041791 L6551 Replacements and Upgrades.

Response IR-20:

Yes. Project Final Dates are continuously being reviewed and revised as project progresses.

(a) Please refer to the Transmission carry-over projects that have a current total estimate amount that exceeds the Board-approved amount by the ATO threshold below in the 2026 ACE Plan:

CI#	Project Title	Project Estimate ($)	NSEB Approved Amount ($)	Variance ($)

C0056240*	2024 Transmission Switch & Breaker Replacements	4,126,028	3,271,622	864,406
C0055539	10H-T1 Transformer Replacement	2,836,396	2,420,892	415,505

*Most recent forecast for this project is within $250,000 or 5% of the approved budget.

(b) The negative number is a forecast of Federal funding expected for the project that is anticipated be received in early 2027.

(c) The amount listed in subsequent spend is project contingency tagged as 2027 spend, however, will be incurred (if needed) in 2026.

Request IR-21:

Section 7.0 Transmission pages 46 to 50

For the following carry-over projects, please provide an explanation for the increase in total project expenditure from prior submissions/fillings and the 2026 ACE application:

- **C0021140 - 138KV-25KV Substation Stellarton.**

- **C0031122 - L6539 2021 Replacements and Upgrades.**

- **C0061550 - L5031 Hubbards to East Chester Phase 2.**

Response IR-21:

- C0021140 - 138KV-25KV Substation Stellarton: The total project expenditure listed in the 2026 ACE Plan carryover list of $12,960,396 is the same as the NSEB-approved amount of $12,960,396 under M12275.

- C0031122 – L6539 2021 Replacements and Upgrades: This project was filed as an Authorization to Overspend (ATO) in April 2025, and was approved by the Board in August 2025 under M12203 for $5,584,042. The total project is still in progress and still forecast to meet the approved budget.

- C0061550 - L5031 Hubbards to East Chester Phase 2: This project was approved in the 2024 ACE Plan at $5,297,584. The total project expenditure in the 2026 ACE Plan carryover list of $5,418,956 has increased due to the need for two new bypass structures required to achieve the transmission outage in lieu of the original plan to use a mobile transformer. There are also additional costs related to building a new gravel access road to a structure for replacement that was not included in the original budget.

Request IR-22:

Section 7.0 Transmission pages 46 to 50

Please identify any transmission projects that are being advanced ahead of confirmed generation or load requirements and explain why early capital commitment is prudent.

Response IR-22:

There are no transmission projects submitted for approval in the 2026 ACE Plan that are being advanced ahead of confirmed generation or load requirements.

Request IR-23:

Section 8.0 Distribution pages 51 to 54

Figure 27: Distribution Carry-over Capital Spending Summary. Have there been changes to the Final Date for any of the projects listed since the ACE Plan has been filed?

(a) Please identify each of these carry-over projects that has a current total estimate amount that exceeds the Board approved amount by the ATO threshold and identify the related dollar amount over the Board approved amount.

Response IR-23:

Yes. Project Final Dates are continuously being reviewed and revised as projects progress.

(a) Please refer to the Distribution carry-over projects that have a current total estimate amount that exceeds the Board-approved amount by the ATO threshold below in the 2026 ACE Plan:

CI#	Project Title	Project Estimate ($)	NSEB Approved Amount ($)	Variance ($)
C0008638	Cogswell HRM Redevelopment Program	8,001,748	6,617,148	1,384,600
C0068954*	2025 PCB Downline Sampling and Replacement	2,286,083	1,716,718	569,365
52184*	37N-412 – Glooscap Trail Rebuild Ph 2	1,173,369	858,046	315,324

*Most recent forecast for this project is within $250,000 or 5% of the approved budget.

Request IR-24:

Section 8.0 Distribution pages 51 to 54

Please explain why the following projects list subsequent spending given that their final dates are in 2026: C0068954 2025 PCB Downline Device Sampling and Replacement; C0071954 87W-312 Dauphiness Mill Lake Rebuild; 52184 37N-412-Glooscap Trail Rebuild PH2; C0031117 2H-411 Prospect Road Phase Extension; and C0070426 2025 Downline Recloser Additions.

Response IR-24:

For C0068954 2025 PCB Downline Device Sampling and Replacement, and 52184 37N-412-Glooscap Trail Rebuild PH2, the dates listed in ACE were an error. C0031117 2H-411 Prospect Road Phase Extension and C0070426 2025 Downline Recloser Additions, these projects show subsequent spending because the listed final dates represent the planned completion of construction, but it is anticipated that final vendor invoices and close out documentation will carry into 2027. For C0071954 87W-312 Dauphiness Mill Lake Rebuild, it is expected that this will have construction that carries into 2027 as this project will need to be executed in multiple phases.

Request IR-25:

Section 8.0 Distribution pages 51 to 54

Please provide an explanation for the increase in total project expenditure from prior submissions/fillings and the 2026 ACE application for C0008638 – D - Cogswell HRM Redevelopment Program.

Response IR-25:

The approved project application identified a budget of $6,617,148.

The 2026 ACE Plan carryover list included a forecast total estimate of $8,001,748. The forecast included cost estimates for additional polychlorinated biphenyls (PCB) remediation work and necessary switchgear equipment upgrades and refurbishment that was not able to be anticipated at the time the original budget was submitted for approval.

Additional detail will be provided in the ATO submission, which is anticipated to be filed later in 2026

Request IR-26:

Section 9.0 General Plant pages 55 to 58

In reference to Figure 29 – General Plant Investment on page 55, Please describe the reasons for the proposed significant increase in general plant investment for 2028 and 2029 compared to the forecasts in the 2025 ACE Plan.

Response IR-26:

The increase in General Plant investment in 2028 and 2029 from the 2025 ACE Plan to the 2026 ACE Plan is driven by:

- 2028 - $44 million increase - Increased investment in the CIS Replacement project and Customer Care & Billing Infrastructure ($30 million) and an increase of $14 million in general IT application replacements and upgrades as improvements in the multi year forecasting process have been made as NS Power continually enhances its understanding of the IT asset's condition, which has given greater visibility into the future investment requirements related to IT infrastructure.

- 2029 - $41 million increase – This increase is primarily driven by a $24 million investment in the Customer Care & Billing infrastructure and an increase of $16 million in general IT application replacements and upgrades.

Request IR-27:

Section 9.0 General Plant pages 55 to 58

Figure 32: General Plant Carry-over Capital Spending Summary. Have there been changes to the Final Date for any of the projects listed since the ACE Plan has been filed?

(a) Please identify each of these carry-over projects that has a current total estimate amount that exceeds the Board approved amount by the ATO threshold and identify the related dollar amount over the Board approved amount.

Response IR-27:

Yes. Project Final Date is continuously being reviewed and revised as project progresses.

(a) There are no General Plant carry-over projects that have a current total estimate amount that exceeds the Board approved amount by the ATO threshold.

Request IR-28:

Section 9.0 General Plant pages 55 to 58

For the following carry-over projects, please provide an explanation for the increase in total project expenditure from prior submissions/fillings and the 2026 ACE application:

- **C0032664 ECC Optimization Tools**
- **C0047277 IT GIS Utility Network Migration**
- **C0053696 ECC Wind Integration**
- **C0061284 IT – OT Cyber Security Control Implementation Phase 1**
- **C0062043 IT Sharepoint Technical Migration**

Response IR-28:

- C0032664 ECC Optimization Tools: There is currently an application in front of the Board for $7.5M. There is $0 variance between 2026 ACE and the application.
- C0047277 IT GIS Utility Network Migration: This was approved in 2024 ACE for $6.2 million and listed in 2026 ACE for $6.3 million. The $0.1 million variance is due to the increase in internal labour and associated overheads and AFUDC for the additional planning effort to determine the path forward.
- C0053696 ECC Wind Integration: There is currently an application in front of the Board for $4.4 million. There is $0 variance between 2026 ACE and the application.

- C0061284 IT – OT Cyber Security Control Implementation Phase 1: This was approved in 2025 for $6.8 million and listed in 2026 ACE for $6.8 million. There is no material variance to explain.

- C0062043 IT Sharepoint Technical Migration: This is listed for the first time in the 2026 ACE as a subsequent submittal. It is not a carry-over project.

Request IR-29:

Section 10.0 Routine Capital Program pages 59 to 86

In reference to Figure 34 – Routine Capital Spending Project Breakdown Yr/Yr on page 59 to 60.

Please describe the reasons for the significant increase in forecast 2026 spending for the "Transmission Line Replacement Add'ns/Mod'ns" routine.

(a) Please describe the reasons for the significant increase in forecast 2026 spending for the "Distribution Upgrade and Replacement" routine.

(b) Please describe the reasons for the significant increase in forecast 2026 spending for the "Work Vehicles" routine.

Response IR-29:

The increase in forecast 2026 spending for the "Transmission Line Replacements Add'ns/Mod'ns" routine is due to the addition of T020 Transmission Switch & Breaker Replacements Routine and T030 Transmission Tower Life Extension/Replacement Routine which are new routines, and were not previously included in this total.

(a) The increase in the Distribution Upgrade and Replacemcent routine category in the 2026 ACE Plan is primarily driven by increased investment in system reliability initiatives and the introduction of a new routine (D020 Padmount Replacement Program).

(b) The increase in the Work Vehicles routine is driven by the supply chain constraints that have been ongoing as a result of the COVID-19 pandemic. Backlogs in truck deliveries caused NS Power orders to be pushed out of previous years and causing large underspends

in the P062 Work Vehicles Routine in 2023 and 2024. These delayed vehicles plus additional orders are the reason for the increases in 2025 and the 2026 budgets.

Request IR-30:

Section 10.0 Routine Capital Program pages 59 to 86

Section 10.1 of the 2026 ACE Plan shows that annual routine capital expenditure remains high.

(a) Please explain why routine capital expenditures continue to increase or remain elevated notwithstanding the characterization of these activities as "like for like" replacements.

(b) Please also explain whether NS Power has realized any efficiency gains in the execution of routine capital work over this period, including learning curve, productivity, or scale efficiencies associated with repeat work.

Response IR-30:

(a) The characterization of routines as largely "like for like" replacements should not be inferred as the routine capital program should stay relatively flat year over year. The routine program also includes both improvement (ROW Widening for example) and new installation (New Customer for example) investments that have seen significant increases over the last number of years.

Routines that are like for like replacements, such as the vehicle replacement routine, can also fluctuate significantly depending on the timing of deliveries, or as is the current situation, still catching up from multiple years of delayed deliveries due to manufacturing backlogs following the COVID-19 pandemic. This is highlighted in Section 10.1 as the 2024 actual spend in this routine was $7.8 million and is forecasted for $23.2 million in 2026.

In 2026, NS Power has also added three new routines that were historically stand-alone capital projects (Transmission Tower Refurbishment / Life Extension, Transmission Switch & Breaker Replacement, and Padmount Replacement Program). This has increased the 2026 Routine program by $7 million.

In general, inflation over the last number of years has impacted utilities more than many other industries as increases to raw materials such as steel has greatly increased the costs of many of the products NS Power purchases in the routine program. The cost of, and demand for, vehicles has risen dramatically since COVID, as have other materials within the routine program.

(b) In all capital routines, and all capital projects in general, efficiencies are pursued whenever possible. NS Power has realized benefits in all of its planned work, including work included in routines, as part of WAM Phase 2, the benefits of which are highlighted in M12253 WAM Phase 2 Annual Benefits Report. NS Power continues to explore and implement new initiatives that could provide further benefits to work within these routines. One such example is depot splitting and service days, a scheduling improvement initiative that serves to decrease travel time and therefore travel costs associated with appointment booked work including renovations which are included in D004.

Request IR-31:

D005 - Unplanned Replacement Deteriorated Equipment

Board staff note that routine capital expenditures have been persistently high, with a planned increase of approximately 18% ($3.3M) in the 2026 ACE Plan. In NS Power's response to Board IR-1 in M12319, it was indicated that the sustained increase is a result of a higher-than-expected volume of reactive power outages due to asset failures and deteriorated assets.

(a) Please provide the number of outages attributable to deteriorated equipment or asset failures for each of the past 5 years. For the same period, please provide additional detail on the nature of these failures, including the asset categories involved.

(b) Please provide a breakdown of the average cost per day for routine capital expenditures, comparing actuals versus budget for each year from 2022–2025 and the 2026 forecast.

(c) Please provide an update on the information requested in Board IR-18 in M12319, including the 2025 actual and 2026 forecast data.

(d) Please explain why D005 was under budget in 2025.

Response IR-31:

(a) Please refer to the table below for the number of outage events coded as failed equipment by asset category. Assets can fail for a number of reasons, depending on the asset, including but not limited to, material fatigue, manufacturing defects, fault conditions, and external stresses.

Asset Category	2021	2022	2023	2024	2025
Anchor	5	6	7	2	5
Arrestor	73	67	92	81	65
Capacitor	2	3	-	1	-
Conductor	667	2,253	1,264	531	587
Conduit	2	2	1	2	1
Connections	851	981	742	502	431
Fuse	1,247	1,533	1,664	1,414	1,428
Guy	17	24	15	13	16
Insulator	121	188	148	119	108
Metering	32	55	51	46	36
Protection Device	26	37	39	18	32
Service	886	1,803	820	457	430
Streetlight	4	4	4	1	3
Structure	321	710	453	426	382
Switch	20	21	26	17	29
Tie Wire	55	127	72	70	55
Transformer	591	600	1,162	628	512
Voltage Regulator	3	9	12	4	2
Total	**4,923**	**8,423**	**6,572**	**4,332**	**4,122**

(b) Please refer to the table below.

D005 - Unplanned Replace Deteriorated	2022 Budget	2022 Actuals	2023 Budget	2023 Actuals	2024 Budget	2024 Actuals	2025 Budget	2025 Actuals	2026 Budget
Total Person Days	8,907	8,267	9,318	9,601	8,682	10,300	8,655	7,718	8,446
Average Person Days Cost ($)	1,915	2,163	2,137	2,523	2,240	2,562	2,455	2,786	2,654
Total Net Forecast ($M)*	17.1	17.9	19.9	24.2	19.4	26.4	21.2	21.5	22.4

* As figures in the table are rounded , calculations may differ due to rounding.

(c) Please refer to the table below.

D005	2025 Actuals ($)	2026 Budget ($)
Regular Labour and Term Labour	1,864,183	2,420,417
Overtime Labour	3,226,297	3,225,875
Materials	7,276,070	7,403,852
Contracts/Consulting	5,391,668	5,560,979
Meals/Travel and Other	137,048	263,166
Royalty, Easement, Appraisal	19,988	22,658

D005	2025 Actuals ($)	2026 Budget ($)
Contractor Overhead	610,523	575,473
Vehicle Allocated Costs	1,713,865	1,278,630
Admin Overheads	1,963,834	2,177,285
Salvage	(100,990)	(81,646)
Total	22,101,034	22,846,689
Capital Contributions	(600,526)	(428,099)
Overall Total	21,501,960	22,418,590

(d) The final 2025 investment for D005 was $21.5M, which was 1.2% over budget.

Request IR-32:

D006 - Regulatory Replacements – Province

Board staff notes that a 104% increase ($2.2M) is contemplated for this routine.

(a) Please provide a detailed explanation for the drivers of this increase.

(b) Please also explain why D006 was under budget in 2025.

Response IR-32:

(a) The increased D006 spend is a result of the volume of work forecasted by the Provincial Department of Public Works and Municipal governments across the province that will impact NS Power plant.

(b) The D006 decrease in spend for 2025 was a result of several key projects that were delayed or deferred by the Department of Public Works in 2025. Some of the key projects that have been deferred include: Port Hastings Roundabout, Argyle Interchange, Lancaster Drive Intersection, Stella Dr/Route 207 Intersection Realignment and Route 207 Lawrencetown Rd Realignment.

Request IR-33:

Section 10.0 Routine Capital Program pages 59 to 86

D055 - Planned Replacement of Distribution Equipment

(a) **This routine is set to increase by $5.6M in 2026. Please provide a detailed explanation of the drivers of this increase.**

(b) **For each year from 2022–2025, please provide a breakdown of budgeted versus actual expenditures by major cost categories (e.g., labour, materials, contractor services, overhead, etc.).**

(c) **Please provide the same cost category breakdown for the 2026 forecast.**

(d) **Please confirm whether this routine includes both replacement of existing devices and installation of new or upgraded devices not previously in service.**

(e) **For the assets replaced under this routine, please provide:**

(i) **Average age at replacement for each major asset category, and**

(ii) **Expected useful life for each major asset category.**

(f) **Please explain why the budget for this routine, which involves planned replacements, is based on historical average expenditures rather than a more forward-looking, componentized approach that considers the condition, age, and expected lifecycle of the individual assets.**

Response IR-33:

(a) The increase in forecast spend for 2026 is primarily driven by incremental investment in system reliability initiatives. Spending within this routine is primarily allocated to targeted equipment replacement, including pole upgrades to larger, stronger poles. This increase in spending is aligned with the Five-Year Reliability Plan and is driven by risk-based decision-making.

(b) Please refer to the table below.

Cost Category	2022		2023		2024		2025	
	Budget ($)	Actuals ($)	Budget ($)	Actuals ($)	Budget ($)	Actuals ($)	Budget ($)	Actuals ($)
Regular Labour and Term Labour	1,526,088	1,778,938	1,642,056	1,496,081	1,791,088	1,731,589	1,908,102	3,446,135
Overtime Labour	239,306	344,499	270,653	530,585	331,398	480,421	498,552	604,444
Materials	1,442,281	745,317	1,421,672	1,610,965	1,284,122	1,937,042	1,507,467	4,102,720
Contracts/Consulting	2,709,920	2,918,201	2,462,492	3,448,410	2,719,887	5,443,006	3,808,550	8,579,368
Meals/Travel and Other	22,633	68,596	26,691	42,369	58,828	42,107	26,747	127,280
Royalty, Easement, Appraisal	100,454	206,239	139,904	(11,244)	115,936	72,899	112,391	91,385
Contractor Overhead	459,244	514,566	455,582	651,259	409,303	824,332	545,811	1,215,559
Vehicle Allocated Costs	657,640	762,886	732,931	698,901	999,581	1,005,427	1,062,008	1,794,948
Admin Overheads	1,194,395	1,413,118	1,461,711	1,437,637	1,130,731	1,103,952	1,221,637	2,115,834
Salvage	(35,866)	(66,366)	(60,443)	(105,752)	(47,532)	(75,462)	(61,688)	(91,806)
Total	**8,316,095**	**8,685,993**	**8,553,250**	**9,799,211**	**8,793,342**	**12,565,311**	**10,629,577**	**21,985,867**
Capital Contributions	(31)	2,836	(7,390)	(1,798)	(2,866)	(53,132)	(8,715)	(5,183)
Overall Total	**8,316,064**	**8,688,829**	**8,545,860**	**9,797,413**	**8,790,476**	**12,512,179**	**10,620,862**	**21,980,684**

(c) Please refer to the table below.

Cost Category	2026 Budget ($)
Regular Labour and Term Labour	2,912,574
Overtime Labour	722,651
Materials	2,295,030

Cost Category	2026 Budget ($)
Contracts/Consulting	5,581,449
Meals/Travel and Other	113,350
Royalty, Easement, Appraisal	-
Contractor Overhead	577,375
Vehicle Allocated Costs	1,041,135
Admin Overheads	1,769,205
Salvage	-
Total	**15,012,770**
Capital Contributions	(12,755)
Overall Total	**15,000,016**

(d) Confirmed.

(e) Asset age is a concern when the frequency of required maintenance is increased, the availability of replacement parts or critical spares is limited, or performance is negatively impacted. This information can be used to inform project prioritization. However, when relevant, age would only be used in concert with asset condition, performance, and legislated requirements; it is not the single determining element in an investment decision.

(i) The ages of individual distribution assets are typically not tracked and does not play a significant role in determining overall risk identification and mitigation activities. Direct assessment of asset condition through inspections and historic performance consistent with NS Power's asset management approach is the preferred method for determining condition and subsequently, risks.

(ii) Ranges for estimated useful life for key distribution assets based on Iowa State curves can be found in Figure 76 of the 2026 ACE Plan Application. Not all individual components that could be replaced under D055 have a well-defined expected useful life.

(f) This routine budget is not solely based on historical averages. While some components are forecast using historical averages expenditures to reflect variable, condition-driven

replacement activity, a large portion of the 2026 budget was developed using forward-looking, project-based estimates. These estimates in particular were developed through asset condition and risk data. Please refer to Figure 42 of the 2026 ACE Plan Application which outlines the forecasting methodology for D055.

Request IR-34:

D004 New Customers

(a) Please provide the calculations used to derive the 2026 ACE Plan budget figures for routine D004 "New Customer Upgrades", routine D061 "New Customers – Residential", and routine D062 "New Customers – Commercial".

(b) Please provide a detailed cost breakdown of actual expenditures for 2025 for D004, categorized by project type, including but not limited to:

(i) New customer connections

(ii) Customer renovations

(iii) Load growth-driven projects.

(c) Please provide the same detailed breakdown used for the 2026 forecast.

Response IR-34:

(a) The same calculation was used for all three projects listed above and is consistent with the method utilized for the 2025 ACE Plan. The forecasted total for all three projects was NS Power's Q3 Forecast plus inflation of 1.8%. Based on the results seen in 2025, NS Power considers this approach to be appropriate for 2026 and will continue to evaluate if a change is needed if actuals vary significantly from budget. Please refer to page 62 of the 2026 ACE Plan for both the 2025 Q3 forecast as well as the 2026 ACE Plan totals for D004, D061, and D062, and the table below for the calculation.

ACE 2026	**D004 ($)**	**D061 ($)**	**D062 ($)**
Total 2025 Q3 Forecast Pre-Overheads	14,994,038	27,706,072	9,782,173
Inflation at 1.8%	269,893	498,709	176,079
Administrative Overheads	4,020,005	7,858,317	2,369,819
Total Budget	**19,283,936**	**36,063,099**	**12,328,071**

(b) New customer connections are included in D061 and D062, not D004.

Please refer to the table below for costs associated with customer renovations:

Customer Connections	
Cost Category	**2025 Total**
Regular Labour and Term Labour	3,427,133
Overtime Labour	922,344
Materials	4,501,098
Contracts/Consulting	4,272,155
Meals/Travel and Other	87,903
Royalty, Easement,Appraisal	41,735
Contractor Overhead	591,518
Vehicle Allocated Costs	1,911,061
Admin Overheads	2,199,563
Salvage	-42,177
Total	**17,912,333**
Capital Contributions	-2,185,494
Overall Total	**15,726,839**

Please refer to the table below costs associated with load growth:

Load Growth-Driven	
Cost Category	**2025 Total**
Regular Labour and Term Labour	250,155
Overtime Labour	73,588
Materials	558,603
Contracts/Consulting	1,094,835
Meals/Travel and Other	15,499
Royalty, Easement,Appraisal	4,550

Cost Category	**2025 Total**
Contractor Overhead	157,587
Vehicle Allocated Costs	139,270
Admin Overheads	161,513
Salvage	-6,940
Total	**2,448,660**
Capital Contributions	-233,281
Overall Total	**2,215,379**

(c) There are no costs associated with individual new customer connections in D004. NS Power does not budget or forecast this project with a distinction between customer renovation-related costs and general load growth-driven costs. Please refer to the table below for the 2026 forecast by account for D004.

Cost Category	**2026 Budget ($)**
Regular Labour and Term Labour	3,363,603
Overtime Labour	1,033,476
Materials	6,139,585
Contracts/Consulting	6,621,457
Meals/Travel and Other	107,488
Royalty, Easement, Appraisal	46,603
Contractor Overhead	691,862
Vehicle Allocated Costs	1,233,457
Admin Overheads	2,094,685
Salvage	(58,727)
Total	**21,273,489**
Capital Contributions	(1,989,554)
Overall Total	**19,283,936**

Request IR-35:

Section 10.0 Routine Capital Program pages 59 to 86

D010 Provincial widening

(a) Please provide more insight into the 2026 D010 budget, including a detailed breakdown of expenditures by major cost category.

(b) For each year from 2022 to 2026, please provide the number of D010 projects completed, the kilometers of line widened, and the average cost per kilometre.

(c) Please provide a regional breakdown of D010 spending for the same period, identifying differences in activity or costs by geographic area.

(d) Please provide data on tree-related outages for 2023 to 2025, distinguishing outages directly attributable to right-of-way width from those caused by other factors. Please also provide a comparison of these outages to other outage causes during the same period.

Response IR-35:

(a) The 2026 costs included in the D010 budget are 100 percent contracts for $13,223,181 and associated administrative overhead.

D010	2026 Budget ($)
Regular Labour	184,500
Contracts	11,300,000
Contractor Overhead*	1,634,206
Admin Overheads*	104,475
Total	13,223,181
* please note D010 was forecasted using 2025 AO rates	

(b) D010 breaks projects down to the feeder level; therefore, each feeder that has widening completed on it is considered a separate project under D010.

Year	D010 Projects	Kms Widened	Cost ($)	Cost $/km
2022	4	49	2,217,877	45,262
2023	3	77	3,478,379	45,173
2024	23	155	7,060,325	45,550
2025	27	190	8,654,266	45,548

(c) The work completed in D010, across all regions, does not have differences in activity. Costs can vary by feeder depending on the vegetative condition or location, but no region has consistent differences compared to another. Please refer to the table below:

Year	Region	Km Widened	Cost ($)
2022			
	Northeast	47	2,152,199
	West	1	65,677
Total		49	2,217,877
2023			
	Northeast	76	3,445,540
	West	1	32,839
Total		77	3,478,379
2024			
	Cape Breton	1	45,469
	Metro	23	1,030,631
	Northeast	86	3,925,490
	West	45	2,058,735
Total		155	7,060,325

Year	Region	Km Widened	Cost ($)
2025			
	Cape Breton	9	429,429
	Metro	35	1,598,993
	Northeast	77	3,503,639
	West	69	3,122,205
Total		190	8,654,266
Grand Total		471	21,410,847

(d) NS Power does not distinguish tree-related outages attributed to right of way width, as the event data does not consistently capture this level of detail and limited field observability often prevents further tree-caused identification. When crews arrive on site, trees or branches may no longer be present, the contact point may be unclear, or only minimal physical evidence remains. These factors can make it difficult to determine whether an outage was related to right of way width or by other tree related factors. Consequently, any comparison between these categories would be inconclusive and potentially misleading. However, previously stated assumptions indicate that approximately 80 percent of tree contacts originate from outside the maintained right-of-way.

Request IR-36:

Section 10.0 Routine Capital Program pages 59 to 86

P062 – work vehicles

(a) Please provide, for each year from 2022 to 2026, the following information for P062: the total fleet size at year-end, the number of vehicles replaced annually, and the number of vehicles retired annually.

(i) For each year provided, please identify the salvage value.

(ii) Please explain the difference between replaced and retired.

(b) For vehicles replaced under this routine, please provide the average age and mileage or hours of use at replacement for each year from 2022 to 2026.

(c) Please also state the expected useful life assumed for each major vehicle class and confirm whether these assumptions remain consistent across the period.

Response IR-36:

(a-b) The table below shows the total replacements (new vehicles added to the fleet) and retirements (units sold at auction) and the total fleet size at the end of the year from 2022 to 2025. Most of the new vehicles in 2025 arrived late in the year and the vehicles taken out of service have not yet been sold. The total salvage value is also listed for each year. As explained in NSEB IR 29, delays in truck deliveries in 2023 and 2024 resulted in the units sold in 2025 being older and more deteriorated than the trucks typically sold in past years, resulting in a lower auction value.

Year	Replaced	Sold	Fleet Size	Salvage Value	Average Age of Replaced Vehicles	Average Odometer Reading at Replacement
2022	8	2	134	$11,264	9.5	254,434
2023	14	6	146	$20,291	8.6	259,604
2024	5	0	151	$N/A	8.5	228,974
2025	22	10	163	$2,353	9.6	252,935

(c) While age and kilometers are a factor in determining the replacement timeframe for a specific vehicle, the reason for vehicle replacement is based on overall asset condition and likelihood of failure in the coming year. These vehicles would have exceeded their expected useful life, which is typically 8 years for a work vehicle. With the increased budget in 2026, NS Power continues to work towards a replacement program that is more aligned with the expected useful life of these vehicles.

Request IR-37:

Section 10.0 Routine Capital Program pages 59 to 86

(a) Please identify which components of P031 relate to routine lifecycle replacement or refresh, cybersecurity risk mitigation or enhancement, and remediation or recovery activities associated with the cybersecurity incident.

(b) Please also identify any new costs incurred under this routine in 2026.

(c) Finally, please explain why this routine was underspent in 2025, including any key drivers, changes in scope, timing of projects, or other factors that contributed to the variance between budgeted and actual expenditures.

Response IR-37:

(a) The P031 Infrastructure Routine captures routine lifecycle replacement and refresh investments. The components listed in the 2026 ACE Plan are for the standard procurement of lifecycle replacements for the different asset types listed. None of the assets presented in the P031 Infrastructure Routine are for cybersecurity risk mitigation, enhancement, nor recovery activities associated with the cybersecurity incident.

(b) The P031 Infrastructure Routine presented in the 2026 ACE Plan is consistent with what was submitted in the 2025 ACE Plan. There are no new costs incurred under this routine in 2026.

(c) The 2025 forecast for the P031 Infrastructure Routine presented in Figure 35 on page 63 did not capture two sub-routines (PC and mobile devices replacements), therefore showed an amount that is lower than the actual forecast. The 2025 forecast should have stated $2,378,500.

Request IR-38:

Distribution routines:

(a) Please explain how the forecasting methodologies illustrated in Figure 42 avoid reliance on historical spending levels as a proxy for future need and instead demonstrate independent evidence of required and necessary capital.

(b) Please indicate whether NS Power accounts for reductions in backlog, improvements in asset condition, or diminishing marginal need resulting from prior years' routine capital investments. Please explain why the methodologies assume no efficiency gains in the execution of routine capital programs.

(c) Do the forecasting methodologies incorporate any external benchmarks?

(d) For any new routines added, please explain in detail why they are being added as routines, including a clear scope definition that specifies what work is explicitly included and excluded.

(e) Please explain how forecast volumes and costs were developed for each routine. Provide actual expenditure for projects that would be classified under each new routine for 2022-2025.

Response IR-38:

(a) The forecasting methodologies for most of the distribution routines rely on historical averages to predict future spend. When scopes of work are known prior to filing then the routine is budgeted based on those scopes of work (i.e. D051). Historical averages or using the prior years Q3 forecast has been deemed the most effective method of forecasting the other routines which are comprised of work from new customer requests, reactive events,

inspection results, storms and any other miscellaneous customer request. These scopes of work are less predictable, and lead times are quite short on these requests. Due to the less predictable nature of these types of work using a historical forecast or Q3 Forecast is the most appropriate methodology to use for forecasting these routines.

(b) For the routines based on customer requests and reactive events the work is required to be done either immediately or within a prescribed time, therefore prior years work does not alleviate the work required in future years as it is based on new customer requests (D004, D061, D0062), joint use partner requests (D007), regulatory requests (D006) and reactive/outage events (D005, D008). The D055 Distribution Planned Replacements Routine addresses deteriorated assets identified through inspections, and completing those replacements does take that specific item out of the list of required assets to be replaced. As time goes on more assets continue to deteriorate and are added to the list on future inspections. Reducing the overall spend for this routine would have a negative impact on reliability and would lead to increased costs in reactive routines D005 and D008. NS Power continuously looks for opportunities for efficiency gains throughout all its processes; therefore, those gains would be included in the historical averages.

(c) No external benchmarks were used.

(d) D020 Padmount Replacements was added as a new routine in 2026. It funds the replacement of deteriorated Padmounted transformer assets, including all related activities necessary to execute the replacement work.

(e) Forecast volume and costs were developed based on asset condition assessments and constrained by what can be practically executed within a single year, considering labour capacity and material procurement timelines. Please refer to the below table for spend of Padmount Replacement projects from 2022-2025:

Year	Actuals ($)
2022	1,355,265
2023	1,335,735
2024	1,655,896
2025	1,583,494

1

Request IR-39:

Section 10.0 Routine Capital Program pages 59 to 86

D061 and D062 – New Customers

(a) Please update the attachment provided in M12319 Board IR-7 to include 2025 actual expenditures and the forecast for 2026.

(b) Please provide the following for each year from 2022 to 2025:

(i) Number of new customers added.

(ii) Kilometers of distribution line installed.

(iii) Number of new connections completed.

(iv) Number of projects requested or initiated.

(c) For D061 and D062, please provide an updated breakdown similar to that provided in Board IR-14 in M12319, incorporating 2025 actual expenditures, and 2026 forecast expenditures.

(d) For each of D004, D061, and D062, please provide the proportion of capital costs funded by customer contributions and the portion funded by NS Power.

(e) For each of D004, D061, and D062, please provide a detailed explanation of how the 2026 forecast was developed beyond reliance on historical averages, including the assumptions and inputs used, such as customer demand, economic or population growth, electrification or technology adoption, and any other factors that influence

the forecast. Please explain how these assumptions are incorporated into the methodology and how the approach differs, if at all, from prior years.

(f) Please explain why D061 came under budget in 2025, including any key drivers, changes in scope, timing of projects, or other factors that contributed to the variance between budgeted and actual expenditures.

Response IR-39:

(a) Please refer to the table below.

D004	2025			2026
Cost Category	Budget ($)	Actuals ($)	%Share	Budget ($)
Regular Labour and Term Labour	2,738,812	3,677,288	20%	3,363,603
Overtime Labour	600,615	995,932	6%	1,033,476
Materials	6,421,323	5,049,307	28%	6,139,585
Contracts/Consulting	5,880,148	5,375,368	30%	6,621,457
Meals/Travel and Other	51,936	103,403	1%	107,488
Royalty, Easement, Appraisal	29,569	46,285	0%	46,603
Contractor Overhead	849,233	749,104	4%	691,862
Vehicle Allocated Costs	1,497,008	2,050,331	11%	1,233,457
Admin Overheads	1,720,931	2,361,076	13%	2,094,685
Salvage	(38,390)	(49,117)	0%	(58,727)
Total	19,751,185	20,358,978	113%	21,273,489
Capital Contributions	(2,408,648)	(2,418,775)	-13%	(1,989,554)
Overall Total	17,342,537	17,940,203	100%	19,283,936

D061	2025			2026
Cost Category	Budget ($)	Actuals ($)	%Share	Budget ($)
Regular Labour and Term Labour	6,357,044	7,670,615	22%	6,981,629
Overtime Labour	2,171,099	1,828,754	5%	2,027,385
Materials	18,640,141	11,425,809	32%	14,640,467
Contracts/Consulting	10,789,722	11,314,267	32%	9,954,155
Meals/Travel and Other	238,565	406,799	1%	184,697
Royalty, Easement,Appraisal	14,439	23,864	0%	22,800
Contractor Overhead	1,559,509	1,611,171	5%	1,037,847
Vehicle Allocated Costs	3,568,819	4,123,744	12%	2,504,435
Admin Overheads	4,214,443	4,853,160	14%	4,316,035

D061	2025			2026
Salvage	(14,151)	(16,125)	0%	(19,983)
Total	47,539,628	43,242,059	123%	41,649,467
Customer Recovery	135,539	74,363	0%	140,829
Capital Contributions	(8,184,891)	(8,147,039)	-23%	(5,727,197)
Overall Total	39,490,277	35,169,382	100%	36,063,099

D062	2025			2026
Cost Category	Budget ($)	Actuals ($)	% Share	Budget ($)
Regular Labour and Term Labour	2,025,213	2,021,131	17%	2,152,762
Overtime Labour	576,964	622,540	5%	726,327
Materials	6,354,358	7,077,358	59%	7,960,227
Contracts/Consulting	3,019,456	1,998,217	17%	2,144,458
Meals/Travel and Other	185,026	521,941	4%	85,233
Royalty, Easement, Appraisal	8,467	15,764	0%	14,343
Contractor Overhead	436,674	276,090	2%	219,358
Vehicle Allocated Costs	1,142,177	1,130,326	9%	792,314
Admin Overheads	1,310,153	1,315,491	11%	1,358,147
Salvage	(2,379)	(1,704)	0%	(2,262)
Total	15,056,108	14,977,154	125%	15,450,908
Customer Recovery	322,851	239,939	2%	293,580
Capital Contributions	(2,927,716)	(3,239,697)	-27%	(3,416,416)
Overall Total	12,451,243	11,977,397	100%	12,328,071

(b)

(i) Please refer to the table below:

Year	**Customers added**
2022	5,119
2023	7,712
2024	8,586
2025	7,285

(ii) Please refer to the table below. Note that the table denotes net change in kilometers of distribution line on the system, not total distance added, as it is derived from a snapshot in time from NS Power's GIS database. Also note that the cyber incident has temporarily impacted NS Power's ability to track these changes as as-builts are not being updated in NS Power's GIS database immediately after the work is

complete; as a result, the 2025 figure has not been provided, as it is expected to change as databases are eventually reconciled. Once reconciliation is complete, there is not expected to be any gaps in the data.

Year	Net Change in Total km of Distribution
2022	377
2023	(74)
2024	465

(iii) Please refer to the table below:

Year	Residential (D061)	Commercial (D062)	Total
2022	6,199	586	6,785
2023	6,224	511	6,735
2024	7,802	625	8,427
2025	6,562	461	7,023

(iv) NS Power does not create new projects for new customer additions. The other factors described above are not incorporated into the forecasting methodology.

(c) Please refer to the table below. Note that NS Power forecasts these projects on financials, not on number of units.

D061 Unit Rate per Customer	2025 Actuals ($)
Regular Labour and Term Labour	1,169
Overtime Labour	279
Materials	1,741
Contracts/Consulting	1,724
Meals/Travel and Other	62
Royalty, Easement,Appraisal	4
Contractor Overhead	246
Vehicle Allocated Costs	628
Admin Overheads	740
Salvage	(2)
Total	**6,590**
Customer Recovery	11

Capital Contributions	(1,242)
Overall Total	**5,360**

Number of D061 units	**6562**

D062 Unit Rate per Customer	**2025 Actuals ($)**
Regular Labour and Term Labour	4,384
Overtime Labour	1,350
Materials	15,352
Contracts/Consulting	4,335
Meals/Travel and Other	1,132
Royalty, Easement,Appraisal	34
Contractor Overhead	599
Vehicle Allocated Costs	2,452
Admin Overheads	2,854
Salvage	(4)
Total	**32,488**
Customer Recovery	520
Capital Contributions	(7,028)
Overall Total	**25,981**

Number of D062 units	**461**

(d) Please refer to the below table for the proportion of capital costs funded by customer contributions and the portion funded by NS Power.

Type	**D004 Budget ($)**	**D061 Budget ($)**	**D062 Budget ($)**
NS Power Funded	21,273,489	41,790,296	15,744,487
Customer Contributions	(1,989,554)	(5,727,197)	(3,416,416)
Total Routine	**19,283,936**	**36,063,099**	**12,328,071**

* As figures in the table are rounded to the nearest dollar, calculations may differ due to rounding.

(e) Similar to the 2025 ACE Plan, the 2026 ACE Plan budget for D004, D061 and D062 was developed based on the Q3 forecast for each of these routines plus inflation. None of the factors referenced above directly impacted the forecast, and given the initial success of this revised forecasting methodology, NS Power does not intend to explore further

incorporation of additional factors; rather, the Company will continue to monitor the effectiveness of the current forecasting methodology.

(f) The 2025 ACE Plan budget was based on the 2024 Q3 forecast plus inflation. 2025 had fewer new residential customers connections than 2024, therefore resulting in the underspend for D061.

Request IR-40:

Directives & Misc pages 87 to 141

Section 11.1.2 Annual Rating/Prioritization of Capital Projects pages 88 to 90

Figure 56, pdf page 88 – Evergreen IRP vs. 2026 ACE Plan Forecast Comparison by Unit: Please provide a table showing the Integrated Resource Plan (IRP) and ACE Plan dollar amounts expected to be spent per unit.

Response IR-40:

Forecast assumptions such as system load and resources may have changed since the 2022-2023 Evergreen IRP. In some cases, this has altered unit utilization and mission priority resulting in changes to the 2026 investment profile. For example, due to increased utilization of Trenton 5 since the IRP forecast, additional boiler and mill investment was required in 2026 to help extend the unit operating safely and reliably until retirement.

Please refer to the table below showing the Integrated Resource Plan (IRP) and 2026 ACE Plan dollar amounts expected to be spent per unit in 2026:

Unit	IRP ($)	2026 ACE Plan ($)
Gas Turbines	24,774,538	13,031,695
Lingan Unit 1	11,974,570	10,069,701
Lingan Unit 2	2,390,016	299,478
Lingan Unit 3	8,000,674	10,612,049
Lingan Unit 4	7,546,476	7,289,107
Pt Aconi	16,442,889	12,607,688
Pt. Tupper	15,993,531	13,221,433
Port Hawkesbury Biomass	5,369,858	5,634,855
Trenton Unit 5	2,930,281	7,409,166
Trenton Unit 6	8,975,746	8,695,470
Tufts Cove Unit 1	7,579,777	11,089,188
Tufts Cove Unit 2	8,177,931	9,800,666
Tufts Cove Unit 3	6,440,227	7,971,078
Tufts Cove Unit 6	6,097,391	6,032,002
Total	**132,693,905**	**123,763,575**

1

Request IR-41:

Directives & Misc pages 87 to 141

Section 11.1.2 Annual Rating/Prioritization of Capital Projects pages 88 to 90

(a) Are all assets rated each year or is there a failure or age threshold to trigger a rating?

(b) NS Power identified in the third bullet that projects are rated according to unit reliability, among other indicators. Please elaborate on the unit reliability assessment and threshold applied to a unit for it to be rated.

Response IR-41:

(a) Not all assets are rated each year. NS Power completes updated risk ratings for all projects brought forward for inclusion in the ACE Plan (please refer to the 2026 ACE Plan Application, Appendix B). Higher-criticality assets are reviewed through NS Power's Asset Strategy Committees, which complete annual formal risk ratings based on asset condition and criticality. Lower-criticality assets are monitored through ongoing inspections, performance data, and subject matter expert judgment, and their ratings are refreshed as needed. This means that when inspections, performance monitoring, alerts, or employee-reported issues indicate abnormal condition or emerging risk on lower-criticality assets, engineering staff initiate a targeted condition review—which may include applying the CEJC risk matrix—to determine the appropriate mitigation and whether a capital project is warranted.

(b) Unit reliability is assessed by examining historical forced outage performance, equipment condition and inspection data, maintenance history, and observed degradation trends. There is no single numeric threshold that automatically triggers a rating; rather, an asset is rated when its reliability performance deviates from expected levels or when evidence

indicates that condition deterioration could increase likelihood of an outage or impact safe, reliable operation. When a reliability concern is identified, the Asset Strategy Committee assigns or updates the risk rating, and if the resulting score meets NS Power's action threshold, an appropriate mitigation plan, such as initiating a potential capital project, is developed. Each major asset class has defined condition-assessment criteria—comprised of both leading and lagging indicators—that inform the likelihood component of the Risk Matrix, while the criticality scoring is assigned using the CEJC framework based on customer, safety, environmental, and reliability impacts.

Request IR-42:

Directives & Misc pages 87 to 141

Section 11.1.3 2026 to 2030 Forecast ACE Plan Expenditures by Functional Class and Spending Program pages 90 to 91

In reference to Figure 57, please discuss the changes made to the 2026 ACE Plan that are different from the forecast provided in the 2025 ACE Plan M12012 Figure 59 on page 91, specifically the change in forecast spending for thermal generation, combustion turbines, hydro generation and wind generation.

(a) Please briefly discuss the change in planned expenditures for combustion turbines in 2029 compared to the planned expenditures for this category in the 2025 ACE Plan forecast.

(b) Please briefly discuss the change in planned expenditures for hydro generation in 2028 compared to the planned expenditures for this category in the 2025 ACE Plan forecast.

Response IR-42:

The multi-year forecast included in the 2025 and 2026 ACE Plans includes changes and updates across almost every function and location across NS Power's assets.

Thermal Generation – the forecast across 2026-2029 (the years represented in the figures in each ACE Plan) decreased by approximately $20 million from the 2025 ACE Plan to the 2026 ACE Plan. The forecast for each unit is updated, consistent with the asset management mechanism detailed in NS Power's Strategic Asset Management plan, to reflect the current expected unit utilization along with any known major refurbishment intervals. This exercise can lead to planned

major outages being moved from one year to another or a reduction in capital investment on a specific unit changing if the future utilization of a unit is expected to increase or decrease. No one specific change is driving the reduction of $20 million.

Combustion Turbines (CT) – In the same manner as Thermal Generation, the utilization of these units is assessed, and any planned major refurbishment (driven by hours of operation as an example) are scheduled based on that utilization. The $4.5 million decrease in 2026-2029 investment in CTs is driven by multiple increases and decreases across all CT assets.

Hydro Generation – The Hydro Generation investment is primarily compiled based on planned dam refurbishment projects, scheduled unit overhauls and an assumed amount to capture investment not related to dams, turbines and generators that is required on an annual basis. The $25 million decrease in 2026-2029 investment is primarily driven by the re-timing of dam refurbishment projects that were determined to be able to be safely deferred.

Wind Generation – The level of significant investment in NS Power wind assets remains fairly low, therefore, longer term forecasts are not asset specific at this point in time, and are instead representative of historical averages. As the NS Power wind assets approach end of life in the early to mid 2030s, NS Power expects that sustaining capital requirements will rise as component condition declines. The $4 million increase in 2026-2029 investment is due to investment in a bridge replacement and two gearbox replacements at the Digby Wind farm that were not known for that timeframe at the time of the 2025 ACE Plan forecast development.-of-life in the early-to-mid 2030s, NS Power expects that sustaining capital requirements will rise as component condition declines

(a) The reduction in 2029 combustion turbine investment from $20 million (2025 ACE Plan) to $12 million (2026 ACE Plan) is the shift of investment in Engine 191-253 from 2029 to 2030.

(b) The increase in 2028 hydro investment from $65 million (2025 ACE Plan) to $79 million (2026 ACE Plan) is primarily driven by the deferral of work related to the Tusket Main Dam Refurbishment project, originally planned for a 2027 construction start in the 2025 ACE Plan, now planned for 2028.

Request IR-43:

Directives & Misc pages 87 to 141

Section 11.1.3 2026 to 2030 Forecast ACE Plan Expenditures by Functional Class and Spending Program pages 90 to 91

In Figure 57 under Transmission, the ECEI Synchronous Condenser presents a spending forecast that is significantly higher than that provided in the 2025 ACE Plan Figure 59. Please discuss the changes to this project's forecast budget.

Response IR-43:

Please refer to NSEB IR-6 part (a).

Request IR-44:

Directives & Misc pages 87 to 141

Section 11.1.3 2026 to 2030 Forecast ACE Plan Expenditures by Functional Class and Spending Program pages 90 to 91

In reference to Impact of Reliability Projects.

(a) On pdf page 92 of the application, NS Power states: "All T&D projects in the 2026 ACE Plan that are included in the Five-Year Reliability Plan will contribute to having a net positive impact on the metrics tracked under performance standards." Please describe the specific improvements that are expected in NS Power's performance standard metrics as a result of completing the 2026 ACE Plan T&D projects.

(b) Figure 58, pdf page 94 – 2026 ACE Plan Distribution Projects for Approval with Risk Rating Inputs: Please provide a similar table for the 2026 ACE Plan Transmission Projects.

Response IR-44:

(a) Please refer to NSEB IR-19.

(b) Please refer to the table below.

2026 ACE Plan Transmission Projects	Line Criticality	Condition Inputs		
		Line Reliability	Clearance Violation	Inspection
C0080109 - L7001 Replacements and Upgrades Phase 1	5	1	1	5

2026 ACE Plan Transmission Projects	Line Criticality	Condition Inputs		
		Line Reliability	Clearance Violation	Inspection
C0080110 - L7012 Replacements and Upgrades Phase 1	5	1	1	5

1

Request IR-45:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

Page 92 of the application states

> **"All T&D projects in the 2026 ACE Plan that are included in the Five-Year Reliability Plan will contribute to having a net positive impact on the metrics tracked under performance standards."**

The use of the term '*net*' implies that there will be some investments that will have a negative impact on the metrics tracked under the performance standards. Please identify if there are any projects that will have a negative effect on performance standard metrics and, if so, explain how they support the overall positive impact on the metrics.

Response IR-45:

The word 'net' should be omitted. This statement should be rephrased to read:

> All T&D projects in the 2026 ACE Plan that are included in the Five-Year Reliability Plan will contribute to a positive impact on the metrics tracked under performance standards.

NS Power does not plan to complete projects that will have a negative impact on metrics tracked under performance standards.

Request IR-46:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

Page 97 addresses the Board's 2025 ACE Plan directive to provide an update on the Centre for Energy Advancement through Technological Innovation (CEATI) Grid Resiliency working group in the 2026 ACE Plan application.

(a) Please provide an update on CEATI activities and progress since submission of the 2026 ACE Plan application.

(b) On pdf page 97 of the 2026 ACE Plan application, NS Power states: "Also in Q3 2025, the working group began development and review of a Resiliency Benchmarking Survey (pending final approval) as well as a discussion paper on Transmission System Resiliency ahead of a Utility Resiliency Workshop taking place at the 2025 CEATI T&D conference in November 2025 (attended by NS Power). The discussion paper provides the initial findings of the working group and outlines the proposed deliverables, as well as key actions for 2026." Please provide a copy of this discussion paper reference on Transmission System Resiliency.

(c) The application states "It is expected that the final terms of reference will be approved by member utilities in late 2025."

(i) Have those final terms of reference been approved?

(ii) If not, does this impede the working group or the proposed deliverables for 2026?

Response IR-46:

(a) Since filing of the 2026 ACE Plan application, CEATI's Grid Resiliency Working Group (GRWG) has continued progressing toward its 2026 deliverables, with the most significant milestone being the November 10, 2025 Grid Resiliency Workshop held at the CEATI T&D Conference in Orlando, Florida. Key activities since filing include the review of the framework, discussion and facilitation of member feedback, and advancement of the working group's roadmap.

The workshop included keynote presentations by Dr. Michel Bruneau (University at Buffalo), Dr. Mathaios Panteli (University of Cyprus), and Mark Lauby (NERC), each addressing the emerging need for measurable, functionality-based resilience metrics and system-level planning approaches for high-impact, low-probability (HILP) events. CEATI also provided updates on the Resiliency Index Framework, Resiliency Journey Roadmap, and Key Resiliency Indicators, reflecting progress of the working group.

(b) Subject to CEATI International's confidentiality agreement, the discussion paper and associated notes cannot be shared outside of the working group member utilities.

(c) The GRWG is now incorporating feedback received from member utilities (including NS Power) into its draft roadmap and resiliency framework. Member feedback was solicited through November 21, 2025, and the group is continuing its work on the 2026 deliverables, including refinement of its terminology, development of mitigation guidance, and preparation of the 2026 Resiliency Document.

As of the date of this IR response, CEATI has not yet finalized the Terms of Reference for the Grid Resiliency Working Group. CEATI continues to incorporate member utility input collected following the November workshop. Finalization is anticipated in Q1 2026.

The absence of finalized Terms of Reference does not impede the Working Group's activities. CEATI is continuing work on all 2026 deliverables in parallel, including development of the mitigation guidance document, refinement of the resiliency framework, and documentation of resiliency case studies and indicators. The Working Group's activities remain fully active, and the schedule for member deliverables is unchanged.

Request IR-47:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

On page 99, NS Power states: "Over the course of the last year, NS Power has continued its work to identify and evaluate potential alternative reliability metrics." Please describe the alternative reliability metrics that NS Power has considered over the past year. For each of these alternative metrics, please explain why NS Power believes they do not currently warrant consideration for use.

Response IR-47:

NS Power's efforts in identifying new metrics to evaluate resiliency and reliability performance has focused in two areas, CEATI's Grid Resiliency Working Group and Electricity Canada reliability programs. In both cases, NS Power endeavors to leverage these industry groups to identify and validate straightforward, quantitative measures of reliability that are easy to communicate to regulators, stakeholders, and customers. Should a potential new metric not provide further information or insights beyond the current suite of metrics, or if the appropriate data to calculate such a metric is unavailable, or if it has not been applied widely in industry, it is likely not a suitable option to drive effective risk mitigation. NS Power is confident in its use of the current methods for risk-based decision-making to address resiliency and reliability performance. Some sample metrics evaluated by NS Power in 2025 based on its investigation are as follows:

- **Momentary Average Interruption Frequency Index (MAIFI):**
    - A measure of the frequency of momentary interruptions experienced on average by a utility's customers

- This metric could potentially provide a sense of emerging reliability concerns such as transient vegetation contact.

- Momentary outages can cause disruption and be a source of frustration to customers, so reducing these events would likely be a positive.

- Data to identify momentary outages and quantify impact is currently limited to telemetered protection devices. Historically this data was largely unavailable and was not collected systematically across NS Power's circuits.

    - Limits historical benchmarking and applicability for all customers

    - Not immediately applicable without change in data availability

- Momentary outages are preferred to sustained outages and current protection strategy would encourage the use of protective devices that would reduce the frequency of sustained outages but could increase the relative frequency of momentary outages.

- **Average Service Availability Index (ASAI):**

    - A measure of the availability of electric service on average for a utility's customers over a period of time, typically a year.

    - Easily consumable measure of the percent of time that electric service was available to customers. Can be applied at a system and circuit level. No additional data collection would be required to calculate.

    - Does not provide further insights into outage events as it is related directly to SAIDI when assessed at the system level and CKAIDI at the circuit level.

- **Reliability Performance in Marginalized Communities**

    - Analysis of a subset of customers and communities that have been historically underserved by public services using existing metrics (SAIFI, SAIDI, CKAIFI, etc.).

    - Potential to provide additional context on service to these communities compared to system averages. Could help to identify systemic issues in serving historically underserved groups.

    - No well-defined criteria on which customers and/or communities should be included. Would require potentially sensitive data collection to identify customer groups or circuits.

    - Circuits are not necessarily limited to a single community, and multiple circuits may supply different areas within communities, making analysis by geographic areas more difficult. Does not account for circuit-by-circuit variability that may drive differences in performance.

Ongoing collaboration with the industry groups discussed above provides NS Power with a forum to discover potential new metrics as well as a sounding board to understand their applicability. NS Power will continue to monitor the industry for new potential metrics and anticipates discussing this matter further as part of the Five-Year Reliability Plan Review (M12558).

As part of the annual Performance Standards reporting, in 2022 the NSEB directed NS Power to report on the development and use of customer-level reliability data, including information available from other Electricity Canada utilities.

NS Power has been tracking values for the following:

- CELID-8 (Customers Experiencing Long Interruption Duration of greater than 8 cumulative hours)

- CEMI-4 / CEMI-5 (Customers Experiencing Multiple (4) or (5) Interruptions)

These metrics are not widely used by Electricity Canada member utilities. HydroOne tracks both CEMI and CELID for internal reporting purposes, and BC Hydro tracks CEMI. Manitoba Hydro previously tracked and reported on CEMI-4 and CELID-8 between 2009 and 2012, but no longer tracks or reports on those metrics.

Tracking these metrics is only useful if there are established industry-wide comparators. Considering these metrics in isolation does not provide an effective foundation for determining what the benchmarks should be for each metric.

Request IR-48:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

In its 2025 ACE Plan application, NS Power discussed the "Resilience Gap" concept as a potential reference point to measure the cumulative impact of resilience investments over time. In response to Board staff IR-50 in that Matter, NS Power stated:

> **"It would be beneficial to discuss the resilience gap concept in greater detail with stakeholders. While a resilience gap metric may be useful in measuring the benefits of investments in the face of a changing climate over time, as discussed in the 2025 ACE Plan and the Five-Year Reliability Plan, NS Power recommends further engagement with industry partners prior to suggesting it as a valuable metric. The Company will work with stakeholders to schedule this discussion by Q3 of 2025."**

(a) Please provide an update on these stakeholder discussions, and an update on the potential use of the "resilience gap" metric by NS Power.

(b) Please calculate NS Power's "Resilience Gap for each of the past five years and provide the results in a table.

Response IR-48:

(a) No specific discussions have taken place on the use of "Resiliency Gap" with stakeholders to date. At this time NS Power does not believe that the "Resilience Gap" provides significantly more insight as a performance metric beyond existing metrics, particularly

without wider adoption in the Canadian utility industry. After further consideration, using this metric without industry comparables is not expected to deliver the potential value originally envisioned in the 2025 ACE Plan. Consequently, NS Power has no plans to use this metric going forward.

(b) Please refer to the table below.

Year	SAIDI All-In	SAIDI MED Excluded	Resilience Gap
2021	5.60	5.60	0.00
2022	74.87	6.11	68.76
2023	23.03	5.82	17.21
2024	6.34	6.34	0.00
2025	10.19	5.90	4.29

Request IR-49:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

On pdf page 100 of the 2026 ACE Plan application, NS Power states:

> **As of November 2025, a residential customer Value of Lost Load (VoLL) survey has been developed by the vendor and NS Power, and the survey has been distributed to a sample of NS Power residential customers.**
>
> **As of the date of this filing, analysis of the results of this survey is underway with a draft report expected for NS Power's review in late 2025.**

(a) What is the status of this report?

(b) What are the summary findings of the report?

Response IR-49:

(a) NS Power is currently reviewing the draft report and providing feedback to the Company's consultant and expects the final report to be issued in Q1 2026.

(b) As the residential VoLL report is still in a draft status, it would be premature to share key findings until they have been finalized at the issuing of the report. NS Power can provide a summary of the key findings at that time.

Request IR-50:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

Page 100 of the application discusses the metrics and the measure of Reliability Cost Efficiency (RCE) and its potential use/challenge. Please provide an example(s) of how the metric would be used by NS Power, showing the associated cost of reducing outage impacts at the project level and highlighting the multiple, inter-related factors in the example(s) that lead to a better result for large customer counts, compared to small customer counts.

(a) Please provide the residential customer VoLL survey referenced on page 100.

Response IR-50:

The intended use of Reliability Cost Efficiency (RCE) would be to evaluate the application of different potential risk mitigation strategies to improve reliability once a risk has been identified using NS Power's Asset Management Mechanism. RCE would not be used as the sole measure to select a project, only to assist in refining the selection of risk mitigating interventions.

For example, consider a rural feeder section of approximately 100 customers where vegetation condition has increased the circuit risk and requires mitigation. From the suite of available risk mitigation strategies, NS Power is considering either strategic undergrounding or targeted vegetation management.

The specifics of the location and applied measures—such as vegetation condition, ground conditions, customer permissions, and anticipated future storms—can vary greatly from circuit to circuit, and even within a single section. Based on current planning assumptions, NS Power

estimates that a project addressing one kilometer of this feeder section would cost approximately $1 million to underground and approximately $40,000 for vegetation management.

Assuming the intervention would mitigate vegetation risk resulting in avoidance of two full section outages for approximately three hours each, avoided customer hours of interruption would be approximately 600 hours. The RCE for the two options would be approximately:

- Undergrounding: $\frac{\$1M}{600\ CHI} = \$1{,}666/CHI$

- Vegetation Management: $\frac{\$40K}{600\ CHI} = \$67/CHI$

All else being equal, the vegetation management option would present a more favourable reliability cost efficiency and would be considered a more appropriate risk mitigation strategy in this case.

Considering a similar scenario but where the target feeder section contains 1,000 customers rather than 100 customers, the outage impact would increase by a factor of 10, from 600 CHI to 6,000 CHI. This would result in a change in RCE as follows:

- Undergrounding: $\frac{\$1M}{6000\ CHI} = \$167/CHI$

- Vegetation Management: $\frac{\$40K}{6000\ CHI} = \$6.67/CHI$

Again, the vegetation management approach presents the more favourable option, but between the two locations (100 vs 1,000 customers), the better RCE is achieved on the feeder section with a larger customer count due to the higher potential avoided reliability impact. This assessment would favour targeting investments in higher customer count areas.

In these simplified examples, the difference in efficiency between undergrounding and vegetation management is very large, so further consideration of undergrounding is likely not necessary. Similarly for a circuit with a larger customer count versus a smaller customer count. This can provide NS Power with a relatively straightforward method to narrow down a large pool of potential risk mitigation strategies for a given scenario.

However, in cases where these RCE differences are more comparable, or a circuit or specific location may have other unique constraints or benefits to consider, additional analysis by Asset Strategy Committees would be warranted to further refine the most appropriate course of action.

(a) Please refer to Attachment 1 for a copy of the residential VoLL survey.

Thank you for participating in this valuable study. Nova Scotia Power is conducting a research project to understand how electricity outages impact you, our valued customer, so we can make more informed decisions to reduce future outages and improve our service.

This survey will take approximately **10 minutes** to complete. Your answers will be kept confidential.

All who complete the survey will be entered into a draw for a chance to win one of two $150 digital gift cards!

If you no longer wish to receive email communications from Nova Scotia Power, please send an email to: unsubscribe@nspower.ca.

If you have questions regarding Nova Scotia Power's privacy policy, please click here for more information: https://www.nspower.ca/en/home/privacy-policy/default.aspx

[SHOW ON SCREEN AS FOOTER ON EVERY PAGE]: Should you require any technical help in accessing or completing this survey, please contact: surveys@narrativeresearch.ca

Section 1: (DO NOT SHOW TITLE – INTERNAL ONLY Aggravating factors)

Q.0 Please indicate the first three characters your postal code:_____

99996 Prefer not to answer

To begin:

Q1 Does your household pay for its own electricity, or does someone else, such as your landlord, pay for it? **ALLOW ONE ONLY**

1 Yes, pay for own
2 No, someone else pays **(thank and terminate)**
94 Varies
98Not sure **(thank and terminate)**

Q1a. **[ONLY IF Q1 = 3 (VARIES)].** Would you say that your household pays for…? ALLOW ONE ONLY.

1 At least half of its own electricity use, OR
2 Less than half of its own electricity use **(thank and terminate)**
HIDDEN ON SCREEN
98 Not sure **(thank and terminate)**

SHOW ON SEPARATE SCREEN:
Power outages can be caused by severe weather, traffic accidents, tree or animal contacts, and equipment failures, among other things. When completing this survey, please note that a "power outage" refers to a **complete** loss of electricity to your residence. If you share a building with other owners or tenants, please answer the questions for your residence only.

Q2. Over the past 12 months, have you experienced any unexpected power outages at your primary residence that **lasted at least 30 minutes**?

1. Yes
2. No

98 Don't know

Q3. Do you or any of your household members earn an income working from home?

1. Yes – at least one person in my household works from home **full time**
2. Yes – at least one person in my household works from home **part time**
3. No – no one works from home

Q4. Does anyone in your household have any health conditions that could be worsened by a power outage? For example, someone might need an oxygen machine powered by electricity or take medication that requires refrigeration.

1. Yes
2. No

98 Don't know

Q4a. [if 3="Yes" In previous] Are you aware of Novia Scotia Power's program for identifying critical customers with special medical needs?

1. Yes
2. No
98. Don't know

Q5. [1 & 2 are multi select. 3 and 98 are exclusive] Does your household have some form of backup electrical power, like a backup generator or battery storage system?

1. Yes – a backup generator
2. Yes – a battery storage system
3. No

98 Don't know

Section 2: SCENARIO

SHOW ON SEPARATE SCREEN:

In the following section, we will present a scenario involving an electrical power outage. We want to understand how your household would respond to the outage and to estimate any extra expenses your household would experience due to the outage. We are interested in subjective costs too, including inconvenience and loss of enjoyment.

There are no right or wrong answers to these questions. We simply want your best estimate.

BACKGROUND ONLY: PERMUTATIONS

Season	Day of Week	Start Time	Duration
Summer	Weekday	*8:00am*	*1 hour*
Winter		*6:00pm*	*4 hour*

RANDOMIZE EACH OF 8 SCENARIOS, EACH RESPONDENT WILL RECEIVE ONE OF THE FOLLOWING 8 SCENARIOS:

1 Summer weekday power outage starting at 8:00am and lasting an hour
2 Summer weekday power outage starting at 6:00pm and lasting an hour
3 Summer weekday power outage starting at 8:00am and lasting 4 hours
4 Summer weekday power outage starting at 6:00pm and lasting 4 hours
5 Winter weekday power outage starting at 8:00am and lasting an hour
6 Winter weekday power outage starting at 6:00pm and lasting an hour
7 Winter weekday power outage starting at 8:00am and lasting 4 hours
8 Winter weekday power outage starting at 6:00pm and lasting 4 hours

For each scenario:

- SEASON: [Summer/Winter]
- DAY OF WEEK: [weekday]
- ASTART: [8:00am / 6:00pm]
- DURATION: [1 hour / 4 hours]
- TEMPERATURE: [23 degrees Celsius / 0 degrees Celsius]

S1. Without any warning, on a **typical** [Season] [Day of Week], a complete power outage occurs at [AStart]. You don't know how long it will last, but you checked the outage map and it estimates power will be restored in [DURATION]. The outdoor temperature is [TEMPERATURE] degrees at the time of the outage. How would your household adjust during this outage (assuming a typical day when you are at home, and no significant event is happening on that day)? (Select all that apply)

1. Contact your utility to check the predicted outage length
2. Stay home and do activities that don't require electricity
3. Stay home and run a backup power generator
4. There's generally no one home at this time
5. Find an alternative location to work

6. Do activities outside the house like going out to eat, shopping or visiting friends
7. Relocate to an area with electricity
8. Go to the store to buy supplies
9. Find a different location to charge electric vehicle
10. Use a propane/gas stove or grill for cooking

99 Other – Please describe: ___

S2. How disruptive would this ***[ADuration_descriptor]*** power outage be to your household?

1 Not at all disruptive
2 Not very disruptive
3 Neutral
4 Somewhat disruptive
5 Extremely disruptive

FOR THE QUESTION BELOW, Abid1 = a randomized option of two amounts as follows:

For 1-hour outages:

$10

$20

For 4-hour outages:

$20

$40

For reference:

1 hr

Bid 1	Bid 2, No	Bid 2, Yes
$10	$5	$40
$20	$10	$60

4 hr

Bid 1	Bid 2, No	Bid 2, Yes
$20	$10	$80
$40	$20	$160

S3. The following question is a hypothetical scenario designed to understand how customers value uninterrupted electricity. It is not a real offer.

Suppose a company that is **not** your electric utility (i.e., not Nova Scotia Power) developed a new service that can instantaneously deliver temporary backup power to your household during an outage like this one. With the purchase of this backup service, you would not experience the outage or need to take any additional actions.

The cost of this hypothetical service would be a **fee** that covers your household's normal electric usage during this single outage (you could buy the service again for future outages). The exact cost of providing this service is not yet known, but it is believed to be between [IF ONE HOUR SCENARIO: $10 and $60; IF FOUR HOUR SCENARIO: $20 and $160]. If something like this were available, would you purchase the backup service to avoid this **single outage** for a **one-time fee** of ***$[ABid1]***?

1 Yes
2 No

FOR THE QUESTION BELOW, calculate amounts for Abid2 as follows:

- **Abid1 x 4**

S4a. [Display if (S3= "Yes") Would you purchase the backup service to avoid this outage for a one-time fee of $[ABid2]? (Reminder: this question refers to the outage scenario you were shown earlier – a [DURATION]outage starting at [TIME] on a [SEASON] weekday, with an outdoor temperature of [TEMPERATURE]. Also please remember that this is a hypothetical scenario, not a real potential service.)

1 Yes
2 No

FOR THE QUESTION BELOW, Calculate amounts for Abid3 as follows:

- **Abid1 x 0.5**

S4b. [Display if (S3= "No") Would you purchase the backup service to avoid this outage for a one-time fee of $[Abid3]? (Reminder: this question refers to the outage scenario you were shown earlier – a [DURATION]outage starting at [TIME] on a [SEASON] weekday, with an outdoor temperature of [TEMPERATURE]. Also please remember that this is a hypothetical scenario, not a real potential service.)

1 Yes
2 No

FOR THE QUESTION BELOW, $[Alow] = Abid3

S5. [Display if (S3 = "No") AND (S4b = "No")] Why you would not pay ***$[ALow]*** for this service to avoid the outage? (Reminder: this question refers to the outage scenario you were shown earlier – a [DURATION]outage starting at [TIME] on a [SEASON] weekday, with an outdoor temperature of [TEMPERATURE]. Also please remember that this is a hypothetical scenario, not a real potential service.)

1 _____Record Verbatim
98 Don't know

Just a few final questions to help us analyse our results:

Programmer Notes: Ask to all. Show as grid with drop-downs for primary and then two separate boxes underneath for secondary / supplemental and tertiary / supplemental. Allow one choice only for primary source and type, allow all that apply for secondary / supplemental & tertiary / supplemental.

Thinking about your heating and cooling systems…
If you have a heat pump, please select 'Electricity' as your heating energy source, and then for the type of heating system, select heat pump.

F1. What are the current sources of heat in your home?

Primary Heating Energy Source	**Primary Type of Heating System**	**Secondary / Supplemental Heating Energy Source(s) [TERTIARY]: – *if you have any, leave blank if not applicable***	**Secondary / Supplemental Type(s) of Heating System(s)**
a. Electricity	Electric baseboard	**a. Electricity**	Electric baseboard\
	Plug in electric heaters		Plug in electric heaters
	Electric fireplaces		Electric fireplaces
	Electric thermal storage room unit (ETS)		Electric thermal storage room unit (ETS)
	Heat Pump (ducted/central system)		Heat Pump (central system)
	Heat Pump (ductless/mini split)		Heat Pump (ductless)
	Heat Pump (geothermal)		Heat Pump (geothermal)
	Heat Pump (Unknown Type)		Heat Pump (Unknown)
	Radiant in-floor		Radiant in-floor
	Electric furnace		Electric furnace
b. Oil	Oil furnace	**b. Oil**	Oil furnace
	Oil hot water baseboard		Oil hot water baseboard
	Oil stove		Oil stove
c. Wood	Wood stove	**c. Wood**	Wood stove
	Wood fireplace		Wood fireplace
	Wood pellet stove		Wood pellet stove
d. Propane	Propane gas forced air	**d. Propane**	Propane gas forced air
	Propane gas hot water baseboard		Propane gas hot water baseboard

	Propane gas (gas, propane heaters, fireplaces)		Propane gas (gas, propane heaters, fireplaces)
e. Natural Gas	Natural gas furnace	**e. Natural Gas**	Natural gas furnace
	Natural gas hot water baseboard		Natural gas hot water baseboard
f. Other		f. Other	
		g. Don't have secondary/ Supplemental heating	

Programmer Notes: Allow entry of numbers only, starting from 1. MAX 20.

F2. Including yourself, how many people live in your household?

_ _ (Record #)

96 Prefer not to answer

F3. Which of the following best describes the area where you live?

1. Urban
2. Suburban
3. Rural

96 Prefer not to answer

98 Don't know

Closing

Programmer Notes: Ask all. Single Response

G1. To assist Nova Scotia Power in understanding what's important to its customers, do you give permission for Narrative Research to share your survey responses directly with Nova Scotia Power so they can connect your responses with your customer profile? This will be used for the purpose of internal analysis only. Your responses will be kept confidential. Please note that you will not be contacted by anyone from Nova Scotia Power regarding your responses to this survey.

1 Yes
2 No

Programmer Notes: Ask all. Single Response

G2. Would you like to be entered into a draw for one of two $150 gift cards?

1 Yes **[**Please confirm your information: **COLLECT NAME AND EMAIL]**
2 No **[THANK AND TERMINATE]**

Request IR-51:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

For each project that NS Power seeks Board approval as part of the 2025 ACE Plan (excluding the Transmission Replacements and Upgrades projects), and which do not contain any "Cost Support Reference" or "Completed Similar Projects" in their respective "Capital Project Detailed Estimate", please provide the specific basis upon which NS Power developed its line-item costs estimates for "Materials", "Contracts" and "Consulting".

Response IR-51:

Please refer to the table below.

CI	Cost Element	Source
CI C0053214 – 76W-T1 Transformer Replacement	Materials	Purchase Agreement
	Contracts	Internal Expertise/Purchase Agreement
	Consulting	External Expertise
CI C0053234 – 96H-T1 Transformer Replacement	Materials	Purchase Agreement
	Contracts	Internal Expertise/Purchase Agreement
	Consulting	N/A

CI C0068969 – 2026 Pennsylvania Breaker Replacements	Materials	Purchase Agreement
	Contracts	Internal Expertise
	Consulting	N/A
CI C0070909 – 70W-T52 Transformer Addition	Materials	Purchase Agreement
	Contracts	Internal Expertise/Purchase Agreement
	Consulting	N/A
CI C0080104 – Baxter's Harbour Rd Reconductor Phase 1	Materials	Internal Expertise
	Contracts	Internal Expertise/MSA
	Consulting	N/A
CI C0080266 – New Distribution Right of Way Phase 11	Materials	N/A
	Contracts	MSA
	Consulting	N/A
CI C0080612 – 57C-426H Melrose Reconductoring and Line Extension Phase 1	Materials	Internal Expertise
	Contracts	Internal Expertise/MSA
	Consulting	N/A

1

Request IR-52:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

Page 106 discusses outage causes, please provide a table with the proportions of outages due to tree contacts, the proportion due to failed equipment and the proportion due to other causes for each of the last five years.

Response IR-52:

The proportion of outage events, customer interruptions, and customer hours of interruption from all events coded as Defective Equipment and Tree Contacts by year are provided in the tables below. As discussed in the 2026 ACE Plan Reliability Directive, a further proportion of tree contact-caused outages are included in the Adverse Weather cause code and are included below for reference.

2021:

CEA Description	Events	CI	CH	% Events	% CHI	% CI
Adverse Weather	1,045	197,720	683,315	9.4	14.7	23.3
**Adverse Weather - Trees*	418	79,088	273,326	3.7	5.9	9.3
Defective Equipment	3,083	240,052	465,752	27.6	17.9	15.9
Tree Contacts	2,173	240,262	680,499	19.5	17.9	23.2
Other Causes	4,857	664,861	1,106,722	43.5	49.5	37.7

2022:

CEA Description	Events	CI	CH	% Events	% CHI	% CI
Adverse Weather	9,471	1,001,627	21,439,047	35.6	32.4	53.9
***Adverse Weather - Trees*	3,788	400,651	8,575,619	14.2	13.0	21.6
Defective Equipment	3,391	413,904	1,896,129	12.7	13.4	4.8
Tree Contacts	8,006	794,630	12,761,769	30.1	25.7	32.1
Other Causes	5,746	880,472	3,681,084	21.6	28.5	9.3

2023:

CEA Description	Events	CI	CH	% Events	% CHI	% CI
Adverse Weather	3,765	533,613	3,862,555	19.7	20.0	31.2
**Adverse Weather - Trees*	1,506	213,445	1,545,022	7.9	8.0	12.5
Defective Equipment	2,999	332,400	753,161	15.7	12.5	6.1
Tree Contacts	4,709	660,773	4,091,892	24.7	24.8	33.1
Other Causes	7,591	1,140,992	3,667,867	39.8	42.8	29.6

2024:

CEA Description	Events	CI	CH	% Events	% CHI	% CI
Adverse Weather	1,033	114,902	461,763	9.0	7.6	13.3
**Adverse Weather - Trees*	413	45,961	184,705	3.6	3.1	5.3
Defective Equipment	2,426	241,600	513,391	21.1	16.1	14.8
Tree Contacts	1,943	259,071	770,960	16.9	17.2	22.3
Other Causes	6,082	886,434	1,714,179	53.0	59.0	49.5

2025:

CEA Description	Events	CI	CH	% Events	% CHI	% CI
Adverse Weather	1,758	143,950	752,972	13.4	8.9	13.4
**Adverse Weather - Trees*	703	57,580	301,189	5.4	3.6	5.4
Defective Equipment	2,137	168,495	516,909	16.3	10.5	9.2
Tree Contacts	2,492	390,975	2,055,782	19.0	24.3	36.5
Other Causes	6,707	907,575	2,302,042	51.2	56.3	40.9

* "Adverse Weather – Trees" represents the proportion (approximately 40 percent) of Events coded as Adverse Weather that NS Power estimates are a result of suspected tree contacts.

Request IR-53:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

Page 106 states

> **"…both tree contact and failed equipment related outages are influenced by the prevailing weather conditions, further contributing to the overall effects of adverse weather on system performance."**

Has NS Power investigated the availability of equipment that is more resilient to adverse weather that is used by other utilities in harsher climates than Nova Scotia?

(a) If so, what are the reasons for not seeking out those more resilient components or manufacturers?

(b) If not, why not?

Response IR-53:

NS Power continually evaluates opportunities to improve the resilience of its equipment to adverse weather, including practices adopted by other utilities operating in similar or harsher climates. This work is carried out through the Company's standards management process, through participation in industry working groups, and engineering reviews undertaken as part of the Asset Strategy Committee processes.

(a) NS Power regularly updates its design and construction standards to reflect lessons learned from extreme weather, evolving industry practices, and available technologies. As these

standards are updated, subsequent equipment purchases incorporate more resilient specifications as appropriate. In many cases, components used by other utilities in similar or harsher climates—such as upgraded conductor types, higher-strength hardware, improved pole materials, and enhanced surge or grounding protection—have already been integrated into NS Power's standards, where appropriate.

Where equipment used in other jurisdictions is not adopted, it is typically due to one or more of the following:

- Suitability and compatibility: Equipment designed for significantly different climate or system conditions may not be compatible with Nova Scotia's electrical system, operating environment, or construction practices.

- Risk-based justification: Some components designed for extreme northern climates may provide incremental benefit that is not proportional to their cost or operational impact when applied across NS Power's asset base.

- Regulatory and standards alignment: NS Power follows applicable CSA standards and regional engineering requirements, which often specify the weather-related design parameters most appropriate for the region. Some materials and equipment in non-Canadian markets may not have approval for use in the Canadian markets per the CSA requirements.

- Supply chain considerations: Some specialized suppliers used in remote or northern jurisdictions do not have established supply chains or support arrangements compatible with NS Power's needs.

(b) Not applicable. NS Power does investigate and adopt more resilient equipment where it provides measurable benefit. The Company's standards have been updated to reflect

increasingly severe weather conditions, and new equipment procured under those standards embeds the improved resilience.

Request IR-55:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

Figure 71 on page 111 presents customer hours of interruption for Year-to-Date October 2025 by device type.

(a) Please provide an update with the complete 2025 data.

(b) How many crossarm failures occurred in 2025?

(c) What was the age of the failed crossarms?

(i) Mean

(ii) Minimum

(iii) Maximum

(d) How many pin insulator failures occurred in 2025?

(e) What was the age of the failed pin insulator?

(i) Mean

(ii) Minimum

(iii) Maximum

(f) How many Primary Aerial Conductor failures occurred in 2025?

(g) What was the age of the failed Primary Aerial Conductors?

(i) Mean

(ii) Minimum

(iii) Maximum

(h) Please expand the table to provide the proportion of outages by each device category that took place during a severe weather event.

Response IR-55:

(a) An updated Figure 71 is below, with data to the end of 2025:

Customer Hours of Interruption		
Device Type	**2025**	**% of Hours**
Pin Insulator	94,754	19.87
Crossarm	73,037	15.32
Primary Aerial Conductor	60,055	12.59
Inline Disconnector	49,189	10.32
Cutout	36,279	7.61
Recloser	35,224	7.39
Wood Pole	34,554	7.25
Jumper	18,963	3.98
Fuse Link	17,874	3.75
Lead	15,816	3.32

(b-g) There were 14 events caused by crossarm failure, 56 events caused by pin insulator failure, and 92 events caused by primary aerial conductor failures in 2025.

The age of the failed crossarms, pin insulators, and conductor is not known. Age data for these individual assets is not tracked.

Please refer to table below for Event Day contributions to CHI attributable to device failures.

Device Failed	Non-Event Day	Significant	Major	Extreme	Event Day Contribution per Device %
Pin Insulator	93,035	-	-	1,718.70	1.8
Crossarm	73,037	-	-	-	0.0
Primary Aerial Conductor	57,671	1,872	511	-	4.0
Inline Disconnector	34,632	-	14,557	-	29.6
Cutout	35,922	159	139	59	1.0
Recloser	12,317	-	22,906	-	65.0
Wood Pole	34,484	-	70	-	0.2
Jumper	16,380	-	2,583	-	13.6
Fuse Link	17,683	81	89	21	1.1
Lead	15,567	19	177	52	1.6

Request IR-56:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

Figure 75: Detail on Outage Causes for identified Event Days on pages 115 to 116.

(a) Please update the table for the whole of 2025.

(b) Page 116 explains that Loss of Supply events are related to tree contacts with transmission lines. Please provide additional detail on these transmission lines outages from tree contacts, and elaborate on the transmission lines' age, height and geographic location.

(i) For those interruptions from Loss of Supply not a result of tree contacts, please explain when they occurred, how many of them occurred (by cause) and which areas of the province they occurred.

Response IR-56:

(a) There were five event days experienced in 2025. An updated Figure 75, with data to the end of 2025 is provided below.

		Significant	Major	Extreme	
CEA Cause Code	**Description**	**Hours of Interruption**	**Hours of Interruption**	**Hours of Interruption**	**% of Hours**
0	Unknown/Other	614	26,242	3,256	1.15
1	Scheduled Outage	11,639	3,993	89	0.60
2	Loss of Supply	143,959	0	170,635	12.02
3	Tree Contacts	58,419	489,401	1,017,792	59.80
4	Lightning	0	0	0	0.00

		Significant	Major	Extreme	
CEA Cause Code	**Description**	**Hours of Interruption**	**Hours of Interruption**	**Hours of Interruption**	**% of Hours**
5	Damaged Equipment	2,336	48,251	2,787	2.04
6	Adverse Weather	22,966	230,196	374,531	23.98
7	Adverse Environment	7	15	0	0.00
8	Human Element	0	0	0	0.00
9	Foreign Interference	10,087	59	634	0.41
	Total	250,026	798,157	1,569,725	

(b) The Loss of Supply cause code is used to refer to outages that originate on the Bulk Electric System (BES) and would include events occurring on NS Power's transmission lines or within substations that result in an interruption to the distribution system. Such events can include, but are not strictly limited to, tree contacts with transmission lines leading to customer outages. Please refer to the table below in part (ii) for the Loss of Supply events that occurred during the five Event Days in 2025. No Loss of Supply events occurred on the December 3rd or December 20th event days. Only one of these Loss of Supply events was caused by a tree contact with a transmission line.

(i) Details for Loss of Supply events, including causes that occurred during 2025 events days are found in the table below.

Event Day	Impacted Transmission Line	Location	Cause
2025.02.17	L-5058	Cumberland County	Adverse Weather (Icing)
2025.07.26	L-6537	Inverness County	Failed Equipment (Substation Transformer)
2025.12.19	L-6503	Colchester County	Failed Equipment (Substation Conductor)
	L-6001	Colchester County	
	L-6527	Colchester County	
2025.12.19	L-6002	Lunenburg County	Tree Contact (Off Right-Of-Way Tree)

Request IR-57:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

T010 and D010 Report on page 117 to 118 provides an update on the progress made on the >69kV transmission widening for T010.

(a) How much of the planned 2025 work was completed for each of T010 and D010 by December 31, 2025?

(b) What was the year end spending for T010 and D010?

Response IR-57:

(a) For 2025 D010 year-end, a total of 3,623 spans (201 kms) were completed, representing 68 percent of the 297 km plan.

Please refer to the table below for T010 results. All 120 kilometers were completed, representing 100 percent completion. Lines L-6503 and L-6002 were added to the plan, totalling 29 kilometers. To accommodate for this, most lines received fewer completed kilometres than planned except for L-7003 which received three additional kilometers of treatment.

2025 T010 Transmission Corridor Widening			
Transmission Line	**Geographic Location of the Line**	**2025 Planned km**	**2025 Completed km**
L-6503-**added**	Onslow to Trenton	0	17
L-6002-**added**	Sackville to Bridgewater	0	12
L-7005	Onslow to Hopewell	16	9
L-7003	Onslow to Port Hastings	29	31

2025 T010 Transmission Corridor Widening			
Transmission Line	**Geographic Location of the Line**	**2025 Planned km**	**2025 Completed km**
L-7004	Dalhousie Mountain to Port Hastings	23	18
L-7009	Brushy Hill to Bridgewater	18	15
L-7008	Brushy Hill to Bridgewater	15	12
L-6511	New Glasgow to Glen Dhu	19	6
	Total km	**120**	**120**

(b) Year-end spending for D010 was $11,944,226. Year end spending for T010 was $2,881,238.

Request IR-58:

Directives & Misc pages 87 to 141

Section 11.1.4 Impact of Reliability Projects pages 92 to 132

Figure 76: Age Based Replacement Ranges for Energy Delivery Assets on page 121. Please confirm or explain otherwise that the definition of High Range Replacements and Low Range Replacements is in reference to NS Power's risk rating.

(a) If confirmed, please provide the threshold risk rating for an asset to be classified as high range and to be classified as low range.

Response IR-58:

Not confirmed. The ranges of asset replacements provided in Figure 76 are based on high and low estimates of the estimated useful life for each asset. It is not related to the assessment of individual asset risk.

(a) N/A.

Request IR-59:

Directives & Misc pages 87 to 141

Section 11.1.6 CIS Replacement Project Cyber attack pages 133 to 134

NS Power's 2025 ACE Plan filing (Matter M12012) identified Work Order C0021835 – IT – Customer Information System Customer Information System (CIS) Replacement, which is included in the 2026 ACE Plan as a project for subsequent submittal. Appendix B in the 2025 ACE Plan filing also indicated this project has a risk rating of 25. The Board understands this to be the highest rating under NS Power's Asset Management Criticality & Condition Risk Alignment Matrix, indicating that the project represents a high level of risk requiring mitigation.

(a) Please provide the amount spent to date on this CIS project, along with the associated tasks.

(b) Please provide an update on the progress made since the ACE 2025 to confirm that this project remains on track for submission in 2026.

(c) Please provide a Gantt chart for this project, along with any risks that could affect the project submission.

Response IR-59:

(a) The spend to date on this project as of December 31, 2025 is $3.42 million. The associated tasks include:

- Identification of requirements for and completion of competitive solicitation for Planning and Procurement partner.

- Development of plan for CIS replacement Procurement (RFP).

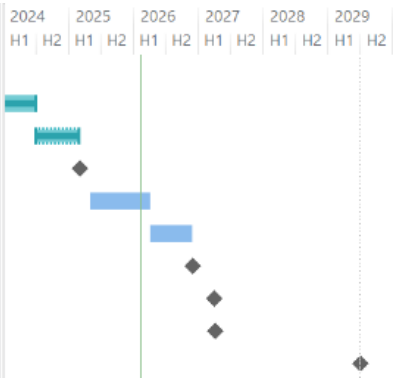
- Issuance of RFP for CIS Replacement Solution and System Integrator Services.

- Evaluation of proposals and recommendation for CIS Replacement Solution and System Integrator (Project paused during this stage).

(b) A procurement partner was selected to create a plan and to develop the Request for Proposals (RFP) package. The RFP was issued to market on March 25, 2025, with responses received on April 25. The first phase of the evaluation process was completed by the first of June, and the project was paused at that time. NS Power confirms that the project remains on track for submission in 2026. Please refer to part (c)

(c) Please refer to the below high level Gantt chart reflecting filing the application in Q3 of 2026 and a planned start date in Q2 of 2027.

Task Name	Status
Identify Planning and Procurement partner	Complete
Develop plan for CIS Replacement Procurement (RFP)	Complete
Issue RFP for CIS Replacement Solution and System Integrator Services	Complete
Project Pause	In progress
Evaluate Vendor Proposals and Develop Capital Filing	-
Application to NSEB	-
NSEB Decision (estimated)	-
Start CIS Replacement Project (subject to NSEB Decision)	-
Launch new CIS System (estimated - subject to detailed planning)	-



A key risk that could impact the submission is access to resources. Completing the second phase of the RFP process and developing the capital filing require key technology and business resources.

Request IR-60:

G01: C0080206 POA Boiler Refurbishment 2026

What is the current forecasted retirement date for the Point Aconi Generating Facility?

(a) Please identify the incremental operating life expected to result from the refurbishment.

(b) Please describe any work NS Power has undertaken to assess opportunities to continue operation of the Point Aconi Generating Facility without requiring the need for the proposed capital project in advance of facility retirement.

Response IR-60:

The forecasted retirement date for the Point Aconi Generating Station is the end of 2029, consistent with NS Power's 2025 10-Year System Outlook.

(a) The incremental operating life resulting from this refurbishment varies by component type and reflects the need to maintain the safe and compliant operation of the boiler. Pressure containing components such as boiler tubes and bends that have reached minimum allowable wall thickness must be replaced or rebuilt in accordance with the Nova Scotia Technical Safety Act and Boiler and Pressure Equipment Regulations, and these refurbishments typically provide at least 10 years of additional service life for the individual component. Noncontaining components such as boiler tubes and bends that have reached minimum allowable wall thickness must be replaced or rebuilt in accordance with the Nova Scotia Technical Safety Act and Boiler and Pressure Equipment Regulations, and these refurbishments-containing components such as boiler tubes and bends that have reached minimum allowable wall thickness must be replaced or rebuilt in accordance with the Nova Scotia Technical Safety Act and Boiler and Pressure Equipment Regulations, and

these typically provide at least 10 years of additional service life for the individual component. Nonpressure-retaining components, including tube shields and alignment fixtures, experience ash related erosion and therefore have shorter, location-dependent operating lives ranging from 2 to 10 years depending on the amount of erosion they're subject to.

(b) NS Power has updated its Boiler Tube Repair & Tube Failure Reduction Quality Process (formerly Thermal Maintenance Process TMP004), as referenced in NSEB IR63, to reduce the minimum allowable wall thickness threshold for replacement or weld buildup of superheater tubes from 70% to 50% of original thickness for boilers nearing end of life. This process, developed in consultation with the Nova Scotia Department of Labour, Skills and Immigration – Technical Safety Division, enables safe deferral of certain tube replacements, including postponement of work in Superheater 3 at the Point Aconi Generating Station. NS Power continues to monitor annual tube thickness inspection data and compare it to historical results to assess wear rates and ensure components are managed to the 50% threshold to mitigate the risk of tube failures.-004), as referenced in -63, to reduce the minimum allowable wall-thickness threshold for replacement or weld buildup of superheater tubes from 70% to 50% of original thickness for boilers nearing end of life. This process, developed in consultation with the Nova Scotia Department of Labour, Skills and Immigration – Technical Safety Division, enables safe deferral of certain tube replacements, including postponement of work in Superheater 3 at the Point Aconi Generating Station. NS Power continues to monitor annual tube-thickness inspection data and compare

Request IR-61:

G01: C0080206 POA Boiler Refurbishment 2026

(a) Please identify the specific deficiencies that necessitated the proposed boiler refurbishment in 2026, including the measured condition indicators.

(b) The application indicates that the final scope will be determined following inspection during the planned outage. Please provide: the base scope assumed in the $1.3M estimate and the contingent scope that may be added depending on inspection results.

(c) Please provide the forecast capacity factor and utilization factor for the Point Aconi Facility for each year prior to the expected retirement date.

(d) What is the required lead time for expected parts delivery?

(i) Will parts be purchased in advance of the planned outage to limit the impact that delivery delay may have on overall outage time?

(ii) After completion of the inspection, if parts and/or components are required for which NS Power does not have spares in inventory, does NS Power expect that such elements can be ordered, delivered and installed without extending the planned unit outage time? Please explain.

Response IR-61:

(a) During the 2026 outage annual inspections, tube thickness measurements and erosion assessments will be conducted across the superheater and reheater sections of the Point Aconi boiler to identify condition-based deficiencies. The key deficiencies and indicators are summarized below:-thickness measurements and erosion assessments

(a) Superheater 1 (SH1) – Severe shield erosion:

In 2025 inspection of Superheater 1 identified tube shields that had worn through to the underlying boiler tubes. These worn through shields were replaced during the 2025 outage; however, because this section is located closest to the combustor where ash erosion, high heat-flux conditions are- most severe, continued inspection and refurbishment during the 2026 outage are required to ensure compliance and prevent accelerated tube wear. The asset risk ranking for this section of the boiler is 16.

(b) Superheater 3 (SH3) – Tube thinning, shield loss, and misalignment:

During the 2026 outage, NS Power will inspect and replace tube shields that are worn through or missing, and inspect and replace tube bundle alignment fixtures based on their condition. Tube thickness testing will be completed on tubes approaching 50% of original wall thickness from previous inspection results, along with testing of approximately 10% of the remaining tubes to confirm their fitness for continued operation. bundle alignment fixtures based on their condition. Tube thickness testing will be completed on tubes approaching 50% of original wall thickness, along with testing of approximately 10% of the remaining tubes to confirm their fitness for continued operation The risk ranking for this section of the boiler is 15.-bundle alignment fixtures based on their condition. Tube-thickness testing will be completed on tubes approaching 50% of original wall thickness, along with testing of approximately 10% of the remaining tubes to confirm their fitness for continued operation.

(c) Reheater (RH) – Tube thinning and original equipment degradation: -equipment degradation:

Some reheater tubes have approached 50% of their original wall thickness in 2025, triggering the need for inspection and replacement in accordance with NS Power's Asset Management criteria. During the 2026 outage, NS Power will replace worn tube shields and inspect the original reheater sections to confirm tube condition and identify any additional components requiring replacement. The risk ranking for this section of the boiler is 20.

(b) The base scope for this project includes cleaning, access preparation, and condition based refurbishment of major boiler pressure part components, with work focused on the superheater, reheater, and economizer sections where tube shield replacement, localized tube repairs, and limited tube replacements are required based on known wear patterns and historical outage findings. The scope also covers refurbishment of fuel and air inlet port components, and other minor component repairs identified during the outage. As part of the broader reliability program, boiler header inspections continue on a multiyear rotating cycle, with a limited number of headers examined each outage to inform long term refurbishment planning by identifying emerging wear trends and determining when header repair or replacement will be required in future capital programs; the number of headers inspected each year reflects operating conditions and past inspection results.

The estimate also includes a contingency to address modest variations in labour, materials, and freight that may arise as planned refurbishment progresses, such as additional overtime, slight increases in shielding, or minor replacement components and expediting costs. This contingency does not cover major refurbishment or largescale component replacement, and any significant findings such as extensive tube replacement, waterwall panel work, or substantial header repairs would be addressed separately under their own capital projects.

(c) The forecasted Utilization and Capacity Factors as per the 2025 10-Year System Outlook provided in the table below.

	2026	**2027**	**2028**	**2029**
Utilization Factor	H	M	L	UL
Capacity Factor	61%	41%	12%	15%

(d) The expected lead time for most boiler components is typically 12 to 16 weeks, particularly for boiler tubing, which has no standard sizing or metallurgy and therefore requires fabrication to specification.

(i) Parts such as tube shields, alignment fixtures, and boiler tubes are maintained in inventory and replenished prior to the outage. Boiler tubes and shields generally have longer lead times than the duration of a typical outage, so inventory levels are reviewed and reordered as needed following each outage to ensure availability.

(ii) The ability to order and install additional components identified after the outage begins depends on the component, customization, and metallurgy. In limited cases, a heavier wall thickness or higher-alloy material may be used as an alternative; however, any such substitution must be engineered and confirmed with the regulator before installation. To mitigate these risks, NS Power maintains appropriate inventory levels and procures known requirements ahead of the outage. If further material needs were to arise during the outage, NS Power would assess availability with its vendor at that time and proceed in a manner that aligns with the planned outage schedule.

Request IR-62:

G01: C0080206 POA Boiler Refurbishment 2026

If the inspection reveals that some parts and/or components do not need to be replaced, can already purchased replacement parts be returned for no additional cost to the project? Please explain.

(a) If not, why not?

Response IR-62:

No, these parts are not able to be returned.

(a) The materials procured for the POA Boiler Refurbishment are custom-fabricated or manufactured to Point Aconi–specific technical and metallurgical requirements. These items involve vendor-specific engineering, ASME documentation, and serial-number traceability, which means they cannot be resold or restocked by suppliers. As a result, unused replacement parts are not able to be returned for a credit. These unused parts will be kept on site for critical spares and future replacement parts during the major inspection period.

Request IR-63:

G01: C0080206 POA Boiler Refurbishment 2026

Please provide a copy of the Point Aconi "Boiler Tube Repair Thermal Maintenance Practice (TMP-004)", as identified in the 2022 ACE Plan.

(a) Please confirm that the proposed capital project meets the requirements of this documented practice. In particular, please confirm that boiler tubes will not be replaced unless they have reached 50% of the original wall thickness.

Response IR-63:

A copy of QP-G004 (formerly TMP-004) is provided as Confidential Attachment 1.

(a) The proposed capital project will meet the requirements of QP-G004. For Point Aconi, NS Power applies a refurbishment criterion whereby internal boiler tubes are not replaced unless they have reached 50% of their original wall thickness, consistent with the practice.

The only exception occurs in instances where known ash-erosion rates—based on inspection data—indicate that a tube currently above the 50% threshold would be expected to fall below the allowable 50% remaining wall thickness before the next planned outage. In such cases, proactive replacement is required to maintain safe operation and mitigate the risk of tube leaks occurring during operation causing a forced outage. Tubes replaced under this exception are typically in the range of 51–53% of their original wall thickness at the time of inspection.

2026 ACE Plan NSEB IR-63 Attachment 1 has been removed due to confidentiality.

Request IR-64:

G02: C0080205 POA Boiler Refractory Replacement 2026

(a) Please confirm if this project will be completed at the same time as C0080206.

(b) Please indicate whether there are any costs that overlap or can be shared such as scaffolding or other common resources.

Response IR-64:

(a) Confirmed.

(b) Several costs overlap between the two projects due to shared access, labour, and outage-support requirements. Common resources that will be shared include scaffolding (including erection, modification, and dismantling), equipment rentals, Boilermaker labour, safety services, and industrial cleaning services. These shared costs will be allocated appropriately between the two projects based on the level of effort required for each project.

Request IR-65:

G02: C0080205 POA Boiler Refractory Replacement 2026

Please describe any work NS Power has undertaken to assess opportunities to continue operation of the Point Aconi Generating Facility without requiring the need for the proposed capital project in advance of facility retirement.

Response IR-65:

NS Power assessed whether the Point Aconi Generating Station could continue operating without the proposed 2026 refractory replacement by reviewing recent inspection findings and the underlying safety and reliability implications. The 2025 condition assessment identified several areas replacements into planned work windows to avoid emergent failures. Based on the 2025 condition information, incorporating the recommended replacement into the regularly scheduled 2026 outage represents the safest and most reliable approach to maintaining compliant operation and predictable boiler performance as the facility approaches retirement.

Request IR-66:

G02: C0080205 POA Boiler Refractory Replacement 2026

What is the required lead time for expected parts delivery?

(a) Will parts be purchased in advance of the planned outage to limit the impact that delivery delay may have on overall outage time?

(b) After completion of the inspection, if parts and/or components are required for which NS Power does not have spares in inventory, does NS Power expect that such elements can be ordered, delivered and installed without extending the planned unit outage time? Please explain.

Response IR-66:

Refractory materials for Point Aconi normally require 4 to 12 weeks of lead time, depending on the required formulation, density, anchoring system, and quantities. Components such as expansion joints or the cyclone may require pre-formed or custom-shaped refractory bricks to match the existing geometry, which can extend manufacturing time. Because refractory integrity is essential for safe boiler operation and compliance with Technical Safety requirements, materials must be secured well in advance of the planned outage.

(a) Yes. Based on the work identified in the 2025 inspection and in accordance with NS Power's Asset Management practices, the required refractory materials are ordered prior to the planned outage. This approach is consistent with the planning cycle used for refractory components identified in the inspection findings.

(b) The ability to order and install any additional refractory materials identified after the outage begins depends primarily on the quantity required. Standard refractory products are

generally available within normal supplier lead times, while larger quantities or components that must be produced to match specific boiler configurations may require additional time. If further material needs were to arise during the outage, NS Power would assess availability with its vendor at that time and proceed in a manner that aligns with the planned outage schedule.

Request IR-67:

G02: C0080205 POA Boiler Refractory Replacement 2026

If the inspection reveals that some parts and/or components do not need to be replaced, can already purchased replacement parts be returned for no additional cost to the project? Please explain.

(a) If not, why not?

Response IR-67:

NS Power can return unused refractory materials in the original unopened packaging back to the vendor with the exception of precast refractory components that are specific to the Point Aconi boiler. For the current project, there are no such precast components anticipated to be required at this time. The only cost typically incurred for returning refractory material would be the associated shipping or handling charges.

(a) N/A.

Request IR-68:

G03: C0021608 TUC Shoreline Sheetpile Refurbishment

(a) NS Power indicates that this investment only has a 50-year life. Will this estimated life need major repair or replacement to reach 50 years, or can it be expected that the structure will go without a major repair or replacement until it is 50 years old?

(b) What is the planned maintenance schedule for the sloped rock revetment?

(c) When will the Tufts Cove Generating Station be retired and removed from service?

Response IR-68:

(a) The 50-year design life for the new sloped rock revetment reflects the expected service life of this type of shoreline protection system when constructed to current engineering standards. The revetment is not expected to require major repair or replacement to reach 50 years. Routine inspections and minor maintenance—such as repositioning armor stone that may shift over time due to wave action—are anticipated, but these activities are limited in scope and do not constitute major rehabilitation. No significant structural work is expected during the 50-year design life.

(b) The sloped rock revetment will be included in NS Power's shoreline monitoring standard, which includes operators to perform visual inspections daily, and on an as-needed basis from Plant Engineers. A more detailed inspection would be triggered if the monitoring program identifies an obvious visual concern with the shoreline infrastructure. The new intake structure will follow the other intake structure inspection standards. Maintenance, where required, typically involves re-placing or adjusting armor stone that has moved due to wave or ice forces. These activities are low in frequency and are not expected to materially impact the long-term service life of the structure.

(c) In NS Power's most recent Integrated Resource Plan (IRP), the Tufts Cove Generating Station was forecast to operate through at least 2050, which was the extent of the modelling horizon studied in the most recent (Evergreen) IRP. The long-term role and retirement timing for Tufts Cove will be re-evaluated as part of the upcoming IRP to be conducted by the Independent Electricity System Operator in Nova Scotia (IESO-NS).

Request IR-69:

G03: C0021608 TUC Shoreline Sheetpile Refurbishment

Page 153, under Description NS Power states: "This work is to mitigate the deteriorated condition of the existing steel sheet pile structures that retain the plant shoreline." Under the heading Why do this project? NS Power states "The shoreline sheet pile wall shows significant corrosion in the splash zone (i.e., above high water), with multiple cells exhibiting large areas of section loss. In the low water zone, the shoreline sheet piles were generally in a corroded condition, with the measured thickness losses ranging from 15% to 65%. The permanently submerged portion of the cells were also in a corroded condition, with thickness losses between 10% and 60%." And, "The condition assessment indicates that the shoreline sheet pile cells have no remaining capacity to support significant loading acting at the top of the cells where corrosion is the most severe, and the remainder of the cells below the midtide zone where capacity is compromised. Without intervention, the continued deterioration poses serious risks to structural stability and safety."

(a) What are the net present value and the cost benefit ratio of mitigating highly corroded steel sheet pile structures against installing a new retaining wall/kingpins to be backfilled with granular materials and to concrete retaining wall with partial cell encapsulation?

(i) If a cost benefit analysis was not performed, please provide the Economic Assessment Model (EAM) in excel format with cells intact.

(ii) Please provide the Net Present Value analysis of the three options described in Attachment 1 to include forecast sustaining capital costs and operating and maintenance costs associated with each option over the expected design life.

Response IR-69:

(a) Neither a cost benefit analysis nor an EAM was required for this project. Rather, an options analysis study was completed by a third party and provided as Attachment 1 to the capital work order in the 2026 ACE Plan application (PDF Pages 158-177 of the 2026 ACE Plan application). The options analysis indicated that there were two alternatives that met the design criteria required. Of those two options, the revetment option was considerably more cost-effective and did not have any higher future costs that would require an EAM or NPV analysis to be completed.

(i-ii) N/A.

Request IR-70:

G03: C0021608 TUC Shoreline Sheetpile Refurbishment

Please provide a copy of the most recent design drawings for the project.

Response IR-70:

Please refer to Attachment 1.

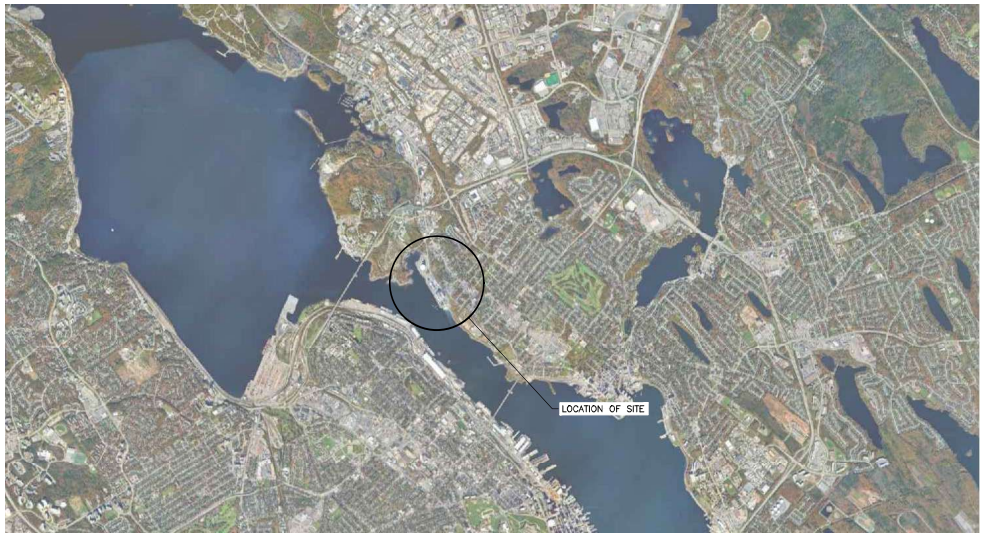
LIST OF DRAWINGS

DRAWING No.	DESCRIPTION
S1	GENERAL ARRANGEMENT
S2	REVETMENT SECTION AND DETAIL
S3	INTAKE EXTENSION SECTION
S4	INTAKE EXTENSION DETAIL, SECTION AND NOTES
S5	HEADWALL, SLAB, FOOTING SECTIONS AND DETAILS
S6	SLAB AND COLUMN SECTIONS
S7	BOREHOLE LOGS

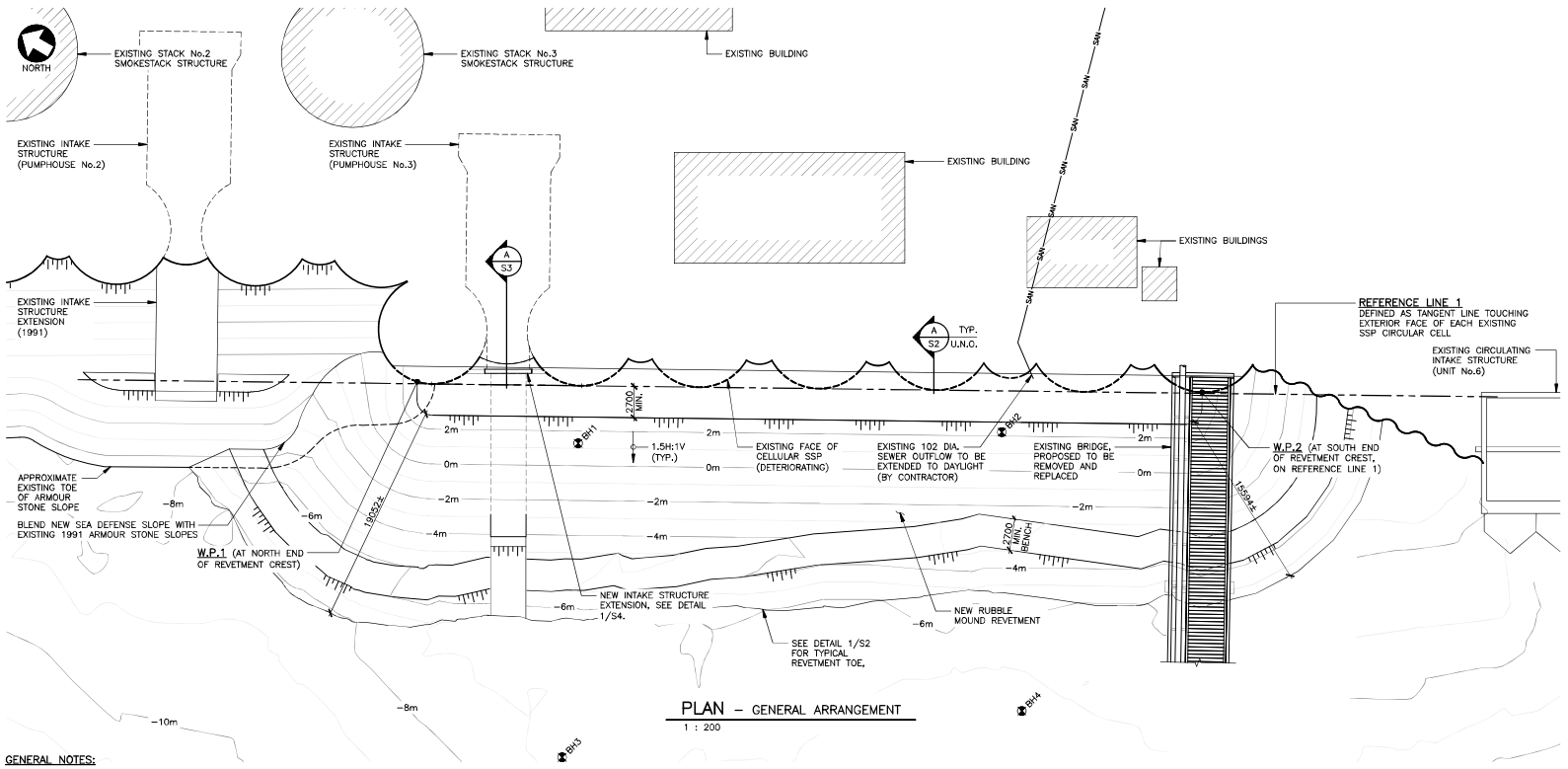
STEEL SHEET PILE (SSP) REFURBISHMENT TUFT'S COVE DARTMOUTH, NOVA SCOTIA

Nova Scotia POWER
An Emera Company

HARBOURSIDE
Engineering Consultants



X:\01 HEC\01 PROJECTS\231267 TUFT'S COVE SSP\03 ENG DWGS\231267 – COVER SHEET.DWG, July 23, 2025, 3:39 PM



PLAN – GENERAL ARRANGEMENT
1 : 200

NOTE:
APPROXIMATE PLAN–AREA FOOTPRINT OF NEW RUBBLE MOUND REVETMENT = ±1790 m²

GENERAL NOTES:

1. ALL DIMENSIONS SHOWN ARE IN MILLIMETERS (mm) AND ELEVATIONS ARE IN METERS (m) UNLESS NOTED OTHERWISE. DO NOT SCALE FROM DRAWINGS.
2. A GEOTECHNICAL INVESTIGATION WAS COMPLETED BY HARBOURSIDE GEOTECHNICAL CONSULTANTS. REFER TO GEOTECHNICAL INVESTIGATION REPORT DATED MAY 22, 2025
3. TOPOGRAPHIC SURVEY COMPLETED BY TALISMAN TECHNICAL SOLUTIONS ON NOVEMBER 03, 2023. BATHYMETRIC SURVEY COMPLETED BY TALISMAN TECHNICAL SOLUTIONS ON MAY 16 AND JUNE 06, 2024.
4. HORIZONTAL GRID COORDINATES ARE TO CSRS NAD83 MTM ZONE 5.
5. ELEVATIONS SHOWN REFERENCED TO CGVD2013.
6. A CONVERSION BETWEEN CGVD2013 AND LOCAL CHART DATUM (2024) IS: 0.000 m C.D. = −1.440 m CGVD2013.
7. EXISTING STRUCTURES AND SITE FEATURES SHOWN ARE APPROXIMATE AND ARE TO BE CONFIRMED IN THE FIELD BY THE CONTRACTOR, AS REQUIRED TO COMPLETE WORK. EXISTING STRUCTURES AND SITE FEATURES SHOWN ARE BASED ON LIMITED HISTORICAL DRAWINGS AND SURVEY.
8. ANY DISCREPENCIES BETWEEN DRAWINGS AND FIELD CONDITIONS SHALL BE BROUGHT TO THE ATTENTION OF THE ENGINEER PRIOR TO PROCEEDING WITH CONSTRUCTION.
9. EXISTING MECHANCIAL AND ELECTRICAL EQUIPMENT NOT SHOWN. CONTRACTOR IS RESPONSIBLE TO VERIFY THE PRESENCE AND LOCATION OF ANY/ALL UTILITIES IN THE VICINITY OF WORK.
10. CONTRACTOR SHALL EXERCISE CARE SO AS NOT TO DAMAGE EXISTING NSPI PROPERTY. CONTRACTOR SHALL REPAIR ANY DAMAGED PROPERTY TO EQUAL OR BETTER CONDITION THAN BEFORE THE DAMAGE OCCURRED, AT THE CONTRACTOR'S OWN EXPENSE. CONTRACTOR SHALL SUBMIT A COPY OF PRE–CONSTRUCTION SITE CONDITION PHOTOS TO NSPI.
    A. THE CONTRACTOR SHALL COORDINATE THE CONSTRUCTION SCHEDULE SO THAT CONSTRUCTION OF THE NEW INTAKE EXTENSION OCCURS DURING NSPI'S SCHEDULED 2026 MAINTENANCE SHUTDOWN. THE SHUTDOWN IS EXPECTED TO LAST A MINIMUM OF 4 WEEKS. ACTUAL DURATION TO BE CONFIRMED BY NSPI DURING RFP PROCESS.
11. CONTRACTOR SHALL COORDINATE WITH NSPI TO PROTECT EXISTING INFRASTRUCTURE, DE–ENERGIZE/ISOLATE UTILITIES AND SCHEDULE WORK.
12. CONTRACTOR IS RESPONSIBLE TO OBTAIN THE NECESSARY PERMITS REQUIRED TO COMPLETE WORK.
13. THE CONTRACTOR IS ADVISED THAT THE EXISTING CELLULAR SSP STRUCTURES ARE IN A DETERIORATED CONDITION.
14. NEW INTAKE EXTENSION HAS BEEN DESIGNED TO EXCEED MINIMUM EXISTING CROSS–SECTIONAL AREA OF INTAKE, SO THAT HYDRAULIC FLOW IN NOT CONSTRICTED.
15. CONTRACTOR SHALL ABIDE BY PROJECT TURBIDITY REQUIREMENTS, BY DFO.
    A. TURBIDITY MONITORING SERVICES SHALL BE SCHEDULED BY AND PAID FOR BY NSPI. CONTRACTOR SHALL COORDINATE TO ACCOMMODATE TURBIDITY MONITORING.

REVETMENT DESIGN NOTES:

1. REVETMENT HAS BEEN DESIGNED TO RETAIN EXISTING GRANULAR MATERIALS WITHIN EXISTING, DETERIORATING CELLULAR SSP, ONLY.
    A. THE REVETMENT HAS NOT BE DESIGNED TO CONTROL WAVE OVERTOPPING AND/OR TRANSMISSION OF WAVE KINETIC ENERGY OVER AND/OR THROUGH THE STONE REVETMENT. (I.E.: A HIGHER REVETMENT WOULD BE REQUIRED TO ACT AS A BREAKWATER–TYPE SEA DEFENSE AGAINST WAVE KINETIC ACTIONS).
    B. THE REVETMENT HAS NOT BEEN DESIGNED TO CONTROL COASTAL FLOODING OVER, AROUND AND/OR THROUGH THE STONE REVETMENT. (I.E.: A HIGHER AND IMPERMEABLE REVETMENT WOULD BE REQUIRED TO ACT AS A DYKE–TYPE SEA DEFENSE AGAINST HIGH–STILL–WATER STATIC–HEAD SEEPAGE).
2. REVETMENT HAS BEEN DESIGNED BASED ON THE FOLLOWING CRITERIA:
    A. THE REVETMENT HAS BEEN DESIGNED TO RETAIN EXISTING GRADES, WITH A MS200–77 DESIGN TRUCK SURCHARGE (I.E.: AS IF THE EXISTING SSP WAS TO FULLY–CORRODE).
    B. THE REVETMENT ARMOUR, FILTER AND CORE STONES HAVE BEEN DESIGNED TO PROVIDE GRANULAR FILTRATION, TO RESIST ANTICIPATED EROSION OF RETAINED GRANULAR MATERIALS.
    C. THE REVETMENT ARMOUR STONES HAVE BEEN DESIGNED TO REMAIN STABLE AGAINST WAVE ACTIONS DURING THE DESIGN STORM EVENT, CONSISTING OF THE DESIGN WAVE OCCURRING AT A WATER LEVEL BETWEEN LLWLT AND THE DESIGN HIGH–WATER LEVEL.
    D. DESIGN HIGH–WATER LEVEL: +2.670m, BASED ON A TOTAL WATER LEVEL ANALYSIS (TIDES, STORM SURGE, SEA LEVEL RISE) FOR A LIFETIME–EQUIVALENT ANNUAL EXCEEDANCE PROBABILITY OF 0.5% PER YEAR, OVER A 50–YEAR MINIMUM DESIGN SERVICE LIFE. REFER TO PROJECT COASTAL STUDY DATED AUGUST 9, 2024, BY DHI EARTH & ENVIRONMENT INC.
    E. DESIGN WAVE: (0.5% AEP FROM S60°W)
        - Hs = 0.9m
        - Tp = 3.0sec.

WORKPOINT TABLE		
WORKPOINT (W.P.)	NORTHING	EASTING
W.P.1	4948822.243	25571607.472
W.P.2	4948763.902	25571641.856

BOREHOLE COORDINATES			
BOREHOLE	NORTHING	EASTING	ELEVATION
BH01	25571612.500	4948802.500	−6.60m
BH02	25571632.200	4948771.700	−4.40m
BH03	25571588.600	4948789.700	−6.97m
BH04	25571612.500	4948757.800	−7.17m

No.	DESCRIPTION	Date (mm/dd/yy)	By
2	RE–ISSUED FOR CONSTRUCTION	07/23/25	BMF
1	ISSUED FOR CONSTRUCTION	05/29/25	BMF
0	ISSUED FOR REVIEW	05/14/25	BMF

ISSUE or REVISION

Client: Nova Scotia POWER An Emera Company

HARBOURSIDE Engineering Consultants

Project: TUFT'S COVE DARTMOUTH, NS

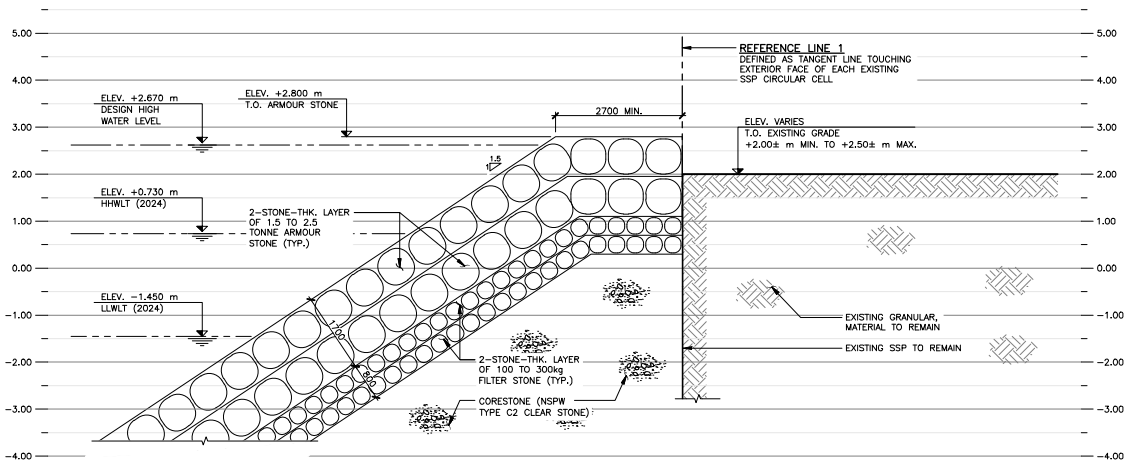
SSP REFURBISHMENT

Title: GENERAL ARRANGEMENT

Scale	Date
AS NOTED	OCTOBER 2024
Drawn: LJD	Designed: BMF
Checked: TSM	Approved: MSR
Contract No.	231267
Drawing No.	S1

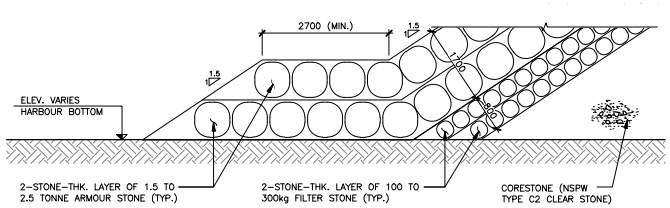
REGISTERED PROFESSIONAL ENGINEER PROVINCE OF NOVA SCOTIA
DATE: July 23, 2025
B. M. Filmore
20210712

X:\01 HEC\01 PROJECTS\231267 TUFTS COVE SSP\80 ENG DWGS\231267 - S1 - TB/P COPY.DWG, July 23, 2025, 3:39 PM



A/S1 **SECTION** – TYPICAL REVETMENT
1 : 50

NOTE: EXISTING UTILITIES NOT SHOWN.



1/S1 **DETAIL** – TYPICAL REVETMENT TOE OF SLOPE
1 : 50

No.	DESCRIPTION	Date (mm/dd/yy)	By
2	RE-ISSUED FOR CONSTRUCTION	07/23/25	BMF
1	ISSUED FOR CONSTRUCTION	05/29/25	BMF
0	ISSUED FOR REVIEW	05/14/25	BMF

ISSUE or REVISION

Client: Nova Scotia POWER, An Emera Company

HARBOURSIDE Engineering Consultants

Project: TUFT'S COVE
DARTMOUTH, NS

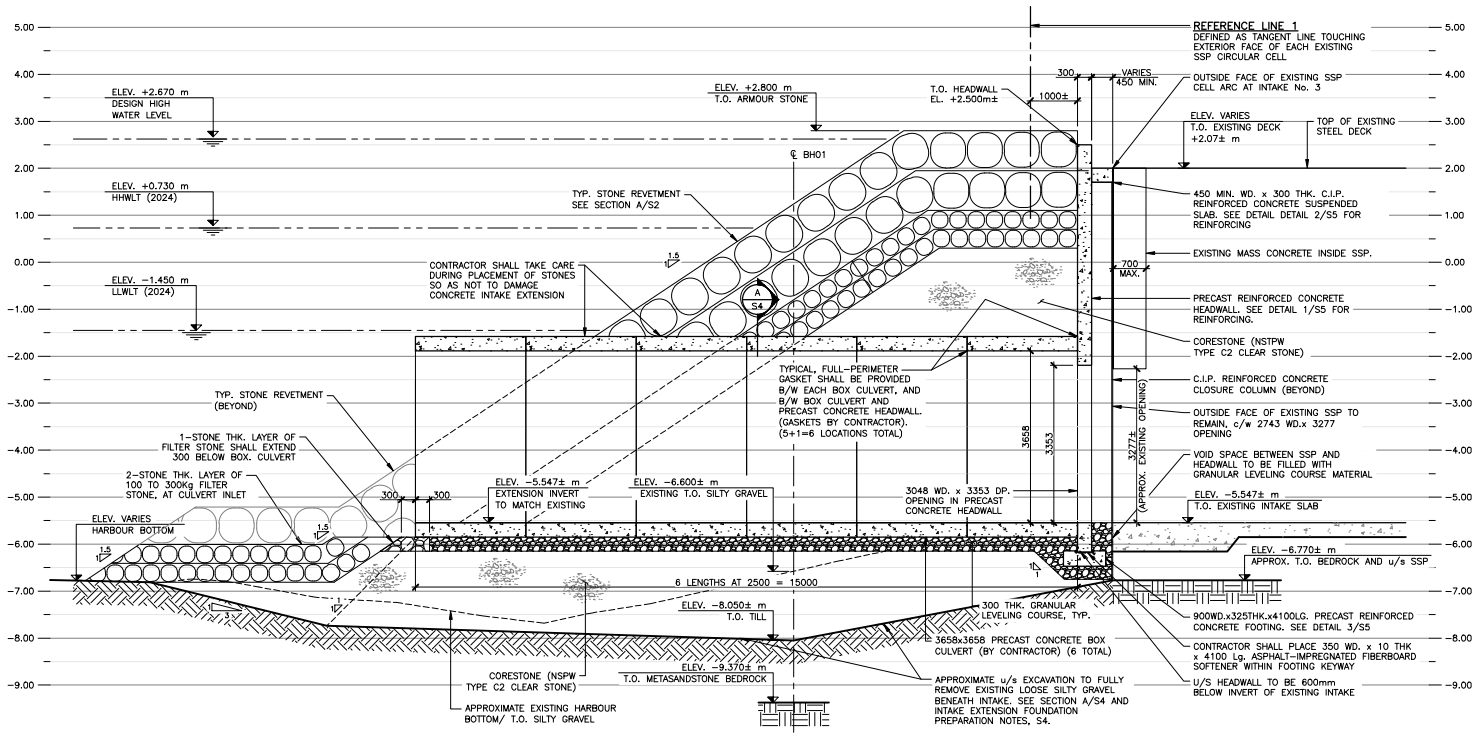
SSP REFURBISHMENT

Title: REVETMENT SECTION AND DETAIL

Scale: AS NOTED	Date: OCTOBER 2024
Drawn: LJD	Designed: BMF
Checked: TSM	Approved: MSR
Contract No.: 231267	
Drawing No.: S2	

REGISTERED PROFESSIONAL ENGINEER PROVINCE OF NOVA SCOTIA
DATE: July 23
S. M. Filmore
20210712

X:\01 HEC01 PROJECTS\231267 TUFT'S COVE SSP\03 ENG DWGS\231267 - S2.DWG, July 23, 2025, 3:39 PM



A/S1 SECTION – INTAKE EXTENSION

1 : 50

NOTE: INTERNAL STRUCTURES WITHIN EXISTING SSP CELL NOT SHOWN. REFER TO HISTORIC DRAWINGS FOR ADDITIONAL INFORMATION.

No.	DESCRIPTION	Date (mm/dd/yy)	By
2	RE-ISSUED FOR CONSTRUCTION	07/23/25	BMF
1	ISSUED FOR CONSTRUCTION	05/29/25	BMF
0	ISSUED FOR REVIEW	05/14/25	BMF

ISSUE or REVISION

Client: Nova Scotia POWER, An Emera Company

HARBOURSIDE Engineering Consultants

Project: TUFT'S COVE DARTMOUTH, NS

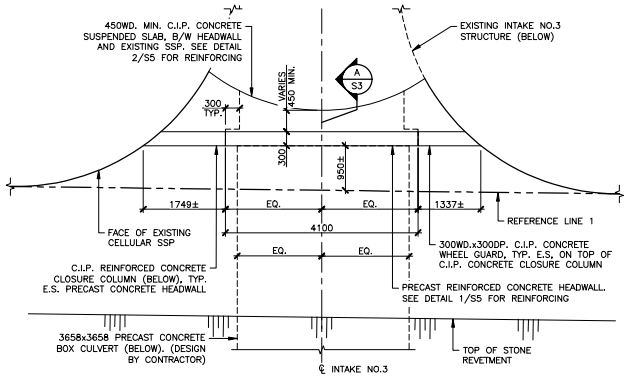
SSP REFURBISHMENT

Title: INTAKE EXTENSION SECTION

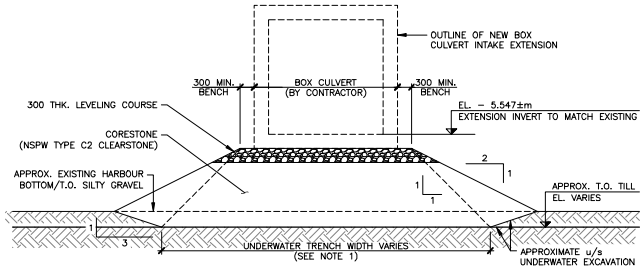
Scale	AS NOTED	Date	OCTOBER 2024
Drawn	LJD	Designed	BMF
Checked	TSM	Approved	MSR
Contract No.	231267		
Drawing No.	S3		

REGISTERED PROFESSIONAL ENGINEER PROVINCE OF NOVA SCOTIA — DATE: July 23 '25 — B. M. Fillmore — 20210712

X:\01 HEC\01 PROJECTS\231267 TUFT'S COVE SSP\03 ENG DWGS\231267 - S3_S4.DWG, July 23, 2025, 3:38 PM



1/S1 **DETAIL** – INTAKE No. 3 EXTENSION 1:50



A/S3 **SECTION** – FOUNDATION PREPARATION AT INTAKE EXTENSION 1:50

INTAKE EXTENSION FOUNDATION PREPARATION NOTES:

1. CONTRACTOR SHALL FULLY EXCAVATE EXISTING LOOSE SILTY GRAVEL LAYER BENEATH NEW INTAKE EXTENSION.
   A. MINIMUM TRENCH WIDTH (u/s EXCAVATION) VARIES BASED ON THICKNESS OF EXISTING LOOSE SILTY GRAVEL LAYER. THEREFORE, MINIMUM TRENCH WIDTH VARIES ALONG LENGTH OF NEW BOX CULVERT INTAKE EXTENSION.
   B. THE MINIMUM TRENCH WIDTH SHALL BE AS INDICATED IN SECTION C, WHICH MAY BE CALCULATED AS THE SUM OF:
      a. EXTERIOR WIDTH OF CULVERT.
      b. 600mm.
      c. TWO TIMES THE THICKNESS OF LOOSE SILTY GRAVEL (TO BE REMOVED). (I.E.: 1H:1V FROM BENCH TO u/s EXCAVATIONS).
2. THE CONTRACTOR SHALL MAINTAIN 3H:1V OR SHALLOWER STABLE SLOPES THROUGH SILTY GRAVEL AT EXCAVATION LIMITS.
3. THE CONTRACTOR SHALL DEMONSTRATE THAT THE LOOSE SILTY GRAVEL LAYER HAS BEEN FULLY REMOVED BENEATH THE INTAKE EXTENSION, TO THE SATISFACTION OF NSPI'S GEOTECHNICAL ENGINEER, PRIOR TO PLACING ANY MATERIALS IN THE TRENCH.
4. PRIOR TO INSTALLATION OF BOX CULVERT INTAKE EXTENSION, THE CONTRACTOR SHALL PLACE CORESTONE AND GRANULAR LEVELING COURSE TO PROVIDE 300 MIN. BENCH AND 2H:1V OR SHALLOWER STABLE SIDE SLOPES, TYPICAL EACH SIDE.
5. UNDERWATER EXCAVATION REQUIREMENTS APPLY TO LOOSE SILTY GRAVEL BENEATH INTAKE EXTENSION, ONLY. EXISTING LOOSE SILTY GRAVEL MAY REMAIN IN–PLACE BELOW NEW REVETMENT, BEYOND LIMITS OF UNDERWATER EXCAVATION AT INTAKE.
6. EXISTING SILTY GRAVEL MATERIAL EXCAVATED BENEATH INTAKE EXTENSION FOUNDATION SHALL BE RE–PLACED AND BURIED BEYOND 2H:1V FOUNDATION SLOPE LIMITS, BENEATH TYPICAL REVETMENT CORESTONE. MAXIMUM THICKNESS OF RE–PLACED SILTY GRAVEL SHALL NOT EXCEED 300 mm ABOVE EXISTING HARBOUR BOTTOM.
7. CONTRACTOR TO PROVIDE A WORK PLAN FOR THE INSTALLATION OF PRECAST COMPONENTS (INCLUDING ENGINEERED LIFT PLANS FOR PRECAST COMPONENTS) FOR NSPI REVIEW PRIOR TO STARTING INSTALLATION.

REINFORCED CONCRETE NOTES:

1. ALL EXPOSED CORNERS OF CONCRETE TO HAVE 25 mm CHAMFERS.
2. LOCATION OF CONSTRUCTION JOINTS AND SEQUENCE OF CONCRETE PLACEMENT TO BE APPROVED BY THE ENGINEER.
3. CONCRETE MATERIAL:
   A. CONCRETE MIX DESIGN TO MEET REQUIREMENTS OF CLASS C–1 AND S–3 EXPOSURES.
   B. MINIMUM 35 MPa CONCRETE COMPRESSIVE STRENGTH AT 28 DAYS.
   C. 20 mm MAX. AGGREGATE SIZE.
   D. 5–8% AIR ENTRAINMENT WITH AIR VOIDS EVENLY DISTRIBUTED IN CAST CONCRETE.
   E. MAX. WATER–TO–CEMENT RATIO 0.40.
4. CONCRETE MATERIALS AND METHODS OF CONSTRUCTION SHALL BE TO CAN/CSA–A23.1 (LATEST EDITION), AND METHODS OF CONCRETE TESTING TO CAN/CSA–A23.2 (LATEST EDITION).
5. CONCRETE COVERS TO REINFORCING STEEL SHALL BE AS NOTED ON DRAWINGS.
6. ALL REINFORCING STEEL SHALL BE BLACK STEEL CONFORMING TO CSA G30.18 (LATEST EDITION) GRADE 400W.
7. WHERE GALVANIZED STEEL COMPONENTS ARE EMBEDDED IN CONCRETE, IT IS THE RESPONSIBILITY OF THE CONTRACTOR TO AVOID POTENTIAL OF GALVANIC REACTION BY PROVIDING ISOLATION BETWEEN GALVANIZED COMPONENTS AND BLACK STEEL REINFORCING BARS. ISOLATION SHALL BE ACHIEVED BY PROVIDING 35 mm CLEAR SPACING BETWEEN BLACK AND GALVANIZED STEEL, OR USING DENSO TAPE (O.A.E.) ON BLACK STEEL AT CONTACT AREA IF 35 mm CLEAR SPACING CANNOT BE ACHIEVED. PLACEMENT OF DENSO TAPE (O.A.E.) SHALL NOT NEGATIVELY EFFECT ANCHORAGES OR LAP SPLICES OF REINFORCING BARS.
8. ALL REINFORCING STEEL SHALL BE DETAILED, FABRICATED, PLACED AND SUPPORTED IN ACCORDANCE WITH REINFORCING STEEL MANUAL OF STANDARD PRACTICE BY THE REINFORCING STEEL INSTITUTE OF CANADA AND CSA A23.3 (LATEST EDITION).
9. ALL SPLICES IN REINFORCEMENT SHALL BE CLASS B LAP SPLICES. WELDING OF REINFORCEMENT IS NOT PERMITTED, UNLESS OTHERWISE APPROVED IN WRITING BY THE CONTRACT ADMINISTRATOR.
10. BARS SHALL BE SUPPORTED ACCURATELY ON CHAIRS TO GIVE SPECIFIED CONCRETE COVER. USE PLASTIC COATED CHAIRS OR APPROVED EQUAL.
11. ALL REINFORCEMENT SHALL BE INSPECTED BY PERSONNEL DESIGNATED BY THE CONTRACT ADMINISTRATOR PRIOR TO CLOSING FORMWORK OR PLACING CONCRETE.
12. CONCRETE SURFACES SHALL BE FINISHED AS FOLLOWS.
   A. CONCRETE SLAB (DECK): UNIFORM BROOM FINISH ON TOP SURFACE OF CONCRETE DECK, EXCLUDING AT COLD JOINTS INTERFACE WITH WHEELGUARDS. BRUSH STROKE GROOVES SHALL RUN PARALLEL TO CROSS–SLOPE OF DECK.
   B. ALL COLD JOINTS SHALL BE INTENTIONALLY ROUGHENED TO AN AMPLITUDE OF 5mm, AT A SPACING OF 15mm ± o.c.
13. APPLY 2 COATS OF SILANE PENETRATING SEALER TO THE FOLLOWING EXPOSED SURFACES:
   A. CONCRETE SLAB (DECK): EXPOSED TOP SURFACE AND VERTICAL SURFACES ALONG EDGES OF DECK.
   B. WHEELGUARDS: ALL EXPOSED SURFACES.
14. REQUIREMENTS FOR PRECAST REINFORCED CONCRETE BOX CULVERTS (BY CONTRACTOR).
   A. DESIGN AND CONSTRUCTION SHALL BE IN ACCORDANCE WITH CSA S6 – THE CANADIAN HIGHWAY BRIDGE DESIGN CODE (LATEST EDITION).
   B. CONTRACTOR SHALL SUBMIT PRECAST REINFORCED CONCRETE BOX CULVERT MANUFACTURER'S SHOP DRAWINGS AND ASSOCIATED SPECIFICATIONS TO CONTRACT ADMINISTRATOR FOR REVIEW AND ACCEPTANCE PRIOR TO ORDERING MATERIALS. SHOP DRAWINGS AND ASSOCIATED SPECIFICATIONS SHALL BE STAMPED BY A PROFESSIONAL ENGINEER LICENSED TO PRACTICE IN THE PROVINCE OF NOVA SCOTIA. SPECIFICATIONS SHALL INCLUDE HANDLING AND INSTALLATION REQUIREMENTS.

GRANULAR AND REVETMENT MATERIAL AND PLACEMENT NOTES:

1. GENERAL GRANULAR AND REVETMENT MATERIALS REQUIREMENTS:
   A. ALL MATERIALS SHALL BE SUPPLIED BY THE CONTRACTOR.
   B. ALL PIECES OF STONE SHALL BE SOUND AND SUBJECT TO APPROVAL BY THE CONTRACT ADMINISTRATOR.
   C. MATERIALS SHALL BE TESTED IN ACCORDANCE WITH ASTM C127, AND SHALL NOT EXCEED MAXIMUM 1.75% ABSORPTION.
   D. THE CONTRACT ADMINISTRATOR RESERVES THE RIGHT TO REJECT ANY SOURCE OF SUPPLY OF MATERIALS SOLELY ON THE BASIS OF PAST FIELD PERFORMANCE, DOCUMENTED BY THE RECORDS AND EXPERIENCE OF THE CONTRACT ADMINISTRATOR, REGARDLESS OF COMPLIANCE WITH GRADATION OR PHYSICAL REQUIREMENTS.
2. CORESTONE:
   A. MEETING THE REQUIREMENTS FOR TYPE C2 CLEAR STONE, IN ACCORDANCE WITH NOVA SCOTIA DEPARTMENT OF TRANSPORTATION AND PUBLIC WORKS STANDARD SPECIFICATION MANUAL (LATEST EDITION).
3. GRANULAR LEVELLING COURSE.
   A. THE LEVELLING COURSE MATERIAL SHALL CONSIST OF QUARRIED OR CRUSHED CLEAR STONE.
   B. LEVELLING COURSE SHALL BE COMPOSED OF CLEAN, UNCOATED PARTICLES, FREE OF MUD, MUDSTONE, SILTSTONE OR OTHER UNCONSOLIDATED ROCK MATERIAL, ORGANIC MATERIALS, AND OTHER DELETERIOUS MATERIALS.
   C. LEVELLING COURSE SHALL NOT CONTAIN ANY FRIABLE, SOLUBLE, OR REACTIVE MINERALS OR OTHER DELETERIOUS MATERIALS OR CONDITIONS THAT WOULD MAKE THE MATERIAL PRONE TO DECOMPOSITION OR DISINTEGRATION.
   D. LEVELLING COURSE SHALL NOT PRESENT ANY ENVIRONMENTAL HAZARD, FROM THE PRESENCE OF THE PARENT MATERIAL OR ITS BY–PRODUCTS, WHEN EXPOSED TO THE NATURAL ELEMENTS AFTER PLACEMENT IN THE WORK.
   E. USE OF SHALE OR SLATE ROCK WILL NOT BE PERMITTED.
   F. LEVELLING COURSE SHALL BE TESTED IN ACCORDANCE WITH ASTM C117 AND ASTM C136 AND CONFORM TO THE GRADATION LISTED IN THE FOLLOWING TABLE.

SIEVE SIZE, µm	PERCENT PASSING BY MASS
75,000	100
50,000	85–100
31,500	10–20
25,000	0–8

4. ARMOUR STONE:
   A. MATERIALS SHALL CONSIST OF HARD, DURABLE STONES WITH ANGULAR FACES.
   B. MATERIALS SHALL BE FREE FROM SEAMS AND CRACKS.
   C. MATERIALS SHALL HAVE SPECIFIC GRAVITY NOT LESS THAN 2.65. ACTUAL SPECIFIC GRAVITY AND ABSORPTION WILL BE DETERMINED BY TESTING SELECTED SAMPLES OF MATERIALS BEING INCORPORATED INTO THE WORKS. MATERIALS WITH A SPECIFIC GRAVITY LESS THAN 2.65 WILL BE REJECTED.
   D. ARMOUR STONE TO BE DURABLE IGNEOUS OR METAMORPHIC ROCK. SHALE OR SLATE STONE SHALL NOT BE PERMITTED.
   E. ARMOUR STONE SHALL BE 1.5 TO 2.5 TONNE STONES.
      a. NEW ARMOUR STONE SHALL BE GRADED WITHIN THE SPECIFIED LIMITS, SUCH THAT THE 50TH PERCENTILE STONE IS APPROXIMATELY IN THE CENTER OF THE SPECIFIED RANGE.
      b. THE LARGEST DIMENSION OF EACH STONE IS NOT TO EXCEED TWO TIMES ITS SMALLEST DIMENSION.
      c. MATERIAL TO BE QUARRIED OR FIELD STONE, ROUGH AND ANGULAR IN SHAPE.
   F. FILTER STONE SHALL BE 100 kg TO 300 kg STONES.
      a. NEW FILTER SHALL BE GRADED WITHIN THE SPECIFIED LIMITS, SUCH THAT THE 50TH PERCENTILE STONE IS APPROXIMATELY IN THE CENTER OF THE SPECIFIED RANGE.
      b. THE LARGEST DIMENSION OF EACH STONE IS NOT TO EXCEED TWO TIMES ITS SMALLEST DIMENSION.
      c. MATERIAL TO BE QUARRIED OR FIELD STONE, ROUGH AND ANGULAR IN SHAPE.
5. ENSURE THE METHOD OF PLACEMENT FOR ALL MATERIAL IS REVIEWED AND ACCEPTED BY THE CONTRACT ADMINISTRATOR BEFORE COMMENCING THE WORK.
   A. METHODS FOR PLACEMENT OF MATERIAL SHALL NOT DAMAGE OR DE–STABILIZE NEW OR EXISTING INFRASTRUCTURE.
   B. CONSIDERATION SHALL BE GIVEN TO FORECAST STORM EVENTS AND MANAGEMENT OF ICE ACCRETION, AS REQUIRED.
6. AN INITIAL LIFT OF 500 mm THICK CORESTONE SHALL BE PLACED USING A CONTROLLED METHOD FOR ALL AREAS WHERE CORESTONE IS SHOWN TO BE PLACED ON TOP OF THE EXISTING HARBOUR BOTTOM SILTY GRAVEL. THE PURPOSE OF THIS CONTROLLED PLACEMENT IS TO MINIMIZE SUSPENSION OF EXISTING HARBOUR BOTTOM SILTS.
   A. AFTER COMPLETED PLACEMENT OF INITIAL LIFT OF CORESTONE, CONTRACTOR MAY DUMP/USE CONVEYOR METHODS FOR PLACEMENT OF CORESTONE, PROVIDED THAT CONTRACTOR CAN ACHIEVE PROJECT TURBIDITY REQUIREMENTS.
7. THE CONTRACTOR SHALL CHOOSE THE ARMOUR AND FILTER STONES AND PLACE THEM IN SUCH A WAY THAT THE WHOLE REVETMENT SLOPE STRUCTURE WILL BE BOUND AND CONSOLIDATED TO AS GREAT AN EXTENT AS THE NATURE OF THE ROCK WILL ALLOW. PLACING SHALL BE DONE IN SUCH A MANNER THAT THE SURFACE OF THE REVETMENT SLOPE SHALL HAVE A UNIFORM APPEARANCE.
   A. DUMPING OF ARMOUR AND FILTER STONE MATERIAL IS NOT PERMITTED. ARMOUR STONES SHALL BE INDIVIDUALLY PLACED. FILTER STONE SHALL BE INDIVIDUALLY PLACED OR OTHERWISE PLACED USING A CONTROLLED METHOD.
8. PLACEMENT SHALL BE TO DIMENSIONS, GRADES AND ELEVATIONS AS INDICATED ON THE CONTRACT DRAWINGS OR AS DIRECTED BY THE CONTRACT ADMINISTRATOR.
   A. THE CONTRACTOR SHALL PROVIDE AS–BUILT SURVEY CROSS SECTIONS AT MAXIMUM 10 METER STATIONS TO THE CONTRACT ADMINISTRATOR TO SHOW THAT LINES AND GRADES HAVE BEEN ACHIEVED AS SHOWN ON THE DRAWINGS, WITHIN THE SPECIFIED TOLERANCE.
9. COMPLETED MATERIAL LAYERS TO BE WITHIN THE FOLLOWING TOLERANCES OF LINES AND GRADES, AS INDICATED:
   A. CORESTONE AND FILTER STONE: ± 150mm.
   B. ARMOUR STONE: ± 300mm.
   C. GRANULAR LEVELLING COURSE: ± 25mm.

No.	DESCRIPTION	Date (mm/dd/yy)	By
2	RE–ISSUED FOR CONSTRUCTION	07/23/25	BMF
1	ISSUED FOR CONSTRUCTION	05/29/25	BMF
0	ISSUED FOR REVIEW	05/14/25	BMF

ISSUE or REVISION

Client: Nova Scotia POWER, An Emera Company

HARBOURSIDE Engineering Consultants

Project: TUFT'S COVE DARTMOUTH, NS

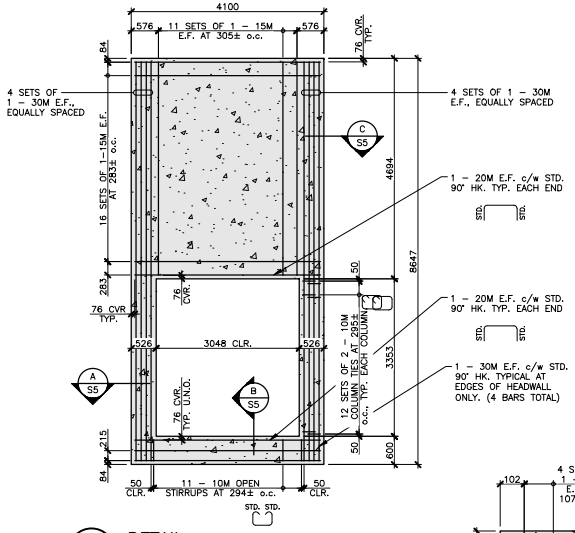
SSP REFURBISHMENT

Title: INTAKE EXTENSION DETAIL, SECTION, AND NOTES

Scale	Date
AS NOTED	OCTOBER 2024
Drawn: LJD	Designed: BMF
Checked: TSM	Approved: MSR
Contract No.	231267
Drawing No.	S4

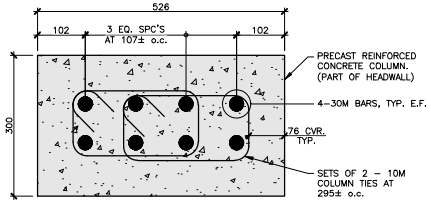
REGISTERED PROFESSIONAL ENGINEER PROVINCE OF NOVA SCOTIA DATE: July 23/25 S. M. Filmore 20210712

X:\01 HEC\01 PROJECTS\231267 TUFT'S COVE SSP\03 ENG DWGS\231267 - S3_S4.DWG, July 23, 2025, 3:38 PM

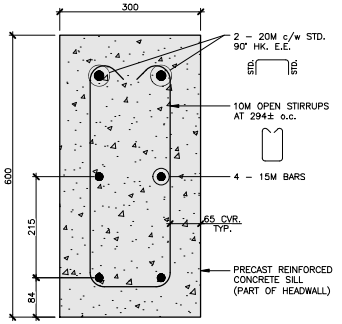


1 / S3 DETAIL – HEADWALL REINFORCEMENT 1:50

NOTE: MIN. CVR. SHALL BE 65mm AT 10M OPEN STIRRUPS ONLY.



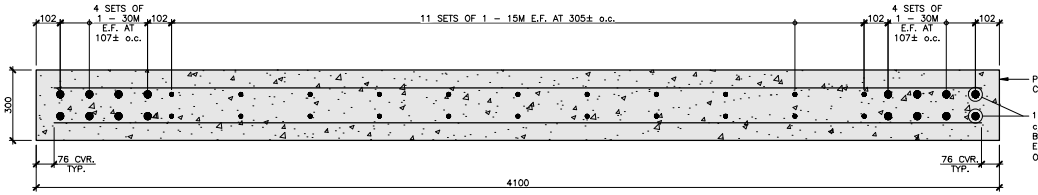
A / S5 SECTION – HEADWALL COLUMN REINFORCING 1:5



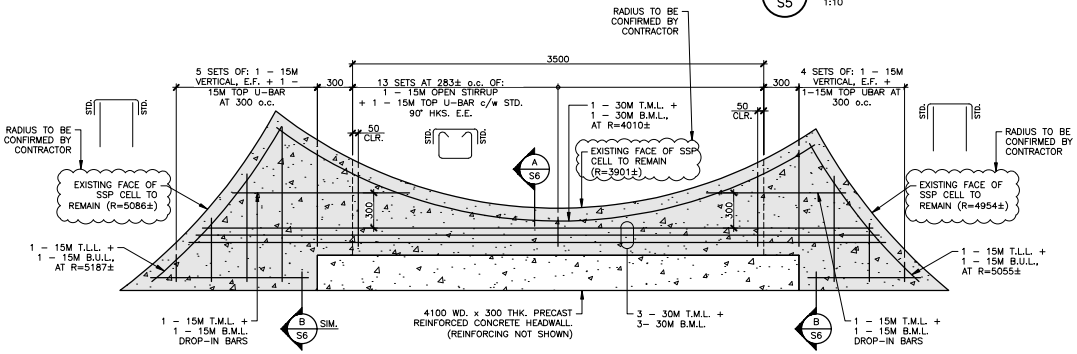
B / S5 SECTION – HEADWALL SILL REINFORCING 1:5

ABBREVIATION LEGEND:

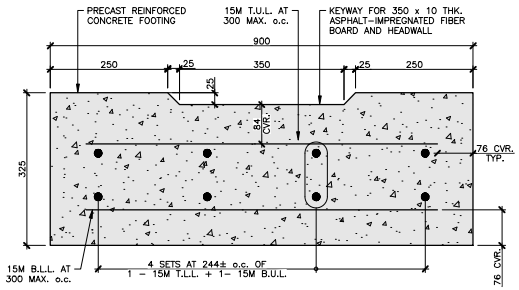
T.U.L.	=	TOP UPPER LAYER
T.M.L.	=	TOP MIDDLE LAYER
T.L.L.	=	TOP LOWER LAYER
B.U.L.	=	BOTTOM UPPER LAYER
B.M.L.	=	BOTTOM MIDDLE LAYER
B.L.L.	=	BOTTOM LOWER LAYER
E.F.	=	EACH FACE
E.E.	=	EACH END
E.S	=	EACH SIDE
U.N.O.	=	UNLESS NOTED OTHERWISE
CVR.	=	COVER (EXTERIOR SURFACE)
CLR.	=	CLEAR (INTERNAL SURFACE)



C / S5 SECTION – HEADWALL REINFORCING 1:10



2 / S4 DETAIL – SLAB REINFORCING PLAN 1:50 (FROM EL. +1.62m TO +2.07m)



3 / S3 DETAIL – FOOTING REINFORCEMENT 1:5

No.	DESCRIPTION	Date (mm/dd/yy)	By
2	RE–ISSUED FOR CONSTRUCTION	07/23/25	BMF
1	ISSUED FOR CONSTRUCTION	05/29/25	BMF
0	ISSUED FOR REVIEW	05/14/25	BMF

ISSUE or REVISION

Client: Nova Scotia POWER An Emera Company

HARBOURSIDE Engineering Consultants

Project: TUFT'S COVE DARTMOUTH, NS

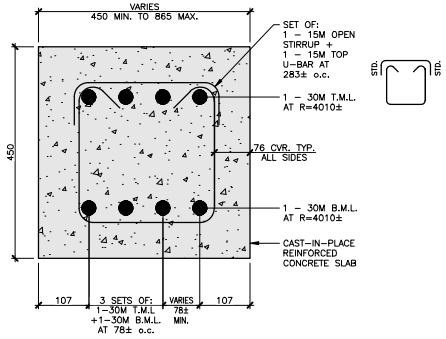
SSP REFURBISHMENT

Title: HEADWALL, SLAB, FOOTING SECTIONS AND DETAILS

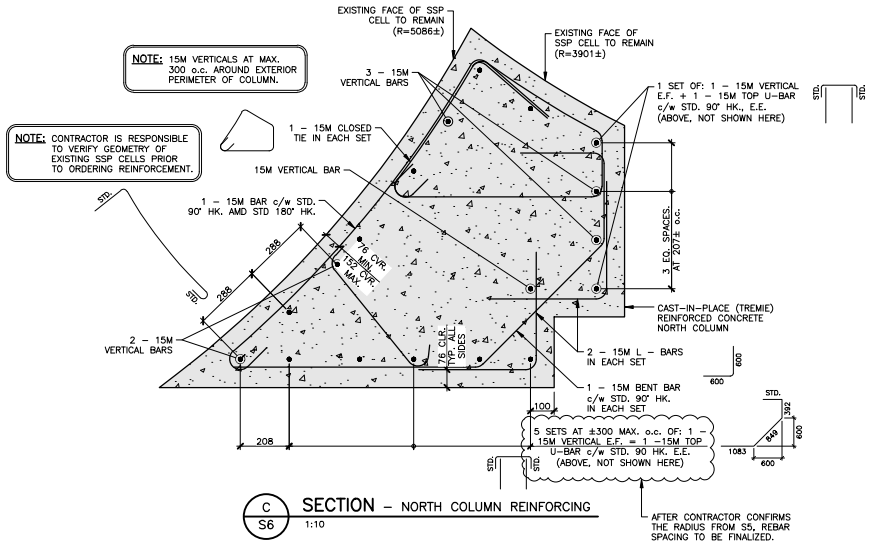
Scale	AS NOTED
Date	OCTOBER 2024
Drawn	LJD
Designed	BMF
Checked	TSM
Approved	MSR
Contract No.	231267
Drawing No.	S5

REGISTERED PROFESSIONAL ENGINEER PROVINCE OF NOVA SCOTIA B. M. Fillmore 20210712 DATE: July 23, 2025

X:\01 HEC\01 PROJECTS\231267 TUFT'S COVE SSP\03 ENG DWGS\231267 - S5-S7.DWG, July 23, 2025, 3:38 PM

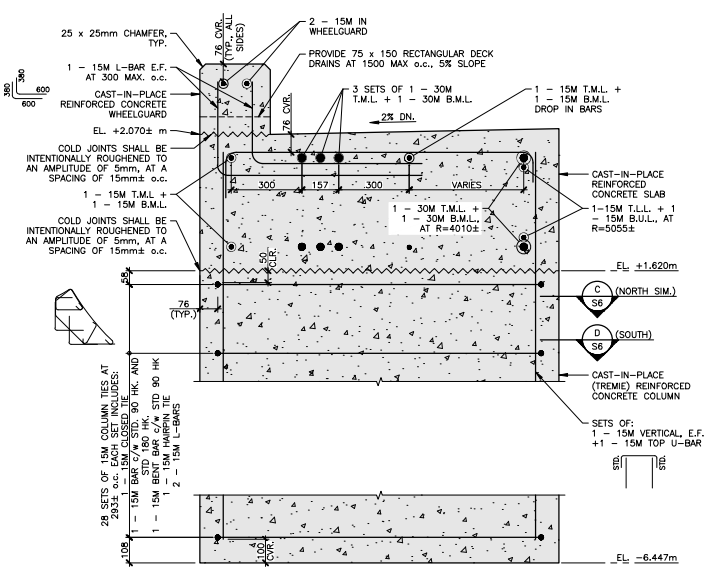


A S5 SECTION – SLAB REINFORCING 1:5

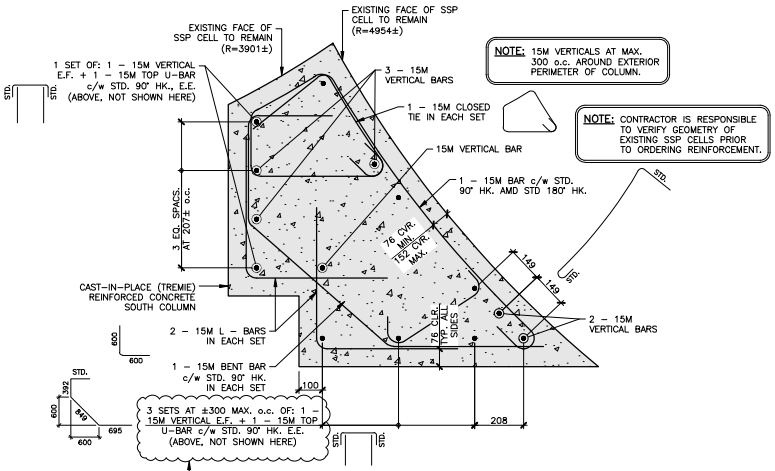


C S6 SECTION – NORTH COLUMN REINFORCING 1:10

AFTER CONTRACTOR CONFIRMS THE RADIUS FROM S5, REBAR SPACING TO BE FINALIZED.



B S5 SECTION – COLUMN REINFORCING 1:10 (SOUTH SHOWN, NORTH SIM)



AFTER CONTRACTOR CONFIRMS THE RADIUS FROM S5, REBAR SPACING TO BE FINALIZED.

D S6 SECTION – SOUTH COLUMN REINFORCING 1:10

ABBREVIATION LEGEND:

T.U.L.	=	TOP UPPER LAYER
T.M.L.	=	TOP MIDDLE LAYER
T.L.L.	=	TOP LOWER LAYER
B.U.L.	=	BOTTOM UPPER LAYER
B.M.L.	=	BOTTOM MIDDLE LAYER
B.L.L.	=	BOTTOM LOWER LAYER
E.F.	=	EACH FACE
E.E.	=	EACH END
E.S	=	EACH SIDE
U.N.O.	=	UNLESS NOTED OTHERWISE
CVR.	=	COVER (EXTERIOR SURFACE)
CLR.	=	CLEAR (INTERNAL SURFACE)

No.	DESCRIPTION	Date (mm/dd/yy)	By
2	RE–ISSUED FOR CONSTRUCTION	07/23/25	BMF
1	ISSUED FOR CONSTRUCTION	05/29/25	BMF
0	ISSUED FOR REVIEW	05/14/25	BMF

ISSUE or REVISION

Client: Nova Scotia POWER An Emera Company

HARBOURSIDE Engineering Consultants

Project: TUFT'S COVE DARTMOUTH, NS

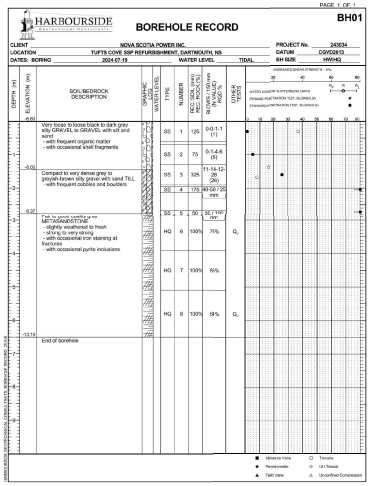
SSP REFURBISHMENT

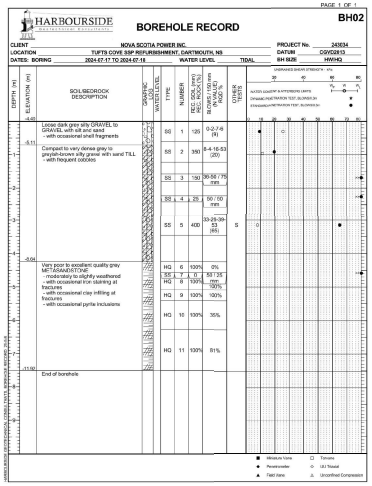
Title: SLAB AND COLUMN SECTIONS

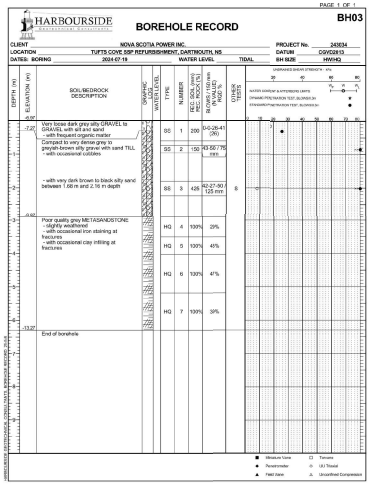
Scale	AS NOTED
Date	OCTOBER 2024
Drawn	LJD
Designed	BMF
Checked	TSM
Approved	MSR
Contract No.	231267
Drawing No.	S6

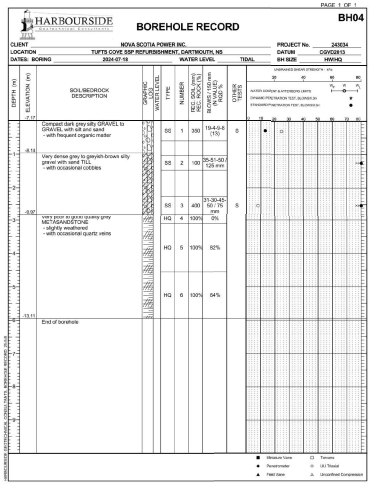
REGISTERED PROFESSIONAL ENGINEER PROVINCE OF NOVA SCOTIA DATE Jul 23 '25 S. M. Filmore 20210712

X:\01 HEC\01 PROJECTS\231267 TUFT'S COVE SSP\03 ENG DWGS\231267 - S5-S7.DWG, July 23, 2025, 3:38 PM









No.	DESCRIPTION	Date (mm/dd/yy)	By
2	RE-ISSUED FOR CONSTRUCTION	07/23/25	BMF
1	ISSUED FOR CONSTRUCTION	05/29/25	BMF
0	ISSUED FOR REVIEW	05/14/25	BMF

ISSUE or REVISION

Client: Nova Scotia POWER, An Emera Company

HARBOURSIDE Engineering Consultants

Project: TUFT'S COVE DARTMOUTH, NS

SSP REFURBISHMENT

Title: BOREHOLE LOGS

Scale	Date
AS NOTED	OCTOBER 2024
Drawn: LJD	Designed: BMF
Checked: TSM	Approved: MSR
Contract No.	231267
Drawing No.	S7

REGISTERED PROFESSIONAL ENGINEER PROVINCE OF NOVA SCOTIA
DATE: July 23/25
S. M. Fillmore
20210712

X:\01 HEC 01 PROJECTS\231267 TUFTS COVE SSP 03 ENG DWGS\231267 - S5-S7.DWG, July 23, 2025, 3:38 PM

Request IR-71:

G03: C0021608 TUC Shoreline Sheetpile Refurbishment

Page 154 states: "The detailed design was used as the basis of the construction Request for Proposals (RFP) which is currently in the process of being awarded in late 2025."

(a) Has the construction RFP been awarded?

(i) If not, why not and when will it be awarded?

(ii) If so, please provide copies of the RFP submission from each respondent complete with the detailed pricing submissions.

Response IR-71:

(a) Yes. The Request for Proposal (RFP) has been awarded to the preferred proponent; however, the contract details are still being finalized.

(i) N/A.

(ii) Please refer to Attachment 1 and 2. Detailed pricing information is at the end of the attachments.

Nova Scotia Power Inc.

Response to Request for Proposal
RFP-06/2025-545
Tufts Cove Shoreline Sheet Pile Rock Revetment

Technical Proposal

DEXTER

MUNICIPAL GROUP
OF COMPANIES

Table of Contents

8.1 Organizational Capabilities 1
a) Brief Overview of Company 1
b) Previous Engagements of Similar Nature / Expertise / Scale and References 2
c) Key Personnel within Management Structure Accountable to NSPI 3
d) HST Number 3
8.2 Technical Requirements 4
a) Alternatives / Deviations from the Specification or Requirements Stated in Attachment "A" 4
8.3 Project Plan 5
a) Step-By-Step Project Plan 5
b) Timeline Details 5
c) Acknowledgement of Completion within Outage Window 5
d) Brief Profiles of Key Personnel 5
e) Own Workforce Versus Work Sublet to Subcontractors 5
8.4 Reporting 7
a) Report Delivery Options 7
b) Samples of Standard Reports 7
c) Charges for Reports 7
d) Non-Standard Reports 7
8.5 Quality and Monitoring 8
a) Brief Description of Quality Assurance Programs and Quality Management System 8
8.6 Specialized Services 9
a) Related Services 9
8.7 Performance Standards 10
a) Standards with Respect to Resolving Service Issues 10
b) Individual Responsible for Responding to NSPI 10
c) Contractual Issues with Unions or Affiliates 10
8.8 Warranty 11
a) Statement of Warranty 11
b) Details and Cost of Extended Warranty Options 11
8.9 Safety 12

a) Workers' Compensation Board – Experience Ratings 12
b) Detailed Safety Plan 15
c) Proponent's Understanding and Acceptance of the Following 15
d) Regulatory Offences, Directives and Orders 15
e) Safety Certifications and Gear 15
f) ISNetwold Registration Particulars 16
8.10 Environment 17
a) Individuals Responsible for Monitoring, Maintenance and Execution of Environmental Measures 17
b) Materials and Equipment Available for Environmental Emergency Preparedness 17
c) Processes for Reporting and Investigating Environmental Incidents 17
d) Proponent's Understanding and Acceptance of the Following 18
e) Environmental Regulatory Offences 18
f) Environmental Regulatory Directives/Orders 18
8.11 Cybersecurity 19
a) Collection and Storage of Data 19
b) Updates/Patches for Known Vulnerabilities 19
c) External Connectivity 19
d) Mature Security Program 19
e) Application Security Questionnaire. 20
8.12 Responsible Sourcing 21
a) Importing Goods from Outside of Canada 21
8.13 Employee Requirements 22
a) Proponent's Understanding and Acceptance of the Following 22
8.14 Insurance 23
8.15 Certifications 24
8.16 Commercial / Price Proposal 27

Appendix A Preliminary Project Schedule
Appendix B Site Specific Project Health & Safety Plan
Appendix C Provincial OHS Profile
Appendix D Environmental Directive

8.1 Organizational Capabilities

a) Brief Overview of Company

Company Name: Dexter Construction Company Limited
927 Rocky Lake Drive, PO Box 48100
Bedford, Nova Scotia B4A 3Z2
Phone: (902) 835-3381

Length of Time in Business: 64 Years

Dexter Construction Company Limited (Dexter), is part of the Nova Scotia based Municipal Group of Companies (Municipal Group). We are the largest and fastest growing civil contractor in Atlantic Canada, and our resources include a powerful, modern fleet of equipment, a dedicated and qualified workforce, and strong industry relationships.

Successfully in business for over 50 years, Dexter has earned a reputation as a reliable, innovative and capable company that strives to complete projects on time, on budget, and to the satisfaction of its' customers. Our areas of expertise include includes all aspects of heavy civil constriction, marine structures, road and highway construction, materials production and placing, concrete placing, utility piping installation, bridge construction, road maintenance and rehabilitation, open pit mining, and more. Dexter has become a leader in all areas of heavy civil construction and is the largest road builder in Atlantic Canada, while remaining a locally owned and privately held family company.

Dexter has the support of the entire Municipal Group comprised of more than 25 affiliated diverse companies. Our size and diversity enable us to complete most civil construction projects with our own forces, resulting in reduced delays, and greater schedule and project management control. We have a fleet of more than 1000 pieces of heavy equipment and 1600 local employees who will complete the work.

Over many years, and across a diverse range of projects, we have proven ourselves to be more than your typical civil contractor. As proud leaders in the construction industry, we consistently deliver a high degree of professionalism and responsibility to our projects. We strategically collaborate with clients at every stage of a project to streamline constructability and maximize value. We know the importance of engaging local employees and contractors from the communities where our projects are located. As well, we implement and execute project-specific quality assurance, quality control and environmental management programs, and we always prioritize safety in everything we do.

Dexter is experienced working with Nova Scotia Power Inc. (NSPI), having completed the Tufts Cove Unit 6 Waste Heat Recovery Project, the Trenton Ash Management Site Closure, and most recently the Springhill Substation Access Road. In addition to our experience working with NSPI we also have experience working for other industrial clients such as Husky Energy and Irving Oil where project controls and safety management is paramount to success. Our project managers thrive in these settings, and we have received numerous compliments from our clients noting our ability to perform in highly controlled environments while still maximizing efficiencies.

Subcontractors Used as Part of this Proposal: Connors Diving Services Ltd.

b) Previous Engagements of Similar Nature / Expertise / Scale and References

Jetty NJ Construction, Halifax Dockyard, Canadian Forces Base

Owner: Defence Construction Canada

Contact: Dean MacMullin, C.E.T.
902-401-9854
Dean.MacMullin@dcc-cdc.gc.ca

Construction of new marginal jetty, Jetty NJ, at Canadian Forces Base Halifax (Dockyard), in Halifax, Nova Scotia. Commenced with the dredging of over 130,000 m³ of marine sediments, till and rock. Upon completion of dredging, a stone mattress was placed that forms the foundation for six (6) concrete caissons. The caissons were slip-formed off-site and transported to site where they were founded on top of this stone mattress. The caissons were ballasted and backfilled. Two steel sheet pile / pipe pile combination walls were constructed on the north and south face of the wharf to tie the wharf into existing elevation on-shore.

Upon completion of ballasting the caissons, a cast-in-place concrete structure, comprised of utility tunnel and slabs, was constructed on-top of the underlying caissons and onshore H-Piles. This tunnel carries all electrical and mechanical utilities from land to ship.

Alma Wharf Rehabilitation

Owner: Public Works and Government Services Canada

Contact: Monique Pellerin
Project Manager
506-380-3608
monique.pellerin@pwgsc-tpsgc.gc.ca

Reconstruction of the spur section of the existing wharf by enveloping the existing wharf within a new sheet pile wall including:

- Dredging 14,500 m³ and off-site disposal of dredged material
- Installing 10,600 tonnes of armour stone to create a new boat harbour
- Demolitions and removals of portions of the existing concrete and asphalt wharf deck and structure, as well as timber and steel components
- Installation of 95 sheet piles to encapsulate and widen the existing wharf, including waler, tieback walls and tie rods
- Installation of 34 H-piles
- Backfilling of the steel sheet pile structure
- Reconstruction of wharf deck with granulars and 370 m³ cast-in-place concrete wharf deck
- Wharf outfitting with fenders, walers, cleats, ladders, sliding moorings, and galvanized steel wheelguard
- Electrical services and lighting
- Completed numerous additional wharf upgrades including boat ramp construction, upgraded boat mooring system, upgraded fendering system and various site improvements

Blacks Harbour, Dredging and Service Area

Owner: Public Works and Government Services Canada

Contact: Monique Pellerin
Project Manager
506-380-3608
monique.pellerin@pwgsc-tpsgc.gc.ca

Construction of new containment cell, harbour dredging, driving 610mm diameter piles for future wharf construction, driving guide piles and installation of new floating wharves. Work took place on barges with high tides (approximately 15m).

Bay St. Lawrence Breakwater Repairs

Owner: Public Works and Government Services Canada

Contact: Meghan Walsh, P.Eng
Project Engineer
902-496-5319 / 902-233-0038
Meghan.Walsh@pwgsc-tpsgc.gc.ca

Supply and installation of 92 sheet piles to repair the deteriorated existing 130m long sheet pile wall. Including tie back system, gravel and concrete infill between pile walls, concrete copewall and deck repairs, and renewed dock outfitting including new ladders, curbs and mooring cleats.

References Currently Using our Services

Owner: Halifax Regional Water Commission
Contact Name: Greg Rice
Phone Number: (902) 476-3520

Owner: Department of Transportation
Contact Name: Don Maillet
Phone Number: (902) 424-2489

Owner: Halifax Regional Municipality
Contact Name: Moe Al Miari
Phone Number: (902) 943-0543

c) Key Personnel within Management Structure Accountable to NSPI

Name	Position	Experience
Kevin Cooke	Manager of Structures	30+ Years

d) HST Number

R101372720

8.2 Technical Requirements

a) Alternatives / Deviations from the Specification or Requirements Stated in Attachment "A"

We do not offer any alternatives or deviations at this time.

8.3 Project Plan

a) Step-By-Step Project Plan

1. Administration & Mobilization

- Complete safety, environmental, and dive plans; NSPI site onboarding.
- Partially remove existing bridge and establish barge access.
- Mobilize marine vessels, barges, cranes, excavators and other required equipment.

2. Intake Extension & Headwall

- Conduct underwater excavation and prepare base.
- Place core stone and leveling stone to design.
- Install precast footing and headwall, precast intake extension sections, and cast-in-place (CIP) headwalls.
- Complete CIP suspended slab and wheelguard.

3. Sheet Pile Rock Revetment

- The revetment will be constructed in two phases:
  1. Revetment up to the intake extension (approx. two-thirds of the total length)
  2. Revetment at the intake extension (remaining length, following completion of the extension work)
- In each phase, place core stone to profile, followed by filter stone and armour stone layers.

4. Quality & Environmental Compliance

- Comply with NSPI, DFO, Transport Canada, and Port of Halifax requirements.
- Coordinate with NSPI's third-party sedimentation monitoring program.
- Maintain progressive survey control and QA/QC records for all placed materials and structures.

5. Demobilization & Close-Out

- Remove marine vessels.
- Remove barge access and reinstate bridge.
- Restore disturbed areas and demobilize.
- Submit as-built drawings, QA documentation, and final reports.

b) Timeline Details

Please see Appendix A for Preliminary Project Schedule in Appendix A.

c) Acknowledgement of Completion within Outage Window

Dexter acknowledges that the job must be completed within the outage window and confirms that we can meet timelines. We understand that failure to meet timelines may result in penalties.

d) Brief Profiles of Key Personnel

Name	Position	Experience
Kevin Cooke	Manager of Structures	30+ Years

e) Own Workforce Versus Work Sublet to Subcontractors

Underwater inspection and construction services will be subcontracted to Connors Diving Services Ltd. All other

work will be performed by Dexter.

8.4 Reporting

a) Report Delivery Options

Reports can be provided electronically via email, fax or hard copies can be made available

b) Samples of Standard Reports

Reporting on project status will be completed by Dexter project management staff. Dexter uses regular reporting procedures that are undertaken on every project and scaled based on the size and complexity of the work, as well as any specific client requirements. Our reports focus on daily activities and physical progress, schedule updates, quality and environmental management updates, quality and environmental inspection and testing plans (ITPs), health and safety updates, change management, manpower requirements, technical queries status, and action item status.

c) Charges for Reports

Any reports requested by the client not otherwise noted as being required in the tender documents will incur a charge with the value to be determined based on requirements.

d) Non-Standard Reports

Any reports requested by the client not otherwise noted as being required in the tender documents will incur a charge with the value to be determined based on requirements.

8.5 Quality and Monitoring

a) Brief Description of Quality Assurance Programs and Quality Management System

Dexter is committed to implementing and maintaining a comprehensive Quality Management System (QMS) which ensures delivered services meet or exceed the requirements of internal and external stakeholders. Dexter's QMS experience on similar projects has confirmed the value of thoughtful quality management in its role to ensure effectiveness, efficiency, continual improvement and overall success of complex construction and operation projects.

Dexter will implement a QMS in accordance with the ISO 9001:2015 International Standard that will provide the framework for planning, performing, monitoring and improving effective and efficient processes which satisfy the requirements of the Project documentation.

Dexter manages its systems using an integrated approach between the QMS, the Environmental Management System (EMS), and the Health and Safety management system (H&S). This integrated management methodology employs common processes wherever possible to foster consistency and efficiency between each management system. Further, this integrated approach ensures that quality, environment, health and safety are considered in all actions and decisions affecting the project, and that the QMS, EMS and H&S are treated with equal importance and without compromise.

Dexter has adopted a "process approach" for its quality management systems. By identifying the key processes within its organizations and managing each key process discretely, Dexter reduces the potential occurrence of nonconforming services. Potential nonconformities and risks are identified and addressed in advance of service provision, by actions taken within each of the key processes. Furthermore, continual improvement efforts can be implemented with a focus toward the clearly defined objectives of each key process. Monitoring and control of key processes ensures effective implementation and control of all the process' component parts.

Following the definition of key processes and the development of the context of the organization, Dexter team members will create comprehensive quality documentation of the system in accordance with governing project documentation. These documents will become the key reference documents for the implementation of the QMS.

Quality documentation will be thoroughly integrated to foster transparency, clarity and ease of understanding to all users. The documented plans and procedures will be presented in a clear and concise manner and in a common format, utilizing detailed step by step procedures, organizational charts and comprehensive process flow diagrams. Each document will distinctly identify process owners, responsible parties, input providers, desired outcomes, measurement metrics and all retained records. All documentation will be meticulously controlled in accordance with Dexter's own document control procedures, which align with the requirements of ISO 9001:2015 international standard.

8.6 Specialized Services

a) Related Services

The diversity of the companies that make up the Municipal Group allow us to provide a broad variety of services. Our ever-expanding capabilities include quarry and asphalt plant services, contaminated soil cleaning, portable sanitation, waste management, traffic control, logistics and trucking, blasting, piling and drilling.

8.7 Performance Standards

a) Standards with Respect to Resolving Service Issues

It is Dexter's belief that the longer an issue remains unaddressed or unresolved the bigger the issue will become, and the more other issues will start impacting on the overall schedule and profitability of the project. Dexter's approach to resolving disputes is to identify and isolate issues early and resolve them quickly. Dexter believes that the strong communication amongst subcontractors and NSPI, specifically through daily dialogue and coupled with a clear contractual structure, is one tool that helps avoid or mitigate potential disputes. Dexter will put into place mechanisms to allow the project to progress despite the occurrence of a dispute, thereby maintaining NSPI's broader objectives at the forefront and maintaining a client first approach to project delivery. If an issue is unable to be resolved at the operational level, it will be escalated to senior project representatives. Dexter has a strong track record in being able to resolve matters smoothly without the need for formal process. Dexter will respect any dispute resolutions outlined in the contract.

b) Individual Responsible for Responding to NSPI

Dexter's Project Manager will serve as the Company's official representative on the project and will be responsible for responding to the customer.

c) Contractual Issues with Unions or Affiliates

Dexter has based this proposal on carrying out the work as a non-union contractor. At present we do not foresee any issues with unions that might affect service levels or costs to NSPI.

8.8 Warranty

a) Statement of Warranty

Dexter typically warrants its work against defects and deficiencies in workmanship identified by its client and made known to Dexter within one year of substantial completion of the work in question. In doing so, Dexter will correct promptly, at its own expense, those defects and deficiencies identified within the warranty period, and re-warranty the corrected portion of the work for an additional one-year period. In addition, Dexter will pass along any manufacturers warranties that it has obtained from suppliers of goods or equipment that are incorporated into the work.

b) Details and Cost of Extended Warranty Options

Extended warranty options to be determined upon project specific requests.

8.9 Safety

a) Workers' Compensation Board – Experience Ratings

WORK SAFE. FOR LIFE.
WORKERS' COMPENSATION BOARD OF NOVA SCOTIA

Visit MyAccount at wcb.ns.ca

Experience Rating Statement for 2025

PRIVATE

DEXTER CONSTRUCTION COMPANY LIMITED
Deanna Rudolph
927 ROCKY LAKE DR
PO BOX 48100
Bedford, NS B4A 3Z2

Business No:	101372720NW0001
Date:	August 17, 2024
Page:	1

Your 2025 assessment rate: $2.89 per $100 assessable payroll

SECTION A: Your Rate Components

Basic Industry Rate:	$2.46	
Experience Rating Merit/Demerit:	$0.29	see details in Section D below
Rate Surcharge:	$0.00	
Levy	$0.14	
TOTAL RATE for 2025	$2.89	per $100 assessable payroll

Note: Your company's workplace injuries and the associated costs determine your Experience Rating Adjustment. You can control your rate by eliminating workplace injuries and helping injured workers return to work in a safe and timely manner.

Your 2025 rate could have been as low as: $1.82 or as high as: $4.13

SECTION B: SIC and Industry Group

To set rates, we classify employers by the industry in which they operate, and group industries with similar activities and risk into industry groups.

Your Standard Industrial Classification (SIC) Code:
4121 Construction, Highways, Streets and Bridges
Your Industry Group for 2025
4100 Heavy Construction

SECTION C: Cost and Payroll

Assessable Payroll

2023	**$81,164,840.00**
2022	**$72,635,286.00**
2021	**$67,180,132.00**
TOTAL	**$220,980,258.00**

Cost of New Injuries
from 2021 to 2023 $1,098,638.73

SECTION D: Your Experience Rating Details

Experience Rating for 2025 is calculated using injury and payroll data from the years 2021 to 2023. The 3-year costs and payroll are determined, and costs are weighted so that the more recent experience has more impact on rates.

The key measure in determining your Experience Rating is the "cost ratio", which is your weighted cost figure divided by your payroll. The lower your cost ratio relative to your rate group, the lower your rate will be.

Your Cost Ratio is: **118.38% Higher** Than Your Rate Group's Cost Ratio
Resulting Merit/Demerit: **11.78% Demerit** Produces an Experience Rating Adjustment of **$0.29**

5668 South Street, P.O. Box 1150, Halifax, NS B3J 2Y2
1.800.870.3331 • 902.491.8999 • wcb.ns.ca • worksafeforlife.ca • Twitter: @WorkSafeForLife

WORK SAFE. FOR LIFE.
WORKERS' COMPENSATION BOARD OF NOVA SCOTIA

Visit MyAccount at **wcb.ns.ca**

Experience Rating Statement for 2024

PRIVATE

DEXTER CONSTRUCTION COMPANY LIMITED
Deanna Rudolph
927 ROCKY LAKE DR
PO BOX 48100
Bedford, NS B4A 3Z2

Business No:	101372720NW0001
Date:	August 19, 2023
Page:	1

Your 2024 assessment rate: $3.16 per $100 assessable payroll

SECTION A: Your Rate Components

Basic Industry Rate:	$2.68	
Experience Rating Merit/Demerit:	$0.33	see details in Section D below
Rate Surcharge:	$0.00	
Levy	$0.15	
TOTAL RATE for 2024	$3.16	per $100 assessable payroll

Note: Your company's workplace injuries and the associated costs determine your Experience Rating Adjustment. You can control your rate by eliminating workplace injuries and helping injured workers return to work in a safe and timely manner.

Your 2024 rate could have been as low as: $1.97 or as high as: $4.49

SECTION B: SIC and Industry Group

To set rates, we classify employers by the industry in which they operate, and group industries with similar activities and risk into industry groups.

Your Standard Industrial Classification (SIC) Code:
4121 Construction, Highways, Streets and Bridges
Your Industry Group for 2024
4100 Heavy Construction

SECTION C: Cost and Payroll

Assessable Payroll

2022	**$72,635,286.00**
2021	**$67,180,132.00**
2020	**$60,418,655.00**
TOTAL	**$200,234,073.00**

Cost of New Injuries

from 2020 to 2022	$1,038,480.17

SECTION D: Your Experience Rating Details

Experience Rating for 2024 is calculated using injury and payroll data from the years 2020 to 2022. The 3-year costs and payroll are determined, and costs are weighted so that the more recent experience has more impact on rates.

The key measure in determining your Experience Rating is the "cost ratio", which is your weighted cost figure divided by your payroll. The lower your cost ratio relative to your rate group, the lower your rate will be.

Your Cost Ratio is: **155.43% Higher** Than Your Rate Group's Cost Ratio
Resulting Merit/Demerit: **12.31% Demerit** Produces an Experience Rating Adjustment of **$0.33**

5668 South Street, P.O. Box 1150, Halifax, NS B3J 2Y2
1.800.870.3331 • 902.491.8999 • wcb.ns.ca • worksafeforlife.ca • Twitter: @WorkSafeForLife

DEXTER

WORK SAFE. FOR LIFE.
WORKERS' COMPENSATION BOARD OF NOVA SCOTIA

Visit MyAccount at **wcb.ns.ca**

Experience Rating Statement for 2023

PRIVATE

DEXTER CONSTRUCTION COMPANY LIMITED
Deanna Rudolph
927 ROCKY LAKE DR
PO BOX 48100
Bedford, NS B4A 3Z2

Business No:	101372720NW0001
Date:	August 20, 2022
Page:	1

Your 2023 assessment rate: $3.19 per $100 assessable payroll

SECTION A: Your Rate Components

Basic Industry Rate:	$2.72	
Experience Rating Merit/Demerit:	$0.31	see details in Section D below
Rate Surcharge:	$0.00	
Levy	$0.16	
TOTAL RATE for 2023	$3.19	per $100 assessable payroll

Note: Your company's workplace injuries and the associated costs determine your Experience Rating Adjustment. You can control your rate by eliminating workplace injuries and helping injured workers return to work in a safe and timely manner.

Your 2023 rate could have been as low as: $2.01 or as high as: $4.58

SECTION B: SIC and Industry Group

To set rates, we classify employers by the industry in which they operate, and group industries with similar activities and risk into industry groups.

Your Standard Industrial Classification (SIC) Code:
4121 Construction, Highways, Streets and Bridges
Your Industry Group for 2023
4100 Heavy Construction

SECTION C: Cost and Payroll

Assessable Payroll

2021	**$67,180,132.00**
2020	**$60,418,655.00**
2019	**$55,164,144.00**
TOTAL	**$182,762,931.00**

Cost of New Injuries
from 2019 to 2021 $1,154,039.06

SECTION D: Your Experience Rating Details

Experience Rating for 2023 is calculated using injury and payroll data from the years 2019 to 2021. The 3-year costs and payroll are determined, and costs are weighted so that the more recent experience has more impact on rates.

The key measure in determining your Experience Rating is the "cost ratio", which is your weighted cost figure divided by your payroll. The lower your cost ratio relative to your rate group, the lower your rate will be.

Your Cost Ratio is: **98.99% Higher** Than Your Rate Group's Cost Ratio
Resulting Merit/Demerit: **11.39% Demerit** Produces an Experience Rating Adjustment of **$0.31**

5668 South Street, P.O. Box 1150, Halifax, NS B3J 2Y2
1.800.870.3331 • 902.491.8999 • wcb.ns.ca • worksafeforlife.ca • Twitter: @WorkSafeForLife

DEXTER

b) Detailed Safety Plan

See Appendix B for Site Specific Project Health & Safety Plan.

c) Proponent's Understanding and Acceptance of the Following

i. *The proponent will comply with all safety programs and practices initiated by NSPI from time to time, including, if applicable, those programs described in Attachment "C". All costs incurred by the proponent in relation to the compliance with NSPI's safety programs will be the responsibility of the proponent.*

   Dexter understands and accepts.

ii. *During the performance of the Goods & Services, if NSPI determines that the proponent's compliance with the applicable safety programs and practices is not satisfactory, NSPI shall have the right to require the proponent to take such additional steps at the proponent's expense as are necessary to ensure compliance.*

   Dexter understands and accepts.

iii. *If, in NSPI's sole determination, the safety performance of the proponent is deemed unacceptable to NSPI, NSPI shall have the right to terminate immediately upon notice to the proponent.*

   Dexter understands and accepts.

iv. *The proponent agrees to comply and be responsible for ensuring all employees, sub-suppliers, agents and representatives of the proponent comply with all federal, provincial and municipal health, safety and environmental statutes, regulations, policies, guidelines and all health, safety and environmental rules as prescribed by NSPI.*

   Dexter understands and accepts.

d) Regulatory Offences, Directives and Orders

v. *Has the proponent ever been convicted of any regulatory offences? If yes, please provide specific details, court locations and jurisdictions.*

   Dexter has not been convicted of any regulatory offences.

vi. *Has your company ever received any regulatory directives/orders? If yes, please provide any and all documentation related to the directives/orders including but not limited to any related inspection reports, directives/orders and compliance notices (within previous 3 years).*

   See Appendix C for Provincial OHS Profile.

e) Safety Certifications and Gear

Dexter will ensure all safety certifications are compliant with Nova Scotia provincial safety training requirements and provide verification to NSPI. (i.e. fall protection, confined space). All safety gear has a documented annual inspection and is CSA approved for use in Nova Scotia.

f) ISNetwold Registration Particulars

8.10 Environment

a) Individuals Responsible for Monitoring, Maintenance and Execution of Environmental Measures

The Dexter Project Manager will have overall responsibility for the project, including environmental management, monitoring, maintenance, and execution of all environmental measures. The entire project team will be accountable for environmental stewardship throughout the project. The project manager and members of the project team will have completed appropriate safety and environmental training including a Dexter environmental awareness course prior to working on the site.

Support for environmental matters will be provided by the Dexter environmental management team who have certifications for erosion and sediment control and watercourse alteration, and have considerable experience working with environmental laws and regulations. Members of the environmental management team who will be available to provide support when needed include:

- Jamie Burns, P.Geo., Director of Remediation and Environmental Services
- Rhett Thompson, P.Eng., Environmental Engineer
- Grace Gillis, BSc, Environmental Manager
- Dawn Negus, Environmental Technologist

b) Materials and Equipment Available for Environmental Emergency Preparedness

- Spill Kits (including absorbent products)
- Heavy Equipment (Excavator)
- Established Contingency and Emergency Response Plans
- Internal and external resources to assist Dexter in any remedial measures required.

c) Processes for Reporting and Investigating Environmental Incidents

Within its Environmental Management Plan, Dexter has developed a registry of Contingency and Emergency Response Plans that outline the process for reporting and investigating environmental incidents including, erosion and sediment control structures failure, and the release of hazardous materials. The general process for reporting and investigating of environmental incidents is:

Step 1 – Notify site supervisor

Step 2 – Site supervisor immediately investigates occurrence

Step 3 – Site supervisor determines of there is a safety risk and responds accordingly

Step 4 – Site supervisor notifies Environmental Management Team (if necessary) who are responsible for liaising with the appropriate authority

Step 5 – Appropriate internal process is followed to rectify the occurrence

Step 6 – For regulatory reportable incidents the site supervisor works with the Environmental Management Team to file a complete record of the incident

Step 7 – At the discretion of the Environmental Management Team additional site clean-up may be completed

Step 8 – Environmental Management Team liaises with regulator (if applicable) to close the file.

d) Proponent's Understanding and Acceptance of the Following

i. *The company shall comply with all applicable environmental legislation, regulations, standards, work practices, and provisions including, but not limited to, NSPI's Contractor Environmental Requirements (Attachment "C"), as may be amended or replaced from time to time.*

Dexter will comply with all environmental legislation, regulations, standards, work practices, and provisions, including the NSPI Contractor Environmental Requirements.

ii. *The company is also responsible for the disposal and/or destruction of all scrap treated wood at an approved facility. All work will be completed using the company's personnel and equipment in accordance with all applicable laws governing the disposal/destruction of treated wood products. A Certificate of Disposal/Destruction shall be provided by the company to NSPI confirming that the scrap treated wood products have been disposed of and/or destroyed in accordance with all applicable laws. The company is also responsible for the disposal and/or destruction of all scrap treated wood at an approved facility. All work will be completed using the company's personnel and equipment in accordance with all applicable laws governing the disposal/destruction of treated wood products. A Certificate of Disposal/Destruction shall be provided by the company to NSPI confirming that the scrap treated wood products have been disposed of and/or destroyed in accordance with all applicable laws.*

All scrap treated wood generated during the project will be disposed of at an approved facility, and confirmation of disposal will be provided to NSPI.

e) Environmental Regulatory Offences

Dexter has not been convicted of any environmental regulatory offenses.

f) Environmental Regulatory Directives/Orders

Dexter was issued a Regulatory Directive related to sedimentation into a stream related to heavy rainfall. See Appendix D for copy of the directive.

8.11 Cybersecurity

a) Collection and Storage of Data

If email or documents, then yes, the products we provide NSPI collect or store data.

i. Personally Identifiable Information (PII) or Confidential in Nature

All email or documents from external vendors is treated as confidential and if PII then also treated as confidential.

ii. Storage and Transmittal of Data

Email and documents are stored in Microsoft Azure.

iii. Cyber Insurance

Yes, we have cyber insurance.

b) Updates/Patches for Known Vulnerabilities

Yes, we require updates/patches for known vulnerabilities and have a scheduled and documented process.

i. Process to update the Products Supplied to NSPI

All Microsoft systems are patched on a monthly interval and supporting firewalls/switches are patched when updates are available via the vendors.

c) External Connectivity

i. Storage of Data

Emails and documents are stored in Microsoft Azure.

ii. Process to Connect to the Product Supplied to NSPI

If emails or documents, through VPN or secure encrypted connection via VPN or secure website with MFA authentication.

iii. Transient Cyber Assets (TCA)

Yes, we do use transient cyber assets to connect to our products supplied to NSPI, assuming laptops and mobile devices

d) Mature Security Program

We do not formally have a mature security program yet, but in the process of attaining NIST Standards

i. Physical Security Practices to Secure the Facility from Unauthorized Access

Yes, we have physical security practices to secure the facility from unauthorized access, and RISK-01 physical security controls and policies.

.1 Monitored Key Access

Yes

.2 Monitored 24/7

Yes, most sites

.3 Video Camera and Surveillance

Yes

.4 Physical Security Policy Document

Yes

e) Application Security Questionnaire.

Not Applicable.

8.12 Responsible Sourcing

a) Importing Goods from Outside of Canada

We will not be importing goods from outside of Canada for this project.

8.13 Employee Requirements

a) Proponent's Understanding and Acceptance of the Following

i. *Employees must be experienced / qualified to safely perform the work.*

Dexter understands and accepts.

ii. *Employees must maintain a professional appearance and attitude.*

Dexter understands and accepts.

iii. *NSPI reserves the right to reject any employees who have been appointed to perform the work where its field personnel determine that the individual does not meet NSPI safety or performance standards and the company shall be obligated to replace the individuals.*

Dexter understands and accepts, NSPI acting reasonably.

8.14 Insurance

See uploaded Certificate of Insurance.

8.15 Certifications

i. Worker's Compensation Letter of Good Standing

WORK SAFE. FOR LIFE.
WORKERS' COMPENSATION BOARD OF NOVA SCOTIA

Visit MyAccount at **wcb.ns.ca**

Clearance Letter

DEXTER CONSTRUCTION COMPANY LIMITED
DEANNA RUDOLPH
927 ROCKY LAKE DR
PO BOX 48100
BEDFORD, NS B4A 3Z2

Date of Issue: June 15, 2025

Account Holder:
DEXTER CONSTRUCTION COMPANY LIMITED
BN: 101372720

This letter confirms that **DEXTER CONSTRUCTION COMPANY LIMITED** is registered with the WCB Nova Scotia and is in good standing. It is valid until **September 30, 2025**.

Sincerely,

WCB Nova Scotia

5668 South Street, P.O. Box 1150, Halifax, NS B3J 2Y2
1.800.870.3331 • 902.491.8999 • wcb.ns.ca • worksafeforlife.ca • Twitter: @WorkSafeForLife

ii. Nova Scotia Construction Safety Association Certificate of Recognition

Letter of Good Standing

Certificate of Recognition Program®

Member ID	DEXTE000
Member Type	M
Certificate No.	43666

tel 902 468-6696
fax 902 468-8843
toll free ns 1-800-971-3888
web constructionsafetyns.ca

35 MacDonald Ave.
Dartmouth N.S. Canada
B3B 1C6

Issued to: DEXTER CONSTRUCTION COMPANY LTD.
PO BOX 48100
BEDFORD, NS
B4A3Z2

Size: **Standard - 20+ Persons Employed**

Based on active participation in the Certificate of Recognition Program®, Construction Safety Nova Scotia hereby issues a letter of good standing:

Date of Issue	Expiry Date
2024/08/08	2025/09/05

This letter of good standing is issued to a firm actively participating in Construction Safety Nova Scotia programs and whose current standing falls into the category noted below:

Certificate of Recognition®

Definition: The certificate of recognition® is awarded to firms who have completed the training requirements, fully implemented a loss control program, and successfully participated in the COR® evaluation.

Conditions:

Jo-Ann MacDonald

Construction Safety Nova Scotia Representative

Original Issue Oct 08, 2000 Revision #11 Revision Date: September 1, 2022 Document # FM 9.00

iii. NSPI Site Orientation

Upon award of contract, employees will be assigned to the project and prior to the commencement of work training records will be provided and NSPI site orientation will occur.

iv. First Aid Training

Upon award of contract, employees will be assigned to the project and prior to the commencement of work training records will be provided and NSPI site orientation will occur.

v. Employee Certifications

Upon award of contract, employees will be assigned to the project and prior to the commencement of work training records will be provided and NSPI site orientation will occur.

vi. Other Certifications

The forgoing documents presented herein, are typical of those submitted prior to the commencement of most projects. Dexter Construction Company Limited will endeavor to provide further documentation which may be requested by Nova Scotia Power Incorporated.

8.16 Commercial / Price Proposal

See uploaded BidTable.

Appendix A

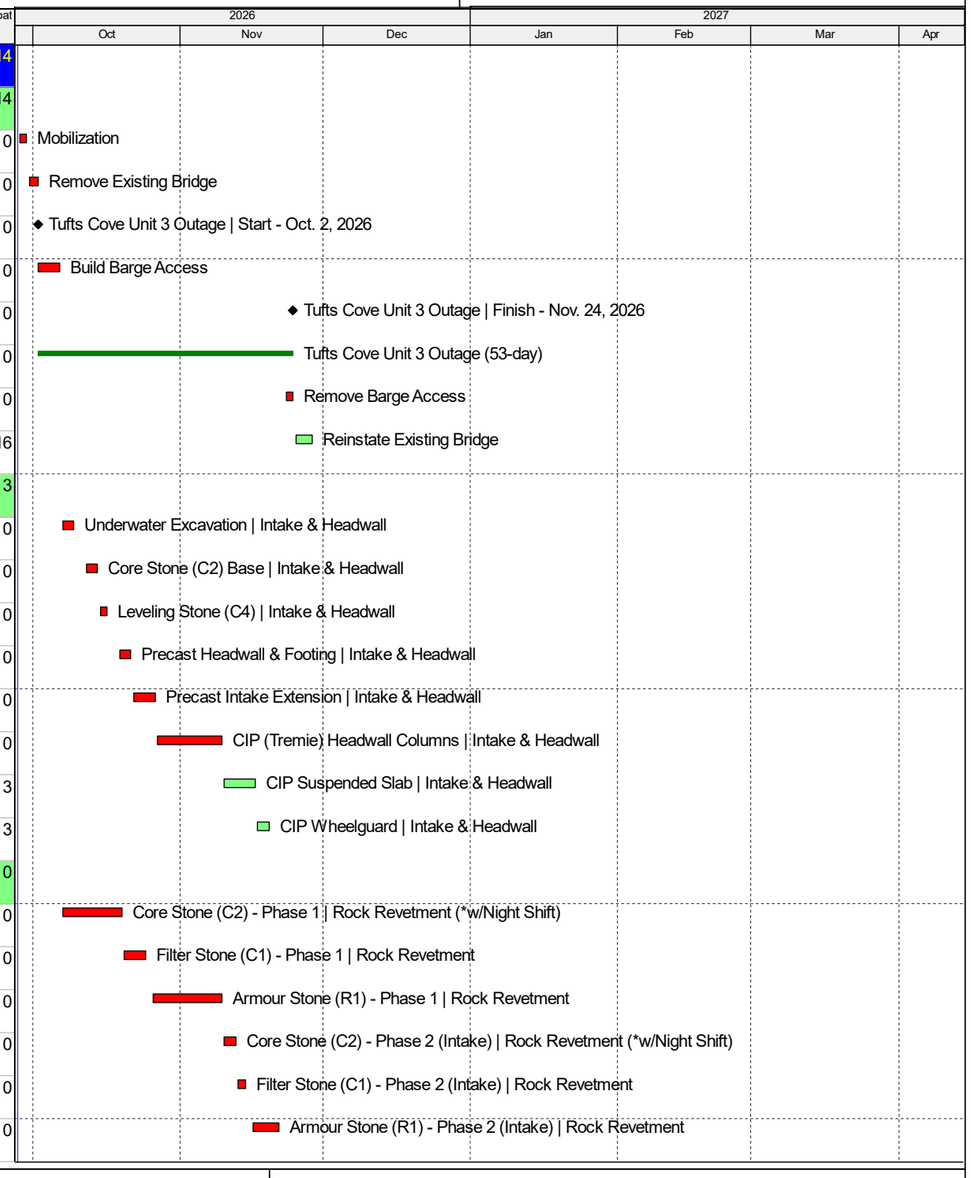
Preliminary Project Schedule

DEXTER
Dexter Construction Company Limited

JOB No. NSPI RFP 06 2025-545
TUFTS COVE SHORELINE SHEET PILE ROCK REVETMENT
Baseline Schedule Layout

26-Aug-25 13:11
Data Date: 28-Sep-26

#	Activity Name	Original Duration	Remaining Duration	Start	Finish	Total Float
1	**TUFTS COVE SHORELINE SHEET PILE ROCK REVETMENT**	45	45	28-Sep-26	28-Nov-26	14
2	**ADMINISTRATION**	45	45	28-Sep-26	28-Nov-26	14
3	Mobilization	2	2	28-Sep-26	29-Sep-26	0
4	Remove Existing Bridge	2	2	30-Sep-26	02-Oct-26	0
5	Tufts Cove Unit 3 Outage | Start - Oct. 2, 2026	0	0	02-Oct-26*		0
6	Build Barge Access	4	4	02-Oct-26	06-Oct-26	0
7	Tufts Cove Unit 3 Outage | Finish - Nov. 24, 2026	0	0		24-Nov-26*	0
8	Tufts Cove Unit 3 Outage (53-day)	54	54	02-Oct-26	24-Nov-26	0
9	Remove Barge Access	2	2	23-Nov-26	24-Nov-26	0
10	Reinstate Existing Bridge	4	4	25-Nov-26	28-Nov-26	16
11	**INTAKE EXTENSION & HEADWALL**	32	32	07-Oct-26	19-Nov-26	3
12	Underwater Excavation | Intake & Headwall	3	3	07-Oct-26	09-Oct-26	0
13	Core Stone (C2) Base | Intake & Headwall	3	3	12-Oct-26	14-Oct-26	0
14	Leveling Stone (C4) | Intake & Headwall	2	2	15-Oct-26	16-Oct-26	0
15	Precast Headwall & Footing | Intake & Headwall	3	3	19-Oct-26	21-Oct-26	0
16	Precast Intake Extension | Intake & Headwall	3	3	22-Oct-26	26-Oct-26	0
17	CIP (Tremie) Headwall Columns | Intake & Headwall	10	10	27-Oct-26	09-Nov-26	0
18	CIP Suspended Slab | Intake & Headwall	5	5	10-Nov-26	16-Nov-26	3
19	CIP Wheelguard | Intake & Headwall	3	3	17-Nov-26	19-Nov-26	3
20	**SHEET PILE ROCK REVETMENT**	40	40	07-Oct-26	21-Nov-26	0
21	Core Stone (C2) - Phase 1 | Rock Revetment (*w/Night Shift)	11	11	07-Oct-26	19-Oct-26	0
22	Filter Stone (C1) - Phase 1 | Rock Revetment	5	5	20-Oct-26	24-Oct-26	0
23	Armour Stone (R1) - Phase 1 | Rock Revetment	13	13	26-Oct-26	09-Nov-26	0
24	Core Stone (C2) - Phase 2 (Intake) | Rock Revetment (*w/Night Shift)	3	3	10-Nov-26	12-Nov-26	0
25	Filter Stone (C1) - Phase 2 (Intake) | Rock Revetment	2	2	13-Nov-26	14-Nov-26	0
26	Armour Stone (R1) - Phase 2 (Intake) | Rock Revetment	6	6	16-Nov-26	21-Nov-26	0



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Milestone

TASK filter: All Activities

© Oracle Corporation

Appendix B

Site Specific Health Project Health & Safety Plan

Project Health & Safety Plan

Tufts Cove Shoreline Sheet Pile Rock Revetment

Company:	Dexter Construction Company Limited
Client:	Nova Scotia Power Incorporated (NSPI)
RFP #:	RFP-06/2025-545
Date Prepared:	August 18, 2025

DEXTER CONSTRUCTION COMPANY LIMITED

Project Health & Safety Plan
Tufts Cove Shoreline Sheet Pile Rock Revetment
RFP-06/2025-545

Table of Contents

1.0 Introduction 5
2.0 HSE Policies & Programs 6
2.1 Corporate Health & Safety Policy Statement 6
2.2 Other Policies and Programs 6
2.3 Emera/NSPI Policies 7
3.0 Responsibilities, Rights & Conduct (Employees & Contractors) 8
3.1 Responsibilities 8
3.2 Rights 9
3.3 Responsibility to Report & Address Hazards 11
3.4 Responsibility for Incident Notification & Reporting 12
3.5 Life Saving Commitments 12
3.6 Workplace Rules 13
3.7 Smoking 14
3.8 Substance Abuse & Impairment 15
3.9 Workplace Violence Prevention Policy 15
3.10 Progressive Discipline Policy 16
3.11 Contractor Management 17
3.12 Visitor Management 18
4.0 HSE Training 19
4.1 General Health & Safety Orientation 19
4.2 Site Specific Health & Safety Orientation 19
4.3 Health & Safety Compliance Theory and Practical Training 20
4.4 Proof of Competencies 20
5.0 Hazard Assessment and Control 21
5.1 Hazards, Risk, and Control 21
5.2 Hazard Assessment Process 26
5.3 Comprehensive Hazard Assessments 27
5.4 Project Hazard Assessments 28
5.5 Standard Operating Procedures (SOPs) 29
6.0 Project Scope of Work 30

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

7.0 Site Location, Control, and Access 31
7.1 General 31
7.2 Site Signage 31
7.3 Site Traffic Regulations 31
7.4 Site Access and Parking 31
7.5 Barriers and Barricades 31
7.6 Emergency Services Accessibility 32
8.0 Project Supervision 33
8.1 Responsibilities and Qualifications 33
8.2 Site Management & Supervisors 34
9.0 Site Procedures 35
9.1 Housekeeping 35
9.2 Working Near Overhead Utilities 36
9.3 Buried/Underground Utilities (General) 36
9.4 Trenching and Excavation 38
9.5 Fall Protection 38
9.6 Confined Space 38
9.7 Stockpiles 38
9.8 Lockout/Tagout 38
9.9 Maintenance and Refueling 39
9.10 Hot Work 39
9.11 Hearing Conservation and Noise Assessment 39
9.12 Dust (Silica) Suppression and Control 40
9.13 Traffic Control 43
9.14 Severe Weather and Natural Disasters 44
9.15 Work in, On or Around Water 44
10.0 Vehicles, Mobile Equipment and Cranes 45
10.1 General 45
10.2 Mobile Cranes 46
10.3 Pendant/Overhead Cranes 46
10.4 Elevating Work Platforms 46

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

10.5 Overhead Loads/Lifting Related Hazards 46
11.0 Personal Protective Equipment (PPE) 47
11.1 Basic PPE 47
11.2 Task-Specific PPE 47
11.3 Maintenance of PPE 48
11.4 PPE-Free Zones 48
12.0 WHMIS/TDG & Chemical Management 49
12.1 General 49
12.2 Employee Information and Training 49
12.3 Chemical Management 49
13.0 Waste Management and Environmental Protection 50
13.1 Spill Response 50
13.2 Waste Disposal 52
13.3 Construction/Demolition Material and Debris 52
13.4 Site Clearing and Plant Protection 53
13.5 Work Adjacent to Waterways 53
13.6 Dewatering Requirements 53
13.7 Dust Control 53
13.8 Sediment and Erosion Control 54
14.0 Inspections 55
14.1 General 55
14.2 Health and Safety Inspections 55
14.3 Equipment and Vehicle Inspections 56
15.0 Emergency Preparedness and Response 57
15.1 Purpose 57
15.2 Emergency Planning 57
15.3 Project Emergency Meeting Point(s) 58
15.4 Nearest Medical Facility 58
15.5 First Aid 58
15.6 Project Emergency Contact Information 59
15.7 Fire Protection and Prevention 60

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

15.8 Emergency Equipment 63
15.9 Communication 64
15.10 Emergency Contact 64
15.11 Evacuation 65
16.0 Incident Notification, Reporting & Investigation 66
16.1 Incident Notification and Reporting 66
16.2 Near Misses 71
16.3 Incident Investigation and Corrective Action 71
16.4 NSPI Incident Reporting Requirements 73
17.0 Project HSE Records & Communication 75
17.1 General Project Requirements 75
17.2 Types of Communication 75
17.3 Daily Huddle Meetings 78
17.4 Toolbox Meetings 78
17.5 Joint Occupational Health and Safety Committee (JOHSC) Minutes 78
17.6 Reporting to External and Regulatory Parties 78
17.7 Other Types of HS Communication 78
17.8 Safety Interaction 79
17.9 Project Joint Occupational Health, Safety Committee (or Rep) 80
Appendix A – Emergency Route to Nearest Medical Facility 81
Appendix B – Corporate Safety Standards Index 82
Appendix C – Daily Huddle Form (Example) 83
Appendix D – NSPI Hazard Analysis 86

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

1.0 Introduction

This Project Health & Safety Plan (H&S Plan) is for:

> ***Shoreline Sheet Pile Rock Revetment, at Tuft's Cove Generating Station, Dartmouth, NS, for Nova Scotia Power Incorporated (NSPI).***

Dexter Construction Company Limited (Dexter) is committed to safe and successful completion of this project and will provide the necessary resources. Dexter is committed to the objective of "Zero Harm" to our employees, clients, visitors, the public and any other stakeholder.

Dexter's commitment:

- To comply with Health and Safety laws and regulations for all areas in which we operate
- To provide a safe and healthy working environment
- To never compromise the Health and Safety of any individual; and,
- To provide the necessary training and resources to ensure that day-to-day activities are carried out safely.

All health, safety and environmental policies, programs, procedures, and practices stipulated by Emera / NSPI will be complied with for the duration of the work.

All relevant occupational health, safety and environmental acts, pursuant regulations, codes of practice, and by-laws or ordinances will be complied with for the duration of the work.

Compliance with Canada Labour Code - Part II (Occupational Health and Safety) and the Canada Occupational Health and Safety Regulations (COSHR) as well as any other regulations made pursuant to the Act is required at all times.

In case of conflict or discrepancy between the above requirements, the more stringent shall apply.

Dexter shall collaborate with Emera / NSPI representatives to ensure their expectations are met with regards to occupational health, safety, and environmental considerations. Dexter shall also comply with all safety programs and practices required by Emera / NSPI.

If during performance of work, Emera / NSPI determines that compliance with the applicable safety programs and practices is not satisfactory, Emera/ NSPI has the right to require any additional steps deemed necessary to ensure compliance. Dexter shall ensure that all employees, sub-suppliers and subcontractors, agents and representatives comply with all federal/provincial/municipal health, safety and environmental statutes, regulations, policies, guidelines and all health, safety and environmental rules prescribed by Emera / NSPI.

Copies of this Project Safety Plan shall be maintained and made available to all workers at the project location at all times. The plan shall be reviewed, updated, and communicated throughout the duration of the project, as necessary.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

2.0 HSE Policies & Programs

2.1 Corporate Health & Safety Policy Statement

This policy applies to Dexter Construction Company Limited ("The Company") and all of its locations.

The Company is committed to providing a healthy and safe work environment for its employees and preventing occupational illness and injury. To express that commitment, we issue the following policy on occupational Health and Safety.

As the employer, The Company is responsible for the Health and Safety of its' employees. The Company will make every effort to provide a healthy and safe work environment. We are dedicated to the objective of eliminating the possibility of injury and illness.

Senior Management commits to take all reasonable precautions to prevent harm to employees.

Managers and supervisors will be trained and held responsible for ensuring that the employees, under their supervision, follow this policy. They are held accountable for ensuring that employees use safe work practices and receive training to protect their Health and Safety.

Managers and supervisors also have a general responsibility for ensuring the safety of equipment, facilities, and the worksite.

The Company through all levels of management, will co-operate with the Joint Occupational Health and Safety Committee and employees to create a healthy and safe work environment. Co-operation should also be extended to others such as contractors, owners, officers, etc.

The employees of The Company will be required to support this Organization's Health and Safety initiative and to co-operate with the Joint Occupational Health and Safety Committee or representative and with others exercising authority under the applicable laws.

It is the duty of each employee to report to the supervisor or manager, as soon as possible, any hazardous conditions, injury, accident, or illness related to the workplace. Also, employees must protect their Health and Safety by complying with applicable Acts and Regulations and to follow policies, procedures, rules, and instructions as prescribed by The Company.

The Company will, where possible, eliminate hazards and, thus, the need for personal protective equipment. If that is not possible, and where there is a requirement, employees will be required to use safety equipment, clothing, devices, and materials for personal protection.

The Company recognizes the employees' duty to identify hazards and supports and encourages employees to play an active role in identifying hazards and to offer suggestions or ideas to improve the Health and Safety program.

NOTE: This policy statement has been developed in co-operation with the Joint Occupational Health and Safety Committee.

2.2 Other Policies and Programs

Include, but are not limited to the following:

- Health and Safety Management System (HSMS)
- Cell Phone Policy

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- Company Vehicle Policy
- Harassment Policy
- Impairment Policy
- Progressive Discipline Policy
- Smoking Policy
- Workplace Violence Prevention Policy
- HSMS Corporate Safety Standards and Standard Operating Procedures / Safe Work Practices

2.3 Emera/NSPI Policies

The Company shall comply with the current version of all NSPI safety policies, programs, and practices, including, but not limited to, the most recent versions of the following:

- NS Power Contractor Safety Management Program
- EMA 1 – Occupational Health and Safety Policy
- EMA 2 – Environmental Policy
- EMA 3 – Respectful Workplace Policy
- EMA 5 – Smoke-Free Workplace Policy
- EMA 8 – Alcohol and Drug Policy
- Alcohol & Drug – Statement of Expectations for Contractors
- Contractor Environmental Requirements
- Contractor Safety Program

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

3.0 Responsibilities, Rights & Conduct (Employees & Contractors)

3.1 Responsibilities

Managers and Supervisors

- Ensure they and their employees complete all required training to adhere to the requirements
- Make each employee aware of hazards at the worksite through orientation and training
- Investigate any and all hazards identified by employees
- Respond to employee concerns
- Eliminate the hazard or, if it cannot be eliminated, minimize the hazard through either engineering controls, administrative controls, personal protective equipment, or a combination of any of these.

Employees

- Complete all required training
- Perform their work in a safe manner and in accordance with this requirement
- Work safely by following The Company policies and procedures
- Take every reasonable precaution in the circumstances to protect the employee's own Health and Safety (potential or actual hazards) and that of other persons at or near the workplace. This includes:
    - Stopping work or the work of others upon identifying an uncontrolled hazard and reporting the hazard to their supervisor as soon as the hazard is noticed
    - Wearing proper safety equipment and using safety procedures when doing a job
    - Co-operating with the Joint Occupational Health and Safety Committee or Health and Safety Representative
- Notify management of the hazard, first verbally and then in writing, that the piece of equipment, procedure or action is unsafe.

Subcontractors

- Shall know and understand the necessary policies, procedures and regulations pertaining to their scope of work
- Shall participate in any orientation program provided by the Company/client
- Shall provide adequate personal protective equipment (PPE) for their employees, and enforce the use of PPE on site at all times
- Shall investigate and complete the necessary reports for all incidents and near misses onsite. Completed investigation reports will be submitted to the Project Management Team and/or Health and Safety Site Representative within 24 hours of the incident.
- Shall immediately correct any unsafe conditions or practices observed by any representative of the Company
- Shall prohibit the use of unsafe tools, equipment, and machinery by their employees
- Shall allow only competent employees to operate tools, equipment, and machinery

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- Shall follow-up and respond in writing, on all safety recommendations made by the Company's representative
- Shall attend and/or holds safety meetings as required. When requested by representatives of the Company, provide copies of such meeting minutes
- Shall participate in pre-job hazard or risk assessments to ensure proper safety precautions will be taken before the job commences.

3.2 Rights

Right to Refuse

A safe workplace is every employee's right, and every employee carries the responsibility for keeping their own workplace safe.

No employee will face disciplinary action for stopping work which is believed to be unsafe.

Employees have a RIGHT TO REFUSE if:

- The employee has reason to believe that the work is in contravention of the applicable legislation
- The work is likely to endanger the employee or any person at or near the workplace; or
- The condition of the workplace is in contravention of the Occupational Health and Safety Act or pursuant regulations.

This procedure applies to all persons employed by the Company. It identifies workplace parties that have the authority to initiate and participate in the process required to address Health and Safety concerns and to address work refusals should they occur.

An employee may not refuse to perform a work-related task or activity where:

- The refusal puts the life, health, or safety of another person directly in danger[1]; or
- The danger referred to above is inherent in the work to be performed[2].

[1]Example: Where a crane is being used to hoist employees in a personnel basket, the operator may not refuse to operate the crane after the lifting of the employees begins as it would endanger the employees in the basket.

[2]Example: A Traffic Control Person (TCP) may not refuse to stand at a control position near moving vehicles because the danger is inherent in the work being performed (unless the temporary workplace contravenes provincial regulations, approved codes of practice or Company policies – e.g., the TCP has not been provided with an escape route, or the temporary workplace is set up improperly).

The following procedure for dealing with a work refusal must be followed by the employee and the supervisor.

1) Upon refusing to work, the employee will promptly report the circumstances of the refusal to their supervisor. The employee will remain at a safe location near the work area.
2) The supervisor and the employee will begin the completing of a Work Refusal Form.
3) The supervisor will then investigate the reported concern while in the presence of the employee. The intent of this procedure is that this investigation be carried out immediately and that work is not continued until the investigation is completed.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

4) The supervisor will review the Work Refusal form with the employee who has brought the concern forward. If required they will involve an employee and/or employee representative from the joint safety committee and will investigate the hazard, determine the validity of the hazard, and use a Hazard Assessment process to evaluate hazards and implement controls by:
    a. Developing a plan to eliminate the hazard or, if it cannot be eliminated, minimize the hazard using the hazard assessment risk matrix and implement engineering controls, administrative controls, personal protective equipment, or a combination of any of these
    b. Implementing the plan
    c. Conveying in writing the plan to the employee that identified the hazard
    d. Having the employee sign off on the new plan.

If the concern is addressed to the employee's satisfaction, the employee will return to work. If the concern was not adequately addressed, steps 5 and 6 below must be followed:

5) If, after the investigation and implementation of any steps taken to address the concern, the employee still has reasonable grounds to believe that the work is unsafe, the employee may continue to refuse to work.
6) The supervisor will then contact a member of the Health and Safety Department to report the work refusal. The Health and Safety Department will notify a Joint Occupational Health and Safety Committee (JOHSC) representative to attend the investigation.

If the concern is addressed to the employee's satisfaction, the employee will return to work. If the concern was not adequately addressed, steps 7 and 8 below must be followed:

7) If, after the investigation and implementation of any steps taken to address the concern, the employee still has reasonable grounds to believe that the work is unsafe, the employee may continue to refuse to work.
8) The supervisor with the assistance of the Health and Safety Department will then notify the applicable Regulator of the occurrence of the work refusal.

An officer from the Regulator's Office will investigate the work refusal. The officer may not arrive the same day. Until the officer arrives, the following additional steps must be followed:

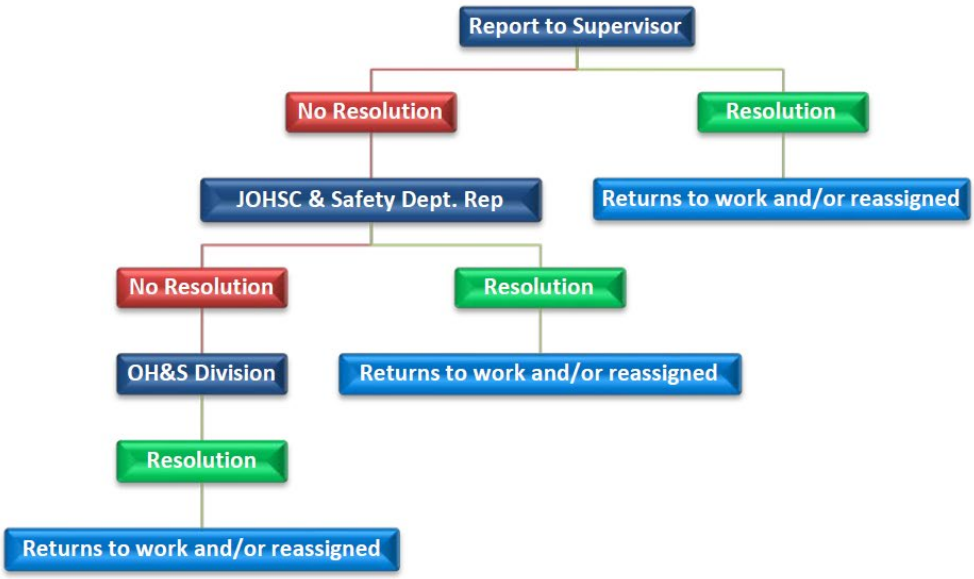
9) Pending the arrival of an officer, the employee must remain at a safe location near their normal work area (this only applies during the employee's normally scheduled work hours).
10) The supervisor may assign the employee alternative tasks during this period.
11) Pending the arrival and investigation of the officer, no other employee may be assigned to do the work in question unless the other employee is advised of
    a) The refusal of work by another employee
    b) The reason for the refusal
    c) The employee's rights pursuant to the applicable legislation.
12) The employee who refuses to work may, pursuant to the above, choose to accompany an officer or the committee member or representative, if any, on a physical inspection of the workplace, or part thereof, which is carried out for the purpose of ensuring others understand the reasons for the

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

refusal.

13) The officer will give their decision in writing to the employee, the supervisor, and the JOHSC representative. Please note that a decision may not be forthcoming immediately, and that the officer may order workplace testing depending on the nature of the work refusal.

Right to Refuse Process Chart



Right to Participate

Employees have a RIGHT TO PARTICIPATE in making the workplace safer.

All personnel also have the right to participate in the management of safety issues affecting the workplace.

Employees may participate by attending safety meetings, participating in audits and inspections, as well providing ideas and suggestions to management for health, safety, and environmental improvement.

Right to Know

Employees have a RIGHT TO KNOW about anything that could affect your Health and Safety in the workplace.

All personnel have the right to know of any potentially hazardous situations which may be encountered in the workplace and the level of risk associated with the hazards.

3.3 Responsibility to Report & Address Hazards

The identification and documentation of workplace hazards is the responsibility of all employees:

- Any person who identifies an immediate danger or hazardous situation, has the responsibility to stop the job/task and take corrective action. The employee must contact their supervisor immediately and correct the hazard if it is safe to do so.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- Any person who recognizes or identifies a hazard, has the responsibility to report it to the person performing the task, the supervisor, and/or the Manager.

3.4 Responsibility for Incident Notification & Reporting

The Company recognizes the benefits of administering an effective incident management program that promotes identification of incident causation and application of pertinent corrective actions to reduce the likelihood of reoccurrence. The objective of this process is to provide management and employees with effective tools to properly investigate incidents, to systematically determine root causes and to support the selection of effective system improvements and corrective actions to reduce risk in the workplace.

Proper management of workplace injuries is important to ensure employee safety, employee health, and operating performance can be effectively managed. Once an injury is reported the matter must be effectively managed immediately to reduce injury severity, control, or eliminate a hazard, and reduce the potential for minor injuries to escalate into lost time injury cases. All incidents must be reported immediately by all employees.

3.5 Life Saving Commitments

The purpose of The Company 12 Life Saving Commitments is no matter your role, working with The Company means working safely. These Commitments have been put in place to ensure that everyone is abiding by the regulations, and that safety remains of the utmost importance.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

12 Life Saving Commitments

OUR 12 Life Saving Commitments	
1	**Fit for Duty** *I commit to being physically, medically, and mentally ready for work every day.* Refer to Corporate Standard: Fit for Duty
2	**Safe Driving** *I commit to driving safely and arriving safely at all times.* Refer to Corporate Standard: Safe Driving (Commercial, Light Duty, and Heavy Equipment)
3	**Safe Work Planning** *I commit to planning the work and working the plan.* Refer to Corporate Standard: Safe Work Planning
4	**Safe Separation** *I commit to managing a safe zone and reducing congestion.* Refer to Corporate Standard: Safe Separation
5	**Lockout / Tagout** *I commit to verifying all energy sources are isolated before performing work on any equipment or machinery.* Refer to Corporate Standard: Lockout / Tagout
6	**Safety Override** *I commit to NEVER overriding or disabling any critical safety devices/equipment.* Refer to Corporate Standard: Safety Override Protection Devices
7	**Fall Protection** *I commit to always protecting myself against falls from height.* Refer to Corporate Standard: Fall Protection/Working from Heights/Ladders
8	**Overhead and Underground Utilities** *I commit to always being aware of overhead wires and buried utilities.* Refer to Corporate Standard: Overhead and Underground Utilities
9	**Rigging, Hoisting and Lifting** *I commit to safely performing any required rigging / hoisting / lifting.* Refer to Corporate Standard: Rigging, Hoisting and Lifting.
10	**Confined Space** *I commit to only entering a confined space when properly training and authorized.* Refer to Corporate Standard: Confined Space Awareness and Entry
11	**Trenching and Excavation** *I commit to always working safely in or around trenches and excavations.* Refer to Corporate Standard: Trenching and Excavation
12	**Blasting** *I commit to always respecting explosives and blasting operations.* Refer to Corporate Standard: Blasting

3.6 Workplace Rules

The following is prohibited all workers, sub-contractors, and visitors:

1) Failing to follow established safety procedures as outlined in the Company Health and Safety Management System

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

2) Practicing or promoting discrimination against, or harassment of, another employee or group of employees based on race, colour, national origin, sex, age, religion, disability, or veteran status
3) Possessing dangerous weapons while on company property or in Company vehicles/equipment
4) Fighting with, threatening, intimidating, coercing, physically abusing or interfering with other employees or persons doing business with the Company
5) Engaging in pranks, contests, feats of strength, unnecessary rough and boisterous conduct
6) Abusive language and/or any conduct that is disruptive to the normal operation of the Company or directed towards workers, supervisors, or persons doing business with the Company
7) Endangering the safety of oneself or other workers; acts which could result in possible physical injury to persons or damage to property of the Company, workers, or persons doing business with the Company
8) Falsifying Company safety documentation
9) Falsifying, or refusing to give testimony, information, or otherwise not cooperating in the investigation of incidents of worker misconduct, accidents, theft, or other incidents
10) Arriving at work or remaining at work when your ability to perform the job safely is impaired
11) Consuming, being under the influence or being in possession of alcohol or drugs in the workplace
12) Use of prescription drugs on the work site without written clearance from a physician and notification to the Company stating that the drug will not impair the worker's ability to work safely
13) Leaving the assigned job or work area without permission before the end of the shift
14) Entering a Company worksite or project during non-scheduled work time without permission or without a legitimate work-related reason
15) Abuse of Company equipment and/or riding on any piece of equipment without occupying a place or seat designated for such a purpose or otherwise operating a vehicle or equipment in an improper/unsafe manner
16) Failing to report incidents, near misses and unsafe acts and conditions immediately to the supervisor (No reprisals or disciplinary action will be taken unless there is willful misconduct, negligence, or criminal intent by the person reporting)
17) Failing to keep your work area neat, clean, orderly, and free of hazards
18) Improper storage and disposal of chemicals as per the product Safety Data Sheet (SDS)
19) Failing to wear proper personal protective equipment (PPE)
20) Using tools and equipment that are defective, or not for their designed purpose, or removing/tampering with guards and safety devices. (All tools or equipment which have been damaged or become worn are to be promptly reported, tagged, and taken out of service for repair or replacement.)

3.7 Smoking

The Company is committed to following the applicable legislation regarding smoking in the workplace.

Smoking is prohibited in the following areas:

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- No smoking in an enclosed space. An enclosed space means the inside or outside or other enclosed part of a building, vehicle other indoor space but does not include a private residence.
- Smoking is not permitted:
  - Within 4 meters of a building entrance, open windows or building intake ventilation.
  - A vehicle in the course of employment.
- "Place of Employment" means an enclosed space, in which employees perform the duties of their employment and includes an adjacent corridor, lobby, stairwell, elevator, escalator, eating area, washroom, restroom, or other shared area frequented by employees during the course of their employment.

3.8 Substance Abuse & Impairment

Impairment

Impairment impacting a person's health and safety on the job site is the issue; such impairment may be due to injury, medical condition, alcohol, drugs, medication, or other conditions affecting behaviour including stress, fatigue, anger, depression, anxiety, etc.

Impairment Policy Statement

This Policy statement applies to all "workers" including permanent, temporary, casual, contract, and student workers, as well as supervisors and managers.

Workers must be Fit for Duty while at work. Impairment is not acceptable nor tolerated in the workplace. "Fit for Duty" means that an individual is in a state (physical, mental, or emotional) which enables that worker to perform assigned tasks competently and, in a manner, which does not compromise or threaten the safety or health of themselves or others. Final determination of "Fit for Duty" is based on the opinion of the worker's supervisor or their designate and, where appropriate, in conjunction with other assessment procedures.

"Impairment" or "Impaired" means that there are reasonable grounds to conclude that an individual is not Fit for Duty. Such reasonable grounds include the condition of a person who is showing signs of physical and behavioural change including the smell of alcohol on their breath or the smell of cannabis on their person, red rimmed eyes, staggering and/or aggressive, loud, or other behaviour not typical to the person. Impairment is commonly thought to refer only to the use of recreational (non-prescription) drugs and/or alcohol. However, impairment can also result from the use of prescription drugs, fatigue and symptoms related to health issues (e.g., a diabetic suffering from insulin instability).

Employees are to contact their supervisor if they feel that they do not have the ability to perform their work in a safe manner or if they observe another worker at the workplace who does not appear Fit for Duty.

3.9 Workplace Violence Prevention Policy

The Company maintains a zero-tolerance policy towards violence in the workplace. We are committed to providing a safe and healthy work environment free from violence, threats of violence, harassment, intimidation, and disruptive behavior for all our employees. HR representatives are familiar with this policy and have received additional training in workplace harassment. The has adopted this policy which prohibits violence, threats of violence, and encourages employees to take affirmative steps to identify and address potentially violent situations. Although some incidents or situations involving workplace violence may be the result of larger societal problems outside of our control, The Company firmly believes that by working together with our employees, the risk of workplace violence can be minimized.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Violence shall include, but not be limited to the following:

- Causing physical harm to another person.
- Threats of any nature; verbal or electronic.
- Aggressive behavior that constitutes a reasonable fear of bodily harm to another person.
- Verbal assault, causing emotional duress.
- Intentional damage or destruction of property belonging to either MEL, or its employees.
- Possession of a weapon while on Company premises, or while conducting Company business.

The Company has instituted these security measures to minimize the risk of violence on our premises. Company property shall be accessed only by employees, contractors, customers, and visitors conducting legitimate business activity.

Weapons

- The Company maintains a full and total ban on the possession of weapons on company premises. This includes weapons either kept or transported in any vehicle on company premises.
- Weapons shall be prohibited while conducting business off-site.
- Weapons shall be defined as, but not limited to: Any gun, knife or other item held with intent to cause bodily harm to any employee.

Violence Reporting Procedures

- If an employee is either directly affected by or witness to any violence in the workplace, it is imperative for the safety of all employees that the incident be reported promptly.
- Report any violence or potentially violent situations immediately to management, or the Human Resources department.
- All reports shall be kept confidential.
- All reports shall be investigated and dealt with appropriately.

Enforcement

- Any employee who threatens, harasses, or abuses another employee, or any other individual at or from the workplace shall be subject to disciplinary action, up to and including termination of employment, and the pursuit of legal action.
- Violent action, threats and harassment are serious criminal offences and shall be dealt with promptly and appropriately.

3.10 Progressive Discipline Policy

The Company is committed to fair and constructive treatment of unacceptable conduct or work performance. The progressive discipline process is carried out with the intent to improve behaviour.

Identification of Performance Issues

The supervisor or foreman is responsible for promptly identifying and responding to any unsatisfactory conduct or performance. The supervisor or foreman is responsible for communicating expectations to the

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

employees so that everyone is aware of the standards expected and that failure to comply could result in disciplinary action. An Employee Warning/ Disciplinary Notice Form is available for documentation purposes

Guidelines

The progressive disciplinary process is initiated for situations in which policies, procedures, or professional practices have been ignored or breached, or an employee's performance fails to meet acceptable standards.

Human Resources is available for consultation at any stage of the process and must be involved prior to a written warning. Human Resources must both be involved prior to suspension or dismissal.

Step 1: Verbal Warning

The supervisor discusses the situation with the employee, specifying clear expectations and standards of performance, a plan of action to bring about the desired change, a reasonable period of time for improvement, and a follow-up interview date.

Step 2: Written Warning

Should the problem continue after the time period specified in Step 1, the supervisor provides a written warning with support from Human Resources. The staff member is advised that continued failure to improve the behaviour could lead to further disciplinary action including dismissal.

Step 3: Suspension

If the employee's performance fails to improve or if there is a recurrence of unacceptable misconduct, the supervisor or foreman, superintendent and Human Resources will determine the need for and length of the suspension.

After the suspension period, prior to returning to work, the supervisor and Human Resources will conduct a re-entry interview with the suspended staff member to discuss the conditions of return to work.

Step Four: Dismissal

If the employee's conduct fails to improve or if there is a recurrence of unacceptable misconduct, the supervisor or foreman, superintendent and Human Resources prepares for termination.

It should be noted that depending upon the severity of the infraction some or all of the disciplinary steps may be skipped (i.e., serious offenses can result in suspension and/or immediate termination)

3.11 Contractor Management

Prior to performing work activities at any MGOC operation or job site, contractors and subcontractors must be provided with information regarding MGOC company expectations and requirements including but not necessarily limited to:

- Company OH&S Policy
- Hazard assessments
- Workplace inspections
- Workplace incident notification and reporting
- Personal Protective Equipment (PPE) requirements
- Workplace procedures and rules
- WCB and insurance requirements

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- Requirement to perform work as per all applicable regulatory OH&S Acts, regulations, and codes of practice and/or standards (including those referenced by applicable regulations)

The Hiring Manager must ensure that the appropriate information is communicated to and formally acknowledged by contractors and subcontractors before they commence their work at any MGOC operation or work site by providing the subcontractor the Company's ***Subcontractor Safety Program Guide & Acknowledgement*** document.

3.12 Visitor Management

A visitor to The Company facility is anyone who is not:

- A Company employee within a given operation; or
- A contract employee providing regular service to the operation.

Visitor Entry and Orientation Requirements

The following steps must be followed to ensure the safety of The Company visitors at facilities/offices:

- All Visitors must sign in and out of the visitor login sheet and be given an orientation including alarms and a briefing on emergency response procedures.
- Visitors must wear PPE as required in the Corporate Safety Standard for PPE.
- Visitors MUST be with a Company employee at all times.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

4.0 HSE Training

4.1 General Health & Safety Orientation

New employees must receive the General Health & Safety Orientation prior to commencing job duties. This orientation familiarizes new employees with the Company safety policy and processes. The purpose of the orientation is to help understand their rights and responsibilities within the Company. The Company Health & Safety Orientation will be documented and saved in the Training Management System (TMS).

The Company Health & Safety Orientation includes:

- Messaging about building a strong Safety Culture
- Company Core Values and Principles
- Incident Reporting
- Hazards and Risks
- Health and Safety Accountabilities
- The Company Life Saving Commitments
- General Workplace Rules

General Health & Safety Orientations are tracked through the Training Management System.

4.2 Site Specific Health & Safety Orientation

Supervisors shall participate in NSPI orientations prior to the start of work, as required.

The Site-Specific HS Orientation for employees and subcontractors is required prior to work and includes:

- General Operation Information
- Operation Site Plan
- Operations Emergency Response Plan
- Operation Visitor Information

Site Orientation includes the following information (as applicable):

Company Safety Policy	General Company Rules	Policies and Procedures	Employees Rights and Responsibilities
OHS Performance Objectives	OHS Legislation	PPE and Requirements	Specialized PPE Requirements
WHMIS	Worksite Hazard Assessments/Control Measures for Worksite Hazards	Toolbox Meetings	Signs and Barricades
Scaffolding	Fall Protection	Trenching and Excavation	Perimeter Guarding
Electrical Safety	Rigging and Crane Safety	Fire Protection	Housekeeping
First Aid Facilities	Emergency Procedures	Incident/Accident Reporting and Investigation	Return to Work Program

This orientation may be documented by a supervisor within a Daily Huddle Meeting form.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

4.3 Health & Safety Compliance Theory and Practical Training

All health & safety compliance theory and practical training requirements are identified by the company through a risk-based approach dependent on the occupation and the type of tasks an employee will be required to complete. The company process for determining the risks and hazards associated with a task is done through a Hazard Assessment.

Employee training certificates achieved from health & safety compliance theory and practical training courses will be kept in the Training Management System (TMS) and will be available through a mobile app.

Formal competency assessments may be completed for many pieces of heavy and light equipment. These assessments may be completed by training personnel and tracked in the TMS.

All health & safety compliance theory and practical training is identified using Hazard Assessments and tracked in a training matrix.

The Company Training Department will maintain the compliance practical training matrices which identify an employee's safety training requirements based on their occupation at The Company.

4.4 Proof of Competencies

Proof of Competencies that are legislatively required to be on the person and/or on the work site at the time the work. Examples include:

- Proof of current and valid Fall Protection Certification (for employees engaged in the type of work tasks where this is required)
- Proof of First Aid Certification (for employees identified as the first aid providers on that worksite, as required under the NS First Aid Regulations)
- Proof of Blasters Certificate where blasting operations exist for persons conducting such work
- Proof of Traffic Control Certification for persons performing Traffic Control Persons or Temporary Workplace Signer job duties.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

5.0 Hazard Assessment and Control

5.1 Hazards, Risk, and Control

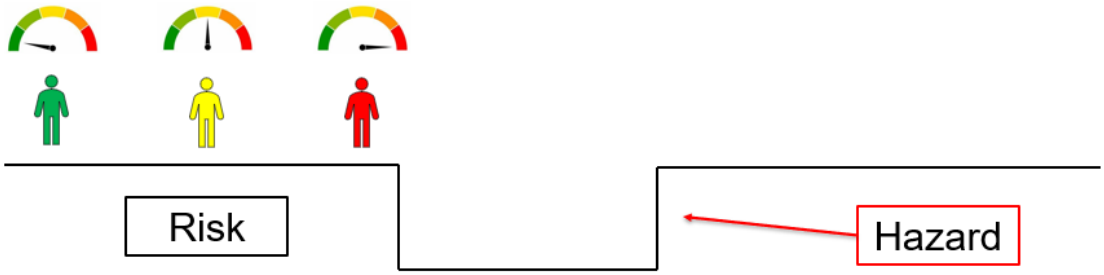
Hazard – *any source of potential damage, harm or adverse effects on something or someone*.

Risk – *the chance or probability that a person will be harmed or experience an adverse health effect if exposed to a hazard. It also applies to situations where there is a chance or probability for equipment loss, process loss or harmful effects on the environment*.

All incidents are the result of uncontrolled risk.

Hazards typically do not change and remain within the workplace unless they are eliminated all together. Managing risk is something we have more control over. As seen in the picture below, the further the person is from the hazard the lower the risk. In this scenario we can also reduce risk by introducing additional controls (e.g., guard rails or covering the hole). To reduce the risk all together the only thing we can do is eliminate the hazard by filling the hole.

The image below shows the difference between a hazard and risk. The hazard (the hole) is a source of potential harm, and as the individual gets closer to the hole, the risk increases.



Hazards

There are six (6) different hazard categories that should be considered when assessing workplace hazards.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

1) **Biological Hazards:** viruses, bacteria, insect, wildlife, etc.
2) **Chemical Hazards:** respiratory system hazards (e.g., silica and asbestos dusts), WHMIS controlled products, etc.
3) **Physical Hazards:** leading edges (fall hazards), heavy equipment, trenches/excavations, etc.
4) **Safety Hazards:** behavioral hazards, untrained employees, inexperienced employees, horseplay, etc.
5) **Ergonomic Hazards:** manual Materials Handlings, workplace, or workstation setup, etc.
6) **Psychosocial Hazards:** workplace violence, stress, etc.

Regardless of the location or industry, all workplaces can be broken down in the same manner to help ensure no hazards go unrecognized.

PEMEP

The acronym PEMEP can also be a helpful tool to use when assessing hazards at your workplace. **PEMEP – *People, Equipment, Materials, Environment*** and ***Process***. This approach will help ensure most hazards are considered in the workplace.

P – People	Do the people or lack thereof create a hazard?	- Untrained Employees - Employee work practices - Inadequate supervision - Public/Pedestrians - Contractors/Other workers
E – Equipment	Does the equipment create a hazard?	- Improper equipment - Exposure to moving parts (unguarded) - Improper maintenance of equipment
M – Materials	Does the material create a hazard?	- Heavy objects - Hazardous materials (e.g., silica or asbestos) - Improper storing - Potential for falling or collapsed material
E – Environment	Does the workplace environment create a hazard?	- Walking surfaces - Excessive noise - Heat or cold stresses - Improper lighting - Work at heights
P – Process	Do the work process create a hazard?	- Improper workplace design (e.g., excessive need to reverse, blind corners) - Schedules for production - Ergonomic conditions

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

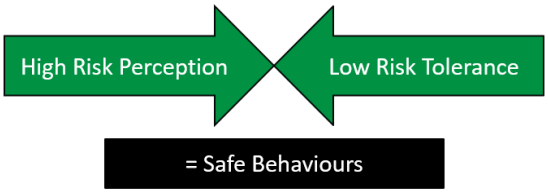
Risk

Risk Perception is the ability of an individual to understand a certain amount of risk. An individual's risk perception can be affected by the following factors:

- Experience
- Age
- Education and training
- Familiarity with a task
- Whether the individual is completing the work voluntarily or if they are completing it unvoluntary
- Whether an individual's supervisor, co-worker, or any other person they respect is willing to accept the risk
- Preconceived biases
- Upbringing and cultural differences

Risk Tolerance is a person's capacity to accept a certain amount of risk. A person's capacity to accept risk can be influenced by similar factors as their perceptions, however, other factors could negatively affect an individual's tolerance, such as:

- Pressure to complete a job
- Peer pressure from peers or supervisors
- Complacency
- Inadequately evaluating/perceiving risk



Evaluating risk is essential to ensure work falls within our acceptable risk tolerance.

Dexter uses the following Risk Ranking tool to objectively evaluate risk. This tool can be used to evaluate each hazard and determine the Likelihood of Loss, the Frequency of Exposure to the Hazard and the Consequences. The Risk Ranking is the sum of the *Likelihood, Frequency*, and *Consequences*.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Risk Ranking = Likelihood + Frequency + Consequence

Likelihood of Loss (potential of an incident)	**Frequency of Exposure**	**Consequence**
1. Practically Impossible	1. Rarely	1. Minor
2. Unlikely	2. Infrequently	2. Moderate
3. Possible	3. Occasionally	3. Serious
4. Likely	4. Frequently	4. Major
5. Almost Certain	5. Continuous or many times per day	5. Catastrophic

Risk Scores:

Class A	13 – 15	Unacceptable Risk
Class B	10 – 12	Critical Risk
Class C	7 – 9	Marginal
Class D	4 – 6	Minimal Risk
Class E	3	Low / No Risk

12	**14**	**15**
9	**11**	**13**
6	**8**	**10**
4	**5**	**7**
3		

CLASS A	**Stop! Unacceptable Risk – Imminent Danger Exists** (loss will occur) Shut down the operation immediately and correct the concern. Class A indicates the immediate potential for severe injury and/or extensive damage of major equipment or material. Task may not be performed unless ranking can be reduced to a Class B minimum.
CLASS B	**Critical Risk – Critical Danger Exists** (loss is likely to occur) Class B indicates potential for injury or illness, resulting in temporary disability or property damage that is disruptive to the operation. ***An SOP must be written for any risk ranked Class B post-controls***
CLASS C	**Marginal Risk – Marginal Danger Exists** (loss may occur but not expected) Class C indicates a potential for injury or illness or property damage that is unlikely to disrupt operation. An SOP should be written for any risk ranked Class C post-controls
CLASS D	**Minimal Risk – Minimal Danger Exists** (loss will rarely occur) Potential for minor loss but does not represent a significant injury or damage potential. An SOP may be written for any risk ranked Class D post-controls
Class E	**Low / No Risk – Practically No Danger Exists** This is the only Risk Level which can be tolerated; however, controls should still be considered.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

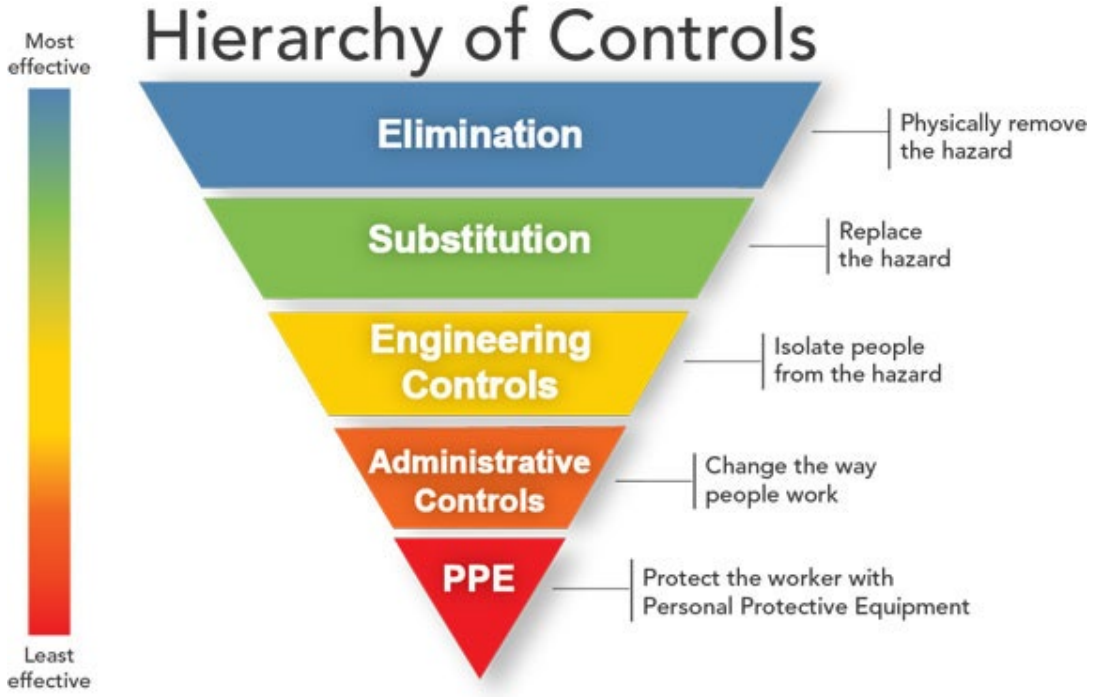
Risk Ranking Clarification Table

Rating	Likelihood of Loss	Frequency of Exposure	Consequence
1	It is almost impossible; likelihood less than 1% chance.	Unlikely an individual will be exposed to the hazard while completing the task (e.g., the employee is exposed to the hazard annually or less then 1% of the duration of the task)	- Injury: First Aid or no treatment - Minor Damage: Less than $10,000 - Environmental: Spill less than regulatory reporting requirements
2	It is conceivable but very unlikely; likelihood 1 – 10% chance.	An individual will be exposed to the hazard infrequently while completing the task (e.g., the employee is exposed to the hazard quarterly or 1 – 10% of the duration of the task)	- Injury: Recordable Injuries (i.e., RWI and MA) - Moderate Damage: at least $10,000, but not exceeding $50,000 - Regulatory Inspection: Compliance Orders - Environmental: Spill resulting in regulatory reporting and internal cleanup
3	Remotely possible; likelihood 11 – 50% chance.	An individual will be exposed to the hazard occasionally while completing the task (e.g., the employee is exposed to the hazard monthly or 11 - 50% of the duration of the task)	- Injury: Lost Time Injuries - Serious Damage: greater than $50,000 but not exceeding $100,000 - Regulatory: Suspension of an operation (e.g., Stop Work Order) - Environmental: Spill resulting in regulatory reporting and 3rd party clean up
4	It is quite possible or probable loss will occur; likelihood 51 – 75% chance.	An individual will be exposed to the hazard frequently while completing the task (e.g., the employee is exposed to the hazard weekly or 51 - 75% of the duration of the task)	- Injury: Disabling Injuries - Major Damage: greater than $100,000 but not exceeding $200,000 - Regulatory: Suspension of multiple operations and/or administrative penalties - Environmental: Spill resulting in significant adverse effects to the public or environment
5	It is almost certain that loss will occur and cause expected results; likelihood 76 – 100% chance.	An individual will be exposed continuously to the hazard while completing the task. (e.g., the employee is exposed to the hazard daily or greater than 75% of the duration of the task)	- Injury: Fatality - Extensive damage: greater than $200,000 - Regulatory: Potential Prosecution - Environmental: Spill resulting in catastrophic environmental impact (e.g., National headlines)

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Controls

Once the hazards have been identified and the risk has been assessed, the next step is to determine the controls. When determining controls, the "Hierarchy of Controls" must be considered.



- **Elimination –** Physically remove the hazard; this is the preferred control option
- **Substitution –** Replace the hazard
- **Engineering Controls –** Isolate people from the hazard (e.g., installing safety devices, guards, barriers)
- **Administrative Controls –** Change the way people work (e.g., Developing Safe Operating Standards, Training, Supervision, and work scheduling)
- **PPE –** Protecting the employee with Personal Protective Equipment; this control should be the last line of defence and used in tandem with another control method (listed above)

5.2 Hazard Assessment Process

All Hazard and Risk Assessments have five (5) basic elements:

1. **Identifying the tasks** – Understanding the scope of work and the tasks required to complete an operation is vital to any hazard assessment. This will ensure the assessment is relevant and effective to control risk for the employees completing the work. It is also important to remember the separate phases of a project can also affect risk (e.g., start-up, normal operation, emergency situations, maintenance, etc.).
2. **Identifying the hazards associated with the tasks** – To identify all the applicable hazards, it is beneficial to go to the place where the work is being completed. While you are looking for and determining hazards,

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

use PEMEP (refer to previous sections for more information). This will ensure all hazard types are considered.

3. **Evaluating the risk for the identified hazards** – Use the risk ranking equation (Likelihood + Frequency of Exposure + Consequence) for evaluating risk. This will ensure consistency and help reduce biases due to differing risk perceptions and tolerances. Pre-control risk rankings (sometimes called pre-rankings) are often higher in risk and are important to help identify appropriate controls.
4. **Applying Controls** – Controls are put in place to reduce risk. Therefore, when selecting controls, we should be thinking about three things:
    a. Will the control reduce the likelihood of loss?
    b. Will the control reduce the frequency an employee is exposed to a hazard?
    c. Will the control reduce the consequence of a loss?

    Use the hierarchy of controls when selecting your controls. Always exhaust each layer before moving onto the next. For example, when looking at a task for heavy lifting we should be considering mechanical aids before job rotation, training on manual material handling (safe lifting) and gloves.
5. **Re-evaluate the risk** – Risk is revaluated once controls have been selected. This will help determine whether we should proceed with the task or consider additional controls. These rankings are called post-control rankings (sometimes call post-rankings). The risk ranking tool is used again for this ranking.

The following are examples of how controls could affect risk ranking, post controls:

12	14	15
9	11	13
6	8	10
4	5	7
3		

5.3 Comprehensive Hazard Assessments

Comprehensive Hazard Assessments have been completed and are available for the following operations:

- Asphalt Plant Operations
- Asphalt Operations
- Blasting Operations
- Concrete Operations
- Demolition Operations
- Drilling Operations
- Micro and Chip Seal Operations
- Miscellaneous and Street Renewal Operations
- Planing Operations
- Quality Control Operations
- Quarry and Crushing Operations
- Snow and Ice Control Operations

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- Facilities Management and Carpentry Operations
- Grade Operations
- Hardware Operations
- Heavy Civil Mass Operations
- Structures Operations
- Survey Operations
- Trenching and Excavation Operations

Comprehensive Hazard Assessments are available on the Company safety management system software.

5.4 Project Hazard Assessments

A Project Hazard Assessment must be completed for each project and must be specific the location, tasks and hazards present at the project. Project Hazard Assessments are documented within the safety management system software or in hard copy.

Specific sections of the Hazard Assessment relevant to the tasks being completed must be communicated daily within a Safety Meeting (e.g., Daily huddle).

A project Hazard Assessment is a live document and must be consistently reviewed and monitored to ensure it remains relevant and effective based on changing site conditions.

It is best practice to review Project Hazard Assessments at the following intervals (while the operational task is being completed):

- Weekly – when the Hazard Assessment has identified Class B ranked risk post-controls
- Bi-weekly – when the Hazard Assessment has identified Class C ranked risk post-controls
- Monthly – when the Hazard Assessment has identified Class D or E ranked risk post-controls
- Annually – for Job Specific Route Hazard Assessments (e.g., Snow plow Routes)
- As per the frequency set by the project team, client, or regulator.

Note: Project Hazard Assessment review cycle must be included in the project schedule, as applicable.

Subcontractors and / or Other Internal Work Groups

Often another work party (external or internal) will be completing work within our workplaces and on our jobsites. It is extremely important that these parties participate in the Project Hazard Assessment process.

Communication is vital. If hazards/controls are not communicated, the value of the assessment is lost.

Subcontractor and internal support crew Hazard Assessments must be included in the overall Project Specific Hazard Assessment and reviewed as appropriate with affected personnel.

Project Specific Hazard Assessment Review

Project Specific Hazard Assessments must be reviewed with all affected personnel[1] upon initial arrival to the workplace, and periodically[2] throughout the length of the project.

Note[1] – Sections including Hazards, Risk and Controls that will be encountered by the worker or visitor.

Note[2] – Review frequency will be established based on task scope, project length and risk rankings.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

5.5 Standard Operating Procedures (SOPs)

Standard Operating Procedures (SOPs) are administrative controls that determine the actions and precautions that should be taken while performing a task to prevent a potential loss or minimize its effect if an incident were to occur.

SOPs must include the following sections:

- Introduction which includes the purpose, scope, and associated hazard assessment
- Life Saving Commitments
- Personal protective equipment and additional resource requirements
- Training requirements
- References
- Process
    - Task Steps (Should include such things as relevant drawings, start up, job steps, shutdown, emergency shutdown, and completion/record keeping)
    - Emergency Procedures
- Amendments

All facilities and employees will have access to all SOPs relevant to their operations either electronically or via hardcopy. SOPs required at a worksite are determined and developed based on the results of applicable Hazard Assessments specific to the type and nature of work performed.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

6.0 Project Scope of Work

The scope of this project is to install an approximately 80-meter-long sloped rock revetment on the shoreline of the Tufts Cove Generating Station (TUC) in Dartmouth, NS. This work is required to mitigate the condition of the existing steel sheet pile structures that retain the plant shoreline. An intake extension will also be required for the unit 3 seawater intake to accommodate the rock revetment.

- Restore the structural integrity of the TUC shoreline and mitigate the need for sheet pile structures
- Extend the existing unit 3 cooling water intake with precast concrete box culverts to accommodate the new rock revetment structure.
- The extension structure is approximately 15000mm long, comprised of 6 3658mmx3658mm concrete box culverts.
- Enhance the existing aquatic habitat through placement of armour stone along the existing sheet pile walls, which will provide greater footprint for aquatic habitat.
- Minimize environmental impacts during construction and comply with all permits and regulations and conditions (e.g. DFO, Transport Canada, Port of Halifax).

Work for this project shall include but may not be limited to:

- Mobilization to site of necessary equipment, materials, tools, site office and personnel to carry out the work
    - Installation of the TUC 3 intake Extension, which includes:
    - Underwater excavation
    - Placement of core stone and granular materials
    - Placement and installation of the concrete box culvert
    - Placement of the concrete cast-in-place intake headwall, including reinforcing steel, and removals of any temporary formworks
- Placement of base core stone throughout the remaining revetment footprint
- Placement of filter stone on top of placed core stone
- Placement of granular leveling courses
- Placement of armour stone on top of the placed core stone and filter stone

NOTE: All diving activities to be conducted by Connors Diving Services Ltd; all construction activities will be coordinated with Connors.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

7.0 Site Location, Control, and Access

7.1 General

Supervisors must control the work and entry points to the work site. Access will only be granted to workers and authorized persons. Everyone has a responsibility to stop and remove non-authorized persons.

All reasonable steps must be taken to isolate the work site from other areas of the premises by use of appropriate means, such as, but not limited to:

- Erecting fences, hoarding, barricades, and temporary lighting as required to effectively delineate the work site, stop non-authorized entry, and to protect pedestrians and vehicular traffic around and adjacent to the work and create a safe environment.
- Post signage at entry points and other strategic locations indicating restricted access and conditions for being granted access.

Supervisors are required to take all reasonable steps to secure the work site against entry when inactive or unoccupied and to protect persons against harm.

Driveways, laneways, walkways, or emergency vehicle routes must not be blocked or restricted at any time by construction vehicles, machinery, equipment, or materials except in the course of demolition or other business activity.

The Company shall provide and maintain all passageways, guard fences, lights and other facilities for protection required by public authority or local conditions, or laws and regulations and will ensure all roadways are passable for emergency services.

7.2 Site Signage

All signage will be professionally made and be clearly visible from outside the work area where the construction project is being undertaken.

7.3 Site Traffic Regulations

Posted speed limits on all site roadways and traffic signs (e.g., stop signs) must be adhered to. Maximum speed is 30 km/h unless otherwise posted and the maximum posted speed limit is not exceeded. Violation of Traffic Rules are considered to be a major safety infraction and progressive discipline will be followed.

7.4 Site Access and Parking

Site access must be restricted to only authorized personnel who are knowledgeable of the Site-Specific Health and Safety Plan

Employee parking will not be permitted within active operational areas. A plan will be developed to arrange for a remote parking area and the potential transporting of employees from the parking area to the operations site, if required.

7.5 Barriers and Barricades

Barriers are used to stop the passage of people or vehicles in a restricted area. Guarding (barricade) is a requirement of the Occupational Health and Safety Act and the Regulations – all openings, sumps, vessels, bins, hoppers, elevated platforms, or pits, other than grease pits, which constitute a hazard, must be fenced, or otherwise guarded. (Occupational Health and Safety Act and Regulations).

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

7.6 Emergency Services Accessibility

Emergency Response Services mobility must be preserved at all times. Operating Routes must be reviewed on a regular basis to ensure that access is maintained at all times. Alternative and approved routes are to be established if new construction is anticipated to interfere with such access areas.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

8.0 Project Supervision

8.1 Responsibilities and Qualifications

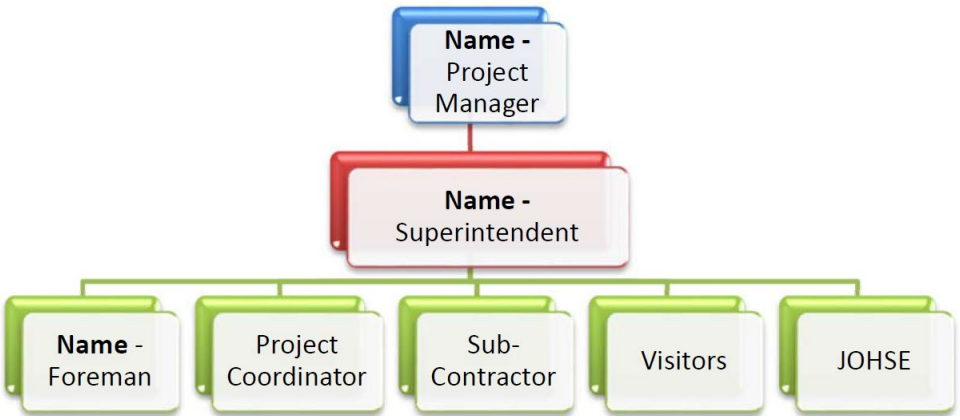
All supervisors are held responsible for the safety of their workers and are responsible for the communication of safety information as well as direct supervision of their employees. The supervisor directing their work shall take each employee to the location that they will be performing the work, to familiarize them with the possible hazards relating to the work they will be expected to perform.

Supervisors are trained to fulfill their responsibilities in an effective and professional manner. Training for all supervisors includes but is not limited to:

- OHS Act / Due Diligence
- Emergency First Aid
- WHMIS
- Workplace Inspections
- Incident Investigation
- Hazard Identification & Control

All subcontractor supervisors are accountable to the Company superintendent for the safe performance of all employees though the safe use of tools, equipment and following safe work practices.

The project manager is responsible for the implementation of this site-specific health and safety plan and will further outline the Company's program requirements and assign specific responsibilities to individuals as work progresses. The project manager must take all reasonable steps to ensure the site-specific health and safety plan is reviewed with each subcontractor supervisor, prior to the commencement of work.



This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

8.2 Site Management & Supervisors

Dexter Project Manager

TBD Phone:
Email:

Dexter Project Coordinator

TBD Phone:
Email:

Dexter Superintendent

TBD Phone:
Email:

Dexter Foreman

TBD Phone:
Email:

Dexter Site Safety Representative

TBD Phone:
Email:

NSPI Project Manager

TBD Phone:
Email:

NSPI Project Coordinator

TBD Phone:
Email:

NSPI Safety Manager

TBD Phone:
Email:

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

9.0 Site Procedures

9.1 Housekeeping

Housekeeping is responsibility shared by all employees, and a major factor in minimizing occupational injuries and illnesses. The guidelines outlined here represent acceptable housekeeping practices for The Company.

All personnel will work towards maintaining their respective workplaces in a clean and orderly manner.

Housekeeping encompasses all activities related to the cleanliness of The Company Operations, project sites, materials, equipment, as well as to the elimination of nonessential materials and hazardous conditions. The following general housekeeping practices must be applied to all areas where employees perform maintenance, construction, or other activities:

- Garbage, scrap, debris, and other trash materials are to be properly disposed of in designated containers and removed at frequent and regular intervals.
- Containers used for garbage and all other trash material (e.g., oily rags, absorbent pads, flammable hazardous wastes) shall be equipped with covers.
- In areas frequented by wildlife, all garbage containers are to be equipped with bear-proof lids.
- Materials, chemicals, and equipment shall be stored only in appropriate storage locations. Chemicals must be properly labelled and stored in their compatible groups.
- Floors, stairs, and other walking surfaces (e.g., parking lots, yards) used by employees should be maintained, clean, and kept free of obstructions, hazards, and accumulations of refuse, ice, and snow. Liquid spills are to be cleaned up immediately.
- Equipment is to be kept clean and in good working condition.
- Individual work areas are to be kept clean to ensure that work activities may proceed in an orderly and efficient manner.
- Tools, supplies, parts, and equipment will not be used in a hazardous manner or in any way that could adversely affect the work quality.
- Housekeeping Inspections must be used to ensure the work area is maintained in an acceptable manner.
- When operating mobile equipment, all tools and equipment (e.g., toolboxes not tied down) must be stored securely.
- Shelved items must be placed in an orderly manner and arranged so that the items cannot easily fall while nearby items are being retrieved.
- Instructions written by the manufacturer or a professional engineer for safely loading, unloading, and maintaining the storage racks must be readily available to employees in the workplace.
- The rated capacity of the storage rack shall be clearly posted near the storage rack and readily visible to employees.
- Items will not be placed in front of shelves so that employees must climb or reach over the items stored in front of the shelves to retrieve items.
- Heavy items should be stored on the floor (away from shelve units) or on the bottom shelves.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- Stored shall remain 18 inches below the plane of the sprinkler heads, or 24 inches below the ceiling in areas without automatic sprinkler systems.
- Report any accumulations of trash, unsanitary conditions, spills, slipping hazards, or other dangerous conditions to your immediate Supervisor.
- In shared storage areas, shops, or offices, all Supervisors should work closely together to ensure that housekeeping is maintained in an acceptable manner.

Burning onsite is forbidden.

Staff and workers must ensure compliance with Company ***HSMS Corporate Safety Standard: Housekeeping Requirements***.

9.2 Working Near Overhead Utilities

Prior to the commencement of work, a project hazard assessment shall be completed and will identify the presence/locations of overhead utilities. Prior to the commencement of any work near overhead utilities, Safe Clearance Reports and utility locate reports shall be obtained from the utility owner. No encroachment closer than the limits specified in the Safe Clearance Reports/Locates, as well as those specified in applicable occupational health and safety regulations.

Phase to Phase Voltage of Energized Electrical Power Line or Power Line Equipment	Distance
750 volts and up to 69 000 volts	3.0 m
greater than 69 000 volts and up to 138 000 volts	5.0 m
greater than 138 000 volts	6.0 m

If the voltage of any overhead utility is not known, there shall be no encroachment closer than 6.0 m.

Spotters/signallers shall be used as required to help ensure adherence to these encroachment limits. Spotters/signallers shall be designated in Toolbox Meeting minutes and/or Daily Job Hazard Analysis.

Safe Clearance Reports shall be reviewed with all applicable personnel on site, including subcontractors, prior to commencing any work activities near overhead utilities. Review of the Safe Clearance Reports shall be documented on Toolbox Meeting minutes and/or Daily Job Hazard Analysis.

Staff and workers must ensure compliance with Company ***HSMS Corporate Safety Standard: Overhead and Underground Utilities***.

9.3 Buried/Underground Utilities (General)

When undertaking excavation works, seek information on any underground services which may be located at the worksite.

This can be done by requesting information from:

- The utility owners. Most utility companies are members of the 'Dial before You Dig' service. For utility owners not registered with this service, you will need to contact them directly. Most utility owners will provide the utility plans without cost unless the scope of work is complex.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- If works are completed on private properties. Check with the property owner for blueprints of the worksite. Utility owners may need to be notified as well.
- Services may be located using a locator device operated by a competent person. (This is not recommended unless necessary).

Summary of Requirements (Underground Services Gas or Electrical lines/ communication lines)

- The location of underground utilities may be dug carefully by hand or other suitable non-destructive methods. This should only be done after obtaining information on the location of any underground services from the utility owner, and it is not safe to use equipment within the safe distance determined by the utility owner.
- If working with equipment 'near' an underground service, and following the No Go Zone guidance, you may not work any closer to the utility with powered equipment (excavator, etc.) than safe distances specified by the utility owner. This is known as the utility corridor (See diagram 3 below).
- For utilities requiring integrity of the material surrounding the utility, greater clearances may be required. Information regarding these clearances can be obtained with the initial utility owner's permit.
- The use of mechanical or powered mobile equipment is not permitted when the location of the underground utility is not known, or within the prescribed distance of the line when the location of the underground utility line is known. Acceptable methods for locating or exposing the underground involve either daylighting or hand exposure (hand shovel).
- The estimated location of utility installations such as sewer, telephone, fuel, electric, water lines, or any other underground installations that may be expected to be encountered during excavation work shall be determined prior to opening a trench or excavation.
- Utility companies or owners shall be contacted within established or customary local response times, advised of the proposed work, and asked to establish the location of the utility underground installations prior to the start of actual excavation. When utility companies or owners cannot respond to a request to locate underground utility installations within 24 hours (unless a longer period is required by legislation or local law), or cannot establish the exact location of these installations, the employer may proceed provided the employer does so with caution and provided detection equipment or other acceptable means to locate utility installations is used.
- When excavation operations approach the estimated location of underground installations, the exact location of the installations shall be determined by safe and acceptable means.
- While the excavation is open, underground installations shall be protected, supported, or removed as necessary to safeguard employees.
- Prior to digging, ensure that all underground installations (sanitary/storm sewers, water lines, electrical and communication lines/conduits, natural gas lines, etc.) are accurately located and marked / identified using coloured paint or flag markers in accordance with the International Colour Code for Underground Utility Marking (see Figure 1 below).
- Where damage or contact has occurred to an underground utility line, work will stop immediately, and the owner of the underground utility notified. If necessary, emergency response procedures shall be activated.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

	White - Proposed Excavation
	Pink - Temporary Survey Markings
	Red - Electric Power Lines, Cable Conduit and Lighting Cables
	Yellow - Gas,Oil,Petroleum and Gaseous Materials
	Orange - Telephone, Cable TV, Communication, Alarm and Signal Line
	Blue - Potable Water
	Green - Sanitary Sewers, Storm Sewers and Drain Lines
	Purple - Reclaimed Water, Irrigation And Slurry Lines

Figure 1 – International Colour Code for Underground Utility Marking

Staff and workers must ensure compliance with Company ***HSMS Corporate Safety Standard: Overhead and Underground Utilities***.

9.4 Trenching and Excavation

All trenching and excavation work must be completed as per applicable occupational health and safety acts and pursuant regulations, and Company ***HSMS Corporate Safety Standard: Trenching and Excavation***.

9.5 Fall Protection

All work at heights must be completed as per applicable occupational health and safety acts and pursuant regulations, and Company ***HSMS Corporate Safety Standard: Fall Protection/Working from Heights/Ladders***.

9.6 Confined Space

All confined space work must be completed as per applicable occupational health and safety acts and pursuant regulations, and Company ***HSMS Corporate Safety Standard: Confined Space Awareness and Entry***.

9.7 Stockpiles

When the removal of material from excavations progresses at a faster rate or at different times than placement of backfill is being accomplished, such excavated materials shall be stockpiled at approved locations.

9.8 Lockout/Tagout

1) Only authorized employees are permitted to perform Lockout / Tagout procedures.
2) If an energy isolating device is capable of being locked out, then it must be locked and tagged.
3) If an energy isolating device is not capable of being locked out, you must consult your supervisor or the Safety Department for guidance.
4) Prior to commencing servicing or work, equipment and machinery shall be inspected to verify they can be effectively isolated.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

5) All potential sources of hazardous energy (e.g., gravity, electrical, mechanical, pneumatic, pressure) must be considered when determining Lockout / Tagout procedures.
6) Each person servicing or working on a machine must apply their own lock. After the lock has been applied, the key must be retained by the person who applied the lock.

Contractors

Whenever outside contractors perform maintenance or servicing work that requires Lockout / Tagout procedures, the designated Company representative and each contractor shall inform each other of their respective Lockout / Tagout procedures. The Company representative must communicate this to affected employees and ensure these respective procedures are mutually understood.

Staff and workers must ensure compliance with Company ***HSMS Corporate Safety Standard: Lockout/Tagout***.

9.9 Maintenance and Refueling

1) Spill kit onsite and readily available, and the contents inspected on a regular basis.
2) All maintenance and refuelling areas must be at least 100m from any watercourse
3) A level surface for working must be sufficiently large enough to accommodate the equipment to be repaired, be demarcated, and segregated from normal traffic areas
4) For all re-fueling activities, mobile equipment must follow site procedure
5) All spills be cleaned up immediately and reported
6) Conduct JHA in case repair and maintenance work is not covered in SOP of equipment manufacturer
7) Authorized Hot Work Permit must be obtained prior to starting any 'hot work'
8) Working near combustible materials not permitted (fire regulations to be adhered to)

9.10 Hot Work

All potentially flammable materials that may be impacted shall be removed or protected and a fire watch shall be maintained for at least 30 minutes after hot work ceases.

Staff and workers must ensure compliance with Company ***HSMS Corporate Safety Standard: Hot Work***.

9.11 Hearing Conservation and Noise Assessment

Employee Exposure

Employees' unprotected exposure to noise is not permitted to exceed 85 dBA Lex, which is the level of an employee's total exposure to noise in dBA, averaged over an entire workday and adjusted to an equivalent eight-hour exposure. Calculated maximum unprotected exposure durations are shown in the following table:

Exposure level (dBA)	Exposure duration
82	16 hours
83	12 hours and 41minutes
84	10 hours and 4 minutes
85	8 hours
88	4 hours
91	2 hours

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Exposure level (dBA)	Exposure duration
94	1 hour
97	30 minutes
100	15 minutes
103	8 minutes
106	4 minutes
109	2 minutes
112	56 seconds
115 and greater	No safe unprotected exposure duration

Although some Provincial/State legislation uses 90 dBA as the threshold for which hearing protection is required, The Company will use 85 dBA.

NOTE: Employees shall wear adequate hearing protection where measured noise levels exceed allowable exposure limits.

Hearing Protection Equipment

Operations Managers are required to ensure that hearing protection equipment is provided for employees exposed to excess noise in accordance with The Company ***HSMS Corporate Standard: Personal Protective Equipment***.

Hearing protection (ear plugs and/or muffs) will be made available by The Company at all worksites at no cost to the employee. The equipment supplied must have an N.R.R. (noise reduction rating) of at least 24 dBs (e.g., bilsom 2318 muffs, ear plugs, etc.).

For sound exposure levels in excess of 105 dBA Lex, the use of a single hearing protection device will be insufficient to reduce the levels below the recommended limit of 85 dBA Lex. For this reason, where 8-hour equivalent noise exposure levels exceed 105 dBA, double or dual protection (earplugs in combination with earmuffs) shall be used.

Equipment must not under any circumstances be altered, and all employees must be informed about the hazards associated with excessive noise exposure and the reasons for wearing the hearing protection provided.

No person is permitted to enter a designated area without wearing hearing protection.

Employees who are provided with hearing protection equipment must be provided with training in the selection, use, and maintenance of the equipment, and all training shall be documented.

Staff and workers must ensure compliance with Company ***HSMS Corporate Safety Standard: Hearing Conservation and Noise Assessment***.

9.12 Dust (Silica) Suppression and Control

Sources

- Rock and sand
- Topsoil and fill
- Concrete, cement, and mortar

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- Masonry, brick, and tile
- Granite, sandstone, and slate
- Fibrous-cement board containing silica

Exposure

- Blasting
- Loading, hauling, dumping, screening, processing, and shipping of material
- Sweeping of operators' compartments, accommodations
- Drilling rock or concrete
- Road construction

Unprotected employees performing these activities (or working nearby) can be exposed to harmful levels of airborne silica.

Risk identification and assessment

A hazard assessment must be completed to identify the work activities that would put employees at risk of exposure. Controls must be put in place to keep the exposure below acceptable limits. Hazard assessments must identify:

- Work activities that may generate airborne silica dust—which should be identified in both the comprehensive risk assessment and daily job hazard analysis.
- Employees at risk of exposure—for example, crushing and screening personnel.
- Amount of exposure—some work activities generate more dust than others, and the amount of exposure varies. Air sampling data must be used to compare silica dust levels from various mining activities.
- Duration of exposure—for example, employees who work at a screening operation for a full shift would be at greater risk than a loader operator that was only working there for an hour.

Elimination and substitution

- During the project planning phase, we will advocate for the use of methods that reduce the need for activities that generate silica dust.
- Whenever possible, we will schedule work that minimizes exposure to silica dust.

Engineering control of dust

- Maintaining positive pressure in operator compartments
- Local exhaust ventilation (LEV)
- Wet dust suppression (WDS)
- Restricting or isolating the work activity with barriers or full enclosures

Administrative controls

- Hazard assessment with controls implemented prior to starting work.
- Procedures established for housekeeping, restricting work areas, personal hygiene, employee training, and supervision.

Respiratory protection

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- All employees who wear respirators will do so in adherence with ***HSMS Corporate Standard: Personal Protective Equipment***.
- Respiratory protection will be selected based upon the site-specific hazard assessment or established procedures.
- Only NIOSH-approved respirators will be used.
- Employees who wear respirators must be clean-shaven. Filtering face-piece respirators give little or no protection to employees with beards, and even a minor growth of stubble can severely reduce the effectiveness of respiratory protection.
- All employees who wear respirators will be fit-tested.
- Employees will be properly trained in the use of respirators, and a high standard of supervision, inspection, and maintenance will be followed. Fit testing and training may be provided by trained Company employees or by third-party providers.

Protective clothing

Employees will wear protective clothing as specified in task-specific safe work procedures to prevent contamination of employee clothing. Employees will not use compressed air to clean themselves, their clothing, or their equipment.

Education and training

All employees who could potentially be exposed to airborne silica dust will receive training on the following:

- Hazards associated with exposure to silica dust
- The risks of exposure to silica
- Signs and symptoms of silica disease
- Safe work procedures to be followed
- Use of respirators and other personal protective equipment (e.g., donning and doffing of personal protective equipment, cleaning, and maintenance of respirators)
- Use of control systems (e.g., wet methods)
- How to seek first aid (the location and use of eyewash stations)
- How to report an exposure to silica dust

Safe work procedures

Safe work procedures must include task-specific instructions, such as:

- Safe operation of all equipment, including dust control attachments and related equipment
- Maintaining cleanliness of equipment cabs and operating areas
- Vacuum and filter system maintenance (e.g., air conditioning systems)
- Cleanup procedures
- Employee decontamination procedures (hygiene facilities to permit proper hand washing are a basic expectation under all control plans)

Staff and workers must ensure compliance with Company ***HSMS Corporate Safety Standard: Silica***.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

9.13 Traffic Control

Essential Principles

There are a number of essential principles that must be considered for all temporary workplace traffic control operations: Function, Planning, Communication, and Implementation.

The necessary elements of care include:

- Designing and carrying out an appropriate traffic control plan.
- Making an on-site review of the plan once it is in implemented.
- Inspecting the site frequently to ensure all signs, markings, devices, signals, and beacons are in place and functioning properly.
- Continual review of the effectiveness of the solution, amending the traffic control plan as the site requires.

All traffic control signs, markings, signals, beacons, devices, and procedures used at temporary workplaces must conform to current versions of all applicable provincial regulations/legislation, approved codes of practice (i.e., applicable provincial Traffic Control Manual), and standards. Road signs, pavement markings, traffic control signals, and any other devices or persons intended or employed to regulate, warn, or direct traffic in a temporary workplace must operate under the authority of the road owner.

Implementation

The following principles shall always be used when preparing and implementing the traffic control plan:

- Avoid frequent or abrupt changes in alignment that require rapid manoeuvres.
- The length of road affected by work must be minimized; public traffic has priority.
- Ensure traffic movement through a temporary workplace is controlled in the least intrusive manner possible while still maintaining safe working and driving conditions.
- Provide for the safe operation of work vehicles (e.g., construction related vehicles and mobile equipment).
- Guide traffic in a clear and positive manner while it approaches and travels through temporary workplaces:
    - Provide adequate warning, delineation, and channelization.
    - Place all signs, markings, devices, signals, and beacons where they do not pose a hazard; however, message must be able to be understood and reacted to safely and comfortably.
    - Aim all signs, markings, devices, signals, and beacons so that they present the best viewing angle for approaching traffic, whatever the road position or passing maneuver.
    - Cover or remove all permanent traffic regulatory or temporary condition signs, markings, devices, signals, and beacons in accordance applicable codes of practice if they conflict with the traffic control plan.
    - Inspect all signs, markings, devices, signals, and beacons in a temporary workplace frequently, relocating or replacing them when required.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Upon project completion, all permanent signs, traffic signals, beacons, and pavement markings impacted by the temporary workplace must be restored.

Codes of Practice (Traffic Control Manuals)

For the purpose of implementing appropriate traffic control at all temporary workplaces, the current legal edition of the applicable province's code of practice must be followed at all times.

Staff and workers must ensure compliance with Company ***HSMS Corporate Safety Standard: Traffic Control***.

9.14 Severe Weather and Natural Disasters

Lightning Storms

- Shutdown equipment and processes
- During the electrical storm, work activity around the operation should be temporarily stopped until the danger has passed

High Winds

- Secure light objects and protect equipment
- Take cover

Loose construction material and equipment becoming projectiles during the storm, which can result in injuries and fatalities and also damage property.

In the case of a hurricane/tropical storm watch or warning

Gather loose construction materials in organized piles and secure them with ropes, zip-ties, and duct-tape, making them more difficult to blow away.

Construction equipment and materials should be stored away in a garage or an area that is at least 100 meters away from the coastal zone to avoid the risk of materials becoming marine debris and saltwater damage.

To prevent loose materials from blowing away, secure materials by using ground anchors, sandbags, weights, and other means to weigh them down.

To decrease water damage to materials, use tarps, heavy duty garbage bags and other coverings to prevent water intrusion.

Empty all waste receptacles and dispose of waste in dumpsters or at an approve dump site. Once emptied all waste receptacles should be secured as described above.

9.15 Work in, On or Around Water

All work conducted from boats/watercraft must be performed by trained, competent personnel who have completed all necessary boating safety training as required by act/regulation and operators must hold the valid class/type license (if applicable) appropriate for the craft being operated.

All requirements of ***Safe Work Practice SWPMISC-029 Working Near Water (Risk of Drowning)*** must be followed.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

10.0 Vehicles, Mobile Equipment and Cranes

10.1 General

The Company shall ensure that all personnel required to operate mobile equipment (e.g., backhoes, trucks, excavators, etc.) are properly trained, possess a current driver's license as well as all other necessary licenses and/or certificates and are competent.

All mobile equipment must be in good operating condition with current maintenance and inspection records available on request.

All vehicles and mobile equipment must meet the following regulatory requirements where applicable:

- Applicable provincial motor vehicle act(s)
- Applicable occupational health and safety act(s), pursuant regulations, and codes of practice
- National Safety Code (pre-trip inspections, lifting devices, air brakes, etc.)

All equipment and machinery required to be operated on or near a body of water will be mechanically sound with no leaking fuel tanks or hydraulic connections.

Hazards/controls associated with this equipment include:

- Completion of pre-operation/post-operation inspections.
- All ground personnel and site visitors to wear proper PPE, including high visibility reflective apparel.
- All equipment operators, site personnel and visitors to remain alert and aware of equipment and personnel movement.
- All equipment back-up warning devices must be functioning properly. Confirm during pre-op inspection.
- Do not operate near the edge of cliffs, overhangs, slopes, embankments, etc.
- During night operations, all equipment must have all necessary lights functioning properly. Confirm during pre-op inspection.

All vehicles/ equipment shall have automatic reverse signalling devices to alarm when vehicle is shifted into reverse. Approved site speed limits shall be adhered too.

No equipment shall have leaking or loose bodywork. Onsite mechanics will be present to address any mechanical issues such as breakdowns and leaks that may occur, or the equipment will be removed from the site.

When not in use ensure all equipment and materials will be stored in approved areas.

Staff and workers must ensure compliance with Company ***HSMS Corporate Safety Standards:***

- ***Load Securement***
- ***Mobile and Heavy Equipment General Safety***
- ***Rigging, Hoisting and Lifting***
- ***Safe Driving (Commercial, Light Duty and Heavy Equipment)***
- ***Safe Separation***

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

10.2 Mobile Cranes

Ensure all necessary arrangements (e.g., crane placement, road restrictions, medical, security, and fire department notification, lockouts, safety watch, etc.) have been made and communicated to all affected personnel.

10.3 Pendant/Overhead Cranes

All personnel who will be operating a pendant/overhead travelling crane during the course of their work must be in possession of a current certified license for overhead travelling crane operation.

10.4 Elevating Work Platforms

Personnel must be given verbal, visual and hands-on instruction on the safe operation and requirements to operate that specific class of elevating work platform, prior to start of job. Operator certificate required at all times.

10.5 Overhead Loads/Lifting Related Hazards

- All on site personnel and site visitors to wear proper PPE
- All equipment operators, site personnel and visitors to remain alert and be aware of powered mobile equipment use, heavy lifts, and potential for overhead loads
- Competent riggers to install rigging
- Use taglines where possible
- Install proper crane pad(s) that are capable of bearing required loads
- Site personnel to stay clear of lifts

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

11.0 Personal Protective Equipment (PPE)

Supervisors/managers are responsible for providing their employees with their required PPE prior to any work activity taking place. PPE requirements must be communicated to employees, visitors, or contractors with signage posted/mounted at the main entrances or on gates of project sites where applicable.

Note: where posting cannot be maintained the information must be available from the Supervisor of the site and they are responsible for communicating this information.

11.1 Basic PPE

The basic PPE requirements are outlined below unless task-specific PPE is stipulated.

- Foot Protection: CSA approved Grade 1 Protective Footwear, minimum height of 8 inches, which complies with the latest version of CSA standard CSA Z195, “Protective Footwear”. For protective footwear utilising zippers or laces, the footwear must be zipped or laced high enough to support the ankle.
- High Visibility Reflective Apparel: CSA approved high visibility clothing that meets the latest version of CSA standard CSA Z96 – Class 2, Level 2 (minimum).
- Head Protection: Class E, Type 2 hard hat as appropriate to the hazard and that complies with 1 of the following standards:
  - The latest version of CSA standard CSA Z94.1, “Industrial Protective Headwear;” or
  - The latest version of ANSI standard ANSI Z89.1, “Industrial Head Protection.”

  Head protection is not required inside the cab of a vehicle or mobile equipment.
- Eye Protection: Employees will wear approved eye protection that satisfies the latest version of CSA standard CSA Z94.3, “Industrial Eye and Face Protectors.”

11.2 Task-Specific PPE

Task-specific/specialized PPE is required for certain tasks, as outlined in applicable company policies and procedures (e.g., Standard Operating Procedures (SOPs)). Task-specific PPE, and training on its use, shall be provided to employees as needed.

Task-specific PPE may include additional or alternate protection in relation to the following:

- Foot protection (additional to basic requirements)
- Head protection (additional to basic requirements)
- Eye and face protection that complies with the latest version of CSA standard CSA Z94.3, “Industrial Eye and Face Protectors”
- Skin protection
- Hearing protection in compliance with:
  - The latest version of CSA standard CSA Z94.2 Selection, “Use and Care of Hearing Protection Devices,” and
  - The latest version of “Municipal Group of Companies Hearing Protection Program”
- Respiratory protection in compliance with:

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- The latest version of CSA standard CSA Z94.4, "Selection, Use, and Care of Respirators," and
- The latest version of company Respiratory Protection Program (refer to Respiratory Protection CSS)

- Fall protection in accordance with the latest version of the Fall Protection CSS and all applicable standards referenced therein
- Other as warranted

11.3 Maintenance of PPE

Employees shall take the necessary steps to ensure their PPE remains functional and is properly maintained in accordance with the following:

- PPE must be worn for its intended use and as per manufacturers' instructions and requirements.
- PPE is to be inspected prior to each use.
- Broken or defective PPE must be removed from service immediately.
- PPE must be maintained and stored appropriately.
- Some specific PPE items (e.g., fall protection, winches, air monitoring systems, etc.) must be inspected annually by a competent person.

11.4 PPE-Free Zones

Some areas are exempted from the Standard PPE requirements based on activity and level of risk. Should risk levels increase, appropriate PPE must be used. Exemptions from the requirement are listed below:

- While traveling within fixed facilities between offices and the property boundary, no specific PPE is required. This includes building entrance areas while waiting for transportation or to/from vehicles.
- While traveling in passenger vehicles, trucks, buses, or mobile equipment, no specific PPE is required.
- While in office areas performing office type work, no specific PPE is required.
- While in any designated lunchroom / eating facility, no specific PPE is required.
- Parking areas are normally PPE free zones unless specific activities require it.

Note: Any person performing work that poses an increased risk of injury in any exempted area will wear all appropriate PPE and ensure their work does not pose additional hazards to other persons in the area. Examples of this may include:

- Tradespersons performing their work in exempted areas
- Personnel using or transferring hazardous chemicals or cleaners in exempted areas.

In all other areas, the "Basic PPE" is the minimum requirement allowed. The Department Manager must authorize any additional exemptions.

If required to delineate the PPE free zones a site map must be completed showing all PPE free zones in yellow hashed markings.

Staff and workers must ensure compliance with Company ***HSMS Corporate Safety Standard: Personal Protective Equipment (PPE)***.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

12.0 WHMIS/TDG & Chemical Management

12.1 General

Hazardous or toxic goods shall be identified with warning labels including, without limitation, in accordance with “WHMIS” (Workplace Hazardous Materials Information System) and “TDG” (Transportation of Dangerous Goods Control Act and Regulations).

A current chemical inventory list and up-to date Safety Data Sheets (SDS) shall be maintained at project sites for all products to be used for the work.

12.2 Employee Information and Training

The following section describes the methods, practices and policies incorporated by the Company to assure appropriate training of employees.

- At the employee's initial assignment.
- Whenever a new potential safety or health hazard is introduced into the workplace.
- Upon employee reassignment to a new area. (This should include temporary assignments.)
- Annual refreshers reviews shall be conducted at Toolbox Meetings.

12.3 Chemical Management

The Company shall:

1) Have a list or inventory of all chemicals being brought to the job site, with up-to-date Safety Data Sheets (SDS). The chemical inventory will contain:
   a) the name of the material
   b) the amount used and stored (e.g., per month, per year or whatever is convenient
   c) where the material is used and stored
2) Have an up-to-date written emergency response plan, which outlines actions to be taken by the contracting employees in the event of a leak, spill, fire, or explosion. Contracting employees must have been properly trained in spill response and control procedures and if expected to respond to a "dangerous goods occurrence", receive Transportation of Dangerous Goods (TDG) training once every three (3) years.
3) Ensure that chemical containers (drums/totes) are labelled as to content, in good condition and impermeable to the chemicals they contain. Noncompatible chemicals are to be segregated. All applicable safety marks, labeling, placarding, and documentation are used.
4) Be in constant attendance when loading/unloading a storage tank.
5) Ensure that valves and nozzles are locked in the closed position when not engaged.
6) Have all required licenses to purchase, store or use a chemical and comply with all chemical storage and chemical waste regulations.

Staff and workers must ensure compliance with Company ***HSMS Corporate Safety Standard: WHMIS***.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

13.0 Waste Management and Environmental Protection

The Municipal Group of Companies (MGOC) has developed a comprehensive Environmental Management Plan to be used as a resource by construction operations to ensure that company activities are carried out in accordance with applicable environmental requirements. The EMP contains information regarding Planning, Implementation, Operational Control and Emergency Response, and Performance Evaluation.

MGOC identifies environmental concerns and hazards that may take place on projects and provides accountability through procedures and guidelines for its personnel to take on all project tasks.

The Environmental Operating Procedures (EOPs) that MGOC has developed are guidelines used to identify relative legal requirements, environmental concerns, and site personnel responsibilities in addition to environmental mitigation measures. MGOC has developed EOPs for Waste Management, Erosion and Sediment Control, and Spill Response and Reporting.

13.1 Spill Response

Preliminary Actions

- Know where the spill kit is stored
- Be aware of all materials being used at the worksite (e.g., oils, cleaners etc.) and make sure Safety Data Sheets are available for the products.
- PPE and spill kits should be suitable for substances and quantity in use.
- Be aware of site drains and sewers at the workplace - store and use hazardous products as far away from these areas as possible.
- Inspect the condition of chemical containers, drums, totes etc., transferring the material to a new container if necessary.
- Ensure level controls, alarms and/or standby backup pumps are in working condition.
- Develop and maintain procedures to respond to a spill and instruct employees in these procedures.

Response and Reporting

- In the event of a chemical spill, the Safety Data Sheet (SDS) must be consulted. Safe handling procedures, instructions in case of fire, health hazard ratings and summarized spill response procedures are listed on all SDS sheets. The SDS sheet must be made available to the Health and Safety Site Representative.
- Contain/clean spill immediately
- If a spill occurs from a piece of equipment, shut down equipment immediately
- Report spill to supervisor/ Dexter representative
- Once spill has been cleaned, all contents shall be put into sealable 45-gallon metal drums with the Name of the supervisor, the date generated, and the contents labeled on the drum. The drums will then be removed from site and dropped off at the Municipal Group of Companies' Maintenance Division where an Environmental Service Provider will be called to take contents of drums and dispose of the contents properly.
- Complete incident investigation and report; provide it to the appropriate personnel.

The following proactive measures will be adopted to prevent the likelihood of spill event:

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- Training of construction staff and subcontractors regarding proper methods for transporting, transferring, and handling substances that have the potential to impact human health or the environment.
- Preventative program including inspection and maintenance schedules to confirm and maintain the mechanical integrity and operability of equipment.
- Implementation of Standard Operation Procedures (SOPs) for handling materials including refuelling vehicles, the use of diesel tanks, the use and handling of processing chemicals, and managing secondary containment areas.
- Fuel will be purchased locally and immediately transferred to vehicles onsite using a fuel pump. Any fuel stored on site are to be kept on a concrete area with secondary containment or an area prepared with impervious chemical resistant material
- Provision of secondary containment, drip trays or other overflow and drop containment measures, for hazardous materials containers at connection points or other overflow points. Identification and provision of all equipment necessary to handle, transfer or transport materials properly.
- Use of transfer equipment that is compatible with and suitable for the characteristics of the materials transferred and designed to ensure safe transfer.
- Use of dripless hose connections for vehicle tank and fixed connections with storage tanks.
- Review of all potential pollutants' characteristics prior to introduction to site and establishment of proper storage, handling and transportation procedures and spill risk analysis.
- Material Safety Data Sheets (MSDS) for all contaminants on-site will be readily available. These will include human health effects of chemicals handled and will be included in the required chemical environmental and safety training for all employees handling or otherwise exposed to the contaminants. All appropriate personal protective equipment, handling and response procedures will also be identified in the MSDS or otherwise recommended by the suppliers/manufacturers and will be followed by the Project staff.
- Bulk transfers of chemicals during delivery will be observed by personnel to identify preliminary hazard analysis methods.
- SOPs for chemical transportation, unloading, transfer, storage if required, handling, use and disposal shall be developed, kept current, effectively implemented.

All personnel on the work site and assigned to the project will be responsible for implementation with the Project Manager and Environmental Manager providing coordination of efforts. A report will be generated by Dexter and disseminated to relevant parties including the DEPP.

Emergency Contacts:

MGOC Environmental Director

Jamie Burns Phone: 902-237-6654
Email: jburns@municipalgroup.ca

When contact is made with the above individuals, report the following information:

- Location of Spill

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- Source of Spill
- Time of Spill
- Volume of Spill
- Potential Hazard of Spill
- Has the spill been contained?
- Has the spill material reached a body of water?
- Responsible party's name, address, telephone, official to contact, etc.
- Weather conditions at the spill site

13.2 Waste Disposal

All waste/garbage generated all projects will be deposited in appropriate bins or removed from site by Dexter.

- Restore the job site and any lands affected by it, to an acceptable condition, free of all waste, debris, and hazardous materials, including empty containers (e.g., drums, cans), leftover construction material and packaging.
- No residuals or contaminated water is to be allowed into if any, site water treatment plants or sewer systems. Liquid industrial waste cannot be dumped down a sink or sewer.
- Segregate any waste generated from a job and identify as either hazardous, liquid, industrial or non-hazardous.
- Waste containers are labelled as to content. The containers must be in good condition and impermeable to the waste it is receiving. The lid will be kept closed unless adding more of the same waste.
- Shipping documents, labelling, and placarding requirements are complied with according to legislation.
- Fires and burning of waste or materials is not permitted on site.
- Burying of rubbish waste or materials is not permitted on site.
- No disposal of waste or volatile materials including but not limited to mineral spirits, oil, petroleum-based lubricants, or toxic cleaning solutions into watercourses, storm, or sanitary sewers.
- Oily rags, waste products, empty containers, and materials subject to spontaneous combustion shall be stored in ULC accepted, sealed containers and shall be removed from site on a daily basis.
- Flammable and combustible materials shall be handled, stored, used, and disposed of in accordance with applicable regulations and Fire Codes.

13.3 Construction/Demolition Material and Debris

1) Measures will be taken to prevent materials such as fresh concrete, cement, concrete debris, and construction debris from entering any watercourse.
2) Construction material will be stored above flood water levels.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

3) All construction debris will be removed/disposed in accordance with Waste Disposal Site Regulations.
4) All wood, garbage and other unwanted refuse must be removed from the site and disposed of at an approved facility.
5) Whenever required (e.g., by regulation, by customer/client, etc.) Dexter shall provide a Certificate of Disposal/Destruction confirming that scrap, treated wood products have been disposed of and/or destroyed in accordance with all applicable laws.

13.4 Site Clearing and Plant Protection

1) Protect trees, plants and foliage on site and adjacent properties where indicated.
2) Protect roots of designated trees to dripline during excavation and site grading to prevent disturbance or damage. Avoid unnecessary traffic, dumping and storage of materials over root zones.
3) Minimize stripping of topsoil and vegetation.

Sparks from power tools, generators, and small vehicles (e.g., ATVs) can cause brush fires. Tools must be equipped with a spark arresting muffler.

A crew member must be assigned to act as a fire watch when required. Fire watch shall remain in effect for at least 30 minutes after completion of hot work.

An appropriate quantity of fire extinguishers must be maintained at the work area. Workers will be trained appropriate use of fire extinguishers.

Any cutting, welding or other hot work creating flame or sparks will require a Dexter Hot Work Permit.

13.5 Work Adjacent to Waterways

1) Do not operate construction equipment in waterways.
2) Do not use waterway beds for borrow material.
3) Do not dump excavated fill, waste material or debris in waterways.
4) Design and construct temporary crossings to minimize erosion to waterways.
5) Do not skid logs or construction materials across waterways.
6) Avoid indicated spawning beds when constructing temporary crossings of waterways.
7) Do not blast under water or within 100 m of indicated spawning beds.

13.6 Dewatering Requirements

Storm sewers shall be kept clear at all times for surface drainage. The flow of water shall not be directed across or over pavements or sidewalks, except through approved pipes or properly designed and constructed methods. To protect against adverse impacts resulting from erosion and sedimentation, surface drainage from dewatering operations shall be intercepted and controlled using properly designed filtering or impoundment methods or both.

13.7 Dust Control

Dexter shall take all reasonable steps to minimize dust emissions. General mitigation techniques include but are not limited to:

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- Wetting roadways and stockpiles
- Water spraying and misting in work areas
- Consolidating wastes in designated storage areas
- Covering material stockpiles
- Minimizing soil disturbance during high winds
- Implementing sediment and erosion controls
- Maintaining good housekeeping practices
- Limiting truck and equipment traffic to designated roadways and routes

13.8 Sediment and Erosion Control

Dexter shall take all reasonable steps to minimize siltation and erosion.

- Projects should be planned and staged to minimize areas of soil disturbance to reduce the potential for erosion.
- Workers and supervisors responsible for sediment and erosion control shall have the necessary training and experience with regards to control measures.
- Sediment and erosion control measures shall be monitored throughout all work shifts and again at the end of the shift
- Contingency supplies of sediment and erosion control should be maintained at the project at all times (e.g., sandbags, hay bales, extra silt fences, etc.)
- Install as needed, silt fences, berms, check dams, swales, ditches, and other controls
- Discharge of diverted water, if required, shall be controlled in such a way to avoid scouring and erosion – installation of flow checks, limits on the rate of discharge, discharge into a prepared location (e.g., a settlement pond)
- Limit stockpiling onsite as much as practical, cover stockpiles as appropriate

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

14.0 Inspections

14.1 General

Workplace safety inspections are required to identify, correct, and control hazards, unsafe conditions, and acts in order to protect persons at or near the workplace from injury or illness. Any unsafe acts or conditions observed during an inspection must be recorded and must include the location of the condition or act observed. Unsafe or harmful conditions or acts found during the course of an inspection shall be communicated and remedied without delay.

Machinery, tools, and equipment shall be inspected in accordance with the manufacturer's recommendations or as otherwise specified by relevant requirements (e.g., client requirements may exceed manufacturer's recommendations for frequency of inspections).

Corrective action must be taken as per the specific target date for any deficiencies noted in the inspection(s). Updates regarding the status of the corrective action must be conveyed to the individual who conducted the inspection on or before the target date. Once the inspection form is completed, the inspector must review the report and its findings with the site supervisor (if available).

Whenever feasible, an inspection must include the participation of members of the JOHSC or the worker health and safety representative.

14.2 Health and Safety Inspections

Document all pertinent information from an inspection within the safety management system software. Below are examples of information that must be captured:

- All positive learning opportunities (i.e., Safe Conditions)[1]
- Any areas for improvement (i.e., At-Risk Conditions)[1], even if the issue was corrected during the inspection[2].
- Assign Action Items for At-Risk conditions identifed3.
- Important conversations
- Pictures to reinforce your messaging.

Note[1]: Safe and At-Risk are defined as:

> **Safe -** *Conditions with little or no danger, almost never resulting in loss (e.g., injury, damage, environmental impact). The known risks are controlled, and everyone observing the action would agree.*
>
> **At-Risk -** *Conditions that could result in loss.*

Note[2]: As mentioned, even if an issue was corrected during a site inspection, it is important the item is still documented At-Risk. This is to ensure accurate tracking can be completed to identify potential trends.

Note[3]: There are two common types of Action Items:

> **Corrective Actions** – Immediate actions taken to prevent additional loss or to correct the condition.
>
> **Preventative Actions** – Long term solutions to prevent recurrence at the workplace or similar areas of operation.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Position	Workplace	Frequency
Senior Management	Operational areas of control	Participate in the inspection process
Manager	Operational areas of control	Conduct 1 inspection weekly
	Facilities	Ensure the completion of 1 inspection monthly
Supervisor	Operational areas of control	Conduct or participate in 1 inspection weekly
	Facilities	Conduct or participate in 1 inspection monthly
Employees	Operational areas	Participate in the inspection process
	Facilities	Participate in the inspection process
Joint Occupational Health and Safety Committee	Operational areas	Conduct or Participate in the inspections as per their terms of reference
	Facilities	Conduct or Participate in the inspections as per their terms of reference

Other factors should also be considered when scheduling and performing inspections and could increase the inspection frequency requirements, such as:

- Past incident records or inspection trends
- Type of work processes (e.g., high-risk activities)
- New processes or machinery
- Legislative requirements
- Client Requirements

After each inspection, it must be reviewed with the supervisor and other applicable parties.

All subcontractor activities shall be included in the inspection process.

14.3 Equipment and Vehicle Inspections

Prior to use by an operator, all company equipment and vehicles must be inspected using applicable pre-use inspection forms. These inspections are required to ensure the safety and operability requirements are met.

Copies of inspections that are completed by employees or supervisors are to be submitted to the maintenance department for follow up on deficiencies noted as per the operations process. Repairs required on equipment or vehicles (identified during formal inspections or otherwise) should be carried out by the employee responsible for the equipment or vehicle whenever reasonable (e.g., changing oil or topping off fluid levels). Repairs beyond the capability of the employee must be reported through the maintenance department. The maintenance department will be responsible for acquiring parts and completing repairs (e.g., new tires, engine repairs, etc.). If the operation does not have a maintenance department, report through your supervisor. Equipment and light duty vehicles may also go to a 3rd party maintenance vendor.

These equipment and vehicle inspections are to identify any substandard acts or conditions for all job factors that could harm employees, damage property or cause production loss. All inspection findings and corrective measures will be documented and prioritized based on the level of risk.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

15.0 Emergency Preparedness and Response

15.1 Purpose

A site-specific emergency response plan will be developed and communicated to all workers on the site. The plan will contain all appropriate actions, required contact numbers, proper notification protocol and muster station locations. In compliance with applicable regulatory requirements, each worksite shall have the adequate number of personnel trained in emergency preparedness, first aid, and use of a fire extinguisher. In addition, all personnel shall be familiar with the site-specific orientation and emergency response plan. If required, these personnel will assist with the coordination and arrival of emergency services to the site. Copies of this plan will be distributed to appropriate parties; and all personnel that visit the site shall be made aware of this procedure through a new-hire and site-specific orientation.

If an emergency situation arises at any MGOC work site, the *Incident Notification Process* must be followed.

15.2 Emergency Planning

Assessing Risk: First, all potential emergencies must be evaluated to determine the level of planning required based on risk. If high-risk work is being conducted, additional planning will be required including training, development of specific rescue plans, additional emergency equipment, and/or additional resources.

Training: The Company Employees receive emergency response awareness training at hiring, including Fire Awareness and WHMIS. Additional training is required based on each employee's occupation risk assessments of the workplace.

Specific Training: This will include education on the ERPs for specific areas, locations of emergency response equipment, and emergency contact information. Also, employees must be aware of any duties they may be required to perform during an emergency. The required number of first aid trained employees must be available as per provincial and federal legislation. Employees required to use any specialty emergency response equipment must be trained in its use.

Job-Specific Requirements: Written plans must be developed for high-risk tasks (e.g., fall protection, confined space).

Muster Point: Designated muster area(s) for gathering employees in the event of an evacuation. It is recommended that the muster point be located near or at the main entrance to sites and facilities and signage posted to identify the location to employees and visitors.

Communication: The ERP must be communicated to employees that will be impacted. The plan must be posted along with emergency phone numbers. For fixed facilities, floor plans must be posted on each floor and emergency exit clearly marked.

Testing: ERPs must be tested, reviewed, and a mock drill completed as required.

Emergency Coordinator(s): At fixed facilities, Emergency Coordinators must be chosen from various areas of the facility. They will be responsible for aiding in an evacuation situation, clearing the area they are responsible for, and performing a head count of employees at the Muster Point.

Types of Emergencies

Fire: In the event of a fire, employees must evacuate the area immediately. If employees are trained and confident that the fire is small enough to contain, employees can extinguish the fire with available and appropriate portable extinguishers however the employee must call for assistance (e.g., supervisor,

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

emergency services) prior to attempting to fight any fire themselves. If the fire is too large to extinguish, Emergency Services 911 or other Emergency call-in line must be notified immediately.

Medical: If an employee is injured, an assessment can be made by a trained First Aider to determine the extent of the injuries. If an injury is minor, first aid should be administered and reported as required. If first aid treatment is insufficient, Emergency services 911 or other Emergency call-in line must be notified for assistance.

Transportation to a Medical Facility: If the severity of the injury is not life threatening, it is possible to transport the injured employee to a medical facility by means of a work vehicle. This requires both a driver as well as a trained first aider. If the injury were to worsen in transit, the first aider could treat the employee accordingly. Transportation to initial medical treatment, including the associated costs, is an obligation of the employer.

Accident (Vehicle, Property, Equipment): If involved in an accident and the situation is immediately dangerous to life and health, call Emergency services 911 or other Emergency call-in line immediately. Commercial vehicles should deploy warning triangles, if possible, to increase visibility of the situation to the travelling public.

Third Party Accidents: If involved in an accident with a third party and the situation is immediately dangerous to life and health, call Emergency services 911 or other Emergency call-in line immediately. Cooperate with authorities and gather information at the scene (e.g., insurance information, driver's license, contact information) and provide the information to the Supervisor. It is important to allow the investigation to find the cause of the incident—NEVER admit fault at an incident scene.

Spills: In the event of a spill, employees must deploy a spill kit and make every attempt to prevent the spilled material from entering waterways (e.g., drains, manholes, ditches). In the case of a fluid spill, employees should use absorbent materials to collect as much of the fluid as possible. If the spill is too large to contain, then cleanup may require external resources. Spills may have to be reported to the local Department of Environment based on provincial/federal legislation. All regulatory reportable spills must be communicated to the Director of Remediation and Environmental Services.

Violence: In the event of a threat of violence against an employee or the Municipal Group of Companies, the Human Resources Department shall be consulted in accordance with MGOC's Workplace Violence Prevention Policy (MGOC HR Policies and Procedures).

15.3 Project Emergency Meeting Point(s)

TBD (or Site Supervisor work vehicle)

15.4 Nearest Medical Facility

Dartmouth General Hospital

325 Pleasant St, Dartmouth NS

15.5 First Aid

All supervisor vehicles as well as service vehicles are equipped with the appropriate sized first aid kits as per the applicable provincial First Aid Regulations. A sufficient number of employees, appropriate for the number of persons working at each job site, will be trained in First Aid as per the applicable regulations.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

First Aid Kits, eye wash and fire extinguishers are located (Mark X if available)***:***

Location	FA Kits	Eye Wash	Fire Extinguisher
Supervisor vehicle / trailer	YES	YES	YES

Employees onsite certified in Emergency First Aid:

Employee Name	Contact #	Expiry
TBD		

NOTE: Provide a clearly marked and fully stocked first aid case and equipment in a readily available location(s) as per applicable requirements.

15.6 Project Emergency Contact Information

Dexter Project Manager

TBD Phone:
Email:

Dexter Project Coordinator

TBD Phone:
Email:

Dexter Superintendent

TBD Phone:
Email:

Dexter Foreman

TBD Phone:
Email:

Dexter Site Safety Representative

TBD Phone:
Email:

NSPI Project Manager

TBD Phone:
Email:

NSPI Project Coordinator

TBD Phone:
Email:

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

NSPI Safety Manager

TBD Phone:
Email:

Contact Numbers for Utilities

Bell Aliant: 1-888-214-7896

Eastlink: 1-888-345-1111

Eastward Energy: 1-866-313-3030 (previously Heritage Gas)

Halifax Water: 902-420-9287

Nova Scotia Power: 1-877-428-6004

Rogers: 1-888-764-3771

Emergency Authorities Contacts		
Organization	**Location**	**Phone Number**
Police	Nova Scotia	911
Ambulance	Nova Scotia	911
Fire Department	Nova Scotia	911
Poison Control	Nova Scotia	1-800-565-8161
Department of Environment	Nova Scotia	1-800-565-1633
Department of Transportation	Nova Scotia	1-902-424-2297
NS Dept of Labour	Nova Scotia	1-800-952-2687
WCB	Nova Scotia	1-800-870-3331
Federal Labour		902-424-4311
Canutec		1-888-226-8832

15.7 Fire Protection and Prevention

Where the Hazard Assessment process determines there is the potential for an explosive atmosphere to be created in a location, the area must be classified as Hazardous or Non-Hazardous in accordance with the applicable electrical code.

Where a hazardous location is in a work area, the boundaries of the hazardous location must be:

- Clearly identified to warn of the nature of the hazards associated with the presence of the flammable substance in that work area, or
- Fenced off to prevent employees or equipment from entering the area without authorization.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Where volatile flammable substances, gases, or vapours are present, or where they can arise out of materials and equipment used or from the work process, all existing or potential sources of ignition shall be controlled or eliminated. Equipment used in a hazardous area must be of a type that will not ignite any flammable substances (i.e., intrinsically safe).

One of the most common causes of an unwanted fire is poor housekeeping, such as from accumulations of trash and other waste materials in locations where there is an ignition source. Some basic rules can help to prevent this from occurring:

- Suitable containers must be provided for waste materials, and these containers must be regularly emptied, and their contents properly disposed of.
- Paints, thinners, oil, and grease must be stored in well-ventilated areas or properly constructed fire cabinets well away from ignition sources, and flammable liquids must be kept in approved containers and only handled in safe areas.
- Oily or paint-soaked rags must be placed in metal containers with lids that are kept closed.
- Mops as well as wiping and cleaning rags must not be placed near engine exhausts or other sources of ignition.
- Flammable liquids should not be used as a manual cleaning solvent unless a thorough review finds that a non-flammable substitute is unavailable.
- Hydrocarbons must be stored a safe distance from other chemicals with which they could react (e.g., strong oxidizers).
- Volatile or flammable substances, gases, or vapours (where present or possible) should be controlled by ventilation to the outside or to a scrubber.

Besides housekeeping, there are a number of other potential causes of fire employees should be familiar with:

- Never try and locate gas leaks with an open flame. Buildings where gasoline or other flammable or combustible liquids are handled must be well ventilated. Use a soapy water mixture with a paint brush and look for the formation of bubbles to identify the leak location.
- Rubber or plastic hoses must not be used to connect gas-fired appliances (properly installed Bunsen burners and propane torches exempted).
- Before an open flame (such as a welding torch) is used in a potentially hazardous area, a combustible gas test must be performed, and the area declared safe in accordance with The Company HSMS CSS Welding and Cutting and The Company HSMS CSS Monitoring and Detection Equipment - Care and Use.
- "No Smoking" signs must be observed. Matches of the non-safety type are not permitted on The Company property. Smoking is only permitted in designated smoking areas.
- Electrical devices will not be tested, repaired, or assembled in any building or area where gas or combustible vapours might be present.
- Only explosion-proof electrical devices (switches, motors, lights, etc.) are permitted in classified areas.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Decontamination

If a flammable or combustible liquid is spilled on an employee's clothing, the employee must avoid activity where a spark could be created and must stay away from any place where there could be an open flame. The employee should remove the clothing immediately and clean it thoroughly before it is used again.

If the employee's skin has been exposed, the employee should wash their skin as soon as possible.

Storage of Flammable Substances

Storage of flammable substances should be kept to the smallest amount practicable and should never be in a sufficient quantity to produce an explosive atmosphere if accidentally released.

Never store flammables near the air intake of ventilation supply system; an internal combustion engine; or the fire box of a fire heater or furnace.

Portable containers used to store flammables should be approved to CSA Standard B376-M1980 (2008), Portable Containers for Gasoline and Other Petroleum Fuels.

Lower Explosive Limit (LEL)

In building or worksites that are indoors and where flammables are stored or processed, LEL detection is required. No person will work in an area where there is the presence of a flammable or explosive substance at 20% or more of the LEL.

Fuelling

Never fill a tank on a heating device, machine, or vehicle while the device, machine, or vehicle is in operation. Never refill a tank on a heating device or machine while the device or machine is hot enough to ignite the liquid.

Employees must not use gasoline or other fuels as cleaning agents.

Electrical Grounding

Grounding occurs when there is an electrical connection between a container and the earth. Grounding drains away static electricity. The following are rules for safe grounding:

- Grounding shall be in accordance with Provincial/State regulations.
- Frames of all electrical machines must be grounded.
- Storage tanks, pumps, and electrical equipment must be grounded.
- All service switch boxes, motors, and conduit systems must be grounded.

Bonding

Bonding is when there is an electrical connection between two or more conductive containers, ensuring that the containers have the same electrical charge and thus preventing a spark jumping from one container to the next.

Liquid Transfers

Containers used to transfer flammable liquids must be bonded and grounded during the transfer. This includes any transfer to or from a truck tank to a receiving tank, between two truck tanks, or between to

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

tanks. Bonding or grounding must also be performed for the filling or discharging of flammable liquids from a container. Containers must be CSA/ANSI approved.

Staff and workers must ensure compliance with Company ***HSMS Corporate Safety Standard: Fire Protection***.

15.8 Emergency Equipment

Fire Extinguishers: There must be portable fire extinguishers available at each facility and field site, as well as inside all MGOC vehicles. Fire extinguishers are required to be inspected monthly (internally) as well as annually by an external provider. Fire extinguishers must be of adequate size and class based on sources of ignition, location, and operations. There are five classes of fire extinguishers, and each can put out a different type of fire:

Class of Fire	Type of Fire	Type of Extinguisher	Extinguisher Identification	Symbol
A	Ordinary combustibles: wood, paper, rubber, fabrics, and many plastics	Water, Dry Powder, Halon		
B	Flammable Liquids and Gases: gasoline, oils, paint, lacquer, and tar	Carbon Dioxide, Dry Powder Halon		
C	Fires involving Live Electrical Equipment	Carbon Dioxide, Dry Powder Halon		
D	Combustible Metals or Combustible Metal Alloys	Special Agents		
K	Fires in Cooking Appliances that involve Combustible Cooking Media: Vegetable or Animal Oils and Fats			

Figure 1

First Aid Kits: First aid kits are required to be available at MGOC fixed facilities, field sites, and in all company vehicles. The number of employees at the location will determine the size and size of first aid kit needed. It must be easily assessable, and everyone should know where to find it. The first aid kit must be kept stocked as per provincial/federal legislation. If a workplace incident results in injuries which requires the use of supplies from a first aid kit, the incident must be reported and recorded as per provincial/federal regulations.

Location and accessibility of supplies and attendant shall be:

a) Accessible during all working hours; and

b) Where not required to be in a first aid room, located at the worksite.

To the extent reasonably practicable, the location of first aid supplies and the location or phone number of the first aid attendant shall be posted throughout the worksite on signs that can easily be seen by all persons at the worksite.

Staff shall be trained in accordance with applicable 1st Aid Regulations. Where a full-time worker is employed in any type of employment that regularly requires the worker to work where there is no one available who could administer first aid or summon assistance within a reasonable length of time, the Company shall ensure that at least one worker on each shift holds a valid emergency first aid certificate. The Company shall ensure in accordance with applicable regulations the appropriate number of workers hold a valid first aid training and certification.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Eye Wash Stations/Showers: Eye was stations or showers must be available when there is a hazard to the eyes and face. Eyewash stations are available at MGOC fixed facilities and field sites. Stand-alone/combination systems are most frequently used at fixed facilities, and portable systems are used most frequently at field sites.

Spill Kits: Size and type of spill kits required will be determined by the type and amount of fluid that could potentially spill. The Municipal Group of Companies requires spill kits at field sites, fixed facilities, and in all MGOC commercial vehicles working on field sites and/or carrying portable fuel tanks. Additional considerations may be needed based on site characteristics such as working near waterways.

Confined Space/Fall Protection: When work will be completed at heights or inside of confined spaces, additional emergency equipment will be required.

Warning Triangles: Are required to be inside company commercial vehicles and employees must check for them during the pre-trip inspections.

Emergency lighting: Can be found over emergency exits and must be tested periodically to ensure anyone can see the way out in case of an emergency.

15.9 Communication

Communication during an emergency is vital to emergency response time. The time it takes to evacuate and/or for assistance to arrive can affect the outcome of the emergency. Devices play a significant role as they are the notification system to warn employees of an emergency.

Fixed facilities: Have an installed alarm system to warn employees of an emergency and to evacuate the building. Direct lines and cell phones are commonly available and used to notify emergency services 911 or other Emergency call in-line.

Field sites: Air horns are used warn employees of an emergency and to evacuate to the muster point. Cell phone & two-way radios are commonly available and used to notify emergency services 911 or other Emergency call in-line. Remote field sites use cell phone boosters, satellite radios and/or identifying the nearest location with cell phone reception.

Commercial vehicles: May be equipped with radios (e.g., two-way radio, CB), cell phones, or other means of communication.

15.10 Emergency Contact

Emergency Contacts: Emergency contact list should include names and contact information of First aid providers and Managers/Supervisors. Emergency contact lists must be posted where possible in prominent areas or available on site to ensure they are easily assessable and/or visible.

Directions to nearest medical facility: Must be communicated to employees working at both fixed facilities and field sites.

Full physical address of the fixed facility or field site.

The following sample document is completed for each project, communicated to workers (e.g., via Toolbox Meeting) which are then posted and/or readily available onsite:

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

First Aid Kits, stretcher, blankets, eye wash and fire extinguishers are located (Mark X if available)*:*

Location	FA Kits	Stretcher & Blankets	Eye Wash	Fire Extinguisher

Workers onsite certified in First Aid:

Worker Name	Contact #	Expiry

Key Phone Numbers:

Project Manager: TBD	Cell No:
Superintendent: TBD	Cell No:
Safety Department	Tel No: **902-835-3381**
NS EMO	Tel No: **902-424-5620**
Police, Fire, Ambulance	Tel No: **911**
Name and Location of nearest Hospital[1]	[1]See below for contact info throughout Nova Scotia
Dexter Construction Company Ltd	Tel No: **902-835-3381** Fax No: **902-835-7300**

15.11 Evacuation

In an event of an evacuation, employees must leave the area immediately and report to the nearest Muster Point and check in with the Emergency Coordinator. Employees must remain at the muster point until cleared by the Supervisor and/or emergency services.

Muster Points: Fixed facilities will have permanent muster points and identified by signage. Site trailers and/or Company vehicles are commonly used Muster points on field sites. Any changes to muster points should be communicated during daily huddles.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

16.0 Incident Notification, Reporting & Investigation

16.1 Incident Notification and Reporting

Notification and reporting are not the same thing.

Notification is immediate and requires acknowledgement from two parties (e.g., a telephone call, face to face conversation or acknowledged text message). Notification ensures appropriate actions taken (e.g., secure scene), appropriate parties are made aware, and required resources are available/brought.

Reporting is the act of capturing the details of an incident for the purposes of investigating and documenting for future reference or is used to verify that an event resulting in loss did not happen at the workplace.

Incident Notification Process

Incident - *An unplanned event, sequence of events and/or conditions that results in unintended harm or loss such as injury, illness, disease, damage, or loss whereby the workplace, or a workplace activity, was a significant factor.*

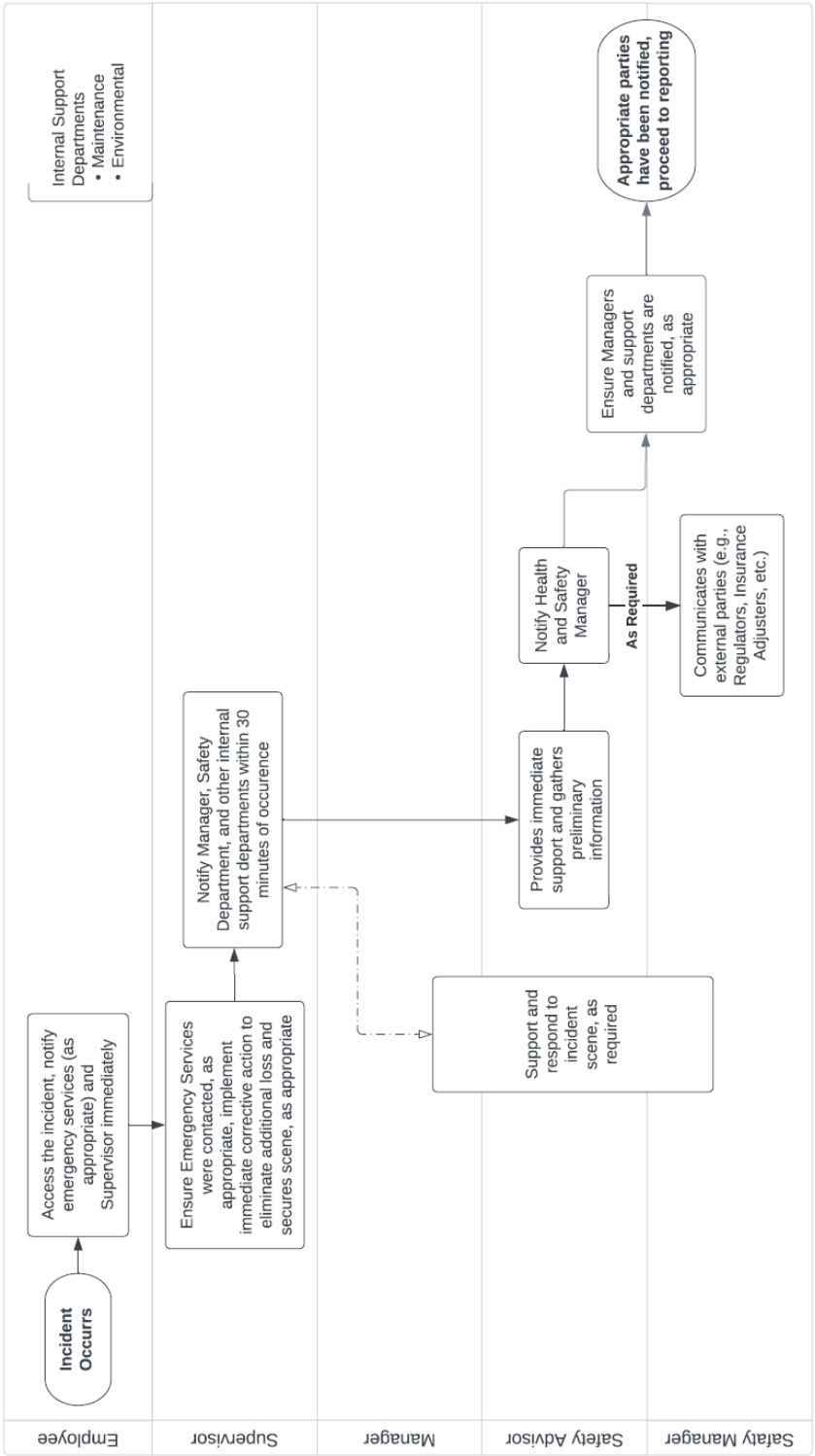
Incident Notification

When a Dexter employee, contractor, or sub-contractor's employee has an incident including any of the following, a notification shall be sent to the Supervisor, Safety as well as the NSP Contract Manager or Site Representative:

- Injuries (First Aid, Medical Aid, Restricted Work Injury, Lost Time Injury)
- Vehicle, Property, or Equipment Damage
- Environmental Incident
- Security

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

This flow chart is meant for internal purposes however it is to be noted that contacting the NSPI Contract Manager or Site Representative is to be done immediately.



All notifications must be direct verbal communication or acknowledged text.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Regulatory Notification Requirements

Scene of Incident

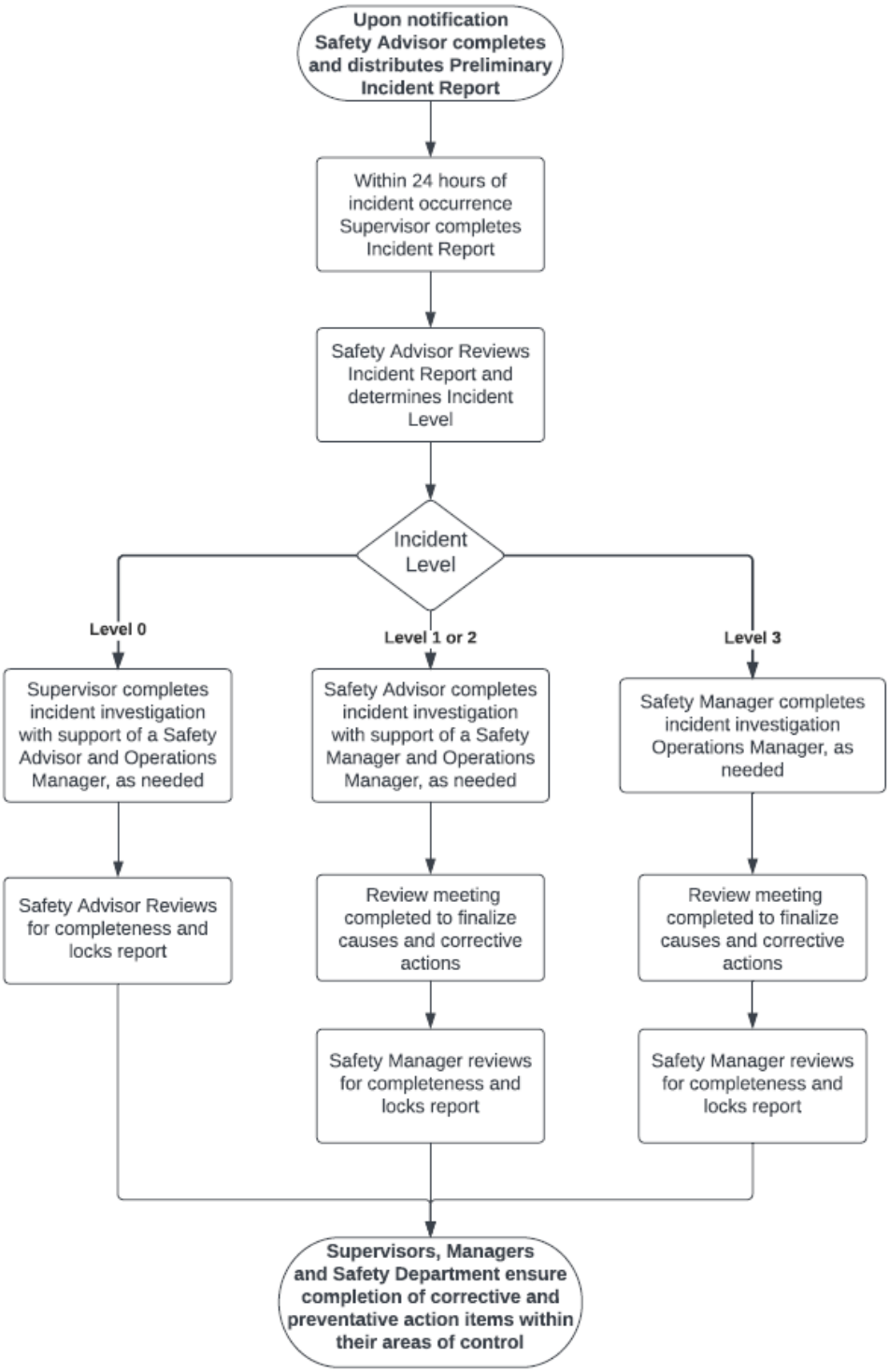
If an incident requires notification of a regulatory agency, except as otherwise directed by a Regulator, no person shall disturb the scene of an incident except as is necessary to:

- Attend injured persons or fatalities
- Prevent further injuries; or
- Protect property that is endangered as a result of the incident

If uncertain about any potential disturbance to the scene of the accident (except as required for emergency medical/rescue) please contact the Safety Department.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Incident Reporting Process



This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

The **Incident Severity Levels Criteria Table** below is used to aid in determination of Level 0, 1, 2, 3 incidents.

Level	Injuries	Vehicle / Equipment / Property Damage:	Environment
0	**Injuries, which include First Aid Injury** (e.g., one time treatment and subsequent observation of minor injuries) & non-treatment injury**.**	Less than $10,000	**On-site spill/emission** less than the regulatory reporting requirements
1	**Workplace Injuries (MTI, RWI),** medical treatment beyond first aid (i.e., application of sutures, removal of foreign body from a wound, muscle/ligament separation/tears, sprains and bruising resulting in restricted or modified duty).	At least $10,000 but not exceeding $50,000	**On-site/Off-site spill/Emission/ Public or Regulatory Complaint** requiring regulatory reporting.
2	**Workplace Injuries (LTI)**, of a more serious nature, requiring prescribed days away from work, or meets criteria for regulatory reporting.)	Greater than $50,000 but not exceeding $200,000	**On-site/Off-site spill/Emission/ Public or Regulatory Complaint** requiring regulatory reporting and third-party clean up.
3	**Critical Injuries, Permanently Disabling, or Fatality** ***Critical Injuries***: • Life in jeopardy • Unconsciousness • Substantial loss of blood • Fractures (excluding fingers and toes) • Amputation • Burns to sizable portion of the body • Loss of sight in an eye	Greater than $200,000	**Off-site spill/Emission/ Public or Regulatory Complaint external agencies notified** and involved. Incident results in significant adverse effect to the public or environment.

High Potential Incidents

All incidents will be ranked using the Risk Matrix to determine potential additional loss beyond the actual result of the incident. Any incident ranked 'A' or 'B' will be classified as 'high potential.' The ranking must consider both the lack of established controls as well as any failures regarding the execution of established controls.

Assignment of this additional classification is over-and-above the initial incident level (i.e., 0, 1, 2, or 3) selected.

Any Level 0 incident deemed 'high potential' will be upgraded to a Level 1 incident.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

16.2 Near Misses

Near Miss Severity

Near Misses are broken down into two severity levels: Red and Green. Identifying the severity level will determine how to proceed with the report.

Red	Green
STOP WORK & REPORT ☐	CONTINUE & REPORT ☐

Red (Stop Work and Report) (High Potential)

A Near Miss classified as Red is one that could have potentially caused a fatality, severe injury, and/or major property damage (e.g., a trench cave-in near the work area). In such cases work must be stopped, and the supervisor must be notified immediately. The applicable work must not resume until proper controls have been implemented. A Near Miss Report including an investigation into its cause must be entered into the safety management system software within 24 hours of occurrence.

Note: The Safety Department must be notified of all Red Near Misses using the same process specified earlier in this section of HSMS Part One, under the heading: Incident Notification Process.

Green (Continue and Report)

A Near Miss classified as Green is one that could have potentially caused minor injury and/or property damage (e.g., an employee slips while getting off an excavator). In such cases work may continue, and the employee must notify their supervisor of the near miss by the end of the scheduled shift. The applicable work must be evaluated to ensure all hazards have been identified and all necessary controls have been implemented. A Near Miss Report must be entered into the safety management system software within 24 hours of occurrence.

Submitting Near Miss Reports

Near Miss Reports will be documented and submitted using the safety management system software. This software also provides a mechanism to assign and document action items.

16.3 Incident Investigation and Corrective Action

An incident investigation will ensure that appropriate corrective actions are identified and completed in an effective and timely manner and help reduce the likelihood of similar incidents occurring in the future.

A properly conducted investigation will identify the incident causes (root and direct) and will apply pertinent corrective actions to reduce the likelihood of reoccurrence. Additional benefits include:

- Improving employee morale
- Improving workplace safety standards
- Improving attitudes towards health and safety in the workplace
- Complying with legal requirements
- Complying with insurance requirements
- Providing information to assist in legal proceedings, evidence to support a defence in enforcement action or where is civil claim is being sought
- Preventing future business losses

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Responding to an Incident

If an incident occurs, it is very important to respond promptly to reduce the risk of further loss – this must become the priority.

Preventing further injury and protecting property that may be endangered because of the incident, must be considered. Administer first aid as required and contact applicable emergency services (e.g., 911) if needed.

The incident scene should be preserved, and disturbance of any physical evidence should be prevented until after the incident investigation is completed. Unless necessary to prevent further injury or damage, clean-up or repair activities should commence only after all pertinent information has been collected.

Third-Party Involvement

If an incident occurs involving a third-party person, vehicle or mobile equipment, or other property, it is important to consider the following:

- Avoid confrontations
- Do not assign or admit fault
- Gather their information (e.g., name, contact number/email, etc.)
- If a motor vehicle is involved, gather driver's license and insurance policy information
- Ask if they would agree to provide a statement

Systematic Cause Analysis Techniques (SCAT)

Dexter uses the DNV SCAT Investigation tool for investigations.

SCAT is used to investigate the cause of loss events (incidents). It is used to accurately identify the corrective actions necessary to prevent similar events happening in the future.

After identifying the type of event (incident), SCAT systematically examines the applicable direct/immediate causes as related to basic/root causes to identify gaps or deficiencies (e.g., inadequate work practices, lack of training) and determine appropriate corrective actions.

Investigation Reports

Investigation reports must be prepared using the established corporate report format to ensure consistency. All efforts should be made to use the Incident Investigation Form on the safety management system software; however, a copy of the form is also available electronically on the Safety SharePoint Site. Paper Copies of the report must eventually be transferred to the safety management system software.

Where it is impractical to complete an investigation report within seven days due to extenuating circumstances, the investigation team must attempt to bring closure to the investigation as soon as possible.

Corrective Actions

All investigated incidents must have corrective actions determined based on the investigation and any identified root causes. Action items will be assigned to an individual and have a due date for completion.

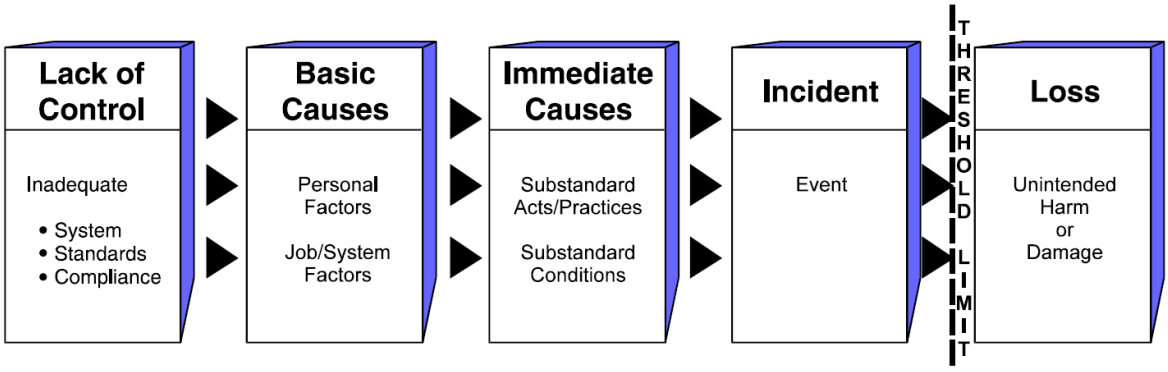
An Incident Investigation cannot be considered closed until all applicable action items have been completed.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Incident Investigation Review Meetings

Confirmation of investigation review completion (including participation of all applicable parties) is documented on the HSMS Incident Investigation Report on the company's safety management system software.

DNV Loss Causation Model



16.4 NSPI Incident Reporting Requirements

- The NSPI Contract Manager / Site Representative shall be notified immediately of all incidents, regardless of severity.
- Initial reports are to be provided to NSPI within 24 hours.
- Completed reports for minor incidents are required to be received by NSPI within 48 – 72 hours or sooner.
- Completed reports for major incidents are required to be received by NSPI in a time set by NSPI after initial report review.
- Where applicable, the final report shall be forwarded to the Department of Labour and Advanced Education and WCB.
- In the event of a severe injury or fatality, the priority is to care for casualties and prevent further injuries.
- The NSPI Contract Manager / Site Representative will follow the notification process as outlined in SWP 03, *Incident Response*.
- Responsibility for notification of next of kin of the injured contract employee or Sub-contractor lies with the Contractor Supervisor (or designate).
- All environmental incidents shall be reported to the NSPI Contract Manager / Site Representative immediately for appropriate action.
- The following incident types may be considered major incidents dependent on the initial investigation:
    - Personal Injury

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- Electrical Contact
- Property Damage
- Vehicle Incidents
- High Potential

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

17.0 Project HSE Records & Communication

17.1 General Project Requirements

Project specific HSE related documents/records that are to be retained for the duration of a project and kept accessible will include at least the following (as applicable):

- Daily Huddle Meetings
- Toolbox Talks
- Inspection reports
- Investigation reports
- Hazard Assessments
- Employee training records
- JOHSC Minutes
- Regulatory Agency inspection reports and/or orders/administrative penalty documentation
- Emergency contact information

17.2 Types of Communication

Health and Safety Communications are distributed via a variety of methods, depending on the type of communication. These methods include:

- Written Standard Operating Procedures (SOPs), documents and controlled/formatted templates
- Email
- Postings (e.g., “Safety Boards”)
- Intranet Site (SharePoint)
- Safety Management System Software (i.e., eCompliance)
- Meetings (e.g., Daily Huddles, Toolbox – for distribution and discussion of health and safety initiatives, policies, procedures)
- Safety Interactions (see Section 6.3 for specific information)
- Hazard/risk analysis and assessments (e.g., comprehensive hazard assessments, job hazard assessments, personal field level hazard assessments as described in Section 2.0 Hazard and Risk Assessment)
- Hazard Alerts, Memos, WIN Toolbox Topics (see Section 6.2 for specific information)
- Joint Occupational Health and Safety Committee (JOHSC) meetings and minutes
- Training Programs & Electronic Training Management System (TMS)
- Signage (e.g., to indicate presence of specific hazards, PPE requirements, equipment traffic)

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Postings ("Safety Boards")

Postings shall include at minimum:

- The Health and Safety Policy
- Current names of the Joint Occupational Health and Safety Committee (JOHSC) members or the Health and Safety Representation and the means of contacting them
- Minutes from the most recent JOHSC Meeting
- The name of the workplace first-aid attendant (including a means for contacting them) and the location of first aid supplies/AED
- Emergency contact numbers and/or site Emergency Response Plan (ERP)
- Address, muster stations, location of exits
- A current copy of the Occupational Health and Safety Act/Regulations
- A current phone number for the applicable Provincial/Federal Department of Labour
- Any order and compliance notice issued by the Department of Labour (in accordance with local regulatory posting requirements)
- The individual or group (e.g., the JOHSC) responsible for updating the Safety Board

The following additional postings should be considered and included, as applicable:

- Life Saving Commitments
- Health and Safety Department First Point of Contact List
- Safety Key Performance Indicator (KPIs)
- Incident Notification Process
- Incident Summaries
- Hazard Alerts, WIN Toolbox Meetings, Memos, and Bulletins
- Annual Safety Improvement Plan
- Letters of Good Standing /Certificates
- Site maps

On the project site the Safety Board contents will be within a Safety Binder available in the site supervisor's truck. The site supervisor is responsible for ensuring this binder is maintained and up to date. Where it is not practicable to erect a Safety Board the Site Supervisor will make available the required information to any employee upon request.

It is recognized that there are several job sites that are managed from a company vehicle and the printing and posting of information is not practical. Supervisors and Managers shall have access to the following to ensure that the information is accessible when requested:

- Provincial Occupational Health and Safety Act and pursuant regulations
- SharePoint

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

- Safety Management System Software (eCompliance)
- Training Management System (TMS) – BISTRAINER

Safety Management System Software (eCompliance)

This platform is used to provide access and the ability to submit the most current versions of various reports (e.g., Incident, Near Miss, Hazard Identification) and meeting forms (e.g., Toolbox, JOHSC, Daily Huddles), and utilize hazard/risk assessment tools and templates, and health and safety communications (e.g., memos, Hazard Alerts).

Meetings

Effective meetings help:

- Ensure roles and directions are understood.
- Reduce unsafe practices.
- Promote emergency response plans.
- Communicate known hazards, associated risk, and controls.
- Learn about hazards encountered by employees.

Dexter uses two main types of Safety Meetings to communicate key safety messages:

- Daily Huddle
- Toolbox Meeting

Safety Meeting Responsibilities

Manager

- Ensure Safety Meetings are completed as per the required frequency within their specific areas of responsibility.
- Periodically participate in Safety Meetings.
- Periodically audit and review Safety Meeting minutes.

Supervisor

- Conduct/facilitate Safety Meetings within their specific areas of responsibility as per the required frequency.
- Engage employees during Safety Meetings and encourage active participation from all employees.
- Document the Safety Meeting minutes on the appropriate form using the company safety management system software.

Employees

- Participate in Safety Meetings.
- Cooperate with any persons conducting a Safety Meeting.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

17.3 Daily Huddle Meetings

The purpose of this meeting is to provide a forum to discuss the following information daily:

Successes and Opportunities from the previous shift. Learning from past successes and failures is a terrific way to proactively move forward and continually improve.

The plan, targets, and objectives for the current shift. Having an entire crew unified and working towards the same goal is extremely important to maintain a safe and effective workplace.

Life Saving Commitments. Every employee must know the Life Saving Commitments that apply to their work and understand how to react to and control the associated hazards.

Hazards, risks, and controls associated with the plan, targets, and objectives. Knowing how to protect yourself and your co-workers is vital to ensure we leave our workplace in the same condition in which we arrived.

Emergency Response. All employees on site must know the site-specific emergency response plan. This will ensure everyone knows how to react in the event of an emergency (e.g., who is the first aid attendant, where are the emergency supplies, where is the muster station and where is the nearest medical facility).

Daily Huddle meetings must be completed prior to the start of **every** new shift, at minimum. Daily Huddle meetings should also be completed at each project location if you are working at multiple project locations with varying hazards, risks, and controls.

17.4 Toolbox Meetings

A Toolbox Meeting is a safety meeting that focuses on safety topics related to the specific job, such as workplace hazards and safe work practices. It is a very effective method to refresh employees' knowledge, share important safety communications, and exchange information with our diverse teams of employees. Toolbox Meetings are also intended to facilitate health and safety discussions on the job site and promote the organization's safety culture.

Toolbox Meetings must be completed on a **weekly** basis, at minimum. Some clients may require additional be conducted; the most stringent requirement will always be upheld.

17.5 Joint Occupational Health and Safety Committee (JOHSC) Minutes

The JOSHC shall operate as per local regulatory requirements, including the distribution of meeting minutes to all applicable parties.

17.6 Reporting to External and Regulatory Parties

Prior to reporting to any external party or regulatory (e.g., provincial, federal) authority, the Health and Safety Department must be consulted. The Health and Safety Department will file the report or provide appropriate guidance.

17.7 Other Types of HS Communication

Hazard Alert

Hazard Alerts are used to communicate and share information when the Health and Safety Department and Operations identify significant incidents, near misses, trends, and best practices/corrective actions that may

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

impact multiple groups. This is intended to eliminate the possibility of reoccurrence at all MGOC workplaces with similar processes and/or equipment.

Memos

Health and Safety Memos are used for distributing general Health and Safety related information such as manufacturer recalls, upcoming events, and revisions to the Health and Safety Management system.

WIN Toolbox Talks

A *WIN* Toolbox Talk is a safety meeting document that focuses on a specific safety topic related to a specific job, such as workplace hazards and safe work practices.

The *WIN (What? Impact? Next?)* model is an approach used for providing effective feedback to positively change behaviors, actions, and outcomes. It is used to establish clear expectations and provide ongoing understanding of performance to foster improvement in the future.

WHAT? An opening statement clearly describing a current behavior, action, or outcome that has been identified and requires modification (change).

IMPACT? A statement clearly describing the effect (the impact) that the current behavior, action, or outcome has on an individual, other persons, work processes, and other results.

NEXT? A closing statement clearly requesting (or directing) a new, specific behavior, action, or outcome for the future.

17.8 Safety Interaction

The Municipal Group of Companies' *Safety Interaction* document is used to capture a conversation or meeting conducted with any employee or contractor to provide guidance or praise towards their Health and Safety ownership.

The *Safety Interaction* form is a versatile tool that can be used to capture and record the details of several types of interactions, including:

- Documenting work instructions to ensure they are fully explained and clear to the employee (e.g., Reviewing an SOP).
- Documenting learning opportunities and coaching/mentoring with an employee (e.g., coaching an employee regarding the workplace safety inspection processes and proper completion of an inspection report form, performance of duties and better ways to accomplish a task).
- Recognizing an employee's positive contributions to the organization as it pertains to Health and Safety (e.g., submission of a Hazard ID or Near Miss to the supervisor).

In addition to capturing discussion points, a *Safety Interaction* can be used to formally document any prescribed necessary actions and indicate whether further follow-up is required.

When follow-up is indicated, the form instructs the facilitator to create and assign an Action Item, stating the following:

- Description of required action
- Person(s) responsible for completing the action
- Date by when the action must be completed

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

A *Safety Interaction* must be factual and not judgmental, as it is intended to describe the conversation or events as they occur; it is not intended to be used as a platform for the opinions, beliefs, and thoughts of the person facilitating the meeting.

All efforts should be made to use the *Safety Interaction* document on the organization's safety management system software; however, a copy of the form is also available electronically on the Safety SharePoint site. Copies can be printed and provided to staff and employees that do not have access to the safety management system software. Hard copies of the form must be submitted to the Safety Department for entry onto the safety management system software.

NOTE: The *Safety Interaction* is not to be used as a method of documenting disciplinary action.

17.9 Project Joint Occupational Health, Safety Committee (or Rep)

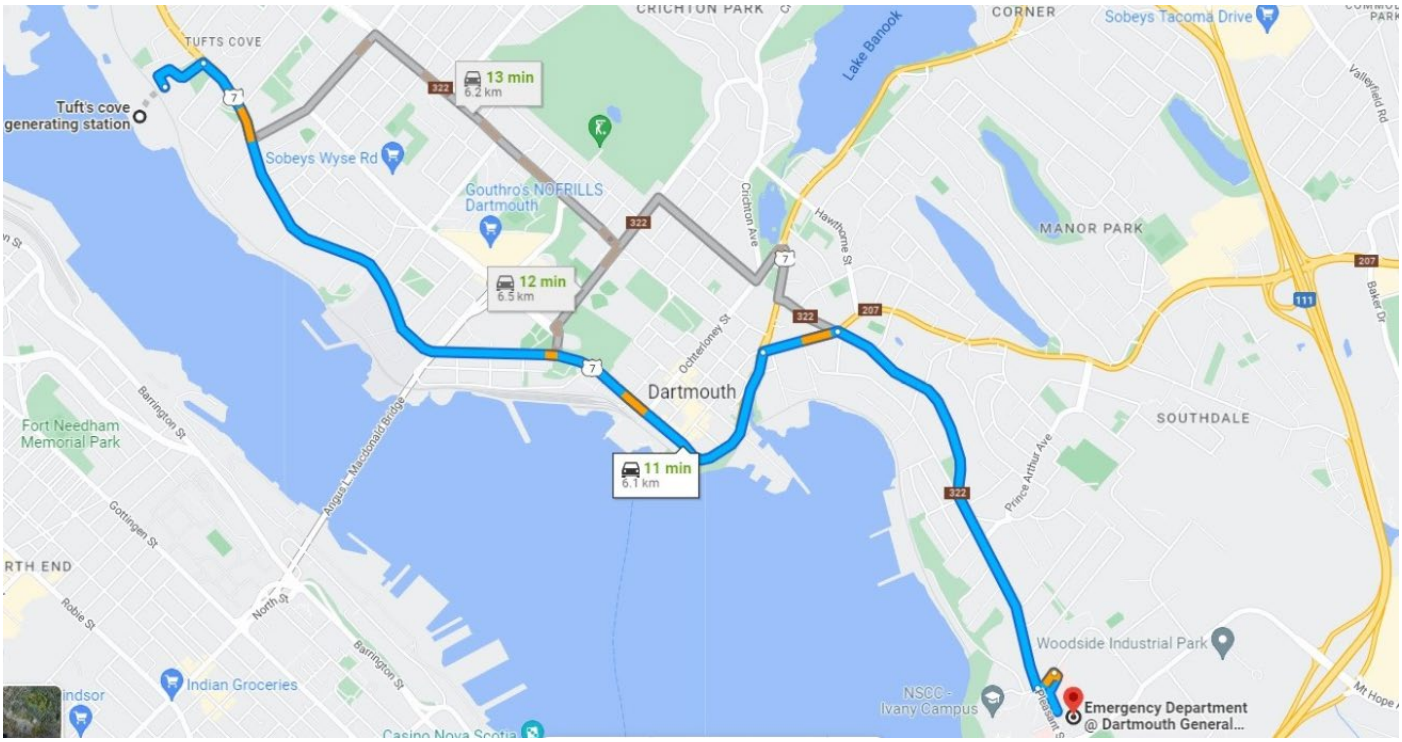
As required and determined by the needs of specific projects; Site-Specific JOHSCs shall be implemented, and/or a designated safety representative selected from the workers, as per the requirements of applicable occupational health and safety acts and pursuant regulations.

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Appendix A – Emergency Route to Nearest Medical Facility

To: Dartmouth General Hospital – 322 Pleasant St, Dartmouth, NS

From (Project Site): Tufts Cove Generating Station – 315 Windmill Rd, Dartmouth, NS



1. Head northwest toward Windmill Rd/Nova Scotia Trunk 7 (East)
2. Turn Right onto Windmill Rd/Nova Scotia Trunk 7 (East) – continue to follow 3.4 km
3. Turn right onto Marine Dr/Portland St/NS-207 (East) – continue to follow for 300 m
4. Turn right onto Pleasant St – 1.8 km
5. Turn left onto Acadia St – 98 m
6. Turn right – 180 m

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Appendix B – Corporate Safety Standards Index

Health & Safety Management System – Corporate Safety Standards

- CHEMICAL and BIOLOGICAL HANDLING CODES OF PRACTICE: SILICA
- FALL PROTECTION / WORKING FROM HEIGHTS / LADDERS
- FIRE PROTECTION
- FIT FOR DUTY
- GUARDING
- HAND and POWER TOOLS
- HEARING CONSERVATION and NOISE ASSESSMENT
- HOT WORK
- HOUSEKEEPING REQUIREMENTS
- LOAD SECUREMENT
- LOCKOUT / TAGOUT
- MANUAL MATERIALS HANDLING and ERGONOMICS
- MOBILE and HEAVY EQUIPMENT GENERAL SAFETY
- OVERHEAD and UNDERGROUND UTILITIES
- PERSONAL PROTECTIVE EQUIPMENT (PPE)
- RESPIRATORY PROTECTION
- RIGGING, HOISTING and LIFTING
- SAFE DRIVING (Commercial, Light Duty, and Heavy Equipment)
- SAFE SEPARATION
- SAFE WORK PLANNING
- SAFETY OVERRIDE PROTECTION DEVICES
- TRAFFIC CONTROL
- TRANSPORTATION OF DANGEROUS GOODS (TDG)
- WEATHER EXTREMES (HEAT and COLD STRESS)
- WELDING and CUTTING
- WORKPLACE HAZARDOUS MATERIALS INFORMATION SYSTEM (WHMIS 2015)

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Appendix C – Daily Huddle Form (Example)

HSMS - Daily Huddle

eCompliance

Id:
Organization: M - Company
Site:
Job Number:
Superintendent :

Location:
Prepared by:
Date:
Supervisor (e.g. Foreman/Signer):

1 Site Orientation and Emergency Response

1.1 Is this the first day on the project or are there any new employees present?
(●) Yes ( ) No

If answer is Yes
1.1a Name and Contact Information of the Site Supervisor and JOHSC/Safety Rep.

1.1b Site Address

1.1c Location of Muster Station and First Aid Supplies

1.1d Applicable PPE required for the project

1.1e In addition to the questions above, the Site Supervisor must review SOPs for the tasks being completed with all employees, as appropriate.

2 Review of Previous and Current Shift

2.1 Were there positive or constructive learning opportunities from the previous shift?
( ) Yes ( ) No

If answer is Yes
2.1a Document discussion and learning opportunities.

2.2 Were there any incidents or near misses in the previous shift?
( ) Yes ( ) No

If answer is Yes
2.2a Document discussion and learning opportunities.

2.3 Was there an inspection completed on site in the previous shift?
( ) Yes ( ) No

Page 1 of 3

eCompliance

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

If answer is Yes
2.3a Review report findings and corrective actions

2.4 What is the plan and goal for the current shift?

3 Hazard Assessment

3.1 Was a specific Project Hazard Assessment available and reviewed with employees?
○ Yes ○ No

3.2 Project Hazard Assessment
☐ Read acknowledgment

3.3 Comprehensive Hazard Assessment
☐ Read acknowledgment

3.4 Are there tasks being completed that are not captured on the hazard assessment?
○ Yes ○ No

If answer is Yes
3.4a What is the task?

3.4b What are the associated hazards?

3.4c What are the controls?

3.4d Additional Comments

3.4e The Project Team must be notified to update the Project Hazard Assessment

3.5 Are there additional hazards associated with the planned tasks or project location, not captured on the hazard assessment?
○ Yes ○ No

If answer is Yes
3.5a What are the hazards?

3.5b What are the controls?

3.5c Additional Comments

3.5d The Project Team must be notified to update the Project Hazard Assessment

eCompliance

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

3.6 Are all controls available and implemented as per the Hazard Assessment?

○ Yes ○ No

If answer is No

3.6a Why?

3.6b What controls are being implemented?

3.6c Additional Comments

3.6d The Project Team must be notified to update the Project Hazard Assessment

4 Additional Comments

4.1 Additional Comments

5 Participant Acknowledgement

5.1 The Supervisor completing this form is required to enter (type) the names of the meeting participant(s) in the section below (workers do not need to sign individually). This can be completed by starting to type the person's last name and then clicking on the appropriate name from the drop-down list that then appears on the screen. Once the desired name is selected, it should be displayed in a blue text box. Names that are entered incorrectly will appear in a grey text box. If you are trying to enter a name and it does not appear in the drop-down list, please contact the Safety Department and the person will be added to the system.

5.2 Participant Name(s)

5.3 By completing and signing this form, I acknowledge that the name(s) of participant(s) on this form were present on such day that this form was completed.

5.4 Supervisor acknowledgement and Sign-off

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Appendix D – NSPI Hazard Analysis

Nova Scotia POWER An Emera Company — Contractor Safety Management Program - Appendix B – NSPI Hazard Analysis — Page 2 of 5

Work Scope:	Install Rock Revetment and Intake Extension	Date:		TBD
Contractor:	TBD	CM/SR:		SR: Gavin McInnis
Hazard	**Controls**	**NSPI**	**CONT**	**Additional Comments**
General	Prepare Job Safety Analyses (JSA)	C	A	Contractor required to prepare a comprehensive job safety plan, provide all employee qualifications, PPE, etc. Contractor must provide an emergency response plan and rescue plan if employees are working near water, or are working from heights. Contractor is responsible for all subcontractors they bring on an NSPI site. All contractor employees, subcontractors, or visitors are required to complete NSPI orientations prior to accessing site.
	Verify Worker Training and Qualifications	C	A	
	Personal Protective Equipment	C	A	
	Complete Notice of Project (if required)	C	A	
	Emergency Response Plan	C	A	
	Rescue Plans	C	A	
	Subcontractor Management	C	A	
	Orientations	A	A	
Electrical	Energization of Equipment	NA	NA	NSPI will provide and hold all applicable lockout permits. NSPI is able to provide temporary power for contractor activities. Needs must be communicated in advance.
	Permits (Control of Hazardous Energy)	A	C	
	Standard Protection Code Permit (SPC)	NA	NA	
	Intrinsically Safe Equipment	C	A	
	Ground Fault Circuit Interrupter	C	A	
	Grounding and Bonding Requirements	C	A	
	Temporary Power Supply Needs	A	C	
	Line Stringing plan and equipment inspections	NA	NA	
	Line truck inspections and daily pre-use inspections	NA	NA	
	Chainsaw safety	NA	NA	
	Equipment Approval and Certification	C	A	
Hazardous Materials	Transportation of Dangerous Goods	C	A	Contractor responsible for any hazardous substances brought onto site.
	WHMIS / GHS Training	C	A	
	SDS available on site	C	A	
	Workplace Supplier Labels	C	A	
	Safe Storage, Handling and Disposal	C	A	
Industrial Hygiene	Asbestos Management and Exposure Control	NA	NA	Exposure to hazardous substances in not anticipated. Contractor responsible for any air quality or atmospheric testing if applicable. Contractor to provide employees with any hearing protection/respiratory PPE if needed.
	Lead Management and Exposure Control	NA	NA	
	Silica Measurement and Exposure Control	NA	NA	
	Air Quality Test Results	C	A	
	Atmospheric Testing	C	A	
	Treated Poles	NA	NA	
	Excess Noise and Hearing Protection	C	A	
	Respiratory Protection	C	A	
	Specialized Tools and Equipment	C	A	
Cranes and Rigging	Crane Certification	C	A	
	Equipment Pre-use Inspection	C	A	

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

	Written Lift Plan	C	A	Contractor fully responsible for any cranes and lifts done on NSPI site. If applicable, NSPI is able to provide safe clearance reports for proximity to overhead lines; This is not anticipated for the work area.
	Safe Clearance Report (Power lines)	A	C	
	Qualified Workers	C	A	
	Engineering lift plan and drawing	C	A	
Trenching and Excavation	Daily Excavation Inspection	C	A	Contractor responsible for any excavation precautions. NSPI can provide drawings of any buried services. It is advised that the contractor complete locates for any land based excavations.
	Shoring and Sloping (Trench Cage)	C	A	
	Underground Utility / Service Locates	A	A	
	Exit and Entry from Excavation	C	A	
Hot Work	Fire Watch	A	A	Any hotwork on an NSPI site requires continuous firewatch, including 1 hour after hot work completion. NSPI, in most circumstances, can provide a fire watch person.
	Hot Work Permit	A	A	
	Written Safe Work Procedure	C	A	
Lockout, uncontrolled energy	Written Work Procedure	A	C	NSPI responsible for providing and holding and lockout/tagout permits. NSPI responsible for communicating and reviewing these permits with the contractor. Contractor shall not start work until the white copy of the permit is reviewed and signed by all personnel involved.
	Thermal Lockout Practice / Permit Holder	A	C	
	Hydro Lockout Practice / Permit Holder	NA	NA	
	Standard Protection Code / Permit Holder	NA	NA	
	Communication	A	A	
Mobile Equipment	Traffic Control Plan	C	A	Contractor is required to work with NSPI if access to any parts of the site are restricted. Traffic control is likely not required on NSPI property. Contractor responsible for any towing/boating activities.
	Qualified Traffic Control Personnel	NA	NA	
	Towing/Transporting Materials and Equipment	C	A	
	ATV/Snowmobile safety	NA	NA	
	Using helicopter or boats to transport people or materials and equipment	C	A	
Confined Space	Confined Space Entry Permit	A	C	NSPI to provide any confined space permits if confined space work is occurring on NSPI property. If confined space work is being completed, all employees entering the confined space require training within the Atlantic Provinces. NSPI can support rescue and a rescue procedure if work is taking place on an NSPI property.
	Qualified Workers	C	A	
	Atmospheric Testing	C	A	
	Rescue Plan	A	A	
Work at Heights	Fall Protection and Fall Arrest	C	A	When working above 10' fall protection is required. All employees requiring fall protection must have valid training within the Atlantic Provinces. All scaffolding to be provided and inspected daily by NSPI.
	Anchor points identified and certified	C	A	
	Scaffold Inspected and Tagged	A	C	
	Guardrails	C	A	
	Secure Tools and Material from Falling	C	A	
Physical	Thermal Stress Prevention	C	A	Contractor required to monitor for thermal stress and adverse weather. Contractor responsible for keeping the worksite tidy.
	Housekeeping	C	A	
	Adverse Weather Precautions	C	A	
	Check-in Procedure for Working Alone	NA	NA	
	Work in Remote Locations	NA	NA	
Work In, On or Around Water	Dive Plan Approved	C	A	Contractor responsible for providing NSPI with detailed diving plans.
	Water Level Flow Information Communicated	A	A	
	Boating Safety Precautions	C	A	

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

	Boating Contractor Approval	A	A
	Qualified Workers	C	A

NSPI Specific Procedures Required for the Scope of Work:

NSPI Working Near Water JSA
NSPI SWPs:
SWP 01 – Deviation from a Safe Work Practice (SWP)
SWP 02 – Hours of Work
SWP 03 – Incident Response
SWP 05 – Post Incident Review
SWP 10 – Risk Assessments
SWP 12 – Thermal Stress
SWP 13 – Tobacco-Smoke-Vapour Free Workplace
SWP 15 – General Facility Safety
SWP 16 – Inspection of Hoists/Rigging/Fall Arrest Equipment
SWP 17 – Fall Protection
SWP 18 – Material Storing, Handling and Disposal
SWP 20 – Confined Space Entry Practices
SWP 21 – Excavation Practice
SWP 25 – Tools and Associated Equipment
SWP 27 – Work at, above or below floor levels
SWP 28 – Personal Protective Equipment
SWP 40 – General Mechanical Practices

Accountable (A), Consulted (C) or Not Applicable (NA)

The following is an extension of the Job Hazard Analysis for environmental considerations. Complete for applicable environmental risks and other life cycle perspectives for consideration in the Contract – place an "x" in each risk area to state whether it's Applicable or Not Applicable.

Risk Category	Risk Area	Applicable	Not Applicable	Additional Comments
Regulatory / Legal	Operating Approval conditions	✓		
	Construction Approval(s)	✓		
	Municipal By-laws	✓		
	Regulation under NS Environment Act	✓		
	Regulation under Canadian Environmental Protection Act	✓		
	Other:			
Company Reputation; Customer / Stakeholder Relationship	Media Interest	✓		
	Public Interest	✓		
	Stakeholders	✓		
	Community Organization	✓		
	Special Interest Group		✓	
	Non-Government Organization (NGO)		✓	
	Other:			
Releases (Air, Land, Water)	Fugitive Dust	✓		
	Chemicals/Fuel	✓		
	Oil and/or PCBs	✓		
	Refrigerant, Compressed Gas or Combustion Gas		✓	
	Treated Wood		✓	
	Hazardous Waste Materials	✓		
	Noise/Blasting	✓		
	Other:			
Land/Aquatic (habitat, species) impacts	Bird Nests/Migratory Birds		✓	
	Species at Risk Habitat	✓		
	Water Management	✓		
	Wildlife Habitat Destruction	✓		
	Wetland or Watercourse Alterations or Instream Work	✓		
	Water Quality (e.g., sedimentation)	✓		
	Erosion & Sediment Control	✓		
	Other			

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Natural, Cultural, Historical, Archaeological resources	Archaeological High Potential		✓	
	Historical Site/Structure		✓	
	Cultural Site		✓	
	Indigenous Traditional Use Area	✓		
	Natural Resource Extraction (minerals, fossil fuels, biomass, etc.)		✓	
	Raw Material Consumption (e.g., water)		✓	
Life cycle considerations that can be controlled to manage environmental impacts	Raw Material Consumption (e.g., water)		✓	
	Raw material acquisition		✓	
	Design		✓	
	Production		✓	
	Transportation/ Delivery		✓	
	Use		✓	
	End-of-life treatment		✓	
	Final Disposal	✓		

NSPI Contract Manager	[redacted]	Date:	
Contractor Representative	[redacted]	Date:	

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever and must not be passed on to any third party without written authority from The Municipal Group of Companies.

Appendix C

Provincial OHS Profile

DEXTER CONSTRUCTION COMPANY LIMITED

Provincial OHS Profile (Nova Scotia)

1.0 Summary of OHS Activity

Year	Inspections	Compliance Orders	Stop Work Orders
2025	12	7	1
2024	5	2	0
2023	10	18	1

2.0 Summary of OHS Orders

2025: 7 Orders as follows:

- Occupational Health & Safety Act 13-1(c) Employers' precautions and duties
- Occupational Health & Safety Act 55-2 Power to require reports, assessments and tests
- Occupational Health & Safety Act 55-4 Orders and consequences of orders (includes 1 Stop Work)
- Occupational Health & Safety Act 47 Powers of officers
- Workplace Health & Safety Regulations 1.7(1) Compliance with policies, procedures, plans, or codes of practice
- Workplace Health & Safety Regulations 1.7(3) A person must comply with all written policies, procedures, plans and codes of practice established for the purposes of the Act and these regulations, including undergoing any training required
- Blasting Safety Regulations 65-1 Flying material

2024: 2 Orders as follows:

- Occupational Health & Safety Act 47 Powers of officers (2)

2023: 18 Orders as follows:

- Occupational Health & Safety Act 47 Powers of officers (5)
- Occupational Health & Safety Act 52 Power to require reports, assessments, and tests (3)
- Occupational Health & Safety Act 55-4 Orders and consequences of orders (3)
- Occupational Safety General Regulations 7-1 Compliance with policies, procedures, plans, and codes of practice (1)
- Occupational Safety General Regulations 7A-1 Communicating and updating policies, procedures, plans, and codes of practice (1)
- Occupational Safety General Regulations 157-1 Demolition (1)
- Occupational Safety General Regulations 169-4 Excavations and trenches (1)
- Blasting Safety Regulations 65-1 Flying material (3)

This document is the property of The Municipal Group of Companies. This document must not be copied or reproduced in any way whatsoever, and must not be passed on to any third party without written authority from The Municipal Group of Companies

Appendix D

Environmental Directive

NOVA SCOTIA
Environment and Climate Change

30 Damascus Road, Suite 115
Bedford, N.S.B4A 0C1

Phone: (902) 424-7773
Fax: (902) 424-0597

Process RSN Number: 16354694

INSPECTION REPORT
Compliance Update

ISSUED TO:	Dexter Construction Company Limited c/o Jamie Burns
INSPECTION DATE:	February 16, 2023
MAILING ADDRESS:	927 ROCKY LAKE DRIVE, P.O. BOX 48100 HALIFAX, NS B4A 3Z2
SITE NAME:	Stillwater Brook-The Puddle- Highway 103 bridge near Queensland- Siltation
SITE ADDRESS:	NS

OVERVIEW OF INSPECTION

The Directive sent to Dexter Construction Company Limited (Dexter) dated August 6, 2021, and updated on December 15, 2022, will be closed. Third party monitoring, inspections, recommendations, and reporting will no longer be required by Nova Scotia Environment and Climate Change.□
□
□
As the site continues to release sediment laden water to watercourses, a new Directive will be issued and included with an inspection report dated January 23, 2023.

This inspection report was prepared on February 16, 2023 by Anthony Heggelin, Environment Officer with Nova Scotia Department of Environment and Climate Change who may be contacted at:

Nova Scotia Department of Environment and Climate Change
30 Damascus Road, Suite 115
Bedford, N.S. B4A 0C1
Phone:(902) 424-7773
Fax: (902) 424-0597
https://novascotia.ca/nse

NOVA SCOTIA
Environment and Climate Change

30 Damascus Road, Suite 115
Bedford, N.S.B4A 0C1

Phone: (902) 424-7773
Fax: (902) 424-0597

Process RSN Number: 16263749

INSPECTION REPORT

ISSUED TO:	Dexter Construction Company Limited c/o Jamie Burns
INSPECTION DATE:	January 23, 2023
MAILING ADDRESS:	927 ROCKY LAKE DRIVE, P.O. BOX 48100 HALIFAX, NS B4A 3Z2
SITE NAME:	Stillwater Brook-The Puddle- Highway 103 bridge near Queensland- Siltation
SITE ADDRESS:	NS

OVERVIEW OF INSPECTION

On January 23, 2023, Environment and Climate Change (ECC)inspector Anthony Heggelin conducted an inspection at Stillwater Brook, Highway 103, near Queensland, NS.□

□

The site consists of many properties owned by the Province of Nova Scotia, managed by Department of Public Works (DPW), and one property owned by Municipal Enterprises Limited (MEL). The highway twinning section and an access road are owned by the Province. The quarry, weigh station, soil storage areas, and roads associated with these are on land owned by (MEL). Dexter Construction Company Limited (Dexter) has been conducting construction activities on all of the properties since March 2021. NSECC received a letter from Jamie Burns (Dexter) on January 24, 2023, dated January 19, 2023, stating Dexter had "achieved substantial completion of the ground works" on the properties managed by DPW. □

□

All properties continue to release sediment laden water to Stillwater Brook and the unnamed brook. NSECC considers Dexter as a "responsible person" for the site. □

□

Inspector Heggelin arrived at the site at 12:30 PM, it was raining. Sediment laden water in the ditch in between the original 103 and the new 103 (ditch 1), the ditch in between the new 103 and the access road (ditch 2), and the ditch above the access road (ditch 3), was gushing by all three pumps. There was one pump in each ditch. □

□

Ditch 1 runs directly into Stillwater Brook and drains the DPW property. Ditch 2 drains the DPW property, stops approximately 10 meters before Stillwater Brook and runs over cleared but not grubbed ground directly into Stillwater Brook. Ditch 3 drains the Municipal property, stops and runs over cleared but not grubbed land into ditch 2. □

□

Inspector Heggelin took a clean sample approximately 80 meters up Stillwater Brook from the new bridge. A sediment laden sample was taken approximately 50 meters up Stillwater Brook from the new bridge, a few meters below where ditch 2 and 3 enter the Brook. A sediment laden sample was taken directly below the outlet culverts of the original highway 103, just before the Puddle.□

□

The small unnamed brook toward the north of the site (Municipal property) was sediment laden. This was viewed from the bridge at the quarry road. The new aggregate storage pile, near the back side of it, closest the unnamed brook, was observed. Water could be seen exiting the base of the aggregate pile and it was heavily sediment laden by the time it hit the unnamed brook. A low wet area at the base of the storage pile, in between the weigh scales and the quarry road bridge, was sediment laden as well. This drains into the unnamed brook.

Took pictures.

The samples were refrigerated at Inspector Heggelin's home until they were dropped at the lab on January 25.

Sample results are as follows: Background 6 mg/l TSS, silt laden above the bridge 530 mg/l TSS, silt laden below the old bridge, 540 mg/l TSS.

Please see the attached Directive

COMPLIANCE ITEMS

In order to ensure compliance with the Environment Act and Regulations, the following items must be addressed:

Item # *Environment Act 67(2)*

No person shall release or permit the release into the environment of a substance in an amount, concentration or level or at a rate of release that causes or may cause an adverse effect, unless authorized by an approval or the regulations.

In order to comply with this section you must:

Please see attached Directive

Item # must be complied with by April 21, 2023

This inspection report was prepared on February 16, 2023 by Anthony Heggelin, Environment Officer with Nova Scotia Department of Environment and Climate Change who may be contacted at:

Nova Scotia Department of Environment and Climate Change
30 Damascus Road, Suite 115
Bedford, N.S. B4A 0C1
Phone:(902) 424-7773
Fax: (902) 424-0597
https://novascotia.ca/nse

NOVA SCOTIA
Environment and Climate Change

30 Damascus Road, Suite 115
Bedford, N.S.B4A 0C1

Phone: (902) 424-7773
Fax: (902) 424-0597

Process RSN Number: 16263749

Environment Act
DIRECTIVE

ISSUED TO:	Dexter Construction Company Limited c/o Jamie Burns
DATE ISSUED:	February 16, 2023
MAILING ADDRESS:	927 ROCKY LAKE DRIVE, P.O. BOX 48100 HALIFAX, NS B4A 3Z2
SITE NAME:	Stillwater Brook-The Puddle- Highway 103 bridge near Queensland-Siltation
SITE ADDRESS:	NS

Pursuant to Environment Act 122A(1) the following action(s) must be completed by April 21, 2023

Effective immediately, take all measures necessary to keep sediment laden water generated from the site, as described in the inspection section, from entering Stillwater Brook or the unnamed brook adjacent the site. This directive will be ongoing until the site consistently does not release sediment laden water during precipitation and thawing events. The comply by date will be adjusted as necessary.

The action(s) outlined in this Directive are the minimum required. Additional actions may be needed to address the non-compliance item(s) identified in this report. Where necessary, you may need to secure the services of a firm/person with sufficient knowledge, experience, and certification to address any item (s) of non-compliance.

Be advised that failing to undertake all action(s) within the time frame specified in this Directive is an offence and may result in further enforcement. An investigation involving the non-compliance item(s) identified in this report continues and is separate from the requirements of this Directive.

This Directive was issued by Anthony Heggelin, Environment Officer with Nova Scotia Department of Environment and Climate Change, who may be contacted at:

Nova Scotia Department of Environment and Climate Change
30 Damascus Road, Suite 115
Bedford, N.S. B4A 0C1
Phone: (902) 424-7773
Fax: (902) 424-0597
https://novascotia.ca/nse

****

Supporting text where applicable:

Prohibition s.67 - (1) No person shall knowingly release or permit the release into the environment of a substance in an amount, concentration or level or at a rate of release that causes or may cause an adverse effect, unless authorized by an approval or the regulations.(2) No person shall release or permit the release into the environment of a substance in an amount, concentration or level or at a rate of release that causes or may cause an adverse effect, unless authorized by an approval or the regulations. Environment Act 1994-95, c. 1

Duty to take remedial measures s.71 - Any person responsible for the release of a substance under this Part shall, at that person's own cost, and as soon as that person knows or ought to have known of the release of a substance into the environment that has caused, is causing or may cause an adverse effect, (a) take all reasonable measures to(i) prevent, reduce and remedy the adverse effects of the substance, and (ii) remove or otherwise dispose of the substance in such a manner as to minimize adverse effects; (b) take any other measures required by an inspector or an administrator; and (c) rehabilitate the environment to a standard prescribed or adopted by the Department. Environment Act 1994-95, c. 1

Assistance to inspectors s.118 - The owner or occupier of any place, or any person the inspector reasonably believes is related to or associated with any activity at the place, in respect of which an inspector is exercising powers or carrying out duties pursuant to this Part shall(a)give the inspector all reasonable assistance to enable the inspector to exercise those powers and carry out those duties(b) furnish all information relative to the exercising of those powers and the carrying out of those duties that the inspector may reasonably require. Environment Act, 1994-95, c.1

Right of entry and inspection s.119 (1) - For the purpose of ensuring compliance with this Act, the regulations, a standard or an order made under Part XIII, an inspector, subject to Sections 22 and 120, may, at any reasonable time, (g) where the inspector believes that any thing may release, is releasing or has released into the environment a substance that may cause, is causing or has caused an adverse effect,(i) require the person having care, management or control of the thing to detain the thing at the place where it is found. Environment Act, 1994-95, c.1

Right of entry and inspection s.119 (1) - For the purpose of ensuring compliance with this Act, the regulations, a standard or an order made under Part XIII, an inspector, subject to Sections 22 and 120, may, at any reasonable time (h) require the production of any documents that are required to be kept pursuant to this Act or any other documents that are related to the purpose for which the inspector is exercising any power under clauses (a) to (g). Environment Act, 1994-95, c.1

Inspector Directives s. 122A (1) - An inspector may issue a directive to a person requiring the person to
(a) take such measures in accordance with clause 71(b) as the inspector may specify;
(b) furnish the inspector with information in accordance with clause 118(b);
(c) detain a thing in accordance with subclause 119(1)(g)(i);
(d) produce a document in accordance with clause 119(1)(h); or
(e) take any action prescribed by the regulations in any circumstance prescribed by the regulations.
(2) A directive is not subject to appeal or review under this Act. Environment Act, 1994-95, c.1

NOVA SCOTIA
Environment

30 Damascus Road, Suite 115
Bedford, N.S.B4A 0C1

Phone: (902) 424-7773
Fax: (902) 424-0597

Process RSN Number: 14537598

INSPECTION REPORT
Compliance Update

ISSUED TO:	Dexter Construction Company Limited c/o Jamie Burns
INSPECTION DATE:	October 07, 2021
MAILING ADDRESS:	927 ROCKY LAKE DRIVE, P.O. BOX 48100 HALIFAX, NS B4A 3Z2
SITE NAME:	Stillwater Brook-The Puddle- Highway 103 bridge near Queensland- Siltation
SITE ADDRESS:	NS

OVERVIEW OF INSPECTION

Dexter/ Design Point submitted a schedule as required by the directive on October 1, 2021.

All recommendations must be implemented. See the Directive.

COMPLIANCE ITEMS

In order to ensure compliance with the Environment Act and Regulations, the following items must be addressed:

Item # 14490076-001 *Environment Act 122A(1)*

An inspector may issue a directive to a person requiring the person to take such measures in accordance with clause 71(b) as the inspector may specify, furnish the inspector with information in accordance with clause 118(b), detain a thing in accordance with subclause 119(1)(g)(i), produce a document in accordance with clause 119(1)(h), or take any action prescribed by the regulations in any circumstance prescribed by the regulations.

In order to comply with this section you must:

Submit a schedule that includes a date of when each of the following issues/ solutions identified at the site will be rectified/ implemented. Most of the following should be rectified by October 8, 2021. If that is not possible, please include justification why.

1) Silt is being released subsurface from the northern pond into a watercourse on the Municipal property. This has to stop immediately. This is unacceptable and needs to be fixed. This needs to be a top priority. (observation 4 from the September 9th visit)

2) Installation of the rain gauge and confirmation that it is working.

3) Entire access road to Stillwater Brook needs to be stabilized (observation 2 from the September 9 visit

and observation 1 in the September 19 visit)

4) Access road to the northern pond needs better stabilization. (observation 5 of the September 9 visit)

5) HYDROSEED all exposed areas that are not going to be further disturbed and are not covered with rock. (recommendation from report 2, recommendation 1 from report 3, and recommendation in report 3)

6) Add rock lining to ditches and road rills to the ditch that is located on the northeast side of the site the runs to the existing large storm pond as well as the rills on the main access road. (recommendation from report 2)

7) Inspection of silt booms before every rain of 15 mm or more. Provide confirmatory statement in schedule.

8) Why has a large area of the disposal pile been exposed? Hydroseed or justify why this cannot be done. (observation 4 of the September 19 visit)

9) All newly exposed soils must be stabilized before the next rain of any amount. Provide confirmatory statement in schedule. (recommendation 1 from report 3).

10) Rock line the access road parallel to Highway 103 that is being used for large off road trucks. Hydroseed the road if it won't continue to be used. (recommendation from report 3).

11) Weekly reports will be submitted on every Monday, Tuesday if there is a holiday (Letter provided by Design Point to Inspector Heggelin on September 21, 2021)

12) A rock lined ditch system was recommended to replace the pond and pump system (Recommendation report 1).

13) There is a large area at the top of the site used to place excess soil and to travel around the site, approximately 100 meters by 100 meters. This needs to stabilized. (Letter provided by Design Point to Inspector Heggelin on September 21, 2021)

Item #14490076-001 was complied with on October 1, 2021

Item # 14490076-002 *Environment Act 67(2)*

No person shall release or permit the release into the environment of a substance in an amount, concentration or level or at a rate of release that causes or may cause an adverse effect, unless authorized by an approval or the regulations.

In order to comply with this section you must:

Comply with the attached Directive

Item #14490076-002 was complied with on October 1, 2021

Item # 14537598-004 *Environment Act 67(2)*

No person shall release or permit the release into the environment of a substance in an amount, concentration or level or at a rate of release that causes or may cause an adverse effect, unless authorized by an approval or the regulations.

In order to comply with this section you must:

See the attached directive

Item #14537598-004 must be complied with by October 31, 2021

This inspection report was prepared on October 07, 2021 by Anthony Heggelin, Inspector Specialist with Nova Scotia Environment who may be contacted at:

Nova Scotia Environment
30 Damascus Road, Suite 115
Bedford, N.S. B4A 0C1
Phone:(902) 424-7773
Fax: (902) 424-0597
http://www.gov.ns.ca/nse

NOVA SCOTIA
Environment

30 Damascus Road, Suite 115
Bedford, N.S.B4A 0C1

Phone: (902) 424-7773
Fax: (902) 424-0597

Process RSN Number: 14537598

Environment Act
DIRECTIVE

ISSUED TO:	Dexter Construction Company Limited c/o Jamie Burns
DATE ISSUED:	October 7, 2021
MAILING ADDRESS:	927 ROCKY LAKE DRIVE, P.O. BOX 48100 HALIFAX, NS B4A 3Z2
SITE NAME:	Stillwater Brook-The Puddle- Highway 103 bridge near Queensland-Siltation
SITE ADDRESS:	NS

Pursuant to Environment Act 122A(1) the following action(s) must be completed by October 31, 2021

Implement all recommendations listed on a letter titled "Inspection Report and Directive, Stillwater Brook-The Puddle- Highway 103 bridge near Queensland- Siltation", dated October 1, 2021, submitted by Dexter Construction company Limited.
Implement all recommendations in emails from Kelly Hines (Design Point) on October 5, 2021 and from Jamie Burns (Dexter) on October 6, 2021.

Recommendation must be implemented by the date given on the Dexter letter and emails. The most updated due date is the one that is expected to be met.

The action(s) outlined in this Directive are the minimum required. Additional actions may be needed to address the non-compliance item(s) identified in this report. Where necessary, you may need to secure the services of a firm/person with sufficient knowledge, experience, and certification to address any item (s) of non-compliance.

Be advised that failing to undertake all action(s) within the time frame specified in this Directive is an offence and may result in further enforcement. An investigation involving the non-compliance item(s) identified in this report continues and is separate from the requirements of this Directive.

This Directive was issued by Anthony Heggelin, Inspector Specialist with Nova Scotia Environment, who may be contacted at:

Nova Scotia Environment
30 Damascus Road, Suite 115
Bedford, N.S. B4A 0C1
Phone: (902) 424-7773
Fax: (902) 424-0597
http://www.gov.ns.ca/nse

****

Supporting text where applicable:

Prohibition s.67 - (1) No person shall knowingly release or permit the release into the environment of a substance in an amount, concentration or level or at a rate of release that causes or may cause an adverse effect, unless authorized by an approval or the regulations.(2) No person shall release or permit the release into the environment of a substance in an amount, concentration or level or at a rate of release that causes or may cause an adverse effect, unless authorized by an approval or the regulations. Environment Act 1994-95, c. 1

Duty to take remedial measures s.71 - Any person responsible for the release of a substance under this Part shall, at that person's own cost, and as soon as that person knows or ought to have known of the release of a substance into the environment that has caused, is causing or may cause an adverse effect, (a) take all reasonable measures to(i) prevent, reduce and remedy the adverse effects of the substance, and (ii) remove or otherwise dispose of the substance in such a manner as to minimize adverse effects; (b) take any other measures required by an inspector or an administrator; and (c) rehabilitate the environment to a standard prescribed or adopted by the Department. Environment Act 1994-95, c. 1

Assistance to inspectors s.118 - The owner or occupier of any place, or any person the inspector reasonably believes is related to or associated with any activity at the place, in respect of which an inspector is exercising powers or carrying out duties pursuant to this Part shall(a)give the inspector all reasonable assistance to enable the inspector to exercise those powers and carry out those duties(b) furnish all information relative to the exercising of those powers and the carrying out of those duties that the inspector may reasonably require. Environment Act, 1994-95, c.1

Right of entry and inspection s.119 (1) - For the purpose of ensuring compliance with this Act, the regulations, a standard or an order made under Part XIII, an inspector, subject to Sections 22 and 120, may, at any reasonable time, (g) where the inspector believes that any thing may release, is releasing or has released into the environment a substance that may cause, is causing or has caused an adverse effect,(i) require the person having care, management or control of the thing to detain the thing at the place where it is found. Environment Act, 1994-95, c.1

Right of entry and inspection s.119 (1) - For the purpose of ensuring compliance with this Act, the regulations, a standard or an order made under Part XIII, an inspector, subject to Sections 22 and 120, may, at any reasonable time (h) require the production of any documents that are required to be kept pursuant to this Act or any other documents that are related to the purpose for which the inspector is exercising any power under clauses (a) to (g). Environment Act, 1994-95, c.1

Inspector Directives s. 122A (1) - An inspector may issue a directive to a person requiring the person to
(a) take such measures in accordance with clause 71(b) as the inspector may specify;
(b) furnish the inspector with information in accordance with clause 118(b);
(c) detain a thing in accordance with subclause 119(1)(g)(i);
(d) produce a document in accordance with clause 119(1)(h); or
(e) take any action prescribed by the regulations in any circumstance prescribed by the regulations.
(2) A directive is not subject to appeal or review under this Act. Environment Act, 1994-95, c.1

Primary Responses

Success: All data is valid!

Status	#	Item	Quantity Required	Unit of Measure	Numeric Unit Price	Total Cost
Mobilization and Demobilization						
Success: All values provided	#1-1	**Mobilization of all necessary equipment, material and labour force.**	1	Lump Sum	$ 100,000.00	$ 100,000.00
Success: All values provided	#1-2	**Demobilization of all equipment, material and labour force off the site and clean-up of construction site after completion of work**	1	Lump Sum	$ 100,000.00	$ 100,000.00
Basket Total						**$ 200,000.00**
Intake Extension and Underwater Excavation - Excavation Activities						
Success: All values provided	#2-1	**Labour (Site Labour)**	1	Lump Sum	$ 11,400.00	$ 11,400.00
Success: All values provided	#2-2	**Materials (Rock fill and consumables)**	1	Lump Sum	$ 0.00	$ 0.00
Success: All values provided	#2-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 38,000.00	$ 38,000.00
Success: All values provided	#2-4	**Surveying and Reporting**	1	Lump Sum	$ 10,000.00	$ 10,000.00
Basket Total						**$ 59,400.00**
Intake Extension and Underwater Excavation - Corestone and Leveling Course Layer at Intake Extension						
Success: All values provided	#3-1	**Labour (Site Labour)**	1	Lump Sum	$ 15,400.00	$ 15,400.00
Success: All values provided	#3-2	**Material**	1	Lump Sum	$ 15,400.00	$ 15,400.00
Success: All values provided	#3-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 69,000.00	$ 69,000.00
Success: All values provided	#3-4	**Surveying and Reporting**	1	Lump Sum	$ 15,000.00	$ 15,000.00
Basket Total						**$ 114,800.00**
Intake Extension and Underwater Excavation - Pre-cast Box Culvert Installation						
Success: All values provided	#4-1	**Labour (Site Labour)**	1	Lump Sum	$ 67,200.00	$ 67,200.00
Success: All values provided	#4-2	**Materials (Precast box culvert and gaskets)**	1	Lump Sum	$ 243,000.00	$ 243,000.00
Success: All values provided	#4-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 137,000.00	$ 137,000.00
Success: All values provided	#4-4	**Surveying and Reporting**	1	Lump Sum	$ 15,000.00	$ 15,000.00
Basket Total						**$ 462,200.00**
Intake Extension and Underwater Excavation - CIP Concrete Headwall						
Success: All values provided	#5-1	**Labour (Site Labour)**	1	Lump Sum	$ 177,700.00	$ 177,700.00

Success: All values provided	#5-2	**Materials (Concrete)**	1	Lump Sum	$ 320,300.00	$ 320,300.00
Success: All values provided	#5-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 249,700.00	$ 249,700.00
Success: All values provided	#5-4	**Removals and Cleanup**	1	Lump Sum	$ 134,800.00	$ 134,800.00
Basket Total						**$ 882,500.00**

Rock Revetment - Corestone Layer

Success: All values provided	#6-1	**Labour (Site Labour)**	1	Lump Sum	$ 212,100.00	$ 212,100.00
Success: All values provided	#6-2	**Materials**	1	Lump Sum	$ 401,600.00	$ 401,600.00
Success: All values provided	#6-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 599,700.00	$ 599,700.00
Success: All values provided	#6-4	**Surveying and Reporting**	1	Lump Sum	$ 20,000.00	$ 20,000.00
Basket Total						**$ 1,233,400.00**

Rock Revetment - Filter Stone Layer

Success: All values provided	#7-1	**Labour (Site Labour)**	1	Lump Sum	$ 61,100.00	$ 61,100.00
Success: All values provided	#7-2	**Materials**	1	Lump Sum	$ 77,600.00	$ 77,600.00
Success: All values provided	#7-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 189,400.00	$ 189,400.00
Success: All values provided	#7-4	**Surveying and Reporting**	1	Lump Sum	$ 20,000.00	$ 20,000.00
Basket Total						**$ 348,100.00**

Rock Revetment - Armour Stone Layer

Success: All values provided	#8-1	**Labour (Site Labour)**	1	Lump Sum	$ 132,600.00	$ 132,600.00
Success: All values provided	#8-2	**Materials**	1	Lump Sum	$ 219,000.00	$ 219,000.00
Success: All values provided	#8-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 381,000.00	$ 381,000.00
Success: All values provided	#8-4	**Surveying and Reporting**	1	Lump Sum	$ 20,000.00	$ 20,000.00
Basket Total						**$ 752,600.00**

Project Closeout

Success: All values provided	#9-1	**Deficencies**	1	Lump Sum	$ 12,500.00	$ 12,500.00
Success: All values provided	#9-2	**Red Lines and As-Builts**	1	Lump Sum	$ 5,000.00	$ 5,000.00
Success: All values provided	#9-3	**Clean Up**	1	Lump Sum	$ 12,500.00	$ 12,500.00
Success: All values provided	#9-4	**Surveying and Reporting**	1	Lump Sum	$ 20,000.00	$ 20,000.00

Basket Total	$ 50,000.00
Grand Total	$ 4,103,000.00

Proposal For:

Nova Scotia Power Inc.

In Response to Request for Proposal #RFP-06/2025-545

Tufts Cove Shoreline Sheet Pile Rock Revetment

Submitted to:
Nova Scotia Power Inc.

Prepared by:
Elliot Excavators Limited
Scott Haverstock, President
103 Park Road, Elmsdale, NS B2S 2L3
Tel: 902-883-0616
Fax: 902-883-8900
e.excavators@ns.sympatico.ca

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

August 27, 2025

Nova Scotia Power Inc.
1223 Lower Water Street
Halifax, NS
B3J 3S8

Re:

Request for Proposal: #RFP-06/2025-545

Please find attached our proposal for this RFP.

I would like to take this opportunity to thank you for inviting Elliot Excavators Limited to submit a proposal for this project.

Please do not hesitate to contact me if you have any questions or need any clarifications regarding our proposal.

Scott Haverstock, President

8.1 ORGANIZATIONAL CAPABILITIES

A. BRIEF COMPANY OVERVIEW

Elliot Excavators Limited (Elliot) was incorporated in March, 1988. Our head office and repair shop are located at 103 Park Road in Elmsdale, Nova Scotia. Scott Haverstock is the president and owner of Elliot.

Elliot has worked as a general contractor or subcontractor on projects for Nova Scotia Power Inc. since 1988. Elliot was the main excavation contractor on site for the Trenton Unit 6 construction from October 1988 through June 1991.

Since 1991, we have worked extensively with the Hydro Division of Nova Scotia Power as well as work at the Tufts Cove Generating Station. Elliot Excavators Limited has also completed projects at the Lingan Generating Station for their fuel tank farm.

We have successfully completed 16 pipeline replacement contracts for Nova Scotia Power Inc. as well as acted as a general contractor or civil subcontractor on hydro projects every year since 1992. Included in the work completed during this timeframe is the replacement of six surge tanks. Also, during the installation of the 16 pipelines, we have rebuilt several headgates.

We currently own a fleet of 40 pieces of heavy equipment with the capabilities to rent whatever other equipment may be required to complete our projects on schedule.

Elliot Excavators Limited HST number is 12087 2254 RT0001.

Elliot has agreements with both the Labourers International Union of North America as well as the Operating Engineers Union.

Elliot Excavators Limited is recognized as a contractor in good standing with both the Nova Scotia Construction Safety Association as well as the Workers Compensation Board of Nova Scotia (documents attached).

B. SIMILAR PROJECTS

Examples of previous completed projects similar to this RFP:

- Rip Rap Parsons Dam and Install New Box Culverts at St. Croix Hydro System for Minas Basin Pulp & Power (2023)
- Rip Rap Slope at Tufts Cove after Oil Spill Clean Up (2018)
- Rip Rap D2 Dam at Wreck Cove Hydro System (2014)
- Rip Rap D7 Dam at Wreck Cove Hydro System (1995)
- Fresh Water Intake to Leper Brook Pumping Station for Town of Truro (1993)

References:

Elliot Excavators Limited has worked extensively for Nova Scotia Power's Hydro Division for 30 years. For references on our firms' capabilities and reliability contact any or all of the following personnel within Nova Scotia Power Inc.; Annie Beth Sampson, EIT, Cletus MacIsaac, Darcy Pettipas, Senior Environmental Technologist, and Elaine Locke, M.Eng.

For a reference outside of Nova Scotia Power Inc., please contact Rob Stewart, Minas Basin Pulp & Power, 902-237-6003.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

C. KEY PERSONNEL

Our project management team would be set up similar to the below example. The superintendent and/or surveyor may vary depending on workload from other sites.

Scott Haverstock
President/Project Manager
(Primary Point of Contact Office: 902-883-0616 Cell: 902-456-3732)
(E-Mail: e.excavators@ns.sympatico.ca)
(46 years supervisory experience in the construction industry)

↓

Edwin Goble
Project Superintendent
(39 years supervisory experience in the construction industry)

↓

Warren Lange
Project Superintendent
(38 years' experience in the construction industry)

See attached resumes for above personnel.

D. HST NUMBER

Elliot Excavators Limited	12087 2254 RT 0001

8.2 TECHNICAL REQUIREMENTS

A. ALTERNATIVES/DEVIATIONS/ FROM THE SPECIFICATION OR REQUIREMENTS STATED IN ATTACHMENT 'A'

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

B. ACKNOWLEDGEMENT OF ADDENDA RECEIVED

ADDENDUM / Q&A #	Date Received
Addendum#1	August 12,2025
Addendum#2	August 18, 2025

8.3 PROJECT PLAN

To complete this project, we will need to remove a section of bridge to the wharf. Nova Scotia Power will either remove piping on bridge or have it assembled in such a manner that it can be unbolted at the bridge joint.

We will utilize the sheet pile face to the south of the bridge to load all of the material required for this project. It is our intention to haul the majority of material required for this project to the Tufts Cove site and stockpile it in the north end of the site prior to the plant shut down.

The work required for the intake extension would be the area where we will start this project and we anticipate this work will take 20 to 25 days.

Once the intake is in, then we will commence with placing the armour stone toe and then work the slope from the north end proceeding south. We plan for the rock placement to take approximately 25 days to complete.

Our fleet of equipment for this work will consist of one spud barge with a crane and or long reach excavator on deck. The excavator will be on first to prepare the bed for the intake structure and then the excavator will be taken off and a crane loaded on to handle the intake sections. Once the intake sections are placed then the crane will come off and the excavator loaded back on to place the various layers of rockfill. There will be a material handling barge as well.

The support equipment on shore will be comprised of two excavators, two off road trucks and two loaders.

We will install a floating silt boom around the work area to prevent any silt that may occur from placing rock on the harbour bottom from migrating into the harbour.

Elliot Excavators Limited will utilize Connors Diving Services Ltd. for any diving requirements. A Dive Plan will be provided once scope of what we require is defined to them.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

B. PRELIMINARY SCHEDULE

See project plan for details.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

Scott Haverstock
5 Laura Court
Fall River, N.S.

EDUCATION

1974	Grade 12 Diploma-Sackville High School, Sackville NS
1974-1976	Land Survey Diploma-Nova Scotia Land Survey Institute, Lawrencetown, NS

WORK EXPERIENCE

1976-1979 **K.W. Robb Land Surveys, Dartmouth NS. Legal Property Surveys**
Started as a junior surveyor and worked my way up to office manager.

1979-1981 **Beaver Marine Construction Halifax, NS. Marine & Heavy Civil Construction**
Started as a construction surveyor responsible for all aspects of surveying required for construction projects. When I left work with Beaver, I was a junior dredge foreman.

1981-1983 **Bernard Fancy Trucking, Harrietsfield, NS. Sitework Contractor**
Foreman responsible for excavation work on commercial and industrial projects. Also, mass site work for the development of both the Burnside and Woodside industrial parks.

1983-1986 **Beaver Marine Construction, Halifax, NS. Marine & Heavy Civil Construction**
Project superintendent for pile driving and wharf construction projects from estimating to project completion.

1986-1988 **Empire Excavators Limited, Halifax, NS. Residential, Commercial & Industrial Excavation Contractor.**
General Superintendent responsible for all estimating, crew hiring and deployment, equipment purchasing and maintenance, and all contract negotiations.

1988-Present **Elliot Excavators Limited, Elmsdale, NS Heavy Civil Construction**
President-Senior Project Manager, responsible for all estimating, project management, crew deployment, equipment purchasing and maintenance.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

Edwin Goble
253 Abercrombie Road
New Glasgow, N.S.

EDUCATION

1978-1981	New Glasgow High School Grade 12
1982-1984	New Brunswick Community College Civil Engineering Technology
1984-1985	New Brunswick Community College Computer Aided Design & Drafting
1992-1992	Technical University of Nova Scotia Certificate in Project Management

WORK EXPERIENCE

1985-1986	**Nova Scotia Department of Lands & Forests**	Responsible for supervising the Survey Crew Chief survey crew doing boundary lines.
1986-1988	**Robert Higgins 1984 Co. Ltd.**	Junior Superintendent Construction surveyor & small job project manager.
1988-1991	**Rocca Construction**	Surveyor
1991-Present	**Elliot Excavators Limited**	Senior Project Superintendent

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

Warren Lange
1811 Old Sambro Road
Williamswood, N.S.

EDUCATION

1984-1985	Queen Elizabeth High School Grade 12	Halifax, NS
1989/1990	Saint Mary's University, Bachelor of Commerce Degree, Accounting Major	Halifax, NS

WORK EXPERIENCE

1986-1987	Residential Carpentry/Painting	
1987-1988	T.A.G. Developments Limited (General Contractors)	Labour Foreman
1988-1990	Curbstone Limited (Concrete Works)	Formwork Foreman
1990-1993	T.A.G. Enterprises (General Contractors)	Site Foreman-Commercial/Civil Projects
1993-2000	T.A.G Enterprises (General Contractors)	Jr. Superintendent Commercial/Industrial Projects. Responsible for the onsite coordination of construction sub trades.
2000-2014	Deco Contracting Limited (General Contractors)	General Superintendent-Commercial/Industrial projects. Responsible for the coordination of construction activity on site, project administration and estimating.
2014-Present	Elliot Excavators Limited	Commercial/Industrial projects. Responsible for the coordination of construction activity on site, project administration.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

Michael Charlton
PO Box 88
Bear River, N.S.

EDUCATION

1982-1986	Digby Regional High School
1982-1984	Irving Forestry

WORK EXPERIENCE

1985-1987	Meat Cutter	
1987-1988	D.J. Lowe Ltd	Heavy Equipment Operator
1988-1990	Upper Clements Park	Lead Hand Carpenter
1990-1992	Irving Forestry	Forestry Operator
1992-1997	D.J. Lowe Ltd	Heavy Equipment Operator
1998-2008	Elliot Excavators Limited	Heavy Equipment Operator
2008-Present	Elliot Excavators Limited	Site Superintendent

C. SUBCONTRACTORS

Elliot Excavators Limited will employ subcontractors for the following tasks:

Task	Subcontractor
Site Work	Own Forces
Diving Requirements	Connors Diving Services Ltd.
Barge Support	Eagle Beach Contractors

D. MUTUALLY BENEFICIAL RELATIONSHIPS

Elliot Excavators Limited is committed to establishing relationships with Mi'kmaq and work to incorporate local Mi'kmaw community opportunities into projects where appropriate.

E. LOCAL LABOUR

Elliot Excavators Limited has agreements with both the Operating Engineers Union Local 721 as well as the Laborers' International Union Local 615.

8.4 REPORTING

Elliot Excavators Limited reports are delivered by email unless a document is not able to be scanned and requires hand delivery. Most of our reports are red lined drawings which come with required notes on the drawings. If third party testing is required, i.e., concrete testing, etc., then copies of these will be forwarded as received during project. There are no charges for reports and a non- standard report will be provided two months after project completion.

8.5 QUALITY AND MONITORING

No testing is required for this project; however, it should be noted Elliot Excavators Limited has all testing completed through an external Consultant when required.

8.6 SPECIALIZED SERVICES

8.7 PERFORMANCE STANDARDS

A. RESOLVING SERVICE ISSUE: STANDARDS

As not only the project manager for this project but also as the owner of Elliot Excavators Limited, Scott Haverstock is responsible for the performance of both the Elliot Excavators Limited crew as well as all subcontractors.

The project superintendent will be the first line contact with the customer and if the issue cannot be resolved at that level, then the project manager will become involved and work to a resolution with the customer. There are no current contractual issues with any unions that will affect the level of service that Elliot Excavators Limited provides to its customers.

B. CUSTOMER RESPONSE

Below are Elliot Excavators Limited key contacts:

Scott Haverstock
President
Office: 902-883-0616
Cell: 902-456-3732
e.excavators@ns.sympatico.ca

Edwin Goble
Senior Project Superintendent
Office: 902-883-0616
Cell: 902-471-0759
edwin@elliotgroup.ca

Warren Lange
Senior Project Superintendent
Office: 902-883-0616
Cell: 902-456-0479
warren@elliotgroup.ca

C. SERVICE LEVELS: UNION & AFFLIATES

Union	Contract Expiration
Operating Engineers Local 721	April 30, 2026
Laborers' Union of North America Local 615	April 30, 2026

8.8 WARRANTY

Elliot Excavators Limited will warrant the work performed on this site for 12 months from completion of work. No extended warranty will apply and any problems that occur that are related to a design flaw will not be covered by our warranty.

Nova Scotia POWER An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

8.9 SAFETY

A. WORKERS'COMPENSATION BOARD-EXPERIENCE RATINGS

Attached please find our Workers' Compensation Board of Nova Scotia Experience Ratings for the past three years.

WORK SAFE. FOR LIFE.
WORKERS' COMPENSATION BOARD OF NOVA SCOTIA

Visit MyAccount at wcb.ns.ca

Experience Rating Statement for 2025

PRIVATE

ELLIOT EXCAVATORS LIMITED
Michelle Smith
103 PARK RD
ELMSDALE, NS B2S 2L3

Business No:	120872254NW0001
Date:	August 17, 2024
Page:	1

Your 2025 assessment rate: $2.28 per $100 assessable payroll

SECTION A: Your Rate Components

Basic Industry Rate:	$3.03	
Experience Rating Merit/Demerit:	$-0.86	see details in Section D below
Rate Surcharge:	$0.00	
Levy	$0.11	
TOTAL RATE for 2025	$2.28	per $100 assessable payroll

Note: Your company's workplace injuries and the associated costs determine your Experience Rating Adjustment. You can control your rate by eliminating workplace injuries and helping injured workers return to work in a safe and timely manner.

Your 2025 rate could have been as low as: $2.24 or as high as: $5.08

SECTION B: SIC and Industry Group

To set rates, we classify employers by the industry in which they operate, and group industries with similar activities and risk into industry groups.

Your Standard Industrial Classification (SIC) Code:
4214 Excavating and Grading

Your Industry Group for 2025
4210 Site Work

SECTION C: Cost and Payroll

Assessable Payroll

2023	$805,347.00
2022	$760,791.00
2021	$1,129,803.00
TOTAL	$2,695,941.00

Cost of New Injuries

from 2021 to 2023	$440.40

SECTION D: Your Experience Rating Details

Experience Rating for 2025 is calculated using injury and payroll data from the years 2021 to 2023. The 3-year costs and payroll are determined, and costs are weighted so that the more recent experience has more impact on rates.

The key measure in determining your Experience Rating is the "cost ratio", which is your weighted cost figure divided by your payroll. The lower your cost ratio relative to your rate group, the lower your rate will be.

Your Cost Ratio is:	**94.88% Lower**	Than Your Rate Group's Cost Ratio
Resulting Merit/Demerit:	**-28.49% Merit**	Produces an Experience Rating Adjustment of $-0.86

ELLIOT EXCAVATORS LTD.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

WORK SAFE. FOR LIFE.
WORKERS' COMPENSATION BOARD OF NOVA SCOTIA

Visit MyAccount at wcb.ns.ca

Experience Rating Statement for 2024

PRIVATE

ELLIOT EXCAVATORS LIMITED
Diane Lockhart
103 PARK RD
ELMSDALE, NS B2S 2L3

Business No:	120872254NW0001
Date:	August 19, 2023
Page:	1

Your 2024 assessment rate: $2.45 per $100 assessable payroll

SECTION A: Your Rate Components

Basic Industry Rate:	$3.25	
Experience Rating Merit/Demerit:	$-0.92	see details in Section D below
Rate Surcharge:	$0.00	
Levy	$0.12	
TOTAL RATE for 2024	$2.45	per $100 assessable payroll

Note: Your company's workplace injuries and the associated costs determine your Experience Rating Adjustment. You can control your rate by eliminating workplace injuries and helping injured workers return to work in a safe and timely manner.

Your 2024 rate could have been as low as: $2.39 or as high as: $5.46

SECTION B: SIC and Industry Group

To set rates, we classify employers by the industry in which they operate, and group industries with similar activities and risk into industry groups.

Your Standard Industrial Classification (SIC) Code:
4214 Excavating and Grading

Your Industry Group for 2024
4210 Site Work

SECTION C: Cost and Payroll

Assessable Payroll

2022	$760,791.00
2021	$1,129,803.00
2020	$914,692.00
TOTAL	$2,805,286.00

Cost of New Injuries

from 2020 to 2022	$440.40

SECTION D: Your Experience Rating Details

Experience Rating for 2024 is calculated using injury and payroll data from the years 2020 to 2022. The 3-year costs and payroll are determined, and costs are weighted so that the more recent experience has more impact on rates.

The key measure in determining your Experience Rating is the "cost ratio", which is your weighted cost figure divided by your payroll. The lower your cost ratio relative to your rate group, the lower your rate will be.

Your Cost Ratio is: **94.46% Lower** Than Your Rate Group's Cost Ratio
Resulting Merit/Demerit: **-28.36% Merit** Produces an Experience Rating Adjustment of **$-0.92**

ELLIOT EXCAVATORS LTD.

Nova Scotia POWER
An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

WORK SAFE. FOR LIFE.
WORKERS' COMPENSATION BOARD OF NOVA SCOTIA

Visit MyAccount at wcb.ns.ca

Experience Rating Statement for 2023

PRIVATE

ELLIOT EXCAVATORS LIMITED
Diane Lockhart
103 PARK RD
ELMSDALE, NS B2S 2L3

Business No:	120872254NW0001
Date:	August 19, 2022
Page:	1

Your 2023 assessment rate: $2.44 per $100 assessable payroll

SECTION A: Your Rate Components

Basic Industry Rate:	$3.22	
Experience Rating Merit/Demerit:	$-0.90	see details in Section D below
Rate Surcharge:	$0.00	
Levy	$0.12	
TOTAL RATE for 2023	$2.44	per $100 assessable payroll

Note: Your company's workplace injuries and the associated costs determine your Experience Rating Adjustment. You can control your rate by eliminating workplace injuries and helping injured workers return to work in a safe and timely manner.

Your 2023 rate could have been as low as: $2.38 or as high as: $5.42

SECTION B: SIC and Industry Group

To set rates, we classify employers by the industry in which they operate, and group industries with similar activities and risk into industry groups.

Your Standard Industrial Classification (SIC) Code:
4214 Excavating and Grading

Your Industry Group for 2023
4210 Site Work

SECTION C: Cost and Payroll

Assessable Payroll

2021	**$1,129,803.00**
2020	**$914,692.00**
2019	**$737,067.00**
TOTAL	**$2,781,562.00**

Cost of New Injuries
from 2019 to 2021 $285.04

SECTION D: Your Experience Rating Details

Experience Rating for 2023 is calculated using injury and payroll data from the years 2019 to 2021. The 3-year costs and payroll are determined, and costs are weighted so that the more recent experience has more impact on rates.

The key measure in determining your Experience Rating is the "cost ratio", which is your weighted cost figure divided by your payroll. The lower your cost ratio relative to your rate group, the lower your rate will be.

Your Cost Ratio is: **93.12% Lower** Than Your Rate Group's Cost Ratio
Resulting Merit/Demerit: **-27.96% Merit** Produces an Experience Rating Adjustment of **$-0.90**

5668 South Street, P.O. Box 1150, Halifax, NS B3J 2Y2
1.800.870.3331 • 902.491.8999 • wcb.ns.ca • worksafeforlife.ca • Twitter: @WorkSafeForLife

ELLIOT EXCAVATORS LTD.

Nova Scotia POWER An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

B. DETAILED SAFETY PLAN (CORPORATE SAFETY POLICY, PERSONAL PROTECTIVE EQUIPMENT)

This project is adjacent to the water in Halifax Harbor, therefore; PFD's will be required at any time that employees are within 3 meters of the water.

The project is on the site of an active thermal power plant so co-ordination with a Nova Scotia Power Plant Representative on a daily basis must occur.

A designated material laydown area and a defined route to transport the material to the waters edge is required and all employees must be made aware of the travel route. Nova Scotia Power employees are also to be made aware of the travel route to exercise precautions when working near or crossing over the defined route.

The area designated for loading barges to be defined and marked out with jersey barriers.

All machine operators must be made aware of the precautions required when working near salt water. Salt spray will get on the windshield and mirrors and reduce visibility. These must be cleaned at the start of each shift and more frequently if required.

Divers will be required to assist with placing the new box culvert intake. A dive plan will be supplied prior to commencing this work. When divers are in the water there will be no equipment operating in their vicinity unless under their direction.

If a storm or rough seas are forecast, we will secure site to avoid any items or silt entering water.

Hearing protection will be provided to all workers on site.

ELLIOT EXCAVATORS LTD.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

CORPORATE SAFETY POLICY

As the President of the **Elliot Group of Companies**, I am committed to a strong safety program. I will ensure that Management will cooperate with the Occupational Health & Safety Committee as well as the Worker Representative to ensure the risks associated with our business are properly managed as well as protect the environment, the employees, and the public. We work throughout Atlantic Canada and will ensure wherever our jobsites are located that all Elliot Group employees are made aware of and following proper Provincial OH&S Legislation.

Employees at every level, including management, are responsible and accountable for the company's overall safety initiatives. Complete and active participation by everyone, every day, in every job is necessary for the safety excellence the company expects. Management supports co-ordination of safety among all workers on the job site.

Management supports participation in the program by all employees and will provide proper equipment, training and procedures to do your job safely. Employees are responsible for working safely, following all safety procedures and legislation, and wherever possible, improving safety measures at the site they are working at.

An injury and incident-free workplace is our goal. Through continuous safety and loss control effort, we can accomplish this.

We recognize that all employees have the right to work in a healthy and save work environment.

Elliot Group of Companies is committed to work in a spirit of consultation and cooperation with its employees. As President, I give you my personal promise to take all reasonable precautions to prevent harm to workers. This Corporate Safety Policy shall be reviewed at least annually to re-enforce our safety commitment.

Please join us in making safety a priority when working for our company.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

TOOL BOX/TAILGATE MEETINGS

Meetings are to be held weekly or as otherwise directed by management. All safety related concerns are to be brought to the attention of your immediate supervisor or Health and Safety Representative.

The duration of the meetings shall be approximately 15 minutes and be limited to health and safety issues of the company. There may be times when the minutes are shorter or longer depending upon the topic at hand.

Sub-contractors on site will attend the **Elliot Group of Companies** meetings and their attendance will be recorded on the Record of Meeting sheet.

At any time, safety concerns may be addressed to the Health and Safety Representative for the company, or your immediate supervisor.

Agenda for Meetings

- Review of the minutes of the previous meeting including any status on any concerns raised.
- Review of incidents reported since the last meeting including status of corrective action recommended or taken.
- Comments and concerns of workers.
- Presentation of a weekly safety topic.
- Possible safety hazards and exposures that apply directly to the individual worker.

Management welcomes your suggestions to improve safety!

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

PERSONAL PROTECTIVE EQUIPMENT POLICY

The Elliot Group of Companies is committed to the use of appropriate personal protective equipment (PPE) to minimize injuries to our employees and those of our sub-contractors.

The **Elliot Group of Companies** requires that all employees are trained on the selection, use, and care of PPE.

The **Elliot Group of Companies** requires that all employees on all work sites wear a minimum of a CSA approved hard hat (only Classes E or G are acceptable), CSA approved, steel-toed work boots in good condition, long pants and appropriate work shirt with sleeves no shorter than four inches. Respiratory protection and hearing protection shall be worn where an SDS or job requirement dictates. A fall arrest or confined space harness system may also be utilized by those employees trained in their use.

The **Elliot Group of Companies** will supply the appropriate hard hats, gloves and safety glasses to all employees. We ask that you be conscientious with any of these items supplied to you by the **Elliot Group of Companies.** Please make every effort not to lose them.

We will supply to any employee all specialized personal protective equipment that they may require from time to time to carry out their duties on behalf of the **Elliot Group of Companies.** An annual review of how to use any specialized personal protective equipment will be performed. Our harnesses will be numbered and an accurate record kept of any maintenance.

All personal protective equipment will he inspected daily by the individual user. All specialty equipment will be maintained by the company that supplied it to us or to manufacturer's standards. Training in proper use and care of specialty equipment will be provided by the supplier of the equipment. All personal protective equipment will meet the required standards of the Nova Scotia Occupational Health and Safety Act or Regulations.

Please join us in supporting our Personal Protective Equipment Policy to further prevent our valued workers from becoming injured on the job.

During new hire orientation as well as during random safety meetings throughout the work season Superintendents will review the proper care and use of standard PPE.

TRAINING POLICY

The purpose of this policy is to provide for general and specialized safety related training throughout all levels of the company.

Elliot Group of Companies will provide, and employees will participate in all safety and related training that is necessary to minimize losses of human and physical resources of the company.

This training will include, but not limited to:

- New hire safety orientations
- Job specific training
- Safety training for Supervisors and Management
- Sub-contractor orientation (as hired)
- Specialized safety and related training
- WHMIS, Fall Protection and First Aid training as per legislative requirements

In addition, weekly toolbox meetings will be used to promote the safety program and communicate, educate and learn from each other. Learning together we can expand our knowledge and continue to be profitable.

I encourage each of my employees to provide their individual experience during our training sessions.

Note: All sub-contractors will ensure that their staff on site has received any required training or training updates as required by legislation. Copies of training cards are to be provided to our office for any of the sub-contractor's employees working on site.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

INSPECTION POLICY

An integral component of the **Elliot Group of Companies** safety program is to conduct safety inspections. The sole objective of this policy is to control hazards within the workplace by conducting inspections on a regular basis.

Company offices, as well as all job sites, vehicles, and shop facilities shall all be included in the inspection program.

Informal on-going inspections are the responsibility of the **Elliot Group of Companies** supervisors. All employees on the site are encouraged to actively participate. Daily formal inspections are to be carried out on vehicles and equipment. Any problems in these areas are to be recorded on your daily time sheet. Copies of these records will be maintained at the office.

Formal, weekly inspections conducted by the Corporate Safety Advisor or supervisor shall be documented when corrective action is required and filed in the **Elliot Group of Companies** office. A formal inspection shall also be completed on projects that are over TWO weeks in duration or that are new or unusual in nature.

These inspections will be reviewed by the **Elliot Group of Companies** management. All **Elliot Group of Companies** sub-contractors are expected to address any hazards identified during our formal inspections and to co-operate fully with the respective supervisor or the Corporate Safety Advisor if safety related items are raised.

Any deficiencies noted during any inspection are to be promptly corrected where necessary by the appropriate individual sub-contractor or management of the **Elliot Group of Companies**.

Inspections save lives!

Nova Scotia POWER An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

INSPECTION SCHEDULE

Item	Frequency	By Whom
Vehicles	Monthly	Employee
Vehicles	By Km required	Management
Tools/Equipment	Each Use	Employee
Personal Protective Equipment (PPE)	Annually	Employee
Office	Annually	Management & Employee
Shop	Monthly	Management & Employee
Employee Orientation	Each New Hire	Management
Employee Acknowledgement	Each New Hire	Management
Next of Kin	Each New Hire	Employee
Employee Training Record	Each New Hire/update as required	Management & Employee
Worksite Hazard Assessment	Beginning of any new or unusual project and annually thereafter	Supervisor & Safety Advisor
Formal Worksite Inspection	Beginning of every job and by-weekly thereafter	Supervisor
Informal Inspection	Daily	Supervisor
Toolbox Meeting Record	Bi-Weekly	Management & Employee
Violation Record	Each incident	Management
Fall Arrest	Each use	Employee
Accident/Incident Report	As they occur	Management & Employee
Job Procedures	Annually	Management & Employee
Safe Work Practices	Annually	Management & Employee
Annual Hazard Assessment	Annually	Management
Due Diligence Checklist	Annually	Management
Safety Statistics	Monthly/Annually	Management

ELLIOT EXCAVATORS LTD.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

ACCIDENT/INCIDENT POLICY

The investigation standard requires that all accidents and incidents are reported and thoroughly investigated. These accidents/incidents include:

Lost Time Injury	Medical Aid	First Aid	Near Misses
Property Damage	Environmental Damage	Loss of Process	

The occurrence of any of these events will indicate the requirement for an immediate investigation. An initial written report will be sent to Management, where practicable, within 24 hours. If Management is not available, it shall be provided within 24 hours to the main office of **Elliot Group of Companies.**

REPORTING RESPONSIBILITIES

All serious accidents shall be reported to the Nova Scotia Department of Labour & Workforce Development, as per Section 63 of the Occupational Health & Safety Act.

The JOH&S Committee, will regularly review investigation findings and monitor corrective actions. Members will also be involved in the conducting of the investigation as required.

Office investigations shall be handled by our Safety Rep. in consultation with our Corporate Safety Advisor. **Elliot Group of Companies** will ensure those investigation results are communicated to all personnel. All supervisors are to be trained by management in our investigation techniques and if the incident requires specialty techniques outside experts will be brought in immediately.

Together, as the Management and Employees of the **Elliot Group of Companies** we can prevent serious accidents and incidents from occurring.

C.HEALTH & SAFETY LEGISLATION

We acknowledge that Elliot Excavators Limited employees, sub- suppliers, agents and representatives shall comply with all federal, provincial and municipal health, safety and environmental statutes, regulations, policies, guidelines and all health, safety and environmental rules as prescribed by NSPI including but not limited to:

- Occupational Health & Safety Act and Regulations
- Elliot Excavators Limited Safety Manual
- Nova Scotia Power Safety Manual
- Nova Scotia Power's SWP 14 Contractor Safety & Environmental Performance Requirements

D.REGULATORY DIRECTIVES/OFFENCES/ORDERS

Please be advised that Elliot Excavators Limited has not been given any regulatory directives/orders from the Provincial Department of Labour.

Please also be advised that Elliot Excavators Limited has not been convicted of any regulatory offences from the Provincial Department of Labour.

F. OUT OF PROVINCE PROPONENTS

Elliot Excavators Limited will ensure all out of province proponents are compliant with Nova Scotia provincial safety training requirements and provide verification to NSPI. Elliot Excavators Limited will ensure all safety gear has a documented annual inspection and is CSA approved for use in Nova Scotia.

Nova Scotia POWER An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

E. ISNETWORLD REGISTRATION

Elliot Excavators Limited has subscribed to ISNetworld. Our account # is 400-618982.

ELLIOT EXCAVATORS LTD.

8.10 ENVIRONMENT

ENVIRONMENTAL POLICY

As a responsible company we will ensure that the proper safeguards are taken to protect our environment. All individuals will have responsibility and we will take the necessary action to protect the environment. **Elliot Group of Companies** will ensure that all acceptable recycling practices are adhered to throughout our organization.

We will train and educate our employees on environmental issues that may affect their work. Employees will also have a good understanding of environmental practices and what measures are needed to control them.

On our projects, we shall use, store, and dispose of excess materials in such a manner that will provide appropriate protection to our employees, clients and the environment through following appropriate waste management practices. We insist that all personal garbage be disposed of in the onsite containers provided. Dispose of paper coffee cups with your construction debris.

Management will develop and enforce good environmental standards in accordance with relevant legislation. All waterways shall be protected in accordance with each provincial Environment Act. The **Elliot Group of Companies** shall adhere to each provinces recycling program.

In the event of an environmental emergency, spill kits shall be available on every jobsite.

All environmental incidents on any work site will be reported, ensuring compliance to statutory obligations.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

Environmental Site Inspection Form

ELLIOT EXCAVATORS LTD.

ENVIRONMENTAL CONTROLS CHECKLIST

Date and Time:	Weather:		
Project Name:	Project Supervisor:		
	NAME(PRINT)	SIGNATURE	POSITION	DATE
PREPARED BY:				
APPROVED BY:				

The following Erosion and Sediment Controls must be inspected daily and any deficiencies corrected immediately.

CONTROLS	YES	NO	N/A	COMMENTS
SILT FENCE				
SILT BAGS				
FLOATING SILT BOOM(S)				
HAY CHECK DAMS				
PUMPS, DISCHARGE HOSES, AREA OF DISCHARGE				
EXPOSED SOIL SLOPES				
FUGITIVE DUST				
SETTLEMENT PONDS				

ELLIOT EXCAVATORS LTD.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

ENVIRONMENTAL PLAN

Elliot Excavators Limited will surround the work area with a floating silt boom.

Where necessary, we will erect a silt fence around stockpiles.

All equipment working near water will be check daily for any fluid leaks.

All machinery on shore will be moved at least 30 meters from the water's edge for re-fueling. Any fuel storage will be at least 100 meters from water courses. A spill kit sea can will be onsite adjacent to our barge loading location.

If our haul route for machinery delivery becomes dusty, we will either utilize a dust control product or sweep the route with a power broom.

B. ENVIRONMENTAL EMERGENCY PREPAREDNESS

The following list of materials will be made available:

- Adequate number and properly sized pumps/hoses
- Silt fence, filter fabric, hay bales, silt bags, absorbent pads
- Silt booms/ Oil Booms
- Properly sized oil spill kits
- Extra fire extinguishers
- Emergency contact numbers posted

C.REPORTING AND INVESTIGATING ENVIRONMENTAL INCIDENTS

The Nova Scotia Power production oil spill notification procedure and power production chemical spill notification procedure will be followed.

D.COMPLIANCE

Elliot Excavators Limited shall comply with all applicable environmental legislation, regulations, standards, work practices and provisions including but not limited to:

- Environmental Act of Nova Scotia
- Nova Scotia Power Inc. Contractor Environmental Requirements
- Elliot Excavators Limited will assume responsibility for the disposal and/or destruction of all scrap treated wood at an approved facility. All work will be completed using Elliot Excavators Limited employees and equipment in accordance with all applicable laws governing the disposal/destruction of treated wood products. A Certificate of Disposal/Destruction will be provided to NSPI confirming material have been disposed of and/or destroyed in accordance with all applicable laws.

E. ENVIRONMETAL REGULATORY DIRECTIVES/OFFENCES/ORDERS

Please also be advised that Elliot Excavators Limited has not been convicted of any regulatory offences from the Provincial Department of Environment.

F. ENVIRONMENTAL REGULATORY DIRECTIVES/OFFENCES/ORDERS

Please be advised that Elliot Excavators Limited has not been given any regulatory directives/orders from the Provincial Department of Environment.

8.11 CYBERSECURITY

A. COLLECTION AND STORAGE OF DATA

Please be advised that the products provided to Nova Scotia Power do not collect and store data.

B. KNOWN VULNERABILITIES

Please be advised that our projects do not require updates/patches for known vulnerabilities.

C. EXTERNAL CONNECTIVITY

Please be advised that Elliot Excavators Limited does not have external connectivity and send information back to our company.

D. MATURE SECURITY PROGRAM

Please be advised that Elliot Excavators Limited does not have a mature security program. It should be noted that our main office location is a locked gated facility and monitored 24/7 by video surveillance cameras.

8.12 RESPONSIBLE SOURCING

Elliot Excavators Limited will not be importing products from outside Canada for this project.

8.13 EMPLOYEE REQUIREMENTS

1. Elliot Excavators acknowledges that our employees shall be experienced and qualified to safely perform the work required.
2. Elliot Excavators Limited acknowledges that our employees shall maintain a professional appearance and attitude.
3. We acknowledge that NSPI reserves the right to reject any employees who have been appointed to perform the work where field personnel determine that the individual does not meet NSPI safety or performance standards and we shall be obligated to replace the individuals.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

8.14 INSURANCE

CERTIFICATE OF INSURANCE

ISSUE DATE(YY/MM/DD): 25/06/14

BROKER
Stanhope Simpson Insurance Ltd
300-3845 Joseph Howe Drive
Halifax NS B3L4H9

This certificate is issued as a matter of information only and confers no rights upon the certificate holder. This certificate does not amend, extend or alter the coverage afforded by the policies below.

COMPANY A: Northbridge Insurance
COMPANY B: Markel Canada Limited
COMPANY C:
COMPANY D:
COMPANY E:

INSURED'S FULL NAME AND MAILING ADDRESS
Elliot Excavators Limited
103 Park Road
Elmsdale NS B2S 2L3

COVERAGES

This is to certify that the policies of insurance listed below have been issued to the insured named above for the policy period indicated, notwithstanding any requirement, term or condition of any contract or other document with respect to which this certificate may be issued or may pertain. The insurance afforded by the policies described herein is subject to all the terms, exclusions and conditions of such policies. Limits shown may have been reduced by paid claims.

TYPE OF INSURANCE	CO LTR	POLICY NUMBER	POLICY EFFECTIVE DATE (YY/MM/DD)	POLICY EXPIRATION DATE (YY/MM/DD)	LIMITS OF LIABILITY (Canadian dollars unless indicated otherwise)	
COMMERCIAL GENERAL LIABILITY (CGL) including, but not limited to: Bodily Injury, Property Damage, Personal Injury and Advertising Injury, Premises - Operations, Cross Liability and Contingent Employers Liability.	A	P04141701	25/03/07	26/03/07	Per Occurrence	5,000,000
					General Aggregate	20,000,000
					Prod & Comp Operation Agg	5,000,000
					Non-Owned Auto - SPF 6	5,000,000
					Tenant's Legal Liability	1,000,000
AUTOMOBILE LIABILITY including, but not limited to: Accident Benefits, Uninsured motorist, Direct Compensation / Property Damage.	A	P04141701	25/03/07	26/03/07	Limit of Liability	5,000,000
Contractor's Pollution Liability	B	EIL744831-04	25/07/26	26/07/26	Limit	5,000,000

DESCRIPTION OF OPERATIONS/LOCATIONS/AUTOMOBILES/SPECIAL ITEMS/ADDITIONAL INSURED
COI for Bid on Tufts Cove Shoreline Sheet Pile Rock Revetment. #RFP-06/2025-545
Additional Insured: Nova Scotia Power Inc. 1223 Lower Water Street, Halifax, NS B3J 2V7
ONLY WITH RESPECT TO THESE SPECIFIC OPERATIONS OF THE NAMED INSURED, ADDITIONAL INSURED IS ADDED EXCLUDING AUTOMOBILE LIABILITY

CERTIFICATE HOLDER
Nova Scotia Power Inc.
1223 Lower Water Street
Halifax NS B3J 2V7

CANCELLATION
SHOULD ANY OF THE ABOVE DESCRIBED POLICIES BE CANCELLED BEFORE THE EXPIRATION DATE THEREOF, THE ISSUING COMPANY WILL ENDEAVOR TO MAIL <30> DAYS WRITTEN NOTICE TO THE CERTIFICATE HOLDER NAMED TO THE LEFT, BUT FAILURE TO MAIL SUCH NOTICE SHALL IMPOSE NO OBLIGATION OR LIABILITY OF ANY KIND UPON THE COMPANY, ITS AGENTS OR REPRESENTATIVES.

AUTHORIZED REPRESENTATIVE

Nova Scotia POWER
An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

8.15 CERTIFICATIONS

WORK SAFE. FOR LIFE.
WORKERS' COMPENSATION BOARD OF NOVA SCOTIA

Visit MyAccount at **wcb.ns.ca**

Clearance Letter

ELLIOT EXCAVATORS LIMITED
SCOTT HAVERSTOCK
103 PARK RD
ELMSDALE, NS B2S 2L3

Date of Issue: June 15, 2025

Account Holder:
ELLIOT EXCAVATORS LIMITED
BN: 120872254

This letter confirms that **ELLIOT EXCAVATORS LIMITED** is registered with the WCB Nova Scotia and is in good standing. It is valid until **September 30, 2025**.

Sincerely,

WCB Nova Scotia

5668 South Street, P.O. Box 1150, Halifax, NS B3J 2Y2
1.800.870.3331 • 902.491.8999 • wcb.ns.ca • worksafeforlife.ca • Twitter: @WorkSafeForLife

ELLIOT
EXCAVATORS LTD.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

Nova Scotia POWER
An Emera Company

Letter of Good Standing
Certificate of Recognition Program®

Member ID	**ATLAN013**
Member Type	**M**
Certificate No.	**51401**

tel 902 468-6696
fax 902 468-8843
toll free ns 1-800-971-3888
web constructionsafetyns.ca

35 MacDonald Ave.
Dartmouth N.S. Canada
B3B 1C6

Issued to: **ELLIOT EXCAVATORS LIMITED**
103 PARK RD.
ELSMDALE, NS
B2S2L3

Size: **Standard - 20+ Persons Employed**

Based on active participation in the Certificate of Recognition Program®, Construction Safety Nova Scotia hereby issues a letter of good standing:

2024/03/13	**2025/03/20**
Date of Issue	Expiry Date

This letter of good standing is issued to a firm actively participating in Construction Safety Nova Scotia programs and whose current standing falls into the category noted below:

Certificate of Recognition®
Definition: The certificate of recognition® is awarded to firms who have completed the training requirements, fully implemented a loss control program, and successfully participated in the COR® evaluation.

Conditions:

Jo-Ann MacDonald
Construction Safety Nova Scotia Representative

Original Issue Oct 08, 2000 Revision #11 Revision Date: September 1, 2022 Document # FM 9.00

ELLIOT EXCAVATORS LTD.

Nova Scotia POWER An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

EMPLOYEE CERTIFICATIONS

ELLIOT EXCAVATORS LTD.

First Aid		
Name	Course Name/Description	Expiry Date
Harvey Mattatall	CSA Intermediate Workplace First Aid CPR C AED	Feb 14/28
Michael Charlton	CSA Intermediate Workplace First Aid- CPR C and AED	Mar 15/26
Rachel Cole	CSA Intermediate Workplace First Aid- CPR C and AED	Mar 15/26
Warren Lange	CSA Intermediate Workplace First Aid- CPR C and AED	Feb 14/28
Edwin Goble	CSA Intermediate Workplace First Aid- CPR C and AED	Feb 14/28
Shane Langely	CSA Intermediate Workplace First Aid- CPR C and AED	Mar 15/26
Steve Palmer	CSA Intermediate Workplace First Aid- CPR C and AED	Mar 15/26
Avery Charlton	CSA Intermediate Workplace First Aid- CPR C and AED	Mar 15/26
Dawson Thurber	CSA Basic Workplace First Aid- CPR C and AED	Feb 19/28
John Comeau	CSA Basic Workplace First Aid- CPR C and AED	Feb 12/28
Travis Trimper	CSA Intermediate Workplace First Aid- CPR C and AED	Feb 14/28

ELLIOT EXCAVATORS LTD.

Nova Scotia POWER An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

ELLIOT EXCAVATORS LTD.

Employee Training Courses

Name	Course Name/Description	Expiry Date	Certificate #
Edwin Goble	Chainsaw Safety and Awareness	n/a	completed 6/22/2017
	Intermediate Workplace First Aid-CPR C and AED	Feb 14/28	Ref #0990965992
	WHMIS Supervisor	n/a	105777
	WHMIS 2015	n/a	completed 08/14/20
	NS Watercourse Installers Certificate	n/a	1500652-I
	BOATSMART	n/a	18032823712
	Leadership for Safety Excellence	n/a	152713
	Health & Safety Committee Rep	n/a	465846
	Fall Protection I-Basic	Feb 19/28	893853
	Fall Protection II-Supervisor	Feb 11/28	893644
	Confined Space- Generic	Mar 20/27	895162
	Type 3 Group A&B - Scissor Lift & Boom Lift	Feb 27/28	Operator # 28781-592
	End-frame Scaffolding Practical	Apr 8/28	895996
Michael Charlton	JOHS Committee Member/Representative	n/a	465845
	Leadership for Safety Excellence	n/a	328269
	BOATSMART	n/a	18032826373
	NS Watercourse Installers Certificate	n/a	
	WHMIS 2015	n/a	completed 08/14/20
	Intermediate Workplace First Aid-CPR C and AED	Mar 15/26	Ref.#0538365963
	Chainsaw Safety & Awareness	n/a	2017-06-22
	Excavation and Trenching	Mar 8/26	871972
	Fall Protection I-Basic	Feb 19/28	893849
	Fall Protection II-Supervisor	Feb 11/28	893640
	Transportation of Dangerous Goods	Feb 15/26	
	Confined Space-Generic	Mar 20/27	895158
	Type 3 Group A&B - Scissor Lift & Boom Lift	Feb 27/28	Operator # 28781-597
	End-frame Scaffolding Practical	Apr 8/28	895994

ELLIOT EXCAVATORS LTD.

Nova Scotia POWER An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

ELLIOT EXCAVATORS LTD.

Employee Training Courses

Name	Course Name/Description	Expiry Date	Certificate #
Shane Langely	WHMIS 2015	n/a	completed 08/14/20
	Leadership for Safety Excellence	n/a	completed on 02/29/24
	Rigging Awareness	Feb 24/28	893989
	Fall Protection I-Basic	Feb 19/28	893861
	Fall Protection II-Supervisor	Feb 11/28	893649
	Hazard Identification & Control	n/a	completed on Feb 7/24
	Confined Space- Generic	Mar 20/27	895168
	First Level Supervisor Training Program	n/a	completed on Aug 3/24
	Construction Project Management	n/a	Apr 1/24
	Introduction to Mentorship	n/a	completed on Mar 18/24
	Standard First Aid(CSA Intermediate Workplace First Aid)CPR C & AED	Mar 15/26	Ref.#2022496475
	Type 3 Group A&B - Scissor Lift & Boom Lift	Feb 27/28	Operator # 28781-593
	End-frame Scaffolding Practical	Apr 8/28	893998
Avery Charlton	WHMIS 2015	n/a	completed 08/14/20
	Transportation of Dangerous Goods	Feb 15/26	
	Excavation and Trenching	Mar 8/26	871971
	Confined Space-Generic	Mar 20/27	895157
	Fall Protection & Aerial Combo	Feb 10/28	1FP093563
	Standard First Aid(CSA Intermediate Workplace First Aid)CPR C & AED	Mar 15/26	Ref#057876750
	Type 3 Group A&B - Scissor Lift & Boom Lift	Feb 10/28	Operator #28781-537
John Comeau	Basic Workplace First Aid-CPR C and AED	Feb 12/28	Ref #1062409380
	Rigging Awareness	Feb 24/28	893984
	Confined Space-Generic	Mar 20/27	895159
	Fall Protection & Aerial Combo	Feb 27/28	1FP111493
	Clearing Saw Safety/Operator	n/a	completed 07/5/19
	Type 3 Group A&B - Scissor Lift & Boom Lift	Feb 27/28	Operator # 28781-596

ELLIOT EXCAVATORS LTD.

Employee Training Courses

Name	Course Name/Description	Expiry Date	Certificate #
Travis Trimper	Intermediate Workplace First Aid-CPR C and AED	Feb 14/28	Ref #1969296909
	Rigging Awareness	Feb 24/28	893996
	Confined Space- Generic	Mar 20/27	895178
	Fall Protection & Aerial Combo	Feb 10/28	1FP093562
	Type 3 Group A&B - Scissor Lift & Boom Lift	Feb 10/28	Operator # 28781-536
Dawson Thurber	Basic Workplace First Aid - CPR C and AED	Feb 19/28	Ref #0455541430
	Rigging Awareness	Feb 24/28	893995
	Confined Space- Generic	Mar 20/27	895177
	Type 3 Group A&B - Scissor Lift & Boom Lift	Feb 27/28	Operator # 28781-595
	Fall Protection & Aerial Combo	Feb 27/28	1FP111494

ELLIOT EXCAVATORS LTD.

Nova Scotia POWER An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

ELLIOT EXCAVATORS LTD.

Employee Training Courses			
Name	**Course Name/Description**	**Expiry Date**	**Certificate #**
Jason Lockhart	WHMIS 2015	n/a	completed 08/14/20
	JOHS Committee Member/Representative	n/a	465849
	BOATSMART	n/a	18032963007
	Transportation of Dangerous Goods	Feb 15/26	
	Fall Protection & Aerial Combo	Feb 10/28	1FP093564
	Standard First Aid(CSA Intermediate Workplace First Aid)CPR C & AED	Mar 15/26	Ref.#1333399641
	Confined Space- Generic	Mar 20/27	895170
	Type 3 Group A&B- Scissor Lift & Boom Lift	Feb 10/28	Operator # 28781-534
Warren Lange	Excavation and Trenching	Mar 8/26	871977
	Rigging Awareness	n/a	
	JOHS Committee Member/Rep	n/a	465848
	WHMIS 2015 Supervisor	n/a	476110
	WHMIS	n/a	w1304
	WHMIS 2015	n/a	505237
	BOATSMART	n/a	18032824180
	Fall Protection I-Basic	Feb 19/28	893860
	Fall Protection II-Supervisor	Feb 11/28	897704
	Transportation of Dangerous Goods	Feb 15/26	
	Confined Space- Generic	Mar 20/27	895167
	Intermediate Workplace First Aid CPR C and AED	Feb 14/28	Ref #0294271081
	Type 3 Group A&B- Scissor Lift & Boom Lift	Feb 27/28	Operator # 28781-594
	End-frame Scaffolding Practical	Apr 8/28	895997
Harvey Mattatall	Fall Protection & Aerial Combo	Feb 10/28	1FP093561
	Transportation of Dangerous Goods	Feb 15/26	
	Intermediate Workplace First Aid-CPR C and AED	Feb 14/28	Ref #0621934879
	Confined Space- Generic	Mar 20/27	895172
	BOATSMART	n/a	
	Type 3 Group A&B - Scissor Lift & Boom Lift	Feb 10/28	Operator # 28781-535

ELLIOT EXCAVATORS LTD.

Nova Scotia POWER An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

ELLIOT EXCAVATORS LTD.

Name	Employee Training Courses Course Name/Description	Expiry Date	Certificate #
Rachel Cole	NS Watercourse Installers Certificate	n/a	Completed Nov 5/21
	Fundamentals of Earthmoving	n/a	Completed Dec 16/16
	Asbestos Awareness (Waste Management Focus)	n/a	Completed Feb 21/18
	WHMIS 2015	n/a	Completed Feb 4/18
	Transportation of Dangerous Goods by Ground	Feb 16/28	Completed Feb 28/24
	Principles of Loss Control	n/a	Cert. # 486811
	Construction Entry Level Trianing	n/a	Cert. # 487716
	COR Evaluation (Course)	n/a	Cert. # 486825
	Accident/Incident Investigation	n/a	Cert. # 487049
	Leadership for Safety Excellence (eLearning Course)	n/a	Cert. # LSEe-753
	Joint Occupational Health & Safety Committee	n/a	Cert. # JOHSC-3593
	Excavation & Trenching	Mar 8/26	871973
	Fall Protection 1 - Basic	Mar 6/26	871906
	Hazard Identification & Control (eLearning Course)	n/a	Cert. # HICe-854
	Occupational Health & Safety Act	n/a	Cert. # ACT-2001
	WHMIS 2015 Supervisor	n/a	Cert. # WS-295
	Construction Safety Supervisor (CSS) Course	n/a	Cert. # CSS-1138
	Standard First Aid(CSA Intermediate Workplace First Aid)CPR C & AED	Mar 15/26	Ref.#1350629219
	Basic Rigging	n/a	Cert. # 18-01-626
	National Construction Safety Officer	June 29/26	Cert.#876250
	Scaffolding Awareness	n/a	Cert.#18-01-625
	H2S Awareness	May 22/28	Cert.#220a07-39c7d7-081cce56
	Construction Industry Ethics	n/a	completed Jan 11/24
	Microsoft Project for Construction	n/a	completed Nov 17/22
	Construction Law	n/a	Completed Mar 19/24
	Gold Seal Certification Construction Safety Practitioner	n/a	Completed Mar 22/24
	Mental Health	n/a	Completed Feb 19/25
	Rigging Awareness	Feb 24/28	893983
	COR Auditor Training	n/a	Completed Feb 07/25 #893448
	Mental Health First Aid Basic (12 -hour)		Cert. #536471
Scott Haverstock	Standard First Aid(CSA Intermediate Workplace First Aid)CPR C & AED	Mar 15/26	Ref.#0896492736
	Transportation of Dangerous Goods	Feb 15/26	

ELLIOT EXCAVATORS LTD.

8.14 COMMERCIAL/PRICE PROPOSAL REQUIREMENTS

Submitted in separate document.

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

EXTRA WORK

We have included our hourly rate sheet for our equipment. These rates include for all costs such as operator wages, fuel, and per diems for operators. Any material or subcontractors will be at our cost plus 10% mark up.

Nova Scotia POWER
An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

Equipment Rental Rates Effective March 2025 *HST Not Included in Hourly or Daily Rental Pricing* *Power not included in electric pump rentals*	ELLIOT EXCAVATORS LTD.
Description	**Rate***
Volvo 210 Excavator	$270.00/hr
Volvo 210 Hydraulic Excavator (c/w Allied 750 Hydraulic Hammer)	$395.00/hr
Volvo 350	$360.00/hr
Volvo 350 c/w Hammer	$460.00/hr
John Deere 135D Hydraulic Excavator	$210.00/hr
John Deere 350 Excavator	$360.00/hr
John Deere 350 c/w Hydraulic Hammer	$460.00/hr
John Deere 350 Excavator c/w Long Reach	$400.00/hr
John Deere 245 Excavator	$270.00/hr
Komatsu 308 Hydraulic Excavator	$320.00/hr
Takeuchi 35 Mini Excavator	$160.00/hr
Takeuchi35 Mini Excavator (c/w Hydraulic Hammer)	$190.00/hr
Bobcat E63 Excavator	$170.00/hr
Bobcat E63 Excavator (c/w Hydraulic Hammer)	$230.00/hr
Bobcat E85 Excavator	$185.00/hr
Bobcat E85 Excavator (c/w Hydraulic Hammer)	$260.00/hr
Bobcat E85 Excavator(c/w Hydraulic Shear)	$260.00/hr
Komatsu 380 Rubber Tire Loader	$280.00/hr
Dresser 530 Rubber Tire Loader	$200.00/hr
Komatsu WA250 Rubber Tire Loader	$230.00/hr
Komatsu WA320 Rubber Tire Loader	$250.00/hr
John Deere 324 Loader	$180.00/hr
Komatsu D39 Dozer	$200.00/hr
Komatsu D51 Dozer	$240.00/hr
Cat 66" Roller	$200.00/hr
B.W. 210 Vibratory Roller	$240.00/hr
Tandem Dump Truck	$150.00/hr
Single Axle Dump Truck	$130.00/hr
Moxy Rock Truck (25 Ton)	$240.00/hr
Moxy Rock Truck (30 Ton)	$300.00/hr
Foreman	$110.00/hr
Labourer	$75.00/hr
Surveyor	$100.00/hr
Diesel Plate Tamper	$400.00/day
Vibrating Deck Screener	$3000.00/day
Chainsaw	$175.00/day
Jumping Jack	$195.00/day
Pipe Cutoff Saw (Blades $15.00 each)	$175.00/day
Honda 2" Gas Pump	$175.00/day
Honda 3" Gas Pump	$235.00/day
Honda 4" Gas Pump	$340.00/day
2" High Head Electric Pump	$220.00/day
3" High Head Electric Pump	$280.00/day
4" High Head Electric Pump	$450.00/day
6" Diesel Pump	$2100.00/day

ELLIOT EXCAVATORS LTD.

Nova Scotia POWER An Emera Company

Tufts Cove Shoreline Sheet Pile Rock Revetment
#RFP-06/2025-545

Equipment Rental Rates Effective March 2025 *HST Not Included in Hourly or Daily Rental Pricing* *Power not included in electric pump rentals*	ELLIOT EXCAVATORS LTD.
Air Compressor (185 C.F.M.)	$600.00/day
Air Compressor (185 C.F.M.) w/ Concrete Breaker	$650.00/day
Pick Up (1 Ton)	$450.00/day
Grade Laser	$450.00/day
5000 W Honda Generator	$280.00/day
6500 W Honda Generator	$300.00/day
25000 W Generator	$2100.00/day
Rescue Boat	$700.00/day
Welder (400 AMP)	$1000.00/day
Light Tower (Diesel Powered)	$700.00/day

ELLIOT EXCAVATORS LTD.

_____ End of Submission_____

Primary Responses

Success: All data is valid!

Status	#	Item	Quantity Required	Unit of Measure	Numeric Unit Price	Total Cost
Mobilization and Demobilization						
Success: All values provided	#1-1	**Mobilization of all necessary equipment, material and labour force.**	1	Lump Sum	$ 150,000.00	$ 150,000.00
Success: All values provided	#1-2	**Demobilization of all equipment, material and labour force off the site and clean-up of construction site after completion of work**	1	Lump Sum	$ 150,000.00	$ 150,000.00
Basket Total						**$ 300,000.00**
Intake Extension and Underwater Excavation - Excavation Activities						
Success: All values provided	#2-1	**Labour (Site Labour)**	1	Lump Sum	$ 70,000.00	$ 70,000.00
Success: All values provided	#2-2	**Materials (Rock fill and consumables)**	1	Lump Sum	$ 45,000.00	$ 45,000.00
Success: All values provided	#2-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 50,000.00	$ 50,000.00
Success: All values provided	#2-4	**Surveying and Reporting**	1	Lump Sum	$ 15,000.00	$ 15,000.00
Basket Total						**$ 180,000.00**
Intake Extension and Underwater Excavation - Corestone and Leveling Course Layer at Intake Extension						

Success: All values provided	#3-1	**Labour (Site Labour)**	1	Lump Sum	$ 50,000.00	$ 50,000.00
Success: All values provided	#3-2	**Material**	1	Lump Sum	$ 200,000.00	$ 200,000.00
Success: All values provided	#3-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 150,000.00	$ 150,000.00
Success: All values provided	#3-4	**Surveying and Reporting**	1	Lump Sum	$ 15,000.00	$ 15,000.00
Basket Total						**$ 415,000.00**

Intake Extension and Underwater Excavation - Pre-cast Box Culvert Installation

Success: All values provided	#4-1	**Labour (Site Labour)**	1	Lump Sum	$ 200,000.00	$ 200,000.00
Success: All values provided	#4-2	**Materials (Precast box culvert and gaskets)**	1	Lump Sum	$ 214,750.00	$ 214,750.00
Success: All values provided	#4-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 350,000.00	$ 350,000.00
Success: All values provided	#4-4	**Surveying and Reporting**	1	Lump Sum	$ 25,000.00	$ 25,000.00
Basket Total						**$ 789,750.00**

Intake Extension and Underwater Excavation - CIP Concrete Headwall

Success: All values provided	#5-1	**Labour (Site Labour)**	1	Lump Sum	$ 50,000.00	$ 50,000.00
Success: All values provided	#5-2	**Materials (Concrete)**	1	Lump Sum	$ 100,000.00	$ 100,000.00

Success: All values provided	#5-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 150,000.00	$ 150,000.00
Success: All values provided	#5-4	**Removals and Cleanup**	1	Lump Sum	$ 20,000.00	$ 20,000.00
Basket Total						**$ 320,000.00**

Rock Revetment - Corestone Layer

Success: All values provided	#6-1	**Labour (Site Labour)**	1	Lump Sum	$ 100,000.00	$ 100,000.00
Success: All values provided	#6-2	**Materials**	1	Lump Sum	$ 600,000.00	$ 600,000.00
Success: All values provided	#6-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 150,000.00	$ 150,000.00
Success: All values provided	#6-4	**Surveying and Reporting**	1	Lump Sum	$ 15,000.00	$ 15,000.00
Basket Total						**$ 865,000.00**

Rock Revetment - Filter Stone Layer

Success: All values provided	#7-1	**Labour (Site Labour)**	1	Lump Sum	$ 75,000.00	$ 75,000.00
Success: All values provided	#7-2	**Materials**	1	Lump Sum	$ 125,000.00	$ 125,000.00
Success: All values provided	#7-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 150,000.00	$ 150,000.00
Success: All values provided	#7-4	**Surveying and Reporting**	1	Lump Sum	$ 15,000.00	$ 15,000.00

Basket Total						$ 365,000.00

Rock Revetment - Armour Stone Layer

Success: All values provided	#8-1	**Labour (Site Labour)**	1	Lump Sum	$ 125,000.00	$ 125,000.00
Success: All values provided	#8-2	**Materials**	1	Lump Sum	$ 515,000.00	$ 515,000.00
Success: All values provided	#8-3	**Equipment Costs & Rentals**	1	Lump Sum	$ 200,000.00	$ 200,000.00
Success: All values provided	#8-4	**Surveying and Reporting**	1	Lump Sum	$ 20,000.00	$ 20,000.00
Basket Total						$ 860,000.00

Project Closeout

Success: All values provided	#9-1	**Deficencies**	1	Lump Sum	$ 25,000.00	$ 25,000.00
Success: All values provided	#9-2	**Red Lines and As-Builts**	1	Lump Sum	$ 25,000.00	$ 25,000.00
Success: All values provided	#9-3	**Clean Up**	1	Lump Sum	$ 25,000.00	$ 25,000.00
Success: All values provided	#9-4	**Surveying and Reporting**	1	Lump Sum	$ 0.00	$ 0.00
Basket Total						$ 75,000.00

Grand Total						$ 4,169,750.00

Request IR-72:

G03: C0021608 TUC Shoreline Sheetpile Refurbishment

The capital application states: "Discussions with regulatory authorities regarding permitting requirements have been initiated. These permitting considerations are a key factor influencing the timing of the work, and early engagement is intended to streamline approvals and avoid delays during execution."

(a) Please describe the status of these discussions.

(b) Does NS Power have permits from the regulatory authorities?

(i) If not, does NS Power have an expected date by which all required permits will be approved?

(ii) If so, what is the expected start date for project construction?

Response IR-72:

(a) The project is located within the marine environment (i.e., federal lands) and therefore requires review under Sections 81–91 of the *Impact Assessment Act*. Given the scope of work, the project also requires a Fisheries Act Authorization (FAA) which is planned to be submitted in February 2026 for approval.

NS Power has met with Fisheries and Oceans Canada (DFO), Transport Canada (TC), and the Halifax Port Authority (HPA)—the primary regulatory authorities for marine works in the project area—to present and discuss the project. NS Power's Mi'kmaq Relations team has also presented the project to the relevant Mi'kmaq communities in Nova Scotia. NS

Power has taken into consideration the information gathered during these interactions for the preparation of the regulatory documentation as needed.

(b) No. NS Power is in the process of preparing the regulatory submissions as described in part (a) above.

(i) NS Power plans to submit an Environmental Effects Evaluation to Transport Canada and an FAA application in February 2026. Following submission of the regulatory documents, Transport Canada will have a minimum of 30 days to issue a determination, and DFO will have up to 90 days to provide a response.

(ii) The project construction is expected to start in October 2026.

Request IR-73:

G03: C0021608 TUC Shoreline Sheetpile Refurbishment

Page 154 states: "The contingency also covers any additional precautions that will need to be exercised based on feedback from governing authorities, such as the Department of Fisheries, or Transport Canada."

(a) Please describe these additional precautions.

(i) Please explain why the associated costs are included in the project contingency estimate rather that in the "base" construction cost estimate.

(b) Please explain if the Class estimate and contingency accounts for potential archaeological findings and associated delays?

Response IR-73:

(a) Additional precautions would include any mandated added scope from regulatory authorities that have not been scoped and priced at the time of the project submission.

(i) Only costs that NS Power is confident that will be required are included in the "base" cost estimate. Any costs that are considered risks, therefore may or may not be required, are better allocated under contingency. At the time the cost estimate was completed it was not known if there would be any additional mandated scope from the authorities. Until NS Power has the required permits approved to proceed with construction from the authorities, there is a potential for additional mandated scope.

(b) The contingency includes provisions for costs associated with potential archaeological findings. However, NS Power has presented the project and associated scope of work to the relevant Mi'kmaq communities and, to date, has not received any expressions of concern related to archaeological resources. Based on NS Power's current understanding, an archaeological investigation is not anticipated, as the project site is located within a marine area that has been subject to extensive disturbance over several decades.

Request IR-74:

G03: C0021608 TUC Shoreline Sheetpile Refurbishment

Page 8 of Attachment 1 (page 165) states: "It is important to note that information on the site, such as existing geotechnical conditions, seabed bathymetry, and environmental conditions, is extremely limited. The options presented are based on assumptions that will have to be validated during detailed design. Within the OPC for each option, probable costs are given for the appropriate investigations to determine this critical information and confirm final configurations."

(a) Has any of this investigative work been completed to date?

(i) If not, why not?

(ii) If so, please describe the related work completed to date, including a description of the findings and mitigative measures incorporated into the design to address the findings.

Response IR-74:

(a) Full bathymetry scanning of the harbour floor has been completed as part of the detailed design. Additionally, boreholes have been taken in multiple locations to support the bearing capacity of the harbour floor.

(i) N/A.

(ii) From the borehole sampling it was found that part of the harbour floor material needed to be unearthed down to solid till to accommodate the extension of the TUC3 CW Intake. In general, the bathymetry scanning and the boreholes

influenced the overall design of the geometry of the rock revetment. There were no significant findings that required major mitigative measures to be incorporated into the design.

Request IR-75:

G03: C0021608 TUC Shoreline Sheetpile Refurbishment

Combi-Wall Option: Pages 166 to 175 state: "Since these soil parameters are currently unknown, conservative assumptions have been made in the conceptual design. It is recommended to complete a geotechnical investigation program during the detailed design phase to reduce the uncertainty of these soil parameters. As design progresses and the soil conditions are better understood, it is possible that these assumptions may be relaxed, resulting in lower overall project costs."

(a) Please confirm that a geotechnical investigation was completed as part of the detailed design process.

(i) If not confirmed, please explain.

(ii) If confirmed, please confirm that the findings of the investigation were used to update the assumptions used to assess the feasibility of the combi-wall option, and used to update the cost estimate of the option.

1. If not confirmed, please explain.

2. If confirmed, please provide the updated cost estimate for the combi-wall option.

Response IR-75:

(a) The combi-wall option was not selected; therefore, detailed design was not completed. Geotechnical analysis was still completed as part of the rock revetment design.

(i) The rock revetment option was selected for this project, therefore the detailed design on the combi-wall was not completed.

(ii) The results of the geotechnical investigation were not used to update assumptions regarding the combi-wall option. The combi-wall option was not chosen to continue with detailed design because it caused significantly greater environmental habitat destruction, offered no geotechnical advantages, and required extensive underwater construction that would delay the project beyond the TUC3 outage window.

Request IR-76:

G03: C0021608 TUC Shoreline Sheetpile Refurbishment

In reference to the Concrete Retaining Wall and Partial Cell Encapsulation Option, page 170 states: "The proposed concrete encapsulation will not provide any structural capacity to resist lateral loads and is intended to be a sacrificial coating to prevents further corrosion of the SSP cells. Consequently, this option continues to rely on the structural integrity of the SSP cells to resist the retained soil and surcharge loads. As such, a detailed analysis of the structural capacity of the SSP cell will need to be undertaken during detailed design to confirm the existing SSP cells have sufficient load carrying capacity. If this analysis determines the existing SSP cells are inadequate, it will be necessary to reinforce the existing SSP cells prior to concrete encapsulation."

(a) Please provide the results of the detailed analysis of the structural capacity of the steel sheetpile (SSP) cell to confirm the existing SSP cells have sufficient load carrying capacity.

(i) Please confirm that the findings of the analysis were used to update the assumptions used to assess the feasibility of the Concrete Retaining Wall and Partial Cell Encapsulation option and used to update the cost estimate of the option.

1. If not, confirmed, please explain.

2. If confirmed, please provide the updated cost estimate for the Concrete Retaining Wall and Partial Cell Encapsulation Option.

(b) Page 171 states: "It is recommended to further investigate the existing condition of the buried portion of existing SSP walls before proceeding with detailed design of this

option. It should be noted that this investigation may not be practical due to the presence of existing pipework, etc."

(i) Please confirm that this investigation was completed as part of the detailed design process.

1. If not confirmed, please explain.

Response IR-76:

(a) The concrete retaining wall option was not selected; therefore, a detailed analysis was not completed on the structural capacity of the existing SSP structures.

(i) The concrete retaining wall option did not address the root cause concerns of the shoreline sheetpile issues. A design option that provided no structural reinforcement to an already severely corroded steel structure is not feasible. Additionally, this option would require continuous monitoring and maintenance. If this option were to fail at some point in its design life, then the combi-wall or rock revetment option would likely need to be implemented to encapsulate this.

(b) As noted above, this option was not considered to be a viable permanent fix. As such, NS Power did not proceed with further investigative work.

Request IR-77:

G03: C0021608 TUC Shoreline Sheetpile Refurbishment

In reference to the Rock Revetment Option, page 172 states: "A geotechnical field investigation and slope stability analysis will be required to confirm the geometry of the slope and if any dredging is required prior to installation. For the purposes of this study, we have assumed that the new material can be placed without dredging."

(a) Please confirm that a geotechnical investigation was completed as part of the detailed design process.

(i) If not confirmed, please explain.

(ii) If confirmed, please confirm that the findings of the investigation were used to update the assumptions used to assess the feasibility of the rock revetment option, and used to update the cost estimate of the option.

1. If not confirmed, please explain.

2. If confirmed, please provide the updated cost estimate for the rock revetment option.

Response IR-77:

(a) Confirmed.

(i) N/A.

(ii) The geotechnical investigation was used to inform the detailed design. After the detailed design was completed, this was sent out as part of the request for proposal (RFP) for firm price bidding. The pricing received from the winning proponent of the RFP was used to update the project estimate seen in the current project submission (Attachment 2).

Request IR-78:

G03: C0021608 TUC Shoreline Sheetpile Refurbishment

Page 177 states: "It is also recommended to complete a coastal study to determine the projected sea level rise and associated impacts to the site. If study results differ from noted design assumptions, the gathered information will still be relevant and can be incorporated into detailed design of all proposed options." Please confirm that a coastal study was completed as part of the detailed design process.

(a) If not confirmed, please explain.

(b) If confirmed, please confirm that the findings of the study were used to update the assumptions used to assess the projected sea level rise impacts to the site, and used the update the related cost estimate for each of the three design options.

(i) If not confirmed, please explain.

(ii) If confirmed:

(1) Please describe how the potential impacts of sea level rise will be incorporated into the project design.

(2) Please describe how this aligns with NS Power's Climate Adaptation Plan.

Response IR-78:

NS Power confirms that a coastal flooding assessment was completed as part of the detailed design process for the Tufts Cove Shoreline Sheetpile Refurbishment Project. DHI Water & Environment Inc. conducted the study to establish site-specific design water levels and wave conditions, including projected sea-level rise (SLR). The study informed the engineering design of the proposed rock revetment in accordance with NS Power's Climate Adaptation Plan. Please refer to Attachment 1 for a copy of the DHI coastal study.

(a) N/A. A coastal study was completed.

(b) The DHI coastal analysis was used to refine the engineering design basis for the preferred revetment solution. This included the 200-year return period total water level, projected SLR to 2080 (reflecting the 50-year design life), and design wave heights. These results were used directly to size armour stone, determine crest elevation requirements, and validate the long-term resilience of the revetment under future coastal conditions.

However, the coastal study did not result in updates to the cost estimates for the three remediation options (revetment, sheetpile replacement, or hybrid solution) developed during the options analysis. Costing for non-selected alternatives was not revisited once the preferred design path was chosen.

(i) N/A.

(ii) The findings of the DHI Coastal Analysis were incorporated into the design in several ways.

(1) The rock revetment has been designed to withstand current extreme water levels and wave conditions over its anticipated 50-year service life. The engineering assumptions related to stone sizing, slope selection, and tie-in

locations were informed by the future hydrodynamic conditions described in the coastal study.

(2) NS Power's Climate Adaptation Plan emphasizes the use of climate-informed engineering analysis, the prioritization of investments that address immediate risks. Consistent with this approach, the immediate risk at Tufts Cove relates to the deteriorated sheetpile wall and the associated potential for structural failure.

The selected revetment design has therefore been developed to address the immediate structural issues at the site while remaining compatible with potential future, site-wide coastal protection measures without requiring rework over the 50-year design life of this project.

The expert in WATER ENVIRONMENTS

MEMO: Halifax Tufts Cove Refurbishment Coastal Study

To:	Thomas McNutt
From:	Danker Kolijn, Patrick Joynt
Cc:	Mark Reynolds, Brandon Fillmore
Client:	Harbourside Engineering Consultants
DHI Ref. No.:	42804099
Date:	2024-12-13
Subject:	Halifax Tufts Cove Refurbishment Coastal Study

1 Introduction

Harbourside Engineering Consultants (HEC) has retained DHI Water & Environment, Inc (DHI) to conduct a coastal study to assess the design water levels and wave conditions at the Tufts Cove Generating Station in Halifax, Nova Scotia. It is understood that the end client, Nova Scotia Power, has contracted HEC to develop a detailed design for a rock revetment at the Generating Station to replace the original steel sheet pile wall within Zone 2 as shown in Figure 1.

Figure 1 Project Location

This document was prepared for the party indicated herein and the purposes outlined in this document. The material and information in the document reflect the opinion and best judgment of DHI Water & Environment, Inc. based on the information available at the time of preparation. Any use of this document or reliance on its content by third parties is the responsibility of the third party. DHI Water & Environment, Inc. accepts no responsibility for any damages suffered as a result of third-party use of this document or for uses other than the intended purposes stated herein.

1.1 Design Parameters

Nova Scotia Power has indicated that the target design life for the structure is 50-years, with a design return period event of 200-years. This corresponds to an encounter probability of 22% over the structure's design life, meaning there is a 22% chance that the 200-year event will occur during the design life of the structure.

1.2 Scope of Work

To support the design, DHI has completed the following tasks, which are detailed further in Appendix A:

- **Water Level Analysis:** Analyzed tides, storm surge, and total water levels using measured gauge data at the Bedford Institute. Extreme water levels were developed considering total water levels (tide inclusive of storm surge), and surge and tide separately.
- **Projected Sea Level Rise:** Developed projections for sea-level rise (SLR) using the Canadian Extreme Water Level Adaptation Tool (CAN-EWLAT) tool, based on the Intergovernmental Panel on Climate Change's Sixth Assessment Report of the United Nations (IPCC AR6).
- **Static Design Water Levels:** Derived static design water levels considering the 200-year design event, 50-year design life, and projected SLR.
- **Offshore Hindcast:** Analyzed a 64-year historical hindcast (MSC50) product to derive the extreme offshore wind and wave conditions.
- **Wave Modelling:** Developed a MIKE21 Flexible Mesh (FM) Spectral Wave (SW) model to transform offshore wave conditions to the project site.
- **Design Wave Conditions:** Presented 2D maps of design significant wave heights and peak wave periods for the governing wave conditions.

2 Summary of Results

A summary of the design water levels, and wave results is presented below. Details on the study methodology and additional results are provided in Appendix A.

2.1 Design Water Levels

Design water levels were determined using measured water level gauge data at the nearby Bedford Institute. Given the proximity of this gauge to the site, it is reasonable to assume that water levels observed at the gauge are representative of those experienced at the Tufts Cove Generating Station. An extreme value analysis was conducted on both total water levels (joint probability of tide and surge) and storm surge residuals to identify the 200-year return period event. The analysis determine that the 200-year total water level is 1.69 m, CGVD2013, while the storm surge residual is 1.52 m. Adding the Higher High Water Large Tide (HHWLT) to the storm surge residuals results in a level of 2.25 m, CGVD2013.

Static design water levels were derived using the concept of cumulative encounter probability, which typically results in less conservative design water level elevation recommendations compared to conventional methods where storm surge, tides, and projected SLR are added together. Nova Scotia Power has provided the following design parameters:

- Design life: 50-years
- Design event return period: 200-years
- Encounter probability: 22% (associated with design life and design event return period)
- Note that it has been assumed that construction will begin in the year 2030, resulting in SLR projections for the year 2080 at the end of the design life.

Figure 2 illustrates the design static water level, which is derived from the total water level extreme value analysis and projected SLR. The resulting design static water level is 2.14 m, CGVD2013. It is important to note that this elevation does not include allowances for freeboard or wave runup / overtopping, which would necessitate a higher design elevation.

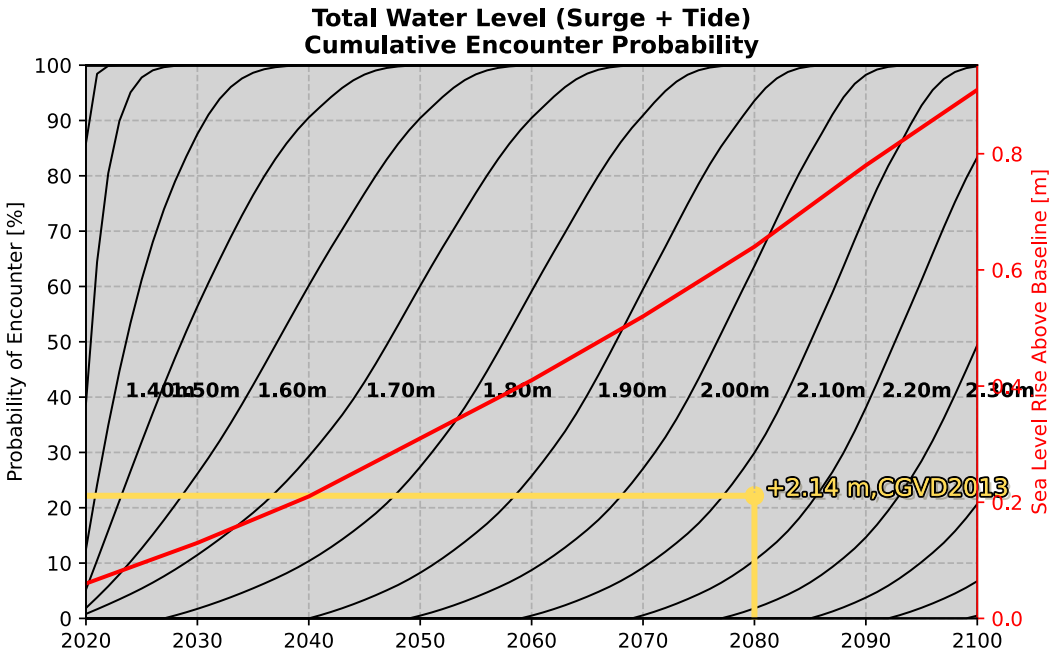


Figure 2 Design Static Water Level

2.2 Design Wave Conditions

The offshore extreme wind and wave conditions were transformed to Tufts Cove using the MIKE21 Flexible Mesh (FM) Spectral Wave (SW) model. The model simulated a range of discrete event scenarios including combinations of extreme winds, waves, and water levels. These scenarios included return periods from 1- to 200-years and extreme winds and waves simulated in 30° directional bins. SLR projections were included for the years 2020 to 2100, in 10-year increments and the extreme water levels used to force the model were based on the results from the total water level extreme value analysis. Further details on the model forcings, resolution, and bathymetric data used in the model can be found in Appendix A.

Figure 3 and Figure 4 present the significant wave heights and peak wave periods at the project location for the design event (200-year return period event with SLR projected to the year 2080) for two directional bins (150° and 240°). The 150° directional bin produced the largest significant wave heights and peak wave periods at the project site, with wave heights on the order of 1.0 – 1.2 m and wave periods on the

order of 3.0 – 3.5 s. However, these waves are highly oblique to the shoreline, which would limit wave runup and overtopping. The 240° directional bin generated the largest significant wave heights and peak wave periods that are perpendicular to the shoreline, wave heights are on the order of 0.8 – 1.0 m and wave periods are on the order of 2.5 – 3.0 s.

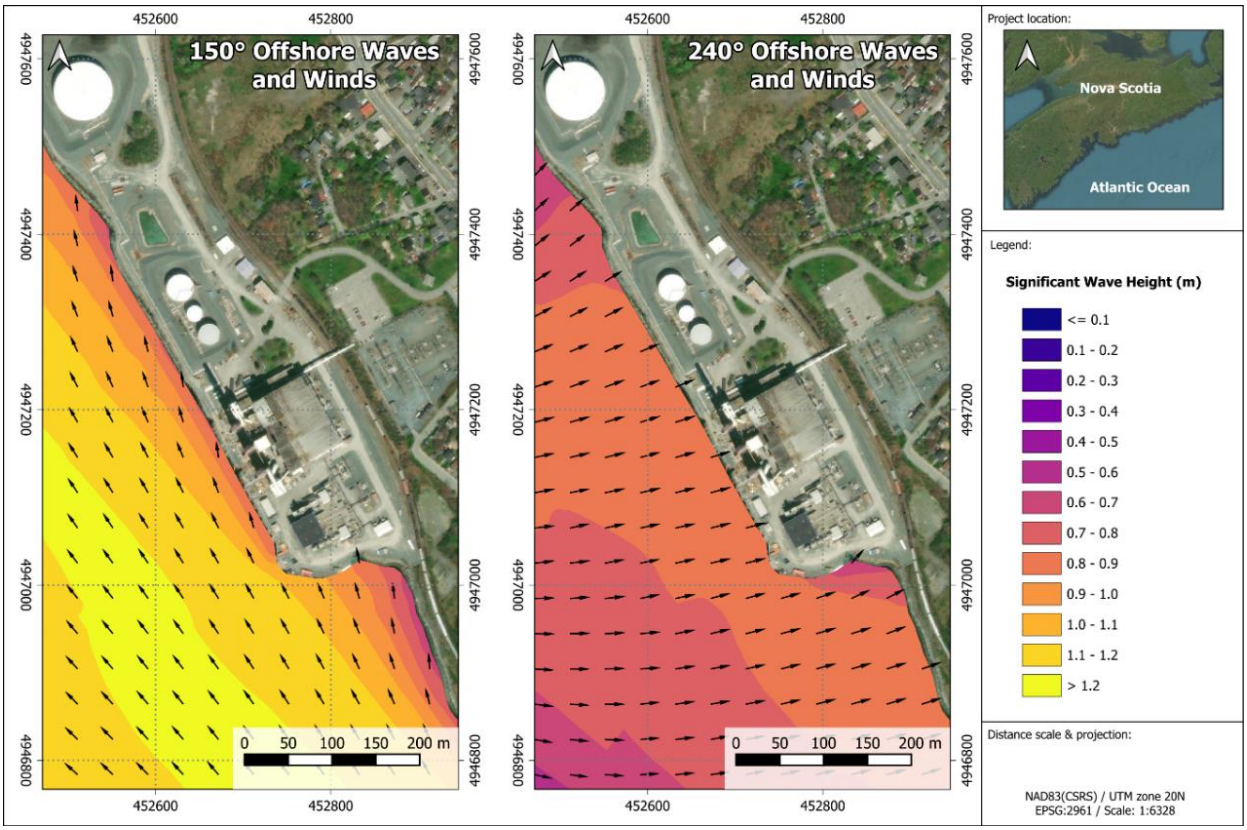


Figure 3 Design significant wave heights for a 200-year return period event with 2080 SLR

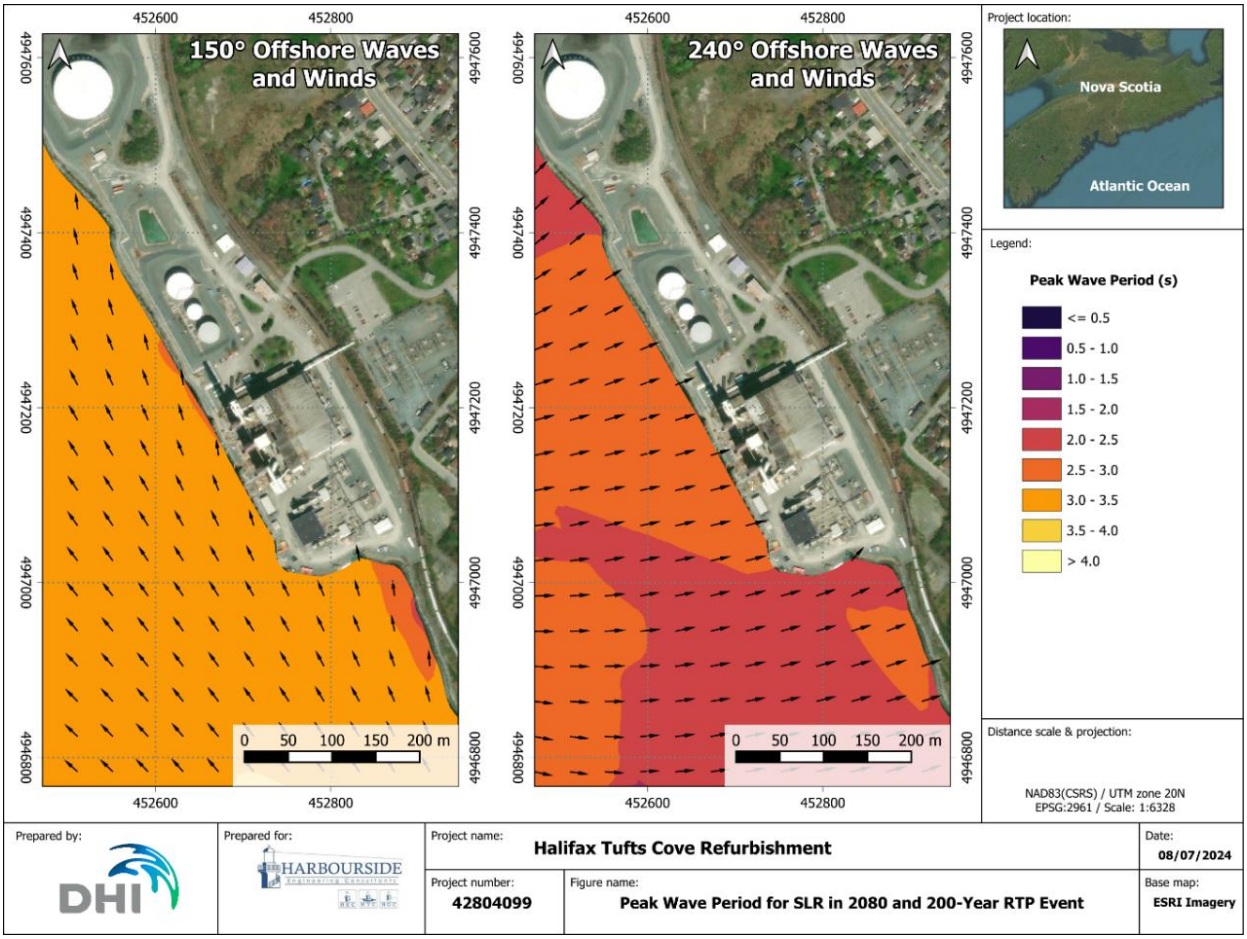


Figure 4 Design peak wave periods for a 200-year return period event with 2080 SLR

3 Conclusions and Recommendations

A coastal study was completed to assess design water levels and design waves at the Tufts Cove Generating Station in Halifax, Nova Scotia. The study concluded the following:

1. The design static water level is 2.14 m, CGVD2013. This water level does not include any allowance for freeboard, wave runup or overtopping. It is assumed that HEC will perform additional analysis to account for these allowances.
2. For assessing armour stone sizing, a significant wave height on the order of 1.0 – 1.2 m and peak wave periods on the order of 3.0 – 3.5 s should be used.
3. For assessing wave runup / overtopping, the resulting runup / overtopping for the design wave conditions from 150° and 240° should be compared, considering wave obliquity for the event from 150°.

It is recommended that a wave runup assessment be conducted to determine the appropriate crest elevation of the revetment to limit wave overtopping below a specified threshold. Additionally, it should be noted that the science of SLR will keep evolving with updated observations and improve model predictions. Implications for infrastructure and coastal flood will need to be re-evaluated with periodic updates in SLR projections.

4 Closure

We trust that this memorandum meets your current needs. Please do not hesitate to reach out to us with any questions or comments.

Best Regards,

Prepared by:

Patrick Joynt, P.Eng., M.A.Sc.
Coastal Engineer, Marine & Coast
Tel: 1 613 316 9163 | pjgj@dhigroup.com

Reviewed by:

Danker Kolijn, P.Eng., M.A.Sc., M.Eng.
Project Director, Americas-Pacific, Marine & Coast
Tel: 1 672 515 8028 | dank@dhigroup.com

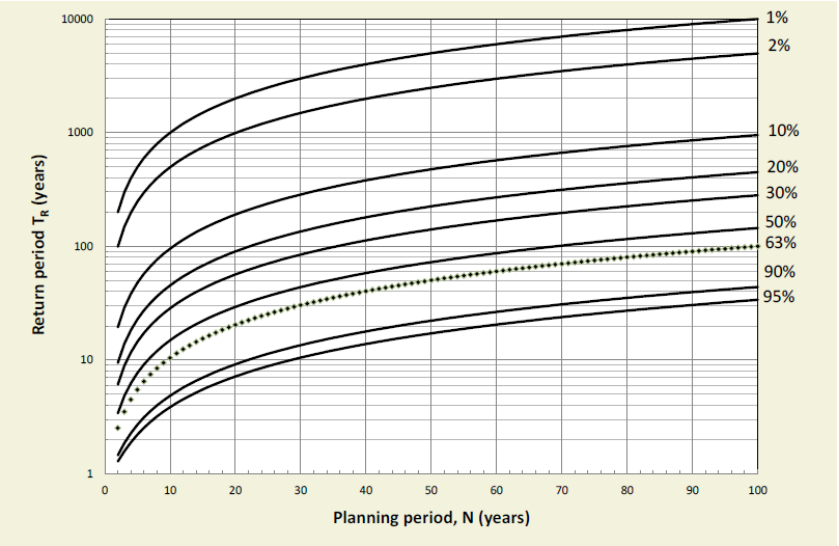
Appendix A PowerPoint Presentation of All Results

COASTAL STUDY – Summary of Results
Tufts Cove
Dartmouth, NS
Project No. 42804099
2024-08-09
Patrick Joynt, P.Eng, MSc.
DHI Water & Environment Inc.
DHI

Encounter Probability

Design Life = 50-years
Design Return Period = 200-years

Encounter Probability = 22%

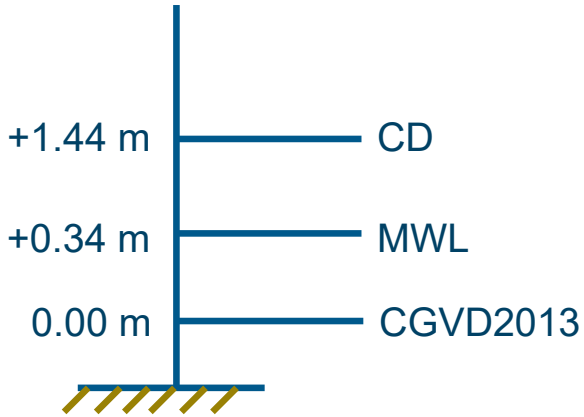


Return period [years]	Design life [years]								
	1	5	10	20	30	40	50	75	100
1	100%	100%	100%	100%	100%	100%	100%	100%	100%
5	20%	67%	89%	99%	100%	100%	100%	100%	100%
10	10%	41%	65%	88%	96%	99%	99%	100%	100%
25	4%	18%	34%	56%	71%	80%	87%	95%	98%
50	2%	10%	18%	33%	45%	55%	64%	78%	87%
100	1%	5%	10%	18%	26%	33%	39%	53%	63%
200	1%	2%	5%	10%	14%	18%	22%	31%	39%

© DHI

Tides at Bedford Institute

Tidal Level	Tide, m (CD)	Tide, m (CGVD2013)
HAT	2.21	0.77
HHWLT	2.17	0.73
HHWMT	1.83	0.39
HWL	1.77	0.33
MWL	1.10	-0.34
LWL	0.46	-0.98
LLWMT	0.36	-1.08
LLWLT	-0.01	-1.45
LAT	-0.05	-1.49

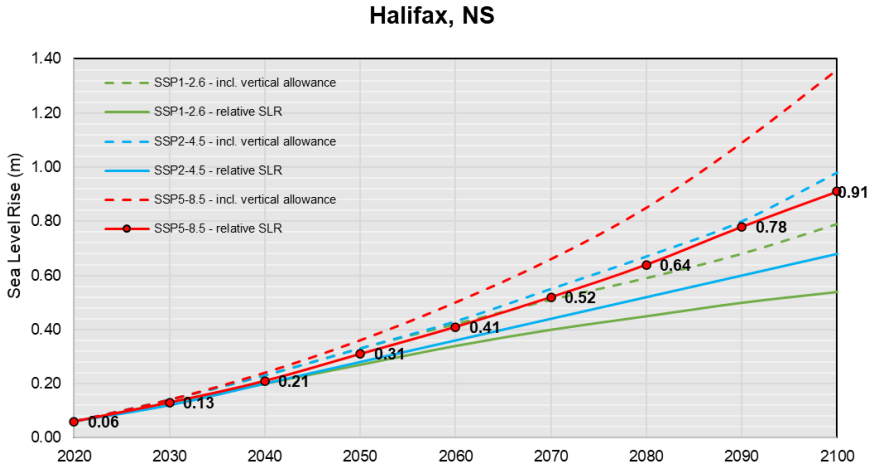


$$Z_{CD} = Z_{CGVD2013} + 1.44$$
$$Z_{CD} = Z_{MSL} + 1.10$$

© DHI

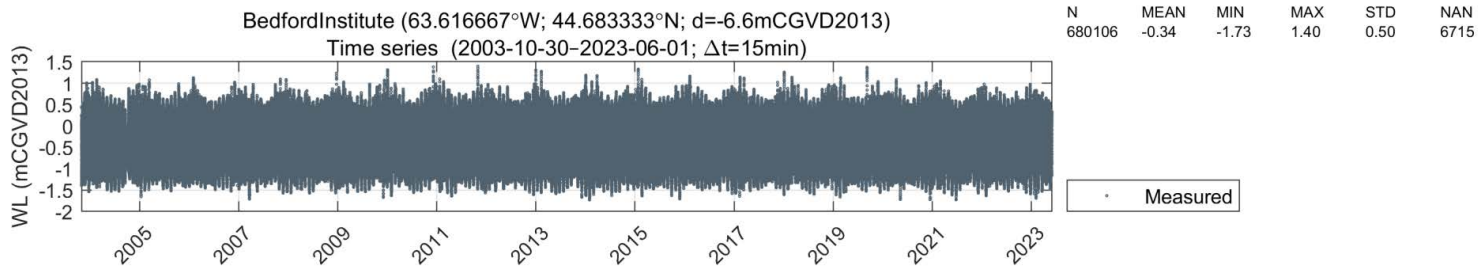
Sea Level Rise

Year	Sea Level Rise (m) SSP8.5 – relative SLR
2020	0.06
2030	0.13
2040	0.21
2050	0.31
2060	0.41
2070	0.52
2080	0.64
2090	0.78
2100	0.91



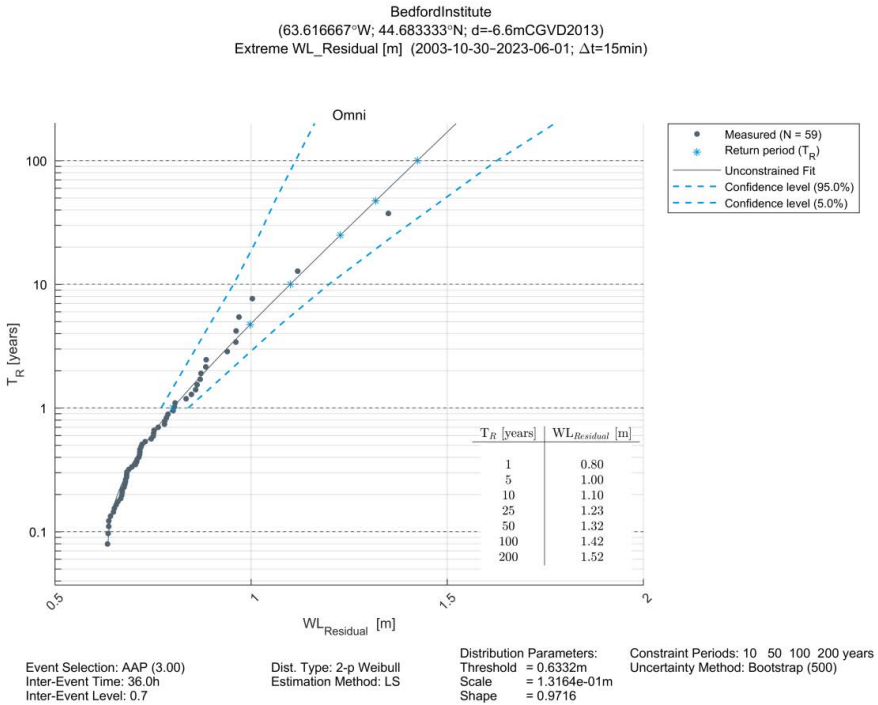
© DHI

Measured Water Levels
Bedford Institute (CHS Station 00491)



Surge Residual at Bedford Institute

RTP	Surge (m)
1	0.80
5	1.00
10	1.10
25	1.23
50	1.32
100	1.42
200	1.52

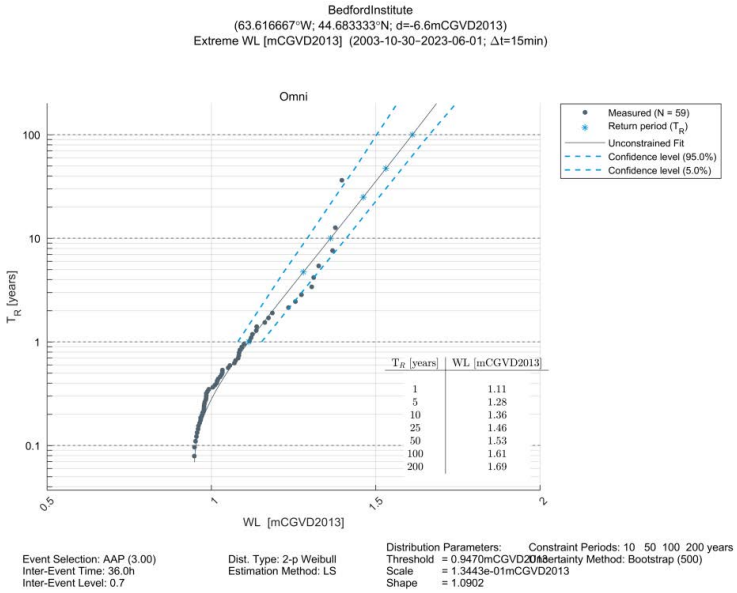


© DHI

Total Water Levels

RTP	Surge Residual (m)	Surge Residual + HHWLT (m, CCGV2013)	Total Water Level (surge + tide) (m CGVD2013)
1	0.80	1.53	1.11
5	1.00	1.73	1.28
10	1.10	1.83	1.36
25	1.23	1.96	1.46
50	1.32	2.05	1.53
100	1.42	2.15	1.61
200	1.52	2.25	1.69

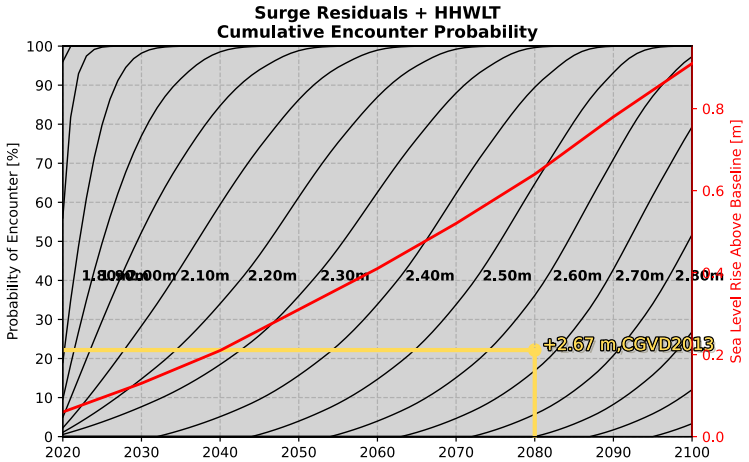
Total Water Level = joint probability of tide & surge



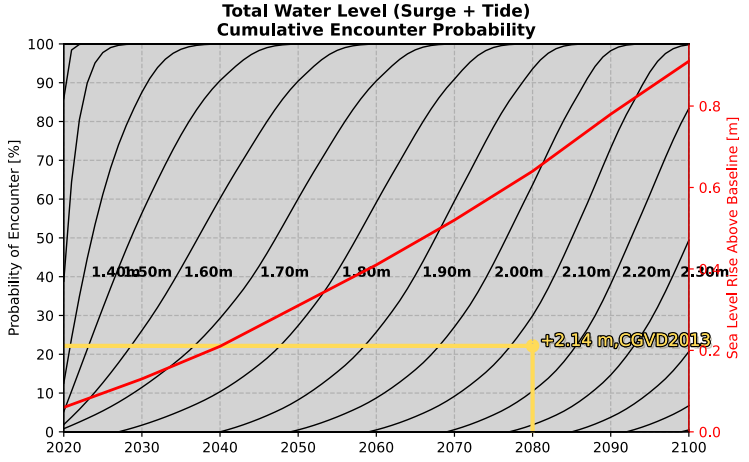
© DHI

Static Design Water Level

Surge Residuals + HHWLT



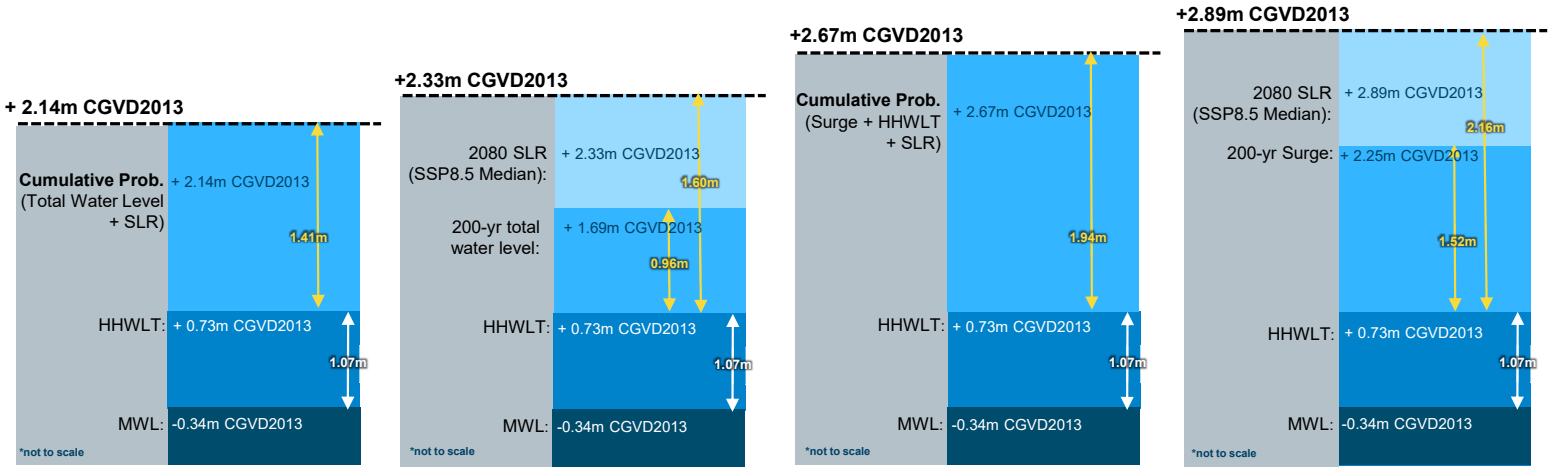
Total Water Levels (tide incl. surge)



- 200-year design event, design life of 50-years, construction in 2030
- No allowance for freeboard or wave runup / overtopping effects is included in this analysis

© DHI

Static Design Water Level



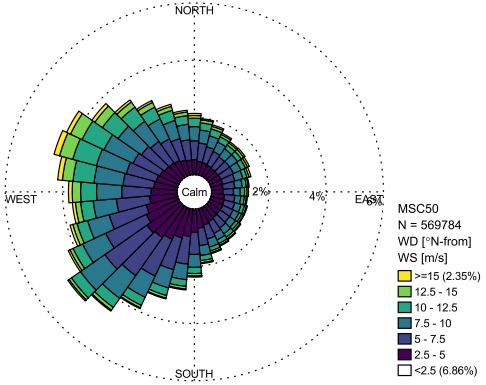
- 200-year design event, design life of 50-years, construction in 2030
- No allowance for freeboard or wave runup / overtopping is included in this analysis

© DHI

Offshore MSC50 Wind Statistics

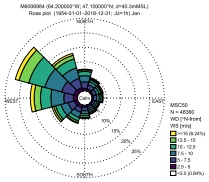
MSC50 Wind Climate
Annual Wind Rose
1954 - 2018

M6006984 (64.200000°W; 47.100000°N; d=40.3mMSL)
Rose plot (1954-01-01-2018-12-31; Δt=1h) Omni

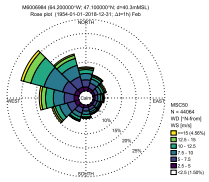


© DHI

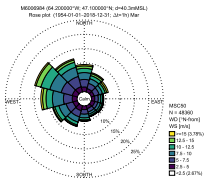
January



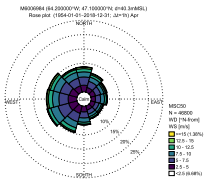
February



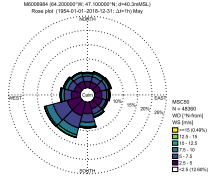
March



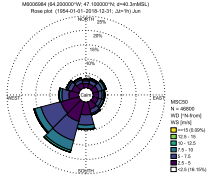
April



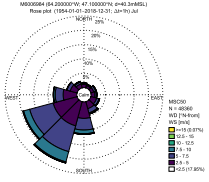
May



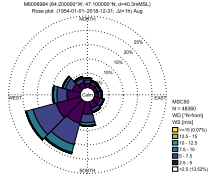
June



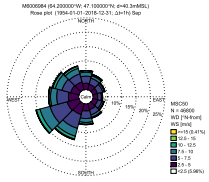
July



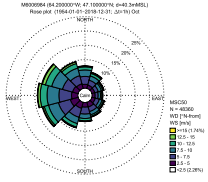
August



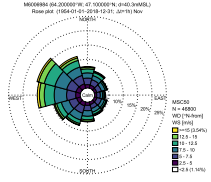
September



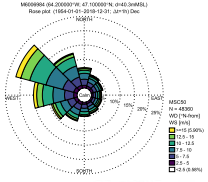
October



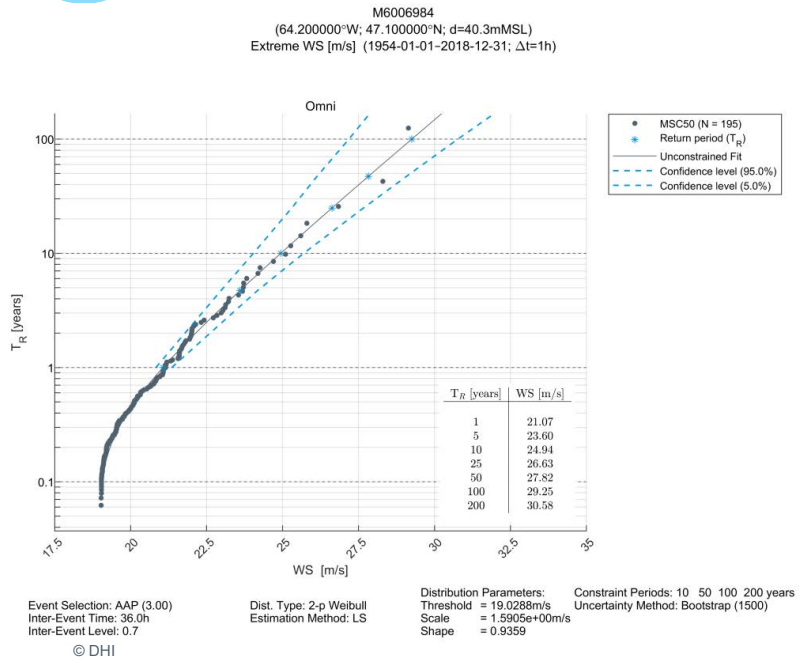
November



December



Offshore MSC50 Wind Statistics



Event Selection: AAP (3.00)
Inter-Event Time: 36.0h
Inter-Event Level: 0.7

Dist. Type: 2-p Weibull
Estimation Method: LS

Distribution Parameters:
Threshold = 19.0288m/s
Scale = 1.5905e+00m/s
Shape = 0.9359

Constraint Periods: 10 50 100 200 years
Uncertainty Method: Bootstrap (1500)

© DHI

Wind Speed (m/s) in 30° bins - Return Period (years)

	1	5	10	25	50	100	200
0 Central Est.	17.45	19.85	20.97	22.27	23.15	24.16	25.06
30 Central Est.	17.25	19.88	21.11	22.55	23.52	24.64	25.65
60 Central Est.	17.81	20.81	22.20	23.81	24.90	26.14	27.26
90 Central Est.	17.36	20.23	21.58	23.18	24.26	25.51	26.64
120 Central Est.	17.06	19.44	20.58	21.92	22.83	23.88	24.83
150 Central Est.	17.33	20.14	21.55	23.28	24.49	25.90	27.20
180 Central Est.	17.41	20.23	21.70	23.53	24.82	26.36	27.78
210 Central Est.	17.50	20.28	21.71	23.47	24.69	26.14	27.48
240 Central Est.	18.22	20.87	22.17	23.72	24.78	26.01	27.13
270 Central Est.	18.23	20.09	20.96	21.99	22.68	23.47	24.19
300 Central Est.	18.17	20.20	21.20	22.42	23.25	24.23	25.13
330 Central Est.	17.65	19.73	20.70	21.85	22.62	23.51	24.31

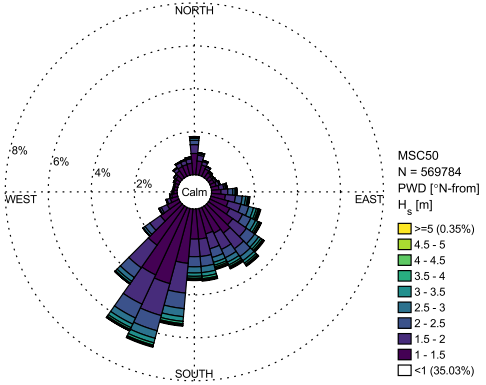
Seasonal Wind Speed (m/s) - Return Period (years)

	1	5	10	25	50	100	200
Jan Central Est.	18.43	20.65	21.69	22.92	23.75	24.71	25.58
Feb Central Est.	17.91	20.60	21.88	23.37	24.39	25.55	26.61
Mar Central Est.	17.24	20.11	21.54	23.27	24.46	25.86	27.14
Apr Central Est.	15.40	17.83	18.96	20.29	21.18	22.20	23.12
May Central Est.	13.10	15.60	16.81	18.25	19.24	20.38	21.42
Jun Central Est.	12.01	14.50	15.71	17.15	18.14	19.29	20.33
Jul Central Est.	10.56	13.41	15.04	17.17	18.73	20.64	22.45
Aug Central Est.	11.44	14.28	15.82	17.75	19.13	20.78	22.33
Sep Central Est.	13.70	17.48	19.55	22.19	24.08	26.37	28.52
Oct Central Est.	16.14	19.24	20.78	22.65	23.94	25.44	26.82
Nov Central Est.	17.26	20.12	21.48	23.10	24.21	25.49	26.64
Dec Central Est.	18.22	20.61	21.76	23.12	24.05	25.13	26.10

Offshore MSC50 Wave Statistics

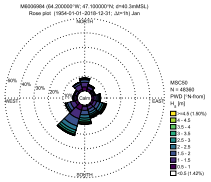
MSC50 Offshore Waves
Annual Wave Rose
1954 - 2018

M6006984 (64.200000°W; 47.100000°N; d=40.3mMSL)
Rose plot (1954-01-01-2018-12-31; Δt=1h) Omni

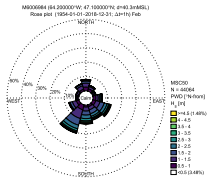


© DHI

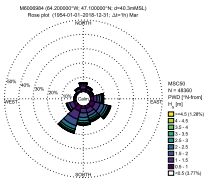
January



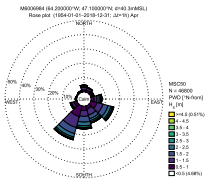
February



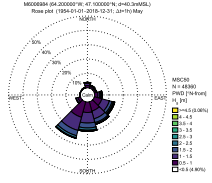
March



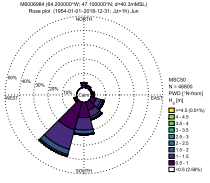
April



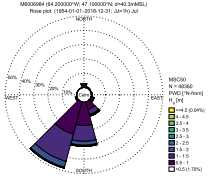
May



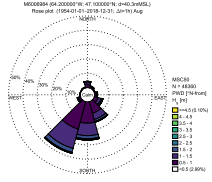
June



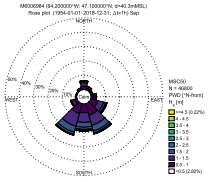
July



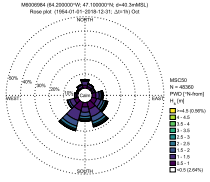
August



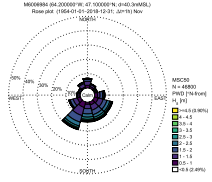
September



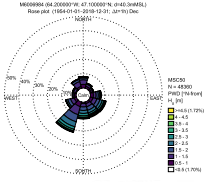
October



November

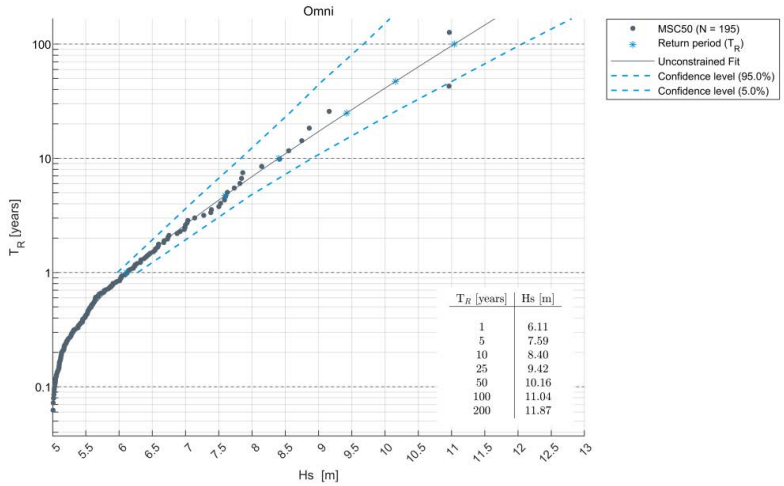


December



Offshore MSC50 Wave Statistics

M6006984
(64.200000°W; 47.100000°N; d=40.3mSL)
Extreme Hs [m] (1954-01-01-2018-12-31; Δt=1h)



Event Selection: AAP (3.00)
Inter-Event Time: 36.0h
Inter-Event Level: 0.7

Dist. Type: 2-p Weibull
Estimation Method: LS

Distribution Parameters:
Threshold = 5.0050m
Scale = 8.5332e-01m
Shape = 0.8900

Constraint Periods: 10 50 100 200 years
Uncertainty Method: Bootstrap (1500)

© DHI

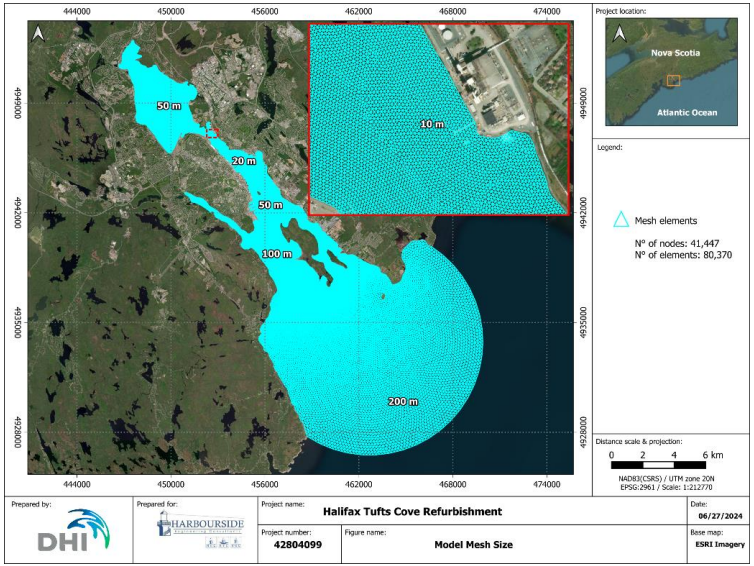
Wave Height (Hs, m) in 30° bins - Return Period (years)

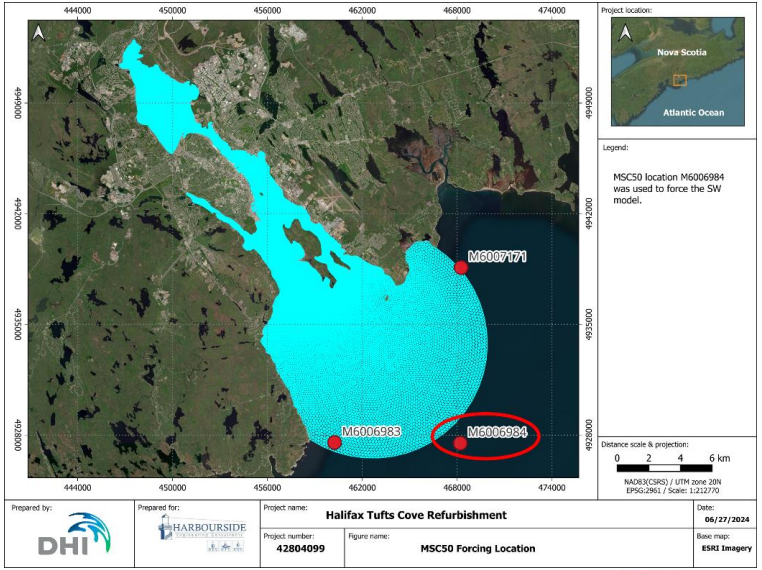
	1	5	10	25	50	100	200
0 Central Est.	4.22	5.19	5.69	6.29	6.71	7.21	7.66
30 Central Est.	2.43	3.00	3.30	3.66	3.91	4.21	4.48
60 Central Est.	2.38	3.09	3.46	3.92	4.24	4.63	4.99
90 Central Est.	3.88	5.03	5.61	6.30	6.79	7.35	7.87
120 Central Est.	5.25	6.32	6.81	7.39	7.77	8.21	8.60
150 Central Est.	5.51	6.78	7.43	8.22	8.77	9.42	10.02
180 Central Est.	5.46	7.02	7.88	8.98	9.78	10.75	11.65
210 Central Est.	4.83	5.94	6.52	7.23	7.72	8.31	8.86
240 Central Est.	2.84	3.33	3.57	3.86	4.06	4.30	4.51
270 Central Est.	2.13	2.62	2.87	3.17	3.38	3.62	3.84
300 Central Est.	2.10	2.57	2.81	3.10	3.31	3.55	3.78
330 Central Est.	2.46	2.96	3.21	3.50	3.70	3.94	4.15

Seasonal Wave Height (Hs, m) - Return Period (years)

	1	5	10	25	50	100	200
Jan Central Est.	4.56	5.70	6.25	6.89	7.33	7.85	8.31
Feb Central Est.	4.49	6.04	6.80	7.71	8.33	9.07	9.73
Mar Central Est.	4.21	5.62	6.35	7.26	7.90	8.66	9.36
Apr Central Est.	3.61	4.72	5.28	5.96	6.44	6.99	7.50
May Central Est.	2.79	3.65	4.08	4.59	4.95	5.36	5.74
Jun Central Est.	2.29	3.16	3.63	4.22	4.65	5.16	5.63
Jul Central Est.	1.99	3.03	3.72	4.67	5.42	6.36	7.30
Aug Central Est.	2.14	3.40	4.23	5.43	6.35	7.55	8.74
Sep Central Est.	2.91	4.58	5.57	6.90	7.89	9.12	10.31
Oct Central Est.	3.55	5.06	5.88	6.92	7.66	8.56	9.40
Nov Central Est.	4.08	5.55	6.31	7.23	7.88	8.65	9.36
Dec Central Est.	4.63	5.95	6.59	7.35	7.86	8.47	9.01

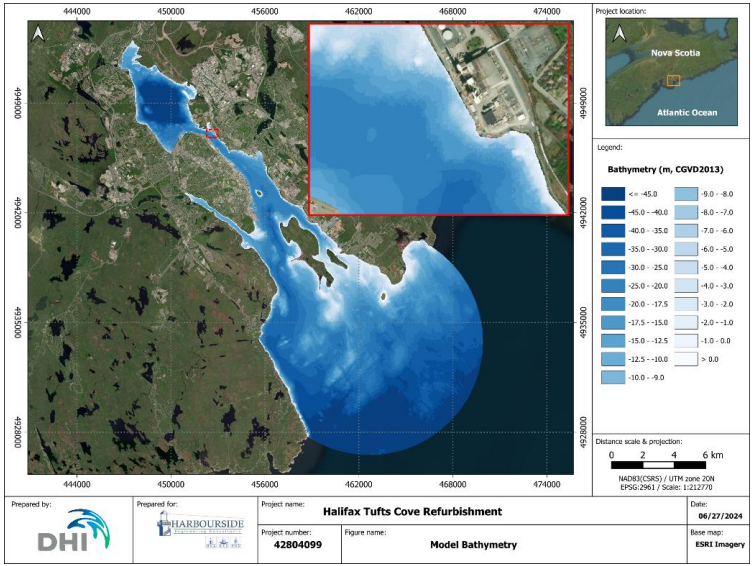
MIKE21 FM SW Domain

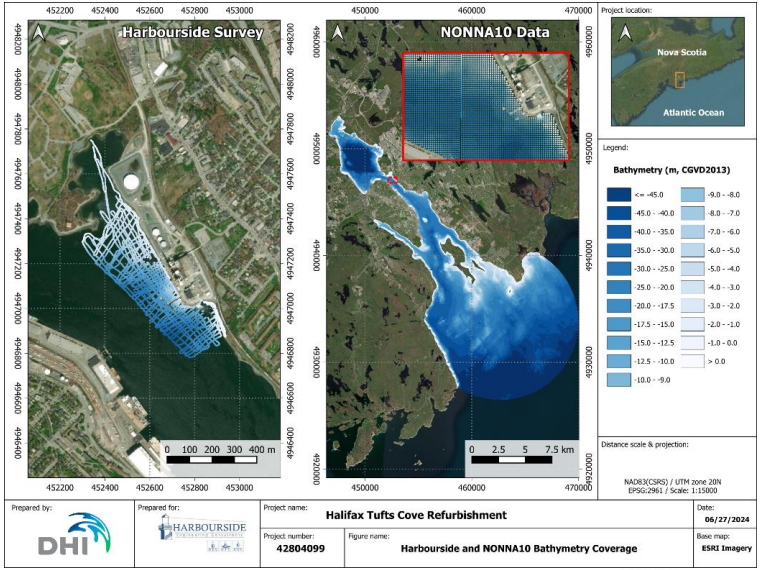




© DHI

Bathymetric Data

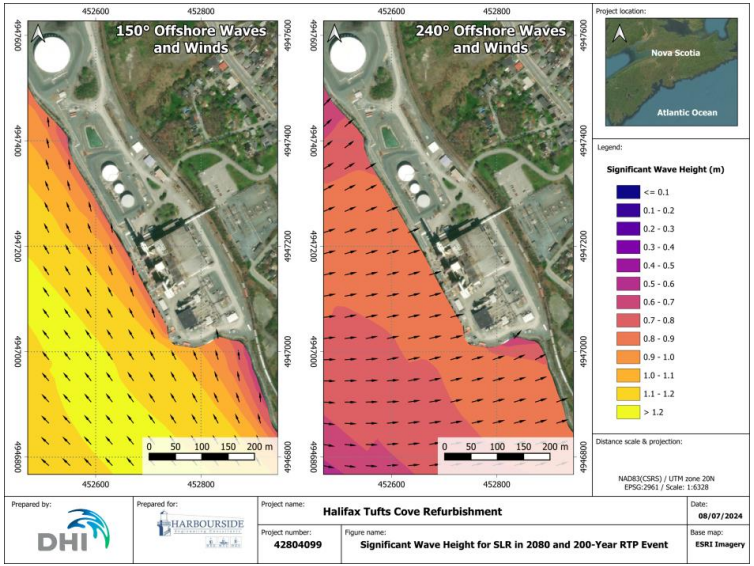


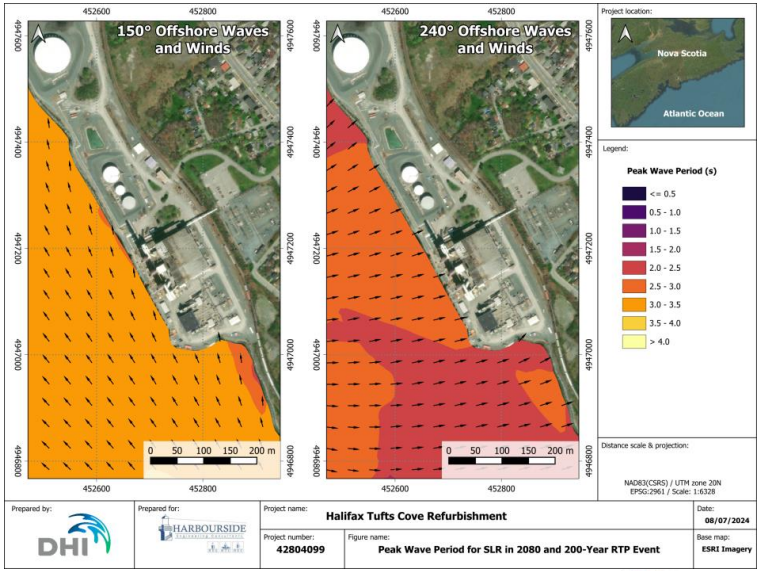


© DHI

Wave Conditions During Design Event
200-year Return Period with 2080 SLR

*Model results are based on water levels using the TWL EVA





© DHI

Request IR-79:

G03: C0021608 TUC Shoreline Sheetpile Refurbishment

Please explain what Attachment 2 is intended to represent.

(a) Please explain how the cost estimates in Attachment 2 were developed.

(b) Please explain how the cost estimates in Attachment 2 align with the cost estimate on page 191.

(c) Please describe the reasons for the significant increase in the project cost estimate between page 191 and Attachment 2.

(i) Given the significant increase in cost, please explain why the cost estimates for the other two options were not updated to determine whether the rock revetment option provides the best value for money.

Response IR-79:

Attachment 2 is the cost table of the preferred proponent of the request for proposal, included for cost support for the values provided in the detailed cost estimate for this project in the 2026 ACE Plan (PDF page 155). The cost table was provided by NS Power to the proponents of the RFP to ensure consistent and detailed pricing amongst each of the proponents bidding.

(a) Attachment 2 is a firm price bid of the preferred proponent resulting from the request for proposal.

(b) The cost estimate on page 191 was completed after the initial option analysis report, whilst Attachment 2 is a firm price resulting from the request from proposal that was supported by the detailed design. They are not intended to align.

(c) The significant increase is cost difference between the high-level cost estimate in the options analysis report, and the RFP costs can be attributed to the following:

- The estimate from the options report is an order of magnitude estimate that assuming the same scope can range from -50% to +100%. In this case, the scope had changed between the options analysis and the final detailed design as more information was gathered to complete the detailed design.

- A geotechnical analysis was not complete when the options analysis was done. The soil conditions were assumed to be sufficient to proceed with this solution without any dredging. The geotechnical analysis revealed that the intake extension footprint required dredging and further work than what was forecasted in the options analysis. Another consideration is that turbidity in the water (debris) must be controlled as part of permitting which is an added complexity factor that may not have been considered in the options analysis.

- At the time of the options analysis estimate, work scheduling was not factored into the cost estimate. NS Power has requested that this work take place during the Tufts Cove Unit 3 scheduled outage, which is a 53-day duration in Fall 2026. This schedule is very aggressive for a project of this scope. Additional labour and equipment requirements for extended working hours and over weekends also factored into a cost increase from the RFP. This schedule was opted for so that TUC 3's operation would not be impacted by construction activities, and to ensure no equipment damage takes place due to construction debris.

- The style of intake extension was changed from a king-pile canal to a pre-cast box culvert canal, possibly introducing additional material, engineering and labour expense. This change was made to better align with the project timeline. The intake extension in the class D estimate was $225K compared to [redacted] in the firm price bid (Attachment 2).

- The equipment costs have proven to be a significant portion of the RFP cost, likely due to the fact the work will need to be completed entirely from marine based machinery. This may not have been considered in the estimate, as mentioned, the "Location Factor".

- Escalation (inflation) costs were not factored into the estimate, which is from 2023.

- Location factor is undefined, which may have generated inconsistencies in the estimate vs. the RFP amount.

- There was 64% more rock revetment material in the actual design vs options analysis assumption. This change is likely due to sea level rise, wave action, and geotechnical parameters of the soil that were outlined in the geotechnical analysis.

(i) Detailed design was not completed for the other options and therefore not sent out for firm price bidding. NS Power is confident that the rock revetment option is the best solution from both a cost and reliability perspective over the desired 50-year timeline.

Request IR-80:

G04: C0068898 TUC1 IP LP Last Stage Blade Replacement

In matter M10985 an application for CI C0055376 in 2023, the Board approved NS Power's request to replace five L-0 blades with re-used blades and refurbishment of an additional two blades. Are any of the blades that were replaced or refurbished in 2023 part of this project request?

Response IR-80:

As part of this project, NS Power will be replacing the three entire L-0 rows (318 blades total) with newly manufactured blades. This approach ensures long-term reliability for the machine and avoids the operational risk associated with mixing new components with blades that are manufactured by a different supplier, have accumulated service time and have experienced in service issues. The blades that were re-used or refurbished as part of CI C0055376 will be removed from service.

Request IR-81:

G04: C0068898 TUC1 IP LP Last Stage Blade Replacement

Please provide the forecast capacity factor and utilization factor for TUC1 for each year from 2026 up to and including 2035.

(a) Given these forecast capacity and utilization factors, please describe any work NS Power has undertaken to assess opportunities to continue operation of TUC1, or shifting of load to other generating facilities, without requiring the need for the proposed capital project.

Response IR-81:

Please refer to Figure 11 of the 2025 10 Year System Outlook for forecast utilization factors.[1]

Please refer to Figure 9 of the 2025 10 Year System Outlook for forecast capacity factors.[2]

(a) These projections reflect the continued system need identified in the Evergreen IRP, which considered the capacity and energy contributions of the Tufts Cove Generating Station — including TUC1 — as well as forecast sustaining capital investment, including in the TUC1 turbine. The analysis within the Evergreen IRP concluded that maintaining TUC1 well beyond 2035 and extending into the 2040-2050 period is the lowest cost option to provide the generation capacity required. The IRP analysis demonstrated that TUC1 provides essential firm capacity and critical winter reliability during periods of low renewable generation availability. As a result, the generation forecasts in the 2025 10-Year System Outlook incorporate the ongoing operational role of TUC1 consistent with IRP-validated long-term resource plan.

[1] M12386, NS Power 10-Year System Outlook, Exhibit N-1, July 14, 2025, page 28 of 64.
[2] Ibid, pages 24-25 of 64.

In addition, the ongoing IESO NS-led Integrated Resource Plan, currently underway, will continue to evaluate the long-term utilization of TUC1 and other thermal assets. This process will further update the system's long-term planning assumptions, including the role of existing firm capacity within a high-renewable, post-2030 portfolio.

Given this demonstrated long-term system need, the last stage blade replacement is required to ensure that TUC1 can continue to operate safely and reliably over the forecast horizon.

Request IR-82:

G04: C0068898 TUC1 IP LP Last Stage Blade Replacement

Page 194 states: "It was determined that individual blade replacement or refurbishment would not significantly reduce the risk of blade failure and would increase the likelihood of repeated work scope in the future."

(a) Please describe how this assessment was completed.

(b) Please explain how this conclusion was reached.

Response IR-82:

(a) The assessment was completed using the March 2025 inspection findings that showed multiple cracks across both LP1 and LP2 last-stage blade rows, combined with engineering review by NS Power's internal turbine specialists and consultations with external experts including Siemens, TGA, Wayland Engineering and Ethos. These scheduled inspections, part of NS Power's planned condition-assessment program and supported by targeted nondestructive examinations, are designed to detect degradation and provide insight into last-stage blade failure modes. The collective condition assessments determined that the cracking was consistent with and a concern for widespread accumulated fatigue affecting the entire blade population—not isolated defects on individual blades.

(b) Based on this assessment, the conclusion was that replacing or refurbishing only the visibly cracked blades would not be prudent, as it would leave other fatigued blades in service and create a high likelihood of recurring cracks, repeated outages, and elevated turbine-damage risk. Full last-stage blade replacement is therefore required to mitigate the failure mechanism and ensure reliable operation of TUC1.

Request IR-83:

G04: C0068898 TUC1 IP LP Last Stage Blade Replacement

How many blades were found to have cracks during the inspection in March 2025?

(a) How many blades will be replaced through this project?

(b) Will spare blades be purchased?

Response IR-83:

A total of five cracked blades were found on LP2 and LP3 during the inspection in March 2025.

(a) A total of 318 blades will be replaced through this project.

(b) A total of 24 spare blades will be purchased as spares to be kept onsite in inventory.

Request IR-84:

G04: C0068898 TUC1 IP LP Last Stage Blade Replacement

Is the manufacturer of the blades based in the United States?

(a) If not, why has a budget line been estimated for US to Canadian dollar conversion?

(b) If so, why was a Canadian manufacturer not sought?

(c) Were other vendors considered?

(i) If so, please provide their quotes.

(ii) If not, why not?

Response IR-84:

Yes. The manufacturer of the blades is Ethos who is based in the United States.

(a) N/A.

(b) There were no approved Canadian suppliers to manufacture the blades.

(c) The replacement of the TUC1 last stage blades was considered urgent due to concerns for the availability and reliability of the unit. NS Power directly approached three vendors to provide quote for manufacturing of the blades due to the expedited delivery requirements of the project.

(i) Ethos was the only supplier to provide a quote and meet the expedited delivery requirements.

(ii) N/A

Request IR-85:

G04: C0068898 TUC1 IP LP Last Stage Blade Replacement

Was cropping of the existing blades considered as an alternative to blade replacement?

(a) If not, why not?

(b) If so, please explain why this was not considered to be a feasible or cost-effective alternative to the proposed project.

Response IR-85:

Yes, blade cropping was considered as an alternative to blade replacement.

(a) N/A.

(b) Blade cropping is not considered a viable solution when compared to replacing the blades due to loss of capacity (MW) for TUC1, negative impacts to heat rate, and overall uncertainty of project success.

Request IR-86:

G04: C0068898 TUC1 IP LP Last Stage Blade Replacement

In reference to Capital Project Detailed Estimate

(a) How long will this project take to complete?

(b) Why is the labour for Maintenance Trades Regular Labour the same amount as Overtime Labour?

(c) Why has a budget for Overtime Meals been included given that Overtime is equal to Regular for this group of workers?

(d) Did NS Power estimate the cost for Office Trailers based on a vendor quote?

(e) How many office trailers will be rented?

(f) How long will NS Power rent the office trailers?

Response IR-86:

(a) The project is planned to take 12 weeks to complete during the TUC1 Outage starting in April 2026.

(b) The rates in the C0068898 estimate for Maintenance Trade Regular Labour and Maintenance Trades Overtime Labour are $427 and $854 respectively. Due to the duration of the outage, both a day and night shift will be used to complete the project, resulting in a similar person-day requirement for both regular labour and overtime labour.

(c) The Overtime Labour rate is not equivalent Regular Labour rate for Maintenance Trades as outlined in part (b). Overtime meals are a separate cost outside of the overtime labour; it captures the cost of meals for NS Power employees when they are required to complete work outside of normal working hours to meet project requirements. These costs are capitalized in accordance with NS Power's Board-approved Accounting Policy 6100 – Cost.

(d) NS Power estimated the office trailers cost based on prior experience with renting similar trailers.

(e) Two office trailers are planned to be rented for this project.

(f) The office trailers will be used for the entirety of the TUC1 outage for this project. Please refer to part (a).

Request IR-87:

G04: C0068898 TUC1 IP LP Last Stage Blade Replacement

In reference to Attachments 1 and 2, please confirm the noted pricing was obtained through a competitive procurement process.

(a) If not confirmed, please explain.

Response IR-87:

(a) Attachment 1 and 2 to the application were not competitively bid. Attachment 1 is a budgetary proposal from a supplier that NS Power has a negotiated master services agreement (MSA) with, for project outage planning and onsite technical support during the outage which was used to support the detailed estimate. Regarding Attachment 2, two additional vendors were contacted for the manufacturing and replacement of the blades associated with this project; however, only Ethos was able to meet the required expedited delivery timeline.

Request IR-88:

G05: C0080134 TUC2 Stack Coating and Structural Refurbishment

Under the heading *Why do this project*, NS Power indicates that the inspection report found "the freeze-thaw cycling as the dominant root cause of the cracking." Will the new two-coat epoxy system provide greater resistance to the freeze-thaw cycling compared to the existing coating?

Response IR-88:

Yes, the new two-coat epoxy system will provide greater resistance to the freeze-thaw cycling compared to the existing coating. The primary cause of cracking is due to lack of air entrainment in the concrete which is a long-term degradation mechanism that occurred over normal operation. Air entrainment is the deliberate introduction of small, evenly distributed air voids in concrete that allows freezing water to expand into and greatly improves resilience to freeze–thaw conditions. This cracking was discovered by the OEM during a routine inspection and core sampling. The two-coat epoxy's primary purpose is to prevent moisture from entering the concrete, which mitigates damage that occurs during freeze-thaw cycles due to the lack of air entrainment. If air entrainment is within the normal range, then a two-coat epoxy would not be required. The OEM has indicated that a proper coating system will alleviate these issues from lack of air entrainment and freeze thaw cycling by removing the old coating system(s), grouting/filling all cracks and construction joints followed by a two-coat epoxy system.

Request IR-89:

G05: C0080134 TUC2 Stack Coating and Structural Refurbishment

In reference to the contingency of 20% relating to contractor costs due to adverse weather. How much does the 20% cover for contract costs in terms of work-days lost and the added expense of equipment rental resulting from delays due to high winds, rain, humidity, etc.?

Response IR-89:

The entire 20 percent contingency is intended to cover the potential costs (including equipment rentals) of up to 33 work days lost due to adverse weather.

Request IR-90:

G05: C0080134 TUC2 Stack Coating and Structural Refurbishment

In reference to Capital Project Detailed Estimate

(a) Please explain why an electrician is required for regular labour.

(b) Do these estimates include items that the contractor has not included and items that NS Power is required to provide as specified in the contractor's quote in attachment 2?

Response IR-90:

(a) An electrician is required for permitting and can provide standby emergency response team (ERT) support for the project due to the high-risk nature of the work. Electricians will also be necessary as per Attachment 2 to the application to set up and supply any power that the coating contractor will require.

(b) There are no line items in the detailed cost estimate to cover the exclusions listed in the quote in Attachment 2 to the application other than the electrician labour hours being incorporated to set up and supply any power the coating contractor will require. The remainder of the exclusions will incur no cost to the capital project.

Request IR-91:

G06: C0080133 TUC3 IP Turbine Refurbishment

Will the turbine materials be ordered from a Canadian manufacturer?

(a) If not, why not?

(b) Is the vendor's price firm?

Response IR-91:

Yes. Unlike CI C0068898 for the TUC1 turbine blades, the materials will be ordered from Siemens Energy Canada Limited, Oakville Ontario.

(a) N/A.

(b) The vendor's price was valid for 30 days. Attachment 1 to the Application (starting on PDF page 277 of 782 of the 2026 ACE Plan) was used for budgetary purposes and will need to be revalidated before ordering the materials. The contingency for this project is intended to cover any difference in the cost from the previously received pricing.

Request IR-92:

G06: C0080133 TUC3 IP Turbine Refurbishment

Did NS Power determine the need for replacement based on operating hours alone or has a visual inspection been carried out as well?

(a) If a visual inspection, such as a borescope inspection, has not been performed, why is a 15% contingency adequate?

(b) Did the contingency setting using previous project experience include the experience from CI C0041506 LM6000 191-253 Engine Refurbishment from matter M11598?

Response IR-92:

The operating hours determine the requirement to disassemble the TUC3 IP Turbine for inspection and any subsequent replacement or refurbishment as required. A visual inspection is not possible for the turbine components being replaced until disassembly of the TUC3 IP Turbine is completed.

(a) The 15% contingency is derived from the expected findings based on run hours, asset age, and previous similar project experience. The contingency is meant to cover cost overages from the disassembly/reassembly/inspection, replacement or refurbishment parts listed in Attachment 1 to the application, or from additional scope of minor findings during the inspection. Major inspections findings or high cost parts required for refurbishment or replacement outside of Attachment 1 to the application is outside the scope of this project and will be completed under a separate capital work order. This contingency strategy is consistent with all turbine refurbishments at Tufts Cove without a fully defined scope.

(b) The contingency assessment for this project was based on our extensive experience with turbine-related scopes of work. Our demonstrated history in managing turbine projects

provides a sound basis for estimating potential risk and variability. This experience indicates that the level of fallout encountered in the LM6000 refurbishment project is not expected to occur in the TUC3 IP turbine scope. As such, the CI C0041506 LM6000 191-253 Engine Refurbishment project was not used as a reference point and did not guide the contingency selection.

Request IR-93:

G06: C0080133 TUC3 IP Turbine Refurbishment

After completion of the inspection, if parts and/or components are required for which NS Power does not have spares in inventory, does NS Power expect that such elements can be ordered, delivered and installed without extending the planned unit outage time? Please explain.

Response IR-93:

The requirement to extend the planned unit outage time, if necessary, is dependent on what is found during the detailed internal inspection of the IP Turbine. To mitigate these risks, the OEM has completed an extensive review of previous outage history and findings to provide a list of recommended IP Turbine parts to order for the outage based on likelihood or requirement to replace these parts during the outage. In addition, NS Power will be working with third party subject matter experts to review any inspection findings and provide recommendations on the best way to proceed. NS Power also has various spare parts available in inventory based on both likelihood and overall impact of requiring replacement. Due to all of these factors, NS Power is confident that extending the planned unit outage time by any significant amount will not be required.

Request IR-94:

G06: C0080133 TUC3 IP Turbine Refurbishment

If the inspection reveals that that some parts and/or components do not need to be replaced, can already purchased replacement parts be returned for no additional cost to the project? Please explain.

(a) If not, why not?

Response IR-94:

Unused replacement parts are not able to be returned for a credit because the parts are custom fabricated for TUC3 and considered by the vendor not applicable to other customer's turbines. These unused parts will be kept on site for critical spares and future replacement parts during the major inspection period.

Request IR-95:

G06: C0080133 TUC3 IP Turbine Refurbishment

In reference to Attachments 1 and 2, please confirm the noted pricing was obtained through a competitive procurement process.

(a) If not confirmed, please explain.

Response IR-95:

Not Confirmed.

(a) The TUC3 IP Turbine refurbishment scope requires specialized teardown, inspection, refurbishment, and reassembly services that can only be performed by the OEM. In accordance with NS Power's procurement policy and past practice for turbine refurbishments, these services are sourced to the OEM due to the proprietary nature of the work and the significantly increased technical and reliability risks associated with non-OEM refurbishment pathways. NS Power has a negotiated Master Service Agreement (MSA) with the OEM to ensure that costs are minimized for the parts and services in Attachments 1 and 2.

This approach is consistent with prior Board-reviewed projects involving turbine refurbishment, where the OEM were the only technically acceptable option. NS Power therefore proceeded with sole source procurement to ensure the required OEM-certified refurbishment quality, timely access to parts, and engineering supplied by the OEM in the event of unexpected detrimental inspection findings.

Request IR-96:

G07: C0068888 TUC3 Continuous Ash Hauling System

The application considers that this investment will reduce operational costs.

(a) What are the annual forecasted costs of NS Power to perform the collecting and disposing of the fly ash?

(i) How does NS Power intend to remove the collected fly ash?

(b) Please identify the costs incurred by NS Power in 2022, 2023, 2024 and 2025 for contracting an external vacuum truck to come to Tufts Cove to remove the collected fly ash and dispose of it.

(c) What are the expected annual savings in optional and maintenance costs as a result of completing this project?

(d) Has NS Power performed a Total Cost of Ownership (TCO) analysis?

(i) If so, please provide the TCO in excel format with cells intact.

(ii) If not, why not?

(e) What is the planned maintenance schedule for the drag chain system?

(f) Do the other units at Tufts Cove have a drag chain system for removing fly ash?

(i) If not, what is used for removing fly ash when heavy fuel oil is burned?

Response IR-96:

(a) The average annual forecasted costs (over a 25-year period and including the estimated operating costs related to conveyor maintenance and live bottom trailer leasing / maintenance costs) for NS Power to perform the collecting and disposing of fly ash for TUC3 is $155,298.

(i) The collected fly ash will be extracted from the ash hoppers using a drag chain conveyor system which will deposit directly into a live bottom trailer. Once the live bottom trailer is full it will be swapped out with another live bottom trailer. The full live bottom trailer will then transport the ash to Point Aconi.

(b) The annual costs incurred by NS Power for contracting an external vacuum truck to come to Tufts Cove to remove the collected fly ash and dispose of it at Point Aconi are provided below.

- 2022: $327,459
- 2023: $412,803
- 2024: $123,121

(c) When considering the average annual costs to perform the collecting and disposal of fly ash (2022-2024), the expected annual operation and maintenance cost savings is $132,497.

(d) No.

(i) N/A.

(ii) Total Cost of Ownership (TCO) analysis is not a relevant analysis for Power Generation projects. Rather, an economic analysis was provided with the application (PDF pages 300-305 of 782 of the 2026 ACE Plan application) which compares purchase cost, depreciation cost, operational cost, and salvage value of alternatives and results in a NPV and PV of Revenue Requirement to show the least cost alternative.

(e) The maintenance frequency of fly ash handling drag conveyors will vary depending on many factors, such as ash content, and speed of the system. The primary internal components requiring the most frequent maintenance and replacement are the drag chain, head sprocket, and tail sprocket. A typical lifespan for these parts would be about 3-8 years. The secondary internal parts requiring maintenance and replacement will be the wear rails. The lifespan of these parts may range from 5-15 years, depending on the application.

(f) No.

(i) Tufts Cove currently uses contracted vacuum truck services to come to site and transfer fly ash from the precipitator ash hoppers to a vacuum roll off bin. Tufts Cove unit 2 and 3 are the heavy fuel oil (HFO) burning units that require fly ash removal. Vacuum truck services are required daily when burning heavy fuel oil. This bin is emptied approximately once per week during consistent heavy fuel oil burning. All collected fly ash is transported to Point Aconi.

Request IR-97:

G07: C0068888 TUC3 Continuous Ash Hauling System

Please confirm that the design/build contract was awarded to the lowest price RFP respondent.

(a) If not confirmed, please explain.

Response IR-97:

Confirmed.

(a) N/A.

Request IR-98:

G07: C0068888 TUC3 Continuous Ash Hauling System

In the Summary of Alternatives:

(a) Why were other systems not evaluated, as identified under the heading Why do this project this way?

(b) On pages 300 and 301, please describe the operating costs changes over time for each alternative, and describe the changes in these costs between 2025 and 2049.

Response IR-98:

(a) Other systems, such as pneumatic systems, were not evaluated beyond initial concept as both contractors NS Power engaged indicated that oil-based precipitators that produce high carbon/moisture content ash are not effectively conveyed using non-mechanical conveyance methods, therefore were not considered viable alternatives.

(b) The operational costs included in the EAM for the continuous ash hauling system includes:

- Trailer based ash hauling for 6 trips which assumes biweekly ash hauling for 3 months of HFO use.
- Annual preventative maintenance and inspections for the conveyor.
- Major conveyor maintenance based on a 6-year interval.
- Live bottom trailer leasing costs which pay off the trailer in the first 3 years and assumes a 10-year life of the asset.

The live bottom trailer leasing cost and 10-year asset life is why the operating costs for the continuous ash hauling system spike for 3 years every 10 years. The operating costs for the "do nothing" option are based on the average of the actual costs (2022-2024) incurred for hauling ash on TUC2 conservatively inflated over time until 2049 at 2% annually.

The operational costs included in the EAM for vacuum truck ash hauling option costs would increase over time with inflation (conservative estimate of 2% used in the EAM).

Request IR-99:

G08: C0080135 CT-BGT2 Engine Refurbishment

Please provide a high-level summary and dates of any refurbishment work conducted on the Burnside Combustion Turbine Unit 2.

(a) How many operating hours has the unit run since its last refurbishment?

(b) In terms of operating hours, what is the Original Equipment Manufacturer's (OEM's) recommended frequency for engine refurbishment?

(c) How many times has the unit been called into operation in 2024 and 2025?

Response IR-99:

The last refurbishment of engine P686632 at Wood Group Pratt & Whitney (WGPW) facility was completed in 2017. The scope of work included a full major overhaul with comprehensive inspection, refurbishment, and replacement activities across all primary sections of the engine. Key elements of the refurbishment included:

- Complete disassembly and detailed inspection of all engine modules.
- Replacement of mainline bearings and other high-wear components.
- Removal of coatings, inspection, and recoating of major rotating and stationary components (e.g., stators, disks).
- Overhaul or replacement of worn carbon seals, seal plates, and air seals.
- Refurbishment or replacement of all compressor and turbine blades (Stages 1–15), including upgrades consistent with current service bulletins (e.g., improved coatings and dovetail enhancements on Stage 9 blades).

- Application of additional service bulletins, including installation of updated tower shaft and gearbox components.
- Gearbox overhaul, with replacement of worn disks, bearings, and associated hardware.
- Repairs and refurbishment of bleed valves.
- Starter system inspection with replacement of components as required.
- Weld repairs to high-pressure case stators and to identified cracks/defects within the combustion chamber.
- Replacement of damaged or worn hardware and fasteners throughout the engine.

This work restored the engine to full serviceable condition consistent with NS Power's overhaul standards and WGPW's refurbishment specifications.

(a) Since its last refurbishment in 2017, the engine has run for 1,521 hours with 918 starts.

(b) The OEM's original 1971 guidance—developed for utilities operating the engines at high duty cycles—referenced a nominal refurbishment interval of approximately 5,600 operating hours. For NS Power's peaking-duty units, degradation mechanisms are driven primarily by long periods of inactivity, short run durations, and environmental exposure rather than accumulated fired engine hours. As a result, NS Power forecasts a calendar-based refurbishment interval of approximately 10 years, informed by condition monitoring, inspection findings, and engineering assessment.

(c) The unit was called into operation 87 times in 2024 and 74 times in 2025.

Request IR-100:

G08: C0080135 CT-BGT2 Engine Refurbishment

Will NS Power have a third-party expert review the inspection findings if the inspection doesn't reveal more damage than has already been observed?

Response IR-100:

NS Power confirms that it plans to engage a third-party expert to review the inspection findings if the depot inspection identifies concerns requiring validation, or if the results differ from expected conditions based on the borescope indications.

This approach is consistent with NS Power's established practice for LM6000 engines, where third-party experts (such as Entrust/TGA) are engaged when uncertainty exists, when damage mechanisms require independent validation, or when risk to continued operation must be evaluated.

Request IR-101:

G08: C0080135 CT-BGT2 Engine Refurbishment

Page 325 of the capital application states: "Fast-acting generation assets like Burnside Unit #2 are critical tools for system operators managing elevated levels of variable generation—such as wind—and responding to system disturbances to maintain system reliability. When energy output from wind or other sources unexpectedly declines, having generation available within 10 minutes helps mitigate the risk of a potential generation shortfall."

(a) Can NS Power's remaining CT units provide sufficient generation to meet this need with the CT-BGT2 unit out of operation? Please explain.

(b) Can NS Power's remaining CT units, coupled with recently completed (and soon to be complete) Battery Energy Storage Systems provide sufficient generation to meet this need with the CT-BGT2 unit out of operation? Please explain.

Response IR-101:

(a) Yes. NS Power plans major unit outages so they do not occur during the coldest winter months or other high-risk periods, ensuring adequate capacity margins and sufficient fast-start capability during peak reliability seasons. This planning is reflected in the 2026 Generation Maintenance Schedule, which staggers major thermal and CT maintenance to maintain system readiness and has this work scheduled to occur in August / September.

(b) Yes. NS Power's remaining combustion turbine units, together with the recently completed two Battery Energy Storage Systems (BESS) sites and soon-to-be-completed third BESS site, are sufficient to meet operating needs while CT-BGT2 is out of service. The BESS facilities provide fast-responding capacity that supports frequency stability and short-duration energy needs, which complements the flexibility provided by the remaining

CT fleet. Although batteries do not replace the longer-duration reliability function of simple-cycle turbines, they reduce reliance on CT output during momentary disturbances and help System Operators manage variability from wind generation. NS Power also maintains the ability to source a leased engine from Wood Group Pratt & Whitney (WGPW) if the CT-BGT2 outage is unexpectedly extended or if additional unplanned CT outages occur. Through this combination of operational CT capacity, BESS assets, and established contingency arrangements, NS Power can maintain the required system response capability during the CT-BGT2 refurbishment outage.

Request IR-102:

G08: C0080135 CT-BGT2 Engine Refurbishment

Page 325 states: "New FT4 engine designs are no longer being produced and the only other option available would have been to purchase a previously owned and refurbished engine. Based on the asset condition of the existing P686632 engine and the available timeline for refurbishment, it was determined to be more cost effective to refurbish the existing engine rather than purchasing a previously owned engine." Please provide the analysis/data to support that refurbishment is more cost effective.

Response IR-102:

The analysis completed for CI C0080135 demonstrates that refurbishing the existing FT4 engine is the most cost-effective and lowest-risk option available to NS Power. This conclusion is based on several factors.

First, FT4 refurbishment costs have remained stable over many overhaul cycles. Unlike LM6000 units—where major overhauls have increased significantly in cost in recent years due to OEM pricing escalation, material shortages, and higher component fallout—the refurbishment costs associated with FT4 engines have shown consistent and predictable behaviour over time. NS Power's experience with FT4 assets indicates that the scope and cost of depot-level work have not exhibited the step-changes seen in LM6000 technology. As a result, the forecast refurbishment cost of $2,462,664 is well supported by past project performance and presents limited exposure to unexpected escalation.

Second, NS Power reviewed the option of purchasing a previously owned and refurbished FT4 engine. Market pricing for used FT4 units is highly variable because the asset quality depends heavily on factors such as prior duty cycles, accumulated hours, and maintenance practices. Used engines also typically require additional depot work after purchase to return them to a serviceable

condition. When this additional work is taken into account, the total cost of a used engine can approach or exceed the cost of refurbishing NS Power's existing unit. Lead times for acquiring and refurbishing a used engine can also be longer than the refurbishment timeline for the existing asset.

Third, the risks associated with a used-engine exchange are materially higher than refurbishing a known engine with a complete and verified maintenance history. NS Power's past experience with engine exchanges, including the BGT1 unit (M10949), confirms that previously owned engines frequently exhibit undisclosed wear, unknown operating stresses, and incomplete service bulletin compliance. Because of this, and combined with a capital cost of double this refurbishment project, NS Power does not consider that to be a viable alternative. In the case of BGT1, the engine required extensive and unexpected additional work once inspected at the depot and later experienced reliability issues requiring further corrective action. This resulted in delays, cost increases, and operational impacts, illustrating the inherent risk associated with acquiring used FT4 engines from the secondary market.

Finally, the existing P686632 engine carries lower technical risk because it has a fully documented operating and maintenance history and its condition is well understood. No abnormal wear mechanisms or unexpected damage were identified during the last inspection, further supporting refurbishment as the most reliable and predictable path forward.

In summary, refurbishing the existing FT4 engine is more cost-effective than purchasing a previously owned engine because FT4 refurbishment costs remain stable, the used-engine market presents significant uncertainty and risk, NS Power has experienced reliability issues with prior engine exchanges, and the condition of the existing engine is well characterized and suitable for refurbishment. This makes refurbishment the lowest-risk and most economical option available to support system reliability.

Request IR-103:

G08: C0080135 CT-BGT2 Engine Refurbishment

Please describe any work NS Power has undertaken to assess opportunities to continue operation of the Engine without requiring the need for the proposed capital project in advance of completion of the IESO Nova Scotia's proposed 300W combustion turbine facility.

Response IR-103:

NS Power has evaluated whether Burnside Unit 2 (BGT2) could continue operating without the proposed engine refurbishment. Based on this evaluation, NS Power determined that continued operation without overhaul would introduce reliability and operational risks that are not acceptable for a fast-acting resource that plays a critical reliability role on the grid.

The unit is approaching the end of the OEM-recommended overhaul interval of approximately 10 years. Its last full refurbishment occurred in 2017, and operation beyond this interval materially increases the likelihood of forced outages, reduced fast-start capability, and accelerated component wear. Of particular concern is the condition of the stage 9 disk and blade-root regions of the High-Pressure Compressor—a known wear location on FT4 engines where industry experience, including NS Power's own operating history, has shown that undetected deterioration can lead to unplanned blade failures. This area can only be fully inspected and validated during a major shop overhaul, and visual or on-unit inspections are insufficient to confirm its integrity. Proceeding without refurbishment would therefore leave a known failure mechanism unaddressed.

As part of its broader asset planning, NS Power is sequencing major engine work across the Burnside CT fleet, with BGT3 planned for major refurbishment in 2027. This staging avoids overlapping outages of multiple fast-acting units, which is important for maintaining system reliability during the resource transition.

The most recent Integrated Resource Plan identifies that the existing simple-cycle CT fleet must continue operating alongside the new 300 MW fast-acting CT facility being procured by the IESO Nova Scotia. Maintaining the reliability contribution of legacy fast-start units remains essential through the transition period, particularly for meeting system capacity requirements, managing variable wind output and responding to system disturbances.

For these reasons, deferring the refurbishment or attempting to extend operation without it is not feasible without jeopardizing system reliability. The refurbishment is necessary to ensure Burnside Unit 2 remains safe, reliable, and fully capable of meeting its fast-start obligations.

Request IR-104:

G08: C0080135 CT-BGT2 Engine Refurbishment

Are materials being sourced from the US?

(a) If so, why is NS Power not using a Canadian supplier?

(b) If not, why did NS Power include a line item for converting from USD to CAD in the Capital Project Detailed Estimate?

(i) Why was 40% applied?

Response IR-104:

Yes.

(a) There are no Canadian suppliers of Wood Group Pratt & Whitney FT4 engines or components.

(b) N/A.

Request IR-105:

G08: C0080135 CT-BGT2 Engine Refurbishment

Please provide the budgeted and actual annual capital cost associated with the CT-BGT2 unit over the past five years.

Response IR-105:

Please refer to the below table showing the budgeted and actual annual capital costs associated with BGT2 from 2021-2025.

Description	2021	2022	2023	2024	2025
BGT2 Annual Capital Actuals	$ 80,321	$ 36,107	$ 624	$ 27,211	$ 32,848
BGT2 ACE Budgets	$0	$ 26,052	$0	$76,143	$50,892

IR-106:

G08: C0080135 CT-BGT2 Engine Refurbishment

Please provide the forecast annual sustaining capital cost associated with the CT-BGT2 unit for each year from 2026 up to and including 2030.

Response IR-106:

The sustaining capital forecast for CT-BGT2 from 2026–2030 is shown below.
The 2026 forecast includes the engine refurbishment (CI C0080135) and the planned Free Turbine refurbishment (CI C0080279), and the 2028 forecast includes the generator rotor out inspection (~$300,000). An additional $500,000 is forecasted across 2026–2030 for balance of plant work.

Year	Forecast Sustaining Capital ($)	Notes
2026	**$2,462,664**	Engine refurbishment
2026	**$963,769**	Free Turbine refurbishment (noted in Appendix B)
2027	**$0**	No major planned work
2028	**~$300,000**	Generator rotor out inspection
2029	**$0**	No major planned work
2030	**$0**	No major planned work
2026–2030	**~$500,000 (cumulative)**	Balance of plant work

Request IR-107:

G08: C0080135 CT-BGT2 Engine Refurbishment

Please provide the budgeted and actual annual operations and maintenance cost associated with the CT-BGT2 unit over the past five years.

Response IR-107:

Please refer to the below table showing BGT2 O&MG actuals from 2021 to 2025. The operations budget for the Gas Turbines is not separated by unit, therefore can only be provided at the total amount budgeted for the Burnside CT site.

Description	2021 ($)	2022 ($)	2023 ($)	2024 ($)	2025 ($)
BGT2 O&MG Actuals	20,539	28,480	42,672	28,307	13,238
BGT Gas Turbine O&MG Budget	822,975	910,568	1,053,750	1,173,611	1,348,268

Request IR-108:

G08: C0080135 CT-BGT2 Engine Refurbishment

Please provide the forecast annual operations and maintenance cost associated with the CT-BGT2 unit for each year from 2026 up to and including 2030.

Response IR-108:

NS Power does not forecast annual operations and maintenance costs by individual units. The below table is the forecasted total Gas Turbine annual operations and maintenance budget from 2026 to 2030.

	2026	2027	2028	2029	2030
Gas Turbine O&MG Budget	2,721,023	2,893,278	2,964,362	3,037,264	3,112,033

Request IR-109:

G08: C0080135 CT-BGT2 Engine Refurbishment

In reference to Attachment 2, please confirm the noted pricing was obtained through a competitive procurement process.

(a) If not confirmed, please explain.

Response IR-109:

Not confirmed.

(a) The CT-BGT2 refurbishment scope requires specialized teardown, inspection, refurbishment, and reassembly services that can only be performed by an OEM-authorized Pratt & Whitney FT4 depot (Wood Group Pratt & Whitney, WGPW). In accordance with NS Power's procurement policy and past practice for FT4 and LM6000 engine overhauls, these services are sole-sourced to the OEM-authorized facility due to the proprietary nature of the work, the limited number of qualified depots, and the significantly increased technical and reliability risks associated with non-OEM refurbishment pathways.

This approach is consistent with prior Board-reviewed projects involving specialized turbine refurbishment, where OEM or OEM-authorized providers were the only technically acceptable option. NS Power therefore proceeded with sole source procurement to ensure (i) the required OEM-certified refurbishment quality, (ii) timely completion to support the planned fall 2026 in-service date, and (iii) efficient and timely access to parts and engineering supplied by the OEM in the event of unexpected detrimental inspection findings.

Request IR-110:

T01: C0080110 L7012 Replacements and Upgrades Phase 1

(a) Please provide the inspection results and condition metrics that support the need for replacement.

(b) Please confirm that LiDAR data/more detailed analysis has been incorporated to minimize additional scope that may arise during the detailed engineering process.

(i) If not confirmed, please explain why.

Response IR-110:

(a) NS Power used both inspection results from NS Power's transmission line inspection program and past reliability performance as tools to evaluate the recommendation to proceed with this project. A report is then generated and condition metrics as well as engineering and SME review is then applied. Please refer to Attachment 1 for NS Power's inspection report.

(b) Confirmed.

Line No: L7012 *Work Order Report*

Str #	Str Type / Frm Type	Pole Lgth L	Pole Lgth C	Pole Lgth R	Access	GPS Lat	GPS Long	Scoping Required	Scheduled	Grd Clr	Min Grd Clr	Work OrderID	Field Priority	Flagged	Comments	Recommendations	Env Notification
L7012-011	230-T-G(O)	70	0	70	Airport	45 39' 32.8957"N	-61 23' 3.1543"W	No	2023S	9.0	6.94	7089013	1-2 years	No	Left spar arm is cracked at the pole connection. Cannot tell how bad it is but shouldn't take any chances	Install 230TG-(O) Framing, Remove 230TG-(O) Framing	
L7012-024	230-T-G(O)	70	0	70	*** PORT HAWKESBURY-DESIGNATED WATER SUPPLY AREAS ***	45 39' 43.2115"N	-61 20' 56.4674"W	No	2023S	8.2	6.26	7089013	2-4 years	No	Right pole is hollow and should be replaced. Rest of the structure is okay	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. Protected Watershed Area: Landrie Lake (& MacIntyre Lake) Watershed (10 business days notification prior to work commencing. Contact Environmental Services.) 2. Municipal Water Supply: Port Hawkesbury (Notification may be required. Contact Environmental Services. Report spills immediately to water supply manager. Halifax Regional Water Commission Lands - Contact Environmental Services and follow LOA.)
L7012-029	230-T-G(O)	90	0	90	*** PORT HAWKESBURY-DESIGNATED WATER SUPPLY AREAS *** Cranday Road	45 39' 47.3059"N	-61 20' 6.8210"W	No	2023S	13.1	11.16	7089013	2-4 years	No	Structure okay but one side guy is broken and there are no guards	Replace 1 Guy, Install 2 Guy Guards	1. Protected Watershed Area: Landrie Lake (& MacIntyre Lake) Watershed (10 business days notification prior to work commencing. Contact Environmental Services.) 2. Municipal Water Supply: Port Hawkesbury (Notification may be required. Contact Environmental Services. Report spills immediately to water supply manager. Halifax Regional Water Commission Lands - Contact Environmental Services and follow LOA.) 3. NSDNR Crown Land: 20801 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-031	230-T-G(O)	70	0	70	*** PORT HAWKESBURY-DESIGNATED WATER SUPPLY AREAS ***	45 39' 49.3069"N	-61 19' 42.4886"W	No	2023S	10.5	8.31	7089013	2-4 years	No	Right pole is hollow and failed last inspection. Work order created for replacement but not completed yet	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. Protected Watershed Area: Landrie Lake (& MacIntyre Lake) Watershed (10 business days notification prior to work commencing. Contact Environmental Services.) 2. Municipal Water Supply: Port Hawkesbury (Notification may be required. Contact Environmental Services. Report spills immediately to water supply manager. Halifax Regional Water Commission Lands - Contact Environmental Services and follow LOA.)

Line No: L7012 *Work Order Report*

L7012-036	230-T-G(O)	70	0	70	*** PORT HAWKESBURY-DESIGNATED WATER SUPPLY AREAS ***	45 39' 53.0815"N	-61 18' 54.7262"W	No	2023S	8.4	6.62	7089013	2-4 years	No	Right pole is hollow and should be replaced. Rest of the structure is okay	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. Protected Watershed Area: Landrie Lake (& MacIntyre Lake) Watershed (10 business days notification prior to work commencing. Contact Environmental Services.)
L7012-041	230-T-G(O)	70	0	70	*** PORT HAWKESBURY-DESIGNATED WATER SUPPLY AREAS ***	45 39' 57.5551"N	-61 18' 0.8228"W	No	2023S	9.5	7.44	7089013	2-4 years	No	Left pole has ants and is hollow. Should be replaced but not urgent	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. Protected Watershed Area: Landrie Lake (& MacIntyre Lake) Watershed (10 business days notification prior to work commencing. Contact Environmental Services.) 2. Significant Species and Habitat: IN122 - Deer Wintering (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.) 3. NSDNR Crown Land: 10994 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-043	230-T-G(O)	70	0	70	Brook 1' wide N45-39-58.8 W61-17-41.8	45 39' 59.1889"N	-61 17' 39.5660"W	No	2023S	9.9	7.84	7089013	2-4 years	No	Both poles are hollow and failed last inspection. Replacement scheduled for 2021 but no work order yet	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. Significant Species and Habitat: IN122 - Deer Wintering (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.) 2. NSDNR Crown Land: 11675 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-048	230-T-G(O)	70	0	70	barterton road.	45 40' 3.6919"N	-61 16' 44.9169"W	No	2023S	9.8	7.52	7089013	1-2 years	No	Left pole is hollow and failed last inspection. Scheduled for replacement in 2021	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 11800 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-059	230-T-G(O)	70	0	70	Acess is West from the Cleveland Substation	45 40' 12.5599"N	-61 14' 58.2495"W	No	2023S	9.1	7.04	7089013	1-2 years	No	Left pole is very hollow and is scheduled for replacement in 2021. Right pole was new 2011	Install 70' LT Pole, Remove 70' LT Pole	
L7012-061	230-T-G(O)	70	0	70	cleveland substation.	45 40' 14.3779"N	-61 14' 35.8563"W	No	2023S	8.5	6.22	7089013	2-4 years	No	Left pole is very hollow and scheduled for replacement in 2021. Replacement is advised	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-062	230-T-G(O)	65	0	65	Dowling Road	45 40' 15.2737"N	-61 14' 26.7297"W		2023S	9.8	7.86	7089013	1-2 years		left arm looks to be starting too sag, both arms have weather cracks , both poles have ants/ sounding little hollow .	Install 65' 230TG-(O), Remove 65' 230TG-(O)	

Line No: L7012 *Work Order Report*

L7012-066	230-T-G(O)	70	0	70	Riverside Road, RE Line	45 40' 15.0157"N	-61 14' 0.8319"W	No	2023S	13.4	11.96	7089013	N/A	No	Both arms starting to moss and develop weather cracks left brace mossy insulators are COB posts rusty at grout one crimped splice in each phase OK for now reassess next inspection	Install 70' 230TG-(O), Remove 70' 230TG-(O), Install ID 7012 Both Sides	
L7012-067	230-T-G(O)	70	0	70	1/0 RE line county County Line road	45 40' 14.9989"N	-61 13' 50.9931"W		2023S	9.2	7.14	7089013	2-4 years		arms have large weather cracks/look rotten. ants in left pole.	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-073	230-T-G(O)	65	0	65	Road into Line just pass civic 198 County Line Rd This is the Road from Cleveland to Westbay	45 40' 15.0433"N	-61 12' 52.5345"W	No	2023S	11.5	9.72	7089013	2-4 years	No	Left pole has ants and sounds hollow almost all the way around from ground up about 5 feet insulators are COB posts rusty at grout	Install 65' 230TG-(O), Remove 65' 230TG-(O)	
L7012-077	230-T-G(O)	70	0	70	same as structure 76.	45 40' 15.0205"N	-61 12' 14.8503"W	No	2023S	9.7	7.64	7089013	N/A	No	New left pole in 2012 Insulators are COB posts rusty at grout OK for now	Re-Insulate 3X12	
L7012-078	230-T-G(O)	70	0	70	county line road.	45 40' 15.0709"N	-61 12' 4.9846"W		2023S	9.3	7.24	7089013	2-4 years		left pole has ants/ sounding little hollow .arms have weather cracks . might be starting too compress a small amount	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-081	230-T-G(O)	70	0	70	same as strurcture 80.	45 40' 15.0967"N	-61 11' 33.2950"W		2023S	9.2	7.26	7089013	2-4 years		right pole sounding hollow , arms have weather cracks	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 20823 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-083	230-T-G(O)	70	0	70	Access is just pass civic 198 County Line Rd there is a wood Rd into the line	45 40' 15.1171"N	-61 11' 13.5832"W	No	2023S	8.5	6.56	7089013	2-4 years	No	Left pole has ants and sounds hollow almost all the way around about 5 feet up Insulators are COB posts rusty at grout OK for now	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-085	230-T-G(O)	70	0	70	Access is a wood rd into Line just pass civic 198 County line Rd Thisis the road from Cleveland to West Bay	45 40' 15.1777"N	-61 10' 54.0616"W	No	2023S	9.3	7.36	7089013	2-4 years	No	Left pole has ants and sounds hollow almost all the way around about 6 feet up Insulators are COB posts rusty at grout	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. Significant Species and Habitat: IN343 - Species at Risk (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.)

Line No: L7012 *Work Order Report*

L7012-088	230-T-G(O)	70	0	70	Swamp	45 40' 15.1867"N	-61 10' 20.8552"W	No	2023S	10.5	8.31	7089013	2-4 years	No	Overhead bonding wire broken at top of right pole this is reason for the failure Down ground needs to be stapled back to right pole Insulators are COB posts rusty at grout	Re-Insulate 3X12, Staple Down Ground	
L7012-091	230-T-G(O)	70	0	70	cooper road.	45 40' 15.3271"N	-61 9' 50.5444"W	No	2023S	10.1	7.91	7089013	N/A	No	Both overhead ground wire eyebolts appear 25 percent worn right pole has ants and sounds a little hollow Insulators are COB posts rusty at grout left overhead ground wire rusty OK for now reassess next inspection One crimped splice in each phase	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15054 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-094	230-T-G(O)	70	0	70	cooper road.	45 40' 15.1987"N	-61 9' 16.3144"W	No	2023S	10.3	8.11	7089013	2-4 years	No	Right pole has ants sounds hollow almost all the way around 5 feet up Insulators are COB posts rusty at grout left overhead ground wire rusty	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15300 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-095	230-T-G(O)	70	0	70	cooper road.	45 40' 15.1483"N	-61 9' 7.2388"W	No	2023S	8.9	6.96	7089013	2-4 years	No	Overhead bonding wire broken at top of right pole this is the reason for the failure left overhead ground wire rusty Insulators are COB posts rusty at grout left pole has ants	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15300 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-096	230-T-G(O)	70	0	70	cooper road.	45 40' 15.2521"N	-61 8' 55.5250"W	No	2023S	10.3	8.11	7089013	2-4 years	No	Overhead bonding wire broken at top of right pole this is the reason for the failure left overhead ground wire rusty both poles have ants Insulators are COB posts rusty at grout	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15300 (Contact Environmental Services and Lands and Rights, an LOA will be required.)

Line No: L7012 *Work Order Report*

L7012-097	230-T-G(O)	70	0	70	Access would be on the Cooper Road off Hwy # 4, Kemp Road. Go East from Cooper Rd	45 40' 15.1957"N	-61 8' 46.1380"W	No	2023S	9.0	7.06	7089013	N/A	No	Left overhead ground wire rusty Right pole has ants sounds hollow one side from ground up as far as I can reach left pole has ants sounds a little hollow one side about 2 feet up left arm just starting to show signs of compression above brace Insulators are COB posts rusty at grout ok for now reassess next inspection	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15300 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-098	230-T-G(O)	70	0	70	Gully Brook 2 metres wide N45-40-14.80 W61-08-40.3	45 40' 15.2683"N	-61 8' 35.3446"W	No	2023S	9.8	7.74	7089013	N/A	No	Structure okay	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-099	230-T-G(O)	70	0	70	gully	45 40' 15.2293"N	-61 8' 25.8850"W	No	2023S	9.5	7.56	7089013	2-4 years	No	Left pole is quite hollow and should be replaced. Orange Genics tag on pole	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-100	230-T-G(O)	70	0	70	black river road.	45 40' 15.2011"N	-61 8' 14.5252"W		2023S	10.3	8.11	7089013	1-2 years		right arm looks too be sagging a bit. has weather cracks .	Install 230TG-(O) Framing, Remove 230TG-(O) Framing, Install ID 10 Both Sides	
L7012-102	230-T-G(O)	70	0	70	Brook / Swamp 2 metres wide N45-40-14.80 W61-07-52.30	45 40' 15.1831"N	-61 7' 50.3236"W	No	2023S	10.3	8.11	7089013	N/A	No	Structure okay but cross arms are deteriorating and should be checked carefully on next inspection	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15059 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-104	230-T-G(O)	70	0	70	Brook / Swamp 1 metres N45-40-15.20 W61-03-34.2	45 40' 15.2299"N	-61 7' 30.3742"W	No	2023S	9.9	7.96	7089013	N/A	No	Left pole has ants and sounds hollow one side from ground up about 4 feet Arm starting to develop weather cracks right one starting to show signs of compression above brace insulators are COB posts rusty at grout ok for now reassess next inspection	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. DNR Wetland: Swamp (Avoid area if possible. Contact Environmental Services. Follow ENV014 including details on pole type selection.)

Line No: L7012 *Work Order Report*

L7012-105	230-T-G(O)	70	0	70	black river road. swampy.	45 40' 15.1627"N	-61 7' 21.4253"W	No	2023S	11.3	9.36	7089013	2-4 years	No	Overhead bonding wire not connected to top of right down ground this is the reason for the failure left pole has ants sounds a little hollow on one side insulators are COB posts rusty at grout	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15298 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-106	230-T-G(O)	70	0	70	black river road.	45 40' 15.1681"N	-61 7' 12.4049"W	No	2023S	8.8	6.86	7089013	2-4 years	No	Both arms showing signs of compression and bowed down above left and right phases overhead bonding wire not connected to top of right down ground insulators are COB posts rusty at grout Right pole has ants and sounds a little hollow one side	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-107	230-T-G(O)	70	0	70	black river road.	45 40' 15.2395"N	-61 7' 1.8509"W	No	2023S	9.9	7.84	7089013	2-4 years	No	Left pole has ants and sounds hollow almost all the way around five feet up Insulators are COB posts rusty at grout arms starting to show signs of compression	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-108	230-T-G(O)	70	0	70	black river road.	45 40' 15.1927"N	-61 6' 52.7783"W	No	2023S	8.8	6.86	7089013	2-4 years	No	Right pole has ants and sounds hollow almost all the way around 5 feet up overhead bonding wire not connected to right down ground Insulators are COB posts rusty at grout arms starting to show signs of compression and are slightly bowed down	Install 70' 230TG-(O), Remove 70' 230TG-(O)	

Line No: L7012 *Work Order Report*

L7012-109	230-T-G(O)	70	0	70	Access is where the line Crosses the Black River Rd going towards Dundee Str is towards West	45 40' 15.2053"N	-61 6' 41.8979"W	No	2023S	9.9	7.84	7089013	2-4 years	No	Right pole has ants and sounds hollow almost all the way around about 5 feet up left arm developing weather cracks and has slight bow down above center and left phases right overhead bonding wire needs to be stapled back to pole and reattached to down ground Insulators are COB posts rusty at grout	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-110	230-T-G(O)	70	0	70	black river road.	45 40' 15.2071"N	-61 6' 31.0859"W		2023S	8.9	6.84	7089013	2-4 years		left arm looks to be compressing/ has long weather cracks . both poles have ants/sounding hollow	Install 70' 230TG-(O), Remove 70' 230TG-(O), Install ID 11 Both Sides	
L7012-111	230-T-G(O)	70	0	70	black river road.	45 40' 15.2317"N	-61 6' 20.6141"W		2023S	8.9	6.84	7089013	2-4 years		right arm looks too be starting to compress some.both arms have weather cracks	Install 230TG-(O) Framing, Remove 230TG-(O) Framing	
L7012-112	230-T-G(O)	75	0	75	black river road.	45 40' 15.3259"N	-61 6' 12.5975"W	No	2023S	11.5	9.72	7089013	N/A	No	Insulators are COB posts rusty at grout arms starting to develop weather cracks and just starting to show signs of compression OK for now reassess next inspection	Install 230TG-(O) Framing, Remove 230TG-(O) Framing	
L7012-114	230-T-G(O)	70	0	70	black river road.	45 40' 15.3049"N	-61 5' 53.3555"W		2023S	8.5	6.44	7089013	2-4 years		right pole sounding hollow has ants. left pole has some weather cracks	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15106 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-115	230-T-G(O)	70	0	70	Gully Brook # 1 1 metre N45-40-15.50 W61-05-49.00 Brook # 2 .5 metres N45-40-15.40 W61-05-41.70	45 40' 15.3529"N	-61 5' 40.5527"W	No	2023S	10.4	8.12	7089013	N/A	No	Structure okay	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15106 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-118	230-T-G(O)	70	0	70	black river road.	45 40' 15.2017"N	-61 5' 14.2007"W	No	2023S	8.1	6.04	7089013	N/A	No	Structure okay but right pole is a bit hollow. Still okay	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15106 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-120	230-T-G(O)	70	0	70	black river road.	45 40' 15.1753"N	-61 4' 52.6535"W		2023S	9.1	7.04	7089013	2-4 years		left pole sounding hollow 1 side. has ants. right arm has weather cracks	Install 70' 230TG-(O), Remove 70' 230TG-(O), Install ID 12 Both Sides	
L7012-123	230-T-G(O)	70	0	70	black river road.	45 40' 15.1933"N	-61 4' 23.8439"W	No	2023S	8.9	6.96	7089013	N/A	No	Structure okay	Install 70' 230TG-(O), Remove 70' 230TG-(O)	

Line No: L7012 *Work Order Report*

L7012-125	230-T-G(O)	65	0	65	Brook 5 metres wide N45-40-15.20 W61-04-11.60	45 40' 15.2725"N	-61 4' 0.5651"W	No	2023S	10.5	8.22	7089013	1-2 years	No	Left spar arm is cracked and should be replaced soon Side guys have no guards	Install 65' 230TG-(O), Remove 65' 230TG-(O)	
L7012-126	230-T-G(O)	65	0	65	Balmoral Road Brook 2.5 metres N45-40-15.3 W61-03-55.10	45 40' 15.0907"N	-61 3' 49.3817"W	No	2023S	8.9	6.71	7089013	2-4 years	No	Structure failed last inspection and replacement of right pole is scheduled for 2021S. One side of pole hollow but will last for a few more years	Install 65' 230TG-(O), Remove 65' 230TG-(O)	
L7012-128	230-T-G(O)	70	0	70	Brook N45-40-15.40 W61-03-32.20	45 40' 15.3145"N	-61 3' 31.2083"W	No	2023S	11.6	9.66	7089013	1-2 years	No	Structure failed last inspection and left pole is scheduled for replacement in 2021S. Proceed with replacement. Pole has orange Genics tag	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15245 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-129	230-T-G(O)	70	0	70	black river road.	45 40' 15.4513"N	-61 3' 19.1735"W	No	2023S	9.5	7.31	7089013	1-2 years	No	Structure failed last inspection. Replacement of left pole is scheduled for 2021S but no work order yet. Proceed with replacement	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15249 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-132	230-T-G(O)	70	0	70	black river road.	45 40' 15.9115"N	-61 2' 50.2949"W		2023S	8.7	6.64	7089013	2-4 years		right arm looks too be starting too compress/ sag a small amount	Install 230TG-(O) Framing, Remove 230TG-(O) Framing	
L7012-133	230-T-G(O)	70	0	70	black river road.	45 40' 16.0241"N	-61 2' 39.4781"W	No	2023S	9.3	7.24	7089013	N/A	No	Structure okay but right pole is hollow. Still hard. Spar arms are weather cracked but still okay	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-140	230-T-G(O)	70	0	70	cameron mountain road.	45 40' 16.9627"N	-61 1' 30.6012"W		2023S	9.5	7.44	7089013	2-4 years		long weather cracks on right arm. both arms might be starting too compress some. right pole sounding hollow	Install 230TG-(O) Framing, Remove 230TG-(O) Framing, Install ID 14 Both Sides	
L7012-144	230-T-G(O)	70	0	70	Brook 2 Metres Wide N45-40-17.70 W61-00-56.10	45 40' 17.5627"N	-61 0' 50.2572"W	No	2023S	9.2	7.14	7089013	2-4 years	No	Both poles are hollow but the right pole is much worse. Replace structure maybe using cca poles	Install 70' 230TG-(O) With Double Crib, Remove 70' 230TG-(O)	
L7012-145	230-T-G(O)	70	0	70	Swamp Brook 1 Metre Wide N45-40-17.90 W61-00-41.60	45 40' 17.7877"N	-61 0' 37.6776"W	No	2023S	11.4	9.12	7089013	2-4 years	No	Structure failed last inspection. Left pole is very hollow. Orange Genics tag on pole. Replacement has work order but not completed yet	Install 70' 230TG-(O), Remove 70' 230TG-(O)	

Line No: L7012 *Work Order Report*

L7012-146	230-T-G(O)	65	0	65	Thibeauville Road.	45 40' 17.6989"N	-61 0' 32.1228"W	No	2023S	13.1	11.42	7089013	N/A	No	Structure okay	Install 65' 230TG-(O), Remove 65' 230TG-(O), Install ID 7012 Both Sides	
L7012-154	230-T-G(O)	70	0	70	River 2 Metres N45-40-18.90 W60-59-18.70 Old Road into line	45 40' 18.9859"N	-60 59' 12.3762"W		2023S	10.4	7.85	7089013	2-4 years		left arm looks too be starting to compress where x brace bolts on, also has weather cracks. top rot starting right pole.	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-157	230-T-G(O)	70	0	70	Sporting Mountain Road	45 40' 19.4281"N	-60 58' 43.9716"W	No	2023S	11.8	9.86	7089013	N/A	No	Structure okay but spar arms are weather cracked	Install 70' 230TG-(O), Remove 70' 230TG-(O), Install ID 7012 Both Sides	
L7012-160	230-T-G(O)	65	0	65	same as structure 159.	45 40' 19.7737"N	-60 58' 14.6868"W		2023S	9.2	7.57	7089013	1-2 years		left arm is sagging. right arm is compressing a small amount	Install 230TG-(O) Framing, Remove 230TG-(O) Framing	
L7012-165	230-T-G(O)	70	0	70	sporting mountain road.	45 40' 20.3773"N	-60 57' 30.4903"W		2023S	12.1	10.47	7089013	2-4 years		both arms have weather cracks, compressing a small amount. left pole sounding hollow	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15202 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-167	230-T-G(O)	70	0	70	Swamp Tower line leaves corridor	45 40' 20.6551"N	-60 57' 8.7673"W	No	2023S	11.1	8.82	7089013	1-2 years	No	Spar arms failed last inspection and are still bad. Work order created but not completed yet. Replace both spar arms	Install 70' 230TG-(O), Remove 70' 230TG-(O)	1. NSDNR Crown Land: 15201 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-169	230-T-G(O)	75	0	75	swampy.	45 40' 20.9322"N	-60 56' 46.4839"W		2023S	10.5	8.22	7089013	1-2 years		both arms are compressing/ sagging a bit.	Install 75' 230TG-(O), Remove 75' 230TG-(O)	1. NSDNR Crown Land: 15201 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-170	230-T-G(O)	70	0	70	sporting mountain road.	45 40' 20.9628"N	-60 56' 38.2939"W	No	2023S	7.9	6.12	7089013	N/A	No	Structure okay	Install 70' 230TG-(O), Remove 70' 230TG-(O), Install ID 17 Both Sides	1. NSDNR Crown Land: 15201 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-172	230-T-G(O)	70	0	70	sporting mountain road.	45 40' 21.1579"N	-60 56' 19.9249"W	No	2023S	9.0	7.06	7089013	N/A	No	Structure okay but spar arms are weather cracked	Install 230TG-(O) Framing, Remove 230TG-(O) Framing	1. NSDNR Crown Land: 15199 (Contact Environmental Services and Lands and Rights, an LOA will be required.)
L7012-174	230-T-G(O)	65	0	65	River Tillard 10 Metres wide N45-40-21.30 W60-55-59.60	45 40' 21.4747"N	-60 55' 55.2985"W	No	2023S	9.2	6.92	7089013	N/A	No	Structure okay but left pole is hollow. Has orange Genics tag on pole. Should be okay for several years yet	Install 65' 230TG-(O), Remove 65' 230TG-(O)	
L7012-175	230-T-G(O)	70	0	70	mountain road.	45 40' 21.5802"N	-60 55' 44.7085"W	No	2023S	8.2	6.57	7089013	N/A	No	Structure okay but right pole has ants. Still okay. Ohgw connectors are worn	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-178	230-T-G(O)	70	0	70	Road to fish hatchery, 3 Phase RE Line.	45 40' 21.8551"N	-60 55' 23.7163"W	No	2023S	12.7	11.07	7089013	N/A	No	Structure okay	Install 230TG-(O) Framing, Remove 230TG-(O) Framing	

Line No: L7012 *Work Order Report*

L7012-180	230-T-G(O)	70	0	70	Hayfield	45 40' 22.0638"N	-60 55' 3.2329"W	No	2023S	8.5	6.87	7089013	N/A	No	Structure okay but spar arms are weather cracked Right pole new 2010. Left pole has ants but still okay	Install 70' 230TG-(O), Remove 70' 230TG-(O), Install ID 18 Both Sides	
L7012-181	230-T-G(O)	70	0	70	hay field .	45 40' 22.1538"N	-60 54' 54.8053"W		2023S	7.9	6.12	7089013	2-4 years		arms look too be compressing some where xbrace bolts on	Install 230TG-(O) Framing, Remove 230TG-(O) Framing	
L7012-183	230-T-G(O)	70	0	70	Long Lake 150 Metres Wide N45-40-22.70 W60-54-42.90	45 40' 22.3728"N	-60 54' 34.1161"W	No	2023S	12.4	10.21	7089013	N/A	No	Structure okay	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-184	230-T-G(O)	70	0	70	oban road.	45 40' 22.4658"N	-60 54' 24.8011"W		2023S	9.8	7.86	7089013	N/A		ants in left pole. both arms have weather cracks	Install 70' 230TG-(O), Remove 70' 230TG-(O)	
L7012-185	230-T-G(O)	70	0	70	oban road.	45 40' 22.5919"N	-60 54' 14.8327"W		2023S	9.0	6.94	7089013	N/A		large crack at base of right pole. right arm has horizontal crack from end of arm in past pole	Install 230TG-(O) Framing, Remove 230TG-(O) Framing	
L7012-189	230-T-G(O)	65	0	70	Long Lake Brook 1 Metre N45-40-22.30 W60-53-49.70	45 40' 23.0556"N	-60 53' 32.2993"W		2023S	10.7	8.33	7089013	2-4 years		arms look too be starting too compress where x brace bolts on.	Install 230TG-(O) Framing, Remove 230TG-(O) Framing	
L7012-190	230-T-G(O)	65	0	65	road off Obon rd at the line	45 40' 23.2249"N	-60 53' 25.4941"W		2023S	8.1	6.47	7089013	2-4 years		left arm looks too be starting too sag. right pole sounding hollow with ants in both poles	Install 65' 230TG-(O), Remove 65' 230TG-(O), Install ID 19 Both Sides	
L7012-191	230-T-G(O)	65	0	65	oban road.	45 40' 23.4138"N	-60 53' 17.4901"W	No	2023S	7.9	6.12	7089013	2-4 years	No	Right pole is hollow and should be replaced	Install 65' 230TG-(O), Remove 65' 230TG-(O)	

Request IR-111:

T01: C0080110 L7012 Replacements and Upgrades Phase 1

Please provide cost support references from similar projects recently completed and update the detailed project estimates for each project.

Response IR-111:

Similar projects that were recently completed consist of:

- CI C0041805 – L7005 Replacements and Upgrades Phase 2

- CI C0041793 – L7002 Replacements and Upgrades Phase 2

Please refer to the below tables for asset replacement comparison and cost details.

Replacement Type	C0041805 – L-7005 R&U Phase 2	C0041793 – L-7002 R&U Phase 2
Structure	44	58
Insulator	7	
Timber and Insulator	15	13
Bond or Guy Wire	2	
Other Deteriorated Assets	3	1

Account	Actuals ($)	
	C0041805 – L-7005 R&U Phase 2	C0041793 – L-7002 R&U Phase 2
Other Income-Salvage	(14,351)	(14,421)
Regular Labour	27,459	27,205
Overtime Labour	33,181	11,269
Term Labour	65	
Term Labour-Overtime	1,459	
Travel Expense	1,122	348
Materials	787,711	1,406,663
Contracts	1,702,936	1,992,521

Account	Actuals ($)	
	C0041805 – L-7005 R&U Phase 2	**C0041793 – L-7002 R&U Phase 2**
Freight Postage Delivery	5,692	7,496
Meals and Entertainment	2,015	459
Personal Equipment		592
Vehicle Allocated Costs	17,880	13,593
Admin Overheads	34,224	27,000
Contractor Admin Overhead	311,057	384,058
Total	**2,910,451**	**3,856,785**

Board approval was granted by the NSEB for CI C0041805 – L-7005 Replacements and Upgrades Phase 2 for final costing in October 2025. Please refer to NSEB M12506 for further details.

Request IR-112:

T01: C0080110 L7012 Replacements and Upgrades Phase 1

Please provide specific details on the criteria used and the work completed to estimate which assets require replacement.

Response IR-112:

Identifying structure or asset replacement is primarily driven by the results of NS Power's Transmission Line Inspection program. This program is conducted by trained inspectors completing a foot patrol of a transmission line and inspecting critical components of all transmission structures. It consists of several elements designed to contribute to the understanding of the transmission line condition for use in risk-based decision making to enable continued reliable service to customers. These elements include an assessment of the structure subcomponents (including poles, insulators, conductor, etc.) undertaken by trained NS Power inspectors, which are then rated according to their condition. Following the inspection, a report is generated that compiles identified deficiencies along the line. The report is reviewed in detail by NS Power's transmission line reliability team and other SMEs to incorporate any further field or engineering input. Based on these assessment and subsequent review the individual structures requiring intervention are identified and prioritized for inclusion in future capital projects.

Request IR-113:

T01: C0080110 L7012 Replacements and Upgrades Phase 1

Do any assets require replacement because they do not meet NS Power's ground clearance requirements?

(a) If so, please describe and explain why the current assets do not meet these requirements.

Response IR-113:

No.

(a) N/A.

Request IR-114:

T01: C0080110 L7012 Replacements and Upgrades Phase 1

Please explain specifically how NS Power determined that 57 structures need replacement.

Response IR-114:

NS Power completed a detailed inspection of transmission line L-7012 as part of the Company's transmission line inspection program as detailed in NSEB IR-112. Based on these assessments, LIDAR and subsequent review it was determined that 57 structures require a full replacement as part of this project.

Request IR-115:

T01: C0080110 L7012 Replacements and Upgrades Phase 1

With regards to the project's detailed cost estimate on page 3 of 5: Please identify the estimated unit materials and contract costs for wood poles, insulators and O/H conductors, and compare these unit costs to those used in the 2025 ACE Plan application.

Response IR-115:

NS Power uses standard work units referred to as compatible units (CUs) to develop the cost estimate for projects such as this. Each CU contains labour rates and material rates, itemizing all the individual tasks and materials to perform each component of a project. The material rates are regularly updated with the latest pricing from vendors, and therefore the material cost reflects the actual cost of materials at the time of submission. The labour from these CUs is awarded per NS Power's Line Services agreement with Connect Atlantic Utility Services; these CUs would have had a rate increase of 2% from 2025 to 2026. These CUs are then mapped to asset classes including wood poles, insulators, and overhead conductor. As such, unit costs cannot be provided as requested.

Request IR-116:

T02: C0070909, 70W-T52 Transformer Addition

The application notes three transformers: 70W-T51, 70W-T53, and 89W-T1. Page 365 that the 2006 Bridgewater Area System Planning Study (211-0606-W61) included recommendations related to transformer 70W-T51 and the conversion of the Bridgewater system. Page 368 provides the load history, in MVA, for these three transformers since 2018.

(a) Please list the feeders for each of the three transformers, along with the number of customers they serve and the peak load current since 2018.

(b) What are the installation dates for transformers 70W-T53 and 89W-T1?

(c) What percentage of the 4 kV–to–12 kV conversion has been completed to date?

(d) Why is the load from 70W-T51 not being transferred to 89W-T1 or 70W-T53?

(e) Are there any steps taken, or is it possible, to reduce the load on either 89W-T1 or 70W-T53? Please include a GIS map drawing to support the explanation.

(f) Please submit the 2006 planning report.

Response IR-116:

(a) Feeder customer counts and peak load data is not available prior to 2022 due to legacy metering and modelling limitations. The table below provides the requested data from 2022-2025.

Transformer	Feeder	Customer Count				Peak Load (A)			
		2022	2023	2024	2025	2022	2023	2024	2025
70W-T51 (4 kV)	70W-203	277	279	274	276	193	206	213	209
	70W-204	277	277	291	278	117	95	135	132
70W-T53 (12 kV)	70W-311	1,172	1,200	1,213	1,181	179	175	204	202
	70W-312	999	1,012	1,143	1,171	171	151	162	177
	70W-313	2,033	2,130	2,156	2,105	221	220	238	274
	70W-314	632	647	667	654	118	108	130	142
	70W-321	1,682	1,708	1,716	1,698	248	236	256	268
	70W-322	1,028	1,042	1,048	1,030	214	181	230	217
89W-T51 (12 kV)	89W-301	371	375	375	368	130	113	141	134
	89W-302	1,300	1,314	1,334	1,327	309	254	336	370
	89W-303	1,409	1,434	1,458	1,426	182	172	208	214
	89W-304	349	360	358	390	106	85	114	143

(b) Transformer 70W-T53 was installed in 1990 and transformer 89W-T1 was installed in 2008.

(c) No significant 4 kV to 12 kV feeder conversions have been completed in this area in recent years. However, incremental upgrades have been made to portions of the existing distribution system to facilitate future conversion. These upgrades include rebuilding lines, poles, cutouts, and insulators to 12 kV standards, as well as replacing service transformers with dual-voltage units capable of operating at either 4 kV or 12 kV.

It is estimated that approximately 50% of service transformers in the area are dual-voltage, and that approximately 10% of the remaining distribution plant could be energized at 12 kV without requiring significant upgrades.

(d) The 12 kV system supplied from the 70W substation is expected to exceed the maximum contingency capacity in 2026. This calculated contingency capacity includes the existing capability to transfer load from 70W to 89W.

Transferring the 4 kV load from 70W-T51 to 70W-T53 would immediately violate the contingency capacity criteria. That is, in the event of a single transformer failure (70W-T53), the entire load could not be supplied through installation of mobile transformer and distribution switching.

The planning study found that some load could be transferred from 70W-T53 to 89W-T1, which could allow the 4 kV load from 70W-T51 to be transferred to 70W-T53. However, this would still result in a contingency capacity violation, since the load transfer capability between 70W and 89W is already relied upon in the event of a single transformer failure (70W-T53) in the current state.

An additional 12 kV transformer at 70W will not only create the capacity required to convert the 4 kV and retire 70W-T51, but it will also provide the following benefits:

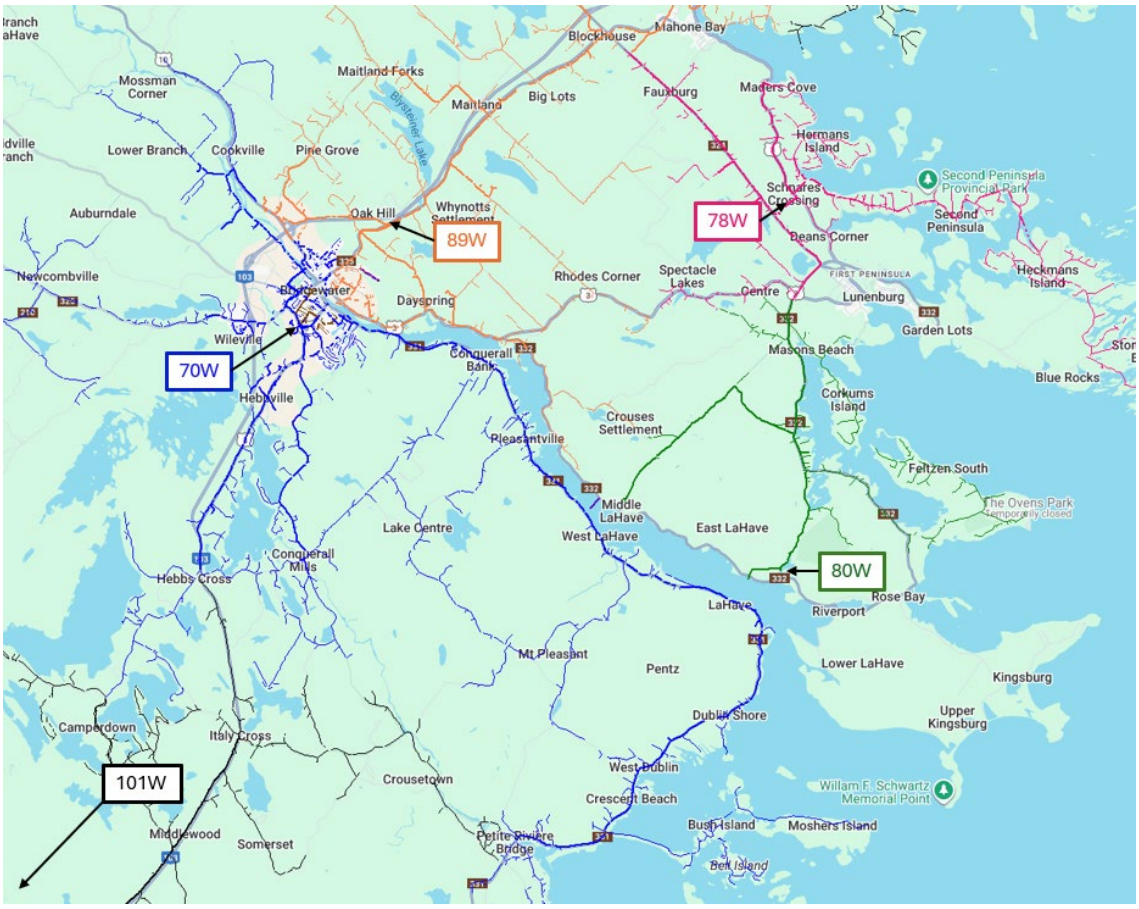
- Additional contingency capacity that will improve restoration times by eliminating the need to install a mobile transformer in the event of a single transformer failure.

- Additional transformation capacity to accommodate the forecasted load growth in the Bridgewater area, including a major development planned near the 70W substation.

(e) Capability to transfer load from 70W to 89W is considered in the available contingency capacity as described above. There are no other distribution feeders capable of supplying load to 70W. Please refer to the GIS map below.

There is limited capability to transfer load from the 89W feeders north of the substation to feeders supplied from 78W and 103W (not shown). These feeder ties do not increase the capacity to supply load south of the Lahave River into Bridgewater.

There are no suitable distribution feeder sources south of Bridgewater. The closest supply originates from a 101W-Bowater feeder. However, this feeder operates at 25 kV, there is a 5 km gap between the three-phase sections of 101W and 70W, and the 101W source is more than 30 km away.



(f) Please refer to Partially Confidential Attachment 1.

NOVA SCOTIA POWER
An Emera Company

Bridgewater
DISTRIBUTION PLANNING STUDY

Report number 211-0606-W62

John Charlton
November, 2006

SUB-TRANSMISSION SYSTEM & DISTRIBUTION SUBSTATION PLANNING STUDY

Bridgewater Area Substations (70W, 73W, 89W)

REPORT #211-0606-W62

Author: John Charlton
Study Period: 2004 - 2013
Reprinted: Nov, 2006
Version 1.1

TABLE OF CONTENTS

1.0 SUMMARY 1

2.0 EXISTING SYSTEM 2

.1 SUB-TRANSMISSION SYSTEM 2
.2 DISTRIBUTION SYSTEM 5

3.0 LOAD HISTORY AND FORECAST 10

.1 LOAD HISTORY 10
.2 TEMPERATURE COMPENSATION: 14
.3 LOAD FORECASTS 14

4.0 CAPITAL CRITERIA VIOLATIONS AND ALTERNATIVE SOLUTIONS 19

.1 BRIDGEWATER 69KV SUB-TRANSMISSION SYSTEM (WITHIN REPORT SCOPE): 19
.1 Capacity Criteria Violation at Bridgewater East (2003) *19*
.2 Deteriorated Plant Criteria Violation: Transformer 70W-T51 (2009) *24*
.3 Capacity Criteria Violation at Auburndale (2010) *26*
.4 Contingency Capacity Criteria Violation at High Street (2012) *26*
.5 Deteriorated Plant Criteria Violation: Line L-5545 (2013) *27*
.2 BRIDGEWATER 69KV SUB-TRANSMISSION SYSTEM (OUTSIDE REPORT SCOPE): 27

5.0 RECOMMENDATIONS 31

APPENDICES

Appendix A: System Data Summary

Appendix B: Economic Analysis Data

Appendix C: Capital Expenditure Justification Criteria

FIGURES

Figure 1: Bridgewater Area - Transmission Switching Diagram 3
Figure 2: Existing Sub-transmission System - Bridgewater Area 6
Figure 3: Town of Bridgewater 7
Figure 4: Feeder Circuit Load History – High Street (70W) 10
Figure 5: Feeder Circuit Load History – Bridgewater East (89W) 11
Figure 6: Historical Growth Rate - High Street (70W) & Bridgewater East (89W) 12
Figure 7: Historical Growth Rate – Auburndale (73W) 13
Figure 8: Historical Temperature Data – Bridgewater Area 14
Figure 9: Load Forecast – High Street (70W) 15
Figure 10: Load Forecast – Auburndale & High Street 16
Figure 11: Load Forecast – Auburndale (73W) 17
Figure 12: Load Forecast – Bridgewater East (89W) 18
Figure 13: Westhavers Elbow Load Data (75W) 29

TABLES

Table 1: Bridgewater Area EHV Substations 2
Table 2: Transmission Line Ratings 4
Table 3: Bridgewater Area Distribution Substations 5
Table 4: Bridgewater Area Distribution Substations 7
Table 5: Bridgewater Area Distribution Circuits 9
Table 6: Sub-station Transformer Data 28

1.0 SUMMARY

The Sub-transmission and distribution systems located in the Bridgewater area have been analyzed in this report over a ten year time frame. Results show that there is an immediate requirement for additional 12kV feeder capacity and for 69-12kV sub-station transformer capacity within the Northeast section of the Town of Bridgewater.

Three alternatives were analyzed to increase the sub-station transformer and 12kV feeder capacities within Bridgewater: *A-1: Add a new Transformer at 70W and Offload 89W; A-2: Replace 89W-T1 with a New 15/20/25 MVA Transformer; and A-3: Utilize the tertiary of 99W-T2 to offload 89W.* Alternative A-2 was recommended, as it was the least cost and least effort option. It had a net present cost of $1,089,970, which was $74,701 less than the option to add capacity at the High Street Sub-station, and $139,257 less than the option to utilize the tertiary windings of transformers 99W-T61 & 99W-T62. It involves replacing 89W-T1 with a new 138/69kV, 15/20/25 MVA transformer in 2004; enlarging 89W to accommodate a new 12kV recloser bay and overhead sub-station exit; building a new 12kV circuit from 89W to Seasons Drive; upgrading 600m of Seasons Drive from two phase to three phase 2/0 ACSR; reconductoring 100m of #2 ACSR on Trunk #10 with 336 ASC; and the addition of a fifth 12kV circuit in 2010 to supply the Oakhill Road Sawmill.

Two alternatives were analyzed to resolve the Deteriorated Plant Criteria Violation that will effect the High Street Transformer 70W-T51 in 2009: *B-1: Replace 70W-T51 in 2009 at the end of its Expected Life; and B-2: Convert the High Street 4kV circuits to 12kV in 2009.* Alternative B-2 was recommended, as it was the least cost option. It had a net present cost of $165,069 which was $65,340 less than the option to replace 70W-T51. It involves the installation of multiple 12-4kV step-down transformers to convert the existing High Street 4kV circuits (70W-203 and 70W-204) to 12kV in 2009.

A capacity criteria violation is expected at the Auburndale Sub-station by 2009, but this can be resolved with the installation of an addition stage of cooling fans on transformer 73W-T51 prior to this date.

The 2km section of Line L-5545 between the Auburndale Tap and Wileville must be reconductored in 2012 (336 ACSR min) in order to avoid a line overload.

A brief analysis of the 69kV Sub-transmission plant supplied via the Westhavers Elbow Sub-station also indicates that a substantial amount of work is required to that system by 2012, and this will also effect the Bridgewater East sub-station. As a result, a full Sub-transmission study of the Westhavers Elbow 69kV system is recommended within the next five years (this study would also include a formal Line survey of Sub-transmission Lines L-5546 and L-5547). This study would be required to compare the options to rebuild the existing 69kV sub-transmission system with the option to convert it to 138kV and eliminate the Westhavers Elbow Sub-station.

2.0 EXISTING SYSTEM

This study was initiated by a capacity criteria violation at the Bridgewater East Sub-station, and covers the period between 2004 and 2013. Forecasts beyond this time frame are uncertain due to the large amount of Sub-transmission work expected in 2012.

.1 Sub-transmission System

The 69kV Sub-transmission System in the Bridgewater area is supplied via the 138kV transmission system transformers identified in table #1 below.

EHV Sub-stations		Transformer Data				
Sub-station Name	Xfmr	Manufacturer	kV	Rating	IMP.	Age
75W - Westhavers Elbow	75W-T1	Fed. Pioneer	138/70.5	20//26	3.71%	1965
99W - Bridgewater	99W-T61	Ferranti Packard	138/69	60/80/100	5.87%	1982
			13.8 (T)	6/8/10	-	
	99W-T62	Westinghouse	138/69	30/40/50//56	5.42%	1978
			13.2 (T)	10/13.3/16.6	-	

Table 1: Bridgewater Area EHV Substations

To minimize operating costs, only one of the Bridgewater transformers is energized at any given time. Typically, 99W-T61 would be energized for 6 months of the year, and 99W-T62 would be energized for the remaining 6 months, thereby saving an estimated $10,000 per year in operating costs.

Under normal operating conditions, the Bridgewater sub-station feeds the Auburndale (73W) and High Street (70W) Sub-stations via the radial Sub-transmission Line L-5545, and feeds the Bridgewater East Sub-station (89W) via Line L-5546. The Westhavers Elbow transformer is used to supply the Mahone Bay, Martin brook, Lunenburg, and Indian path sub-stations, but can also provide a contingency supply to Bridgewater East under light loading conditions via Line L-5546.

The Sub-transmission System Operating Diagram for the Bridgewater Area is shown in Figure 1.

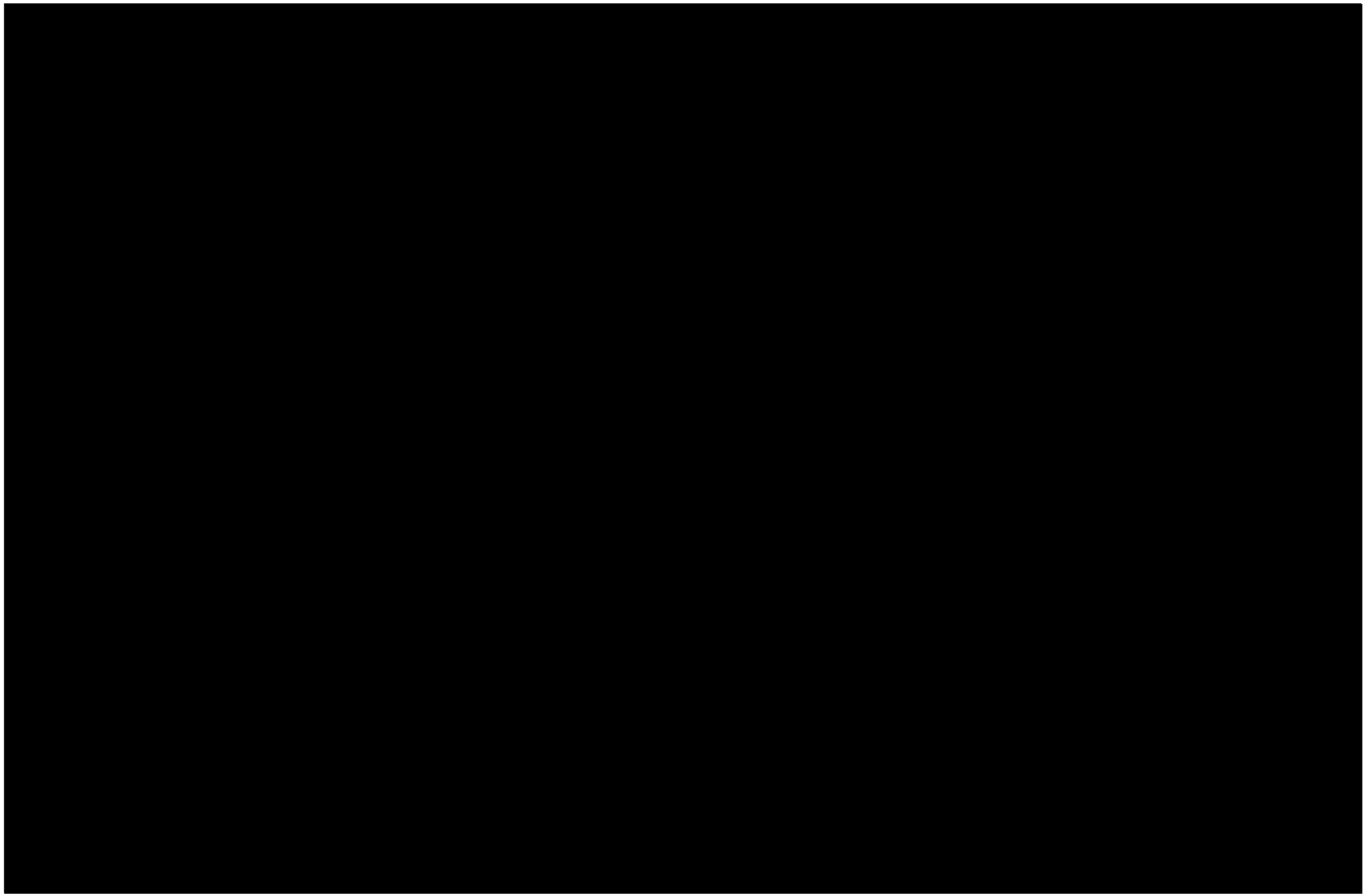


Figure 1: Bridgewater Area - Transmission Switching Diagram

2.1/

The Summer and Winter Ratings for the 69kV transmission lines relevant to this study are included in Table 2.

NSPI Transmission Line Ratings Last Updated: 2006-05-29

LINE	STATION	CONDUCTOR Type	Maximum Operating Temp. (Celcius)	SUMMER RATING 26 DEG (MVA)	WINTER RATING 6 DEG (MVA)	BREAKER 100% Name-plate	SWITCH 100% Name-plate	CURRENT TRANSFORMER RELAYING Ratio	R.F.	MVA	FULL SCALE METERING Ratio	R.F.	MVA	TRIP MVA
L-5545a	70W High St.	2/0 Quail - 4/0 Robin	50	23	34		72				NA			
	73W Auburndale						72				NA			
L-5545b	73W Auburndale	ACSR 556.5 Dove	50	50	82		72				NA			
	99W Bridgewater					143	48	600	2	143	800	1	100	43
L-5546	89W Bridgewater East	ACSR 2/0 Quail	50	23	34		72				NA			
	99W Bridgewater					143	48	600	1	72	800	1	100	43
L-5547	75W Westhavers Elbow	ACSR 2/0 Quail	50	23	34	96	72	400	2	96	NA			38
	82W National Sea										NA			

Table 2: Transmission Line Ratings

Factors Relevant to Report:

1. Section 2 of Transmission Line L-5545 and Section 2 of Transmission Line L-5546 were built in 1957; are now 49 years old; and will either need to be rebuilt or replaced during the period covered by this report.

2. Section 3 of Transmission line L-5546 was also built in 1957. A decision will be required to either rebuild or retire this line during the period covered by this report.

3. The entire length of Transmission Line L-5547 from Westhavers Elbow to Lunenburg town (13.7km) was built in 1955, and will need to be rebuilt or replaced during the period covered by this report.

2.1/

4. The previous Distribution Planning Report (#133-0788-W44) for the Bridgewater Area was conducted in 1988 and contained the following major recommendations:

   - Uprate the 69kV line from 99W to the 70W spur in 1990 ***(complete)***
   - Replace the 69-12kV, 7.5/10//11.2 MVA transformer at 70W with a 15/20/25MVA unit in 1990/91 ***(complete)***
   - Rebuild 12kV bus with transfer bus scheme at 70W in 1990/91 ***(complete)***
   - Rebuild 4kV bus at 70W in 1990/91 ***(complete)***
   - Add sixth feeder from 70W to pick up 89W load in 1993/94 ***(complete)***
   - Add a second 69-12kV, 15/20/25MVA transformer at 70W in 1998/99 ***(not complete)***
   - Replace 73W-T1 with a 15/20/25MVA unit in 2000/01 ***(not complete)***
   - Replace 89W-T1 with a 15/20/25MVA unit in 2003/04 ***(not complete)***

   These recommendations were based in part on the following projected load growth rates:

High Street 12.5kV:	4.0% per year	Auburndale:	3.0% per year
High Street 4kV:	2.1% per year	Bridgewater East:	4.0% per year

   In the past fifteen years, the annual growth rate in these areas has dropped to 2.1% for the High Street & Bridgewater East sub-stations, and to 1.3% for the Auburndale Sub-station.

.2 Distribution System

The distribution sub-stations affected by this report are shown in Table #3.

Sub-stations		Transformer Data				
Sub-station Name	**Xfmr**	**Manufacturer**	**kV**	**Rating**	**IMP.**	**Age**
70W - High Street	70W-T51	Westinghouse	69-4.16	5/6.7 (55°C)	7.70%	1957
70W - High Street	70W-T53	T.T.I. (A.B.B.)	69-13.2	15/20/25	6.39%	1990
73W - Auburndale	73W-T1	General Electric	69-24.94	7.5/10//11.2	6.40%	1973
89W - Bridgewater East	89W-T1	Westinghouse	69-12.47	7.5/10//11.2	6.86%	1973
103W - Gold River	103W-T61	Virginia	138-13.2	7.5/10/12.5	7.80%	1999

Table 3: Bridgewater Area Distribution Substations

2.2/

Figure #2 shows the routing of the main sub-transmission lines that feed the 69kV substations within the Town of Bridgewater:

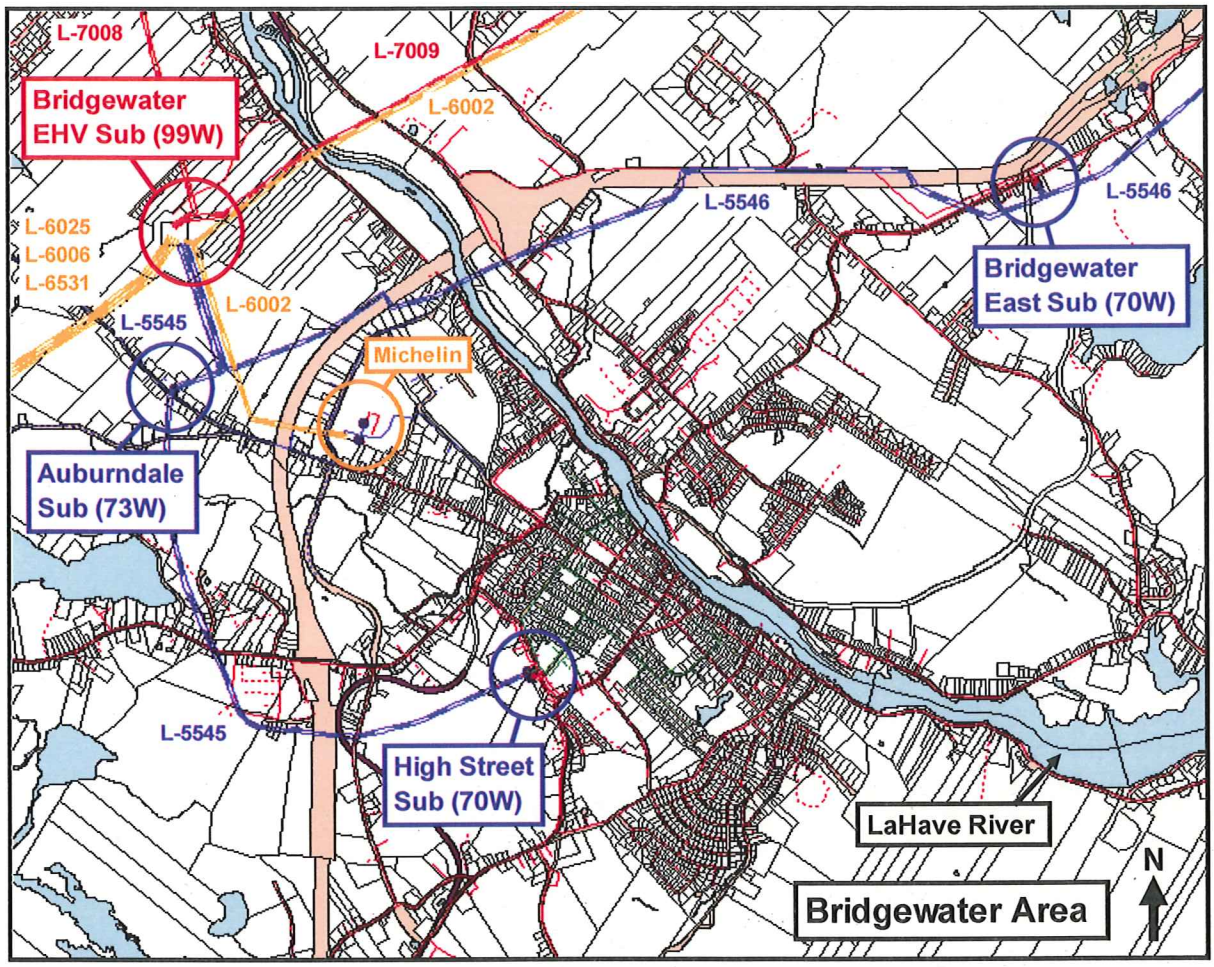


Figure 2: Existing Sub-transmission System - Bridgewater Area

Load Distribution

The Town of Bridgewater is effectively cut in half by the LaHave River, which runs through the town center. The Southwest portion of the town is supplied via the High Street Sub-station (70W), and the Northeast side is supplied via the Bridgewater East Sub-station (89W) and also by High Street via two river crossings. The majority of new development within Bridgewater is occurring on the Northeast side of the river.

Distribution within the Town of Bridgewater is supplied at the 4kV, 12kV, and 25kV voltage levels. Figure 3 shows 4kV circuits in green, 12kV circuits in red, and 25kV circuits in blue. The majority of Bridgewater load is supplied at 12kV.

2.2/

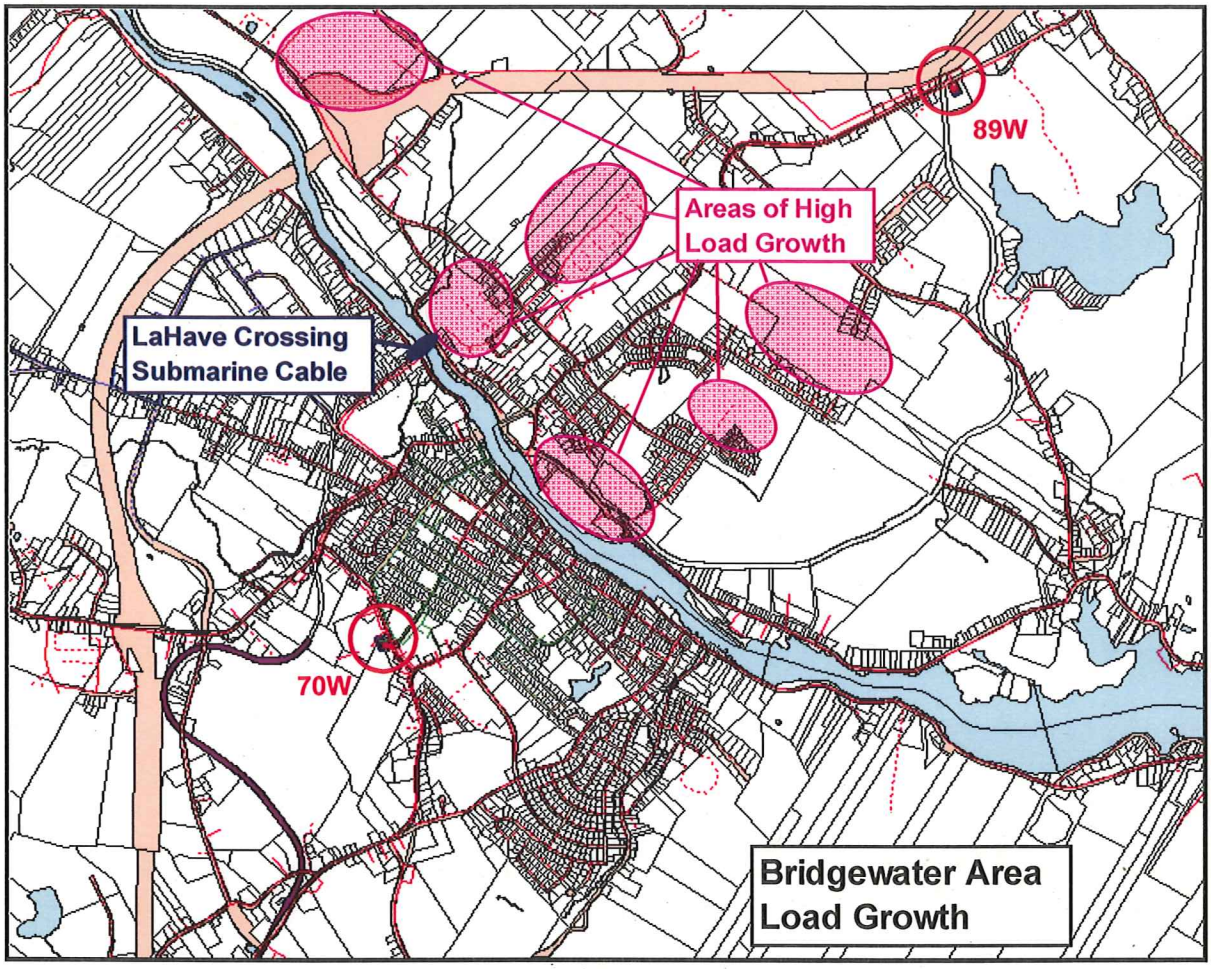


Figure 3: Town of Bridgewater

The distribution feeders included within this report are shown in Table #4.

Bridgewater Area Feeder Circuits		
Sub-station Name	**Xfmr**	**Feeder Numbers**
70W - High Street	70W-T51	70W-203, 70W-204
70W - High Street	70W-T53	70W-311, 70W-312, 70W-313, 70W-314, 70W-321, 70W-322
73W - Auburndale	73W-T1	73W-411, 73W-412
89W - Bridgewater East	89W-T1	89W-301,89W-302, 89W-303, 89W-304
103W - Gold River	103W-T61	103W-311, 103W-312

Table 4: Bridgewater Area Distribution Substations

2.2/

12kV & 4kV Distribution:
The commercial and residential loads in the town are fairly evenly distributed between the two sides of the LaHave River. Each side has approximately 10MVA of peak load in the urban core, and 8-9 MVA of peak load in rural areas (not including 3MVA of industrial load supplied by 89W). Due to capacity limitations at the Bridgewater East Sub-station, the High Street sub-station is presently used to supply 5 MVA of peak load to the Northeast side of the river.

3 MVA of the load in Bridgewater is supplied at the 4kV level from two circuits at the High Street Sub-station, and the remaining 37 MVA is supplied at 12kV from six circuits at the High Street Sub-station and three circuits at the Bridgewater East Sub-station.

25kV Distribution:
The 25kV distribution in the Bridgewater area is fed from the Auburndale Sub-station. Auburndale supplies 1.5 MVA of industrial load within the Bridgewater Industrial Park via circuit 73W-412 and also maintains a 3 MVA reserve for the Michelin Bridgewater Plant located within the park. The second circuit out of Auburndale, 73W-411, supplies 10MVA of rural load and has the highest customer count of any circuit in the province (5236). An analysis of circuit 73W-411 is not included within this report.

Desired Target:
The desired circuit arrangement for the Bridgewater area makes use of the boundaries imposed on the Town by the LaHave River and Highway 103. Ideally, there should be sufficient capacity to the Northeast of the river to supply the Northeast side load, and there should be sufficient capacity to the Southwest of the river to supply the Southwest side load. River crossings would then be used to minimize distribution losses and to provide offload capacity during contingency operations.

Highway 103 forms a natural boundary to the North and East of Bridgewater, and should be used as a border to separate 12kV distribution and 25kV distribution in these directions. At present, there are two 12kV circuits supplied by High Street (70W-321 & 70W-322) that supply 4MVA of peak load on the far side of the highway, and these would eventually have to be converted to 25kV to comply with the desired target.

Although voltage conversion to 25kV cannot be justified at the present time, it may be a valid alternative once the 25kV load at the Auburndale Sub-station exceeds the capacity of transformer 73W-T1 and the load at the High Street Sub-station approaches its' contingency limit.

The peak 2002 load associated with each of the Bridgewater distribution circuits is shown in Table 5.

2.2/

Bridgewater Area Feeder Circuits					
Station Name	Xfmr I.D.	Feeder kV (L-L)	Feeder #	Peak Feeder Amps 2002	Limit
High Street 70W	70W-T51 Built 1957	4.16	70W-203	242	300
			70W-204	146	240
	70W-T53 Built 1990	13.2	70W-311	156	240 #2 Cu
			70W-312	147	240 #2 Cu
			70W-313	187	300 1/0 Cu
			70W-314	112	240 #2 Cu
			70W-321	205	240 - 2/0 Cu
			70W-322	218	240 - 336 Cu → 2/0 Cu
Auburndale 73W	73W-T1 Built 1973	24.94	73W-411	230	300
			73W-412	44	260
Bridgewater East 89W	89W-T1 Built 1974	12.47	89W-301	308	300
			89W-302	248	300
			89W-303	235	300

Table 5: Bridgewater Area Distribution Circuits

Factors Relevant to Report:

1. There is presently a capacity criteria violation on Circuit 89W-301 during periods of peak load.

2. The Bridgewater Planning and Development office has identified the following projects planned for the town:
   - A new 250,000 ft^2 Walmart Complex will be built in 2004 on property adjacent to Highway 103 - Exit 12, and will be accessible via Pine Grove Road.
   - A new 60 room hotel is planned adjacent to the Walmart Complex.
   - A New 49 Unit Appartment Complex on North Street is planned for 2004.
   - Expansion of Eisenhower estates off North Street will continue in 2004.
   - A new Sobeys Store is presently under construction on LaHave Street.
   - A New Empire 7 Cinema Complex will be built on the old Sobeys Store site.

3. The Auburndale feeder circuit 73W-412 maintains a 3 MVA reserve for the Michelin Bridgewater site. This reserve was purchased in May of 1983.

3.0 LOAD HISTORY AND FORECAST

.1 Load History

Load data dating back to 1991 was obtained for each feeder circuit in Sub-stations 70W, 73W, and 89W (refer to Appendix A for feeder data summary). This data was checked against the available sub-station transformer load data, and also against the sub-transmission line load data. It was then used to calculate the combined historical load growth rate for the High Street and Bridgewater East sub-stations, and also for the Auburndale Sub-station.

High Street (70W) Feeder Circuits:

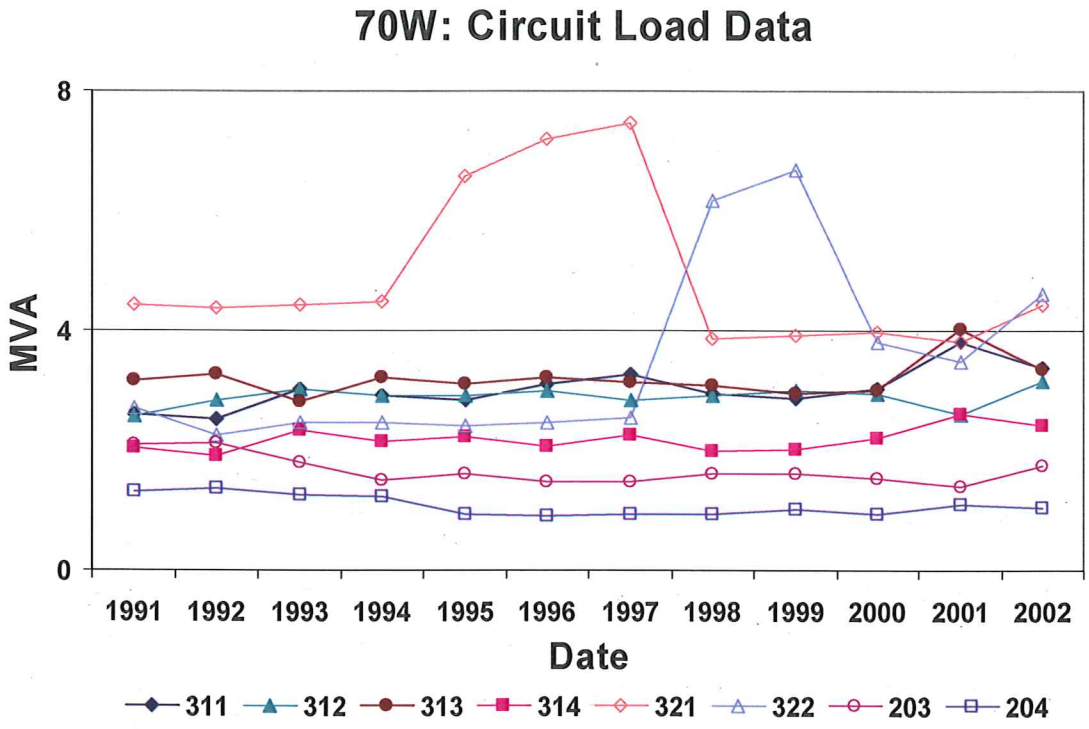


Figure 4: Feeder Circuit Load History – High Street (70W)

Relevant Information:

The load history shown in Figure 4 reflects the following:

- 4kV load on 70W-203 and 70W-204 has remained fairly constant since 1995 (this will slowly be decreased as opportunities arise to convert 4kV to 12kV).
- 2.6 MVA of peak load was transferred from 89W-301 to 70W-321 in 1995.
- 70W-321 & 70W-322 were reconfigured in 1998 (the supply to the LaHave River crossing was changed to circuit 322).
- 2.9 MVA of peak load was transferred from 70W-322 to 89W-301 in 2000.
- 0.9 MVA of peak load was temporarily transferred to 70W-313 from 89W-322 during the 2001/2 Winter peak period.

3.1/

Bridgewater East (89W) Feeder Circuits:

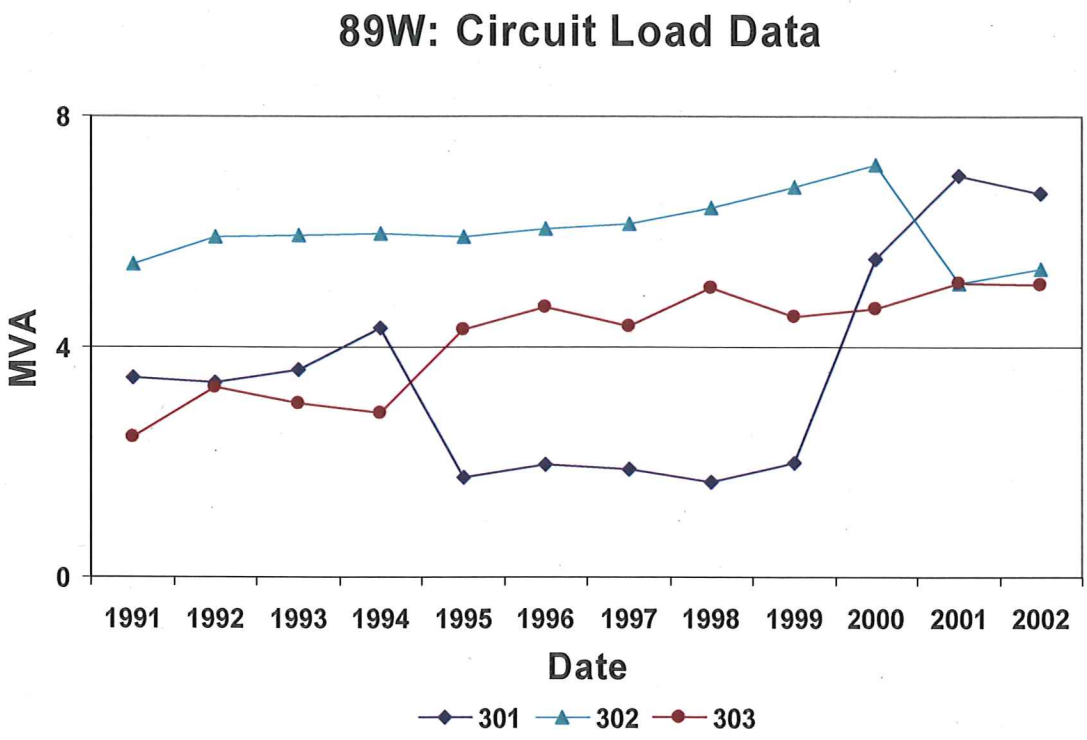


Figure 5: Feeder Circuit Load History – Bridgewater East (89W)

Relevant Information:

The load history shown in Figure 5 reflects the following:

- 1.5 MVA of peak load was Transferred to 89W-303 from 84W-302 (Robinson Corner) in 1995.
- 2.6 MVA of peak load was offloaded from 89W-301 to 70W-321 in 1995.
- 2.9 MVA of peak load was transferred from 70W-322 to 89W-301 in 2000 (South Shore Hospital load plus area malls).
- The expansion of the Bowater Mersey Paper ltd Mill on the Oakhill Road added 1 MVA of peak load to 89W-302 between 1999 and 2002.
- 1.9 MVA of peak load was transferred from 89W-302 to 89W-301 in 2001 after the failure of a voltage regulator (E312-003) on 89W-302. A further 0.9 MVA of load was temporarily transferred from 89W-302 to 70W-313 after this event.
- 2.0 MVA of peak load was transferred from 89W-303 to 103W-311 on February 14, 2003, to offload 89W-T1.
- Load supplied via Sub-station 89W has a poor power factor (0.93 Avg).
- There is presently a capacity criteria violation on Circuit 89W-301 during periods of peak load

3.1/

High Street (70W) & Bridgewater East (89W) Historical Growth Rate:

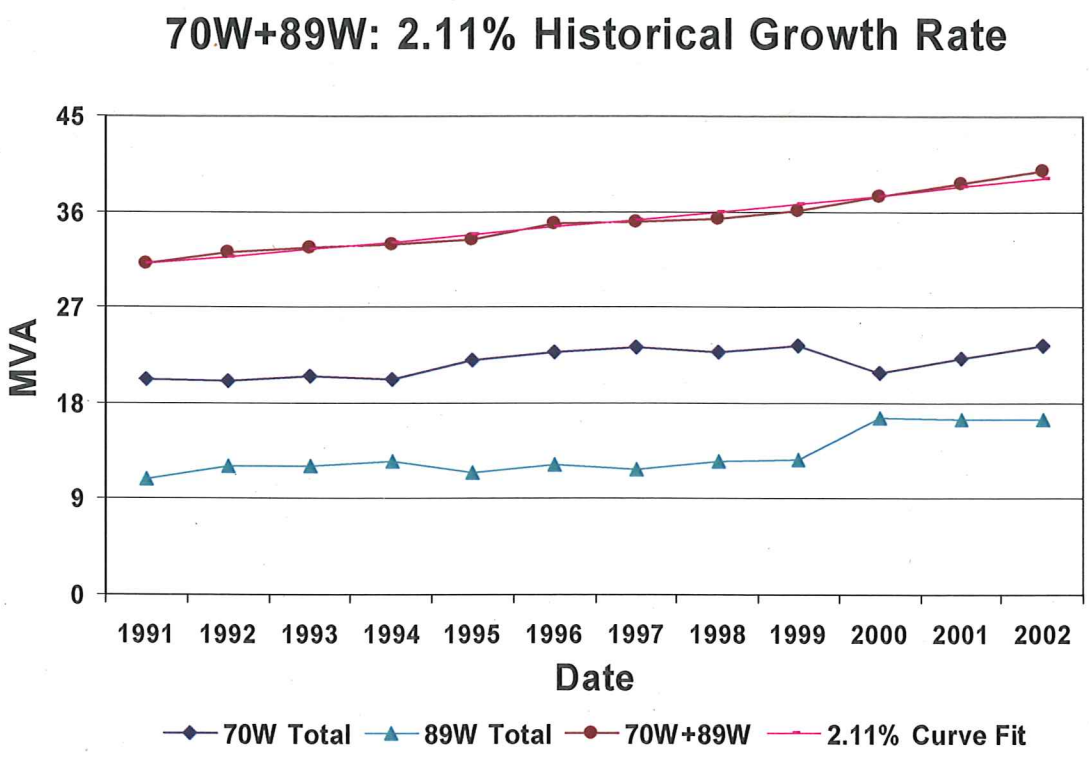


Figure 6: Historical Growth Rate - High Street (70W) & Bridgewater East (89W)

Relevant Information:

1. The historical growth rate for the combined High Street and Bridgewater East Sub-stations was found to be 2.11% per year.

2. Frequent Load transfers between the High Street and Bridgewater East Sub-stations made it necessary to combine these two sub-stations.

3. The majority of growth within Bridgewater has occurred in those areas supplied by circuits 89W-301, 89W-302, and 70W-322, and is almost entirely contained to the Northeast side of the LaHave River.

3.1/

Auburndale (73W) Sub-station:

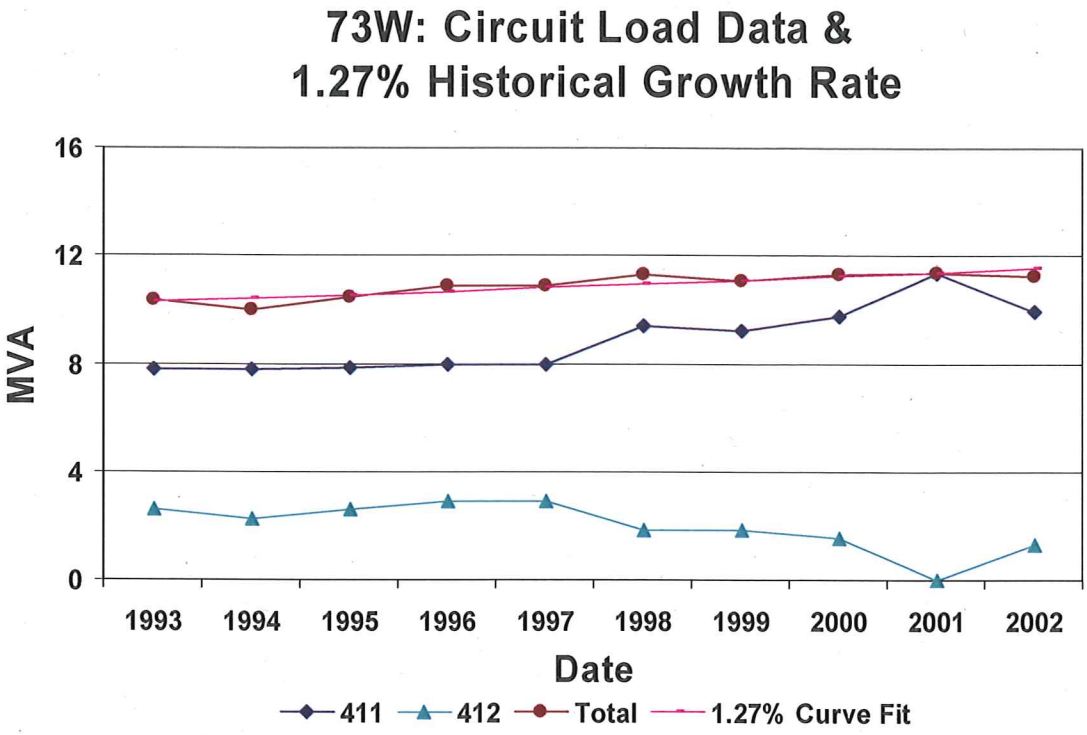


Figure 7: Historical Growth Rate – Auburndale (73W)

Relevant Information:

1. The historical growth rate for the Auburndale feeder circuits (25kV) was found to be 1.27% per year.

2. The Auburndale feeder circuit 73W-412 maintains a 3 MVA reserve for the Michelin Bridgewater site. This reserve was purchased in May of 1983.

3. The Auburndale Sub-station transformer 73W-T1 has provision for an additional stage of cooling which is capable of raising its top rating to 14 MVA. This additional cooling would raise the top overload limit on 73W-T1 during Winter operations to 1.33 x 14 = 18.9 MVA.

3/

.2 Temperature Compensation:

Prior to performing any load forecasting analysis, it is necessary to determine the effect of minimum ambient temperature on each of the sub-stati

3.3/

High Street (70W) Sub-station:

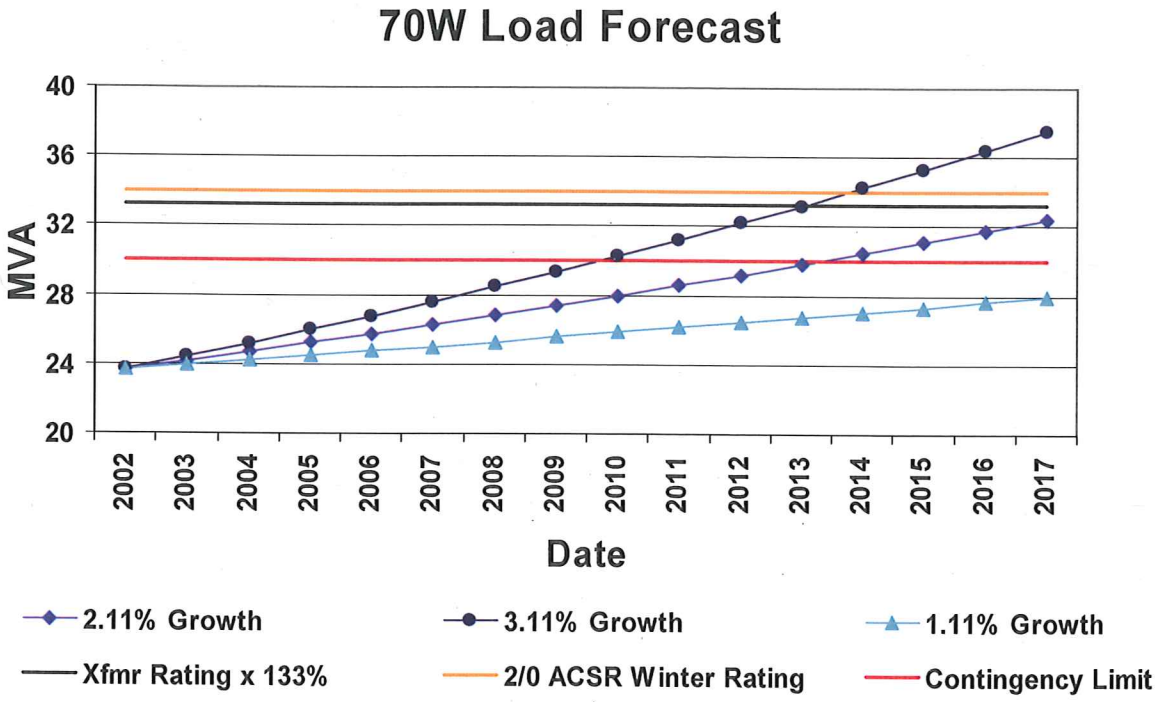


Figure 9: Load Forecast – High Street (70W)

Assumptions:

1. The peak feeder loading for 70W occurs during the Winter months, so that the sub-station transformer 70W-T53 can be loaded to 133% of its top nameplate rating before being considered to be in an overloaded condition.

2. The present contingency capacity is limited to the 30 MVA rating of mobile sub-station 5P-MS (or 6P-MS).

The load forecast for the High street substation shows that there will be a contingency capacity issue by 2014, assuming that the remaining 2.5 MVA of 4kV load will have been converted to 12 kV by this date. Also evident is the fact that the winter rating of the remaining 2km section of 2/0 ACSR supplying this station will be exceeded by 2018, and that Transformer 70W-T53 will exceed 133% of its top nameplate rating in 2018 (provided that load continues to grow at the normal forecasted rate of 2.11% per year). A Higher than normal growth rate of 3.11% would advance these issues by four years.

3.3/

Auburndale & High Street (73W+70W) Sub-stations:

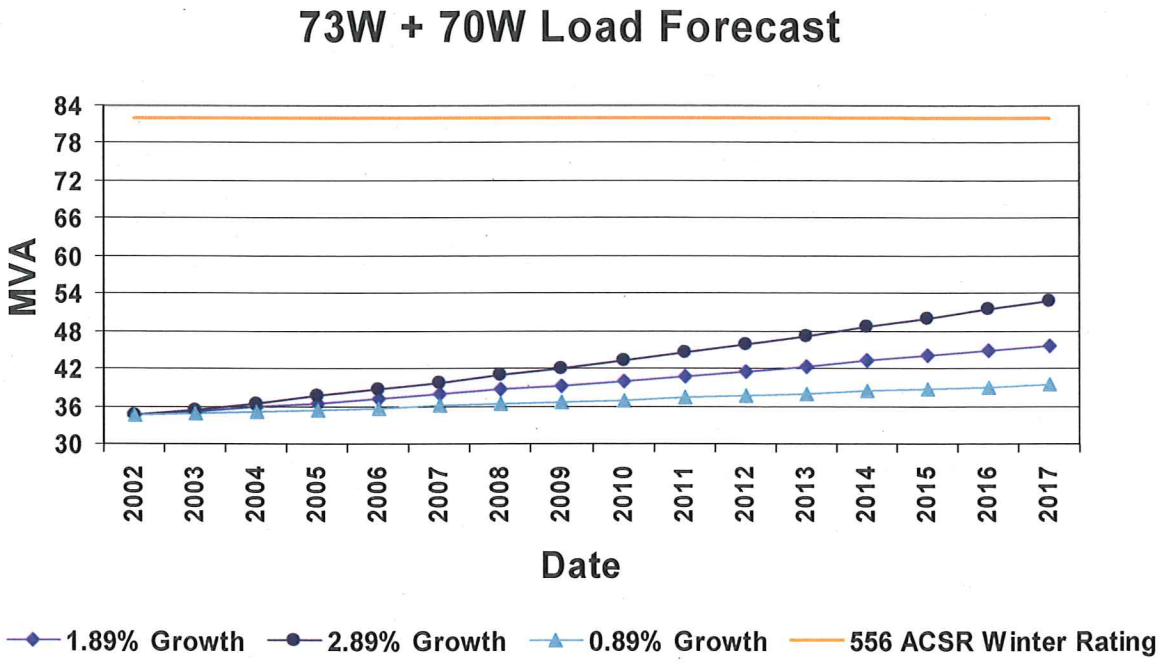


Figure 10: Load Forecast – Auburndale & High Street

The load forecast for the combined Auburndale & High Street loads shows that the section of Line L-5545 between the Bridgewater Sub-station and the Auburndale tap is operating well within criteria limits.

3.3/

Auburndale (73W) Sub-station:

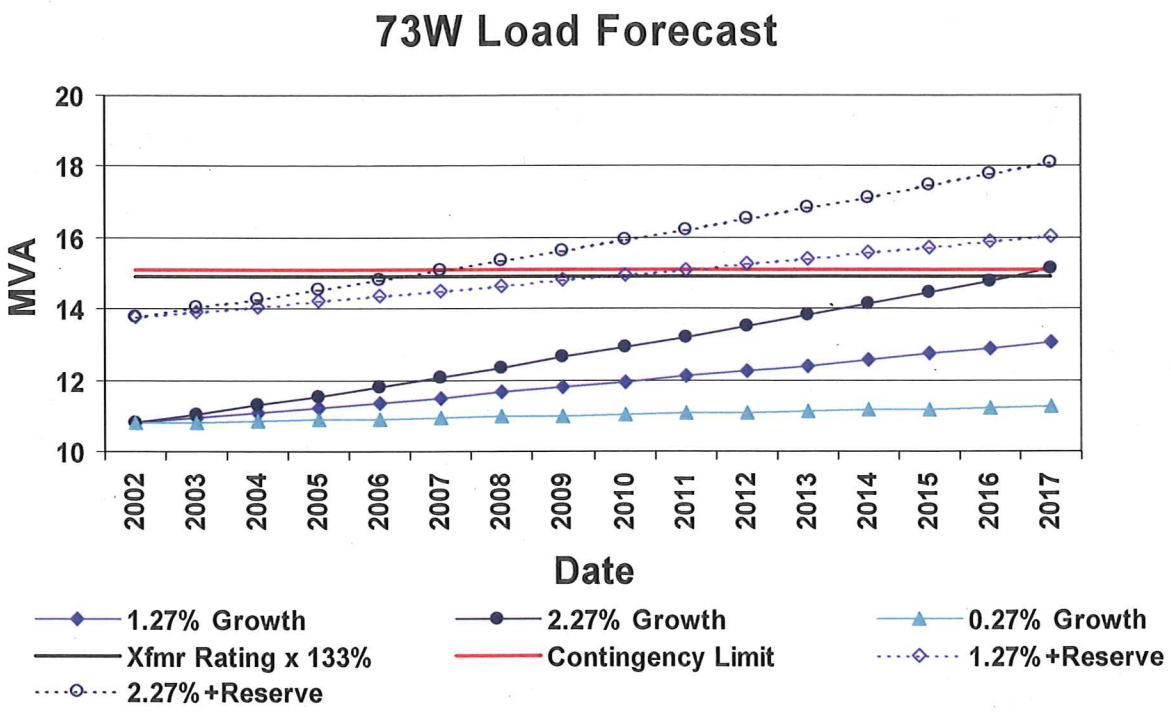


Figure 11: Load Forecast – Auburndale (73W)

Assumptions:

1. The peak feeder loading for 73W occurs during the Winter months, so that the sub-station transformer 73W-T1 can be loaded to 133% of its top nameplate rating before being considered to be in an overloaded condition.

2. The present contingency capacity is limited to the 15 MVA rating of mobile sub-station 4P-MS (if 4P is not available, either 5P-MS or 6P-MS could also be used).

3. The Auburndale feeder circuit 73W-412 must maintain a 3 MVA reserve for the Michelin Bridgewater site, which must be factored into its capacity limitations.

The load forecast for the Auburndale Sub-station shows that there will be a capacity issue at 73W by 2010 at present growth levels. A higher than normal growth rate of 2.27% per year would advance this issue by three years to 2007. Any large addition to the Bridgewater Industrial Park would also have an immediate impact on this date.

3.3/

Bridgewater East (89W) Sub-station:

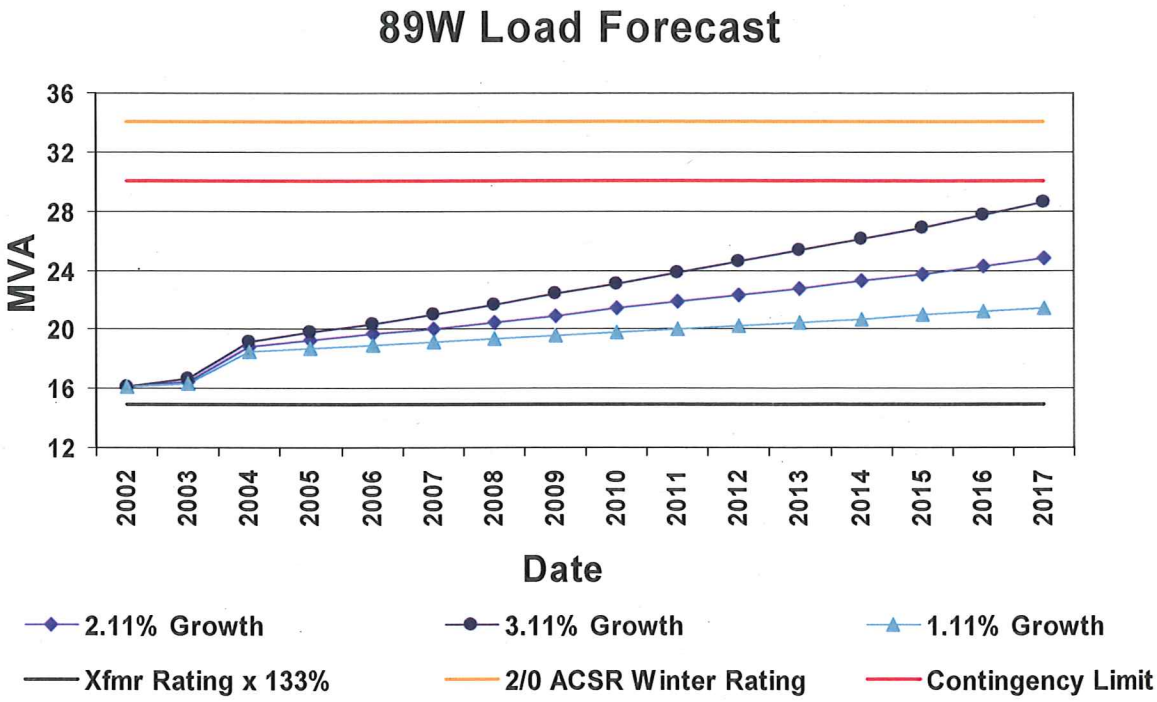


Figure 12: Load Forecast – Bridgewater East (89W)

Assumptions:

1. The peak feeder loading for 89W occurs during the Winter months, so that the sub-station transformer 89W-T1 can be loaded to 133% of its top nameplate rating before being considered to be in an overloaded condition.

2. The present contingency capacity is limited to the 30 MVA rating of mobile sub-station 5P-MS (or 6P-MS).

3. In February of 2003, 2 MVA of peak load was transferred from 89W to 103W, dropping the load on 89W-T1 to 15.5 MVA. A feeder study completed in 2003 identified low voltages on circuit 103W-311 unless 500kVA of this load was transferred back to 89W prior to the 2003 Winter peak. The new development on Pine Grove Road will also add another 1.5-2 MVA to local feeder circuits.

The load forecast for the Bridgewater East Sub-station shows that there is a serious capacity issue at 89W now, and that action will be necessary to relieve this situation prior to the Winter peak of 2003/04.

4.0 CAPITAL CRITERIA VIOLATIONS AND ALTERNATIVE SOLUTIONS

Refer to Appendix C for relevant sections of the NSPI Capital Expenditure Justification Criteria.

.1 Bridgewater 69kV Sub-transmission System (Within Report Scope):

There are a number of criteria violations concerning the Bridgewater Sub-transmission system that will occur before 2012 if load at the Bridgewater East & High Street Sub-stations continues to grow at the rate of 2.1% per year, and if load at the Auburndale Sub-station continues to grow at the rate of 1.3% per year.

- Capacity Criteria Violation at Bridgewater East (2003)
- Deteriorated Plant Criteria Violation at High Street: 70W-T51 (2009)
- Capacity Criteria Violation at Auburndale (2010)
- Contingency Capacity Criteria Violation at High Street (2012)
- Deteriorated Plant Criteria Violation: Line L-5545 (2013)

.1 Capacity Criteria Violation at Bridgewater East (2003)

There is presently a capacity criteria violation at the Bridgewater East Sub-station during periods of peak load. The recorded 2002/03 Winter peak was 17.2 MVA, which is 154% of the top nameplate rating of 89W-T1.

To relieve 89W-T1, 2MVA of peak load was transferred from Sub-station 89W to 103 W (Gold River) in February of 2003. Further attempts to offload Transformer 89W-T1 from the High Street Sub-station were prevented by the failure of the LaHave River submarine cable (near Park Street) in October of 2003.

All available offload capacity for Sub-station 89W has now been utilized. Peak load on this unit during the 2003/04 Winter peak is expected to be 16 MVA (143% top rating), although a further 2-2.5 MVA of load will have to be supplied from this site after the following construction is completed in 2004:

- 250,000 ft^2 Walmart Complex off Pine Grove Road.
- 60 room hotel adjacent to the Walmart Complex.
- 49 Unit Appartment Complex on North Street
- Continued Expansion of Eisenhower estates off North Street
- Sobeys Store (LaHave Street)
- Empire 7 Cinema Complex (on the old Sobeys Store site)

The existing transformer overload at 89W and the prospect of 2-2.5 MVA of new load on the northeast side of the LaHave River is driving the need to add transformer capacity at the Bridgewater East Sub-station.

4.1.1/

Alternate Solutions:
Three potential solutions were analysed to relieve the overload on the Bridgewater East Transformer 89W-T1. These included the option to add a second transformer at Sub-station 70W; the option to replace Sub-station Transformer 89W-T1 with a new 15/20/25 MVA unit; and the option to utilize the tertiary windings of Transformers 99W-T61 & T62 to create a new 12kV supply within the Bridgewater EHV Sub-station. These options are discussed in more detail below.

A fourth option to relieve load at 89W by converting 12kV load to 25kV and supplying it via the Auburndale sub-station was not included in the analysis due to substantially higher costs associated with that work. This alternative would have required the replacement of the Auburndale Sub-station transformer in addition to conversion costs, and would not have resolved all the capacity issues at 89W.

Alternative A-1: Add a new Transformer at 70W and Offload 89W
This option relies on the installation of a second transformer at the High Street Sub-station to offload the distribution circuits supplied by the Bridgewater East Sub-station.

- Install a new 69-13.2kV, 15/20/25 MVA transformer at High Street in 2004
- Convert circuit 70W-204 to 12kV using 12.5-4.16kV step-down transformers and create a new 12kV circuit from 70W to King Street in 2004 (reconductor existing #2 Cu with new 336ASC).
- Infill the 12kV between Victoria Road and King Street using 4/0 ASC and upgrade the existing single phase section of line between Victoria Road and Starr Street to three phase 4/0 ASC. Use this new route to supply the rural 70W-321 load in 2004.
- Double circuit the river crossing at Starr Street in 2004
- Replace the existing Submarine cable at the LaHave River Park Street Crossing with new 4/0 cable in 2004.
- Reconductor the existing #2 Cu & 1/0 ACSR between the High Street Sub-station and King Street with 336 ASC in 2004 and reconfigure circuits 70W-321 & 322 so that circuit 70W-321 consists of 2/0 Cu + 2/0 ACSR (existing) and 70W-322 consists entirely of the new 336 ASC.
- Install one new span of 336 ASC distribution line between LaHave Street and the Eisenhower Estates adjacent to the Starr Street river crossing (1 new pole required)
- Upgrade the #4Cu along LaHave Street between the Starr Street river crossing and Aberdeen Road to 336 ASC and install new 336 ASC along Aberdeen Road to meet up with circuit 89W-301.
- Use existing circuit 70W-321 to supply the new mall complex and hotel, and circuit 70W-322 to pick up North Street load and to offload circuit 89W-301.

4.1.1/

- Reconductor circuit 70W-312 along Dufferin Street and Jubiliee Road down to Desbrisay Drive using 336 ASC in 2004.
- Upgrade Brook Street and Pine Street to three phase 2/0 ACSR in 2004
- Use circuits 70W-312 and 70W-314 to offload circuit 70W-313 in 2004
- Use Circuit 70W-313 as a dedicated feed to the Northeast side of the LaHave River to offload circuits 89W-301 and 302.
- Reconductor the 100m section of #2 ACSR on Trunk #10 (by McCullock Road) with 336 ASC in 2004.

This option makes use of the fact that there is already provision for a second transformer at the High Street Sub-station. This location has a HV bus, switch, transformer pad, and low voltage bus already in place, although two of the bays in the LV bus are occupied by the 4kV circuits 70W-203 & 204.

Alternative A-2: Replace 89W-T1 with a New 15/20/25 MVA Transformer
This option requires that the existing 8.4/11.2 MVA transformer at Bridgewater East be replaced by a new 15/20/25 MVA unit.

It involves the following work:
- Install mobile sub-station at 89W prior to station work in 2004
- Move 89W-T1 to stores in 2004
- Remove the existing concrete pad at 89W in 2004
- Install a new pad complete with oil containment in 2004
- Install a new 138/69-13.2kV, 15/20/25 MVA Transformer in 2004
- Enlarge Sub-station 89W by 10m x 30m in 2004
- Install a new recloser bay complete with overhead sub-station exit in 2004
- In 2004, build a new 12kV circuit from 89W to Seasons Drive (Eisenhauer Estates) via Highway 325 => Orphans Home Road => Oak Lane => and 200m of new Line.
- Upgrade 600m of Seasons Drive from two phase to three phase 2/0 ACSR.
- Reconductor the 100m section of #2 ACSR on Trunk #10 (by McCullock Road) with 336 ASC in 2006.
- Add a fifth circuit from 89W to the Oakhill Road Sawmill in 2010 to offload circuit 89W-302, which will enable the offloading of the High Street circuit 70W-322.

The new circuit from 89W would be used to offload North Street and Eisenhauer Estates from circuit 70W-322, and also the lower section of Aberdeen Road from circuit 89W-301. This would free up capacity on circuit 70W-322 to supply the new mall and hotel developments on the Pine Grove Road. The addition of a fifth circuit in 2010 would offload 3MVA from circuit 89W-302 which would then be able to pick up additional Bridgewater load.

4.1.1/

Alternative A-3: Utilize the tertiary of 99W-T2 to offload 89W

This alternative makes use of the fact that there is 12.5kV (delta) available from the tertiary windings of the power transformers within the Bridgewater EHV Sub-station 99W.

It involves the following work:

- Install a new 12kV bus assembly within 99W complete with two recloser bays & U/G station exits, a switch bay, and a bay to connect a new grounding (zigzag) transformer in 2004.
- Install a new grounding transformer within 99W in 2004
- Utilize the 16MVA, 12.5kV tertiary winding of transformer 99W-T62 to supply the new 12kV bus in 2004.
- Utilize the 10MVA, 12.5kV tertiary winding of transformer 99W-T61 as an alternate supply to the new 12kV bus in 2004. *(only one of these transformers is energized at any given time to reduce the cost of losses).*
- Upgrade the existing station services distribution line from 99W to King Street to double circuit 336 ASC in 2004.
- Double circuit the distribution line between the 99W station services tap and the North King Street Bridge using 336 ASC in 2004
- Upgrade the section of Trunk #10 between the North King Street Bridge and Pine Grove Road to three phase 336 ASC in 2004.
- Reconductor the 100m section of #2 ACSR on Trunk #10 (by McCullock Road) with 336 ASC in 2004.
- Supply the new mall complex and hotel from 99W-T62 via the new line down Trunk #10 in 2004.
- Supply existing circuit 70W-321 from the second circuit out of 99W in 2004
- Replace U/G under Highway 103 & Rail Bridge in 2004
- Install a new span of 336 ASC distribution line between LaHave Street and the Eisenhower Estates adjacent to the Starr Street river crossing (1 new pole required) in 2004.
- Reconductor 70W-322 with 336 ASC.
- Double circuit the existing overhead Lahave River crossing.
- Use circuits 70W-321 and 70W-322 to offload circuit 89W-301, and to pick up North Street load in 2004.
- Replace the existing Submarine cable at the Lahave River Park Street Crossing with new 4/0 cable in 2004.
- Reconductor circuit 70W-312 along Dufferin Street and Jubiliee Road down to Desbrisay Drive using 336 ASC in 2004.
- Upgrade Brook Street and Pine Street to three phase 2/0 ACSR in 2004
- Use circuits 70W-312 and 70W-314 to offload circuit 70W-313 in 2004
- Use Circuit 70W-313 as a dedicated feed to the Northeast side of the LaHave River to offload circuits 89W-301 and 302.

4.1.1/

The two circuits from 99W would be used to supply the new load on Pine grove Road and to offload circuits 70W-322 and 321, which would then be used to completely offload circuit 89W-301. This would lower the peak load on sub-station transformer 89W-T51 back to approximately 100% of its top transformer nameplate rating of 11.2MVA.

Economic Analysis

The relevant financial data, economic analysis calculations, NPV results, and alternative summary sheets have been included in Appendix B of this report.

Alternative A-1: Add a new Transformer at 70W and Offload 89W
NP Cost = $1,164,671

Alternative A-2: Replace 89W-T1 with a New 15/20/25 MVA Transformer
NP Cost = $1,089,970

Alternative A-3: Utilize the tertiary of 99W-T2 to offload 89W
NP Cost = $1,229,227

The results of the analysis show that Alternative A-2, *Replace 89W-T1 with a New 15/20/25 MVA Transformer (in 2004)* is the most economic choice.

Qualitative Analysis

70W: Adding a transformer at Sub-station 70W would place additional capacity as near to the geographic load centre of Bridgwater as possible, and would therefore lower costs associated with system losses. The distribution circuits out of this station would also benefit, as two of them would require re-conductoring, and a third would need to be converted from 4kV to 12kV (advanced from 2010 to 2004).

However, in order to provide for long term growth, additional river crossings would be required to get the new capacity from High Street to the area of greatest growth – the Northeast side of the LaHave River. It would also be necessary to offload nearly all of circuit 89W-301 just to lower the peak load on transformer 89W-T51 back to 100% of its top nameplate rating (11.2MVA).

System reliability would also suffer by adding new capacity at High Street. Radial Sub-transmission Line L-5545 supplies both the Auburndale and High Street Sub-stations, which have a total connected capacity of 36 MVA. The addition of a new 15/20/25 MVA source would increase this to 61MVA. Minimal offload capacity would be available from 89W, which would only be offloaded to 100% of its' top rating.

4.1.1/

89W: Replacing the existing Bridgewater East Sub-station Transformer 89W-T51 with a larger unit in 2004 represents both the 'least effort' and 'least cost' solution to the capacity problems within Bridgewater. Although Sub-station 89W is further from the existing load centre than Sub-station 70W, it is located on the same side of the LaHave river that is experiencing the majority of load growth.

As previously mentioned, the 12kV commercial and residential loads in Bridgewater are fairly evenly distributed between the two sides of the LaHave River. Each side has between 10-12 MVA of peak load in the urban core, and 8-9 MVA of peak load in rural areas (not including 3MVA of industrial load supplied by 89W). Replacing 89W-T1 would ensure that there is sufficient capacity on both sides of the river to supply local load, while also providing some offload capacity via the one surviving river crossing.

99W: Utilizing the tertiary windings of both of the existing 138/69-12.5kV auto-transformers at the Bridgewater EHV sub-station would eliminate the need to purchase a new $550,000 transformer in 2004. It would improve the voltage profile of the rural circuit 70W-321, and would provide for an additional feeder circuit route into the Northeast side of Bridgewater and for the double circuiting of the existing river crossing.

Disadvantages of this option include the fact that distribution plant would be built within an EHV sub-station, and that each of the new circuits supplied via this sub-station would require voltage regulation. This option also has the same drawback as Alternative A-1, which is that it would be necessary to offload nearly all of circuit 89W-301 just to lower the peak load on transformer 89W-T51 back to 100% of its top rating of 11.2MVA.

The results of this analysis favour Alternative A-2: *Replace 89W-T1 with a New 15/20/25 MVA Transformer (in 2004).*

.2 Deteriorated Plant Criteria Violation: Transformer 70W-T51 (2009)

The 5/6.7 MVA, 69-4.16kV Transformer 70W-T51 was built in 1957, and is located at the High Street Sub-station. It is now 46 years old and has reached 118% of the average service life for *'Transmission Plant - Station Equipment'* [1]. According to the IOWA State Survivor Curve R-2.5, and based on an average service life of 39 years, we can estimate that 70W-T51 will reach the end of its useful life in 2009. By this date, it will either have to be replaced or retired, which would require the conversion to 12kV of the two remaining 4kV circuits supplied from High Street.

[1] Average life span of transmission and distribution equipment and their associated IOWA State survivor curves were obtained from the Nova Scotia Power Depreciation Report, which was filed in April, 2003, and is subject to approval by the UARB.

4.1.2/

Solution:

Alternative B-1: Replace Transformer 70W-T1 at the end of its Expected Life
This alternative involves the purchase and installation of a new 5 MVA, 69-4kV transformer within the High Street sub-station.

Alternative B-2: Convert the remaining 4kV circuits to 12kV in 2009
This alternative acknowledges that 4kV distribution is being phased out by NSPI wherever it is practical to do so. It utilizes multiple 12-4kV step-down transformers to convert circuits 70W-203 and 70W-204 to 12kV. These step-downs would be connected to existing 12kV circuits supplied via the High Street Sub-station.

Economic Analysis:
The relevant financial data, economic analysis calculations, NPV results, and alternative summary sheets have been included in Appendix B of this report.

Alternative B-1: Replace 70W-T1 in 2009 at the end of its Expected Life
NP Cost = $230,409

Alternative B-2: Convert the High Street 4kV circuits to 12kV in 2009
NP Cost = $165,069

The results of the analysis show that Alternative B-2, *Convert the remaining 4kV circuits to 12kV in 2009,* is the most economic choice.

Qualitative Analysis
70W-T51: Replacing 70W-T51 at the end of its expected life is the simplest means of correcting this issue. However, this option goes against current practices within NSPI, which involve the phasing out of 4kV whenever it is practical to do so.

There are now only fifteen 69-4kV sub-station transformers remaining on the NSPI sub-transmission system. These have an average age of 41 years, which is two years older than the average expected lifespan for sub-station transformers (according to the Iowa State Survivor Curves, it is probable that up to six of these units will fail by the year 2010). Replacing these transformers with new 4 kV units would serve to perpetuate 4kV distribution and would require the continued acquisition of parts and spares at the 4kV voltage level.

It should also be noted that the two remaining 4kV distribution circuits at the High Street sub-station are occupying 12kV recloser bays. At least one of these would have to be converted to 12kV prior to the addition of any new 12kV circuit.

4.1.2/

Conversion: The two High Street 4kV circuits supply a total peak load of approximately 3 MVA, which could easily be supplied via two or three banks of single phase step down transformers. A new 12kV circuit would eventually supply the converted load and could also be used to offload existing 12kV circuits.

The results of this analysis favour Alternative B-2, *Convert the remaining 4kV circuits to 12kV in 2008.*

.3 Capacity Criteria Violation at Auburndale (2010)

The Auburndale sub-station is presently supplying approximately 11 MVA of industrial and residential (rural) load at the 25kV voltage level via Transformer 73W-T1. This load has a winter peak, and Transformer 73W-T1 can be loaded to 133% of its top rating of 11.2 MVA before being considered in an overloaded condition (1.33 x 11.2 = 14.9 MVA).

In addition to the existing load, NSPI has an agreement with the Michelin Bridgewater Plant that states that the Auburndale Sub-station must provide a back-up reserve of 3 MVA to their plant – accessible at any time. Therefore, for planning purposes, the total available capacity from 73W-T1 must be reduced from a maximum of 14.9 MVA to 11.9 MVA.

Provided that load growth continues at 1.3% per year, load on the Auburndale Sub-station Transformer 73W-T1 will exceed the 11.9 MVA limit in 2010.

Solution:

73W-T1 has provision for an additional fan kit that would raise its' top rating to 14 MVA. This would allow the Auburndale transformer to be loaded to 15.9 MVA (14 MVA x 1.33 – 3MVA Reserve = 15.9 MVA) before again being considered in an overloaded condition.

It should be noted, however, that the addition of a single new industrial customer in the Bridgewater Industrial Park with a peak load greater than 750kVA would immediately require the installation of the fan kit.

.4 Contingency Capacity Criteria Violation at High Street (2012)

Provided that load growth continues at 2.11% per year and that existing 4kV load is converted to 12kV, the High Street Sub-station Transformer 70W-T53 will experience a contingency capacity criteria violation in 2012.

Solution:

The creation of a new circuit at 89W in 2010 will permit the offloading of circuit 70W-322 by 2-3 MVA, which will defer the need for additional capacity at High Street for an additional 4 years.

4.1/

.5 Deteriorated Plant Criteria Violation: Line L-5545 (2013)

The 2km section of Line L-5545 that runs between the Auburndale Tap and Wileville (L-5545 Section 3) was built in 1957; is now 46 years old; and has reached 110% of the average service life for '*Transmission Plant - Poles and Fixtures* [2]. According to the IOWA State Survivor Curve R-2, and based on an average service life of 42 years, we can estimate that this section of Line L-5545 will require a major rebuild/replacement by 2013.

Solution:

Rebuild the 2km section of Line L-5545 between the Auburndale Tap and Wileville (Section 3) prior to 2013 utilizing 336 ASC conductor. [3]

.2 Bridgewater 69kV Sub-transmission System (Outside Report Scope):

Two criteria violations concerning the Bridgewater 69kV Sub-transmission system are expected to occur by 2013. These are worthy of mention but do not fall within the scope of this report.

a) Deteriorated Plant Criteria Violation: Line L-5547 (2012)
b) Deteriorated Plant Criteria Violation: Line L-5546 (2013)

a) Deteriorated Plant Criteria Violation: Line L-5547 (2012)

In addition to providing an alternate supply to Sub-station 89W via line L-5546, Westhavers Elbow also supplies Sub-stations 76W, 78W, 81W, and 82W via 17km of radial Line L-5547, and Sub-station 80W via 10km of radial Line L-5551. The 17km section of L-5547 was built in 1955; is now 48 years old; and has reached 114% of the average service life for '*Transmission Plant - Poles and Fixtures.* According to the IOWA State Survivor Curve R-2, and based on an average service life of 42 years, we can estimate that this line will require a major rebuild/replacement in 2012. Due to the radial nature of this line, replacement work will need to be done under live line conditions unless a new right of way can be obtained.

[2] Average life span of transmission and distribution equipment and their associated IOWA State survivor curves were obtained from the Nova Scotia Power Depreciation Report, which was filed in April, 2003, and is subject to approval by the UARB.

4.2/

There are a few considerations that should be taken into account prior to rebuilding or replacing this line:

Operating Voltage: If the new line was rated for 138kV operation, it would be possible to plan for the eventual retirement of the Westhavers Elbow Sub-station.

Age of 69kV Plant: In addition to the age of Line L-5547, Transformer 75W-T1 and many of the sub-station transformers supplied at 69kV by 75W-T1 will be approaching their end of useful life by 2012. Table #6 shows the respective ages of these units referenced to 2012.

SUBSTATION I.D.		TRANSFORMER DATA					
SUB No.	SUBSTATION NAME	HV kV	LV kV	XFMR I.D.	XFMR AGE	XFMR RATING	AGE IN 2012
75W	WESTHAVERS ELBOW	138	69	T1	1965	20/26.6	47
76W	MAHONE BAY	69	4.16	T1	1971	3.75/5 (55°C)	41
78W	MARTINS BROOK	66	12.5	T1	1960	2.5/3	52
80W	INDIAN PATH	69	12.47	T1	1970	5/6.7//7.46	42
81W	LUNENBURG TOWN	69	6.9	T51	1982	7.5/10/12.5	30
			4.16	T2	1974	7.5//8.4	38

Table 6: Sub-station Transformer Data

When the time comes to replace these units, new transformers having dual rated primary voltages could be installed, which would help make it possible to convert line L-5547 to 138kV operation (Note that the transformers at Mahone Bay and Lunenburg Town are customer owned).

Load on Transformer 75W-T61: The peak load supplied via Westhavers Elbow in 2002/03 was approximately 22 MVA, which is within the 26MVA rating of the unregulated Transformer 75W-T1 (refer to Figure 13 for load data). At some point in the future, load at 75W will exceed this rating, and will rise to the 30MVA contingency rating of the mobile sub-station. It will then be necessary to upgrade Sub-station 75W and replace Transformer 75W-T1 with two new 138-69kV transformers – one for normal operations, and one for a contingency supply.

However, it would probably be easier and less costly to convert the Westhavers Elbow 69k system to 138kV provided that steps have been taken to prepare for this eventuality.

4.2/

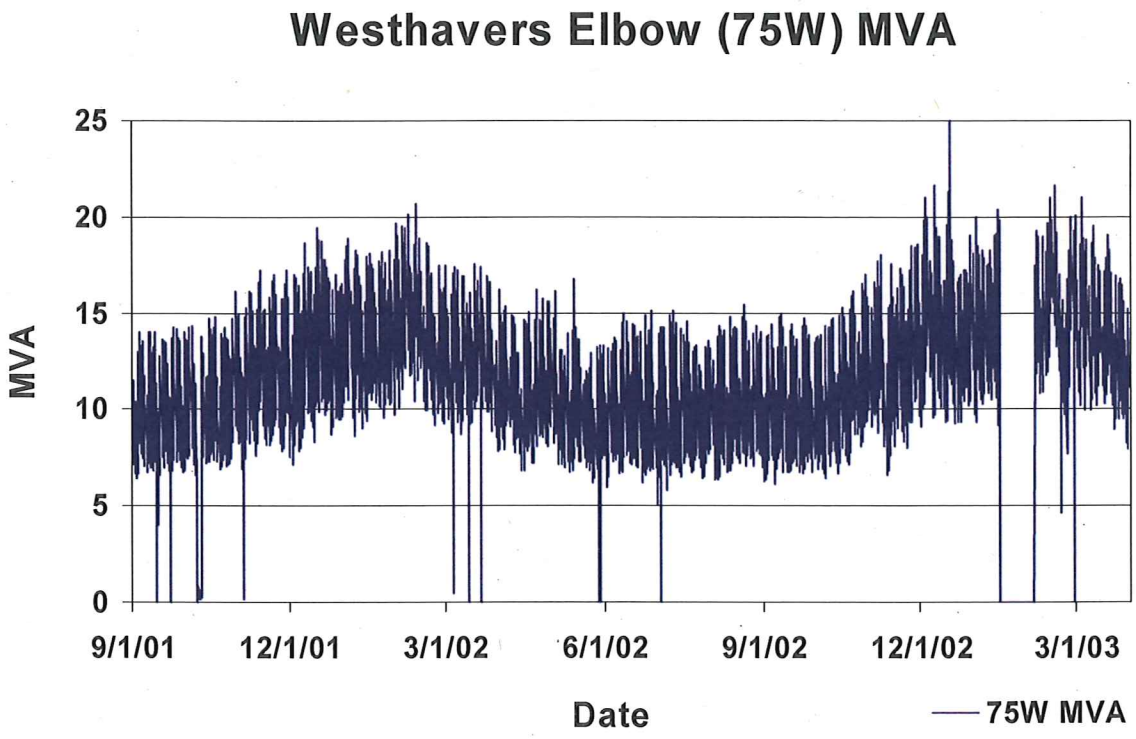


Figure 13: Westhavers Elbow Load Data (75W)

It is evident that major changes/revitalization will be required to the Westhavers Elbow 69kV Sub-transmission System within the next ten to 15 years. As such, a separate Sub-transmission Study should be undertaken to examine the future of this system. This study should compare the option to Upgrade/Rebuild the Westhavers Elbow 69kV Sub-transmission System with the option to gradually convert it to 138kV operation and replacing Sub-station 75W with a single 138kV Line tap.

b) Deteriorated Plant Criteria Violation: Line L-5546 (2013)

The 5.7km section of Line L-5546 between the Bridgewater and Bridgewater East Sub-stations, and the 5.9km Section of L-5546 between the Bridgewater East and Westhavers Elbow Sub-stations were built in 1957. These '*Wooden Poles and Fixtures*' are now 46 years old and will require a major rebuild/replacement by 2013.

Comments:

The simplest solution to this violation would involve the rebuild of the 5.7km section of line between the Bridgewater and Bridgewater East sub-stations followed by the abandonment of the section between the Bridgewater East and Westhavers

4.2/

Elbow sub-stations (during the rebuild of the first section, a mobile would have to be installed at Westhavers Elbow to supply the Bridgewater East sub-station). However, this decision will be impacted by the work required to revitalize or replace the 69kV plant supplied via the Westhavers Elbow Sub-station.

A second option for the supply to Bridgewater East would involve the construction of a new 2.5km line tap to the existing 138kV Line L-6002. This would offload the 69kV system by 20-25 MVA, and would allow the abandonment of Sub-transmission Line L-5546 in its entirety (11.6km).

Summary:

Sub-transmission Lines L-5546 & L-5547
In order to ascertain the true condition of lines L-5546 and L-5547 it will be necessary to have these lines surveyed prior to 2010.

Effects on Distribution Work
As a result of the uncertainty regarding the long term future of the Westhavers Elbow 69kV Sub-transmission System, the replacement transformer for the Bridgewater East Sub-station should be rated for both 69kV and 138kV operation (refer to Section 4.1.1).

5.0 RECOMMENDATIONS

Sub-transmission System

.1 Proceed with the recommendations of **Alternative A-2:** ***Replace 89W-T1 with a New 15/20/25 MVA Transformer*** in 2004. This option involves the following work:

- Install mobile sub-station at 89W prior to station work
- Move 89W-T1 to stores
- Remove the existing concrete pad at 89W
- Install a new pad complete with oil containment
- Install a new 138/69-13.2kV, 15/20/25 MVA Transformer at 89W
- Enlarge Sub-station 89W by 10m x 30m
- Install a new recloser bay complete with overhead sub-station exit
- Build a new 12kV circuit from 89W to Seasons Drive (Eisenhauer Estates) via Highway 325 => Orphans Home Road => Oak Lane => and 200m of new Line.
- Upgrade 600m of Seasons Drive from two phase to three phase 2/0 ACSR.
- Reconductor the 100m section of #2 ACSR on Trunk #10 (by McCullock Road) with 336 ASC in 2006.
- Add a fifth circuit from 89W to the Oakhill Road Sawmill in 2010 to offload circuit 89W-302, which will enable the offloading of the High Street circuit 70W-322.

This alternative had a net present cost $74,701 less than the option to add capacity at the high Street Sub-station, and $139,257 less than the option to utilize the tertiary windings of the Bridgewater EHV Sub-station transformers 99W-T61 & 99W-T62.

.2 Proceed with the recommendations of **Alternative B-2:** ***Convert the remaining 4kV circuits at High Street to 12kV*** in 2009. This option involves the installation of multiple 12-4kV step-down transformers to convert circuits 70W-203 and 70W-204 to 12kV. Alternative B-2 had a net present cost of $165,069, which was $65,340 less than that of the option to replace Transformer 70W-T51.

.3 Install a new fan kit on the Auburndale Sub-station transformer 73W-T1 before 2009 in order to raise its' top rating to 14 MVA.

.4 Rebuild the 2km section of Line L-5545 between the Auburndale Tap and Wileville in 2012 utilizing 336 ACSR (min).

.5 Perform a Line survey of Sub-transmission Lines L-5546 and L-5547 by 2009.

.6 Perform a Sub-transmission Study of the Westhavers Elbow 69kV Sub-transmission System by 2009. This study should compare the option to Upgrade/Rebuild the existing 69kV system with the option of converting it to 138kV and eliminating Sub-station 75W.

Appendices

Appendix A: System Data Summary

Bridgewater - Data Summary Sheet

Station Name	Transformer I.D.	Transformer Rating (MVA)	Feeder kV (L-L)	Feeder #	Load 2002 Peak Amps	Load 2002 Feeder MVA	Calc 2002 Total MVA
High Street 70W	70W-T51 Built 1957	5/6.7	4.16	70W-203	242	1.74	2.80
				70W-204	146	1.05	
	70W-T53 Built 1990	15/20/25	13.2	70W-311	156	3.57	23.43
				70W-312	147	3.36	
				70W-313	187	4.28	
				70W-314	112	2.56	
				70W-321	205	4.69	
				70W-322	218	4.98	
Auburndale 73W	73W-T1 Built 1973	7.5/10//11.2 12.5//14 (prov)	24.94	73W-411	230	9.94	11.84
				73W-412	44	1.90	
Indian Path 80W	80W-T1 Built 1970	5/6.7//7.46	12.47	80W-301	71	1.53	5.25
				80W-302	77	1.66	
				80W-303	95	2.05	
Bridgewater East 89W	89W-T1 Built 1974	7.5/10//11.2	12.47	89W-301	308	6.65	17.08
				89W-302	248	5.36	
				89W-303	235	5.08	
Gold River 103W	103W-T61	7.5/10/12.5	13.2	103W-311	97	2.22	6.47
				103W-312	186	4.25	

Bridgewater - Data Summary Sheet

Year label represents period from listed date to following year (1985 means the 1985 to 1986 period)

Feeder I.D.	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
70W-201	0	0	0	0	0	0	0	0	0	0	0	0
70W-203	290	296	250	210	224	206	206	222	222	214	195	242
70W-204	182	190	176	172	130	128	132	130	142	132	151	146
70W-311	120	117	140	135	132	144	152	137	133	140	177	156
70W-312	119	132	141	136	136	139	132	135	139	137	120	147
70W-313	147	152	131	149	144	149	145	143	137	139	186	187
70W-314	94	88	108	100	103	96	105	92	93	102	121	112
70W-321	205	203	205	208	304	333	345	179	181	184	176	205
70W-322	126	104	114	114	112	114	118	286	310	177	162	218
73W-411	143	150	180	180	182	184	184	218	214	226	263	224
73W-412	46	22	60	52	60	68	68	43	42	36	0	44
89W-301	160	156	166	200	80	90	86	76	92	256	322	308
89W-302	252	274	275	276	274	280	284	297	314	332	236	248
89W-303	112	152	139	131	199	217	201	232	209	215	236	235
103W-311	0	0	0	0	0	0	0	0	0	77	56	97
103W-312	0	0	0	0	0	0	0	0	0	83	95	186

70W-321 & 322 reconfigured at corner of King & Starr St's (160A Transferred to 322)
Load balancing after circuit changes at 70W
120A Transferred from 89W-301 (2.6 MVA)
40A Transferred from 57W (0.86 MVA)

70A Transferred from 84W 302 (1.5 MVA)
135A Transferred from 70W-322 (2.9 MVA)
60A transferred from 89W-302 to 301 (1.3 MVA)
40A transferred from 89-302 to 70W-313

Bridgewater - Data Summary Sheet

Meter Point Data

Feeder	2002 Peak Current			Avg	Voltage	A			B			C			Total	Power
I.D.	A	B	C	I	kV(L-L)	MVA	MW	MVAR	MVA	MW	MVAR	MVA	MW	MVAR	MVA	Factor
70W-203	264	300	162	242	4.16	0.634	0.609	0.178	0.721	0.692	0.202	0.389	0.374	0.109	1.74	0.96
70W-204	180	150	108	146	4.16	0.432	0.415	0.121	0.360	0.346	0.101	0.259	0.249	0.073	1.05	0.96
70W-311	212	128	128	156	12.47	1.526	1.465	0.427	0.922	0.885	0.258	0.922	0.885	0.258	3.37	0.96
70W-312	120	180	140	147	12.47	0.864	0.829	0.242	1.296	1.244	0.363	1.008	0.968	0.282	3.17	0.96
70W-313	192	128	240	187	12.47	1.382	1.327	0.387	0.922	0.885	0.258	1.728	1.659	0.484	4.03	0.96
70W-314	148	124	64	112	12.47	1.066	1.023	0.298	0.893	0.857	0.250	0.461	0.442	0.129	2.42	0.96
70W-321	224	184	208	205	13.2	1.707	1.639	0.478	1.402	1.346	0.393	1.585	1.522	0.444	4.69	0.96
70W-322	222	198	234	218	13.2	1.692	1.624	0.474	1.509	1.449	0.423	1.783	1.712	0.499	4.98	0.96
73W-411	242	211	236	230	24.94	3.485	3.345	0.976	3.038	2.917	0.851	3.398	3.262	0.951	9.92	0.96
73W-412	45	39	49	44	24.94	0.648	0.622	0.181	0.562	0.539	0.157	0.706	0.677	0.198	1.92	0.96
80W-301	72	84	58	71	13.2	0.549	0.527	0.154	0.640	0.615	0.179	0.442	0.424	0.124	1.63	0.96
80W-302	40	120	72	77	13.2	0.305	0.293	0.085	0.915	0.878	0.256	0.549	0.527	0.154	1.77	0.96
80W-303	84	104	96	95	13.2	0.640	0.615	0.179	0.793	0.761	0.222	0.732	0.702	0.205	2.16	0.96
84W-301	276	342	294	304	13.2	2.103	2.019	0.589	2.606	2.502	0.730	2.241	2.151	0.627	6.95	0.96
84W-302	0	0	90	30	13.2	0.000	0.000	0.000	0.000	0.000	0.000	0.686	0.658	0.192	0.69	0.96
89W-301	360	270	294	308	13.2	2.744	2.552	1.008	2.058	1.914	0.756	2.241	2.084	0.824	7.04	0.93
89W-302	276	222	246	248	13.2	2.103	1.956	0.773	1.692	1.573	0.622	1.875	1.744	0.689	5.67	0.93
89W-303	240	240	224	235	13.2	1.829	1.701	0.672	1.829	1.701	0.672	1.707	1.588	0.627	5.37	0.93
103W-311	84	119	87	97	13.2	0.640	0.615	0.179	0.907	0.871	0.254	0.663	0.637	0.186	2.21	0.96
103W-312	198	169	190	186	13.2	1.509	1.449	0.423	1.288	1.236	0.361	1.448	1.390	0.405	4.24	0.96

Appendix B: Economic Analysis Data

Print Summary Sheet

NOVA SCOTIA POWER
An Emera Company

Bridgewater Study
Summary of Alternatives

Budget Year :	2004	Date :	30-Nov-06
Division :		CI Number:	
Department :		Project No. :	
Originator :			

	Alternative	After Tax WACC	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Add Capacity to 70W and Offload 89W	7.01%	-1,164,671	3	#DIV/0!	0.0 years
B	Replace Transformer 89W-T1	7.01%	-1,089,970	2	#DIV/0!	0.0 years
C	Use 99W-T62 Tertiary to Offload 89W	7.01%	-1,229,227	4	#NUM!	0.0 years
D	Test 4	7.01%	0	1	#NUM!	0.0 years

Recommendation :

Replace 89W-T1 with a New 15/20/25 MVA Transformer in 2004. This has a NPC $74,701 less than Alt A and $139,257 less than Alt C. Alt B is the 'least effort' and 'least cost' solution to the capacity problems within Bridgewater. Although 89W is further from the load centre than 70W, it is located on the same side of the LaHave river that is experiencing the majority of load growth.

Notes/Comments :

Add Capacity to 70W and Offload 89W

This option requires a second transformer at 70W to offload 89W circuits. This location has a HV bus, switch, transformer pad, and low voltage bus already in place, although two of the bays in the LV bus are occupied by the 4kV circuits 70W-203 & 204. Work required in 2004 includes installing a new 69-13.2kV, 15/20/25 MVA transformer at 70W; Converting 70W-204 to 12kV; creating a new 12kV circuit from 70W to King Street; Upgrading various sections of distribution lines; double circuiting the river crossing at Starr Street; replacing the failed submarine cable across the LaHave River; Reconfiguring circuits 70W-321 & 322. 70W-321 would then supply the new mall complex and hotel; 70W-322 would offload 89W-301; 70W-312 & 314 would offload 70W-313; and 70W-313 would offload 89W-301 & 302.

Replace Transformer 89W-T1

This option requires that the existing 8.4/11.2 MVA transformer at Bridgewater East be replaced by a new 15/20/25 MVA unit.
In 2004, it involves installing a mobile at 89W; Moving 89W-T1 to stores; Replacing the concrete transformer pad; Installing a new 138/69-13.2kV, 15/20/25 MVA transformer; Enlarging 89W by 10m x 30m; Installing a new recloser bay c/w overhead exit; and building a new 12kV circuit from 89W into Bridgewater. A fifth circuit from 89W to the Oakhill Road Sawmill will be required in 2010 to offload 89W-302.

Use 99W-T62 Tertiary to Offload 89W

This alternative makes use of the fact that there is 12.5kV (delta) available from the tertiary windings of the power transformers within the Bridgewater EHV Sub-station 99W. In 2004, it involves installing a 12kV bus assembly within 99W c/w 2 recloser bays, U/G exits, switch bay, and zigzag transformer; Upgrading the line from King Street to 99W; Double circuiting the line from 99W to the N. King St Bridge; Upgrading line on Trunk #10; Reconfiguring various circuits; Replacing U/G cable; Reconductoring 70W-322; Double circuiting the o/h river crossing; Replacing the failed Submarine cable; and Reconductoring sections of 70W-312. The new circuits in 99W would offload 70W-322 & 321, which would then be used to completely offload circuit 89W-301, which would lower load on 89W-T51 to 11MVA.

Test 4

Not Applicable

Reprinted in Nov. 2006

Bridgewater Study
Add Capacity to 70W and Offload 89W

Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	Discount Factor	PV of CF	CNPV
2004	-	(6,000.0)	##########	25,075.0	1,228,675.0	(1,259,750.0)	7,105.2	(1,252,644.8)	1.000	(1,252,644.8)	(1,252,644.8)
2005	-	(6,126.0)	-	49,147.0	1,179,528.0	(6,126.0)	16,529.1	10,403.1	0.934	9,721.6	(1,242,923.2)
2006	-	(6,254.6)	-	47,181.1	1,132,346.9	(6,254.6)	16,572.4	10,317.7	0.873	9,010.2	(1,233,913.0)
2007	-	(6,386.0)	-	45,293.9	1,087,053.0	(6,386.0)	16,724.6	10,338.6	0.816	8,437.0	(1,225,476.0)
2008	-	(6,520.1)	-	43,482.1	1,043,570.9	(6,520.1)	17,446.4	10,926.3	0.763	8,332.5	(1,217,143.4)
2009	-	(6,657.0)	-	41,742.8	1,001,828.0	(6,657.0)	16,900.2	10,243.2	0.713	7,299.8	(1,209,843.6)
2010	-	(6,796.8)	-	40,073.1	961,754.9	(6,796.8)	16,379.0	9,582.2	0.666	6,381.4	(1,203,462.2)
2011	-	(6,939.6)	-	38,470.2	923,284.7	(6,939.6)	15,881.9	8,942.3	0.622	5,565.2	(1,197,897.0)
2012	-	(7,085.3)	-	36,931.4	886,353.3	(7,085.3)	15,408.0	8,322.7	0.582	4,840.3	(1,193,056.7)
2013	-	(7,234.1)	-	35,454.1	850,899.2	(7,234.1)	14,956.4	7,722.3	0.543	4,196.9	(1,188,859.8)
2014	-	(7,386.0)	-	34,036.0	816,863.2	(7,386.0)	14,526.4	7,140.4	0.508	3,626.4	(1,185,233.4)
2015	-	(7,541.1)	-	32,674.5	784,188.7	(7,541.1)	14,117.1	6,576.0	0.475	3,121.0	(1,182,112.4)
2016	-	(7,699.5)	-	31,367.5	752,821.2	(7,699.5)	13,727.7	6,028.3	0.444	2,673.6	(1,179,438.8)
2017	-	(7,861.1)	-	30,112.8	722,708.3	(7,861.1)	13,357.7	5,496.5	0.414	2,278.1	(1,177,160.7)
2018	-	(8,026.2)	-	28,908.3	693,800.0	(8,026.2)	13,006.1	4,979.9	0.387	1,928.8	(1,175,231.9)
2019	-	-	-	27,752.0	666,048.0	-	9,548.7	9,548.7	0.362	3,456.0	(1,171,775.9)
2020	-	-	-	26,641.9	639,406.1	-	9,166.7	9,166.7	0.338	3,100.5	(1,168,675.4)
2021	-	-	-	25,576.2	613,829.8	-	8,800.1	8,800.1	0.316	2,781.5	(1,165,894.0)
2022	-	-	-	24,553.2	589,276.6	-	8,448.1	8,448.1	0.295	2,495.3	(1,163,398.7)
2023	-	-	-	23,571.1	565,705.6	-	8,110.1	8,110.1	0.276	2,238.5	(1,161,160.2)
2024	-	-	-	22,628.2	543,077.3	-	7,785.7	7,785.7	0.258	2,008.2	(1,159,151.9)
2025	-	-	-	21,723.1	521,354.2	-	7,474.3	7,474.3	0.241	1,801.6	(1,157,350.3)
2026	-	-	-	20,854.2	500,500.1	-	7,175.3	7,175.3	0.225	1,616.2	(1,155,734.1)
2027	-	-	-	20,020.0	480,480.1	-	6,888.3	6,888.3	0.210	1,450.0	(1,154,284.1)
2028	-	-	-	19,219.2	461,260.9	-	6,612.8	6,612.8	0.197	1,300.8	(1,152,983.4)
2029	-	-	-	18,450.4	442,810.4	-	6,348.3	6,348.3	0.184	1,166.9	(1,151,816.4)
2030	-	-	-	17,712.4	425,098.0	-	6,094.3	6,094.3	0.172	1,046.9	(1,150,769.6)
2031	-	-	-	17,003.9	408,094.1	-	5,850.6	5,850.6	0.161	939.2	(1,149,830.4)
2032	-	-	-	16,323.8	391,770.3	-	5,616.6	5,616.6	0.150	842.5	(1,148,987.9)
2033	-	-	-	15,670.8	376,099.5	-	5,391.9	5,391.9	0.140	755.8	(1,148,232.0)
2034	-	-	-	15,044.0	361,055.5	-	5,176.2	5,176.2	0.131	678.1	(1,147,553.9)
2035	-	-	-	14,442.2	346,613.3	-	4,969.2	4,969.2	0.122	608.3	(1,146,945.6)
2036	-	-	-	13,864.5	332,748.8	-	4,770.4	4,770.4	0.114	545.7	(1,146,399.9)
2037	-	-	-	13,310.0	319,438.8	-	4,579.6	4,579.6	0.107	489.6	(1,145,910.3)
2038	-	-	-	12,777.6	306,661.3	-	4,396.4	4,396.4	0.100	439.2	(1,145,471.1)
2039	-	-	-	12,266.5	294,394.8	-	4,220.5	4,220.5	0.093	394.0	(1,145,077.1)
2040	-	-	-	11,775.8	282,619.0	-	4,051.7	4,051.7	0.087	353.5	(1,144,723.6)
2041	-	-	-	11,304.8	271,314.3	-	3,889.7	3,889.7	0.082	317.1	(1,144,406.5)
2042	-	-	-	10,852.6	260,461.7	-	3,734.1	3,734.1	0.076	284.5	(1,144,122.0)
2043	-	-	-	10,418.5	250,043.2	-	3,584.7	3,584.7	0.071	255.2	(1,143,866.8)
2044	-	-	-	16,373.2	233,670.0	(318,576.0)	5,880.0	(312,696.0)	0.067	(20,804.0)	(1,164,670.9)
Total	-	(104,513.4)	##########	##########	24,949,507.3	(1,676,839.4)	381,202.4	(1,295,637.0)	14.3	(1,164,670.9)	(48,043,589.0)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)
REDACTED 2026 ACE Plan NSEB IR-116 Attachment 1 Page 42 of 52

Bridgewater Study
Replace Transformer 89W-T1

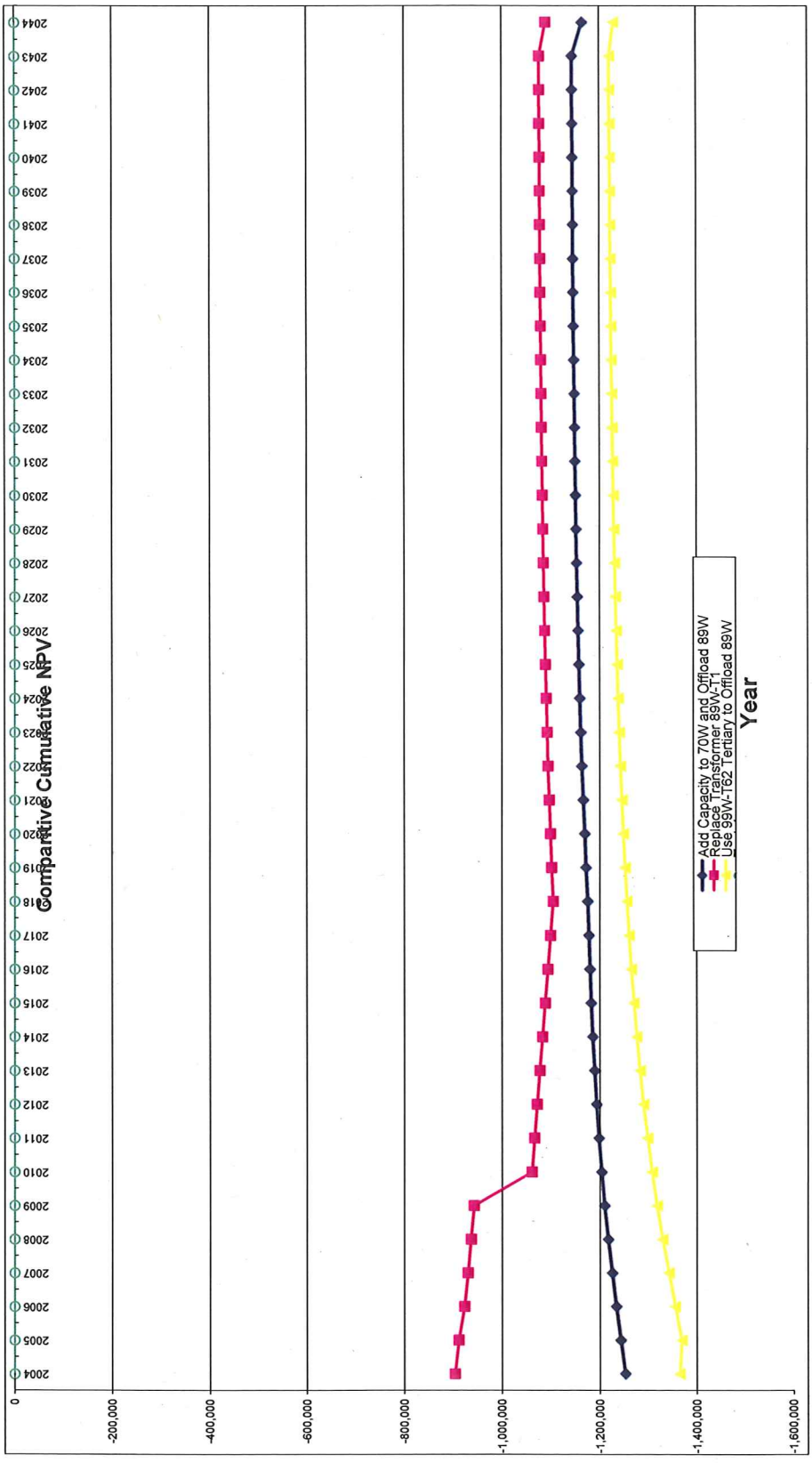
Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	Discount Factor	PV of CF	CNPV
2004	-	(43,000.0)	(880,000.0)	17,600.0	862,400.0	(923,000.0)	19,338.9	(903,661.1)	1.000	(903,661.1)	(903,661.1)
2005	-	(28,560.0)	-	34,496.0	827,904.0	(28,560.0)	20,577.9	(7,982.1)	0.934	(7,459.2)	(911,120.3)
2006	-	(29,131.2)	(5,202.0)	33,220.2	799,885.8	(34,333.2)	20,810.3	(13,522.9)	0.873	(11,809.2)	(922,929.4)
2007	-	(29,713.8)	-	31,995.4	767,890.4	(29,713.8)	21,139.2	(8,574.6)	0.816	(6,997.5)	(929,926.9)
2008	-	(30,308.1)	-	30,715.6	737,174.8	(30,308.1)	22,121.8	(8,186.3)	0.763	(6,242.9)	(936,169.8)
2009	-	(30,914.3)	-	29,487.0	707,687.8	(30,914.3)	21,930.2	(8,984.1)	0.713	(6,402.5)	(942,572.4)
2010	-	(31,532.5)	(168,924.4)	31,686.0	844,926.1	(200,456.9)	22,791.8	(177,665.1)	0.666	(118,319.4)	(1,060,891.8)
2011	-	(32,163.2)	-	33,797.0	811,129.1	(32,163.2)	23,889.2	(8,274.0)	0.622	(5,149.2)	(1,066,041.0)
2012	-	(32,806.5)	-	32,445.2	778,683.9	(32,806.5)	23,669.3	(9,137.2)	0.582	(5,313.9)	(1,071,355.0)
2013	-	(33,462.6)	-	31,147.4	747,536.6	(33,462.6)	23,472.9	(9,989.7)	0.543	(5,429.2)	(1,076,784.1)
2014	-	(34,131.8)	-	29,901.5	717,635.1	(34,131.8)	23,299.3	(10,832.5)	0.508	(5,501.6)	(1,082,285.7)
2015	-	(34,814.5)	-	28,705.4	688,929.7	(34,814.5)	23,148.0	(11,666.5)	0.475	(5,537.0)	(1,087,822.7)
2016	-	(35,510.8)	-	27,557.2	661,372.5	(35,510.8)	23,018.4	(12,492.4)	0.444	(5,540.6)	(1,093,363.2)
2017	-	(36,221.0)	-	26,454.9	634,917.6	(36,221.0)	22,909.8	(13,311.2)	0.414	(5,516.9)	(1,098,880.2)
2018	-	(36,945.4)	-	25,396.7	609,520.9	(36,945.4)	22,821.9	(14,123.5)	0.387	(5,470.2)	(1,104,350.4)
2019	-	-	-	24,380.8	585,140.1	-	8,388.8	8,388.8	0.362	3,036.2	(1,101,314.1)
2020	-	-	-	23,405.6	561,734.5	-	8,053.2	8,053.2	0.338	2,723.8	(1,098,590.3)
2021	-	-	-	22,469.4	539,265.1	-	7,731.1	7,731.1	0.316	2,443.6	(1,096,146.7)
2022	-	-	-	21,570.6	517,694.5	-	7,421.8	7,421.8	0.295	2,192.2	(1,093,954.6)
2023	-	-	-	20,707.8	496,986.7	-	7,125.0	7,125.0	0.276	1,966.6	(1,091,988.0)
2024	-	-	-	19,879.5	477,107.2	-	6,840.0	6,840.0	0.258	1,764.3	(1,090,223.7)
2025	-	-	-	19,084.3	458,022.9	-	6,566.4	6,566.4	0.241	1,582.8	(1,088,640.9)
2026	-	-	-	18,320.9	439,702.0	-	6,303.7	6,303.7	0.225	1,419.9	(1,087,221.0)
2027	-	-	-	17,588.1	422,113.9	-	6,051.6	6,051.6	0.210	1,273.8	(1,085,947.2)
2028	-	-	-	16,884.6	405,229.4	-	5,809.5	5,809.5	0.197	1,142.8	(1,084,804.4)
2029	-	-	-	16,209.2	389,020.2	-	5,577.1	5,577.1	0.184	1,025.2	(1,083,779.3)
2030	-	-	-	15,560.8	373,459.4	-	5,354.0	5,354.0	0.172	919.7	(1,082,859.6)
2031	-	-	-	14,938.4	358,521.0	-	5,139.9	5,139.9	0.161	825.1	(1,082,034.5)
2032	-	-	-	14,340.8	344,180.2	-	4,934.3	4,934.3	0.150	740.2	(1,081,294.3)
2033	-	-	-	13,767.2	330,413.0	-	4,736.9	4,736.9	0.140	664.0	(1,080,630.3)
2034	-	-	-	13,216.5	317,196.5	-	4,547.4	4,547.4	0.131	595.7	(1,080,034.5)
2035	-	-	-	12,687.9	304,508.6	-	4,365.5	4,365.5	0.122	534.4	(1,079,500.1)
2036	-	-	-	12,180.3	292,328.3	-	4,190.9	4,190.9	0.114	479.4	(1,079,020.7)
2037	-	-	-	11,693.1	280,635.1	-	4,023.3	4,023.3	0.107	430.1	(1,078,590.6)
2038	-	-	-	11,225.4	269,409.7	-	3,862.3	3,862.3	0.100	385.9	(1,078,204.7)
2039	-	-	-	10,776.4	258,633.3	-	3,707.9	3,707.9	0.093	346.2	(1,077,858.6)
2040	-	-	-	10,345.3	248,288.0	-	3,559.5	3,559.5	0.087	310.5	(1,077,548.0)
2041	-	-	-	9,931.5	238,356.5	-	3,417.2	3,417.2	0.082	278.6	(1,077,269.4)
2042	-	-	-	9,534.3	228,822.2	-	3,280.5	3,280.5	0.076	249.9	(1,077,019.5)
2043	-	-	-	9,152.9	219,669.3	-	3,149.3	3,149.3	0.071	224.2	(1,076,795.3)
2044	-	-	-	12,838.7	206,830.6	(202,598.7)	4,574.2	(198,024.5)	0.067	(13,174.8)	(1,089,970.1)
Total	-	(499,215.7)	##########	847,295.8	20,760,862.5	(1,755,940.7)	473,650.2	(1,282,290.5)	14.3	(1,089,970.1)	(43,489,394.3)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)
REDACTED 2026 ACE Plan NSEB IR-116 Attachment 1 Page 43 of 52

Bridgewater Study
Use 99W-T62 Tertiary to Offload 89W

Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	Discount Factor	PV of CF	CNPV
2004	-	-	##########	27,400.0	1,342,600.0	(1,370,000.0)	5,338.2	(1,364,661.8)	1.000	(1,364,661.8)	(1,364,661.8)
2005	-	-	-	54,101.8	1,288,498.2	(19,890.0)	15,733.4	(4,156.6)	0.934	(3,884.3)	(1,368,546.1)
2006	-	-	-	52,335.5	1,236,162.7	-	15,872.0	15,872.0	0.873	13,860.6	(1,354,685.5)
2007	-	-	-	50,242.1	1,185,920.6	-	15,974.6	15,974.6	0.816	13,036.4	(1,341,649.1)
2008	-	-	-	48,232.4	1,137,688.1	-	16,626.2	16,626.2	0.763	12,679.3	(1,328,969.8)
2009	-	-	-	46,303.1	1,091,385.0	-	15,962.4	15,962.4	0.713	11,375.6	(1,317,594.1)
2010	-	-	-	44,451.0	1,046,934.0	-	15,325.1	15,325.1	0.666	10,206.0	(1,307,388.1)
2011	-	-	-	42,673.0	1,004,261.1	-	14,713.3	14,713.3	0.622	9,156.7	(1,298,231.4)
2012	-	-	-	40,966.0	963,295.0	-	14,126.0	14,126.0	0.582	8,215.3	(1,290,016.0)
2013	-	-	-	39,327.4	923,967.6	-	13,562.2	13,562.2	0.543	7,370.8	(1,282,645.3)
2014	-	-	-	37,754.3	886,213.3	-	13,021.0	13,021.0	0.508	6,613.0	(1,276,032.2)
2015	-	-	-	36,244.1	849,969.2	-	12,501.4	12,501.4	0.475	5,933.2	(1,270,099.0)
2016	-	-	-	34,794.4	815,174.8	-	12,002.5	12,002.5	0.444	5,323.3	(1,264,775.7)
2017	-	-	-	33,402.6	781,772.2	-	11,523.7	11,523.7	0.414	4,776.1	(1,259,999.6)
2018	-	-	-	32,066.5	749,705.7	-	11,064.0	11,064.0	0.387	4,285.2	(1,255,714.5)
2019	-	-	-	30,783.8	718,921.9	-	10,622.6	10,622.6	0.362	3,844.7	(1,251,869.7)
2020	-	-	-	29,552.5	689,369.4	-	10,198.9	10,198.9	0.338	3,449.6	(1,248,420.2)
2021	-	-	-	28,370.4	660,999.0	-	9,792.2	9,792.2	0.316	3,095.0	(1,245,325.1)
2022	-	-	-	27,235.6	633,763.5	-	9,401.8	9,401.8	0.295	2,777.0	(1,242,548.1)
2023	-	-	-	26,146.1	607,617.3	-	9,026.9	9,026.9	0.276	2,491.6	(1,240,056.5)
2024	-	-	-	25,100.3	582,517.1	-	8,667.1	8,667.1	0.258	2,235.6	(1,237,821.0)
2025	-	-	-	24,096.3	558,420.8	-	8,321.6	8,321.6	0.241	2,005.8	(1,235,815.2)
2026	-	-	-	23,132.4	535,288.3	-	7,990.0	7,990.0	0.225	1,799.7	(1,234,015.4)
2027	-	-	-	22,207.1	513,081.2	-	7,671.6	7,671.6	0.210	1,614.8	(1,232,400.6)
2028	-	-	-	21,318.8	491,762.4	-	7,366.0	7,366.0	0.197	1,448.9	(1,230,951.7)
2029	-	-	-	20,466.1	471,296.3	-	7,072.6	7,072.6	0.184	1,300.1	(1,229,651.6)
2030	-	-	-	19,647.5	451,648.8	-	6,790.9	6,790.9	0.172	1,166.5	(1,228,485.1)
2031	-	-	-	18,861.6	432,787.3	-	6,520.5	6,520.5	0.161	1,046.7	(1,227,438.3)
2032	-	-	-	18,107.1	414,680.2	-	6,260.9	6,260.9	0.150	939.2	(1,226,499.2)
2033	-	-	-	17,382.8	397,297.4	-	6,011.7	6,011.7	0.140	842.7	(1,225,656.4)
2034	-	-	-	16,687.5	380,609.9	-	5,772.5	5,772.5	0.131	756.2	(1,224,900.2)
2035	-	-	-	16,020.0	364,589.9	-	5,542.8	5,542.8	0.122	678.5	(1,224,221.7)
2036	-	-	-	15,379.2	349,210.7	-	5,322.3	5,322.3	0.114	608.9	(1,223,612.8)
2037	-	-	-	14,764.0	334,446.7	-	5,110.7	5,110.7	0.107	546.4	(1,223,066.5)
2038	-	-	-	14,173.5	320,273.2	-	4,907.5	4,907.5	0.100	490.3	(1,222,576.2)
2039	-	-	-	13,606.5	306,666.7	-	4,712.4	4,712.4	0.093	439.9	(1,222,136.3)
2040	-	-	-	13,062.3	293,604.4	-	4,525.1	4,525.1	0.087	394.8	(1,221,741.5)
2041	-	-	-	12,539.8	281,064.6	-	4,345.4	4,345.4	0.082	354.3	(1,221,387.2)
2042	-	-	-	12,038.2	269,026.4	-	4,172.8	4,172.8	0.076	317.9	(1,221,069.3)
2043	-	-	-	11,556.7	257,469.8	-	4,007.1	4,007.1	0.071	285.3	(1,220,784.0)
2044	-	-	-	13,729.7	243,740.1	(131,764.8)	4,856.7	(126,908.1)	0.067	(8,443.3)	(1,229,227.4)
Total	-	-	##########	##########	26,863,700.5	(1,521,654.8)	378,336.6	(1,143,318.2)	14.3	(1,229,227.4)	(51,572,685.4)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)
REDACTED 2026 ACE Plan NSEB IR-116 Attachment 1 Page 44 of 52


Comparative Cumulative NPV
0
-200,000
-400,000
-600,000
-800,000
-1,000,000
-1,200,000
-1,400,000
-1,600,000
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
Year
Add Capacity to 70W and Offload 89W
Replace Transformer 89W-T1
Use 99W-T62 Tertiary to Offload 89W

Print Summary Sheet

NOVA SCOTIA POWER
An Emera Company

High Street 4kV
Summary of Alternatives

Budget Year :	2004	Date :	30-Nov-06
Division :		CI Number:	
Department :		Project No. :	
Originator :			

	Alternative	After Tax WACC	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Replace Transformer 70W-T51 in 2009	7.01%	-230,409	2	#DIV/0!	0.0 years
B	Convert 4kV at High Street in 2009	7.01%	-165,069	1	#DIV/0!	0.0 years
	0	NA	NA	NA	#NUM!	0.0 years
	0	NA	NA	NA	#NUM!	0.0 years

Recommendation :

Notes/Comments :

Replace Transformer 70W-T51 in 2009

Convert 4kV at High Street in 2009

0

0

Reprinted in Nov. 2006

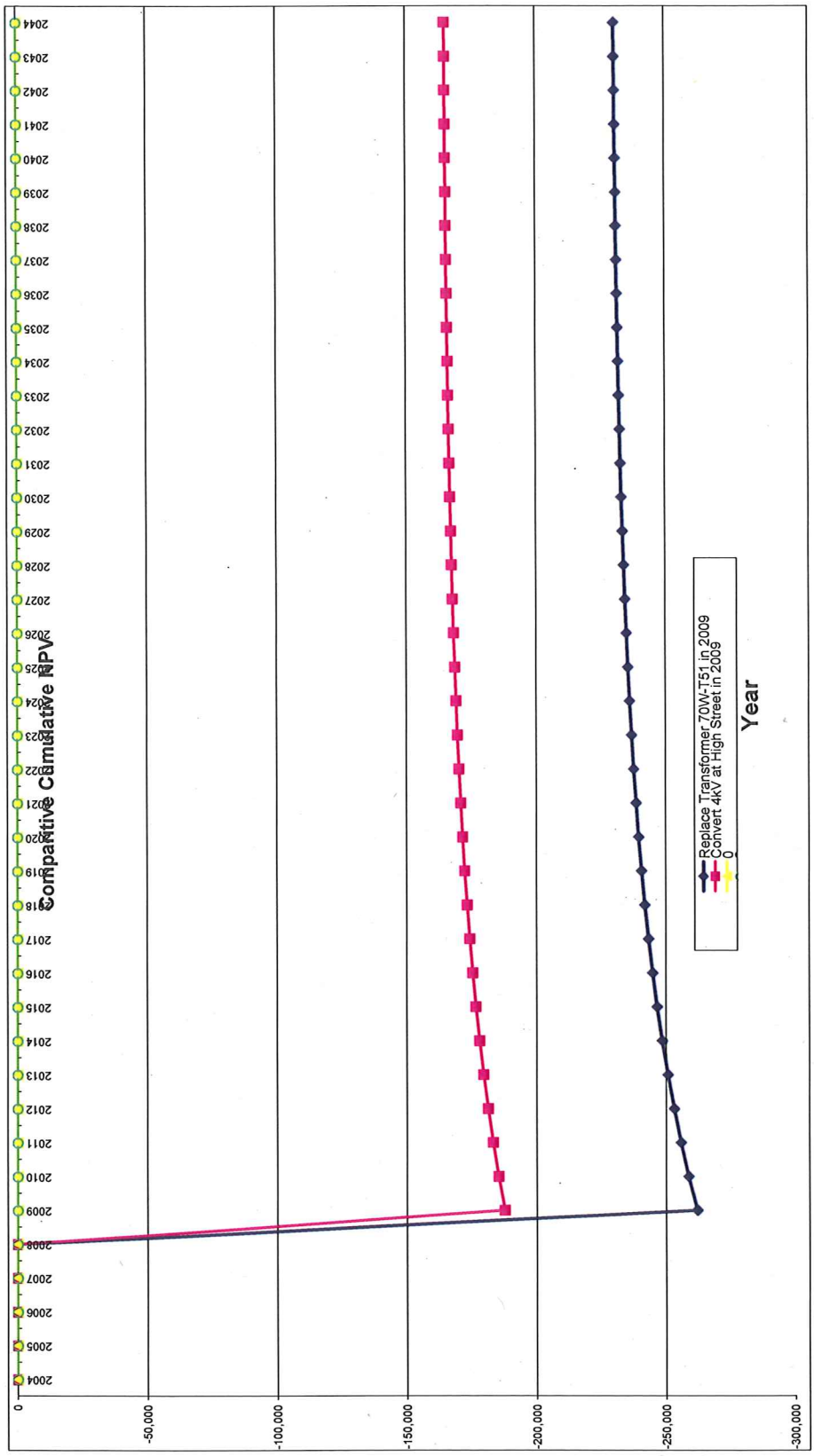
High Street 4kV
Replace Transformer 70W-T51 in 2009

Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	Discount Factor	PV of CF	CNPV
2004	-	-	-	-	-	-	-	-	1.000	-	-
2005	-	-	-	-	-	-	-	-	0.934	-	-
2006	-	-	-	-	-	-	-	-	0.873	-	-
2007	-	-	-	-	-	-	-	-	0.816	-	-
2008	-	-	-	-	-	-	-	-	0.763	-	-
2009	-	-	(369,867.1)	7,397.3	362,469.7	(369,867.1)	2,259.1	(367,607.9)	0.713	(261,976.9)	(261,976.9)
2010	-	-	-	14,498.8	347,970.9	-	4,988.6	4,988.6	0.666	3,322.3	(258,654.7)
2011	-	-	-	13,918.8	334,052.1	-	4,789.1	4,789.1	0.622	2,980.4	(255,674.2)
2012	-	-	-	13,362.1	320,690.0	-	4,597.5	4,597.5	0.582	2,673.8	(253,000.4)
2013	-	-	-	12,827.6	307,862.4	-	4,413.6	4,413.6	0.543	2,398.7	(250,601.7)
2014	-	-	-	12,314.5	295,547.9	-	4,237.1	4,237.1	0.508	2,151.9	(248,449.8)
2015	-	-	-	11,821.9	283,726.0	-	4,067.6	4,067.6	0.475	1,930.5	(246,519.3)
2016	-	-	-	11,349.0	272,377.0	-	3,904.9	3,904.9	0.444	1,731.9	(244,787.5)
2017	-	-	-	10,895.1	261,481.9	-	3,748.7	3,748.7	0.414	1,553.7	(243,233.8)
2018	-	-	-	10,459.3	251,022.6	-	3,598.7	3,598.7	0.387	1,393.8	(241,839.9)
2019	-	-	-	10,040.9	240,981.7	-	3,454.8	3,454.8	0.362	1,250.4	(240,589.5)
2020	-	-	-	9,639.3	231,342.4	-	3,316.6	3,316.6	0.338	1,121.8	(239,467.7)
2021	-	-	-	9,253.7	222,088.7	-	3,183.9	3,183.9	0.316	1,006.4	(238,461.4)
2022	-	-	-	8,883.5	213,205.2	-	3,056.6	3,056.6	0.295	902.8	(237,558.6)
2023	-	-	-	8,528.2	204,677.0	-	2,934.3	2,934.3	0.276	809.9	(236,748.7)
2024	-	-	-	8,187.1	196,489.9	-	2,816.9	2,816.9	0.258	726.6	(236,022.1)
2025	-	-	-	7,859.6	188,630.3	-	2,704.3	2,704.3	0.241	651.8	(235,370.2)
2026	-	-	-	7,545.2	181,085.1	-	2,596.1	2,596.1	0.225	584.8	(234,785.5)
2027	-	-	-	7,243.4	173,841.7	-	2,492.3	2,492.3	0.210	524.6	(234,260.9)
2028	-	-	-	6,953.7	166,888.0	-	2,392.6	2,392.6	0.197	470.6	(233,790.2)
2029	-	-	-	6,675.5	160,212.5	-	2,296.9	2,296.9	0.184	422.2	(233,368.0)
2030	-	-	-	6,408.5	153,804.0	-	2,205.0	2,205.0	0.172	378.8	(232,989.3)
2031	-	-	-	6,152.2	147,651.8	-	2,116.8	2,116.8	0.161	339.8	(232,649.5)
2032	-	-	-	5,906.1	141,745.8	-	2,032.1	2,032.1	0.150	304.8	(232,344.6)
2033	-	-	-	5,669.8	136,075.9	-	1,950.8	1,950.8	0.140	273.5	(232,071.1)
2034	-	-	-	5,443.0	130,632.9	-	1,872.8	1,872.8	0.131	245.3	(231,825.8)
2035	-	-	-	5,225.3	125,407.6	-	1,797.9	1,797.9	0.122	220.1	(231,605.7)
2036	-	-	-	5,016.3	120,391.3	-	1,726.0	1,726.0	0.114	197.4	(231,408.3)
2037	-	-	-	4,815.7	115,575.6	-	1,656.9	1,656.9	0.107	177.1	(231,231.1)
2038	-	-	-	4,623.0	110,952.6	-	1,590.7	1,590.7	0.100	158.9	(231,072.2)
2039	-	-	-	4,438.1	106,514.5	-	1,527.0	1,527.0	0.093	142.6	(230,929.7)
2040	-	-	-	4,260.6	102,253.9	-	1,465.9	1,465.9	0.087	127.9	(230,801.8)
2041	-	-	-	4,090.2	98,163.8	-	1,407.3	1,407.3	0.082	114.7	(230,687.0)
2042	-	-	-	3,926.6	94,237.2	-	1,351.0	1,351.0	0.076	102.9	(230,584.1)
2043	-	-	-	3,769.5	90,467.7	-	1,297.0	1,297.0	0.071	92.3	(230,491.8)
2044	-	-	-	3,618.7	86,849.0	-	1,245.1	1,245.1	0.067	82.8	(230,408.9)
Total	-	-	(369,867.1)	283,018.1	6,977,366.8	(369,867.1)	97,092.5	(272,774.6)	14.3	(230,408.9)	(8,576,262.1)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)
REDACTED 2026 ACE Plan NSEB IR-116 Attachment 1 Page 47 of 52

High Street 4kV
Convert 4kV at High Street in 2009

Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	Discount Factor	PV of CF	CNPV
2004	-	-	-	-	-	-	-	-	1.000	-	-
2005	-	-	-	-	-	-	-	-	0.934	-	-
2006	-	-	-	-	-	-	-	-	0.873	-	-
2007	-	-	-	-	-	-	-	-	0.816	-	-
2008	-	-	-	-	-	-	-	-	0.763	-	-
2009	-	-	(264,979.4)	5,299.6	259,679.8	(264,979.4)	1,618.5	(263,360.9)	0.713	(187,685.0)	(187,685.0)
2010	-	-	-	10,387.2	249,292.6	-	3,573.9	3,573.9	0.666	2,380.1	(185,304.8)
2011	-	-	-	9,971.7	239,320.9	-	3,431.0	3,431.0	0.622	2,135.2	(183,169.6)
2012	-	-	-	9,572.8	229,748.1	-	3,293.7	3,293.7	0.582	1,915.6	(181,254.0)
2013	-	-	-	9,189.9	220,558.1	-	3,162.0	3,162.0	0.543	1,718.5	(179,535.6)
2014	-	-	-	8,822.3	211,735.8	-	3,035.5	3,035.5	0.508	1,541.7	(177,993.9)
2015	-	-	-	8,469.4	203,266.4	-	2,914.1	2,914.1	0.475	1,383.0	(176,610.9)
2016	-	-	-	8,130.7	195,135.7	-	2,797.5	2,797.5	0.444	1,240.7	(175,370.1)
2017	-	-	-	7,805.4	187,330.3	-	2,685.6	2,685.6	0.414	1,113.1	(174,257.0)
2018	-	-	-	7,493.2	179,837.1	-	2,578.2	2,578.2	0.387	998.6	(173,258.5)
2019	-	-	-	7,193.5	172,643.6	-	2,475.1	2,475.1	0.362	895.8	(172,362.6)
2020	-	-	-	6,905.7	165,737.9	-	2,376.1	2,376.1	0.338	803.7	(171,559.0)
2021	-	-	-	6,629.5	159,108.4	-	2,281.0	2,281.0	0.316	721.0	(170,838.0)
2022	-	-	-	6,364.3	152,744.0	-	2,189.8	2,189.8	0.295	646.8	(170,191.2)
2023	-	-	-	6,109.8	146,634.3	-	2,102.2	2,102.2	0.276	580.2	(169,611.0)
2024	-	-	-	5,865.4	140,768.9	-	2,018.1	2,018.1	0.258	520.5	(169,090.4)
2025	-	-	-	5,630.8	135,138.1	-	1,937.4	1,937.4	0.241	467.0	(168,623.4)
2026	-	-	-	5,405.5	129,732.6	-	1,859.9	1,859.9	0.225	418.9	(168,204.5)
2027	-	-	-	5,189.3	124,543.3	-	1,785.5	1,785.5	0.210	375.8	(167,828.7)
2028	-	-	-	4,981.7	119,561.6	-	1,714.1	1,714.1	0.197	337.2	(167,491.5)
2029	-	-	-	4,782.5	114,779.1	-	1,645.5	1,645.5	0.184	302.5	(167,189.0)
2030	-	-	-	4,591.2	110,187.9	-	1,579.7	1,579.7	0.172	271.4	(166,917.7)
2031	-	-	-	4,407.5	105,780.4	-	1,516.5	1,516.5	0.161	243.4	(166,674.2)
2032	-	-	-	4,231.2	101,549.2	-	1,455.8	1,455.8	0.150	218.4	(166,455.8)
2033	-	-	-	4,062.0	97,487.2	-	1,397.6	1,397.6	0.140	195.9	(166,259.9)
2034	-	-	-	3,899.5	93,587.7	-	1,341.7	1,341.7	0.131	175.8	(166,084.2)
2035	-	-	-	3,743.5	89,844.2	-	1,288.0	1,288.0	0.122	157.7	(165,926.5)
2036	-	-	-	3,593.8	86,250.5	-	1,236.5	1,236.5	0.114	141.5	(165,785.0)
2037	-	-	-	3,450.0	82,800.5	-	1,187.1	1,187.1	0.107	126.9	(165,658.1)
2038	-	-	-	3,312.0	79,488.4	-	1,139.6	1,139.6	0.100	113.8	(165,544.3)
2039	-	-	-	3,179.5	76,308.9	-	1,094.0	1,094.0	0.093	102.1	(165,442.2)
2040	-	-	-	3,052.4	73,256.5	-	1,050.2	1,050.2	0.087	91.6	(165,350.5)
2041	-	-	-	2,930.3	70,326.3	-	1,008.2	1,008.2	0.082	82.2	(165,268.3)
2042	-	-	-	2,813.1	67,513.2	-	967.9	967.9	0.076	73.7	(165,194.6)
2043	-	-	-	2,700.5	64,812.7	-	929.2	929.2	0.071	66.2	(165,128.4)
2044	-	-	-	2,592.5	62,220.2	-	892.0	892.0	0.067	59.3	(165,069.1)
Total	-	-	(264,979.4)	202,759.2	4,998,710.6	(264,979.4)	69,558.8	(195,420.6)	14.3	(165,069.1)	(6,144,187.8)


Comparitive Cumulative NPV
0
-50,000
-100,000
-150,000
-200,000
-250,000
-300,000
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
Year
Replace Transformer 70W-T51 in 2009
Convert 4kV at High Street in 2009
0

Appendix C: Capital Expenditure Justification Criteria

Relevant Sections

N.S.P.I Capital Expenditure Justification Criteria - System Design

The NSPI capital expenditure justification criteria that are applicable to this study are:

4. SUBTRANSMISSION SYSTEM

The Design Criteria are:

1. Sub-transmission system loading shall be within the thermally limited ratings.

2. The sub-transmission system voltages shall not be less than 97.5% or greater than 105% of nominal.

3. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

4. From normal system conditions, following the loss of any one sub-transmission system element with or without a fault, any sub-transmission system bus which remains connected to the system, shall maintain sufficient voltage following automatic tap-changer correction to permit operation of any affected distribution bulk supply bus at 105% of nominal following a steady state settling out of the system. In no case shall any bus experience a voltage change from pre-fault to post-fault condition greater than 10% before tap-changer correction.

   (The application of the above criteria does not guarantee a continuity of supply for any single contingency. In the case of a line, since a lengthy outage is considered to have a low probability time to repair is considered adequate for restoration of service; however, in the case of transformation, since an outage is generally a prolonged one, either the use of a mobile transformer for a short-term replacement or the installation of a spare transformer and interconnections with adjacent substations at the distribution level, are considered in decisions concerning the guaranteeing, after outage, of an alternative supply.)

5. TRANSFORMATION

Capacity for any individual transformation point shall, under nominal system conditions, be sufficient to meet the daily load requirements after due consideration is given to the following:

a) Economic dispatch or outage of generation.
b) Loading of transformer(s) to their (or their associated equipment) thermally limited ratings as per Note 4.

Reinforcement is required in all cases when, for a single contingency, there will result either, thermal damage to equipment in attempting to continue to supply the load, or, consideration is given to the following:

a) The capacity of the underlying interconnection(s) with another supply point(s) when applicable
b) Out-of-merit running of generation when applicable
c) Loading of remaining sub-station(s) transformer(s) to their (or their associated equipment) thermally-limited ratings as per Note 4. (This in conjunction with (a) and (b) above as applicable.)
d) Largest available suitable mobile transformer loaded to its nameplate rating. (This in conjunction with (a) and (b) above as applicable).

Note:4. *Generally in accordance with methods accepted within North America, and particularly with reference to ANSI/IEEE Std. C57.115-1991 "IEEE Guide for Loading Mineral-Oil Immersed Power Transformers rated in Excess of 100 MV.A (65 deg. C Winding Rise), it is NSPI practice to permit the loading of transformers exceed the nominal or nameplate value such that thermal limits calculated in accordance with the above references are not regularly exceeded. When calculations are not specifically conducted, overload capability assumptions based on normal cyclic daily loading may be made, but shall not exceed 133% of top nameplate rating*

Request IR-117:

T03: C0080109 L7001 Replacements and Upgrades Phase 1

(a) Please provide the inspection results and condition metrics that support the need for replacement.

(b) Please confirm that LiDAR data/more detailed analysis has been incorporated to minimize additional scope that may arise during the detailed engineering process.

(i) If not confirmed, please explain why.

Response IR-117:

(a) Please refer to NSEB IR-110 (a), and to Attachment 1.

(b) Confirmed.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Line No: L7001 ***Work Order Report***

Str #	Str Type / Frm Type	Pole Lgth L	Pole Lgth C	Pole Lgth R	Access	GPS Lat	GPS Long	Scoping Required	Scheduled	Grd Clr	Min Grd Clr	Work OrderID	Field Priority	Flagged	Comments	Recommendations	Env Notification
L7001-001	230-T-G(O)	80	0	80	Inside pcb storage site at 67N Onslow	45 24' 10.7269"N	-63 18' 31.8711"W	No	2026S	13.5	12.5	7214555	N/A	No	Structure okay	reinsulate 3 x 12/phase, install 7001 on both sides	
L7001-003	230-T-G(O)	70	0	70	Old woods rd beside 67N Onslow.	45 24' 13.5506"N	-63 18' 44.9244"W	No	2026S	12.7	11.665	7214555	2-4 years	No	LARGE WEATHER CRACKS IN BOTH SPAR ARMS, BEGINNING TO GO WAVY. GROUT IN INSULATORS DETERIORATED. WOODPECKER HOLES IN LEFT POLE, SHOULD BE FILLED. ANTS IN LEFT POLE, STILL SOUND SOLID.	replace both 9100mm spar arms and re-insulate 3 x 12/phase, transfer 2 x ohgws	
L7001-004	230-T-G(O)	70	0	70	Old woods rd beside 67N Onslow.	45 24' 15.7874"N	-63 18' 52.4754"W	No	2026S	9.0	8.155	7214555	N/A	No	LARGE WEATHER CRACKS IN SPAR ARMS. GROUT DETERIORATED IN INSULATORS	re-insulate 3 x 12/phase, replace both 9100mm spar arms, transfer 2 x ohgws	
L7001-008	230-Dha-3(60-90 Deg)	65	50	65	Old woods rd beside 67N Onslow.	45 24' 26.1409"N	-63 19' 27.3027"W	No	2026S	9.8	8.84	7214555	N/A	No	Ants in right pole, still sounds ok. 30 guys no guards.	install 30 guy guards	
L7001-011	230-T-G(O)	75	0	75	telephone lines, RR tracks N45-24-12.10 W63-19-38.60, swamp	45 24' 7.9930"N	-63 19' 42.0843"W	No	2026S	11.9	10.940000000000001	7214555	N/A	No	GROUT BEGINNING TO DETERIORATE IN INSULATORS. 2 HOOKED GUYS, SLACK. CROSSES RR.	tighten 2 guys, install 2 guy guards, re-insulate 3 x 12/phase	
L7001-012	230-T-G(O)	60	0	60	Woods Rd off end of Back Road follow 138kv ROW.	45 24' 4.0835"N	-63 19' 45.3285"W	No	2026S	10.7	9.8549999999999999	7214555	1-2 years	No	Grout deteriorated in insulators, cracked and discoloured.	reinsulate 3 x 12/phase	
L7001-013	230-T-G(O)	70	0	70	Woods Rd off end of Back Road follow 138kv ROW.	45 23' 58.1094"N	-63 19' 50.2283"W	No	2026S	9.6	8.64	7214555	2-4 years	No	RIGHT SPAR ARM BIGINNING TO SAG ABOVE RIGHT PHASE, LARGE WEATHER CRACKS ON RIGHT END. SHOULD BE REPLACED.	replace both 9100mm spar arms and re-insulate 3 x 12/phase, transfer 2 ohgw's	
L7001-014	230-T-G(O)	70	0	70	Woods Rd off end of Back Road follow 138kv ROW.	45 23' 53.4376"N	-63 19' 54.0709"W	No	2026S	12.3	11.57	7214555	N/A	No	GROUT BEGINNING TO DETERIORATE IN INSULATORS. 1 WOODPECKER HOLE RIGHT POLE.	re-insulate 3 x 12/phase	
L7001-015	230-T-G(O)	70	0	70	L6513 N45-23-52.50 W63-19-54.80	45 23' 50.7599"N	-63 19' 56.1882"W	No	2026S	13.5	12.9	7214555	N/A	No	GROUT BEGINNING TO DETERIORATE IN INSULATORS.	remove 70' 230-T-G(0), install 70' cl1 230-T-H(1S-0)-BG(crosses over L6613)	
L7001-016	230-T-G(O)	70	0	70	Woods Rd off end of Back Road follow 138kv ROW. In wetland.	45 23' 42.8471"N	-63 20' 2.7152"W	No	2026S	10.3	9.190000000000001	7214555	N/A	No	GROUT BEGINNING TO DETERIORATE IN INSULATORS.	re-insulate 3 x 12/phase	

Line No: L7001 ***Work Order Report***

L7001-017	230-T-G(O)	70	0	70	1M Stream N45-23-39.80 W63-20-05.10	45 23' 37.1937"N	-63 20' 7.2537"W	No	2026S	10.5	9.54	7214555	N/A	No	LARGE WEATHER CRACK IN RIGHT SPAR ABOVE CENTER PHASE. GROUT BEGINNING TO DETERIORATE IN INSULATORS.	replace both 9100mm spar arms and reinsulate 3 x 12/phase	
L7001-020	230-T-G(O)	70	0	70	cultivated field	45 23' 21.2445"N	-63 20' 20.4970"W	No	2026S	10.6	9.860000000000001	7214555	2-4 years	No	One side of the right pole is rotted and has ants. This pole should be replaced but much of it is still solid	remove 70' 230-T-G(0), install 70' cl1 230-T-H(1S-0)-BG	
L7001-021	230-T-G(O)	75	0	75	across fields from Back Road, Onslow	45 23' 15.7519"N	-63 20' 25.0518"W	No	2026S	9.6	9.01	7214555	N/A	No	GROUT BEGINNING TO DETERIORATE IN INSULATORS	re-insulate 3 x 12/phase, replace both 9100mm spar arms, transfer 2 x ohgw	
L7001-022	230-T-G(O)	70	0	70	Higgins Brook 2M Stream N45-23-12.10 W63-20-27.60	45 23' 8.8064"N	-63 20' 30.4804"W	No	2026S	12.5	11.39	7214555	N/A	No	GROUT BEGINNING TO DETERIORATE IN INSULATORS	reinsulate 3 x 12/phase (x's hwy 104)	
L7001-024	230-T-G(O)	75	0	75	off hwy 104 service road.	45 22' 56.5999"N	-63 20' 40.7658"W	No	2026S	10.6	9.565	7214555	1-2 years	No	Insulator grout deteriorating. Large weather cracks in spar arms. 1 broken insulator in left phase.	re-insulate 3 x 12/phase, replace both 9100mm spar arms and transfer 2 x ohgw	
L7001-025	230-T-G(O)	75	0	75	off hwy 104 service road.	45 22' 50.1041"N	-63 20' 45.8219"W	No	2026S	10.9	9.865	7214555	1-2 years	No	Insulator grout deteriorating. Both spar arms are heavily weathered on tops and have major weather cracks on south side. <10 small woodpecker holes in right pole, 1 potential nest cavity between x-braces in right pole.	re-insulate 3 x 12/phase, replace both 9100mm spar arms and transfer 2 x ohgw	
L7001-027	230-T-G(O)	65	0	65	off hwy 104 service road.	45 22' 40.8881"N	-63 20' 56.0898"W	No	2026S	12.2	11.469999999999999	7214555	2-4 years	No	Insulator grout beginning to deteriorate. Spar arms heavily weathered on tops, some large weather cracks.	remove 65' 230-T-G(0), install 65' cl1 230-T-H(1S-0)-BG	
L7001-029	230-T-G(O)	75	0	75	1M Drainage Ditch N45-22-36.10 W63-21-03.60 Inside electric fence, occupied horse pasture.	45 22' 31.6279"N	-63 21' 10.9194"W	No	2026S	11.5	10.39	7214555	1-2 years	No	Insulator grout deteriorating. Spar arms both look a little green on the top side. Looks like ants in right pole, did not sound.	replace both 9100mm spar arms and reinsulate 3 x 12/phase	b'1. IBA: Cobequid Bay (Work prohibited during certain times of year. Contact Environmental Services.)'
L7001-033	230-T-G(O)	75	0	75	Ingelwood Farm fields across railbed/walking trail.	45 22' 0.0205"N	-63 21' 11.1324"W	No	2026S	11.8	10.690000000000001	7214555	1-2 years	No	Insulator grout deteriorating. Right spar arm is sagging over x-brace, has large weather cracks. 2 storm guys, no guards.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	b'1. IBA: Cobequid Bay (Work prohibited during certain times of year. Contact Environmental Services.)'

Line No: L7001 ***Work Order Report***

L7001-034	230-T-G(O)	75	0	75	Ingelwood Farm fields across railbed/walking trail.	45 21' 52.2991"N	-63 21' 8.6010"W	No	2026S	10.4	9.2900000000000001	7214555	1-2 years	No	Insulator grout deteriorating. Large weather cracks in both spar arms. 2 storm guys, no guards.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	b'1. IBA: Cobequid Bay (Work prohibited during certain times of year. Contact Environmental Services.)'
L7001-036	230-T-G(O)	75	0	75	Farm road	45 21' 40.9585"N	-63 21' 4.6452"W	No	2026S	13.2	12.354999999999999	7214555	2-4 years	No	Spar arms are in poor condition. Replace and reinsulate	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	b'1. IBA: Cobequid Bay (Work prohibited during certain times of year. Contact Environmental Services.)'
L7001-038	230-T-G(O)	70	0	70	off old rd #3	45 21' 30.2307"N	-63 21' 0.5662"W	No	2026S	16.1	15.255	7214555	1-2 years	No	Insulator grout deteriorating. Left spar arm appears to be beginning to compress at x-brace.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	b'1. IBA: Cobequid Bay (Work prohibited during certain times of year. Contact Environmental Services.)'
L7001-040	230-T-G(O)	70	0	70	Cutten's Farm fields	45 21' 19.7209"N	-63 20' 56.7522"W	No	2026S	10.0	8.965	7214555	1-2 years	No	Insulator grout deteriorating. Large weather crack in left spar arm.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	
L7001-042	230-T-G(O)	70	0	70	Cutten's Farm fields	45 21' 6.5611"N	-63 20' 55.3656"W	No	2026S	10.2	9.2399999999999998	7214555	N/A	No	GROUT BEGINNING TO DETERIORATE IN INSULATORS.	re-insulate 3 x 12/phase	
L7001-043	230-T-G(O)	70	0	70	Cutten's Farm fields	45 21' 0.2189"N	-63 20' 56.3224"W	No	2026S	10.3	9.34	7214555	1-2 years	No	Insulator grout deteriorating.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	
L7001-045	230-T-G(O)	75	0	75	Cutten's Farm fields	45 20' 46.2385"N	-63 20' 58.5414"W	No	2026S	11.7	10.665	7214555	N/A	No	GROUT BEGINNING TO DETERIORATE IN INSULATORS. STORM GUYED.	re-insulate 3 x 12/phase	
L7001-046	230-T-G(O)	70	0	70	Cutten's Farm fields	45 20' 39.2389"N	-63 20' 59.7216"W	No	2026S	11.0	9.965	7214555	1-2 years	No	Insulator grout deteriorating. Large weather cracks in both spar arms.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	
L7001-047	230-T-G(O)	70	0	70	Cutten's Farm fields	45 20' 33.2209"N	-63 21' 0.5232"W	No	2026S	10.5	9.655	7214555	2-4 years	No	Right pole is hollow and soft. Spar arms are deteriorated. Replace pole and spar arms	remove 70' 230-T-G(0), install 70' cl1 230-T-H(1S-0)-BG	
L7001-050	230-T-G(O)	70	0	70	Access from Jeff Cuttens field	45 20' 11.5933"N	-63 21' 4.0350"W	No	2026S	11.3	10.34	7214555	1-2 years	No	Spar arms are weather cracked, insulator grout is failing, replace arms and reinsulate	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	b'1. Significant Species and Habitat: CO400 - Species at Risk (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.)'
L7001-052	230-T-G(O)	75	0	70	Access from Jeff Cuttens field	45 19' 56.7427"N	-63 21' 6.3072"W	No	2026S	11.8	10.84	7214555	1-2 years	No	Grout failing on insulators, spar arms are weather cracked, right pole hollow but ok for now	remove 75' 230-T-G(0), install 75' cl1 230-T-H(1S-0)-BG	b'1. Significant Species and Habitat: CO400 - Species at Risk (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.)'
L7001-053	230-T-G(O)	70	0	70	1M Stream N45-19-52.00 W63-21-07.30	45 19' 49.3837"N	-63 21' 7.4436"W	No	2026S	12.4	11.365	7214555	1-2 years	No	Insulator grout deteriorating. Large weather cracks in both spar arms and left pole.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	b'1. Significant Species and Habitat: CO400 - Species at Risk (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.)'

Line No: L7001 ***Work Order Report***

L7001-054	230-T-G(O)	70	0	70	Samsons X-mas tree lot	45 19' 41.1475"N	-63 21' 8.7492"W	No	2026S	11.4	10.290000000000001	7214555	1-2 years	No	Insulator grout is failing, both poles are hollow,spar arms are weather cracked, replace structure	remove 70' 230-T-G(0), install 70' cl1 230-T-H(1S-0)-BG	b'1. Significant Species and Habitat: CO400 - Species at Risk (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.)'
L7001-055	230-T-G(O)	70	0	70	Access from Samson X-mas tree lot	45 19' 34.2301"N	-63 21' 9.8868"W	No	2026S	11.5	10.465	7214555	2-4 years	No	Right pole is very hollow and should be replaced	remove 70' 230-T-G(0), install 70' cl1 230-T-H(1S-0)-BG	b'1. Significant Species and Habitat: CO400 - Species at Risk (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.)'
L7001-058	230-T-G(O)	70	0	70	Access from Samson X-mas tree lot	45 19' 15.8251"N	-63 21' 12.6732"W	No	2026S	10.5	9.465	7214555	1-2 years	No	Insulator grout deteriorating. Large weather cracks in both spar arms. Ants in right pole, still ok.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	b'1. Significant Species and Habitat: CO400 - Species at Risk (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.)'
L7001-062	230-T-G(O)	75	0	75	1M Stream with culvert N45-18-51.50 W63-21-16.7	45 18' 49.3525"N	-63 21' 16.9002"W	No	2026S	12.2	11.09	7214555	1-2 years	No	Insulator Grout deteriorated, right pole hollow but ok, 2 storm guys, only one guard	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	b'1. Significant Species and Habitat: CO400 - Species at Risk (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.)'
L7001-065	230-T-G(O)	70	0	70	Gully with 1 M Stream N45-18-32.50 W63-21-19.20	45 18' 28.1578"N	-63 21' 20.2064"W	No	2026S	13.0	12.2	7214555	1-2 years	No	See previous inspection. Updated structure status to match field priority.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	b'1. Significant Species and Habitat: CO400 - Species at Risk (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.)'
L7001-066	230-T-G(O)	65	0	65	Access from Irwin Lake Rd Hilden	45 18' 21.8260"N	-63 21' 21.3055"W	No	2026S	9.9	9.22	7214555	1-2 years	No	Insulator grout deteriorating. Left spar arm beginning to compress at the x-brace. Pole tops a little mossy, 4 small woodpecker holes in right pole below the bottom xbrace.	remove 65' 230-T-G(0), install 65' cl1 230-T-H(1S-0)-BG	b'1. Significant Species and Habitat: CO400 - Species at Risk (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.)'
L7001-067	2Pole: 230-T-G(O)	70	0	70	Irwin Lake Rd	45 18' 16.7335"N	-63 21' 22.0848"W	No	2026S	10.9	10.4	7214555	2-4 years	No	Replace spar arms and insulators	replace both 9100mm spars, reinsulate 3 x 12/phase, transfer 2 x ohsw	b'1. Significant Species and Habitat: CO400 - Species at Risk (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.) 2. NSDNR Crown Land: 4549 (Contact Environmental Services and Lands and Rights, an LOA will be required.)'
L7001-069	230-T-G(O)	70	0	70	Access through sheep pastrure off Irwin Lake Rd	45 18' 2.9185"N	-63 21' 24.2562"W	No	2026S	10.7	9.739999999999998	7214555	2-4 years	No	Structure inside electric fence. Spar arms are deteriorated and should be replaced. Reinsulate at the same time	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	b'1. Significant Species and Habitat: CO400 - Species at Risk (Consultation with Lands and Forestry (formally DNR) may be required. Contact Environmental Services.)'
L7001-070	230-T-G(O)	70	0	70	Irwin Lake Road	45 17' 55.4185"N	-63 21' 25.3224"W	No	2026S	11.0	9.965	7214555	1-2 years	No	BONDING WIRE NOT CONNECTED TO OHGW ON RIGHT SIDE, PEICE MISSING, SHOULD BE FIXED. LARGE WEATHER CRACKS IN BOTH SPAR ARMS. GROUT BEGINNING TO DETERIORATE IN INSULATORS. AIR LINE AND STR ID.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, re-attach ohgw bond	

Line No: L7001 ***Work Order Report***

L7001-071	230-Da-3(O)(0-60 Deg)	70	65	70	1M Stream with Atv Bridge N45-17-51.20 W63-21-25.8	45 17' 47.2483"N	-63 21' 26.5143"W	No	2026S	11.5	10.39	7214555	1-2 years	No	LEFT SIDE IDLER SPAR HAS MAJOR WEATHER CRACKS AND IS STARTING TO SAG, SHOULD BE REPLACED. 3 SMALL WOODPECKER HOLES IN CENTER POLE. 16 WRAPPED GUYS, 8 HOOKED GUYS. 3 BRIDAL GUYS.	replace 9000mm and 6300mm idler arms, re-insualte 3 x 12/phase idlers	
L7001-072	230-T-G(O)	70	0	70	Acces by Good Brookfield Lumber Road in ROW	45 17' 43.2715"N	-63 21' 31.6947"W	No	2026S	8.9	8.17	7214555	N/A	No	1 SMALL WOODPECKER HOLE BOTTOM OF LEFT POLE, HOLLOW, STILL OK.	reinsulate 3 x 12/phase	
L7001-073	230-T-G(O)	70	0	70	Access By Good Brookfield Lumber Road in ROW	45 17' 36.8398"N	-63 21' 39.9600"W	No	2026S	10.1	8.99	7214555	1-2 years	No	Insulator grout deteriorating. Top of left pole is mossy, has multiple small woodpecker holes below xbrace.	remove 70' 230-T-G(0), install 70' cl1 230-T-H(1S-0)-BG	
L7001-076	230-T-G(O)	70	0	70	woods rd from Pleasant Vally Rd.	45 17' 20.5507"N	-63 22' 1.1976"W	No	2026S	9.5	8.465	7214555	2-4 years	No	Spar arms are deteriorated and should be replaced. Reinsulate at the same time	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	
L7001-077	230-T-G(O)	70	0	70	woods rd from Pleasant Valley Road.	45 17' 16.3633"N	-63 22' 6.6198"W	No	2026S	9.9	9.055	7214555	1-2 years	No	LEFT OHGW SHOE MISSING COTTER KEY, SHOULD BE REPLACED. ANTS IN RIGHT POLE. GROUT BEGINNING TO DETERIORATE IN INSULATORS.	install cotter key in left oghw, reinsulate 3 x 12/phase	
L7001-078	230-T-G(O)	70	0	75	woods rd from Pleasant Valley Road.	45 17' 11.1121"N	-63 22' 13.4628"W	No	2026S	11.2	10.165	7214555	1-2 years	No	SHOE CLAMP BOLT LOOSE ON RIGHT OHGW, NEEDS TO BE TIGHTENED. GROUT BEGINNING TO DETERIORATE IN RIGHT INSULATORS. ANTS IN RIGHT POLE, SOUNDS HOLLOW. LARGE WEATHER CRACK LEFT SPAR ARM.	remove 75' 230-T-G(0), install 75' cl1 230-T-H(1S-0)-BG	
L7001-079	230-T-G(O)	70	0	70	1M Stream N45-17-09.80 W63-22-15.40 Access to Road to Left of ROW	45 17' 5.3581"N	-63 22' 20.9783"W	No	2026S	10.3	9.5	7214555	1-2 years	No	Insulator grout deteriorating.	reinsulate 2 x 12/phase	
L7001-080	230-T-G(O)	70	0	70	woods rd from Pleasant Valley Road.	45 17' 0.4465"N	-63 22' 27.3522"W	No	2026S	9.8	9.1200000000000001	7214555	N/A	No	Structure okay	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	
L7001-081	230-T-G(O)	70	0	70	woods rd from Pleasant Valley Road.	45 16' 55.7209"N	-63 22' 33.3408"W	No	2026S	9.8	9.1200000000000001	7214555	2-4 years	No	Spar arms are deteriorated and should be replaced. Reinsulate at the same time. Right pole is hollow but still okay	remove 70' 230-TG(0), install 70' cl1 230-TG(0)	

Line No: L7001 ***Work Order Report***

L7001-083	230-T-G(O)	70	0	70	Access Woods Road off Pleasant Valley Road Highway 289	45 16' 46.3171"N	-63 22' 45.6798"W	No	2026S	9.6	8.64	7214555	1-2 years	No	BOTH SPAR ARMS HAVE MULTIPLE MAJOR CRACKS THROUGH ATTACHMENT POINTS, NEED TO BE REPLACED. BOTH POLE TOPS APPEAR TO BE ROTTEN. GROUT BEGINNING TO DETERIORATE IN INSULATORS. ANTS IN RIGHT POLE.	remove 70' 230-T-G(0), install 70' cl1 230-T-H(1S-0)-BG	
L7001-086	230-T-G(O)	70	0	70	Swampy Area, access from south.	45 16' 30.7423"N	-63 23' 5.9016"W	No	2026S	10.6	9.565	7214555	1-2 years	No	Insulator grout deteriorating. Large weather cracks in both spar arms. Ants in left pole.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	
L7001-088	230-T-G(O)	70	0	70	swampy, good logging road	45 16' 19.2463"N	-63 23' 20.7018"W	No	2026S	12.4	11.17	7214555	1-2 years	No	Insulator grout deteriorating. Large weather cracks in both spar arms. Ants in left pole, still ok.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	
L7001-093	230-T-G(O)	70	0	70	Access Woods Road off Pleasant Valley Road Highway 289	45 15' 57.0421"N	-63 23' 49.4334"W	No	2026S	9.4	8.555	7214555	1-2 years	No	Insulator grout deteriorating. Right spar arm has cross grain cracking on outer shell. Large weather cracks in both spar arms.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	
L7001-094	230-T-G(O)	65	0	65	Access from 1898 Pleasant Valley Rd	45 15' 52.9093"N	-63 23' 54.8040"W	No	2026S	11.9	11.055	7214555	N/A	No	RT SPAR ARM HAS WEATHER CRACKS, OK FOR NOW	reinsulate 3 x 12/phase	
L7001-095	230-T-G(O)	70	0	70	Andrew Brook 4 M N45-15-50.90 W63-23-57.3 Gravel Road Brookfield Lumber	45 15' 46.8506"N	-63 24' 3.3488"W	No	2026S	10.7	9.59	7214555	1-2 years	No	Insulator grout deteriorating. Large weather cracks in both spar arms. 1 broken insulator in left phase.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	
L7001-096	230-T-G(O)	70	0	70	Access from Creelman Woods Road off Hwy 289	45 15' 42.0180"N	-63 24' 9.4142"W	No	2026S	9.5	8.54	7214555	1-2 years	No	Insulator grout deteriorating. Left spar arm compressed at x-brace, weather cracks in both arms. Replace arms. Ants in both poles, still ok.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	
L7001-097	230-T-G(O)	65	0	65	.5M Stream N45-15-39.40 W63-24-12.00 Access by Road to Right of ROW	45 15' 36.1195"N	-63 24' 17.1474"W	No	2026S	11.9	10.790000000000001	7214555	1-2 years	No	Insulator grout deteriorating. Large weather cracks in both spar arms. Right arm split at right pole bolt, needs to be changed. Ants in left pole, still ok.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	
L7001-098	230-T-G(O)	70	0	70	Access from Creelman Woods Road off Hwy 289	45 15' 31.8499"N	-63 24' 22.6962"W	No	2026S	9.8	8.955	7214555	1-2 years	No	Insulator grout deteriorating. Large weather cracks in both spar arms.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	

Line No: L7001 ***Work Order Report***

L7001-099	230-T-G(O)	65	0	65	.5M Stream N45-15-27.2 W63-24-28.2 Good Road to Left of ROW	45 15' 24.6213"N	-63 24' 32.3195"W	No	2026S	14.2	12.96 9999 9999 9999 9	7214555	1-2 years	No	Insulator grout deteriorating. Both spar arms are starting to sag, large weather cracks. Replace arms.	replace both 9100mm spar arms and reinsulate 3 x 12/phase, transfer 2 x ohgw	

Request IR-118:

T03: C0080109 L7001 Replacements and Upgrades Phase 1

Please provide cost support references from similar projects recently completed and update the detailed project estimates for each project.

Response IR-118:

Please refer to NSEB IR-111.

Request IR-119:

T03: C0080109 L7001 Replacements and Upgrades Phase 1

Please provide specific details on the criteria used and the work completed to estimate which assets require replacement.

Response IR-119:

Please refer to NSEB IR-112.

Request IR-120:

T03: C0080109 L7001 Replacements and Upgrades Phase 1

Do any assets require replacement because they do not meet NS Power's ground clearance requirements?

(a) If so, please describe and explain why the current assets do not meet these requirements.

Response IR-120:

No.

(a) N/A.

Request IR-121:

T03: C0080109 L7001 Replacements and Upgrades Phase 1

Please explain specifically how NS Power determined that 12 structures need replacement.

Response IR-121:

NS Power completed a detailed inspection of transmission line L-7001 as part of the Company's transmission line inspection program as detailed in NSEB IR-112. Based on these assessments, LIDAR and subsequent review it was determined that 12 structures require a full replacement as part of this project.

Request IR-122:

T03: C0080109 L7001 Replacements and Upgrades Phase 1

With regard to the project's detailed cost estimate on page 3 of 5: Please identify the estimated unit materials and contract costs for wood poles, insulators and O/H conductors, and compare these unit costs to those used in the 2025 ACE Plan application.

Response IR-122:

Please refer to NSEB IR-115.

Request IR-123:

T04: C0053214, 76W-T1 Transformer Replacement

Page 383 of the application notes that the existing 76W-T1 69-4.16kV, 3.75/5 MVA transformer will be replaced with a 69-13.2/4.16kV, 5/6.66 MVA unit. The low voltage equipment, owned by the Town of Mahone Bay but operated by NS Power, will be upgraded outside of this project and filed by the Town of Mahone Bay. This transformer also experiences mild overloading during system peaks, which increases thermal stress and accelerates aging.

On page 384, the application notes using a low side dual voltage unit will enhance the substation's capabilities in the future when the distribution system is upgraded to a rated 12kV voltage and supports future load growth. Another option that was explored was to connect Mahone Bay to an existing nearby feeder. This was determined to be infeasible because it could risk overloading the feeder during winter peak periods. Building a new feeder from another nearby substation would require similar upgrades to another transformer elsewhere on the system to handle the increased load.

(a) When was transformer 76W-T1 installed?

b) Please provide the annual load growth for the proposed transformer, along with the peak load values from 2020 to 2035.

(c) Please explain the need of dual 13.2/4.16kV secondary voltage.

(d) Please provide the cost difference between low side dual voltage compared to the original low voltage.

(e) Please provide any communications confirming that Mahone Bay will upgrade their secondary system, along with the associated timeline.

(f) Please provide a breakdown of the total project cost, identifying NS Power share and the Town of Mahone Bay share, along with a description of the associated work.

(g) Please provide a distribution study demonstrating that the proposed solution is the most effective option. If a study is not available, please explain why.

Response IR-123:

(a) 76W-T1 was originally installed in 1971.

(b) Load growth and distribution data are managed by the Town of Mahone Bay. No load growth information has been provided or made available to NS Power.

(c) The existing distribution feeders operate at 4.16 kV. The Town of Mahone Bay plans to upgrade their distribution bus structure and feeders to a 12.5 kV design. Using a dual-voltage secondary is advantageous because it allows the transformer to remain in service through the transition and requires replacement only once.

(d) No formal quote was documented at the time, but NS Power's transformer supplier indicated that the price difference would have been approximately 5%.

(e) Communication has been through phone and in-person discussions. No emails or communications are available. The Town of Mahone Bay has confirmed that their project is still within the design/funding phase.

(f) This project will be funded solely by NS Power, as the work pertains exclusively to equipment on the NS Power-owned portion of the system.

(g) No distribution study is available, as the distribution system is owned and managed by the Town of Mahone Bay.

Request IR-124:

T05: C0070586, L6536 Switch Replacements

(a) Please provide the number and duration of outages associated with routine switching activities or other work activities involving manual switches over the past 10 years. Please confirm the percentage of these outages that is expected to be reduced following the installation of live line switches.

(b) In reference to Attachment 2, please confirm the noted pricing was obtained through a competitive procurement process.

(i) If not confirmed, please explain.

Response IR-124:

(a) NS Power does not track this information, and therefore can not provide a total list showing the number and duration of outages associated with switching activities over the past ten years. Tracking is currently not possible due to systems limitations, and tracking has not been pursued because this information is not required for operational or investment decisions. The transmission rated switches are replaced based on condition and operability, not time based. Based on feedback from regional field personnel, each switch is unique and the operation of the switch can vary based on the condition, ambient temperature, and manufacturer of the switch. To operate some manual live-line and manual non-live-line operable switches can take between 1 to 8 hours. However, based on experience with these assets, the Company expects outages to be reduced with the installation of live-line switches.

(b) Confirmed. NS Power undertook a competitive process to enter into a Master Services Agreement (MSA) with this vendor, thus ensuring competitive pricing. This switch

manufacturer is the preferred option due to their high-quality design and time-tested durable build along NS Power's transmission network. The switches are considered long lead material items. Therefore, at the early stage of this project, a purchase order was sent to the manufacturer to secure a manufacturing space at the switch factory.

(i) N/A.

Request IR-125:

T06: C0053234, 96H-T1 Transformer Replacement

(a) When was transformer 96H T1 installed, and what was its expected service life?

(b) Please provide the energy output of the Ruth Falls Hydro Generating Station for each of the past five years.

(c) Why can't the oil tank itself be replaced, refurbished, or repaired?

(d) Please provide NS Power's transformer risk assessment report, as well as all repair reports completed on this transformer over the past 12 years.

(e) What are the causes of the severe internal and external corrosion? What steps were taken by the utility to mitigate corrosion?

(f) Please provide the risk assessment showing the reasons that led to classifying the risk as significant.

(g) Are there any oil leak containment systems or traps designed for this transformer as part of the original design? If not, why not?

(h) What steps are currently being taken to mitigate the significant environmental risks noted in the application?

(i) Have there been any significant leaks that required regulatory reporting? If yes, please share the report.

Response IR-125:

(a) Transformer 96H-T1 was installed in 1966. The industry-standard service life for power transformers is estimated to be 50 years but actual service-life is influenced by many factors such as service environment, design margins, duty cycle, number and severity of faults experienced, and many more.

(b) Please refer to the table below:

Ruth Falls Generation (Gross) - GWh					
	2021	**2022**	**2023**	**2024**	**2025**
Ruth Falls 1	5.35	3.17	12.37	6.73	3.61
Ruth Falls 2	5.64	5.35	7.83	7.09	5.87
Ruth Falls 3	7.03	7.37	15.89	7.67	5.66
Ruth Falls (Total)	18.02	15.90	36.09	21.49	15.14

(c) The "oil tank" is the main transformer tank, and it is 60 years old alongside all the internal components. Replacing the main tank only to put a 60-year-old core and coil assembly inside of it would result in significant costs with no meaningful extension to the life of the asset. Refurbishment or repair would require the power plant to be offline for approximately 8 months while the transformer is shipped to a repair shop, refurbished and then returned to site. A spare transformer could be put in its place, but that would then have to be replaced with the refurbished transformer again; further increasing costs. Each of these options was deemed to have unacceptable risk, and decreased cost effectiveness as compared to replacing the transformer in its entirety.

(d) NS Power does not maintain a single standalone "transformer risk assessment report" for 96H-T1; rather, the unit's risk rating is developed using NS Power's transformer risk-assessment methodology, which evaluates condition and criticality factors consistent with the CEJC Risk Matrix. The condition score is informed by inspection findings, maintenance history, oil testing, and evidence of deterioration, while the

criticality score reflects environmental sensitivity, station configuration, and potential customer and operational impacts.

For 96H-T1, the Asset Strategy Committee assigned a Condition score of 5 due to advanced tank corrosion, active leaks, and age-related deterioration (see Attachment 1). The transformer has a Criticality score of 5 because it is the primary step-up transformer function for the Ruth Falls Generating Station. The unit's criticality is further elevated by its proximity to environmentally sensitive habitat, including the adjacent hydro reservoir. This puts the overall risk score at 25 out of 25 which is above the threshold to trigger risk mitigating activities, in this case capital investment. NS Power does not document repair reports when repairs similar to repairs on 96H-T1 occur.

(e) Corrosion is anticipated and part of the normal part of asset operation and degradation. Nova Scotia has a corrosive atmosphere due to most of its landmass being coastal or near proximity to coastal water, which increases exposure to salt. Salt, when mixed with atmospheric humidity, is corrosive over time to galvanically active metals like the steel that transformer tanks are made from. Mitigating measures include rust removal and coating to minimize direct steel exposure to atmosphere, as well as leak repair and gasket replacement to minimize moisture ingress. These measures only extend the life, and there comes a point when corrosion has compromised metal thickness to a point where repair and re-coating can no longer effectively extend the service life. This unit, at 60 years of age, has exceeded its expected life.

(f) Please refer to part (d).

(g) There is an oil containment system accompanied with an oil-water separation system. The system allows oil to be removed and water to drain to a safe location. This existing system is sized correctly for the existing transformer and can be re-used for the new transformer.

(h) There is an existing oil containment system for the transformer that was installed in 1994. The concrete containment system directs any mineral oil resulting from any leaks or accidental release to an oil water separator which is checked monthly and emptied as needed. Due to the ongoing leaks, oil absorbent pads are also used to collect leaking mineral oil and are replaced as needed. Routine maintenance checks are also completed to monitor mineral oil levels in the transformer and identify any potential damage that may result in a significant release.

(i) Routine maintenance work in August 2024 identified damage to the transformer infrastructure that resulted in the release of approximately 300 L of mineral oil. During subsequent emergency repairs, it was discovered that the oil containment system was compromised, resulting in mineral oil impacts migrating underneath the concrete transformer pad and oil containment system into the underlying soil and bedrock. The containment system was repaired and NS Power retained Strum Consulting to complete environmental site assessment, shown in Attachment 2, which have been ongoing since August 2024.

MP-160

POWER TRANSFORMERS

B INSPECTION

TRANSFORMER SYSTEM NO. 96H-T1 DATE Sep 23 2018

TESTED BY: JS/SF/CAB

OIL TESTING

MAIN TANK POWER FACTOR SEE DOBLE RESULTS

MAIN TANK BREAKDOWN 22kV

TAPCHANGER POWER FACTOR SEE DOBLE RESULTS

TAPCHANGER BREAKDOWN 30 kV

TAPCHANGER

	YES	NO	N/A
AUTO REGULATORS OPERATING SATISFACTORILY			x
UNUSUAL NOISES IN TAP GEARS			x
RELAY CONTACTS O.K.			x

COUNTER READING

REMARKS : Tap changer not operational / Leaking / Broken Vent

OIL CONTAINMENT SYSTEM

	YES	NO	N/A
SYSTEM OPERATING NORMALLY	x		
OIL PRESENT IN SEPARATOR TANKS		x	
WAS IT REMOVED			x

REMARKS : Tap changer leaking from main tank. All three head gaskets

REMARKS : appear to be failing. Tightened nuts on back side in main tank
Replaced main tank cover gasket. As well as Tap changer cover gasket.
Replaced broken vent cover. Gaskets still leaking .
Advised not to repair the head gaskets,test and return to service.

Environmental Site Assessment for Limited Remediation Checklist

This checklist is for all sites undergoing L1, L2 or L3 Limited Remediation

NOVA SCOTIA

☑ New submission ☐ Updated checklist NSE file number (mandatory) 33000-30-BED-2024-6188182

Instructions for completing this checklist

- All relevant sections of this checklist must be completed and must accompany the Environmental Site Assessment for Limited Remediation Report.
- The signature required on this checklist is from the managing site professional.
- All regulatory protocols must be followed, and all forms/checklists must be completed separately for each property. This means that a source property and an impacted third-party property must have all documents filed separately. Once the source property or impacted third-party property is identified by the check box below, all subsequent reference on this form/checklist are to that site owner.
- Each checklist item corresponds to a requirement in the Regulations or Protocols. It is not acceptable to check a field and refer to justification of why a minimum requirement was not completed.
- Forms/checklists must be complete prior to filing with the Minister.

1 - Site Location and Contact Information

Details provided on this form are applicable to ☑ Source Property or ☐ Impacted Third-Party Property

Site Location
Mandatory must be completed.

Site Address: 16 Ruth Falls Road — City: Sheet Harbour
Parcel Identification Number (PID): 00583732 — Postal Code:
GPS (NAD83 UTM coordinates, source central point) Easting: — Northing:
Zone (select one) ☐ 19 ☑ 20 ☐ 21
Description (optional): NSPI hydro power station

Property Owner
Mandatory must be completed.

Name: Nova Scotia Power Incorporated — Phone: (902) 399-6873
Email: thomas.crane@nspower.ca — Fax:
Recognized Agent (if applicable): Thomas Crane, P.Eng., Environmental Engineer
Company Name (if applicable): Nova Scotia Power Incorporated — City: Halifax
Mailing Address: 1223 Lower Water Street — Postal Code: B3J 3S8
Preferred method of correspondence (select one) ☐ Letter or ☑ Email

Contact for Correspondence
If different than above.

Name: — Phone:
Email: — Fax:
Recognized Agent (if applicable):
Company Name (if applicable): — City:
Mailing Address: — Postal Code:
Preferred method of correspondence (select one) ☐ Letter or ☐ Email

Site Professional
Mandatory must be completed.

Name: Jeff Faulkner, P.Geo — Phone: (902) 835-5560
Email: jfaulkner@strum.com — Fax: (902) 835-5574
Company Name: Strum Consulting — City: Halifax
Mailing Address: 211 Horseshoe Lake Drive, Suite 210 — Postal Code: B3S 1B4
Professional Registration Number: 0225
Preferred method of correspondence (select one) ☐ Letter or ☑ Email

Environmental Site Assessment for Limited Remediation Checklist

This checklist is for all sites undergoing L1, L2 or L3 Limited Remediation

NOVA SCOTIA

2 - Environmental Site Assessment (ESA) Requirements for Limited Remediation

Type of Environmental Site Assessment conducted under Limited Remediation

Check type of ESA completed and complete corresponding section below.

☐ L1 ESA ☑ L2 ESA ☐ L3 ESA

2a - L1 Environmental Site Assessment Requirements Confirm **all** the following information has been submitted to the Department. Indicate 3 digit report ID, section and page number where information is documented. It is not acceptable to provide justification for not completing a minimum requirement. The site professional must ensure all work has been completed in accordance with the PRO-200, Environmental Site Assessment for Limited Remediation Protocol.	**Supporting Information provided**	**Reference Document**		
	Yes	Report	Section	Page Number
Restrictions for use of L1				
1 Contamination has not extended below the water table. All potential pathways in the subsurface have been fully investigated to ensure contamination has not come into contact with groundwater	☐			
2 Contaminants listed in Section 4.1 b) of PRO-200, Environmental Site Assessment for Limited Remediation Protocol exceeding Tier 1 EQS are not present at a depth greater than 0.3 m from surface	☐			
3 Contamination has not directly impacted a watercourse, wetland or potable water	☐			
4 Contamination has not come in contact with bedrock on a potable site	☐			
5 Measures greater than short-term emergency action and/or temporary excavation are not required to address vapours within a building	☐			
Intrusive Investigation				
6 All contamination has been delineated to appropriate Tier 1 EQS criteria specified in the PRO-100, Notification of Contamination Protocol	☐			
7 With the exception of the evaluation process for inaccessible soils below building structures outlined in PRO-200, Environmental Site Assessment for Limited Remediation Protocol, including the use of Tier 2 PSS tables where applicable, all contamination has been remediated to appropriate Tier 1 EQS criteria	☐			
8 Air sampling requirements not applicable to the site **or** where applicable soil vapour, sub-slab and/or indoor air sampling work followed the latest version of the Atlantic RBCA Guidance for Soil Vapour and Indoor Air Monitoring Assessments available from the Atlantic RBCA website atlanticrbca.com	☐ ☐			
9 Confirmatory soil samples have been collected from the side walls and floor of the excavation in accordance with Table 1 (Confirmatory Sampling Requirements) of PRO-700, Confirmation of Remediation Protocol	☐			

Environmental Site Assessment for Limited Remediation Checklist

This checklist is for all sites undergoing L1, L2 or L3 Limited Remediation

NOVA SCOTIA

2a - L1 Environmental Site Assessment Requirements continued Confirm **all** the following information has been submitted to the Department. Indicate 3 digit report ID, section and page number where information is documented. It is not acceptable to provide justification for not completing a minimum requirement. The site professional must ensure all work has been completed in accordance with the PRO-200, Environmental Site Assessment for Limited Remediation Protocol.	**Supporting Information provided**	**Reference Document**		
	Yes	Report	Section	Page Number
10 Contamination does not remain below any part of a building footprint; **or** where contaminated soil below any part of a building footprint has been left in place, full delineation of contamination and verification through soil vapour, sub-slab or indoor air sampling that the indoor air quality is not affected above an acceptable level has been completed	❑ ❑			
11 Contamination has not extended to bedrock; **or** where contaminated soil has extended to bedrock on non-potable sites and no evidence of free product is present, the site professional has used their professional judgement to determine whether a groundwater assessment is required. In cases where it is determined that a groundwater assessment is not required, and contaminated soil contained gasoline or volatile organic compounds an evaluation of soil vapour, sub-slab or indoor air has been accomplished through the collection and interpretation of empirical site data and the indoor air quality is not affected above an acceptable level	❑ ❑			
12 Composite soil sampling procedures for volatile organic compounds have not been used	❑			
13 Site does not rely on a potable well or spring supply water source; **or** on sites where there is a potable well or spring supplied water source, the well or spring has been analyzed for the contaminant being addressed in the soil	❑ ❑			
14 All sampling and analysis have conformed to the laboratory requirements identified in Section 4.2.4 of PRO-200, Environmental Site Assessment for Limited Remediation Protocol	❑			
Reporting The environmental site assessment, remedial action plan and confirmation report requirements of the Contaminated Sites Regulations may be compiled and documented in a single report for an L1 limited remediation. The time requirements specified in the Contaminated Sites Regulations must be followed.				
15 A cover page title that identifies the site location, and report title	❑			
16 Project background description	❑			
17 Basic site information, including physical address, PID and/or GPS coordinates	❑			
18 Summary of the results and findings of the L1 ESA	❑			
19 Site plan(s) showing the site location, location of sample points. All spatial information represented on a scaled diagram	❑			
20 Results of all analyses conducted displayed in a table and compared to relevant environmental quality standards, with exceedance values/data highlighted	❑			

Environmental Site Assessment for Limited Remediation Checklist

This checklist is for all sites undergoing L1, L2 or L3 Limited Remediation

NOVA SCOTIA

2a - L1 Environmental Site Assessment Requirements continued Confirm **all** the following information has been submitted to the Department. Indicate 3 digit report ID, section and page number where information is documented. It is not acceptable to provide justification for not completing a minimum requirement. The site professional must ensure all work has been completed in accordance with the PRO-200, Environmental Site Assessment for Limited Remediation Protocol.	**Supporting Information provided**	**Reference Document**		
	Yes	Report	Section	Page Number
21 Interpretation and evaluation of the findings from the site investigation, which identify and describe any contaminants found at the site including concentrations, locations, possible sources, potential pathways and receptors of concern	☐			
22 Clear and concise conclusions of the L1 ESA, including a summary of risks posed by contaminants remaining on site and potential risk to receptor(s) both on and off the property	☐			
23 Recommendations regarding risks posed by any contaminants remaining on site, and recommended action(s)	☐			
24 Excavation practices	☐			
25 Soil sampling procedures used for each contaminant	☐			
26 QA/QC procedures	☐			
27 Copies of laboratory analytical data sheets	☐			
28 Site professional sign-off, with original or electronic signatures, and a stamp/seal confirming the findings and conclusions contained in the report	☐			

2b - L2 Environmental Site Assessment Requirements Confirm **all** the following information has been submitted to the Department. Indicate 3 digit report ID, section and page number where information is documented. It is not acceptable to provide justification for not completing a minimum requirement. The site professional must ensure all work has been completed in accordance with the PRO-200, Environmental Site Assessment for Limited Remediation Protocol.	**Supporting Information provided**	**Reference Document**		
	Yes	Report	Section	Page Number
Intrusive Investigation				
1 Soil sampling conducted at source area(s)	☑	PH3	4.2	7
2 Groundwater flow direction, velocity, hydraulic gradient, and elevation has been evaluated by the placement of at least 3 drilled boreholes and the installation of monitoring wells within the boreholes	☑	PH3	5.1	11
3 Determination has been made whether free product in soil or groundwater exist at the site	☑	PH3	5.1	11
4 The horizontal extent of soil contamination on and off the property, for each contaminant has been determined and described in text and on a graphical site plan	☑	PH3	APP	A
5 The vertical extent of soil contamination on and off the property has been determined, including the maximum depth at which contamination was identified, and confirmation that the vertical depth of contamination has been determined, using site profiles as appropriate	☑	PH3	6.0	17

Environmental Site Assessment for Limited Remediation Checklist

This checklist is for all sites undergoing L1, L2 or L3 Limited Remediation

NOVA SCOTIA

2b - L2 Environmental Site Assessment Requirements continued Confirm **all** the following information has been submitted to the Department. Indicate 3 digit report ID, section and page number where information is documented. It is not acceptable to provide justification for not completing a minimum requirement. The site professional must ensure all work has been completed in accordance with the PRO-200, Environmental Site Assessment for Limited Remediation Protocol.	**Supporting Information provided**	**Reference Document**		
	Yes	Report	Section	Page Number
6 The estimated area of soil contamination exceeding applicable environmental quality standards on and off the property have been calculated for each contaminant	☑	PH3	6.0	17
7 The horizontal and vertical extent of groundwater contamination, exceeding applicable environmental quality standards has been determined, on and off the property for each contaminant, and is described in text and on a graphical site plan	☑	PH3	APP	A
8 Sediment and surface water have not been impacted;	☑	PH3	6.0	17
or				
where Sediment or surface water contamination, exceeding applicable environmental quality standards has been determined, contamination is described on a graphical site plan	☐			
9 Laboratories that have performed analysis are accredited to ISO/IEC 17025 standards (and subsequent revisions) by the Standards Council of Canada (SCC) or the Canadian Association of Laboratory Accreditation Inc. (CALA)	☑	PH3	APP	C
10 All sampling and analysis has been conducted in accordance with laboratory-approved recommendations concerning sample containers, storage and preservation	☑	PH3	APP	C
11 Appropriate laboratory analytical methods have been used to ensure adequate conformance to data quality objectives, assessment endpoints (ecological or human health) and method/reportable detection limits	☑	PH3	APP	C
Reporting				
12 A cover page title that identifies the site location and report title	☑	PH3	E. Sum.	i
13 Project background description	☑	PH3	2.0	1
14 Basic site information, including physical address, PID and/or GPS coordinates if available	☑	PH3	2.1	1
15 Summary of all preliminary work and field activities conducted at the site as part of the Limited Phase 2 ESA program	☑	PH3	2.3	3
16 Conceptual site model which represent an understanding of the site characteristics, including expected locations of contaminants, likely contaminant transport mechanisms, and the existence of potentially preferential pathways for contaminant transport to receptors	☑	PH3	2.5	5
17 A description of geological, hydrogeological and hydrological information as required by PRO-200, Environmental Site Assessment for Limited Remediation Protocol	☑	PH3	5.1	11
18 Site plans showing the site location, location of sample points, groundwater elevation maps, and location(s) of samples exceeding the applicable regulatory criteria. Locations where contaminant concentrations exceed background values should also be identified. All spatial information must be represented on a scaled diagram	☑	PH3	APP	A
19 Results of all analyses conducted are displayed in a table and compared to relevant environmental quality standards, with exceedance values/data highlighted	☑	PH3	APP	F

Environmental Site Assessment for Limited Remediation Checklist

This checklist is for all sites undergoing L1, L2 or L3 Limited Remediation

NOVA SCOTIA

2b - L2 Environmental Site Assessment Requirements continued Confirm **all** the following information has been submitted to the Department. Indicate 3 digit report ID, section and page number where information is documented. It is not acceptable to provide justification for not completing a minimum requirement. The site professional must ensure all work has been completed in accordance with the PRO-200, Environmental Site Assessment for Limited Remediation Protocol.	**Supporting Information provided**	**Reference Document**		
	Yes	Report	Section	Page Number
20 Interpretation and evaluation of the findings from the site investigation, which identify and describe any contaminants found at the site including concentrations, locations, source, potential pathways and receptors of concern	☑	PH3	6.0	17
21 Clear and concise conclusions of the Limited Phase 2 ESA, including a summary of risks posed by contaminants remaining on site and potential risk to receptor(s) both on and off the property	☑	PH3	7.0	18
22 Recommendations regarding risks posed by any contaminants remaining on site, and recommended action(s)	☑	PH3	7.0	18
23 A list of any references and supporting documentation used in the preparation of the Limited Phase 2 ESA report	☑	PH3	9.0	24
24 Complete test pit, borehole stratigraphic, and monitoring well installation logs	☑	PH3	APP	E
25 Borehole drilling practices	☑	PH3	APP	C
26 Excavation Practices ☐ Not Applicable	☑	PH3	APP	C
27 Soil sampling procedures used for each contaminant	☑	PH3	APP	C
28 Monitoring well installation, development and groundwater sampling procedures	☑	PH3	APP	C
29 QA/QC procedures	☑	PH3	APP	C
30 Copies of laboratory analytical data sheets	☑	PH3	APP	G
31 Site professional sign-off, with original or electronic signatures, and a stamp/seal confirming the findings and conclusions contained in the report	☑	PH3	Cover	2

2c - L3 Environmental Site Assessment Requirements Confirm **all** the following information has been submitted to the Department. Indicate 3 digit report ID, section and page number where information is documented. It is not acceptable to provide justification for not completing a minimum requirement. The site professional must ensure all work has been completed in accordance with the PRO-200, Environmental Site Assessment for Limited Remediation Protocol.	**Supporting Information provided**	**Reference Document**		
	Yes	Report	Section	Page Number
Investigation				
1 Phase 1 ESA conducted in accordance with PRO-300, Phase 1 ESA Protocol	☐			
2 Phase 2 ESA conducted in accordance with PRO-400, Phase 2 ESA Protocol	☐			
Reporting				
3 Phase 1 ESA reporting requirements completed in accordance with PRO-300, Phase 1 ESA Protocol	☐			

Environmental Site Assessment for Limited Remediation Checklist

This checklist is for all sites undergoing L1, L2 or L3 Limited Remediation

NOVA SCOTIA

2c - L3 Environmental Site Assessment Requirements continued Confirm **all** the following information has been submitted to the Department. Indicate 3 digit report ID, section and page number where information is documented. It is not acceptable to provide justification for not completing a minimum requirement. The site professional must ensure all work has been completed in accordance with the PRO-200, Environmental Site Assessment for Limited Remediation Protocol.	Supporting Information provided	Reference Document		
	Yes	Report	Section	Page Number
4 CHK-300, Phase 1 ESA checklist has been completed and appended to this checklist	☐			
5 Phase 2 ESA reporting requirements conducted in accordance with PRO-400, Phase 2 ESA Protocol	☐			
6 CHK-400, Phase 2 ESA checklist has been completed and appended to this checklist	☐			

3 - Declaration

Site Professional Declaration

I acknowledge it is an offence under Section 158 of the Environment Act to provide false or misleading information and confirm to the best of my knowledge and belief the information provided in this form and supporting documentation is true and accurate and complies with the relevant provisions of the Environment Act and Contaminated Sites Regulations. By signing below, I confirm my qualifications and liability insurance as a site professional as prescribed within the regulations.

☑ Reports and checklist/s have been provided to affected property owner.

Name (print) Jeff Faulkner, P.Geo

Professional Registration Number/Stamp 0225

Signature _____ Site Professional

Date 2025/05/12 YYYY/MM/DD

Reports Applicable to Checklist	
Report Title	**3 Digit Report ID**
Phase II Environmental Site Assessment, 116 Ruth Falls Road, Sheet Harbour, NS (October 2024)	PH2
Phase III Environmental Site Assessment, 116 Ruth Falls Road, Sheet Harbour, NS (May 2025)	PH3

Return completed form and associated documents to your local Nova Scotia Environment office.

Find office locations online novascotia.ca/nse/dept/regional-office-locations.asp or call 1-877-936-8476.

Request IR-126:

T07: C0068969, 2026 Pennsylvania Breaker Replacements

(a) How did the utility determine that the fourteen circuit breakers currently in operation pose a manageable level of risk and safety, and that only four of them require replacement at this time? Please provide any supporting analysis.

(b) How many total circuit breakers were purchased, and how many have been replaced?

(c) When did the utility first observe issues with these circuit breakers?

(d) When and how did the utility conclude that these circuit breakers required replacement? Please provide any analysis that supports this conclusion.

Response IR-126:

(a) NS Power is executing on a plan to replace Pennsylvania Breakers on the system based on a prioritized, risk analysis. This project recommends proceeding with four Pennsylvania breaker replacements in 2026. Prior Pennsylvania Breaker replacement projects are listed in the summary of related CIs section for the CI (PDF page 408 of 782). NS Power anticipates one additional project filing to complete the two remaining replacements. In the interim, until all breakers have been replaced, the breakers remain on regular monthly, annual, and out-of-service inspection intervals, and spare parts are kept on hand from previously replaced units. If a breaker fails to operate as expected, all effort is made to repair it on-site using the parts from the previously replaced units. If a breaker fails to a point that it cannot be feasibly repaired, NS Power can replace it using existing breaker inventory.

(b) A total of sixteen Pennsylvania Breakers were purchased and placed in service. At the time of this IR response, three have been replaced.

(c) Issues with these circuit breakers were first observed in 2011-2012 during their initial on-site commissioning. To confirm the breakers would function properly, the manufacturer provided on-site technical support on several occasions during the breakers' first year in service.

(d) As mentioned in part (c), NS Power worked closely with the manufacturer for the breakers' first year in service. However, despite multiple parts replacements and service visits from the manufacturer, the breakers continued to not function reliably and would sometimes fail to successfully complete a close or open operation. Further, the manufacturer ceased operations shortly after that first year, which essentially eliminated any availability of technical support or replacement parts. Thus, NS Power ultimately initiated a multi-year capital program to replace them all.

Request IR-127:

Distribution Capital Investments

D01: C0080266, New Distribution Right of Way Phase 11

The new distribution Rights-of-Way (ROW) Program was launched in 2016 as a result of recommendations made after the 2014 Tropical Storm Arthur review (M06321).

Since 2016, for overhead transmission lines (69 kV and above) that have had vegetation management under the Program, please provide the yearly data for the following in an Excel sheet, where applicable:

(a) A breakdown of total transmission lines, including voltage level, length in kilometres, span count, money spent on vegetation management, and the percentage of spans on which vegetation work was completed. Please also indicate whether the lines are subject to NERC vegetation requirements.

(b) A percentage breakdown of outage causes, along with the number of outages, their duration, and restoration times.

(c) Please list the vegetation management work completion percentages based on risk classifications such as hazard trees, customer requested, and sustainability.

(d) The annual storm budget cost specifically attributed to the vegetation portion.

Response IR-127:

(a) Please refer to. Attachment 1 (line data) and Attachment 2 (Costs). As a result of the cyber incidence, some data is unavailable at this time. NS Power's IT team is working with cyber

security experts to bring affected data sets back online, but it is uncertain at this time whether the data required to fully respond to the foregoing question will be recovered.

(b) Please refer to Attachment 3 for details of transmission outages that affected Customers due to tree contacts.

(c) This is not applicable to the Vegetation capital program as hazard trees, customer requested, and sustainability are all considered operating expenses as these are costs to either maintain the existing right-of-way, or (in the case of hazard trees) do not create or widen a ROW.

(d) NS Power does not track storm costs related to a specific type of failure mechanism. The costs would be blended into the overall storm response for labour, materials, logistics, etc.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Transmission Corridor Widening (2016 to 2025)

Line	Total Line Length (km)	Voltage (kV)	% of Line completed (2016-2024)	Vegetation Mangement Cost	NERC Vegetation Management Requirement
L-5003	13.5	69	28%	N/A	No
L-5004	12.1	69	10%	N/A	No
L-5010	0.5	69	0%	N/A	No
L-5011	9.3	69	18%	N/A	No
L-5012	10.4	69	7%	N/A	No
L-5014	10.8	69	100%	N/A	No
L-5015	19	69	80%	N/A	No
L-5016	6.7	69	67%	N/A	No
L-5017	18.4	69	63%	N/A	No
L-5019	3.4	69	60%	N/A	No
L-5020	9.2	69	56%	N/A	No
L-5021	7.2	69	59%	N/A	No
L-5022	15	69	32%	N/A	No
L-5023	1.2	69	100%	N/A	No
L-5024	4.7	69	99%	N/A	No
L-5025	30.2	69	67%	N/A	No
L-5026	47.5	69	65%	N/A	No
L-5027	104.5	69	49%	N/A	No
L-5028	29	69	86%	N/A	No
L-5029	20.2	69	74%	N/A	No
L-5030	2.9	69	95%	N/A	No
L-5031	19.8	69	96%	N/A	No
L-5032	0.8	69	0%	N/A	No
L-5033	12.2	69	14%	N/A	No
L-5035	0.8	69	59%	N/A	No
L-5036	3.4	69	95%	N/A	No
L-5037	3.7	69	19%	N/A	No
L-5039	9.52	69	5%	N/A	No
L-5040	42.3	69	99%	N/A	No
L-5041	0.6	69	55%	N/A	No
L-5042	1.9	69	0%	N/A	No
L-5044	3.8	69	95%	N/A	No
L-5046	2.7	69	43%	N/A	No
L-5047	3.1	69	95%	N/A	No
L-5048	5.5	69	78%	N/A	No
L-5049	0.5	69	100%	N/A	No
L-5050	15.9	69	53%	N/A	No
L-5053	25.7	69	78%	N/A	No
L-5054	23.4	69	50%	N/A	No
L-5055	20.8	69	69%	N/A	No
L-5056	4	69	20%	N/A	No
L-5057	2.2	69	95%	N/A	No
L-5058	39.3	69	66%	N/A	No
L-5500	12.5	69	84%	N/A	No
L-5501	7.6	69	95%	N/A	No
L-5502	6.1	69	68%	N/A	No
L-5505	11.5	69	47%	N/A	No
L-5506	8.4	69	36%	N/A	No
L-5508	1.7	69	0%	N/A	No
L-5510	71.1	69	87%	N/A	No
L-5511	31.7	69	57%	N/A	No
L-5512	6.5	69	88%	N/A	No
L-5521	4.5	69	7%	N/A	No
L-5524	35.4	69	27%	N/A	No
L-5527A	17.4	69	75%	N/A	No
L-5530	67.5	69	95%	N/A	No
L-5531	23.9	69	81%	N/A	No
L-5532	96.3	69	78%	N/A	No
L-5533	13.1	69	84%	N/A	No
L-5534	8.4	69	34%	N/A	No
L-5535	64.3	69	92%	N/A	No
L-5536	20.2	69	55%	N/A	No
L-5537	3.4	69	26%	N/A	No
L-5538	7.5	69	89%	N/A	No
L-5539	8.4	69	95%	N/A	No
L-5540	2	69	30%	N/A	No

Transmission Corridor Widening (2016 to 2025)

Line	Total Line Length (km)	Voltage (kV)	% of Line completed (2016-2024)	Vegetation Mangement Cost	NERC Vegetation Management Requirement
L-5541	14.2	69	95%	N/A	No
L-5544	6.7	69	100%	N/A	No
L-5545	5.2	69	63%	N/A	No
L-5546	12.5	69	95%	N/A	No
L-5547	19.5	69	100%	N/A	No
L-5548	17.1	69	15%	N/A	No
L-5549	11.9	69	2%	N/A	No
L-5550	33.7	69	98%	N/A	No
L-5551	9.7	69	100%	N/A	No
L-5555	15.5	69	44%	N/A	No
L-5559	38.7	69	83%	N/A	No
L-5560	6.6	69	0%	N/A	No
L-5561A	15	69	88%	N/A	No
L-5563	7.1	69	100%	N/A	No
L-5564	19.1	69	66%	N/A	No
L-5565	18.9	69	89%	N/A	No
L-5569	1.7	69	0%	N/A	No
L-5571	6.4	69	0%	N/A	No
L-5572	13.6	69	68%	N/A	No
L-5573	15.8	69	3%	N/A	No
L-5575	12.6	69	78%	N/A	No
L-5576	21.1	69	85%	N/A	No
L-5579	41.1	69	19%	N/A	No
L-5581	16.2	69	31%	N/A	No
L-6001	81.34	138	N/A	N/A	No
L-6002	88.17	138	N/A	N/A	No
L-6003	14.37	138	N/A	N/A	No
L-6004	47.38	138	N/A	N/A	No
L-6005	16.37	138	N/A	N/A	No
L-6006	41.46	138	N/A	N/A	No
L-6007	5.62	138	N/A	N/A	No
L-6008	18.05	138	N/A	N/A	No
L-6009	9.94	138	N/A	N/A	No
L-6010	16.1	138	N/A	N/A	No
L-6011	30.04	138	N/A	N/A	No
L-6012	40.48	138	N/A	N/A	No
L-6013	42.5	138	N/A	N/A	No
L-6014	4.61	138	N/A	N/A	No
L-6015	42.51	138	N/A	N/A	No
L-6016A	11.01	138	N/A	N/A	No
L-6016B	17.12	138	N/A	N/A	No
L-6020	57.4	138	N/A	N/A	No
L-6021	58.63	138	N/A	N/A	No
L-6024	111.62	138	N/A	N/A	No
L-6025	42.28	138	N/A	N/A	No
L-6033	12.22	138	N/A	N/A	No
L-6035	10.59	138	N/A	N/A	No
L-6038	5.49	138	N/A	N/A	No
L-6040	9.55	138	N/A	N/A	No
L-6042	17.1	138	N/A	N/A	No
L-6043	28.89	138	N/A	N/A	No
L-6044	8.07	138	N/A	N/A	No
L-6047	9.39	138	N/A	N/A	No
L-6048	10.3	138	N/A	N/A	No
L-6050	3.82	138	N/A	N/A	No
L-6051	27.45	138	N/A	N/A	No
L-6052	3.75	138	N/A	N/A	No
L-6053	17.72	138	N/A	N/A	No
L-6054	25.15	138	N/A	N/A	No
L-6055	6.17	138	N/A	N/A	No
L-6503	66.11	138	N/A	N/A	Yes
L-6507	21.81	138	N/A	N/A	No
L-6508	21.86	138	N/A	N/A	No
L-6510	12.49	138	N/A	N/A	No
L-6511	36.22	138	N/A	N/A	No
L-6512	2.16	138	N/A	N/A	No

Transmission Corridor Widening (2016 to 2025)

Line	Total Line Length (km)	Voltage (kV)	% of Line completed (2016-2024)	Vegetation Mangement Cost	NERC Vegetation Management Requirement
L-6514	19.93	138	N/A	N/A	No
L-6515	49.25	138	N/A	N/A	Yes
L-6516	127.19	138	N/A	N/A	No
L-6517	11.37	138	N/A	N/A	No
L-6518	11.1	138	N/A	N/A	No
L-6521	1.6	138	N/A	N/A	No
L-6523	2.11	138	N/A	N/A	No
L-6527	1.66	138	N/A	N/A	No
L-6531	41.23	138	N/A	N/A	No
L-6533	13.79	138	N/A	N/A	No
L-6534	13.84	138	N/A	N/A	No
L-6535	0	138	N/A	N/A	No
L-6536	59.17	138	N/A	N/A	No
L-6537	94.27	138	N/A	N/A	No
L-6538	35.45	138	N/A	N/A	No
L-6539	35.28	138	N/A	N/A	No
L-6543	0.2	138	N/A	N/A	No
L-6545	45.16	138	N/A	N/A	No
L-6548	0.46	138	N/A	N/A	No
L-6549	45.21	138	N/A	N/A	No
L-6551	12.83	138	N/A	N/A	No
L-6552	18.92	138	N/A	N/A	Yes
L-6613	65	138	N/A	N/A	No
L-7001	73.4	230	N/A	N/A	Yes
L-7002	75.05	230	N/A	N/A	Yes
L-7003	159.95	230	N/A	N/A	Yes
L-7004	130.34	230	N/A	N/A	Yes
L-7005	159.5	230	N/A	N/A	Yes
L-7008	85.43	230	N/A	N/A	Yes
L-7009	92.45	230	N/A	N/A	Yes
L-7011	102.93	230	N/A	N/A	Yes
L-7012	103	230	N/A	N/A	Yes
L-7014	36.86	230	N/A	N/A	Yes
L-7015	46.86	230	N/A	N/A	Yes
L-7018	73.81	230	N/A	N/A	Yes
L-7019	29.59	230	N/A	N/A	Yes
L-7021	36.42	230	N/A	N/A	Yes
L-7022	36.46	230	N/A	N/A	Yes
L-8001	120.83	345	N/A	N/A	Yes
L-8002	105.86	345	N/A	N/A	Yes
L-8003	54.42	345	N/A	N/A	Yes
L-8004	209.82	345	N/A	N/A	Yes

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Transmission Vegetation Management Costs from 2016 to 2025 by Voltage.

	Year						
Voltage (kV)	2016	2018	2019	2020	2022	2023	2025
69	$ 5,419,868.00	$ 5,609,478.00	$ 5,446,286.00	$ 2,379,540.00	$ 4,588,800.00	$ 5,388,495.00	$ -
138 /230/345	$ 585,000.00	$ 596,037.00	$ 715,518.00	$ 505,508.00	$ 591,795.00	$ 699,362.00	$ 2,822,880.00

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Year	Line Number	Interruption Count	BES Duration (Min)	Customer Interruptions	Customer Hours of Interruption
2016	L-5053	1	1,307.83	5,286	7,500.58
2016	L-5055	2	2,781.00	1,736	3,340.95
2016	L-5512	1	930.83	1,788	40,259.80
2016	L-5532	2	364.00	5,089	12,049.57
2016	L-5535	1	1,500.90	864	1,165.05
2016	L-5539	1	252.00	5,255	7,250.00
2016	L-5541	1	2.00	5	0.17
2016	L-5547	1	286.18	1,990	8,917.70
2016	L-6539	1	8.00	3,450	516.00
2017	L-5028	1	274.00	2,604	11,891.60
2017	L-5031	1	236.68	2,127	8,393.15
2017	L-5505	1	576.00	300	2,880.00
2017	L-5536	1	1,803.00	1,699	3,567.90
2017	L-5547	2	465.38	3,893	15,486.91
2018	L-5031	1	303.95	2,139	10,835.82
2018	L-5040	1	11.92	4,426	879.30
2018	L-5532	1	174.67	2,174	6,328.88
2018	L-5533	1	221.45	3,326	12,275.71
2018	L-5541	1	1,409.18	4	93.95
2018	L-5544	1	343.00	17	97.18
2018	L-5546	1	43.45	1,982	1,435.30
2018	L-5547	1	529.52	1,909	16,847.57
2018	L-5549	1	445.33	2,153	15,979.93
2018	L-5561A	1	279.85	4,037	18,829.24
2019	L-5011	1	8,091.12	9,393	204,637.60
2019	L-5015	2	2,316.25	17,898	131,622.65
2019	L-5016	1	989.48	1	2.26
2019	L-5017	1	1,736.83	5,320	139,399.80
2019	L-5026	1	2,953.27	6,044	297,492.70
2019	L-5027	2	5,305.80	8,686	236,989.51
2019	L-5029	1	892.68	1,133	16,856.80
2019	L-5501	1	2,138.38	6,052	228,764.44
2019	L-5505	1	2,470.33	304	12,516.30
2019	L-5512	1	2,282.47	2,818	107,151.80
2019	L-5530	1	2,471.37	3,733	149,606.30
2019	L-5532	1	4,616.45	2,673	159,204.70
2019	L-5533	2	1,390.32	9,789	113,424.32
2019	L-5535	2	3,992.13	3,634	28,271.80
2019	L-5538	1	391.45	6,105	39,830.10
2019	L-5544	1	4,412.12	17	1,250.10
2019	L-5545	1	1,194.88	13,842	275,658.90
2019	L-5564	1	1,060.10	1,358	23,993.60
2020	L-5532	1	110.93	2,661	4,908.45
2020	L-5544	1	750.78	17	212.72
2020	L-6536	1	212.43	7,285	13,080.22
2020	L-6613	1	373.42	3,960	5,665.00
2021	L-5536	2	8,660.72	3,581	2,645.67
2022	L-5003	2	5,102.39	1,158	18,660.12
2022	L-5026	1	112.83	6,134	9,492.47
2022	L-5028	2	1,306.08	5,547	60,940.81
2022	L-5029	1	941.00	1,120	68,133.39
2022	L-5040	1	4,212.72	7,218	1,135,189.58
2022	L-5501	2	4,322.46	36,407	951,607.67

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Year	Line Number	Interruption Count	BES Duration (Min)	Customer Interruptions	Customer Hours of Interruption
2022	L-5532	1	216.77	2,765	6,923.70
2022	L-5533	1	91.87	1,084	1,657.44
2022	L-5535	1	122.60	944	1,917.12
2022	L-5541	1	54.85	4	2.57
2022	L-5561A	1	2,562.87	2,692	410,060.96
2022	L-6537	1	142.27	10,845	25,615.89
2023	L-5026	1	1,161.95	3,166	29,302.62
2023	L-5027	1	43.95	6,297	4,590.51
2023	L-5547	1	724.23	1,982	23,892.14
2023	L-6002	1	107.33	10,169	18,164.68
2023	L-6536	1	1,448.65	4,870	14,600.26
2024	L-5011	1	6.77	18,086	2,025.61
2024	L-5535	1	1,551.72	968	2,913.14
2024	L-5539	1	64.22	730	781.83
2024	L-5544	1	776.58	18	226.89
2025	L-5508	1	160.00	1	2.70

Request IR-128:

Distribution Capital Investments

D01: C0080266, New Distribution Right of Way Phase 11

Since 2016, for primary overhead distribution lines that have had vegetation management under the Program, please provide the yearly data for the following in an Excel sheet, where applicable:

(a) A breakdown of total primary overhead distribution lines, including voltage level, length in kilometres, span count, money spent on vegetation management, urban or rural classification (or other applicable categories), and the percentage of spans on which vegetation work was completed.

(b) A percentage breakdown of outage causes, along with the number of outages, their duration, and restoration times.

(c) Please list the vegetation management work completion percentages based on risk classifications such as hazard trees, customer requested, and sustainability.

(d) The annual storm budget cost specifically attributed to the vegetation portion.

Response IR-128:

(a) Due to the cyber incident, vegetation management records are only available from 2018 onward. NS Power does not explicitly classify vegetation management work as rural or urban. All primary overhead distribution lines total approximately 28,229 km and have voltages between 4kV and 25kV. Please refer to the table below for a summary of all capital

vegetation management work by spans complete, km complete, and investment by year since 2018.

Table 1 . Distribution Capital Widening Data (2019-2025)

Year	D010 and New ROW Spend	Spans Complete	Kilometers Complete	% of System
2018	$12,906,941	2880	160	0.6
2019	$8,155,355	3582	199	0.7
2020	$7,558,203	2988	166	0.6
2021	$9,790,894	5310	295	1.1
2022	$10,425,938	4986	277	1.0
2023	$15,842,568	5094	283	1.0
2024	$30,862,374	5724	318	1.1
2025	$30,451,009	4609	256	0.9

(b) Please refer to Attachment 1 for the All-Events Annual Outage Data from 2018–2025. The annual results include all outage events from 2018–2025 for every feeder in all phases of the vegetation management program, regardless of when each feeder was added to the program.

(c) Due to the cyber incident NS Power is not able to provide data regarding vegetation management work completion percentages based on risk classifications such as hazard trees, customer requested, and sustainability, but hope to recover this data in 2026.

(d) The annual storm budget is not broken out by work type. It's based on historical averages at the total level, therefore no specific vegetation management budget amount for storm response can be shown. It should be noted that no costs included the New Distribution ROW program is related to storm response.

		Year			
	CEA Description	2018	2019	2020	2021
% Total Customer Hours of Interrupts (CHI)	Adverse Environment	0.6%	0.4%	0.2%	0.3%
	Adverse Weather	36.3%	57.3%	23.7%	23.6%
	Defective Equipment	7.9%	4.0%	12.7%	13.9%
	Foreign Interference	2.8%	1.0%	5.7%	8.6%
	Human Element	0.1%	0.0%	0.0%	0.1%
	Lightning	0.0%	0.3%	1.2%	2.2%
	Loss of Supply	17.1%	11.0%	16.2%	15.5%
	Scheduled Outage	1.0%	0.6%	3.1%	2.4%
	Tree Contacts	27.0%	24.4%	31.9%	29.2%
	Unknown	7.2%	1.1%	5.3%	4.2%
% Total Customer Interruptions (CI)	Adverse Environment	1.2%	0.8%	0.2%	0.9%
	Adverse Weather	25.3%	28.1%	16.2%	13.8%
	Defective Equipment	14.0%	12.9%	16.8%	14.7%
	Foreign Interference	4.4%	3.9%	6.7%	7.8%
	Human Element	0.0%	0.0%	0.3%	0.1%
	Lightning	0.1%	1.5%	1.2%	2.3%
	Loss of Supply	20.9%	18.6%	23.9%	23.2%
	Scheduled Outage	2.9%	4.7%	5.6%	6.0%
	Tree Contacts	24.4%	25.4%	23.9%	25.8%
	Unknown	6.9%	4.0%	5.2%	5.4%
% Total Event Count	Adverse Environment	0.8%	0.4%	0.7%	0.5%
	Adverse Weather	17.1%	38.2%	11.0%	9.4%
	Defective Equipment	22.8%	16.0%	30.0%	26.0%
	Foreign Interference	13.1%	7.4%	15.1%	15.0%
	Human Element	0.1%	0.1%	0.2%	0.3%
	Lightning	1.3%	2.1%	3.9%	4.2%
	Loss of Supply	1.6%	1.5%	1.1%	1.2%
	Scheduled Outage	1.6%	1.4%	2.9%	3.3%
	Tree Contacts	30.2%	25.4%	24.2%	23.7%
	Unknown	11.4%	7.5%	10.8%	16.4%
Event Count	Adverse Environment	67	50	48	32
	Adverse Weather	1,417	4,522	727	617
	Defective Equipment	1,881	1,899	1,973	1,714
	Foreign Interference	1,080	871	995	991
	Human Element	11	11	12	19
	Lightning	104	248	259	280
	Loss of Supply	132	181	74	79
	Scheduled Outage	136	167	194	219
	Tree Contacts	2,497	3,003	1,592	1,562
	Unknown	941	883	712	1,080

		Year			
	CEA Description	2022	2023	2024	2025
% Total Customer Hours of Interrupts (CHI)	Adverse Environment	0.1%	7.6%	0.5%	0.0%
	Adverse Weather	47.3%	29.8%	14.6%	10.6%
	Defective Equipment	3.2%	4.4%	15.0%	7.9%
	Foreign Interference	0.7%	2.1%	9.7%	4.1%
	Human Element	0.0%	0.0%	0.0%	0.0%
	Lightning	0.2%	3.5%	1.0%	0.3%
	Loss of Supply	10.0%	10.7%	18.0%	21.8%
	Scheduled Outage	0.4%	1.5%	9.5%	8.0%
	Tree Contacts	37.3%	36.9%	27.7%	42.6%
	Unknown	0.8%	3.4%	4.0%	4.7%
% Total Customer Interruptions (CI)	Adverse Environment	0.2%	0.7%	0.9%	0.0%
	Adverse Weather	29.4%	18.5%	6.3%	7.3%
	Defective Equipment	11.8%	11.0%	15.1%	9.8%
	Foreign Interference	4.1%	5.1%	9.7%	6.4%
	Human Element	0.2%	0.1%	0.1%	0.0%
	Lightning	1.0%	3.9%	1.0%	0.2%
	Loss of Supply	16.3%	19.2%	26.9%	22.3%
	Scheduled Outage	2.7%	5.7%	13.9%	18.4%
	Tree Contacts	31.1%	29.1%	22.0%	29.1%
	Unknown	3.2%	6.6%	4.1%	6.5%
% Total Event Count	Adverse Environment	0.3%	1.0%	0.7%	0.7%
	Adverse Weather	34.6%	20.3%	9.2%	13.9%
	Defective Equipment	11.7%	14.3%	19.8%	15.0%
	Foreign Interference	6.4%	8.9%	15.5%	11.2%
	Human Element	0.1%	0.2%	0.2%	0.2%
	Lightning	0.9%	6.7%	3.7%	1.6%
	Loss of Supply	2.1%	1.4%	1.6%	1.4%
	Scheduled Outage	1.2%	6.7%	12.7%	11.2%
	Tree Contacts	33.2%	29.2%	20.3%	22.6%
	Unknown	9.5%	11.3%	16.3%	22.4%
Event Count	Adverse Environment	50	113	44	50
	Adverse Weather	5,608	2,227	600	1,044
	Defective Equipment	1,892	1,562	1,292	1,121
	Foreign Interference	1,034	980	1,012	836
	Human Element	18	18	13	14
	Lightning	149	730	240	118
	Loss of Supply	345	156	102	105
	Scheduled Outage	194	738	830	836
	Tree Contacts	5,375	3,193	1,322	1,690
	Unknown	1,537	1,236	1,063	1,675

Request IR-129:

Distribution Capital Investments

D01: C0080266, New Distribution Right of Way Phase 11

Page 408 states "Over the last five years (2020-2024), tree contacts have caused over 19,200 outage events, 2.2 million customer interruptions and 19.2 million customer hours of interruption, which represents 24 percent, 22 percent, and 31 percent of these totals, respectively." Please provide a breakdown of the above statistics for outage events, customer interruptions and customer hours of interruption, along with their respective contribution to the totals for each year from 2020 to 2024.

(a) For the targeted circuits included in Phase 11, please provide the following for each year from 2020 to 2024:

(i) Statistics for outage events, customer interruptions and customer hours of interruption, along with their respective contribution to the totals.

(ii) Current SAIDI, SAIFI, CKADI and CKAFI.

(iii) Are there any branch circuits of the feeder that have a higher SAIFI than the overall feeder SAIFI?

Response IR-129:

Please refer to the table below for the breakdown of tree contact contribution to 2020-2024 annual outage events, customer interruptions and customer hours of interruptions.

Year	Event Count	CI	CHI	% of Total Events	% of Total CI	% of Total CHI
2020	2,432	287,901	989,488.10	21%	21%	29%
2021	2,173	240,262	680,498.57	19%	18%	23%
2022	8,006	794,630	12,761,769.24	30%	26%	32%
2023	4,709	660,773	4,091,891.79	25%	25%	33%
2024	1,943	259,071	770,960.43	17%	17%	22%
TOTAL	**19,263**	**2,242,637**	**19,294,608.13**	**24%**	**22%**	**31%**

(a)

(i) Please refer to Attachment 1 for tree-related outage statistics for the Phase 11 targeted circuits and their impact to overall annual totals for 2020-2025.

(ii) Please refer to Attachment 2 for All Events 2025 SAIFI and SAIDI as well as the 2025 CKAIFI and CKAIDI for the above circuits.

(iii) Yes. By definition, it is expected that some branch circuits will exhibit a higher CKAIFI than the overall feeder CKAIFI, as the feeder value represents an average across all sections.

2026 ACE Plan NSEB IR-129 Attachment 1 has been filed electronically.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

ALL EVENTS AND CAUSES INCLUDED

Source	2025 CKAIFI	2025 CKAIDI
100C-422	3.88	6.26
102W-311	7.12	10
137H-411	2.48	1.22
137H-412	2.9	3.64
137H-414	0.94	0.23
15N-401	5.94	25.08
22C-403	1.34	2.12
22C-404	4.05	8.41
23W-301	0.28	0.74
24C-442	5.58	12.43
25W-302	4.82	16.17
30N-412	6.73	25.96
3S-308	1.04	1.81
48H-301	4.07	9.18
4N-313	6.29	37.3
57C-417	1.14	10.03
57C-426	5.29	27.95
57S-401	6.72	24.31
57S-402	3.25	6.98
57W-401	5.43	29.14
57W-402	6.31	29.31
62N-413	2.75	11.82
63V-313	2.21	7.4
74N-412	2.32	7.43
76V-301	9.25	43.85
77V-401	2.83	3.98
78W-301	4.1	18.15
78W-302	3.5	15.34
80W-301	2.3	4.35
81S-305	4.9	15.44
85S-401	7.49	23.02
91W-411	6.24	23.21
92W-302	3.34	5.8
96H-412	4.07	18.89

	2025 SAIFI	2025 SAIDI
System	2.92	10.19

Request IR-130:

Distribution Capital Investments

D01: C0080266, New Distribution Right of Way Phase 11

What is the expected improvement in SAIDI and SAIFI as a result of completing the Phase 11 work?

Response IR-130:

After completing Phase 11, the expectation is to observe a decline in both SAIDI and SAIFI over time due to tree caused outages. As per the 5-Year Reliability Plan, the goal is to reduce overall SAIDI by 20 percent and achieve performance standards SAIFI of 2.05 by the end of 2029. The expected SAIDI reduction as a result of vegetation management work is a range of 0.7 hours to 1.25 hours improvement by the end of 2029.

Request IR-131:

Distribution Capital Investments

D01: C0080266, New Distribution Right of Way Phase 11

What is the expected improvement in CKADI and CKAFI for each of the related circuits as a result of completing the Phase 11 work?

Response IR-131:

After completing Phase 11 the expectation is to observe a decline in both CKADI and CKAFI over time from tree-caused outages. It is difficult to quantify the expected improvement given the numerous other variables that contribute to these Metrics. Please refer to NSEB IR-130.

Request IR-132:

Distribution Capital Investments

D01: C0080266, New Distribution Right of Way Phase 11

Board staff analysis of Attachment 1 reveals that the utility worked on 71 feeders, totaling 753 km. Out of these 71 feeders, 23 feeders, totaling 215 km, maintained, or worsened, their original ranking even after vegetation mitigation work. Please provide the cost of vegetation management work performed in 2024 on the 21 feeders described above.

(a) Please explain why a feeder's condition score would worsen after completion of 2024 vegetation management work.

(b) On average, it appears that the result of the 2024 vegetation management work improved condition ratings by approximately 35%. By how much does NS Power believe this result reduce its SAIDI and SAIDFI performance metrics?

(c) Please provide the total cost to complete the 2024 vegetation management work outlined in the Attachment.

Response IR-132:

Attachment 1 includes all capital vegetation management work that exceeded 5km on an individual feeder. This cutoff was put in place so as not to show updates on feeders that had small sections of work completed, therefore would not be expected to have a material impact on the overall condition of the feeder. The total kilometres completed in 2024 on the capital program was 940km as a total cost of $30,862,374.

(a) Of the 71 feeders listed, two had their condition worsen. In both cases, a relatively small amount of vegetation management work was completed (6km in both instances) which represent a small percentage of the overall feeder. While the portion of the feeder that had work completed would have seen a significant improvement in vegetation condition, the remaining sections of the feeder would have seen their condition worsen, outweighing the improvements on the 6km. The feeder condition metric utilized in this application utilized historical work completed, with the condition score being based percentage of the feeder than had vegetation management work completed in a specific time period (i.e., if work on 20% of the feeder went from being completed 7 years ago to 8 years ago, that would indicate a worse vegetation condition score).

(b) Please refer to NSEB IR-130.

(c) The exact cost for each of the feeders in Attachment 1 is not readily available due to the cyber incident. This work would be similar to all of the work within the program, therefore an estimate of the cost would be $24.7M based on 80% of the kilometres completed being included in Attachment 1.

Request IR-133:

Distribution Capital Investments

D01: C0080266, New Distribution Right of Way Phase 11

Please provide a status and cost update of C0061521 - New Distribution Rights-of-Way Phase 10.

(a) How many kilometers of New Distribution Rights-of-Way work have been completed to date for Phase 10?

(b) How many kilometers of New Distribution Rights-of-Way work are projected to be completed in total for Phase 10?

(c) Please explain any discrepancy with this amount and the amount identified in NS Power's capital application under Matter M11921.

(d) What is the expected final unit cost per km for "contracts" for Phase 10?

Response IR-133:

(a-d) Please refer to the table below, which shows the planned areas for Phase 10, with what has been completed for 2025. The Phase 10 contracts cost for 2025 is $18,432,930. Including work that took place in 2024 the total project spend is $19,167,403. 2025 cost per span, based on the 256 kilometers completed equates to $3,067/span or $55,212/km. An additional 31 kilometers of work is expected to be completed in phase 10 for a total of 287 kilometres. The amount included in the Phase 11 application is lower as NS Power expected to reduce that cost per kilometre in 2026. This is expected to naturally occur due to 2025 experiencing significant costs to monitor wildfire risks at the end of each workday,

which slowed down productivity. A continued focus on contractor efficiency is also expected to help reduce the unit cost.

Feeder	Geographic Location	Plan KM	Actual Phase 10 KM Complete	Change Description
100C-421	Havre Boucher	15	23	
103W-312	Borgols Point	15	0	Removed due to priority shift.
113H-433	Upper Lawrencetown	10	0	Removed due to priority shift.
11S-302	Blacketts Lake	5	0	Removed due to priority shift.
11S-411	Ben Eoin/Eskasoni	15	0	Removed due to priority shift.
16N-301	Stewiacke	5	1	
16W-301	Hebron	10	0	Removed due to priority shift.
16W-302	Lake George	5	8	
1V-443	Vaughn	20	13	
1W-411	Indian Gardens	2	2	
24C-442	Canso	10	0	Removed due to priority shift.
25W-301	Upper Ohio	10	0	Removed due to priority shift.
25W-302	Roseway (XC)	5	2	
30N-412	River Hebert	10	12	
37N-411	Economy	5	0	Removed due to priority shift.
37N-412	Dilligent River, Parrsboro	10	0	Removed due to priority shift.
3S-403	Boularderie/Pt. Aconi	10	19	
46W-303	White Point	5	0	Removed due to priority shift.
4C-430	Cape George	5	30	
50N-410	French River	5	8	
55V-314	Alyesford Mountain	10	1	
56N-414	Scotsburn	10	0	Removed due to priority shift.
57S-401	Little Lorraine	10	0	Removed due to priority shift.
57S-402	Trout Brook	15	0	Removed due to priority shift.
57W-401	South Brookfield	15	0	Removed due to priority shift.
57W-402	Caledonia	5	0	Removed due to priority shift.
58C-403	Inverness	10	6	
59C-402	Lake Uist	10	1	
62N-413	Sherbrooke	10	25	
70V-311	Bridgetown	10	0	Removed due to priority shift.
70W-311	Conquerall Mills	12	0	Removed due to priority shift.
70W-313	Highway 332	20	0	Removed due to priority shift.

Feeder	Geographic Location	Plan KM	Actual Phase 10 KM Complete	Change Description
73W-411	Stanburne	60	17	
76V-301	Maitland Bridge	12	0	Removed due to priority shift.
77V-401	Gulliver's Cove (512V-311)	5	0	Removed due to priority shift.
80W-301	Feltzen South	15	0	Removed due to priority shift.
82V-401	Shubenacadie	12	0	Removed due to priority shift.
85S-401	Red River	5	5	
87W-312	Fox Point (Hwy 329)	20	0	Removed due to priority shift.
88H-401	Musquodobit	12	0	Removed due to priority shift.
88H-402	Caribou Mines	12	0	Removed due to priority shift.
91W-411	Molega Lake	12	0	Removed due to priority shift.
93V-313	Meteghan Station/Mavillette	12	0	Removed due to priority shift.
96H-411	Sheet Harbour	12	0	Removed due to priority shift.
96H-412	Sheet Harbour/Liscomb	6	0	Removed due to priority shift.
100C-422	Mulgrave	0	4	Added. Reliability.
101W-411	Brooklyn	0	1	Carry over from previous year.
104S-313	Baddeck	0	11	Added. Reliability.
126H-311	Porters Lake	0	2	Added. Wildfire risk.
126H-313	Porters Lake	0	1	Added. Wildfire risk.
126H-314	Porters Lake	0	1	Added. Wildfire risk.
16V-314	Weymouth	0	1	Added.
1N-402	Truro	0	1	Added.
22C-402	Riverside	0	3	Added.
22N-403	Tidnish	0	1	Carry over from previous year.
24C-443	Guysborough	0	3	Carry over from previous year.
30N-411	Maccan	0	2	Added.
46W-301	Granite Village	0	2	Added.
4C-432	Loch Katrine	0	2	Added.
50W-412	Port Medway	0	8	Carry over from previous year.
58C-405	Inverness	0	6	Added.
63V-312	Bishop Mountain	0	3	Added. Wildfire risk.
74N-412	Collingwood	0	4	Carry over from previous year.
77V-301	Digby	0	1	Added.
77V-302	Digby	0	4	Added.
78W-321	Maders Cove	0	3	Added.

Feeder	Geographic Location	Plan KM	Actual Phase 10 KM Complete	Change Description
81N-412	Wentworth	0	9	Added.
82V-402	Fall River	0	9	Added.
MISC	Provincial	0	1	Added.
	Total	**509**	**256**	

1

Request IR-134:

Distribution Capital Investments

D01: C0080266, New Distribution Right of Way Phase 11

The estimated unit cost estimate for C0061521 - New Distribution Rights-of-Way Phase 10 was $34,200 per km (page 6 of 8 of NS Power's capital application in M11921). In the current application for Phase 11, the unit estimate cost is $43,200 per km. Please explain the reasons for this 26% increase in unit cost complete with supporting information.

Response IR-134:

The observed cost/kilometer has increased due to a variety of reasons and is reflected in Phase 11. Contractor operating costs have increased, including fuel surcharges.

In addition, to reduce the number of fall-in threats, NS Power has increased its focus on removing more trees outside the designated right of way. Some of the trees have been damaged from previous storms or have species-specific characteristics that make them prone to windthrow/failure. The number of trees removed are included in the costs of widening the ROW and would account for an uptick in the observed cost per kilometer. It is very difficult to know in advance how many of these trees will be encountered, since most are discovered while work is in progress and are completed while resources are already on site.

The 26% increase is reasonable when cumulatively considering the reasons indicated above.

Request IR-135:

Distribution Capital Investments

D01: C0080266, New Distribution Right of Way Phase 11

Please provide NS Power's estimated annual reduction of long-term operational costs resulting from completion of the widening program.

Response IR-135:

As discussed in M11921 (C0062521 - New Distribution Rights-of-Way Phase 10) IR-8, reductions in long-term operating costs resulting from Phase 11 and subsequent phases of the program are reductions compared to what costs would have been if no work had been completed, not necessarily reductions to current operating costs. As previously discussed, with the increasing frequency of higher winds and severe weather, outage frequency could stay consistent with historical data; however, if this work were to not be completed, that frequency would increase. The operational savings were included as an estimate in the original application and can still be assumed to be the best estimate for these costs. The main driver of this project is to avoid tree caused outages for improved reliability, and any cost savings achieved through that should be considered as an additional benefit. The original estimate for avoided storm costs for the years 2026-2034 is as follows:

Year	Avoided OM&G ($)
2026	1,878,737
2027	2,123,374
2028	2,247,527
2029	2,281,240
2030	2,315,459

Year	Avoided OM&G ($)
2031	2,350,191
2032	2,385,444
2033	2,421,225
2034	2,457,544

1

Request IR-136:

Distribution Capital Investments

D01: C0080266, New Distribution Right of Way Phase 11

What is the average actual "contracts" cost per km achieved to date for the new distribution right-of-way program?

Response IR-136:

Phase 11 started January 1, 2026, therefore no actual "contracts" costs per kilometer are available at this time. Currently, the contract cost estimate to complete a kilometer of new ROW is $46,800, based on historical actuals achieved in the program.

Request IR-137:

Distribution Capital Investments

D01: C0080266, New Distribution Right of Way Phase 11

(a) Please explain if any analysis has been carried out to reduce the propagation of outages using modern automation technologies such as sectionalizers, automatic reclosers, or any other suitable devices.

(b) In Matter M06321, the Board approved in principle a 10-year Vegetation Management Program estimated to cost approximately $100M, from 2016-2025. Please explain what, if any, analysis the utility has conducted demonstrating that vegetation management has improved the overall reliability and resilience of the NS Power electrical distribution system. Please provide any supporting documentation.

(c) Please explain how the Board should assess the effectiveness of the 10-year Vegetation Management Plan when addressing the further vegetation management plans proposed by NS Power.

(d) The Board notes that NS Power's Five-Year Reliability Plan is being reviewed in Matter M12558. Should the Board await the results of this review before approving further large-scale vegetation management investments? If not, why not?

Response IR-137:

(a) Yes. NS Power has performed detailed engineering and reliability analyses to justify investments in sectionalizers, automatic reclosers, and advanced distribution automation technologies to limit outage propagation by sectionalizing feeders and enabling automatic isolation and restoration. The strategic application of such protection technologies is

assessed as one set of risk mitigation measures available to Asset Strategy Committees when developing mitigation plans. Ongoing and planned deployments in projects such as including remote connectivity to downline reclosers (up to 28 in 2025/2026), PCB downline device replacements, and FLISR/self-healing systems to reduce outage propagation.

(b) Measuring the effectiveness of the 10-year vegetation management program is demonstrated by the improvement in the condition rating of the feeders where work has been completed. For example, in 2025, 71 feeders had work completed with all areas worked on seeing notable improvements in condition ratings. NS Power has not conducted specific quantitative analysis isolating the impact of the M06321-approved 10-year Vegetation Management Program (2016-2025, ~$100 million) on overall system reliability metrics like SAIDI or SAIFI, as utility-wide attribution is challenging due to multiple factors influencing performance.

(c) The positive impact on the safe operation of NS Power's energy delivery system is first and foremost. The vegetation management program is designed to incorporate all available tools and methods to create and maintain separation between conductors and trees and provide improved access to the right of way for maintenance and restoration, as required. Measuring the success of the program should be considered from a risk point of view. Creating adequate vegetation separation will reduce the risk of an outage caused by vegetation in conflict with energized conductors. Continuing to target off right-of-way hazard trees will also continue to reduce risks of outages caused by fall ins. All future proposed vegetation plans will continue to focus on reducing risk and providing safe and reliable service for customers.

(d) No; in NS Power's view, it is imperative to continue to improve the condition of the vegetation within and adjacent to the rights-of-way across the province, regardless of the outcome of the review of the Five-Year Reliability Plan. As detailed in Section 11.1.4 of the 2026 ACE Plan and Section 2.0 of the Five-Year Reliability Plan update, tree contacts

continue to be one of the leading causes of outages across the system and are the leading cause during weather events. As these vegetation initiatives directly address the ongoing risks associated with these outage events, delaying this work would significantly impact NS Power's ability to reduce outages for customers and achieve the overall goal of achieving performance standards SAIDI.

Request IR-138:

Distribution Capital Investments

D01: C0080266, New Distribution Right of Way Phase 11

The application notes that Phase 11 will be influenced by vegetation condition data derived from Satellite Imagery and artificial intelligence. This data will allow NS Power to be better informed on the updated vegetative condition information, leading to an improved prioritization process on what feeders require work ahead of others.

(a) Please provide a cost benefit analysis demonstrating that the costs of satellite imagery and artificial intelligence will pay for itself.

Response IR-138:

(a) There was no formal cost benefit analysis performed as there are no viable alternatives to this approach to realize a comprehensive and accurate vegetation assessment without taking significantly more time for individuals to assess all 28,000 kilometers of the distribution system, while also not having the capability to produce the detailed and accurate measurements that this technology can. Further, through NS Power's relationships with other utilities and the Company's engagement with CEATI, NS Power has had conversations with other utilities that have observed a measurable improvement in reliability after implementation compared to previous vegetation management methodologies. NS Power's use of satellite imagery and analysis technology to inform the overall vegetation management strategy was not pursued as a cost savings opportunity. The value lies in improving the precision and effectiveness of NS Power's vegetation management program by understanding the areas with the highest risk of tree contracts, therefore improving reliability in those targeted areas.

This technology provides a province-wide, up-to-date assessment of vegetation encroachment and condition, enabling NS Power to more accurately identify the locations where vegetation poses the highest risk to system reliability. By improving prioritization, NS Power can deploy vegetation management resources more strategically and achieve a higher-quality, more cost-effective program than would be possible using traditional methods alone.

This enhanced targeting supports the overall objectives of the Five-Year Reliability Plan, including the goal of reducing SAIDI by 20% by the end of 2029 and to help ensure that vegetation management work is focused on the areas where it will produce the greatest reliability benefit.

Request IR-139:

D02 C0080104 36V-303 Baxter's Harbour Rd Reconductor Phase 1

Please explain why this project cost significantly more than CI C0075168 16W-301G-Short Beach Reconductor $672,641, CI C0043230 65V-301- Nictaux West Reconductor $286,340 and CI C0031107 55V-314G- Aylesford East Reconductor $363,650.

Response IR-139:

36V-303 Baxter's Harbour Rd Reconductor Phase 1 includes the reconductoring of 5.28 kilometres of overhead line as well as pole replacements as outlined in the submission. As a comparison, 16W-301G Short Beach Reconductor is approximately 2.6 kilometres, 55V-314G Aylesford East Reconductor was 1.34 kilometres and 65V-301 Nictaux West Reconductor was 2.5 kilometres and was completed in early 2024.

Request IR-140:

D02 C0080104 36V-303 Baxter's Harbour Rd Reconductor Phase 1

Please describe how the budget for 'travel expense' was estimated.

Response IR-140:

The travel expense budget was calculated by reviewing the project location in relation to the nearest NS Power depot with consideration for the project's total expected duration. The travel cost estimate provides an allowance for the expected travel expenses that will occur for NS Power's project manager, engineering, and design-scoping.

Request IR-141:

D03: C0080612 57C-426H Melrose Reconductor and Line Extension Phase 1

Please explain why the estimated costs of this project is about 50% more than CI C0070646 57C-425H Stillwater Phase Extension.

Response IR-141:

The 57C-426H Melrose Reconductor and Line Extension Phase 1 project includes both reconductoring a portion of the existing line and construction of a new line section. In contrast, The Stillwater Phase Extension project has a smaller overall scope consisting of adding a crossarm and two insulators at each pole as well as two phase conductors for the 3.3 kilometre length of the project.

The additional materials and labour associated with reconductoring and new line construction contribute to the higher estimated cost of the Melrose project.

Request IR-142:

D03: C0080612 57C-426H Melrose Reconductor and Line Extension Phase 1

In reference to the Capital Plan Detailed Estimates:

(a) Why does NS Power consider that easements will be required for this project, but not for CI C0080266 New Distribution Right of Way Phase 11?

(b) Why is vegetation management listed under this capital project and not assigned to other capital expenditures?

Response IR-142:

(a) Easements are required when installing poles and anchors outside of the Public Works right-of-way to allow NS Power the right to install and maintain infrastructure on customer owned property. In contrast, work completed under the New Distribution Right of Way program that falls outside the current Public Works right of way is all done via public permission, which has proven very successful over the 10 years that the program has been active. Where there is no need to potentially return to the widened section of a ROW to complete maintenance, in the way that is required if infrastructure like poles and conductor are in place, completing the vegetation management work without an easement both reduces the cost and speed of the project.

(b) The Melrose Reconductor and Line Extension project requires tree clearing to create a right of way for the installation of new poles and associated equipment. In some cases, line upgrades can proceed without additional vegetation management work. Each project/site is evaluated to determine whether work can proceed without additional tree trimming.

Request IR-143:

General Plant Capital Investments

GP01 C0080111, 2026 RTU Deployment

(a) Is this project a continuation of C0051815, Remote Terminal Unit (RTU) Replacements Program, Phase 6 mentioned in ACE 2025, which involves replacing 14 of the 74 RTUs that will have been replaced?

(b) Please provide a breakdown of the internal and external labour tasks, along with the allocated hours required to replace a single RTU in this project.

(c) Please provide a list of all substations and locations as part of this project, along with their peak load and the number of customers they serve.

(d) Do the selected substations have any existing communication systems? If yes, please provide their installation dates along with the system type.

(e) Why are there test equipment and tools included in this project and in earlier phases of the RTU replacement? What is their expected life?

(f) Will this project be completed by a contractor or by internal resources? Please provide a cost comparison demonstrating that this approach is in the best interest of ratepayers.

Response IR-143:

(a) No. CI C0051815 – RTU Replacements Phase 6 focuses on the replacement of existing RTUs at substations where RTU infrastructure already exists, while this project involves deploying RTUs to substations that currently do not have existing RTUs or infrastructure.

(b) The scope of this project involves deployment of new RTUs and telecom to substations that do not have existing RTUs. Internal labour includes engineering, drafting, system maintenance technicians, telecom field technicians, electrical technologists, power line technicians, RTU technician and project management, and the work is performed in parallel across multiple sites over the life of the project. Please refer to the table below for the estimated average hours per RTU for the internal labour categories identified for the project:

Regular Labour	Per Day	Quantity	Hrs/Day	Total Hrs	Avg Hrs/RTU
Telecom Field Technician	PD	54	8	428	20
Engineering	PD	1,437	7	10,059	479
Drafting	PD	189	7	1,323	63
Power Line Technician	PD	84	8	672	32
Electrical Technologist	PD	315	7	2,205	105
System Maintenance Technician	PD	578	8	4,620	220
Project Manager	PD	543	7	3,800	181
Term Labour					
RTU Technician	PD	630	8	5,040	240
Overtime Labour					
System Maintenance Electrician	PD	24	8	195	9
Telecom Field Technician	PD	13	8	106	5

The external labour categories include electrical design technologist, telecom construction (i.e. tower and rigging contractors), civil construction, and tower analysis consulting, which are delivered under contract and, similar to internal labour above, span multiple

installations. The first table below provides the estimated average hours per RTU for electrical design technologist. For the second table, tower analysis/upgrades consulting has been identified to be needed for only eight of the twenty-one sites. And for the other labour categories for external labour, their level of effort required varies by site and therefore the table reflects the estimated average cost per site. The associated estimates are based on experience with similar projects.

Table 1

External Labour (Contracts)	Per Day	Quantity	Hrs/Day	Total Hrs	Avg Hrs/RTU
Electrical Design	PD	457	7	3,197	152

Table 2

Consulting			Estimate ($)	Avg Cost Per Site ($)
Tower Analysis/Upgrades	Lot	1	$ 200,000	$25,000
Contracts				
Civil Construction	Lot	1	$ 428,750	$20,417
Telecom Construction	Lot	1	$ 521,000	$24,810

(c) Please refer to the table below.

S/N	Substation Name	Location	Location Property ID	Peak Load (MVA)	Number of Customers
1	100C Cape Porcupine	Aulds Cove, NS	35173871	5.77	1,445
2	84S Victoria Junction Distribution	Grand Lake Road, NS	15228489	6.41	513
3	91W Middlefield Distribution	Middlefield, NS	70110838	7.71	1,217
4	3N Oxford Junction	Oxford Junction, NS	25460759	6.35	1,049
5	103C Cheticamp	Belle-Marche, NS	50100098	6.58	1,894
6	104S Baddeck	Baddeck, NS	85064582	6.94	2,293

S/N	Substation Name	Location	Location Property ID	Peak Load (MVA)	Number of Customers
7	76V Maitland Bridge	Maitland Bridge, NS	05305966	0.57	307
8	23W Clyde River	Clyde River, NS	80079775	4.05	1,163
9	36W Green Harbour	East Green harbour, NS	80122674	2.82	1,160
10	64V Greenwood Village	Greenwood, NS	55106017	9.05	1,477
11	20W Lower East Pubnico	Lower East Pubnico, NS	90067844	2.54	718
12	57W Caledonia	Caledonia, NS	70154653	3.07	1,290
13	92W Carleton Yarmouth	Carleton, NS	90113663	1.94	947
14	124H Akerley Blvd	Dartmouth, NS	40549743	7.53	472
15	6N Black River Road	Springhill, NS	25224460	1.33	219
16	46W Broad River	Summerville, NS	70174370	3.83	1,224
17	20N Park Street	Amherst, NS	25025545	2.65	1,088
18	74V Cornwallis	Cornwallis Park, NS	05209937	0.56	87
19	21W Lower Wood's Harbour	Lower Woods Harbour, NS	80010937	2.81	666
20	9C Aberdeen	Whycocomagh Bay, NS	50146430	0.75	311
21	37W Lockeport	Lockeport, NS	80078835	1.96	472

Notes:

Peak Load data is from the 2025 peak load model for February 6, 2025

Customer counts are based on April 2024 GIS model

(d) No; the substations do not currently have any form of telecommunication systems.

(e) Test equipment and tools are included in this project, as well as in earlier RTU projects like the RTU replacement program as it represents an allowance for tools and test equipment required for the project or that has worn out and needs to be replaced as well as consumable parts and items, all of which are required to execute this work and therefore place these assets into service.

(f) This project will be completed leveraging both internal resources and specialized external consultants and contractors.

The allocation of work was based on the nature of the tasks required, the specialized skills associated with each labour category, and the availability of internal resources to perform the work. NS Power does not have the capability of using only internal resources due to the amount of work required and the resource capacity constraints on the Company's internal resources. Therefore, experienced external consultants and contractors will be engaged to assist with the project engineering workload, tower structural analysis, civil activities and telecom tower rigging contractors. It does not make sense for NS Power to maintain a specialized resource complement for these activities. It is much more efficient to outsource this work to experienced consultants and contractors who specialize in this area.

Request IR-144:

General Plant Capital Investments

GP01 C0080111, 2026 RTU Deployment

The application notes a system operator can remotely disconnect power within seconds in an emergency (such as a house fire or car accident) compared with response times of approximately 45 minutes or more for a field crew to be deployed and arrive on site.

(a) Is the utility suggesting that there is no other protection available to disconnect power in an emergency, as noted above? Please use the substation protection drawing to explain this statement in terms of the existing configuration and the changes that will occur after this project.

Response IR-144:

(a) NS Power is not suggesting that there is no other protection available on the system. Substations are already equipped with standard protection devices, such as reclosers, or overcurrent protection, that automatically operate when fault conditions occur. These protections are designed to detect electrical faults, tree contacts or ground faults, and will isolate a feeder when the electrical characteristics indicate an unsafe condition.

However, these protection systems only operate when an electrical fault is present. In other emergency scenarios (such as a house fire, wildfire, or car accident) where conductors might remain intact and no electrical fault occurs, the protection equipment will not automatically trip, because nothing in the electrical system indicates an abnormal condition. In such cases, notification of the incident may be provided from first responders or the public. If the substation has an RTU installed to provide remote monitoring and

control, a system operator could then take appropriate action to disconnect the affected feeder.

At sites without remote monitoring and control, the system operator would normally have to dispatch a field crew to manually pull fuses or open switches. As referenced in the application, the response time for a crew to arrive on site can be approximately 45 minutes or more depending on where the field crew is located and where the safety incident is located. The system operator also has the option of opening the transmission source which would take out an entire transmission line, resulting in many more customers being without service. The ability to drop a single feeder result in fewer customer outages.

The project does not introduce or modify any protection schemes within the substation. The existing protection configuration that is shown on the substation protection drawing remains unchanged. No new relays, protection elements, or fault detection functionality are being added.

Rather, the project adds remote monitoring (i.e. visibility) and control (i.e. SCADA – Supervisory Control And Data Acquisition) for the system operator for the sites where new RTUs are installed. This remote operational capability closes the gap between what automatic protection can detect and the range of real-world emergencies that require de-energization for the public and worker safety. This also provides faster restoration time reducing outage duration.

Request IR-145:

GP02: C0080252, Intelligent Asset Data Capture & Integration Platform

(a) Please provide a report outlining the business case for this technology, including the expected improvements in areas such as time, cost, volume, or quality.

(b) Please explain how the utility will measure the actual business impact following the deployment of this project.

Response IR-145:

(a) A specific business case report was not developed but the following benefits are expected to be achieved, and the external funding provides this at a significant discount to the benefit of customers. A number of potential benefits, as outlined in the submission are the expected outcome of this project. These benefits include enhancing current planning tasks to streamline execution based on additional and readily available information. This information and enhanced business process can help to reduce truck rolls for work execution; contribute to resource planning and scoping work deskside instead of site visits; and assist with ensuring teams are equipped with materials required to carry out specific tasks before site visits. Through the deployment of this tool to NS Power Field resources, NS Power can further streamline back-office processes by automating linkage of asset and attachment pole data to a specific pole and the geolocation of the pole. The more granular visibility of these assets through high resolution photographs and annotations, that are not available through current tools or technologies leveraged by NS Power, enables an ability to more concisely plan proactive maintenance and capital work. Once completed, this data residing in the NS Power GIS database can also be leveraged by other databases through existing system-to-system integration to enhance processes carried out through those solutions. The allocation of federal funding provides these benefits at a significantly reduced cost to customers.

(b) NS Power will measure direct benefits through baselining current datasets prior to project start and following project completion. While currently unable to fully and accurately quantify, we anticipate indirect benefits can be realized through process improvements based on expanded access to more granular levels of data being available to resources across several business units, and through this updated information flowing into the tools and databases utilized by teams in carrying out their day to day responsibilities.

Request IR-146:

GP02: C0080252, Intelligent Asset Data Capture & Integration Platform

(a) What are the expected annual operations and maintenance costs associated with the proposed project?

(i) What will be the sustaining costs for this project over the next 10 years?

(b) Does NS Power expect to hire additional staff to operate and maintain the new system?

(i) If so, please identify the number of staff that will be hired, complete with the associated annual cost.

(c) Please provide a TCO analysis for the project.

(d) Please identify the expected annual cost benefits/savings associated with the project over each of the next 10 years.

Response IR-146:

(a) There are no new annual operations and maintenance costs currently forecasted for this platform. This is a one-time purchase for the initial data collection and annotation, as well as acquisition of 100 licenses for end user ongoing collection and annotation functionality.

(i) None currently planned.

(b) No.

(i) N/A.

(c) A TCO analysis is completed when multiple cost factors (purchase price, future operating and maintenance costs, or licensing costs) are present. In this project, no future operating costs are anticipated, therefore no TCO was completed.

(d) Cost benefits/savings have not been quantified for this project; however, the costs to execute this project would be less than the alternative of equivalent manual data collection efforts.

Request IR-147:

Appendix B Database

Appendix B contains the risk rating for investments included in the 2026 ACE Plan. Please confirm, or explain otherwise, that:

(a) 41 projects have a rating of 25, which is equivalent to a rating of 5 for both criticality and condition; 95 projects have a rating of 20; and 210 projects have a rating of 16, which requires a mitigation plan.

(b) Please describe the mitigation plans for the projects with ratings of 25 for General Plant – IT – Identity & Access Management.

(i) Are any of the General Plant - IT projects specifically for license renewals?

(c) Please explain the rating of 25 for the ECEI Synchronous Condensers.

Response IR-147:

(a) Confirmed.

(b) All IT projects with ratings of 25 are included in the ACE Plan as subsequent submittal projects, with brief descriptions as to what will be completed (which is how the risk is being mitigated). Further details on the exact nature of this risk mitigation will be provided when these projects are filed.

CI Number	Description	Mitigation Plan
C0021835	IT - CIS Replacement	This project will replace Nova Scotia Power's Customer Information System (CIS). The CIS system is critical to

CI Number	Description	Mitigation Plan
		delivering customer care, billing and communications to customers.
C0047278	IT - Oracle MDM Upgrade	The Meter Data Management (MDM) System is nearing end-of-life and requires an upgrade to maintain vendor support. Upgrading the current version ensures vendor support is available; allows NS Power to apply newly released bug fixes, system patches, cybersecurity enhancements that are released by the vendor; and ensures that new system features can be utilized as they are released by the vendor.
C0047301	IT - Cloud Integration Platform	This project will implement a scalable cloud integration solution to streamline the secure exchange of data between on-premises and cloud-based business systems. It will improve our ability to deliver and manage data integrations in a timely and cost-effective manner.
C0068714	IT - Identity & Access Management	This project introduces new, advanced access management tools to streamline and secure identity and access controls, strengthening the security posture. The project will follow a phased implementation approach, deploying capabilities such as Privileged Access Management (PAM) and Endpoint Privilege Manager (EPM). Subsequent phases will establish a comprehensive Identity Governance and Administration (IGA) framework.
C0068718	IT - DERMS Solution Project	This project will procure and implement a Distributed Energy Resource Management System (DERMS) allowing for the visibility, monitoring, control and optimization of distribution-connected energy resources on the power grid. NS Power has received confirmation of funding for this project.
C0068719	IT - Distributed Intelligence Apps	This project will evaluate, pilot, procure and deploy distribution intelligence solutions through the Advanced Metering

CI Number	Description	Mitigation Plan
		Infrastructure (AMI) network meters. The implementation of these applications will enable precise analysis, advanced event detection and improve situational awareness of system conditions at the meter. NS Power has received confirmation of funding for this project.
C0068721	IT - ADMS Upgrade 2026	This project will upgrade the Advanced Distribution Management System to the latest major version to ensure vendor support and compatibility with emerging technologies. This upgrade encompasses the design and implementation of both physical and software assets, positioning the system for future enhancements and improved outage restoration capabilities.
C0082133	IT - Renew Microsoft Enterprise Agreement	This project funds the on-premises portion of the Microsoft Enterprise Agreement for software assurance on our Microsoft SQL Server, Windows Server and Visual Studio licenses over a 3-year license term.
C0080618	IT - Lifecycle: DR Hardware Refresh	This project involves upgrading aging disaster recovery hardware to preserve vendor supportability and enhance cybersecurity.
C0047296	IT - Microsoft SQL Consolidation	This project will consolidate all possible applications to a new SQL database cluster, which will improve SQL Server license utilization, and provide room for growth at no additional license costs.
C0080619	IT - Lifecycle: Network Devices 2026	This project involves replacing end-of-life network switches at remote locations to maintain vendor supportability and enhance cybersecurity.
C0022002	IT - Storm Centre Upgrade	Upgrade of the KUBRA Storm Center outage-map platform from an end-of-life version to maintain vendor support, enhance cybersecurity, and ensure continued delivery of real-time outage information such as outage cause and estimated restoration times on the customer-facing outage map.

CI Number	Description	Mitigation Plan
C0082198	IT - Plant Phone System Upgrade	This project replaces voice routers and analog voice gateways (hardware), and purchases required licenses to mitigate the risk of phone systems located at NS Power generating stations from interruptions.
C0082197	IT - Phone Recording for Compliance	This project will upgrade business-critical phone recording capabilities at Ragged Lake. The solution involves integrating the NICE platform for analog and legacy channels and implementing Verint Financial Compliance (VFC) for Microsoft Teams and Webex calls.
C0068724	IT - Safety IRD Replacement	Development of new data analysis and reporting capabilities to replace legacy Safety Incident Response Database reporting and meet NS Power's compliance and usability requirements.
C0061347	IT - Wireless Video Solution	This project aims to establish a supported standard for point-to-point wireless connectivity, enabling the placement of security cameras at greater distances from NS Power's facilities than current infrastructure permits.

(i) CI C0082133 IT Renew Microsoft Enterprise Agreement is the only project specifically for license renewal.

(c) The rating of 25 for the ECEI Synchronous Condensers reflects both the criticality and condition assessments under the CEJC framework. These units are assigned a criticality rating of 5 because synchronous condensers are required to meet system reliability and stability obligations established by the NS Power transmission planning study work assessing the system needs to maintain reliability with the integration of significantly higher levels of wind generation as part of the Path to 2030. The synchronous condenser units are needed to provide essential grid services such as inertia, short-circuit strength, and voltage support services that are needed by the system as wind capacity increases and synchronous support from traditional resources decreases as coal generation is phased out in the province.

The condition rating of 5 reflects that these synchronous condenser units are not yet in service, and no equivalent equipment currently exists in NS Power's fleet that could meet these functional requirements. As a result, the absence of these assets represents a material gap in system capability that must be addressed to ensure compliance with emerging system performance requirements and to support the reliable integration of new renewable generation.

Accordingly, the combination of a legislated or policy-driven requirement to have this functionality available on the system, coupled with the absence of any existing in-service assets capable of providing it, results in the overall risk rating of 25.

Request IR-148:

Appendix B Database

Please confirm, or explain, otherwise, that summing the amounts in Appendix B Less than $1M, the total budget for Trenton 5 is $5.4M.

(a) Overall, how much is NS Power planning to spend on Trenton 5 in 2026, including other expenditures, like routines?

(b) In Appendix B the criticality ratings for Trenton 5 investments are predominantly rated at 15 or higher. However, there are two investments, in Less than $1M, with a rating of 12 for a total of $403,618 for the two projects. Why is NS Power making low risk rating capital investments in a generating unit that will soon be retired?

(i) According to Section 6.2 of the Capital Expenditure Justification Criteria (CEJC), "A lower ranking suggests a lower level of risk and urgency, but not always a lower level of priority". The inclusion of capital projects with a ranking of 12, suggests that this project is a priority project. Please confirm or explain otherwise that these two projects with risk ratings of 12 are regarded as priority projects.

(a) If confirmed, please describe why these projects are a priority investment for NS Power.

(ii) Given the expected useful life remaining on Trenton 5, please describe the monetary value of the benefits to be gained through the investment up to the point the unit is retired.

(c) How much will NS Power spend on the whole of Trenton (units 5 and 6 and common) station in 2026?

(i) How much was spent on all of Trenton in 2025?

(ii) How much was spent on Trenton 5 in 2025?

Response IR-148:

Summing the Less than $1 million amounts in Appendix B for Trenton 5 is $5,498,914 (rounded $5.5 million).

(a) NS Power is forecasting investment of $5.5 million on Trenton 5 in 2026.

(b) Continued investment in Trenton 5 is necessary to ensure the safe and reliable operation of the unit through to its planned retirement. The two projects identified with a risk rating of 12 relate to assets that are approaching the end of their useful life. These investments are considered essential to maintain full capacity and safe operation of Trenton 5 until its retirement date.

(i) Confirmed. The two Trenton 5 projects with a CEJC risk rating of 12 are considered essential to ensuring the unit can continue to operate safely and reliably through to its planned retirement. While a rating of 12 signifies a lower level of urgency within the CEJC framework, it does not diminish the operational importance of these investments. Investment in a project with a risk rating of 12 can be appropriate if the expectation is that the rating will reach or exceed 15 before the next opportunity to complete any risk mitigation activities.

The two Trenton 5 projects assigned a rating of 12 are TRE5 – 5-4 Feedwater Heater Refurbishment and TRE5 – Bottom Ash Refractory Replacement.

Feedwater Heater 5-4 Refurbishment:

The Trenton 5 Feedwater Heater (FWH) 5-4 was last inspected in 2009. Recent 2025 inspections of adjacent heaters FWH 5-5 and FWH 5-6 identified multiple tubes below minimum wall thickness, indicating significant degradation and a high likelihood of similar conditions on FWH 5-4 due to identical design, age, and operating environment. A tube leak on FWH 5-4 is estimated to result in a production derate of approximately 15 MW, and repairs would require roughly one week of outage time. Although the project received a rating of 12 during the submission, the more recent inspection results demonstrate that its risk level should have been scored higher, as FWH 5-4 is exposed to the same failure mechanisms already observed in the other heaters.

Bottom Ash Refractory Replacement:

Inspections of the Trenton 5 bottom ash system have revealed extensive cracking, spalling, and thinning of the refractory liner, confirming that the existing material is nearing the end of its service life. Continued operation for another year is expected to accelerate this deterioration to the point that replacement will be unavoidable. Completing this work is required to mitigate the risk of in-service refractory failure and maintain safe unit operation and should be considered a higher risk rating than 12.

Together, these projects address critical end-of-life degradation in key thermal and ash-handling systems. Completing them is necessary to ensure Trenton 5 remains safe, reliable, and capable of meeting operational requirements through to its planned retirement.

(ii) These two projects are essential to maintaining Trenton 5's operational capacity and ensuring safe, reliable performance through to its planned retirement.

Refurbishing Feedwater Heater 5-4 will prevent an estimated 15 MW derate and associated efficiency losses and forced outages resulting from potential feedwater heater tube leaks or failures. Similarly, replacing the bottom ash refractory is required to avoid safety risks caused by deteriorating refractory material, including the development of exterior hot spots and the increased likelihood of forced outages to complete emergency repairs.

These investments are not driven by monetary benefit; rather, they are required to mitigate operational and safety risks and to preserve Trenton 5's ability to operate safely and at its intended capacity.

(c) NS Power is forecasting investment of $16,207,708 on the whole of Trenton (Units 5 & 6 and Common Station) in 2026.

(i) $21,491,191 was invested in all of Trenton in 2025.

(ii) $10,594,246 was invested on Trenton 5 in 2025.

Request IR-149:

Appendix D CEJC Stakeholder Engagement and Amendments pages 454 to 632

Pages 25 and 26 review the Stakeholder Engagement discussions for the CEJC update, and page 453 Appendix D explains that definition of Scope Change centres on a change in stated intent rather than include deliverables, boundaries or tasks.

(a) Please site the applications NS Power has filed with the Board for approval of a Scope Change since 2020.

(i) Please identify projects that NS Power filed with the Board for approval that would have been classified as a Scope Change in 2024 and 2025 according to the New Updates.

(b) Please elaborate on how a change in stated intent is unambiguous and free from subjective interpretation so that a consistent approach is used.

Response IR-149:

(a) No Scope Change applications have been filed with the Board since 2020.

(i) No projects filed in 2024 or 2025 would have triggered a scope change application.

(b) NS Power considers the further language proposed in CA IR-1 to the definition of scope change to remove ambiguity. In each application, the intent of the project is defended as the best alternative under the *Why do the Project This Way* section. This includes justifications such as why refurbishment is more beneficial that replacement, why a Software as a Service solution is better than an on-premises solution or where completing component replacement on a transmission line is preferred to fully replacing the line or

reconductoring the line. NS Power believes that this update will provide additional clarity and remove subjectivity to that existed prior to the update.

Request IR-150:

Appendix D CEJC Stakeholder Engagement and Amendments pages 454 to 632

Page 563 of the application provides the updated definition of a scope change as follows: "A project is considered to have had a scope change when the overarching intent of the project description has been changed." Further, pdf pg. 454 provides the definition of a "scope change applications" as follows: "Scope Change applications may experience cost variances from the original application but are submitted regardless of whether the thresholds for ATO and Final Cost (FIN) applications have been exceeded when the overarching intent of the project description has been changed."

(a) Would the Tusket Main Dam Refurbishment project meet the definition of a "scope change" and require a "scope change application"? Please explain.

Response IR-150:

(a) No, the Tusket Main Dam Refurbishment project would not constitute a scope change application as the intent of the project is to refurbish the Main Dam structure to meet current Canadian Dam Association (CDA) Dam Safety Guidelines, and this remains the intent of the project. This project can also be considered an example of where significant change in effort related to achieving the project intent occurs, the thresholds related to ATO applications provides appropriate regulatory oversight by examining the requirements for the additional spend thorough a separate application to the Board.

Request IR-151:

Appendix D CEJC Stakeholder Engagement and Amendments pages 454 to 632

In Appendix D on page 455, the proposed change to the requirements directing when to apply for a FIN is an increase of the underspent threshold from -5%/ $250,000 to -10%/ $500,000 in order to exclude contingency.

(a) Please provide stakeholder feedback that NS Power received on these proposed changes.

(b) Did NS Power consider maintaining the threshold but excluding budgeted contingency in the estimation as to whether the threshold had been met?

(c) If the final cost of a project falls below the $1M approval threshold, but had been approved because its budget was greater than $1M and the underspending meets the requirements for a FIN, does NS Power intend to notify the Board of its significant underspending?

Response IR-151:

(a) All relevant stakeholder feedback from the stakeholder engagement sessions was included in Section 4.1 of the 2026 ACE Plan. No specific written stakeholder feedback was received relating to the proposed FIN change. Clarification questions were asked during the stakeholder engagement sessions and were answered by NS Power.

(b) NS Power recognizes this alternative as an option; however, increasing the threshold is a simpler alternative that better supports project governance, as it can be more easily queried, reported on and tracked without requiring manual adjustments to project approvals to

remove contingency. The current proposed approach reduces the risk of reporting errors and potential missed filings.

(c) Historically, if a project is approved at greater than $1M, then subsequently underspends by more than the approved threshold and also has a final cost less than $1M, NS Power has filed Final Cost applications in these instances. However, to align with the *Public Utilities Act*, NS Power considers that this circumstance should not require a Final Cost (FIN) application and that these underspends would instead be captured in the Quarterly Capital Reporting that NS Power provides on all submitted capital projects. Specifically, on tab R2 within the quarterly reports, NS Power provides status updates on all projects which includes spend to date until after project completion.

Request IR-152:

Appendix D CEJC Stakeholder Engagement and Amendments pages 454 to 632

Page 465 of the ACE Plan application provides the definition of "scope" as contained in the CEJC Summary Document as follows: "Scope: A project's stated goals (overall objectives the project aims to achieve), deliverables (end result that will be produced for the asset), and boundaries (what the project will and will not achieve)."

(a) Board staff notes that the "Project Management Book of Knowledge (PMBOK)" as published by the Project Management Institute (PMI) defines Project Scope as: "The work performed to produce a product, service, or result with specified features." Please explain how the CEJC definition of project scope aligns with that of the PMBOK.

(b) Board staff notes that the PMBOK defines a "Project Scope Statement" as: "a formal document that provides a detailed description of the project scope, major deliverables, assumptions, and constraints. It serves as the primary tool for stakeholders and the project team to share a common understanding of the project's boundaries and goals." The PMBOK also noted that a Project Scope Statement generally includes: a) A Project Scope Description providing a detailed account of the work required to produce the deliverables, b) A list of Major Deliverables to be produced, c) a list of Acceptance Criteria outlining specific conditions that must be met for the deliverables to be accepted by stakeholder, d) Identification of Project Exclusions explicitly stating what is not included in the project to manage expectations and prevent "scope creep", e) Identification of Project Constraints noting limitations that restrict the team's options, such as budget, schedule, or resources, and f) A list of Project Assumptions.

(i) Please explain how NS Power's definition of project scope in its CEJC facilitates the development of an adequate project scope statement.

(ii) Please provide two NS Power project scope statements for two capital projects (greater in value than $1M) initiated by the Company in 2025.

(c) Please explain how NS Power's definition of project scope adequately serves as:

- **A benchmark for measuring and controlling project performance.**
- **A baseline to ensure all essential work, and only that work, is included for successful project completion.**
- **A means to protect against project scope creep.**
- **A baseline to facilitate project change control and to determine the impact of changes on project cost, schedule, and resources.**
- **A foundation to create a project's Work Breakdown Structure (WBS).**

Response IR-152:

(a) NS Power acknowledges that the proposed definition in the CEJC for project scope does not directly align with the PMBOK definition and is a departure from how project scope has been detailed in NS Power's project descriptions in the past. The purpose of this proposed definition is to find the proper balance in what should require an updated project application to the NSEB when changes occur to a project, and to avoid filing a significant number of scope change applications when a project is still being completed as intended, but experiences potentially minor variances in what was originally included in the application. This proposed definition also recognizes that there are other regulatory

mechanisms in place such as the ATO and FIN processes that would capture other type of variances that occur in projects.

(b) (i) As detailed in part (a), it is not NS Power's intention to have the definition of scope facilitate the development of an adequate project scope statement consistent with the PMBOK. The proposed definition of scope also does not remove the requirement for each of those pieces of information that PMBOK indicates should be in a project scope statement from being included in the project application as justification for how a project should be completed. It is NS Power's intent to still provide all of the same relevant information that it has in the past within the project description to allow for a fulsome review of the projects necessity, but not considering that to be project scope when it comes to the threshold for triggering a scope change application.

(ii) Two examples of project scope statements that were filed in 2025 are as follows:

- C0073965 TRE5 U&U Burner Nest Waterwall Tube Replacement - The scope of this project includes the replacement of all 16 burner nests on the front wall of Unit 5 boiler at the Trenton Generating Station.

- 49036 HYD Avon 2 Controls Upgrades - This project is for the upgrade and modernization of the control system for the hydro turbine and generator at the Avon 2 Hydro Station.

In these scenarios, if NS Power's proposed scope definition is accepted, the scope statement on TRE5 Burner Nest Waterwall Tube replacement would remove the quantity from the scope statement, but still include that information within the project description. This is to avoid a situation where one burner nest may be found to not need replacement, thus replacing 15 burner nests, and then requiring to file a scope change application for a project that still meets the initial intent of the project,

which is replacing burner nest waterwall tubes. In the event that a significant change in quantity were to occur, NS Power believes that the ATO / FIN thresholds are sufficient to trigger new applications when significant change in a project occurs. The statement for the Avon 2 project would stay the same if the proposed scope definition is accepted.

(c) NS Power's proposed definition of project scope is not intended to serve the purposes listed above. NS Power believes that the ATO / FIN thresholds are such that significant change in how a project is completed will be captured in almost all circumstances and current processes such as the Project Delivery Model and ongoing cost minimization efforts also lead to NS Power completing all capital projects in a manner mitigates the risk in the most cost effective manner possible. How NS Power defines scope in the CEJC for purpose of determining what requires a scope change application does not hinder NS Power from managing items such as scope creep or the project schedule.

Request IR-153:

Appendix D CEJC Stakeholder Engagement and Amendments pages 454 to 632

Page 465 of the ACE Plan application provides the definition of "scope change" as contained in the CEJC Summary Document as follows: "A project is considered to have had a scope change when the stated intent from the original capital application of the project description has been changed." Board staff notes that the PMBOK defines a Project Scope change as: "any modification to the agreed-upon project scope as documented in the approved Scope Baseline", where Scope Baseline includes the Project Scope Statement and the Project's WBS. Please explain how the CEJC definition of project scope change aligns with that of the PMBOK.

Response IR-153:

As detailed in NSEB IR-152, it is not NS Power's intention to align the updated scope or scope change definition to the PMBOK or to how the term scope has been used in prior applications. The intention of the proposed definitions is to find the proper balance in what should require a scope change application to the NSEB. By relying on industry definitions of scope, which are generally very detailed, scope change applications could be required in situations where very slight changes in work quantities occur, but do not represent a true change in the projects objectives. An example of this would be a Transmission Line Replacement & Upgrade project that historically would have provided a detailed project scope statement in its application to include the following information (example taken from C0031122 L6539 Replacement and Upgrades):

- Structure Replacements: 28 Structures
- Pole Replacements: 2 Structures
- Timber and Insulator Replacements: 66 Structures

- Insulator Replacements: 11 Structures

- Bond and Guy Wire Replacements: 6 Structures

- Other Deteriorated Assets: 3 Structures

By following industry, or PMBOK, definitions of scope and scope change, NS Power would be required to file a scope change application if insulator replacements occur on 10 structures instead of 11. This change in quantity does not represent a significant change in project objectives, which is why NS Power is proposing to consider project scope to be the intent of the project. In the case of a transmission project such as this, that would lead to the project scope being clearly defined in the application as "The scope of this project includes the replacement of deteriorated assets on L6539". In the event that a significant change in quantity were to occur, the thresholds for ATO / FIN requirements will capture that and necessitate an updated filing. NS Power views that the strict PMBOK definition in this context could result in significant regulatory inefficiencies and additional costs. NS Power believes that the definition proposed has struck an appropriate balance and will complement current regulatory processes in place such as ATO and FIN filings.

Request IR-154:

Appendix E Mersey Update pages 627 to 647

Page 632 states: "The most recent update includes $45.1 million in sustaining investment between the years of 2026–2030, compared to the prior year forecast of $40.6 million over the same period. Attachment 1 outlines the current MHS investment profile included in the HIP for 2026–2065."

(a) Please identify how much was spent in sustaining capital in 2025 for the Mersey hydro system.

(i) Please compare this amount to what was forecast for 2025 in Attachment 1 of Appendix G of the 2025 ACE Plan.

(1) Please describe the reasons for any significant differences between actual spending and forecast spending.

Response IR-154:

(a) In 2025, $6.1 million was invested in sustaining capital for the Mersey Hydro System.

(i) By comparison, $4.9 million was forecast for 2025 in Attachment 1 of Appendix G of the 2025 ACE Plan, a variance of approximately $1.2 million.

(1) The primary driver for the variance was 2025 actual spend of $2.35 million for Matter M12590 - C0070486 HYD Lower Great Brook Spillway Drawdown (Stop Log Refurbishments) versus forecast spending of $1.08 million, a variance of $1.27 million.

As documented during the 2024 inspection and reflected in the Board's January 27, 2026 decision in this matter, progressive structural degradation of the concrete piers and stoplog system was identified, requiring additional refurbishment work during the reservoir drawdown. These conditions were not evident at the time the original forecast was developed and the resulting increase was necessary to maintain safe and reliable water management at the Lower Great Brook facility.

Request IR-155:

Appendix E Mersey Update pages 627 to 647

Page 632: What are the forecast dates for the next major refurbishment of the Cowie Falls Unit 12 turbine and generator?

Response IR-155:

Cowie Falls Unit 12 is presently undergoing a full turbine overhaul approved under CI C0038126, with an in-service date scheduled for March 2026; the associated generator refurbishment is being completed under the approved CI C0053654. In accordance with NS Power's Hydro Interval Plan, major turbine components typically require overhaul on a 25-year interval and generator components on a 40-year interval. Based on these intervals the next turbine overhaul would fall around 2051 and a next generator overhaul in 2066. However, because Cowie Falls forms part of the Mersey Hydro System - where a system-level redevelopment or decommissioning decision is anticipated - NS Power does not anticipate undertaking additional sustaining-capital overhauls for Unit 12 beyond the work now underway.

Request IR-156:

Appendix E Mersey Update pages 627 to 647

Page 632: What is the forecast date for the next major refurbishment of the Big Fall Unit 6 generator?

Response IR-156:

Big Falls Unit 6 is currently undergoing rotor re-insulation and associated generator component refurbishment under approved CI C0080112. In NS Power's Hydro Interval Plan, a placeholder exists for major generator stator refurbishment in 2032. This timing reflects interval-based planning assumptions and will be re-evaluated as the unit approaches that date, informed by updated condition assessments and operational performance following completion of the current rotor work. Big Falls is part of the Mersey Hydro System, which is expected to reach a strategic decision point regarding redevelopment or decommissioning in the coming decade. As that system-level planning progresses, the timing and necessity of the 2032 stator refurbishment will be reassessed. At this time, the 2032 placeholder remains in the plan, subject to refinement based on asset condition and long-term lifecycle decisions.

Request IR-157:

Appendix E Mersey Update pages 627 to 647

Page 634 states that active project work on the Mersey redevelopment remains paused.

(a) Please explain why the work has been paused.

(i) Please explain why NS Power is not currently working on preliminary engineering, stakeholder engagement and environmental studies to assess and confirm the needs of the project, to further develop project cost estimates, and to ensure the projects remains on schedule.

Response IR-157:

(a) Active project work on the Mersey Redevelopment remains paused as NS Power awaits the outcome of the ongoing IESO Nova Scotia-led Integrated Resource Plan (IRP) process. The IRP will inform the long-term role of the Mersey Hydro System within the overall provincial resource portfolio and is expected to assess the costs associated with the potential future options for the Mersey Hydro system and determine the appropriate long-term pathway for the system.

(i) With respect to preliminary engineering, stakeholder engagement, and environmental studies for the projects, NS Power is not conducting this work at this time because these activities would presuppose a redevelopment option and require significant expenditure ahead of strategic direction from the IRP. Advancing these activities prematurely would risk misalignment with the resource pathway ultimately selected and could result in unnecessary or inefficient costs for customers. NS Power is, however, engaging with stakeholders indirectly on other projects in the region to understand sensitivities and requirements in a broader

context. As noted in NSEB IR-160, NS Power will resume detailed planning once the IRP provides clarity on the preferred long-term approach for the Mersey System.

Request IR-158:

Appendix E Mersey Update pages 627 to 647

Page 634, NS Power states: "in order to move forward with the Mersey Redevelopment, NS Power must have a clear understanding of the conditions associated with continued compliance with the *Fisheries Act* and requirements for permit approval. In particular, NS Power is continuing conversations with Fisheries and Oceans Canada (DFO) in order to understand requirements associated with fish passage that may not have been in place previously."

(a) Please describe the DFO fish passage requirements for the Mersey system that were not previously in place.

(i) Please describe the order of magnitude that these new fish passage requirements could have on the redevelopment project, as well as the decommissioning options.

(ii) Please confirm that the cost estimates in Attachment 1 of Appendix E include costs related to the new fish passage requirements.

(1) If not confirmed, please explain.

Response IR-158:

(a) The reference in Appendix E relates to Fisheries and Oceans Canada's (DFO) current interpretation of fish passage requirements under the Fisheries Act. Historically, upstream and downstream fish passage were required at three of the six Mersey generating stations. However, DFO is now indicating that full upstream and downstream passage for all species should be provided across all six generating stations on the system in order to support

basin-wide connectivity. These requirements were not previously in place for the Mersey system and must be confirmed through ongoing engagement with DFO.

(i) At this stage, the magnitude of the potential impact relates primarily to the permitting and regulatory obligations that would apply to either redevelopment or decommissioning construction activities. While NS Power has incorporated fish passage construction costs into its capital forecasts, broader requirements—such as the extent of passage infrastructure, sequencing, and DFO expectations for system-wide connectivity—may influence project scope, timelines, and permitting complexity. As noted in U-10 of the 2025 ACE Plan, fish passage elements are currently estimated at approximately 3 percent of redevelopment costs, but these allowances will be refined as regulatory expectations are confirmed.

(ii) Confirmed.

(1) N/A.

Request IR-159:

Appendix E Mersey Update pages 627 to 647

Page 636: in compiling NS Power's Mersey NPV analysis, the Company used an annual average MHS production of 190,000 MWh based on 2015 to 2024 data.

(a) Please provide the annual MHS annual production for each year from 2015 to 2024.

(b) Please explain why NS Power used the 10-year average production of the MHS in its NPV analysis rather than more recent data using the average of 2022 to 2024 data.

Response IR-159:

(a) The period used was erroneously reported as '2015-2024' on page 650 of 782 of the 2026 ACE Plan Application. However, 2016-2025 was the period used in the calculation. The assumption at the time of submission was that there would be marginal, if any, additional production for the remainder of 2025 for MHS based on the extremely low reservoir levels.

The following table lists the annual MHS production:

Year	Annual Production (MWh)
2016	204,198
2017	219,842
2018	225,198
2019	224,410
2020	165,588
2021	187,401
2022	217,883
2023	202,584

2024	131,736
2025	121,282

This results in an average production of 190,082 MWh, which was rounded to 190 GWh or 190,000 MWh for the purpose of this calculation.

(b) NS Power used the 10-year average production of approximately 190 GWh in its NPV analysis because it provides a more accurate and representative long-term estimate of expected Mersey Hydro System (MHS) generation rather than relying solely on the most recent three years of data. Hydroelectric production is inherently variable from year to year due to fluctuations in precipitation, inflows, reservoir conditions, seasonal constraints, and operational requirements such as riparian flow releases. A shorter dataset—such as 2022 to 2024—can be disproportionately influenced by short-term hydrological anomalies, including both exceptionally wet and exceptionally dry years, and therefore does not provide a stable basis for long-term capital planning.

By contrast, the 10-year average captures a broader range of hydrological conditions, including both high-water and drought periods such as the significantly reduced hydrology observed in 2025. This longer dataset reduces the influence of year-to-year variability and produces a more robust estimate of expected annual production for use in a redevelopment NPV model extending through 2065.

Request IR-160:

Appendix E Mersey Update pages 627 to 647

Redevelopment Costs: on page 637, NS Power states: "This year, the estimate has been updated to include preparatory work leading up to construction. The cost of this work is roughly estimated to be $8.5 million. Activities include completion of detailed engineering design and preparation of IFC packages, procurement of Contractors, carrying out environmental studies, applying for permits as well as associated Administrative Overhead (AO) / Allowance for Funds Used During Construction (AFUDC)."

(a) In Attachment 1 of Appendix E, it appears that this $8.5M is projected to be spent in 2028 to 2030; please confirm.

(i) If confirmed, please explain why none of this work will be undertaken in 2026 and 2027.

(b) Please confirm that this work, and the related cost estimates, also includes Mi'kmaq and stakeholder engagement activities.

(i) If not confirmed, please explain.

Response IR-160:

(a) Confirmed.

(i) Please refer to NSEB IR-157.

(b) Confirmed.

(i) N/A.

Request IR-161:

Appendix E Mersey Update pages 627 to 647

Partial Decommissioning Costs:

(a) On page 638, NS Power states:

> **"The MHS partial decommissioning cost estimate was based on detailed work completed in 2021, leveraging the Big Falls rebuild scenario as a baseline due to significant overlap in scope. Under this option, the decommissioning scope includes removal of the powerhouse, concrete water control and retaining structures, and associated electrical and mechanical equipment. The rebuild and refurbishment of concrete water control structures and dams remain unchanged, as do the new fishways and the Big Falls switchyard upgrade. The primary exclusion is the construction of a new powerhouse and generation equipment."**

(i) Please explain what NS Power means by

> **"The MHS partial decommissioning cost estimate was based on detailed work completed in 2021, leveraging the Big Falls rebuild scenario as a baseline due to significant overlap in scope."**

(ii) In prior capital projects (notably the Tusket Main Dam Rehabilitation Project), and in NS Power's most recent General Rate Application, "partial decommissioning" costing of hydro systems excluded removal of concrete water control and retaining structures. In this context, please explain why the partial decommissioning option for the MHS includes costs related to removal of concrete water control and retaining structures.

(b) On page 638, NS Power states: "The total combined estimate to partially decommission the MHS is $512 million CAD." Board staff notes that Attachment 1 of

Appendix E denotes an estimate partial decommissioning cost of $624M. Please explain this discrepancy.

Response IR-161:

(a)

(i) In the case of the Mersey Hydro System, the scope of work required on the water retaining structures is identical in both the redevelopment and partial decommissioning scenarios. Both options require the dams, spillways, gates and associated water control infrastructure to remain in service to safely manage the Mersey River. Since the scope of the partial decommissioning scenario is similar for the Mersey system as a whole, the cost estimate developed for Big Falls was extrapolated for the remaining five sites, with minor adjustments made to reflect known variances.

(ii) In NS Power's 2026-2027 General Rate Application (GRA) partial decommissioning had been defined as the removal or stabilization of equipment required for power generation. It did not include the removal of water retaining structures such as dams, spillways and gates. However, it is important to note that the water retaining structures which will remain in a partial decommissioning scenario must be refurbished or replaced to ensure the long-term safe and reliable management of water on NS Power's Hydro Systems. This will mean that there will be ongoing investment to safely manage water on these systems in a partial decommissioning scenario.

In the GRA, NS Power stated that the partial decommissioning costs included for recovery would be the minimum and acknowledged that if water retaining structures required investment the costs would be higher. As part of the GRA settlement agreement NS Power did not include any cost recovery, in the proposed depreciation rates, for partial decommissioning of water retaining structures.

In the case of the Mersey Hydro System, the concrete water retaining and control structures are generally considered to require future investment due to deteriorated concrete condition. As a result, the partial decommissioning scope includes costs associated with the removal of those existing structures and the costs required to replace them with new structures.

(b) The value of $512 million CAD stated on page 638 in reference to the partial decommissioning cost was an error. The value noted in Attachment 1 of Appendix E, $624 million, is the correct value.

Request IR-162:

Appendix E Mersey Update pages 627 to 647

Attachment 1:

(a) Please provide a copy of Attachment 1 in electronic format, complete with all formulae intact.

(b) Please explain why the estimated cost for partial decommissioning is higher than that for full decommissioning.

(c) Please explain why the partial decommissioning option does not include sustaining capital costs for infrastructure that will not be removed.

(d) What inflation allowance has NS Power incorporated into its capital sustaining cost estimates?

Response IR-162:

(a) Please refer to Attachment 1.

(b) The partial decommissioning and full decommissioning estimates were developed using different approaches and different levels of detail, so a direct comparison between them is not practical. The estimate for the partial decommissioning scenario is Class 4, incorporating the known details. The full decommissioning estimate was based on high level metrics and assumptions applied broadly across the Mersey Hydro System, and does not account for the full scope included in the partial decommissioning estimate. Additionally, the accuracy bound for the full decommissioning estimate is significantly higher than that for the partial decommissioning estimate.

(c) NS Power has not yet developed a sustaining capital (CAPEX) profile for the partial decommissioning scenario, as planning had not advanced to that stage when work on the Mersey Redevelopment was paused. However, as noted in NSEB IR-161, water retaining structures which will remain in a partial decommissioning scenario must be refurbished or replaced to ensure the long-term safe and reliable management of water. In the case of the Mersey Hydro System, the concrete water retaining and control structures would be replaced in a partial decommissioning scenario.

Following the major replacement of the concrete water-retaining and control structures under a partial decommissioning scenario, the level of sustaining capital required in subsequent decades would be minimal, as these civil assets are long-lived and are typically planned on 40-year or longer reinvestment cycles. As a result, most sustaining capital needs associated with partial decommissioning would occur beyond the current Hydro Interval Plan horizon, which ends in 2065. NS Power will undertake additional work to develop and incorporate an appropriate sustaining capital profile for the partial decommissioning option as part of the future MHS application, once the long-term operating configuration for the system is confirmed.

(d) NS Power incorporates 2% inflation allowance in the capital sustaining cost estimates.

2026 ACE Plan NSEB IR-162 Attachment 1 has been filed electronically.

Request IR-163:

Appendix F Path to 2030 Update pages 648 to 702

The Path to 2030 Appendix F provides the projected retirement dates for some of NS Power's generating assets with projects listed in this appendix for projects less than $1M, specifically Trenton generating station.

(a) Please explain whether Trenton 5 will be retired or converted in 2027.

(b) Is it NS Power's intention to retire or convert Trenton 6 in 2029?

(i) When will Trenton Common be retired or converted?

(ii) Please explain the value for money of these investments if NS Power intends to retire Trenton 5 in 2027 and Trenton 6 in 2029.

Response IR-163:

(a) Trenton 5 is to currently planned to be retired after the winter of 2027/2028, as referenced in NS Power's 2025 10-Year System Outlook.

(b) Currently, it is NS Power's intent to retire Trenton 6 in 2029 (please refer to NS Power's 2025 10-Year System Outlook for details). The value of sustaining capital investments in the Trenton generating station is ensuring NS Power has dispatchable resources available to meet customer demand during peak system periods and when other resources (wind/solar) are not available until the new fast acting generation is procured and online. Any other potential options to convert Trenton 6 will be identified in the updated Integrated Resource Plan, which will be completed by the IESO-NS in 2026.

Request IR-164:

Appendix F Path to 2030 Update pages 648 to 702

In NS Power's General Rate Application (GRA), matter M12451, exhibit N-7 page 655 notes that both Trenton units 5 will be retired on 12-2029 and that of the composite remaining life, there are 5.9 years for Trenton 5. Please explain the discrepancy in retirement dates between the two matters and confirm the planned retirement dates for Trenton 5.

Response IR-164:

The planned retirement date for Trenton 5, as referenced in the 2025 10 Year System Outlook and the Updated Path to 2030 is 2027. This is subject to change depending on the timing of the replacement capacity.

The forecast retirement date for Trenton 5 in the GRA reflects the expected need to maintain units available in cold reserve until reliable operation of replacement generation has been established.

Request IR-165:

Appendix F Path to 2030 Update pages 648 to 702

Please explain cold reserve and identify which of NS Power's generating units are currently being held in cold reserve.

(a) What are the strategic operating benefits of holding generating units in cold reserve?

(b) What are the quantified benefits of holding generating units in cold reserve rather than immediately pursuing full decommissioning?

Response IR-165:

A generating unit held in cold reserve is a unit that is maintained in a non-operating, offline condition but preserved such that it can be returned to service with sufficient notice. While the unit is not producing energy, essential preservation and maintenance activities continue so that it remains technically capable of operating if required.

At this time, Lingan Unit 2 is the only NS Power generating unit being held in cold reserve.

(a) Holding Lingan Unit 2 in cold reserve provides NS Power with strategic reliability benefits by ensuring that the system retains an additional source of firm capacity during the energy transition period. Maintaining the unit in cold reserve allows NS Power to respond to unexpected events without compromising service to firm customers. Maintaining a unit in cold reserve also supports NS Power's ability to meet NPCC and NERC planning reserve margin requirements during periods when system conditions are tight. Cold reserve status also preserves operational flexibility at a time when new replacement resources, including those procured through the IESO Nova Scotia process, are still being developed and integrated.

(b) Keeping the unit in cold reserve rather than fully decommissioning it provides quantifiable system benefits by avoiding the significantly higher costs associated with emergency replacement energy, natural gas supply and pricing crunches, customer outages, or the need to rebuild equivalent capacity if an unforeseen reliability issue emerges. Once a unit is fully decommissioned, the cost to restore similar firm capacity would be materially greater than the cost of maintaining it in a preserved, non-operating state. As a result, maintaining Lingan Unit 2 in cold reserve is the lowest-cost, lowest-risk option to support reliability until sufficient new capacity is online.

The value of preserving additional firm capacity was recently demonstrated during the January 23–26, 2026 extreme cold event, when all available thermal resources, including Lingan Unit 2, were essential in maintaining supply–demand balance and avoiding customer load shedding.

Request IR-166:

Appendix F Path to 2030 Update pages 648 to 702

In reference to Figure 1 – 2030 Clean power Plan Resources on pages 653 to 654.

(a) Why does the nameplate capacity of the seven listed Wind &Solar Resources on page 653 total 1,385 MW but the Total New Wind and Solar on page 660 shows a nameplate capacity of 1,139 MW?

(b) The Green Choice Program shows a reduction in the nameplate capacity from Figure 1 in last year's update, from 416 MW to 262 MW. The Board understands from the information in this year's update that 4 of the 6 anticipated wind farm projects associated with the Green Choice Program are not proceeding and that the Province of Nova Scotia will be doing a new Green Choice Program procurement. In Figure 1, page 653, there is an item listed as Future Procurement with a nameplate capacity of 350 MW which was not in Figure 1 from last year's update. Is this the anticipated Green Choice Program procurement? If not, please describe what the Future Procurement relates to.

(c) Does NS Power know the status of the new Green Choice Program procurement?

Response IR-166:

(a) This is a typo; the Total New Wind & Solar line in Figure 1 should read 1,385MW.

(b) Yes, it is anticipated the additional 350 MW noted as future procurement is intended to be captured in the additional Green Choice Program procurement announced by the Province of Nova Scotia in September of 2025.

(c) To date, the most current information available is the Energy Minister's public announcement of the Department's intent to reissue a call for new renewable energy projects.[1] Please also refer to NSEB IR-171.

[1] https://www.cbc.ca/news/canada/nova-scotia/onshore-wind-energy-green-choice-new-procurement-1.7643425

Request IR-167:

Appendix F Path to 2030 Update pages 648 to 702

On page 659, NS Power states,

> **"In addition, the CER establishes the potential for "planned unit" designation, which allows units in development that meet specific milestone criteria by the end of 2025, have started construction by 2027 and are in operation by 2035 to be exempt from the CER until the end of 2049."**

(a) Could any of the Fast-Acting Generation Resources or the Fuel Conversion of Existing Units listed in Figure 1 qualify for the "planned unit" designation? Please explain.

Response IR-167:

(a) Yes, the fast-acting generation could qualify for the "planned unit" designation if they meet the requirements in the CER and Environment and Climate Change Canada (ECCC) agrees the milestones have been met. For the fuel conversion projects, the CER does not allow for converted units to be considered for the "planned unit designation". Please note, submitting the designation for approval for the fast-acting generation with ECCC is the responsibility of the IESO-NS as they are managing the procurement of those assets.

Request IR-168:

Appendix F Path to 2030 Update pages 648 to 702

In reference to Rate Base Procurement (RBP), Figure 3 on page 663 presents four wind projects under the RBP Program and the anticipated commercial operation dates (COD). Are all of the COD dates still accurate or have any been modified since the ACE Plan application was filed?

Response IR-168:

The Benjamin's Mill RBP project commercial operation date was December 19, 2025 and Higgins Mountain is in the process of commissioning with an anticipated in-service date of mid-March in 2026.

The COD for the remaining two RBP projects, Weavers Mountain and Wedgeport, of December 31, 2026 and November 15, 2026, respectively, remain unchanged at this time.

Request IR-169:

Appendix F Path to 2030 Update pages 648 to 702

On page 669 Figure 7 – GIP Status for RtR Projects, why was IR-785 – West Wind Farm withdrawn?

Response IR-169:

The RtR project IR 785 (West Wind Farm) was withdrawn as per the requirements of the Generation Interconnection Procedures (GIP). The withdrawal was consistent with Section 3.6 of the GIP due to failure to comply with all GIP requirements because the Interconnection Customer did not execute the Interconnection System Impact Study Agreement (SISA) or provide the required deposits, as required under Section 7.2 of the GIP. As these actions did not occur, IR 785 was withdrawn.

Request IR-170:

Appendix F Path to 2030 Update pages 648 to 702

Section 6.2.1, page 674, NS Power Battery Storage Project ECEI, note that the Bridgewater and Spider Lake sites were to go into service by December 31, 2025, and the White Rock Road Battery Energy Storage System (BESS) site is on track to go into commercial operation in July 2026.

(a) Have the Bridgewater and Spider Lakes sites gone into commercial operation?

(i) If so, when?

(ii) If not, why not?

(b) Is the White Rock Road site still on track to go into service in July 2026?

(i) If not, why not?

Response IR-170:

(a) Yes, the Bridgewater and Spider Lake Battery Energy Storage System (BESS) project sites have gone into commercial operation. Both sites received Substantial Completion Notice on December 30, 2025, and went into Commercial Operations on December 31, 2025.

(b) Yes.

Request IR-171:

Appendix F Path to 2030 Update pages 648 to 702

On page 673 additional renewable energy procurements were discussed. NS Power states, "the Nova Scotia Energy Minister announced the DOE was planning to reissue a call for new renewable energy sources and the Province was looking for a new procurement administrator to lead this initiative."

(a) Has a new administrator been hired?

(b) If not, what is the status of the process?

Response IR-171:

(a-b) At the time of this response, NS Power has not received any formal notification from the Department of Energy regarding the hiring of a procurement administrator or further details on the status of the process. Please also refer to NSEB IR-166.

Request IR-172:

Appendix F Path to 2030 Update pages 648 to 702

In Appendix F the Path to 2030 Update on page 683, the retirement date for Lingan 2 is 2027. According to Exhibit N-7, page 655 in matter M12415, Lingan 2 will be retired on 12-2029. What is the retirement date for Lingan 2?

(a) Appendix F describes Lingan 2 as being held in cold reserve. Has this status changed?

(b) Please describe the sustaining investments in Lingan 2 for 2026.

(c) What is the total amount that NS Power will spend on Lingan 2 to keep the unit in cold reserve?

(d) How often is it anticipated Lingan 2 be moved from cold reserve to full use in 2026?

(i) What is the cost associated with switching Lingan 2 from cold reserve to full operations, when NS Power requires the generation?

(1) How often does NS Power anticipate this change in status for the generating unit throughout 2026?

(e) What is the estimated cost of emissions, as stipulated under the Output Based Pricing System (OBPS) that will be incurred in 2026 from Lingan 2 while the unit is in cold reserve?

(f) What are the estimated costs of emission, as stipulated under the OBPS, that will be incurred in 2026 from Lingan 2 operating (not in cold reserve)?

Response IR-172:

The retirement date for Lingan 2, as per the 2025 10-Year System Outlook and the Updated Path to 2030, is after the 2027/2028 winter. However, NS Power has continually noted the need to continue to retain Lingan 2 to maintain planning reserve margin until new firm generation resources come online.[1] Accordingly, the forecast retirement date for Lingan 2 included in the GRA reflects the need to maintain units available in cold reserve until reliable operation of replacement generation has been established.

(a) Lingan 2 continues to be held in cold reserve and used during periods where the system is constrained. In January 2026, LIN2 was dispatched during the January 23-26 cold weather event when the system was constrained, and was recalled again in early February on a temporary basis to help offset high marginal fuel costs in particular to reduce the risk of exposure to unusually high natural gas prices experienced this winter.

(b) There is $2.5 million in sustaining capital investment for Lingan 2 planned in 2026 that are expected to include, but are not limited to, a boiler refurbishment, ash system refurbishment, breaker refurbishments, mill refurbishments, turbine valve refurbishments, common system refurbishments, miscellaneous valve replacements, and unit specific safety projects.

(c) There is $20 million in sustaining capital investment forecasted in 2026 and 2027 to maintain Lingan 2 in cold reserve through the 2027/2028 winter. As with all capital investment, the condition of the asset will be reassessed before any investment is made and if the condition allows, or non-capital mitigating measures are available, that investment would be deferred. Additionally, the IESO-NS will be completing an updated Integrated Resource Plan (IRP) to assess new resource needs and the timing of those resources which could impact unit retirement targets.

[1] M12386, NS Power 2025 10-Year System Outlook, page 18.

(d) Since this unit is in cold reserve and is only intended to be used during periods where the system is constrained and in the temporary circumstance described above in (a), the annual utilization of Lingan 2 is not forecast. However, in 2024, Lingan 2 operated for 2,155 hours over 12 cycles, and in 2025 operated 2,655 hours over 5 cycles, and the utilization of Lingan 2 is expected to be similar in 2026 to these previous years.

(i) There are no additional costs associated with moving Lingan 2 from cold reserve to available or operational outside of standard unit startup or layup costs. Lingan 2 is strategically moved from layup state to an available state when its need is determined through near term forecasting. NS Power processes also restrict unit cycles on Lingan 2 to mitigate investment in areas that may degrade through repeated thermal cycling.

(e) While the unit is in cold reserve, the unit will not be generating and therefore, there would be no costs associated with the OBPS.

(f) When the unit is called upon and brought out of cold reserve to support system needs, costs associated with the OBPS would be incurred, which would depend on the duration of the period of Lingan 2 generation. The forecast cost of GHG OBPS compliance for the Lingan plants is estimated to be between $9 and $10 per MWh for 2026 depending on the achieved average heat rate.

Request IR-173:

Appendix F Path to 2030 Update pages 648 to 702

According to Exhibit N-7, page 655 in matter M12415, Point Aconi will be retired on 12-2029. Is this the current date for Point Aconi's retirement? If not, please provide the current expected date of retirement.

(a) In total, how much will NS Power spend on the Point Aconi generation plant in 2026?

(i) Please provide the total project costs for Point Aconi as identified in the 2026 ACE Plan, including those being incurred beyond 2026 and those investments less than $1M.

(b) Please confirm, or explain otherwise, that NS Power is requesting approval for two capital projects with a budget of about $19M, of which about $16.4M will be spent in 2026.

(i) Through the two investments, how will this change Point Aconi's remaining life?

(c) Please confirm, or explain otherwise, that NS Power intends to spend $8.5M on 34 capital projects valued at less than $1M on Point Aconi.

(d) Please describe the benefits of continued investment in Point Aconi in 2026 for an asset that will be retired by the end of the decade.

Response IR-173:

Yes, Point Aconi's planned retirement is 2029, as referenced in the 2025 10 Year System Outlook and the Updated Path to 2030 document.

(a) NS Power plans to spend $12.7 million on the Point Aconi Plant in 2026.

(i) Including 2026, NS Power plans to spend $33.4 million on the Point Aconi Plant prior to its retirement at the end of 2029 to maintain safe operation and to ensure the plant can reliably provide the system capacity needs required in that timeframe. As seen on January 25, 2026, where NS Power saw a record 2,459MW system peak, the availability of Point Aconi is crucial for NS Power to continue to meet these ever increasing system demands.

(b) (i) To clarify, NS Power is requesting approval of two Point Aconi capital projects within the 2026 ACE Plan that have a total investment of $2.3 million. These two investments, along with all investment included in the 2026 ACE Plan related to Point Aconi, will extend the life of the components within the project to allow Point Aconi to reliably meet the system capacity needs between now and 2030.

(c) NS Power plans to spend $7.9 million on 34 projects valued at less than $1 million at Point Aconi in 2026.

(d) Please refer to part (a). Continued, targeted investment for Point Aconi in 2026 is required to operate the station safely, reliably, and in compliance through its remaining service period.

Request IR-174:

Appendix F Path to 2030 Update pages 648 to 702

The transmission planning team, along with the system security team, have been collaborating to ensure the control system design parameters of the new inverter-based resources (IBRs) aid in maintaining the stability of the grid. This is currently done by the completion of Model Quality Tests (MQTs) as well as commissioning studies.

(a) What control system design parameters are being tested and studied?

(b) Will the ultimate configuration of the control design parameters add to the cost of IBR resources?

(c) If so, who will be responsible for these costs?

Response IR-174:

(a) The IBRs being commissioned are required to successfully complete system performance testing to ensure their generating facilities meet the requirements of the NS Power Transmission System Interconnection Requirements (TSIR). This is to ensure the IBRs can be connected to the system while maintaining the stability and reliability of the grid. Each IBR is required to test at minimum Power Quality, Active Power, Reactive Power, Voltage Change, Frequency Response, Automatic Generation Control function, and ride fault through test. The data collected from the system performance test is then evaluated against the approved model, and results are shared with the interconnection customer to confirm that their facility meets the TSIR requirements or if any updates are required at their facility to meet the TSIR requirements.

(b) Any updates to the configuration of the control design parameters or parameters required to meet the TSIR may add to the cost of the IBR resources.

(c) It is the responsibility of the interconnection customer responsible for the IBRs to have their facility meet the TSIR requirements, including any associated costs required to achieve these requirements.

Request IR-175:

Appendix F Path to 2030 Update pages 648 to 702

Page 678, NS Power states "…Decision Gate 3 (DG3) governance milestone is planned for December 2025. Advancement of the project through DG3 enables project sanction, with kickoff of the construction contract in Q1 2026." The Board has been updated on DG3 after the filing of this application.

(a) Please confirm, for the record in this proceeding, that the DG3 governance milestone has been achieved, the project has been sanctioned, and kickoff of the construction contract is still anticipated to occur in Q1 2026.

Response IR-175:

(a) Confirmed. Please refer to Wasoqonatl Transmission Inc.'s December 22, 2025 letter to the Nova Scotia Energy Board notifying both the Board and participants in Matter M12217 of the NS-NB Reliability Intertie Project achieving the Decision Gate 3 milestone. The letter is provided as Attachment 1 for ease of reference.

WASOQONATL
TRANSMISSION LINE

December 22, 2025

Crystal Henwood
Clerk of the Board
Nova Scotia Energy Board
1601 Lower Water Street, 3rd Floor
Halifax, NS B3J 3S3

RE: Wasoqonatl Transmission Incorporated's Confirmation of Decision Gate Three Milestone

Dear Ms. Henwood:

In its Decision in Matter M12217, the Nova Scotia Energy Board (NSEB, the Board) directed Wasoqonatl Transmission Incorporated (WTI, the Company) to confirm to the Board and registered parties in the Matter when all conditions have been satisfied to meet Decision Gate 3 (DG3).

WTI is pleased to inform the Board and Intervenors that all conditions required to meet DG3 have been satisfied and the NS-NB Reliability Intertie Project will begin major construction in 2026 as planned.

Yours truly,

Mary Ellen Greenough

Director, Legal and Regulatory, ECEI Projects, Nova Scotia Power Inc.

[On behalf of WTI]

Request IR-176:

Appendix F Path to 2030 Update pages 648 to 702

Page 679, NS Power states

> **"Upon receiving direction from the Province that procurement of fast-acting generation would be led by the IESO Nova Scotia, NS Power worked to consolidate and transfer all relevant project materials, including preliminary engineering work, site selection studies, and technical assessments to the Province by November 28, 2024 so that the Province and IESO Nova Scotia were equipped to proceed without delay. NS Power also committed to an ongoing advisory role and has actively supported the IESO Nova Scotia in 2025 through ongoing meetings, providing technical input, clarifications, and emphasizing the urgency of maintaining project momentum."**

(a) Since the filing of this application, the Board understands several NS Power employees have transferred to the IESO Nova Scotia. Please confirm and advise of the number of employees that have transferred and the functions they perform.

(b) Has the transfer of NS Power employees to the IESO Nova Scotia altered NS Power's ongoing advisory role and the support it provides to the IESO Nova Scotia. Please explain.

Response IR-176:

(a) 19 employees from the System Planning Team at NS Power and their functional roles have transferred to the IESO-NS. 17 of these employees support the resource and transmission planning functions (including the VP of System Planning and Procurement for the IESO-NS), with two of the employees providing support for the interconnection engineering function.

(b) NS Power's advisory role is now limited to business and regulatory functions that were not affected by the transfer.

Request IR-177:

Appendix F Path to 2030 Update pages 648 to 702

On page 680, NS Power states "NS Power anticipates that clear direction on project timelines will be available in 2026, following completion of the IESO Nova Scotia-led RFP. If it is evident following this RFP that the currently anticipated timeline is not achievable, NS Power will, in collaboration with the IESO Nova Scotia, consider the appropriate alternatives, including but not limited to options such as adjusting unit retirement dates, requesting equivalency agreements to extend the use of coal until replacement capacity is online, or converting all existing coal facilities to alternative fuels (fuel switching)." In addition to the IESO Nova Scotia collaboration, please confirm that all the suggested options require the approval of both the Federal and Nova Scotia governments, including legislative changes.

Response IR-177:

NS Power confirms that any of the options referenced, including adjusting unit retirement dates, seeking equivalency agreements that would extend coal use, would require approval and/or authorization from both the Federal and Nova Scotia governments. These actions would also need to align with, and in some cases be enabled through changes to, existing regulatory frameworks such as the federal Clean Electricity Regulations (CER) and Nova Scotia's 2030 coal phase-out requirements in provincial legislation.

Request IR-178:

Appendix F Path to 2030 Update pages 648 to 702

At page 681, NS Power states

> **"Transition to the peaking use of Heavy Fuel Oil (HFO) for Lingan units 1, 3 and 4 (approximately 450 MW total) was identified in the 2030 Clean Power Plan and emerged as a consistent outcome across all 2023 Evergreen IRP scenarios. The value of this conversion is supported by the low capital cost (these units already operate on HFO) and the ability for these units to operate in a peaking capacity during periods of net peak demand."**

(a) What is the current estimated cost of the conversion of Lingan units 1, 3 and 4?

(b) What is the current estimated cost of the Point Tupper unit 2 to natural gas

Response IR-178:

(a) and (b) The full cost of conversions is still being developed, with the expectation that the costs can be provided in the 2027 ACE Plan.

Request IR-179:

Appendix F Path to 2030 Update pages 648 to 702

Section 7.3 Green Hydrogen Projects, page 690, discusses three project developers and explains that developers will create and supply renewable resources; will require a new tariff to use the NS Power grid; require energy from NS Power when their self-supplies resources are inadequate; and NS Power may purchase the excess/surplus energy from these developers from time to time.

(a) Is NS Power aware of any off-take agreement between these developers and foreign buyers?

(i) If so, when does NS Power consider that these green hydrogen developments will require access to NS Power's grid and associated tariff?

(b) Are these developers currently constructing their renewable energy supply?

(c) Does NS Power have any information on the potential amount of top up energy the potential project proponents may require?

(d) Does NS Power have any information on the potential transmission system impacts and costs the potential green hydrogen projects could generate?

(e) Is the concept that the "new tariff structure" discussed at page 690 would cover the costs associated with the transmission of power on the NS Power grid required for the green hydrogen projects?

Response IR-179:

(a) No.

(b) NS Power understands that EverWind Fuels (EWF) has acquired and is developing wind projects to support its future operations. According to EWF's website, it is currently progressing four wind projects for a total of 768 MW of installed wind capacity.[1]

(c) NS Power continues to engage with prospective green hydrogen project developers, as described in the 2026 Update to the Path to 2030 Report and prior Path to 2030 updates, to better understand their requirements. As part of this engagement, the Company has been undertaking modeling to better understand how prospective green hydrogen projects may interact with the electricity system, including the amount of top-up that may be required and the level of spill that may be produced. This modeling, and the associated understanding of hydrogen developer requirements, remain under development. Also, as a product of this engagement and modeling, a tariff construct to establish the hydrogen developer-specific utility services is required. The corresponding cost structure and the associated pricing is under development. More information will be available when an application for a proposed tariff to provide service to these customers is filed, at which time the Company expects more details in relation to hydrogen project specific electricity and utility service requirements will be available. Any proposed tariff will be subject to Board approval.

(d) Prospective hydrogen plant projects and their self-supplied resources will have interconnection studies completed to understand the transmission upgrades required to enable the connection to the grid while supporting system stability. The remaining studies yet to be completed will be conducted by the Nova Scotia Independent Energy System

[1] https://everwindfuels.com/projects/#phase-1-nova-scotia

Operator and the results will be provided to NS Power to support future capital work to connect the interconnection and load customers to the system.

(e) Yes. The new tariff structure will provide the framework for the provisions required by new hydrogen developers to connect their facilities and self-supplied generation to the system and transport this electricity to the hydrogen/ammonia production facilities, and the cost structures for these provisions. This is expected to include provisions for firm load, top-up and spill, transportation and ancillary services, fixed-cost recovery, and considerations for renewable energy accounting. As provided in part (c), the construct and provisions of this tariff remain under development. However, work to date has focused on service to the hydrogen market being provided as part of a single comprehensive industry-specific tariff offering, not unbundled utility service tariffs. Once an application for a proposed tariff is ready to be made, more information on the tariff provisions will be available.

Request IR-180:

In reference to Section 8.3 Risk Management, pages 698 and 699

(a) Has consideration of the risks presented by the United States government changing tariff requirements been incorporated into the Supply Chain risks and Transition Planning risks?

(i) Is NS Power able to restrict its procurement to Canadian and European manufacturers/suppliers?

(b) Does this category consider geopolitical risk aside from the Russian invasion of Ukraine?

Response IR-180:

(a) Yes, NS Power examines the tariff requirements as part of the supply chain risks for projects procured by NS Power.

(i) NS Power identifies appropriate procurement strategies for each project to ensure the resources are procured appropriately and at the lowest cost to customers.

(b) Yes, NS Power is aware of geopolitical risks and considers this in the procurement processes on a project by project basis.

Request IR-181:

Appendix F Path to 2030 Update pages 648 to 702

NS Power states "The lead time for combustion turbines, a key component to the Path to 2030, has increased over the last 12 months. Greater clarity on the timelines for combustion turbines will be available in 2026 following the IESO Nova Scotia led RFP and any impact will be assessed at that time."

(a) What was the anticipated lead time for combustion turbines twelve months ago?

(b) What is the magnitude of the increase in the lead time for combustion turbines that occurred in the last twelve months?

Response IR-181:

(a) Twelve months ago, NS Power's understanding of combustion turbine delivery timelines was based on OEM information gathered as part of the 2024 Fast-Acting Generation Plant technology assessment. At that time, OEM-quoted delivery schedules for new simple-cycle gas turbines ranged from 12 to 36 months, depending on the model and manufacturer.

(b) Across OEMs, the magnitude of lead-time increases over the past year has varied by technology. For some industrial turbine models that had previously been available on 12- to 18-month timelines, industry feedback in 2025 indicates that these lead times have lengthened by 6 to 12 months. Overall, NS Power has observed tightening global OEM manufacturing availability and increased demand for fast-acting simple-cycle units, resulting in extended delivery timelines for technologies that previously offered shorter procurement periods. These longer horizons reinforce the importance of the IESO Nova Scotia-led RFP process, which will provide greater clarity in 2026 on achievable delivery schedules for the technology selected through that competitive procurement.

Request IR-182:

Appendix G 5 Year Reliability Plan pages 703 to 773

Page 710, NS Power describes the benefits of the Five-Year Reliability Plan. "The benefits of the program and the impact on the reliability of the system will be felt cumulatively as the combined impacts of reliability investments made over the five years are completed, resulting in a reduction of approximately one hour of SAIDI overall by 2029."

(a) Given that the Plan is projected to cost approximately $1.3B over 5 years, has NS Power calculated the impact on rates the Plan will have?

(b) Has NS Power sought feedback on whether customers might be willing to forego one hour of overall SAIDI improvements to alleviate rate pressures?

(c) How have these targets been developed to ensure they are the most appropriate ones to strive for?

Response IR-182:

(a) The increased investment in 2025, 2026, and 2027 related to the reliability investment plan are included in the General Rate Application currently before the NSEB in matter M12451. The Five-Year Reliability Plan is the investment amount required for NS Power to achieve Board-established performance standards by 2029.

(b) There is currently an ongoing review of the Performance Standards to be in place from 2027-2031, and NS Power expects that the appropriateness of the standards themselves will be discussed in further detail during the review. Customer representatives will have an opportunity to provide feedback about the appropriateness of the standards, and the NSEB will be able to make decisions based on that feedback. If this process results in changes to

the standards or targets, NS Power would revisit the pace and scale of the remaining years of the Five-Year Reliability Plan as necessary.

(c) The targets for SAIDI and Adverse Weather response included in the Five-Year Reliability Plan are directly taken from the targets set in the Performance Standards currently in place.

Request IR-183:

Appendix G 5 Year Reliability Plan pages 703 to 773

Page 710, "NS Power agrees with the NSEB and stakeholders that effective investments lead to the best possible balance between reliability improvements and affordability for customers." How has this trade off been determined?

Response IR-183:

Please refer to NSEB IR – 182 (a).

Request IR-184:

Appendix G 5 Year Reliability Plan pages 703 to 773

Figure 3 at page 714 graphically depicts the Annual Customer Hours of Interruption (Tree Contacts). The 2025 projected total and the 2020 actual total appear roughly equal at just over 500,000 customer hours of interruption.

(a) Does the projected total for 2025 continue to be accurate?

(b) Is it not concerning that vegetation management over a five-year period does not appear to have resulted in significant improvement from the 2020 total to customer interruptions from Tree Contacts?

Response IR-184:

(a) The reported 2025 Customer Hours of Interruption due to Tree Contacts is 548,589.

(b) NS Power does not view its recent vegetation management performance as concerning over the 2020–2025 timeframe, as focusing solely on the customer hours of interruption does not provide the entire context of these efforts. It is important to note that outage duration, and consequently its influence on customer hours of interruption, can be affected by operational response factors outside the initiating cause, such as weather severity, access limitations, crew availability, and time of day.

As shown in tables below, customer hours of interruption related to Tree Contacts, including approximately 40% of adverse weather impacts, have shown improvement as a result of the vegetation initiatives outlined in the Five-Year Reliability Plan. These improvements are further reflected in reduced tree-related customer interruptions

(frequency) during both normal and adverse weather conditions, with considerable improvement observed in 2025.

Year	CI Tree Contact	CI Adverse Weather	CI Tree Contact + 40% Adverse Weather
2020	228,662	127,102	279,503
2021	240,262	197,720	319,350
2022	246,830	104,737	288,725
2023	210,681	129,238	262,376
2024	259,071	114,902	305,032
2025	214,341	47,182	233,214

Year	CH Tree Contact	CH Adverse Weather	CH Tree Contact + 40% Adverse Weather
2020	509,709	312,227	634,600
2021	680,499	683,315	953,825
2022	758,744	430,529	930,956
2023	686,530	394,945	844,508
2024	770,960	461,763	955,666
2025	548,590	148,245	607,888

In addition to lagging performance indicators, NS Power's vegetation management program has improved feeder condition through targeted interventions, a key leading indicator of reduced future tree contacts. Targeted right-of-way widening and trimming on feeders identified with poor condition has reduced the likelihood of future tree-related outages and customer interruptions, even in areas where vegetation-related outages were not yet a large contributor to performance. As vegetation encroaches on conductors and equipment, the risk of tree contacts rises, especially under severe weather conditions. NS Power's vegetation management program improves vegetation condition by addressing these encroachments, mitigates overall system risk, and supports continued reliability improvements reflected in both leading and lagging indicators.

Request IR-185:

Appendix G 5 Year Reliability Plan pages 703 to 773

Figure 4 at page 715 graphically depicts the Annual Customer Hours of Interruption (Failure of Equipment). The 2025 projected total and the 2020 actual total appear roughly equal at just over 400,000 customer hours of interruption.

(a) Does the projected total for 2025 continue to be accurate?

(b) Is it cause for concern that the Plan to date has not shown significant improvement from the 2020 total?

Response IR-185:

(a) Outages coded as Failure of Equipment resulted in 465,871 Annual Customer Hours of Interruption in 2025.

(b) NS Power does not view its recent Distribution Targeted Devices Plan as concerning over the 2020–2025 timeframe, as focusing solely on the customer hours of interruption does not provide the entire context of these efforts. It is important to note that outage duration, and consequently its influence on customer hours of interruption, can be affected by operational response factors outside the initiating cause, such as weather severity, access limitations, crew availability, and time of day.

As shown in the table below, customer interruption frequency and reported incidents related to Failure of Equipment have demonstrated considerable improvements in 2025 compared with 2020, a 38.3% reduction in customer interruptions, reflecting the benefits of NS Power's distribution targeted device replacement program.

Year	Customer Interruption (CI)	Customer Hours of Interruption (CHI)	Event Count
2020	253,326	418,145	3,530
2021	240,052	465,752	3,083
2022	306,092	530,680	2,942
2023	256,600	497,393	2,741
2024	241,600	513,391	2,426
2025	156,378	465,871	2,091

1

Request IR-186:

Appendix G 5 Year Reliability Plan pages 703 to 773

In reference to 2025 Overview – Year One of Five Year Plan on page 716. Please provide the SAIDI and SAIFI for 2025 compared to 2024.

Response IR-186:

The table below shows SAIFI and SAIDI Performance Standards relative to the Five-Year Plan. 2025 results are preliminary, and remain subject to confirmation and/or change in the Annual Performance Standards Report to be filed later in 2026.

Performance Standards	2024	2025
SAIFI	1.97	1.57
SAIDI	5.26	4.79

Request IR-187:

Appendix G 5 Year Reliability Plan pages 703 to 773

In reference to the Overview- Year One of Five Year Plan. The last bullet states "118 hazard tree locations in addition to the 617 kilometers of corridor widening have been proactively identified and addressed from beyond cleared rights-of-way. This work involves coordination with customers and landowners to remove each individual tree. Some of these locations include the removal of multiple trees." How were the hazard trees proactively identified?

Response IR-187:

Hazard trees are identified as defective trees that have a high likelihood of failure. These hazard trees are identified by NS Power employees during regular patrols and by contractors performing right-of-way work. Some healthy trees are also targeted based on species type, exposure to wind and overall perceived risk to the system.

Request IR-188:

Appendix G 5 Year Reliability Plan pages 703 to 773

Page 716 highlights that trees have been cleared from about 617km of distribution line and about 105kms of transmission line rights-of-way.

(a) Please describe the planned maintenance schedule for right-of-way widening.

(b) Please describe how the planned maintenance schedule accounts for local vegetation, weather and other geographical attributes.

Response IR-188:

(a) The planned maintenance schedule for right-of-way widening is determined through the analysis of satellite imagery (proximity of vegetation to conductors) and performance data such as CKAIDI / CKAIFI and historical tree outage data. Ground observations are then conducted to ensure the targeted locations are accurate and the proposed work is achievable. Many of the locations identified will be limited to rural areas and not urban centers. Widening is often not obtainable in urban centers due to a variety of reasons including aesthetics/shade tree benefits, overall customer acceptance, and municipal restrictions.

(b) NS Power field staff will conduct surveys of the identified work and protect vegetation that is compatible with utility overhead infrastructure. Contractors work closely with NS Power field staff and are trained to identify compatible species. For example, low growing species such as alder is a preferred species that are encouraged to grow in the right-of-way. Weather does not play a significant role in identifying locations for planned work. Much of the province has similar exposure to all types of weather events so the perceived outage risks are similar throughout the province. However, post weather event analysis has

influenced the vegetation management plan in the past to address tree damage and hazard trees and likely will influence the plan in the future. Other geographical attributes such as slope, exposure to wind and hydrology is taken into consideration when selecting locations to complete work.

Request IR-189:

Appendix G 5 Year Reliability Plan pages 703 to 773

In reference to Demonstrated Reliability Impact/Benefit on page 719, NS Power states "… it is important to recognize that the full impact of the program will take time to materialize. Meaningful trends and improvements in SAIDI will be more accurately assessed over the full duration of the program at a network level, as upgrades are completed and benefits accumulate across the system." If meaningful trends and improvements can only be accurately assessed after the fact, what recourse do ratepayers have if a $1.3B spend does not result in meaningful improvements?

Response IR-189:

The statement made by NS Power at page 719 of the 5-Year Reliability Plan should not be interpreted as suggesting that no demonstrable or meaningful improvements will occur until the program is fully completed. Rather, NS Power was clarifying that the reliability impact of an individual project is difficult to quantify in isolation. Accordingly, the absence of an immediate improvement in performance metrics following the completion of a single project should not be taken as evidence that the Plan is not achieving its intended objectives.

The effectiveness of the program is best assessed on a cumulative basis, by evaluating changes in the risk score of an asset, such as a distribution feeder, over time following one or more investments. This approach incorporates both leading and lagging indicators of risk, including performance metrics, and provides confidence that capital investments are producing the intended outcomes.

Ultimately, the program is expected to deliver a more reliable grid that is better able to withstand and recover from external system stresses. Based on 2025 results, NS Power is already observing

improvements toward meeting performance standards. NS Power's improvements will continue to be assessed on an ongoing basis through annual performance standards reviews.

Request IR-190:

Appendix G 5 Year Reliability Plan pages 703 to 773

In reference to Storm Hardening-Vegetation Management on pages 723 to 724, NS Power discusses work restrictions imposed by the Department of Natural Resources because of drought and wildfire conditions, and their impact on the vegetation management work plan. NS Power goes on to say the restrictions.

> **"…did result in a reduction in the number of kms of vegetation managed under the program in 2025 as detailed in Figure 9 and Figure 12. This work will be reprioritized for completion in 2026."**

(a) Will the full 2025 vegetation management budget of $45M still be spent in 2025 despite the lower number of kms? If so, please explain why.

(b) Does this mean NS Power anticipates spending more than $45M on vegetation management in 2026?

Response IR-190:

(a) Yes, the full $45 million budget in 2025 was spent. The lower number of kms is primarily driven by the wildfire restrictions (mandated by the Department of Natural Resources from August 5, 2025, to October 31, 2025 (please refer to Section 4.1 Wildfire Mitigation of Appendix G to the 2026 ACE Plan application). which significantly reduced efficiency due to mandatory monitoring activities.

(b) No, NS Power forecasts close to $45 million investment in Vegetation Management in 2026.

Request IR-191:

Appendix G 5 Year Reliability Plan pages 703 to 773

Figure 19 on page 736 shows the 2025 Recloser Installation Plan and Progress.

(a) How were these locations chosen?

(b) Can the seven new reclosers be remotely operated?

Response IR-191:

(a) Consistent with NS Power's asset management mechanism, the seven vacuum electronic reclosers installed in 2025 replaced existing hydraulic reclosers, with emphasis placed on feeders with higher risks resulting from reliability performance measures (including performance feeders). Specific hydraulic reclosers were selected for replacement based on customers served, overload, required significant maintenance, and/or required more advanced and configurable overcurrent protection settings to properly coordinate with other overcurrent protection devices on the feeder.

(b) No, the devices will not be able to be remotely operated immediately upon installation. The replacement reclosers will be installed with standard intelligent recloser controls that are compatible with remote monitoring and control capabilities.

Request IR-192:

Appendix G 5 Year Reliability Plan pages 703 to 773

Figure 20 on page 737 shows the 2025 Planned Trip Saver Installation's.

(a) How were the locations for the Trip Saver Installations chosen?

(b) Can the Trip Savers be operated remotely?

Response IR-192:

(a) The locations for the TripSaver installations were identified through NS Power's asset management mechanism, using feeder risk profiles to prioritize locations where targeted reliability improvements will have the greatest customer benefit. The 16 trip savers were installed on single-phase sections of feeders as a compliment to other reliability interventions such as vegetation management, targeted device replacements, etc.. Specific installation locations were selected by identifying longer single-phase sections to help resolve transient faults where a fuse is less effective.

In plain terms, these were sections of line where a transient or temporary fault—such as a tree branch contact or momentary lightning strike—would cause a fuse to blow and leave a large number of customers without power until a crew arrived. TripSavers are designed to "trip and reclose" automatically for temporary faults, restoring power within seconds without dispatching a crew. Installing TripSavers at these locations therefore helps prevent unnecessary outages due to transient faults, improves restoration speed, and reduces customer impact on feeder sections that historically have experienced more reliability challenges and protection coordination limitations.

(b) No.

Request IR-193:

Appendix G 5 Year Reliability Plan pages 703 to 773

Can NS Power provide a breakdown of the anticipated 2025 investments by the following categories:

- **Recloser Installations**
- **Trip save Installations**
- **New Distribution Feeders**
- **Updated Overhead Standards**
- **Distribution Build to Roadside**
- **Distribution System Conductor Upgrades**
- **Distribution System Underground Upgrades**

Response IR-193:

Please refer to the table below.

Program	Investment by Program (M)
Recloser Installations	$0.36M
Trip Saver Installations	$0.09M
New Distribution Feeders	$0.51M
Distribution Build to Roadside	$2.03M
Distribution System Conductor Upgrades	$8.29M
Distribution System Underground Upgrades	$4.06M

Please note, updated overhead standards is not a specific project. Rather, new, updated standards are incorporated into all distribution projects.

Request IR-194:

Appendix G 5 Year Reliability Plan pages 703 to 773

Figure 38 on page 758 summarizes the 2026 Ongoing Maintenance Around Existing Power Lines work plan. How were or will the locations be selected?

Response IR-194:

The locations are selected based on a combination of currently assessed vegetation condition and past performance related to events coded as tree contacts and adverse weather.

Request IR-195:

Appendix G 5 Year Reliability Plan pages 703 to 773

Figure 39 on page 759 summarizes the 2026 Build to Roadside Projects. How were these projects selected?

Response IR-195:

These projects are selected by adhering to the principles and guidelines within NS Power's Asset Management Mechanism. Build to Roadside Projects targeted high risk feeders with emphases on performance feeders and poor reliability. Specific segments were selected where rebuilding to roadside offered the most effective mitigating measure to reducing outage impacts, improve accessibility for field resources, and delivers the greatest overall improvement in reliability and value to customers. In addition, project readiness and Grade 1 assessments were evaluated to further refine the 2026 project locations and flag scheduling constraints. Locations which did not have grade 1 assessment requirements or significant easement concerns were expected to have a quicker turnaround time. A grade 1 strength assessment is required for any pole lines that are built over 100 series highways, rail crossings and some waterways, these are designed by an external engineering consultant and often take upwards of a year to complete. Designs that would include multiple easements often take a significant amount of time as well (a year or more in many cases) to have agreements in place or can often require redesigns with new easement requests.

Request IR-196:

Appendix G 5 Year Reliability Plan pages 703 to 773

Figure 40 on page 760 summarizes the 2026 Distribution System Conductor Upgrades. How were the locations selected?

Response IR-196:

These locations are selected based on NS Power's assessment of feeder risk. Condition is assessed through a combination of inspections results (e.g. indicating the number of sleeves per distribution line), history of past failures, and SME input on other conditions impacting the conductor. This is combined with the criticality of the feeders, including consideration for customer counts and overall loading. Specifically for conductor assets, there is also consideration of the ability to work with live line methods on the conductor based on sizing and type.

Request IR-197:

Appendix G 5 Year Reliability Plan pages 703 to 773

Figure 41 on page 760 summarizes the 2026 Distribution System Underground Upgrades. How were the locations selected?

Response IR-197:

To clarify, Figure 41 does not outline underground upgrades; it provides details about the Distribution Line and Phase Extension Projects by Region. NS Power assumes this question does relate to underground upgrades, and accordingly, has provided its response below.

The locations for Distribution System Underground Upgrades were identified through NS Power's Asset Management Mechanism, utilizing feeder risk profiles to prioritize locations where targeted reliability improvements will have the greatest customer benefit. Upgrades for Kentville (50V-202) were selected due to condition assessments and several recent failures on specified section of underground line. Upgrades in Halifax were selected based on criticality of specified locations and condition assessments derived from inspections.

Request IR-198:

Appendix G 5 Year Reliability Plan pages 703 to 773

Figure 42 on page 763 illustrates the 2026 Targeted Transmission Projects. How were the locations selected?

Response IR-198:

These projects are selected by adhering to the principles and guidelines stated within the Board-approved Capital Expenditure Justification Criteria (CEJC) and NS Power's Asset Management Mechanism. As per Appendix G 5 Year Reliability Plan page 747, this investment and work plan is informed by the NS Power's transmission risk profiles, including inputs from transmission inspection programs and past reliability performance, with projects focused on replacing and upgrading transmission structures, reinforcing conductor systems, and executing targeted realignments and rebuild.

Request IR-199:

Appendix G 5 Year Reliability Plan pages 703 to 773

Figure 43 on page 764 summarizes the 2026 Substation Upgrades and Replacements. How were the locations selected?

Response IR-199:

The locations identified in Figure 43 were selected through NS Power's asset management mechanism, which assigns each transformer a risk profile based on its probability of failure and the consequence of that failure. These profiles are updated regularly using information from condition assessments, including dissolved gas analysis, oil quality results, electrical testing performed during maintenance work, thermography, and visual inspections. Changes in system conditions—such as load growth, feeder loading, contingency performance, and customer criticality—are also incorporated into the risk evaluation. Assets demonstrating deteriorating condition, elevated operational risk, or emerging system constraints are prioritized for investment ahead of others. When the risk level indicates that mitigation is required and repair or refurbishment is not technically or economically viable, replacement or addition is recommended.

Please also refer to the "Justification" column in the table below.

Transformer	Location	Region	Activity	Justification
91H-T11	Dartmouth	Metro	Replacement	Please refer to CI C0031048 in 2025 ACE Plan.
10H-T1	Halifax	Metro	Replacement	Please refer to CI C0055539 in 2023 ACE Plan.
10H-T2	Halifax	Metro	Replacement	The transformer is at the end of its useful life. This is a sister project with CI # C0055539 (10H-T1); both transformers are identical and provide the hospital with a redundant power supply. This project will be submitted to the NSEB for approval at a later date.

96H-T1	Sheet Harbour	Northeast	Replacement	Please refer to CI C0053234 in 2026 ACE Plan.
1N-T66	Onslow	Northeast	Addition	This transformer addition is necessary to supply local load growth in the area and reduce the loading on existing transformers in the 1N substation. This project will be submitted to the NSEB for approval at a later date.
77V-T1	Conway	West	Replacement	This transformer will be replaced with a larger capacity unit to supply local load growth in the area. This project will be submitted to the NSEB for approval at a later date.
76W-T1	Mahone Bay	West	Replacement	Please refer to CI C0053214 in 2026 ACE Plan.
70W-T52	Bridgewater	West	Addition	Please refer to CI C0070909 in 2026 ACE Plan.

1

Request IR-200:

Appendix G 5 Year Reliability Plan pages 703 to 773

Figure 44 on page 765 summarizes the 2025/2026 Planned Remote Terminal Unit Replacements. How were the locations chosen?

Response IR-200:

The planned 2025/2026 Remote Terminal Unit (RTU) replacements in the project C0051815*, RTU Replacements Phase 6,* were identified and prioritized using NS Power's asset management mechanism. NS Power's RTU Risk Matrix assigns each RTU a risk rating based on its probability of failure and consequence of that failure. The Risk Matrix incorporates factors such as equipment age, issue history, lifecycle support status, and the criticality of the connected substation, along with operational considerations such as the presence of overloaded or problem feeders. RTUs that are older, exhibit operational issues, are no longer supported by the manufacturer, or serve high-criticality substations are prioritized ahead of others.

The sites identified for 2025/2026 replacement were chosen based on several factors including coordination of work with scheduled outages or other capital work at the sites. The order of implementation of the sites is subject to change as more information becomes available during this multi-year project.

Request IR-201:

Appendix G 5 Year Reliability Plan pages 703 to 773

Figure 45 on page 766 summarizes the 2025/2026 Planned Communications Path with Downline Reclosers Installation. How were the locations selected?

Response IR-201:

The locations were selected based on addressing feeder risk factors and leveraged input from local regional engineering experience in consideration of factors including:

- Reclosers located in remote areas with significant customer counts.
- Locations where outages commonly result in longer drive times where remote connectivity would be most effective.
- Locations where access to fault information would be opportune to troubleshooting and restoration efforts.
- Areas where other projects (such as C0071528 FLISR Project) were being planned or considered were not included in the selection.

In line with NS Power's asset management mechanism, the selected locations reflect feeder risk profiles that identify where targeted automation enhancements will deliver the greatest reliability benefit. These locations represent sections of the system where improved situational awareness and faster fault response are expected to meaningfully reduce customer impact.

Request IR-202:

Appendix I Completed Transmission Line Replacement and Upgrade Projects page 782

In response to one of the 2025 ACE Plan Board directives, the utility provided a list of transmission line replacement and upgrade projects that have been approved and completed since the 2021 ACE Plan. If the cost of C0043010 is excluded, please confirm that the total actual cost of the nine transmission line replacement and upgrade projects is $22,377,307.

(a) Please provide the dates on which these transmission lines were originally commissioned, and indicate how many kilometers were refurbished and upgraded as part of the project noted in Appendix I.

(b) How does the utility assess the effectiveness of refurbishment and upgrade activities in terms of reducing the probability of failure of existing transmission lines and the cost per kilometer? Please provide an example, if possible.

Response IR-202:

Confirmed.

(a) Please refer to the table below. Upgrades were completed on 144.92 kms of transmission line associated with the project in Appendix I. NS Power estimated the number of kilometers based on the number of structures refurbished and the span lengths.

CI#	Project Long Title	Original Commissioned Date	Number of Structures Refurbished	Avg Structures Per Km	Estimated Kms
C0031069	L6020 Replacements and Upgrades	1963	76.00	4.91	15.48

C0031085	L6516 Line Replacement and Upgrades	1964	77.00	4.26	18.08
C0041789	L5550 Replacements and Upgrades Phase 2	1976	76.00	4.68	16.24
C0041793	L7002 Replacements and Upgrades Phase 2	1970	72.00	4.53	15.09
C0041796	L6020 Replacements and Upgrades Phase 2	1963	114.00	4.91	23.22
C0041800	L5537 Replacements and Upgrades	1971	16.00	6.23	2.57
C0041805	L7005 Replacements and Upgrades Phase 2	1983	71.00	4.65	15.27
C0041810	L5022 Replacements and Upgrades	1981	101.00	6.65	15.19
C0011339	L6549 Replacements and Upgrades Phase 2	1977	105.00	4.57	22.98

(b) Consistent with NS Power's overall asset management system, the Company uses a risk-based approach to identify lines and structures requiring mitigating interventions, including asset replacement, based on their assessed condition and criticality. Such asset replacements would be reflected in updated rating for condition factors associated with the work and consequently the ultimate risk rating for a given line would change following execution of the project. The scale of change in condition rating would depend on the scope and scale of the interventions and multi-phase projects may require several years to realize the full condition changes.

The effectiveness of a project (in this case, the refurbishment of transmission lines with more modern materials and construction practices), is determined by the resultant improvement in the overall asset condition, which corresponds to a reduction in the likelihood of future outages due to equipment failure compared with a do-nothing approach. For example, in C0080110 of the 2026 ACE Plan (page 358), 72 structures are listed as requiring full or partial structure replacements as they are deteriorated and at risk

of failure. Once the project is completed, the associated structures are better able to withstand wind and ice loading, thereby improving the line's ability to perform reliably.