CI 43324

Replace L6513 / Upgrade Line Terminals

NON CONFIDENTIAL

January 27, 2022

Nova Scotia
POWER
An Emera Company

Nova Scotia POWER An Emera Company

UARB APPROVAL SHEET

Project Title: Replace L6513/Upgrade Line Terminals

CI Number: 43324

Date: January 27, 2022

Expenditure Profile

Year	Budget Amount	Project Estimate
2013	54,114	54,114
2014	323,882	319,327
2015	10,481,516	1,772,577
2016	10,440,016	229,737
2017	767,619	8,183,452
2018		8,043,563
2019		22,523
2020		1,872
2021		(736)
Total	$22,067,148	$18,626,428

Type of Filing

- [X] Capital Project Authorization
  - [ ] Unforeseen and Unbudgeted (U&U)
  - [ ] Planned & Advanced (P&A)
  - [ ] Subsequent Approval Item
- [ ] Authorization to Overspend (ATO)
- [ ] Scope Change
- [ ] Final Cost (FIN)

COMMENTS

This project was originally submitted to the NSUARB on on January 13, 2015. The NSUARB provided its Decision on August 28, 2015 and did not approve it at that time. NS Power is resubmitting this project for the Board's approval as part of the Company's General Rate Application.

Original Submission	$22,067,148
Current Amount	$18,626,428
Variance	($3,440,719)

Submitted on behalf of NOVA SCOTIA POWER INCORPORATED

Lia M. MacDonald

January 21, 2022

Authorized Signatory — DATE
Lia MacDonald
VP Trans/Distribution/Delivery

Approved on behalf of NOVA SCOTIA UTILITY AND REVIEW BOARD

DATE

CI Number: 43324

Title: Replace L6513/Upgrade Line Terminals

Start Date: 2013/08
In-service Date: 2018/07
Final Cost Date: 2021/11
Function: Transmission
Forecast Amount: $18,626,428

DESCRIPTION:

This project consisted of building a new transmission line (L6613) which replaced the adjacent line (L6513) for a designed operating temperature of 100˚C with a summer rating of 320 MVA and a winter rating of 363 MVA utilizing 1113 kcmil Beaumont conductor. This replacement line was necessary to support the energy flows associated with the Maritime Link project (ML). L6513 had an operating temperature of 50˚C, with a summer rating of 110 MVA and a winter rating of 165 MVA. Also included in this project was the upgrading of protection schemes and metering at both the 1N-Onslow and 74N-Springhill substations to accommodate the increase.

This project was originally submitted to the NSUARB on January 13, 2015. The NSUARB provided its Decision on August 28, 2015 and did not approve it at that time. NS Power is resubmitting this project for the Board's approval as part of the Company's General Rate Application.

Summary of Related CIs +/- 2 years
Pursuant to Section 11.2 of the CEJC, related CIs for Transmission projects include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)."

- 2015 – CI 43678 Separate L8004/L7005 on Canso Crossing Double Circuit Tower $20,385,511
- 2015 – CI 45066 Upgrade L6511 and L7019 Thermal Rating $2,691,017
- 2014 – CI 45067 345 KV Node Swap $2,982,715

Depreciation Class: Transmission Plant- Station Equipment, Poles and Fixtures, Overhead Conductors and Devices, Land Rights- Easements

Estimated Useful Life: 45 Years

Retirement Information:
Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets

- Percentage of Asset Pool: 1.0%

JUSTIFICATION:

Justification Criteria: Transmission

Why do this project?

This project was required for a 330 MW Firm Point-to-Point transmission service request and a 170 MW Network Service request as part of the new Maritime Link HVDC interconnection between Nova Scotia Power and Newfoundland and Labrador Hydro. This project allows Nova Scotia (NS) to export up to 330 MW while delivering 170 MW of ten-minute operating reserve (if called upon to do so by NB under the reserve sharing agreement) from NS to New Brunswick (NB) for a total of 500 MW flow from NS to NB. This project benefits NS by facilitating electrical energy purchases or sales from NL to NS or to NB and from NB to NS or to NL when such economic transactions benefit NS.

Why do this project now?

The System Impact Study Report TSR400-SIS2-R1 prepared by the Nova Scotia Power System Operator dated 2013-03 identified six actual, or potential, system upgrades required to prevent NS Power transmission related thermal overloads and / or voltage collapses which may occur during system contingency events. This project was identified as one of the required system upgrades and was addressed (and placed in-service) prior to the interconnection of the ML Project to the NS Power transmission system.

This new line (L6613) eliminated the system constraints and associated system reliability concerns when the ML Project was brought online. Energy from the Maritime Link is being received by NS Power.

Why do this project this way?

L6513 which is located between the 1N-Onlsow and 74N-Springhill substations was originally built in 1965 utilizing a wood pole H-frame / timber cross arm design and was approaching 50 years of service. The line previously had a number of electrical clearance issues and deteriorated poles, cross arms, insulators, and associated hardware that would need to have been addressed. At the time, NS Power determined it was not technically feasible to repair or upgrade this line in its condition. The line design requirements did not accommodate an upgrade or repair as the new line has a larger conductor and therefore a different pole structural design. Therefore, the line was replaced.

L6513 directly supplied distribution customers fed off the 81N-Debert substation which is located approximately 12 km from the 1N-Onslow end and 52 km from the 74N-Springhill terminal. To avoid unnecessary disruptions in service to the customers in this area, the most cost effective solution was to maintain service with the existing line while constructing a new line in the adjacent right-of-way. The adjacent new line was built to present day standards and helped minimize the required customer interruptions during the final connection phase of the project as well as addressing the previously listed ongoing operating concerns with the old line.

Variance Explanation

The reduction of $3,440,719 from $22,067,148 in the original submission to $18,626,428 in this submission is due to the completion of subsequent additional detailed engineering and scoping. The design was subsequently optimized to reduce the quantity of transmission wood structure and respective hardware required to support the weight of the heavier conductor (Beaumont conductor) that is necessary to accommodate the 100˚C thermal rating. This has resulted in corresponding cost reductions in most budget categories as described in more detail in the Variance Page.

CI Number : 43324-T782 - Replace L6513 / Upgrade Line Terminals

Project Number 43324-T782

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General

Budget Version UARB Submissions

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - TP - Land Rights	1,437,235
Additions	0300 - TP - Bldg.,Struct.Grnd.	48,140
Additions	3500 - TP - Wood Poles	15,112,393
Additions	3800 - TP - Insulators	245,231
Additions	3900 - TP - O/H Cond.	1,678,388
Additions	4000 - TP - O/H Cond.Devices	2,185
Additions	4300 - TP - Substn Dev.	102,856
	Total Cost:	18,626,428
	Original Cost:	4,104,507

Capital Project Detailed Estimate

Location: Transmission
CI# / FP#: 43324-T782
Title: Replace L6513 / Upgrade Line Terminal
Execution Year: 2013-2020

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
530050 Regular Labour						
T&D Labour	PD	722	$ 426	$ 307,687		
			Sub-Total	$ 307,687		
530200 OT Labour						
T&D Overtime Labour	PD	29	$ 734	$ 21,524		
			Sub-Total	$ 21,524		
530300 Term Labour						
T&D Labour	PD	208	$ 367	$ 76,353		
			Sub-Total	$ 76,353		
530320 Term Labour - Overtime						
T&D Overtime Labour	PD	2	$ 734	$ 1,740		
			Sub-Total	$ 1,740		
530900 Office Supplies						
Office Supplies	LOT	1	$ 32	$ 32		
			Sub-Total	$ 32		
530950 Travel Expense						
Travel Expenses	LOT	1	$ 26,495	$ 26,495		
			Sub-Total	$ 26,495		
531400 Materials						
Wood Poles	LOT	1	$ 1,493,486	$ 1,493,486		
Conductor	LOT	1	$ 1,260,854	$ 1,260,854		
Insulators, Guys, Connectors, Hardware, Miscellaneous	LOT	1	$ 698,413	$ 698,413		
Steel Cross-arms & Cross-braces	LOT	1	$ 530,876	$ 530,876		
Composite Poles	LOT	1	$ 179,803	$ 179,803		
Right of Way Clearing	LOT	1	$ 44,010	$ 44,010		
Protection & Control (P&C) Materials	LOT	1	$ 33,505	$ 33,505		
Other	LOT	1	$ 15,313	$ 15,313		
Crane	LOT	1	$ 2,400	$ 2,400		
			Sub-Total	$ 4,258,660		
531550 Contracts						
Line Construction Services	LOT	1	$ 8,860,618	$ 8,860,618		
Right of Way Clearing	LOT	1	$ 894,159	$ 894,159		
Protection & Control - Engineering, Construction Supervision	LOT	1	$ 386,514	$ 386,514		
Design & Construction Survey Services	LOT	1	$ 265,645	$ 265,645		
Line Design - Engineering	LOT	1	$ 89,094	$ 89,094		
Delivery & Offload Miscellaneous Material	LOT	1	$ 14,147	$ 14,147		
CADD Services	LOT	1	$ 12,970	$ 12,970		
Crane	LOT	1	$ 12,428	$ 12,428		
Protection & Control - Engineering	LOT	1	$ 7,490	$ 7,490		
Wood Poles	LOT	1	$ 7,202	$ 7,202		
Archaeological Screening	LOT	1	$ 4,471	$ 4,471		
Steel Cross-arms & Cross-braces	LOT	1	$ 4,174	$ 4,174		
Railway Flagging	LOT	1	$ 3,575	$ 3,575		
Traffic Control	LOT	1	$ 3,022	$ 3,022		
			Sub-Total	$ 10,565,509		
532100 Telephones						
Telephones	LOT	1	$ 685	$ 685		
			Sub-Total	$ 685		
532500 Consulting						
Archaeological Assessments	LOT	1	$ 67,825	$ 67,825		
Line Design	LOT	1	$ 175,626	$ 175,626		
			Sub-Total	$ 243,451		
533400 Meals						
Meals	LOT	1	$ 2,931	$ 2,931		
			Sub-Total	$ 2,931		
533100 External Legal and Audit						
Legal and Audit	LOT	1	$ 34,054	$ 34,054		
			Sub-Total	$ 34,054		
535950 Royalty, Easement, Appraisal						
Royalty, Easement, Appraisal	LOT	1	$ 159,948	$ 159,948		
			Sub-Total	$ 159,948		
605050 Interest Capitalized						
AFUDC				$ 440,263		
			Sub-Total	$ 440,263		
535650 Vehicle Overhead						
Vehicle AO				$ 86,119		
			Sub-Total	$ 86,119		
535700/535705 Administrative Overhead						
Labour AO				$ 683,633		
Contract AO				$ 1,717,344		
			Sub-Total	$ 2,400,978		
			SUB-TOTAL (no AO, AFUDC)	$ 15,699,068		
			TOTAL (AO, AFUDC included)	$ 18,626,428		
Original Cost				$ 4,104,507		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Account	Original Submission	Final Submission Actuals	Variance	Reason for Variance
530050 Regular Labour	95,163	307,687	212,524	These costs primarily include project management, project administration, T&D engineering (drawing review and design (for switch replacements and upgrading of protection schemes at both the 1N-Onslow and 74N-Springhill substations)), CADD support, procurement, material and contractor management. Additional costs are primarily due to providing engineering construction support internally as oppose to outsourcing as originally forecasted.
530200 Overtime Labour	-	21,524	21,524	
530300 Term Labour	-	76,353	76,353	Environmental department hired a term employee to oversee onsite construction from an Environmental perspective.
530320 Term Labour-Overtime	-	1,740	1,740	
530900 Office Supplies	-	32	32	
530950 Travel Expense	7,400	26,495	19,095	
531400 Materials	4,337,250	4,259,883	(77,367)	The design was optimized to reduce the quantity of transmission wood pole structures and associated framing (including cross-arms, cross-braces, anchors, guys, insulators, hardware, etc.) installs required to support the weight of the heavier Beaumont conductor that is necessary to accommodate the 100C thermal rating, which resulted in less materials required.
531550 Contracts	10,801,256	10,565,509	(235,747)	The design was optimized to reduce the quantity of transmission wood pole structures and associated framing (including cross-arms, cross-braces, anchors, guys, insulators, hardware, etc.) installs required to support the weight of the heavier Beaumont conductor that is necessary to accommodate the 100C thermal rating, which resulted in less overall work for the Contractor to complete the job.
532100 Telephones	-	685	685	
532500 Consulting	313,400	243,451	(69,949)	Engineering construction support was intended to be outsourced but was performed inhouse which resulted in a reduction of consulting costs. The line design was performed by external consultants as intended.
533100 External Legal and Audit	30,686	34,054	3,368	
533400 Meals	5,000	2,931	(2,069)	
535100 Other Goods and Services	1,545,191	-	(1,545,191)	Contingency was not required.
535650 Vehicle Allocated Costs	38,158	86,119	47,962	Due to increased labour.
535700/535705 Admin Overheads	2,648,444	2,399,755	(248,689)	Lower Contract AO as a result of decreased contracts, partially offset by increased administrative AO as a result of increased labour.
535950 Royalty, Easement, Appraisal	125,426	159,948	34,522	
605050 AFUDC Interest	2,105,976	440,263	(1,665,713)	As a result of changes in the timing of execution of the project. Original submission assumed significant work would be completed on the project in 2015-2016, with a 2017 in-service date, resulting in increased AFUDC; however, due to changes in timing of execution of the project, this significant work on the project was completed from 2017-2018, resulting in lower AFUDC.
536100 Rental/Maint of Equipment	13,800	-	(13,800)	
Grand Total	**22,067,148**	**18,626,428**	**(3,440,719)**	

CI 43678

Separate L8004/L7005 on Canso Crossing Double Circuit Tower (DCT)

NON CONFIDENTIAL

January 27, 2022

Nova Scotia
POWER
An Emera Company

Nova Scotia POWER An Emera Company

UARB APPROVAL SHEET

Project Title: Separate L8004/L7005 on Canso Crossing Double Circuit Tower (DCT)

CI Number: 43678 **Date:** January 27, 2022

Expenditure Profile		
Year	Budget Amount	Project Estimate
2014	68,290	68,290
2015	1,345,363	1,345,363
2016	1,174,001	1,174,001
2017	16,663,946	15,165,340
2018		2,609,863
2019		22,654
2020		-
2021		1,767
Total	$19,251,601	$20,387,278

Type of Filing

- [X] Capital Project Authorization
- [ ] Unforeseen and Unbudgeted (U&U)
- [ ] Planned & Advanced (P&A)
- [ ] Subsequent Approval Item
- [ ] Authorization to Overspend (ATO)
- [ ] Scope Change
- [ ] Final Cost (FIN)

COMMENTS

This project was originally forecasted as a subsequent submission in the 2014, 2015, 2016, and 2017 ACE Plans. It was referenced in the 2018 ACE Plan with an updated budget of $19,251,601. It is now being submitted for approval as part of the Company's General Rate Application. It was not previously submitted to the NSUARB. The project is complete and all costs are final.

Original Submission	$19,251,601
Current Amount	$20,387,278
Variance	$1,135,677

Submitted on behalf of NOVA SCOTIA POWER INCORPORATED

Lia M. MacDonald

January 21, 2022

Authorized Signatory DATE
Lia MacDonald
VP Trans/Distribution/Delivery

Approved on behalf of NOVA SCOTIA UTILITY AND REVIEW BOARD

DATE

CI Number: 43678

Title: Separate L8004/L7005 on Canso Crossing Double Circuit Tower (DCT)

Start Date: 2014/01
In-Service Date: 2018/07
Final Cost Date: 2021/11
Function: Transmission
Forecast Amount: $20,387,278

DESCRIPTION:

This project consisted of building a second transmission line tower crossing over the Strait of Canso to physically separate two existing transmission lines that shared common towers. As a result of the increased capacity and energy supplied by the Maritime Link, the transmission lines in the vicinity of the Canso Causeway needed to be reconfigured.

The previous crossing consisted of two double circuit suspension towers, six anchor structures and high strength self-dampening conductor. The span over the Strait of Canso was approximately 1.5 km with additional spans of 1.0 km and 0.7 km to the anchor towers on the adjacent hills. A 345kV transmission line L8004 and a 230kV transmission line L7005 shared common towers on the existing crossing.

The new crossing consists of a completely integrated design from anchor structure to anchor structure, as well as supporting structures to reconnect back into the existing circuit (L7005). The new transmission line crossing, with associated suspension and anchor towers, was constructed approximately 45 m south of the existing L7005/L8004 structures which are located approximately 1.5 km north of the Canso Causeway.

This project was originally forecast as a subsequent submission in the 2014, 2015, 2016, and 2017 ACE Plans. It was referenced in the 2018 ACE Plan with an updated budget of $19,251,601. It is now being submitted for approval as part of the Company's General Rate Application. It was not previously submitted to the NSUARB. The project is complete and all costs are final.

Summary of Related CIs (+/- 2 years):
Pursuant to Section 11.2 of the CEJC, related CIs for Transmission projects include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)."

- 2015 – CI 43324 L-6513 Rebuild/Upgrade Line Terminals $18,627,164
- 2015 – CI 45066 Upgrade L6511 and L7019 Thermal Rating $2,691,017
- 2014 – CI 45067 345 KV Node Swap $2,982,715

Depreciation Class: Transmission Plant – Poles and Fixtures, Overhead Conductors and Devices, Station Equipment, Land Rights – Easements

Estimated Life of the Asset: 45 Years

Retirement Information:
Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets

- Percentage of Asset Pool: 0.0%

JUSTIFICATION:

Justification Criteria: Transmission

Why do this Project?

L8004 is a 345kV line between 101S-Woodbine and 79N-Hopewell. L7005 is a 230kV line between 3C-Port Hastings and 67N-Onslow.

The Transmission Service Request and associated System Impact Study (Report TSR400-SIS2-R1 prepared by the Nova Scotia Power System Operator dated 2013-03) for the Maritime Link Project studied the requirement for

330MW of firm point-to-point transmission capacity and the addition of a 170MW Network Resource. The study identified that for the single contingency of a common tower failure on the previous 345kV/230kV Strait Crossing, a number of the remaining 230kV and 138kV lines would be overloaded beyond the acceptable criteria of 110 percent. The simultaneous loss of both of these lines, with the additional power flows from the Maritime Link, would have resulted in the remaining transmission system becoming electrically unstable.

The transmission lines across the Strait of Canso have been re-configured to remove the single contingency associated with the common towers to reliably meet the required transfer level of the Maritime Link energy. The reconfiguration entailed the separation of the 345kV line (L8004) and the 230kV line (L7005) that originally shared the existing double circuit tower (DCT) at the Auld's Cove crossing location.

Why do this Project Now?

The System Impact Study Report TSR400-SIS2-R1 prepared by the Nova Scotia Power System Operator dated 2013-03 identified six actual, or potential, system upgrades required to prevent NS Power transmission related thermal overloads and/ or voltage collapses which may occur during system contingency events. This project was identified as one of the required system upgrades for the Maritime Link Project and was placed in-service prior to the interconnection of the Maritime Link Project to the NS Power transmission system.

The Maritime Link Project was initially scheduled to be in-service by Q3 2017. The execution on this project was scheduled to effectively meet design and material delivery timelines, accommodate system outage constraints, and minimize or avoid environmental impacts associated with construction. Energy from the Maritime Link is being received by NS Power.

Why do this Project this Way?

The option executed under this project was compared to two alternatives to determine the most cost-effective and technically feasible option:

- Swap L7005 and L6515 which would place L7005 on the Canso Causeway (L6515 Right of Way (ROW)) and L6515 on the double circuit tower (DCT) on the previous/old crossing.

- Remove L7005 from the double circuit tower (DCT) and go undersea across the Strait of Canso with submarine cable.

The first alterative was not technically feasible as it was determined to present safety risks, a long schedule, and environmental and customer impacts. The second alternative to construct a submarine cable was not pursued as costs were expected to be more than triple the budget for the project, and there were high potential safety risks.

Of the technically feasible options to eliminate the potential for a single contingency common tower fault, the option to build a second crossing, directly adjacent to the existing tower crossing located at Auld's Cove, to physically separate these two lines was chosen. This option was chosen because it was the best technical solution, the most cost effective, and minimized environmental and customer impact.

Reason for Variance

The increase of $1,135,677 over the 2018 ACE Plan budget of $19,251,601 to $20,387,278 in this submission is due to the completion of subsequent additional detailed engineering and scoping. At the time of the 2018 ACE Plan the detailed engineering was complete and construction was underway. The cost increase was a result of contracting specialized contractors, such as deploying a Skycrane helicopter for the installation of the towers. Further, post construction avian monitoring was carried out as a requirement of the registered Environmental Assessment as identified under Schedule A of the Regulations.

CI Number :	43678-T800	- Separate L8004/L7005 on Conso Crossing Double Circuit Tower(DCT)	**Project Number**	43678-T800
Parent CI Number :		-		
Asset Location :	1455	- 1455 Transmission Plant General	**Budget Version**	UARB Submissions

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	0200 - TP - Land Rights		672,151
Additions	0300 - TP - Bldg.,Struct.Grnd.		24,529
Additions	3500 - TP - Wood Poles		2,682,913
Additions	3800 - TP - Insulators		1,155,471
Additions	3900 - TP - O/H Cond.		15,848,813
Retirements	3500 - TP - Wood Poles		1,914
Retirements	3900 - TP - O/H Cond.		1,487
		Total Cost:	20,387,278
		Original Cost:	4,630

Location: Transmission
CI# / FP#: 43678-T800
Title: Separate L8004/L7005 on Canso Crossing Double Circuit Tower (DCT)
Execution Year: 2014-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
530050 Regular Labour						
T&D Labour	PD	857	$ 426	$ 364,976		
			Sub-Total	$ 364,976		
530200 OT Labour						
T&D Labour	PD	20	$ 734	$ 15,007		
			Sub-Total	$ 15,007		
530300 Term Labour						
T&D Labour	PD	18	$ 367	$ 6,635		
			Sub-Total	$ 6,635		
530950 Travel Expense						
Travel Expenses	LOT	1	$ 14,932	$ 14,932		
			Sub-Total	$ 14,932		
530900 Office Supplies						
Office Supplies	LOT	1	$ 178	$ 178		
			Sub-Total	$ 178		
531400 Materials						
Towers	LOT	1	$ 1,892,770	$ 1,892,770		
Conductor	LOT	1	$ 706,524	$ 706,524		
Tower Hardware			$ 503,787	$ 503,787		
Tower Lighting			$ 418,373	$ 418,373		
Communications			$ 10,140	$ 10,140		
Other			$ 3,897	$ 3,897		
Wood Poles	LOT	1	$ 1,119	$ 1,119		
			Sub-Total	$ 3,536,610		
531550 Contracts						
Construction Services	LOT	1	$ 10,761,421	$ 10,761,421		
Engineering Design, CADD Services, Construction Supervision	LOT	1	$ 417,761	$ 417,761		
Design & Construction Survey Services	LOT	1	$ 102,572	$ 102,572		
Right of Way Clearing	LOT	1	$ 52,833	$ 52,833		
X-ray Services for Hardware	LOT	1	$ 41,712	$ 41,712		
Witness of Tower & Conductor Factory Acceptance Test	LOT	1	$ 10,622	$ 10,622		
LiDAR & Thermal Rating Study	LOT	1	$ 7,400	$ 7,400		
Crane	LOT	1	$ 5,129	$ 5,129		
Other	LOT	1	$ 3,463	$ 3,463		
			Sub-Total	$ 11,402,913		
531800 Freight Postage Delivery						
Freight	LOT	1	$ 49	$ 49		
			Sub-Total	$ 49		
532100 Telephones						
Telephones	LOT	1	$ 1,074	$ 1,074		
			Sub-Total	$ 1,074		
532500 Consulting						
Engineering Design	LOT	1	$ 629,997	$ 629,997		
Habitat & Rare Bird Species Surveys & Monitoring	LOT	1	$ 445,319	$ 445,319		
Mi'kmaq Ecological Knowledge Study	LOT	1	$ 38,180	$ 38,180		
Archaeological Screening & Reconnaissance	LOT	1	$ 4,722	$ 4,722		
Other	LOT	1	$ 2,173	$ 2,173		
			Sub-Total	$ 1,120,391		
533350 Advertising						
Advertising	LOT	1	$ 12,700	$ 12,700		
			Sub-Total	$ 12,700		
533400 Meals						
Meals	LOT	1	$ 6,417	$ 6,417		
			Sub-Total	$ 6,417		
535950 Royalty, Easement, Appraisal						
Royalty, Easement, Appraisal		1	$ 426,032	$ 426,032		
			Sub-Total	$ 426,032		
530050 Other Income/Salvage						
Salvage		1	$ (279)	$ (279)		
			Sub-Total	$ (279)		
605050 Interest Capitalized						
AFUDC		1	$ 910,863	$ 910,863		
			Sub-Total	$ 910,863		
535650 Vehicle Overhead						
Vehicle AO		1	$ 59,002	$ 59,002		
			Sub-Total	$ 59,002		
535700/535705 Administrative Overhead						
Labour AO		1	$ 1,443,396	$ 1,443,396		
Contractor AO		1	$ 1,066,384	$ 1,066,384		
			Sub-Total	$ 2,509,780		
			SUB-TOTAL (no AO, AFUDC)	$ 16,907,634		
			TOTAL (AO, AFUDC included)	$ 20,387,278		
Original Cost				$ 4,630		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI 45066

Upgrade L6511 and L7019 Thermal Rating

NON CONFIDENTIAL

January 27, 2022

Nova Scotia
POWER
An Emera Company

Nova Scotia POWER An Emera Company

UARB APPROVAL SHEET

Project Title: Upgrade L6511 and L7019 Thermal Rating

CI Number: 45066

Date: January 27, 2022

Expenditure Profile		
Year	Budget Amount	Project Estimate
2014	159,565	159,565
2015	3,372,430	2,192,324
2016	214,680	171,832
2017	210,855	167,296
Total	$3,957,530	$2,691,017

Type of Filing

- [X] Capital Project Authorization
  - [ ] Unforeseen and Unbudgeted (U&U)
  - [ ] Planned & Advanced (P&A)
  - [ ] Subsequent Approval Item
- [ ] Authorization to Overspend (ATO)
- [ ] Scope Change
- [ ] Final Cost (FIN)

COMMENTS

This project was originally submitted to the NSUARB on April 24, 2015. The UARB provided its Decision on September 24, 2015 and did not approve it at that time. NS Power is resubmitting this project for the Board's approval as part of the Company's General Rate Application.

Original Submission	$3,957,530
Current Amount	$2,691,017
Variance	($1,266,513)

Submitted on behalf of NOVA SCOTIA POWER INCORPORATED

Lia M. MacDonald

January 21, 2022

Authorized Signatory
Lia MacDonald
VP Trans/Distribution/Delivery

DATE

Approved on behalf of NOVA SCOTIA UTILITY AND REVIEW BOARD

DATE

CI Number: 45066

Title: Upgrade L6511 and L7019 Thermal Rating

Start Date:	2014/02
In-Service Date:	2018/01
Final Cost Date:	2021/11
Function:	Transmission
Forecast Amount:	$2,691,017

DESCRIPTION:

This project upgraded the thermal ratings of transmission lines L6511 and L7019 which consisted of replacing 138kV and 230kV wooden transmission structures and associated framing (including cross-arms, cross-braces, insulators, jumpers, hardware, etc.), along with transferring of conductor from the old structure to the new to avoid line clearance violations and associated safety concerns due to the additional post-contingency generation flow along these lines.

This project was originally submitted to the NSUARB on April 24, 2015. The NSUARB provided its Decision on September 24, 2015 and did not approve it at that time. NS Power is resubmitting this project for the Board's approval as part of the Company's General Rate Application.

Summary of Related CIs +/- 2 years:
Pursuant to Section 11.2 of the CEJC, related CIs for Transmission projects include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)."

- 2015 – CI 43324 L6513 Rebuild/Upgrade Line Terminals $18,627,164
- 2015 – CI 43678 Separate L8004/L7005 on Canso Crossing Double Circuit Tower $20,385,511
- 2014 – CI 45067 345 KV Node Swap $2,982,715

Depreciation Class: Transmission Plant – Station Equipment, Poles and Fixtures, Overhead Conductors and Devices

Estimated Useful Life: 45 years

Retirement Information:

- Categorization of Retirement: Accounting Policy 6420 - Retirement and Disposal of Capital Assets
- Percentage of Asset Pool: 0.02%

JUSTIFICATION:

Justification Criteria: Transmission

Why do this project?

This project was undertaken to avoid thermal overloads on transmission line L6511 and line L7019 due to increased energy flow onto these transmission lines from the Maritime Link. In addition, these system upgrades also avoided line clearance violations and associated safety concerns due to the additional generation flow along these transmission corridors.

Why do this project now?

This project was completed in advance of the Maritime Link Project to eliminate the thermal overload constraints as identified. To complete this work, transmission line outages were taken that were coordinated with system constraints based on load conditions and availability of Trenton thermal generation. This work was completed in 2018 which allowed NS Power the opportunity to take advantage of aligning this work with a Trenton Generation plant shutdown. Energy from the Maritime Link is being received by NS Power.

Why do this project this way?

Completing the project this way had the least impact to NS Power customers and the NS Power transmission system. The alternative was the construction of additional transmission capacity (the construction of a new transmission line) to accommodate the system contingencies. The option of rebuilding sections of the existing lines (Line L6511 and Line L7019) was undertaken during planned thermal maintenance periods and resulted in a lower capital cost overall to the project.

Reason for Variance:

The reduction of $1,266,513 from $3,957,530 in the original submission to $2,691,017 in this submission is due to a large decrease in the number of structures that needed to be replaced. The original budget estimate was completed without Lidar & Thermal studies, which identified the final number of structures in need of replacement. This has resulted in corresponding cost reductions in most budget categories as described in more detail in the Variance Page.

CI Number : 45066-T802 - Upgrade L6511 and L7019 Thermal Rating

Project Number 45066-T802

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General

Budget Version UARB Submissions

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	0700 - TP - Environmental		66,703
Additions	3500 - TP - Wood Poles		774,399
Additions	3800 - TP - Insulators		63,264
Additions	3900 - TP - O/H Cond.		1,641,792
Retirements	3500 - TP - Wood Poles		135,380
Retirements	3800 - TP - Insulators		6,328
Retirements	3900 - TP - O/H Cond.		3,151
		Total Cost:	2,691,017
		Original Cost:	33,950

Location: Transmission
CI# / FP#: 45066-T802
Title: Upgrade L6511 and L7019 Thermal Rating
Execution Year: 2014-2017

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
530050 Regular Labour						
T&D Labour	PD	161	$ 426	$ 68,616		
			Sub-Total	$ 68,616		
530200 OT Labour						
T&D Labour	PD	11	$ 734	$ 8,199		
			Sub-Total	$ 8,199		
530300 Term Labour						
T&D Labour	PD	2	$ 367	$ 850		
			Sub-Total	$ 850		
530950 Travel Expense						
Travel Expenses	LOT	1	$ 5,723	$ 5,723		
			Sub-Total	$ 5,723		
531400 Materials						
Wood Poles including Cross-arms & Cross-braces	LOT	1	$ 330,677	$ 330,677		
Insulators, Guys, Connectors, Hardware, Miscellaneous	LOT	1	$ 183,846	$ 183,846		
Delivery Miscellaneous Material	LOT	1	$ 1,000	$ 1,000		
			Sub-Total	$ 515,523		
531550 Contracts						
Construction Services	LOT	1	$ 1,142,114	$ 1,142,114		
Construction Supervision	LOT	1	$ 91,230	$ 91,230		
LiDAR & Thermal Rating Study	LOT	1	$ 48,630	$ 48,630		
Right of Way Clearing	LOT	1	$ 17,880	$ 17,880		
CADD Services	LOT	1	$ 5,722	$ 5,722		
Delivery & Offload Miscellaneous Material	LOT	1	$ 2,188	$ 2,188		
Traffic Control	LOT	1	$ 2,112	$ 2,112		
			Sub-Total	$ 1,309,874		
532500 Consulting						
Consulting	LOT	1	$ 1,485	$ 1,485		
			Sub-Total	$ 1,485		
533400 Meals						
Meals	LOT	1	$ 2,186	$ 2,186		
			Sub-Total	$ 2,186		
535950 Royalty, Easements, Appraisals						
Royalty, Easements, Appraisals	LOT	1	$ 14,727	$ 14,727		
			Sub-Total	$ 14,727		
530050 Other Income/Salvage						
Salvage	PD	1	$ (10,656)	$ (10,656)		
			Sub-Total	$ (10,656)		
605050 Interest Capitalized						
AFUDC		1	$ 405,475	$ 405,475		
			Sub-Total	$ 405,475		
535650 Vehicle Overhead						
Vehicle AO		1	$ 10,002	$ 10,002		
			Sub-Total	$ 10,002		
535700/535705 Administrative Overhead						
Labour & Contract AO		1	$ 359,013	$ 359,013		
			Sub-Total	$ 359,013		
			SUB-TOTAL (no AO, AFUDC)	$ 1,916,526		
			TOTAL (AO, AFUDC included)	$ 2,691,017		
Original Cost				$ 33,950		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.

Account	Original Budget Subn	Final Project Actuals	Variance	Reason for Variance
455300 Other Income-Salvage		(10,656)	(10,656)	
530050 Regular Labour	84,488	68,616	(15,872)	A decrease in Engineering and project management as a result of a decrease in the number of structures needed to be replaced. The original submission was completed without Lidar & Thermal studies, which came back favorable in the number of structures in need of replacement.
530200 Overtime Labour	55,680	8,199	(47,481)	A decrease in OT construction labour as a result of a decrease in the number of structures needed to be replaced.
530300 Term Labour		850	850	
530950 Travel Expense	7,000	5,723	(1,277)	
531400 Materials	630,405	515,523	(114,882)	A decrease in materials (primarily wood poles and hardware) as a result of a decrease in the number of structures needed to be replaced.
531550 Contracts	1,844,627	1,309,874	(534,753)	A decrease in construction (under the EUS line services agreement) as a result of a decrease in the number of structures needed to be replaced. The original submission was completed without Lidar & Thermal studies, which came back favorable in the number of structures in need of replacement.
532500 Consulting	3,510	1,485	(2,025)	A decrease in consulting as a result of a decrease in the number of structures needed to be replaced.
533400 Meals and Entertainment	10,000	2,186	(7,814)	
535100 Other Goods and Services	263,571	-	(263,571)	Contingency was not required.
535650 Vehicle Allocated Costs	30,690	10,002	(20,688)	Due to decreased labour.
535700 Admin Overheads	513,372	359,013	(154,359)	Due to decreased labour and decreased contracts.
535950 Royalty, Easement, Appraisal		14,727	14,727	Costs primarily associated with Overhead Water Crossing License Fees, and Railway Flagging Protection Services during Construction.
605050 AFUDC Interest	514,186	405,475	(108,712)	Due to decreased project costs.
Grand Total	**3,957,530**	**2,691,017**	**(1,266,513)**	

CI 45067

67N Onslow 345 KV Node Swap

NON CONFIDENTIAL

January 27, 2022

Nova Scotia
POWER
An Emera Company

UARB APPROVAL SHEET

Project Title: 67N Onslow 345 kV Node Swap

CI Number: 45067

Date: January 27, 2022

Expenditure Profile		
Year	Budget Amount	Project Estimate
2014	1,030,887	899,897
2015	2,242,625	1,636,863
2016	240,592	242,539
2017	236,370	203,409
2018		266
2019		(260)
Total	$3,750,474	$2,982,714

Type of Filing

- [X] Capital Project Authorization
  - [ ] Unforeseen and Unbudgeted (U&U)
  - [ ] Planned & Advanced (P&A)
  - [ ] Subsequent Approval Item
- [ ] Authorization to Overspend (ATO)
- [ ] Scope Change
- [ ] Final Cost (FIN)

COMMENTS

This project was originally submitted to the NSUARB on November 14, 2014. The NSUARB provided its Decision on April 27, 2015 and did not approve the Project at that time. NS Power is resubmitting this project for the Board's approval as part of the Company's General Rate Application.

Original Submission	$3,750,474
Current Amount	$2,982,714
Variance	($767,760)

Submitted on behalf of NOVA SCOTIA POWER INCORPORATED		Approved on behalf of NOVA SCOTIA UTILITY AND REVIEW BOARD
Lia M. MacDonald	January 21, 2022	
Authorized Signatory Lia MacDonald VP Transmission, Distribution & Delivery	DATE	DATE

CI Number: 45067

Title: 67N Onslow 345kV Node Swap

Start Date: 2014/03
In-Service Date: 2018/01
Final Cost Date: 2021/11
Function: Transmission
Forecast Amount: $2,982,714

DESCRIPTION:

This project included the change (swap) of the node locations of Line L8003 and Transformer 67N-T82 on Bus 67N-B82, the addition of a new 345kV breaker, and the addition of two new isolation switches at the 67N-Onslow Substation (345kV). This created a new node between the existing Breaker 67N-815 and the new breaker 67N-816 in the substation.

This project was originally submitted to the NSUARB on November 14, 2014. The NSUARB provided its Decision on April 27, 2015 and did not approve it at that time. NS Power is resubmitting this project for the Board's approval as part of the Company's General Rate Application.

Summary of Related CIs +/- 2 years
Pursuant to Section 11.2 of the CEJC, related CIs for Transmission projects include "Work completed on the same asset class (Padmount transformers, Breakers, etc.) or in the same location (feeder, Transmission Line)."

- 2014 CI 45066 Upgrade L6511 and L7019 Thermal Rating – $2,691,017
- 2015 CI 43324 L6513 Rebuild / Upgrade Line Terminals – $18,627,164
- 2015 CI 43678 Separate L8004/L7005 on Canso Crossing Double Circuit Tower – $20,385,511

Depreciation Class: Transmission – Station Equipment

Estimated Life of the Asset: 25 years

JUSTIFICATION:

Justification Criteria: Transmission

Why do this project?

As a result of the additional generation associated with the Maritime Link Project, a system impact study noted the potential for system voltage collapse based on the current configuration of the 67N-Onslow Substation (345kV). Originally, Breaker 67N-812 was located between the node for Line L8002 and the node for L8003 and the failure of that circuit breaker would result in the loss of both transmission lines. To avoid this contingency, the Project swapped the node for Line L8003 and the node for Transformer 67N-T82 with the addition of new Breaker 67N-816.

Why do this project now?

Completing the Project eliminated the system constraints that would be introduced if the Maritime Link Project were to be completed before this work was carried out. Additionally, completing the Project increased the power transfer capability from Onslow to Halifax (by approximately 80 MW) and reduced planned system outages for the work that was conducted due to NPCC requirements on the Bulk Power System (CI 43291 – Protection Risk Reduction 67N – Onslow 230 kV). Energy from the Maritime Link is being received by NS Power.

Why do this project this way?

Two alternatives were considered:

(1) Relocate three existing system elements (Line L8002, Line L8003 and Transformer 67N-T82) and the addition of Breaker 67N-816.

(2) Relocate two existing elements (Line L8003 and Transformer 67N-T82) and the addition of Breaker 67N-816.

The second option was selected by NS Power as it represented an overall cost and project schedule saving to NS Power.

Reason for Variance

The final costs of $2,982,714 for the project were $767,760 lower than the original submission of $3,750,474, primarily due to the use of internal versus external labour.

At the time of the original submission, the Project planned and budgeted for the use external resources for implementation; however, once the detailed engineering design for the Project was completed and the schedule for the required transmission and generation system outages was established, NS Power's internal resources were determined to be available to execute the Project. NS Power Substation Operations labour was dedicated to the completion of the Project.

The shift to utilizing internal labour resources resulted in direct and indirect cost savings to the Project due to lower labour rates. This has resulted in corresponding cost reductions in most budget categories as described in more detail in the Variance Page. Due to the cost saving, the contingency for the Project was not required. Furthermore, as the costs to execute the Project were lower than budgeted, the associated AFUDC costs were also lower. The cost savings achieved on the Project were partially offset by cost increases due to market conditions, unforeseen conditions, and unforeseen requirements for the Project.

CI Number : 45067-T801 - 67N Onslow 345 KV Node Swap

Project Number 45067-T801

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General

Budget Version UARB Submissions

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	0300 - TP - Bldg.,Struct.Grnd.		752,279
Additions	0700 - TP - Environmental		2,345
Additions	4300 - TP - Substn Dev.		2,228,090
		Total Cost:	2,982,714
		Original Cost:	

Capital Project Detailed Estimate

Location: **Transmission**
CI# / FP#: 45067-T801
Title: 67N Onslow 345 kV Node Swap
Execution Year: 2014-2017

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
530050 Regular Labour						
Administrative Support Staff	Lot	1	$ 5,902	$ 5,902		
Environmental Staff	Lot	1	$ 1,455	$ 1,455		
Project Management Support Staff	Lot	1	$ 112,090	$ 112,090		
Substation Operations Staff	Lot	1	$ 189,032	$ 189,032		
T&D Engineering Staff	Lot	1	$ 2,237	$ 2,237		
				$ -		
			Sub-Total	$ 310,716		
530200 OT Labour						
Project Support Staff	Lot	1	$ 5,553	$ 5,553		
Substation Operations Staff	Lot	1	$ 46,264	$ 46,264		
			Sub-Total	$ 51,817		
530300 Term Labour						
P&C Engineer	Lot	1	$ 3,396	$ 3,396		
				$ -		
			Sub-Total	$ 3,396		
530950 Travel Expense						
Travel	Lot	1	$ 6,733	$ 6,733		
				$ -		
			Sub-Total	$ 6,733		
531400 Materials						
Civil Work - Concrete	Lot	1	$ 168,992	$ 168,992		
Civil Work - Structural Steel	Lot	1	$ 49,247	$ 49,247		
Disconnect Switch	Lot	1	$ 74,375	$ 74,375		
Instrument Transformers	Lot	1	$ 39,960	$ 39,960		
BUS Materials	Lot	1	$ 32,678	$ 32,678		
Conduit	Lot	1	$ 11,476	$ 11,476		
Cables	Lot	1	$ 104,052	$ 104,052		
Frame Leakage Current Transformers	Lot	1	$ 4,140	$ 4,140		
Insulators	Lot	1	$ 22,390	$ 22,390		
345kV Breaker	Lot	1	$ 259,672	$ 259,672		
Spare Pole for Breaker	Lot	1	$ 115,536	$ 115,536		
P&C Protection Systems	Lot	1	$ 127,642	$ 127,642		
Other	Lot	1	$ 20,363	$ 20,363		
			Sub-Total	$ 1,030,525		
531550 Contracts						
CADD Services	Lot	1	$ 14,370	$ 14,370		
Crane	Lot	1	$ 30,168	$ 30,168		
Civil Work - Concrete	Lot	1	$ 116,063	$ 116,063		
Civil Work - Engineering	Lot	1	$ 3,921	$ 3,921		
Civil Work - Structural Steel	Lot	1	$ 39,595	$ 39,595		
Construction Supervision	Lot	1	$ 247,298	$ 247,298		
Technical Project Manager	Lot	1	$ 16,535	$ 16,535		
Snow Removal	Lot	1	$ 7,616	$ 7,616		
Other	Lot	1	$ 7,537	$ 7,537		
			Sub-Total	$ 483,102		
532100 Telephones						
Telephones	Lot	1	$ 524	$ 524		
				$ -		
			Sub-Total	$ 524		
532500 Consulting						
Civil Engineering Design	Lot	1	$ 9,962	$ 9,962		
Protection & Controls Engineering Design	Lot	1	$ 71,379	$ 71,379		
			Sub-Total	$ 81,340		
533400 Meals						
Meals	Lot	1	$ 2,353	$ 2,353		
				$ -		
			Sub-Total	$ 2,353		
605050 Interest Capitalized						
AFUDC				$ 534,843		
				$ -		
			Sub-Total	$ 534,843		
535650 Vehicle Overhead						
Vehicle AO				$ 114,092		
				$ -		
			Sub-Total	$ 114,092		
535700/535705 Administrative Overhead						
Labour AO				$ 240,396		
Contractor AO				$ 122,875		
			Sub-Total	$ 363,271		
			SUB-TOTAL (no AO, AFUDC)	$ 1,970,508		
			TOTAL (AO, AFUDC included)	$ 2,982,714		
Original Cost				$ -		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Account	Original Submission Budget	Final Application Costs	Variance	Reason for Variance
Regular Labour	197,800	310,716	112,916	Original budget only provided for NS Power substation operations labour to participate in the commissioning process and all of the installation work would be completed by contracted PLTs and electricians/electrical technicians. However, once the design was completed and NS Power resource availability was established, it was decided to complete the entire scope of work using NS Power internal resources.
Overtime Labour	-	51,817	51,817	There was very little ability for the Transmission Outage Scheduler to accomodate any Project delays in the outage schedules to complete elements that must be completed during an outage before placing the line back in service. Therefore, overtime labour was required to ensure that the Project scopes of work were completed during the scheduled line and thermal generation maintenance outages.
Term Labour	58,000	3,396	(54,604)	The original project plan and budget included hiring term labour to provide electrical construction supervision during the execution of the Project. However, it was not feasible to hire term labour to provide construction supervision within the project schedule and an engineering firm was contracted to provide this service on the Project site.
Travel Expense	24,050	6,733	(17,317)	The original project plan and budget included travel for the term labour construction supervisor to travel to site plus travel to perform manufacturer site visits. However, as construction supervision was contracted to an engineering firm the amount of travel was limited to manufacturer site visits and project support labour travel to the Project site on a weekly basis.
Materials	883,645	1,030,525	146,880	During construction it was determined that the water table beneath the site was higher than assumed during the design process and the footing designs needed to be made larger to adapt the difference in geological conditions. Furthermore, due to the need to adapt the civil design to the found conditions, additional cable and conduit lengths were required to implement the Project design. As a result, additional materials were required.
Contracts	1,024,456	483,102	(541,354)	The original project plan and budget included an allowance for contract labour to execute the Project scope of work. However, based on the availability of NS Power resources, this work was completed by NS Power substation operations staff, which significantly decreased 'Contracts' expenditures. This decrease was partially offset by costs associated with securing electrical construction supervision from a local engineering firm in place of Term Labour, and the services of a civil construction supervisor, CADD services, and electrical design services from local engineering firms.
Freight, Delivery & Postage	15,000	-	(15,000)	Delivery fees were included in the cost of the materials.
Telephones	-	524	524	
Consulting	191,750	81,340	(110,410)	The original project plan and budget included allowances for consultants to complete the protection and controls design, electrical design, CADD services, and civil construction supervision services for the Project. However, electrical design, CADD services, and civil construction supervision were performed by contractors working within NS Power's facilities. Thus, those costs were allocated to the appropriate Contracts account code.
Meals	5,000	2,353	(2,647)	
Other Goods and Services	239,970	-	(239,970)	Contigency was not required.
Vehicle Allocated Costs	20,298	114,092	93,793	Due to increased labour costs.
Labour Admin Overheads	153,044	240,396	87,352	Due to increased labour costs.
Contractor Admin Overhead	251,622	122,875	(128,747)	Due to decreased contractor costs.
AFUDC Interest	685,838	534,843	(150,995)	The decrease in AFUDC is due to lower project costs.
Total	**3,750,474**	**2,982,714**	**(767,760)**	

REPORT:

COST OF CAPITAL

PREPARED FOR:

NOVA SCOTIA POWER INC.

BEFORE THE:

NOVA SCOTIA UTILITY AND REVIEW BOARD

SEPTEMBER 2025

TABLE OF CONTENTS

TABLE OF FIGURES

SECTION 1: INTRODUCTION AND QUALIFICATIONS

A. James M. Coyne

My name is James M. Coyne, and I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Senior Vice President. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

I am among Concentric's professionals who provide expert testimony before federal, state, and Canadian provincial agencies on matters pertaining to economics, finance, and public policy in the energy industry. Concentric provides financial, economic, and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. I regularly advise utilities, generating companies, public agencies and private equity investors on business issues pertaining to the utilities industry. This work includes calculating the cost of capital for the purpose of ratemaking and providing expert testimony and studies on matters pertaining to incentive regulation, rate policy, valuation, capital costs, fuels and power markets. I have testified or provided expert evidence in state, provincial and federal jurisdictions in Canada and the U.S., including before the Nova Scotia Utility and Review Board ("UARB", or the "Board"). This work has been provided on behalf of utilities, regulatory commissions, and staff.

I am also a frequent speaker and author of articles and white papers on the energy industry. For example, on behalf of the Canadian Gas Association and the Canadian Electricity Association, I prepared a discussion paper for utility executives and provincial regulators that examined the roles that Canada's utilities and regulators can play to promote innovation. In addition, I facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white papers to facilitate further discussion on emerging industry issues. I have been an invited speaker for several CAMPUT events, including the Energy Regulation Course at Queen's University where I spoke on "Innovations in Utility Business Models and Regulation."

In earlier positions, I served as Senior Economist for the Massachusetts Energy Facilities Siting Council, where I analyzed the supply plans and facilities proposals from the state's electric and gas utilities, and I also served as State Energy Economist for the Maine Office of Energy Resources.

I hold a B.S. in Business Administration from Georgetown University and a M.S. in Resource Economics from the University of New Hampshire. My qualifications are detailed more fully in Attachment 1.

B. John P. Trogonoski

My name is John P. Trogonoski, and I am employed by Concentric as an Assistant Vice President. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

I provide expert testimony before U.S. state and Canadian provincial regulatory agencies on matters pertaining to finance, economics, and public policy in the utility industry. I have testified or provided expert evidence on more than 30 occasions in various U.S. state and Canadian provincial jurisdictions. This testimony has been filed on behalf of both utilities and regulatory commission staff.

Prior to joining Concentric, I was a member of the Staff of the Colorado Public Utilities Commission from 1999-2008, where I supervised the financial analysts in the energy and telecommunications sections, provided advisory services to the Commissioners on financial and economic matters, and filed expert testimony on rate of return, revenue requirement, cost allocation, rate design, incentive regulation, and public policy matters. I hold a M.S. in Business Administration and a B.S. in Marketing from the University of Colorado at Denver. My qualifications are detailed more fully in Attachment 2.

C. Executive Summary

We have prepared this report on behalf of Nova Scotia Power Inc. ("NSPI" or the "Company"), a wholly-owned subsidiary of Emera Inc. Specifically, we have been asked to provide an estimate of the cost of capital for NSPI for the purpose of establishing the return on equity ("ROE") and capital structure for rate-making purposes. In order to estimate the cost of capital, we have relied upon analytical tools and data sources normally used for such purposes before regulators in Canada and the U.S. We have also reviewed past decisions of the Board in consideration of such matters. The analysis provided in this report supports our overall recommendation on the ROE and capital structure for NSPI. That analysis includes the following:

- examination of the legal and regulatory requirements for determination of a fair rate of return;

- selection of Canadian, U.S. Electric and North American Electric proxy groups with companies comparable to NSPI with respect to business and financial risks;
- estimation of the cost of common equity for the proxy group companies using the Discounted Cash Flow ("DCF") method, the Capital Asset Pricing Model ("CAPM"), and the Bond Yield Plus Risk Premium ("Risk Premium") approach;
- examination of authorized ROEs for other investor-owned electric utilities in Canada and the U.S.;
- development of a range of results for the Canadian, U.S. Electric and North American Electric proxy groups; and
- an assessment of the appropriateness of NSPI's current and proposed capital structure based on an examination of the Company's business and financial risks relative to the respective proxy groups.

As shown in Figure 1 the various ROE estimation models produce a range of results for the proxy group companies from 9.29 percent (the Multi-Stage DCF results for the North American Electric proxy group) to 10.69 percent (the CAPM results for the U.S. Electric proxy group). The three model average for the Canadian proxy group is 9.6 percent, for the U.S. Electric proxy group is 10.2 percent and for North American Electric proxy group is 9.9 percent. From an investor's perspective, the utilities in the North American Electric proxy group are most representative of NSPI due to the ownership of regulated generation facilities and the associated risk profile of these companies, so we place greater weight on those results. ****

Figure 1: Summary of Results[1]

	Canadian Regulated Utilities	US Electric Utilities	North American Electric Utilities
CAPM – Historical MRP	9.71%	10.69%	10.32%
Multi-Stage DCF	9.60%	9.35%	9.29%
Risk Premium	9.54%	10.45%	10.00%
Average	**9.62%**	**10.16%**	**9.87%**

The average of all three methods for the North American Electric proxy group is 9.87 percent, within the range of 9.29 percent to 10.32 percent. Based on this analysis, we believe a reasonable estimate of NSPI's required ROE is 9.9 percent, which is the average for the North American Electric proxy group. The average for Canadian regulated utilities, several of which have unregulated business activities and many of which do not own any regulated generation and several of which have significant U.S. operations, is 9.6 percent. We do not believe that any one model should be weighted more heavily than the others, so the average would form the basis of our recommendation. In an effort to promote rate stability and affordability for customers, however, NSPI is proposing to maintain its current authorized ROE of 9.0 percent.[2] NSPI's proposed ROE is below the low end of the range for the three proxy groups and meaningfully below our estimate of the Company's cost of equity given the results of the models and conditions in the economy and capital markets. In order to attract investment in Nova Scotia and to effectively manage the energy transition, it is critical that NSPI's ROE be set at a competitive level.

Completing the cost of capital analysis, we conclude that a common equity ratio for NSPI of 40.0 percent is reasonable, if not conservative, given the business and financial risks of the Company. In particular, the ownership of substantial regulated generation assets (including thermal assets) distinguishes NSPI from other electric utilities in Canada, coupled with the need to accelerate the retirement of the Company's thermal generation and transition the generation mix to include more renewable resources by 2030. The requested common equity ratio is approximately equal

[1] DCF results are based on 90-day average stock prices for proxy group companies. Results include 50 basis points for flotation costs and financial flexibility except for U.S. risk premium results.

[2] The current NSUARB-approved range of ROE is between 8.75 and 9.25 percent, with rates set on a 9.0 percent ROE.

to the average deemed equity ratio for Canadian electric utilities, many of which do not own any generation assets, and well below the average authorized equity ratio of 52.0 percent for integrated electric utilities in the U.S. since January 2023. This indicates that NSPI has greater financial risk (i.e., more leverage) than its U.S. comparators.

D. Report Organization

The remainder of the report is organized as follows: Section II discusses the legal requirements and regulatory precedents for the determination of a fair rate of return. Section III provides an overview of economic and financial market conditions in Canada and the U.S. and how those conditions affect the ROE for NSPI. Section IV describes our selection of proxy group companies to estimate the ROE for NSPI and discusses the precedent in Canada for the use of U.S. data. Section V discusses the methods used to estimate the ROE and summarizes the results of the DCF, CAPM and Risk Premium analyses. Section VI provides an assessment of a reasonable capital structure for NSPI given the business and financial risks of the Company. Section VII summarizes our overall conclusions and recommendations.

SECTION 2:

LEGAL REQUIREMENTS AND KEY REGULATORY PRECEDENTS FOR THE DETERMINATION OF A FAIR RETURN

A. The Fair Return Standard

The principles surrounding the concept of a "fair return" for a regulated company (Fair Return Standard) were established by the Supreme Court of Canada in *Northwestern Utilities v. City of Edmonton* (1929) S.C.R. 186 ("Northwestern"), where the Supreme Court of Canada found:

> *By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.*[3]

More recently, the Supreme Court of Canada in *Ontario (Energy Board) v. Ontario Power Generation Inc.* confirmed *Northwestern*, stating:

> *This means that the utility must, over the long run, be given the opportunity to recover, through the rates it is permitted to charge, its operating and capital costs ("capital costs" in this sense refers to all costs associated with the utility's invested capital). This case is concerned primarily with operating costs. If recovery of operating costs is not permitted, the utility will not earn its cost of capital, which represents the amount investors require by way of a return on their investment in order to justify an investment in the utility. The required return is one that is equivalent to what they could earn from an investment of comparable risk. Over the long run, unless a regulated utility is allowed to earn its cost of capital, further investment will be discouraged and it will be unable to expand its operations or even maintain existing ones. This will harm not only its shareholders, but also its customers.*[4]

The law regarding fair return for utility cost of capital in the United States has evolved similarly. The U.S. Supreme Court set out guidance in the bellwether cases of *Bluefield Water Works* and *Hope Natural Gas Co.* as to the legal criteria for setting a fair return. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*[5], the Court recognized that a rate of return may become unreasonable due to changing market conditions:

[3] Northwestern, at 193.
[4] Ontario (Energy Board) v. Ontario Power Generation Inc. 2015 SCC 44, at para 16.
[5] (262 U.S. 679, 693 (1923)).

> *The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.*

The U.S. Supreme Court further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591, 603 (1944)), when it described the relevant criteria as follows:

> *From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.*

With the passage of time, the Fair Return Standard has been interpreted many times in both Canada and the U.S. For example, the Canadian Energy Regulator ("CER," formerly the National Energy Board) summarized its interpretation of the "fair return standard" in its RH-2-2004 Phase II Decision and more recently reiterated that interpretation in its *Trans Québec & Maritimes Pipelines Inc.* RH-1-2008 Decision.

> *The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:*
>
> *be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);*
>
> *enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and*
>
> *permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).*

> *In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.*[6]

All three standards must be met, and none ranks in priority to the others. To that point, the Ontario Energy Board ("OEB") articulated the legal requirements for satisfying the Fair Return Standard in Canada in its 2009 Generic Cost of Capital Order as follows:

> *The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.*[7]

***

> *… all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration to the comparability test is not sufficient to meet the [Fair Return Standard].*[8]

The UARB has previously cited the statutory requirement in the Public Utilities Act to provide regulated utilities with a fair return on rate base. In the 2022 NSPI GRA decision, the Board articulated the importance of a fair return as follows:

> *A fair return on rate base is important for the sustainability of NS Power's service. A low return on rate base may discourage investment in the Utility. It may also lead to a poor credit rating, which will cause financial institutions to increase the rate of interest on loans used by the Utility to provide service. This may result in the Utility's rates*

6 National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, at 17.

7 Ontario Energy Board, EB-2009-084, Report of the Board on the cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at i.

8 Ibid, at 19.

> *increasing just to cover additional borrowing costs. It might even cause it to be excluded from participating in some debt markets altogether.*[9]

The assessment of whether the Fair Return Standard has been met requires an examination of the required returns by investors in comparable-risk enterprises. Investors must consider whether there are alternative investment opportunities that would provide a better return for the same risk. This weighing of alternatives and the highly competitive nature of capital markets causes stocks and bonds to settle on a price that provides investors with an adequate return for the risks involved. Thus, for any given level of risk, there is a corresponding return that investors expect in order to take on that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor-required" return.

In addition to setting the fair return at the "opportunity cost" of capital, a fair return must also be adequate to support the financial integrity of the utility, which requires a return sufficient to maintain credit metrics such that the utility can maintain a favorable credit rating in order to minimize debt costs and provide lenders assurance that the company's earnings are adequate to meet its fixed obligations. A fair return must therefore be sufficient to attract incremental capital on reasonable terms and conditions, to the benefit of both investors and customers.

B. The Stand-Alone Principle

The Stand-Alone Principle provides that the utility must be regulated as if it were a stand-alone entity, raising capital on the merits of its own business and financial characteristics. In this way, capital is efficiently allocated, with each business segment earning a return based on its own unique set of risks and business characteristics regardless of affiliations within the holding company structure. For example, within the Emera corporate structure, NSPI must compete for capital with other subsidiaries including Tampa Electric Company, which has a much higher authorized ROE and approved common equity ratio in Florida. In order to establish a fair return and satisfy the Stand-Alone Principle, the utility must be allowed a return sufficient to meet all three requirements of the Fair Return Standard on the basis of the utility's individual risk profile.

[9] Nova Scotia Utility and Review Board, 2023 NSUARB 12, M10431, Decision issued February 2, 2023, at para. 228.

C. The Relationship Between Capital Structure and ROE

The cost of common equity depends in part on the company's capital structure. The common equity ratio and equity rate of return must therefore be considered together to determine whether the Fair Return Standard has been met. Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate shareholders for the additional financial risks. Consequently, when a regulator approves a capital structure, that decision impacts the required rate of return on common equity.

The risk to the earnings stream of the company is a function of both its business and financial risk. Business risk refers to the political and regulatory environment in which the company operates and the operational and competitive market forces that could potentially exert pressure on earnings. Financial risk refers to the amount of debt in the utility's capital structure and the extent to which fixed debt obligations must be met before utility shareholders receive their returns. Both business and financial risks need to be considered when setting the capital structure.

SECTION 3:

ECONOMIC AND CAPITAL MARKET CONDITIONS

A. Summary and Relevance to Utility Cost of Capital

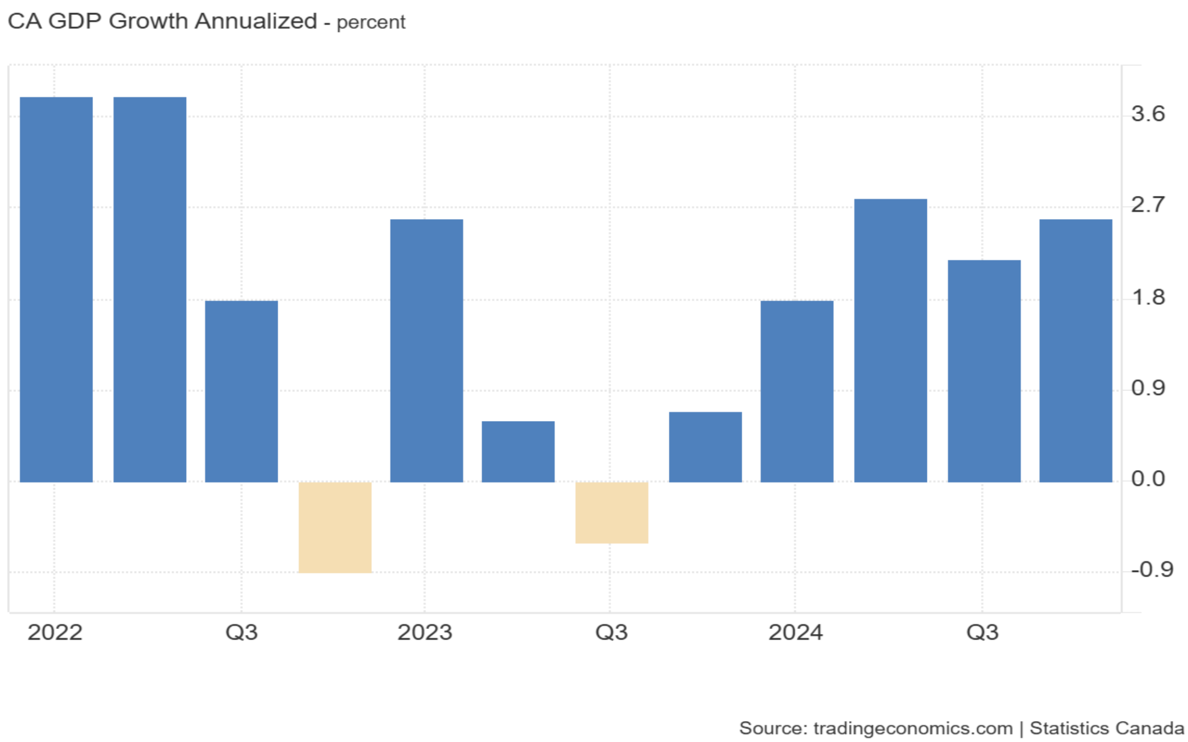
Utilities raise debt and equity in a global market influenced by macroeconomic fundamentals, capital markets and central bank policies. The cost of debt for utilities is observable based on the interest rates on recent debt issuances, but the ROE must be estimated with an informed view of the macroeconomic and capital market factors that impact the analysis. Projections of real GDP growth, inflation and interest rates are direct inputs to the cost of capital models. Additionally, the ROE for regulated utilities is influenced by factors such as central bank policy, investor confidence, and uncertainty and volatility in financial markets. Each of these factors is discussed in this section of our report, starting with macroeconomic conditions in Canada and the U.S.

B. Macroeconomic Conditions

1. Canada

GDP is an important indicator of economic activity that is a direct input to the multi-stage DCF model and also signals demand for all inputs to the economy, including capital. Figure 2 shows that the Canadian economy slowed substantially from the third quarter of 2022 through the first quarter of 2024, as tighter monetary policy and higher long-term interest rates weighed on economic growth. GDP growth accelerated throughout the remainder of 2024, with quarterly annualized growth rates of 2.8 percent (in Q2), 2.2 percent (in Q3) and 2.6 percent (in Q4).

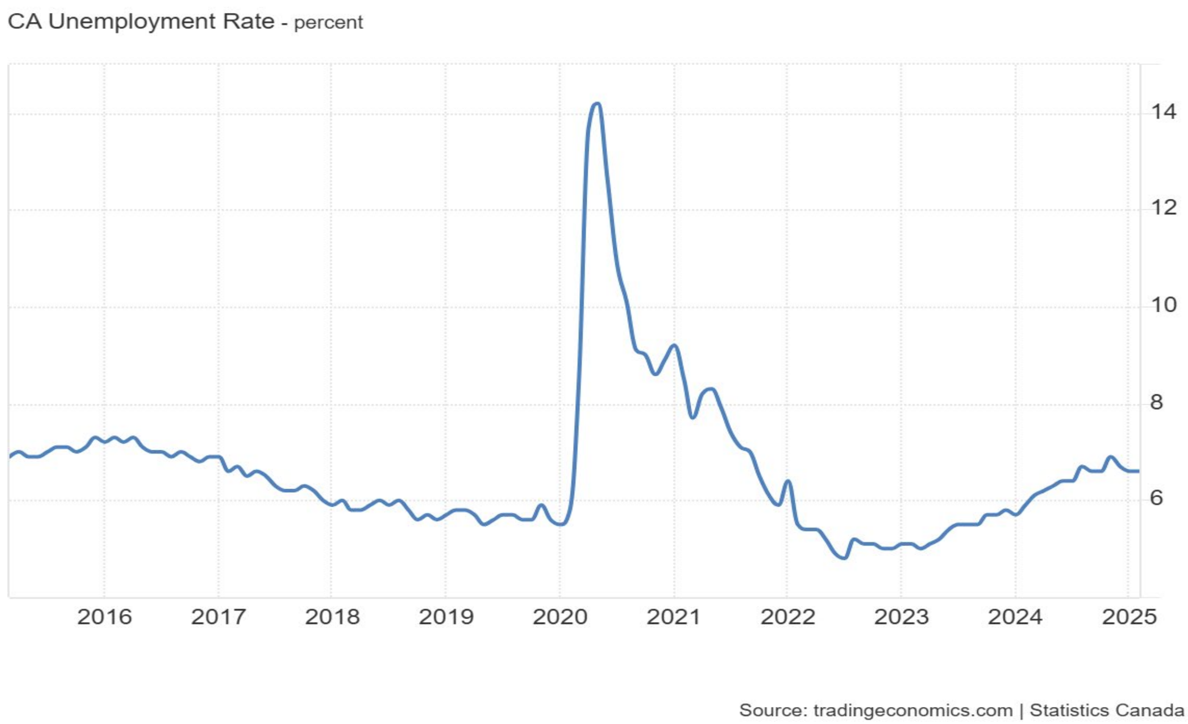
Figure 2: Canadian Real GDP Growth[10]



The unemployment rate in Canada increased from 5.6 percent in February 2020 to 13.7 percent in May 2020, which represented the highest level for unemployment in Canada over the period from 1966-2020. As shown in Figure 3, the unemployment rate declined to 4.9 percent in June and July 2022, as the Canadian economy responded to the economic stimulus of lower interest rates during the pandemic, but it has since increased to 6.6 percent in February 2025. Unemployment is not a direct input to the cost of capital models but provides another indicator of the relative strength (or weakness) of the economy.

10 https://tradingeconomics.com/canada/gdp-growth-annualized

Figure 3: Canadian Unemployment Rate[11]



For many years, consumer prices in Canada increased by less than 2.0 percent. This all changed in the Spring of 2021. Figure 4 shows the CPI Trimmed Mean, which is the Bank of Canada's preferred measure of inflation. After peaking in June 2022 at 5.7 percent, this inflation measure steadily declined through April 2024. More recently, CPI Trimmed stood at 2.9 percent in February 2025, up from 2.7 percent in January 2025, and still higher than the Bank of Canada's target of 2.0 percent. Inflation is an important factor in the cost of capital and is also an input to the multi-stage DCF model. Higher inflation rates drive higher capital costs to provide stable "real" returns (after the effects of inflation) to investors.

11 https://tradingeconomics.com/canada/unemployment-rate

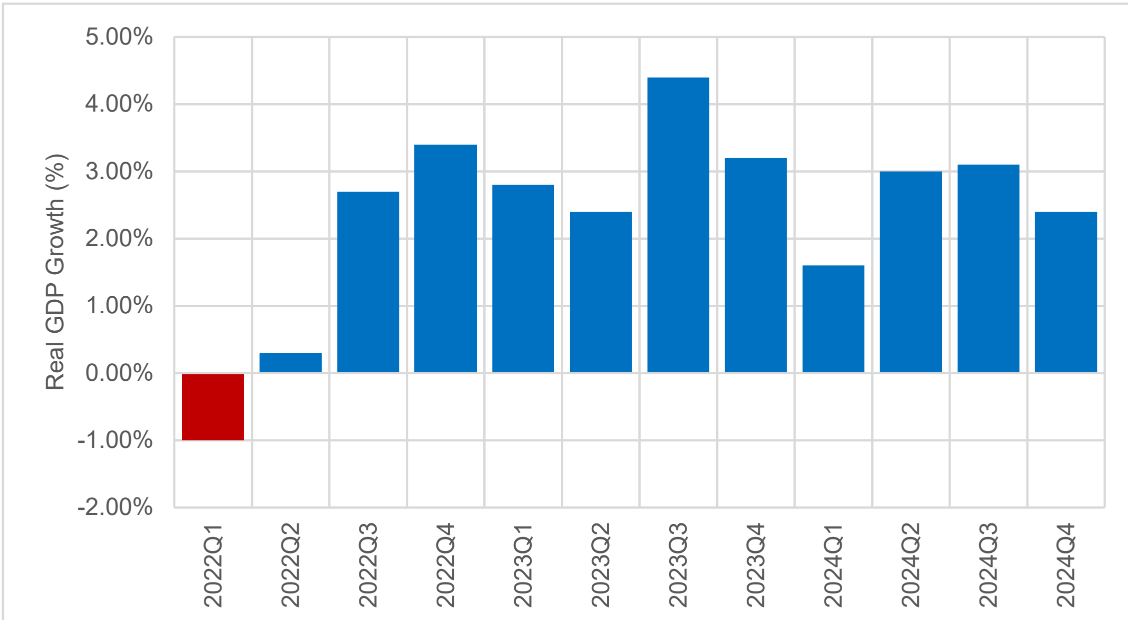
Figure 4: Canadian Inflation Rate[12]

2. United States

Figure 5 shows that the U.S. economy has grown steadily since the third quarter of 2022, with GDP growth of 2.7 percent or higher in seven of the nine quarters. The "final" estimate for 4Q 2024 shows continued growth at a 2.4 percent annual rate.[13] For all of 2024, real GDP grew by 2.8 percent in the U.S. compared to 2.9 percent in 2023.

[12] Source: https://tradingeconomics.com/canada/cpi-trimmed-mean
[13] Source: https://www.bea.gov/data/gdp/gross-domestic-product

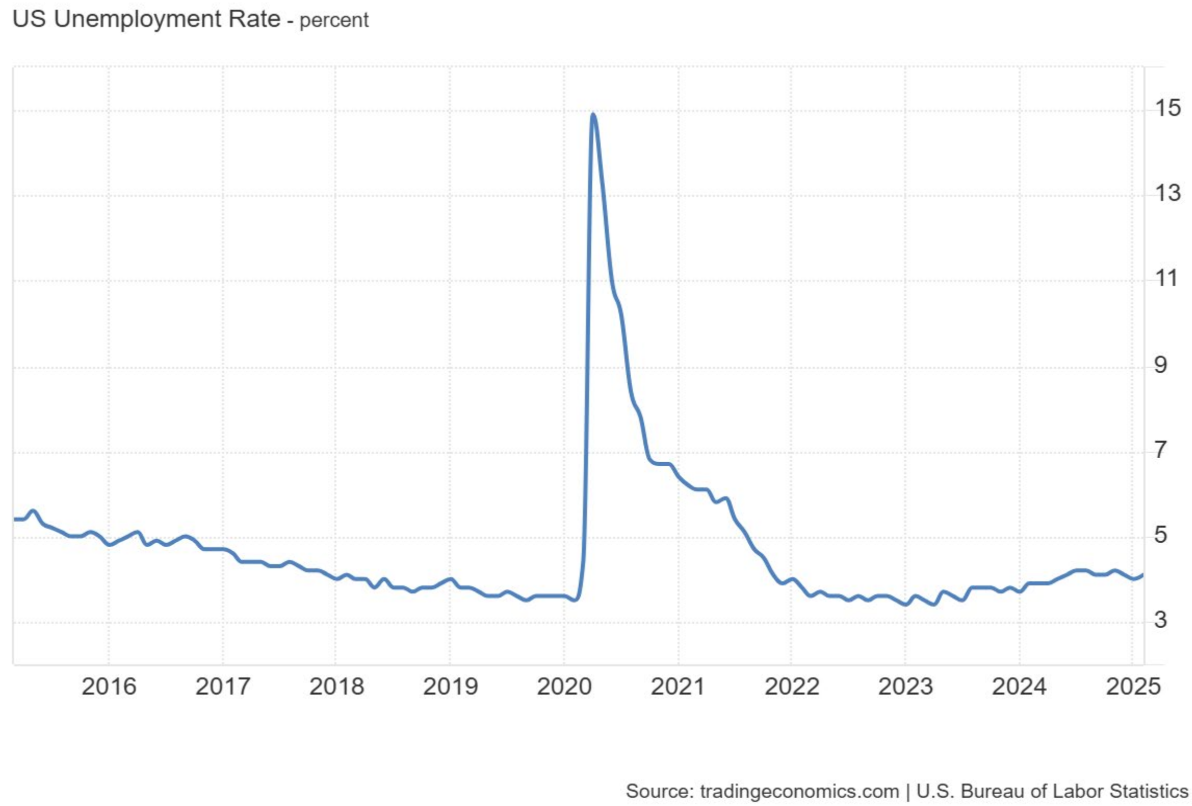
Figure 5: U.S. Real GDP Growth[14]



After reaching a low of 3.5 percent in January 2020, the U.S. unemployment rate spiked to 14.7 percent in April 2020 as businesses were forced to close due to COVID-19. As shown in Figure 6 the U.S. unemployment rate stood at 4.1 percent in February 2025, up slightly from 4.1 percent in January.

[14] Source: U.S. Department of Commerce, Bureau of Economic Analysis

Figure 6: U.S. Unemployment Rate[15]



The U.S. Federal Reserve's preferred measure of inflation is the Personal Consumption Expenditure ("PCE") index. As shown in Figure 7 inflationary pressure mounted in the second quarter of 2022, with the PCE reaching 5.6 percent. Inflation has gradually eased since September 2022 but has remained more persistent than expected. The PCE index increased at an annual rate of 2.6 percent in January 2025, above the U.S. Federal Reserve's target of 2.0 percent. Another measure of inflation frequently cited by economists is "core" inflation, which measures the increase in consumer prices excluding the volatile food and energy sector. Core inflation in the U.S. was 3.1 percent in February 2025, according to the U.S. Bureau of Labor Statistics.

15 Source: https://tradingeconomics.com/united-states/unemployment-rate

Figure 7: U.S. Personal Consumption Expenditure Index[16]

C. Central Bank Policies

The policies of central banks directly impact interest rates, inflation, and the pace of economic growth. All of these factors influence the cost of capital for utilities. In 2022, central banks in both the U.S. and Canada embarked on a path of tightening monetary policy in response to stronger employment and excess demand, which contributed to the highest inflation in 40 years. The shift to a more restrictive monetary policy in 2022 followed a period of extreme policy accommodation in response to the COVID-19 pandemic. Inflationary pressure has gradually eased as higher interest rates have slowed economic growth, although inflation has proven more persistent than anticipated. The following section discusses the circumstances in each country.

1. Canada

In response to inflation being higher than its target range of 1-3 percent (consumer prices increased by 6.3 percent in 2022), the Bank of Canada ("BOC") raised the overnight rate on multiple occasions from 0.25 percent in March 2022 to 5.00 percent. In June 2024, the BOC

[16] Source: https://tradingeconomics.com/united-states/core-pce-price-index-annual-change

determined that inflation had declined sufficiently to allow it to start reducing the overnight rate due to concerns with weak economic growth and rising unemployment. The overnight rate was reduced five times in 2024 to 3.25 percent. In announcing the most recent reduction in the overnight rate to 2.75 percent in March 2025, the BOC stated:

> *While economic growth has come in stronger than expected, the pervasive uncertainty created by continuously changing US tariff threats is restraining consumers' spending intentions and businesses' plans to hire and invest. Against this background, and with inflation close to the 2% target, Governing Council decided to reduce the policy rate by a further 25 basis points.*
>
> *Monetary policy cannot offset the impacts of a trade war. What it can and must do is ensure that higher prices do not lead to ongoing inflation. Governing Council will be carefully assessing the timing and strength of both the downward pressures on inflation from a weaker economy and the upward pressures on inflation from higher costs. The Council will also be closely monitoring inflation expectations. The Bank is committed to maintaining price stability for Canadians.*[17]

In its January 2025 Monetary Policy Report, the BOC underscored several key messages about the outlook for the Canadian economy:[18]

1) Inflation in Canada has been around 2% since August 2024. Inflation rates for most major components of the consumer price index are below their historical averages, but inflation in shelter prices is elevated and is easing slowly. Inflation expectations have largely normalized.
2) Inflation is projected to be volatile through March, reflecting the effects of the GST/HST holiday on some goods and services. Inflation is expected to remain near the 2% target over the projection horizon.
3) Growth in the Canadian economy was softer than expected in the third quarter of 2024, but there are signs activity has gained momentum despite a slowdown in population growth. Past interest rate cuts are contributing to an increase in household spending and housing activity. The labour market is still soft, and there are some signs that wage growth has slowed. The economy remains in modest excess supply.

17 Bank of Canada, Press Release issued March 12, 2025.
18 Bank of Canada, Monetary Policy Report, January 29, 2025, at 1-2.

4) Canadian economic growth is forecast to average 1.8% in 2025 and 2026. Household spending strengthens and is expected to remain robust, supported by past cuts to interest rates. Excess supply is expected to gradually dissipate over the projection.
5) Both upside and downside risks surround the outlook, and the Bank is equally concerned with inflation rising above the 2% target or falling below it. Excluding new wide-ranging US tariffs, the risks to the outlook for inflation are roughly balanced. However, US trade policy has emerged as a major source of uncertainty.
6) The new U.S. administration has imposed tariffs on imports from its trading partners, including Canada. This has prompted retaliatory tariffs. Broad-based tariffs would severely disrupt global trade and economic growth, as recently noted by the Bank of Canada. In Canada, there are already signs that the threat of tariffs is weighing on consumer and business confidence and investment intentions. This threat has also contributed to the recent depreciation of the Canadian dollar.

Underscoring these concerns, on February 1, 2025, President Trump issued an executive order implementing a 25 percent additional tariff on imports from Canada and Mexico, and a 10 percent additional tariff on imports from China.[19] Further, on February 10, President Trump restored a 25 percent tariff on steel and increased the tariff on aluminum to 25 percent.[20] Although the effect of these tariffs on both economies is uncertain, economists generally agree that higher tariffs increase inflation by increasing the cost of consumer goods. Higher inflation could complicate the unwinding of restrictive monetary policies, as well as increase long-term bond yields like the 30-year Treasury yield. Longer-term bonds are more sensitive to inflation expectations because their value is eroded more by inflation; thus, as the value (price) of bonds declines due to higher inflation expectations, the yield increases. Because utilities are capital intensive enterprises, higher inflation and interest rates tend to have a negative effect on utility stocks. If realized, all these factors suggest that the cost of capital for companies, including utilities and consumers may increase in the future.

19 https://www.whitehouse.gov/fact-sheets/2025/02/fact-sheet-president-donald-j-trump-imposes-tariffs-on-imports-from-canada-mexico-and-china/

20 https://www.whitehouse.gov/fact-sheets/2025/02/fact-sheet-president-donald-j-trump-restores-section-232-tariffs/

2. United States

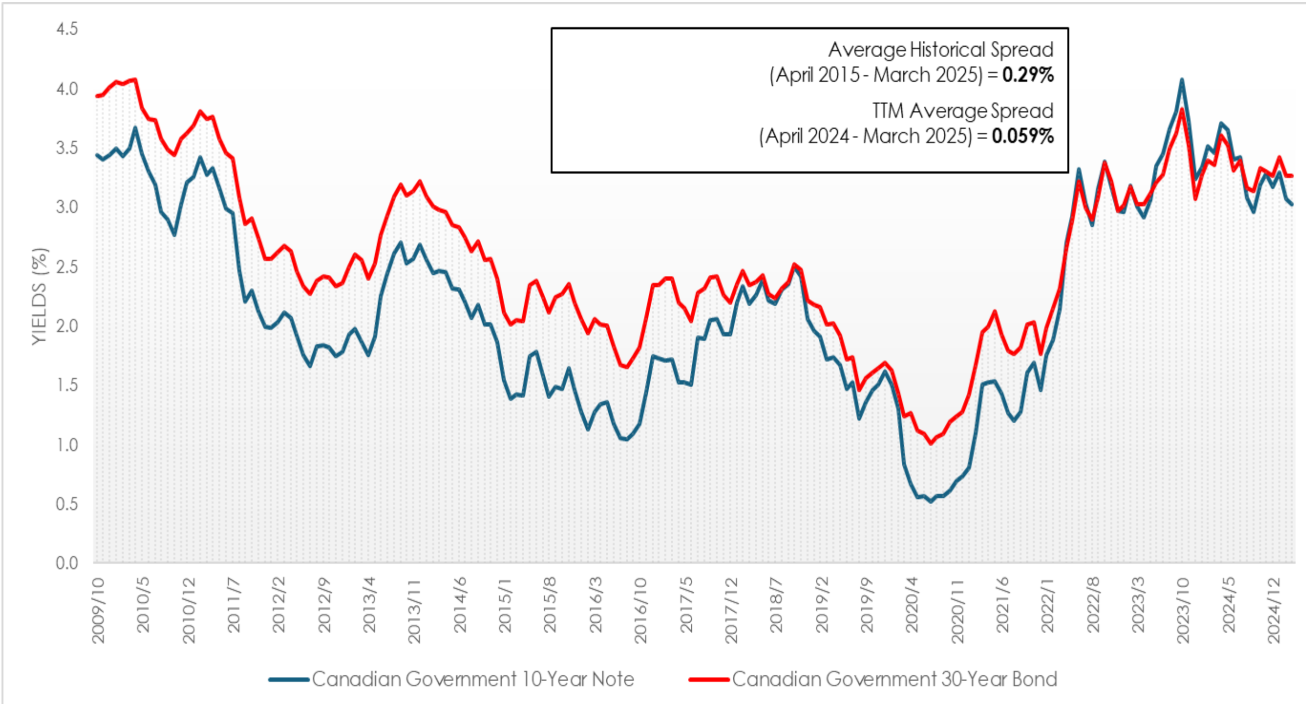
Monetary policy followed a similar path in the U.S. in 2022, with the U.S. Federal Reserve raising the federal funds rate to combat higher than expected inflation. The Federal Reserve raised the discount rate on numerous occasions from a range of 0.00-0.25 percent in March 2022 to a range of 5.00 to 5.25 percent in July 2023. Following the lead of other central banks around the world, the Federal Reserve voted to reduce the federal funds rate in September 2024, and it stands at 4.25 to 4.50 percent as of March 2025. The Federal Reserve has indicated that one or two additional cuts in the federal funds rate are possible in 2025, depending on the balance of economic data on inflation, unemployment, and economic growth, although the Federal Reserve noted after its March 2025 meeting the "additional economic uncertainty" due to the effect of tariffs. As a result, the Federal Reserve revised its economic projections to forecast lower than expected GDP growth and higher than expected inflation for the remainder of 2025.

D. Overview of Bond Yields and Equity Markets

1. Interest Rates

Bond yields are the most direct indicator of the cost of capital, as they reflect the level of interest required to compensate debt (but not equity) investors in the current market. Bond yields are a direct input to the CAPM and Risk Premium models. Figure 8 shows that both the 10- and 30-year Canadian government bond yields increased sharply after trading at or near all-time lows in July 2020. Average yields on 10-year bonds in March 2025 were 3.02 percent, as compared to 2.96 percent in January 2023 (the UARB approved the settlement agreement in NSPI's previous GRA on February 2, 2023). For 30-year government bonds, the average yield in March 2025 was 3.26 percent, compared to 3.01 percent in January 2023. The spread between 10- and 30-year Canadian government bonds was 5 basis points in January 2023 and 24 basis points in March 2025, reflecting ongoing uncertainty regarding both the economy and inflation. The average historical spread over the past 10 years has been approximately 29 basis points in Canada.

Figure 8: Canadian Government Bond Yields - 10-Year and 30-Year[21]



Yields on Canadian utility bonds have remained about the same since the UARB approved the settlement in NSPI's previous GRA. As Figure 9 illustrates, the Canadian Utility "A" rated bond yield index was 4.60 percent in January 2023 compared to 4.52 percent in March 2025. The spread between Canadian A-rated utility bonds and the 30-year Government of Canada long bond decreased from 159 basis points in January 2023 to 126 basis points in March 2025, which is below the historical average spread of 150 basis points over the last ten years.

[21] Bloomberg series GCAN10YR and GCAN30YR as of March 31, 2025.

Figure 9: Canadian Utility "A" Rated Bond vs. 30-Year Canada Long Bond[22]

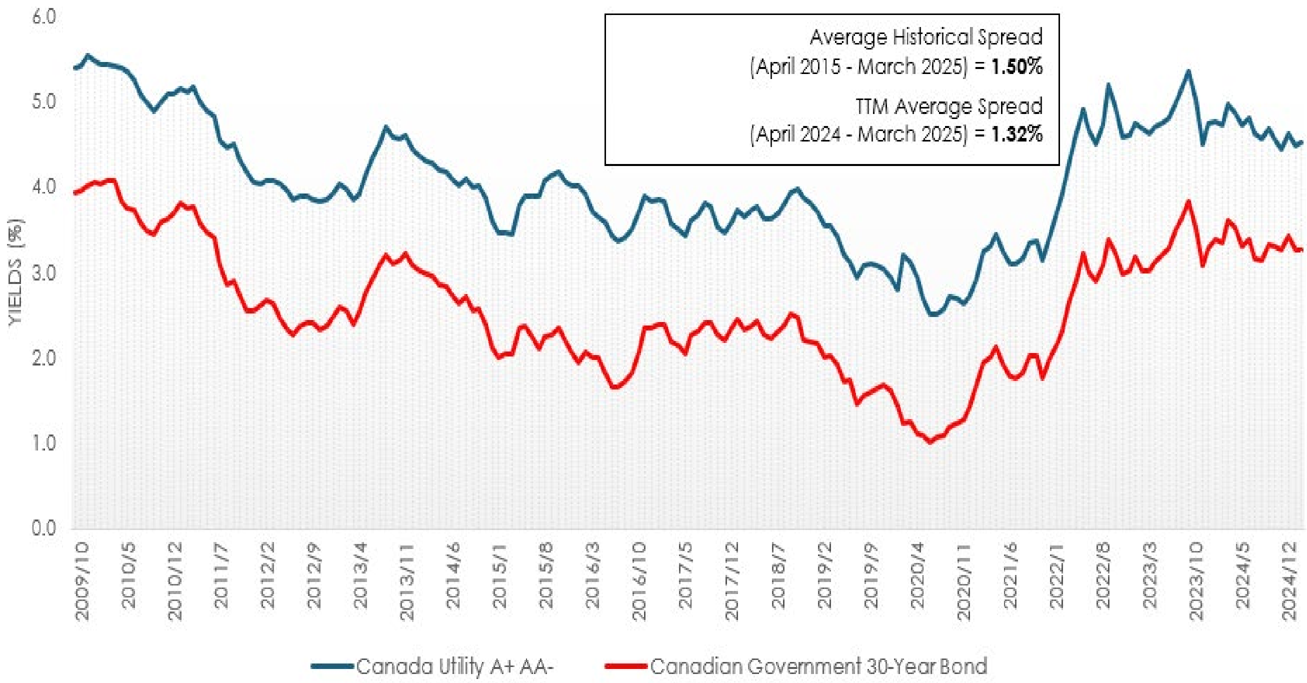


Figure 10 shows the forecast 10-year government bond yields for Canada and the U.S. from Consensus Economics. Our ROE analysis relies on forecast bond yields. According to the Consensus forecast, 10-year government bond yields are expected to increase slightly in Canada as compared to the average yield of 3.29 percent in January 2025, while in the U.S., 10-year government bond yields are expected to decline from the average yield of 4.63 percent in January 2025, on a path toward convergence as would be expected by the strong historical correlation between these bond yields (see Exhibit CEA-2).

[22] Bloomberg series BVCAUA30 and GCAN30YR as of March 31, 2025 (BVAL Yield Curve 30 Year replaces C29530Y Index, which was discontinued on 2/2/24).

Figure 10: Long-Term Forecast for 10-Year Government Bond Yields[23]

	2026	2027	2028	2029	2030-2034
Canada	3.2%	3.4%	3.5%	3.5%	3.5%
U.S.	3.7%	3.7%	3.7%	3.8%	3.8%

2. Yield Curve

The yield curve measures the difference between long-term and short-term interest rates. It is not a direct input to the models, but the cost of capital for utilities is more determined by long-term rates, so it is an indicator. A flat or inverted yield curve occurs when long-term interest rates are equal to or less than short-term interest rates, which usually occurs prior to a recession, while a steepening yield curve occurs when the difference between long-term interest rates and short-term interest rates is increasing and indicates that the economy is entering a period of expansion.[24] From a utility cost of capital standpoint, a steepening yield curve generally signals a higher cost of both equity and debt.

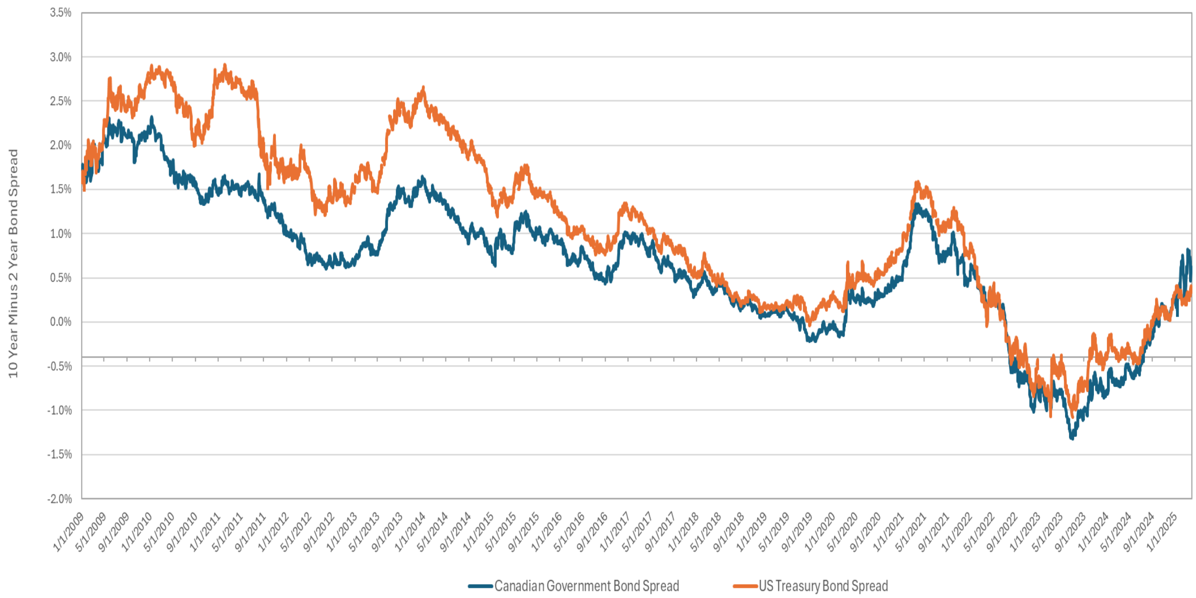
To test this measure, we calculated the difference between the yield on the 10-year government bond and the 2-year government bond ("bond spread") from January 2023 to March 2025. We selected the 10-year government bond yield to represent long-term interest rates and the 2-year government bond to represent short-term interest rates. The 2/10 yield curve became inverted in July 2022 in both countries, reflecting greater uncertainty regarding economic growth, due to much tighter monetary policy in response to inflationary pressure. More recently, the 2/10 curve has returned to an upward slope, as market conditions normalize and central banks return to a more neutral monetary policy. In Canada, the monthly average bond spread was negative 80 basis points in January 2023 versus 65 basis points in March 2025, while in the U.S. the bond spread was negative 68 basis points in January 2023 versus 31 basis points in March 2025.

---

23 Consensus Forecasts by Consensus Economics Inc., Survey Date October 7, 2024, at 3 and 29.

24 "What is a yield curve", Fidelity.com. https://www.fidelity.com/learning-center/investment-products/fixed-income-bonds/bond-yield-curve .

Figure 11: 10-year Government Bond Yield Minus 2-year Bond Yield[25]

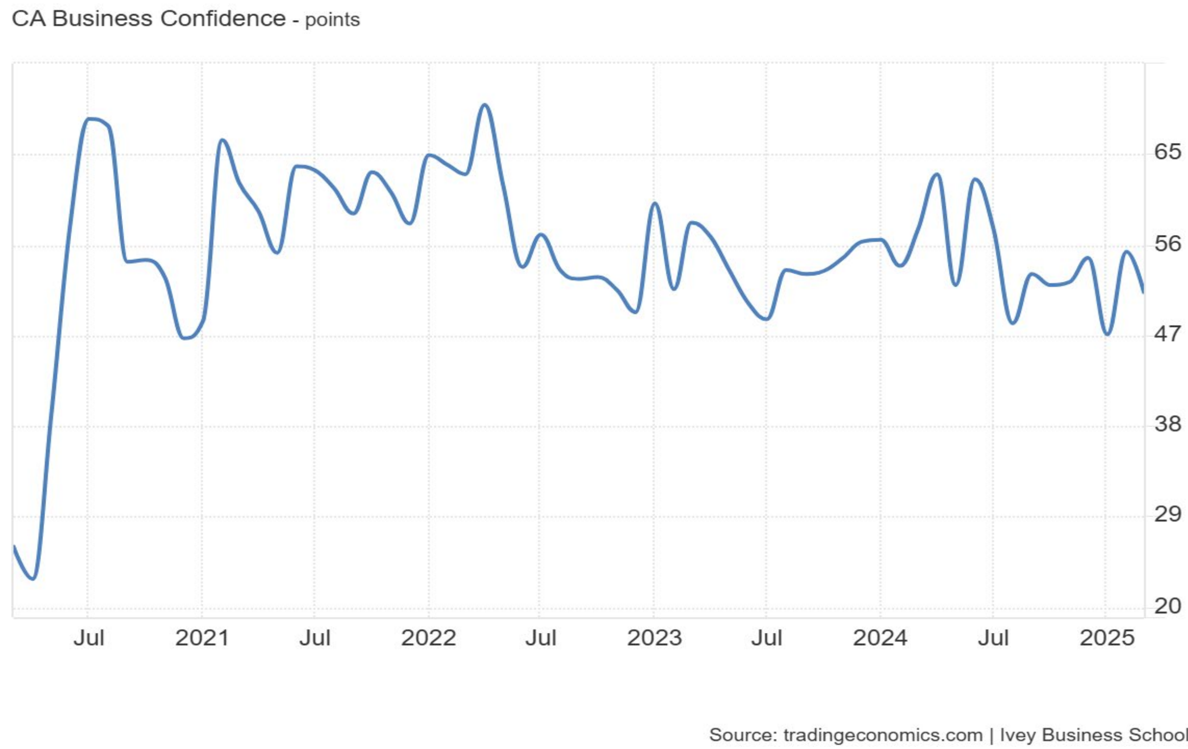


3. Business/Investor Confidence

One indicator of market risk is investor confidence. Greater confidence ordinarily translates to a greater willingness to invest and a lower cost of capital. In Canada, the Richard Ivey School of Business at the University of Western Ontario publishes a monthly Purchasing Managers Index ("PMI") that measures business confidence. The PMI is an economic index which measures the month-to-month variation in economic activity as indicated by a panel of purchasing managers from across Canada, and is based on one question only: "Are your purchases (in dollars) higher, the same, or lower than the previous month?" As shown in Figure 12 the PMI was at 54.7 in December 2024. After falling to a several year low of 47.1 in January 2025, the Index rebounded to a seven-month high of 55.3 in February, then eased to 51.3 in March 2025, but remained in expansionary territory. The most recent round of tariff announcements have yet to be fully registered. The PMI is used as a leading indicator of price levels, supplier deliveries, job creation and inventories.

[25] Federal Reserve Bank of St. Louis, 10-Year Treasury Constant Maturity Minus 2-Year Treasury Constant Maturity [T10Y2Y], retrieved from FRED, Federal Reserve Bank of St. Louis; as of March 31, 2025.

Figure 12: Canadian Business Confidence Index[26]



E. Integration of Canadian and U.S. Capital Markets

In a world of increasingly linked economies and capital markets, investors seek returns from a global basket of investment options. Investors distinguish between risks on a country-to-country basis, factoring in the comparability of the economic, business, and political environments.

Country-specific economic, business, and political conditions that affect investment risk can be measured through a variety of qualitative and quantitative metrics. One such measure, produced by The Economist Intelligence Unit, rates Canada and the U.S. precisely the same from an overall country risk perspective (A) with AAA being the highest rating.[27] The Economist provides the following description of its country risk ratings:

> *The Economist Intelligence Unit's Country Risk Service produces reports on 100 emerging markets and 20 OECD countries. These country-specific reports are complemented by this Risk ratings review, which analyses regional and global risk*

[26] https://tradingeconomics.com/canada/business-confidence .
[27] The Economist Intelligence Unit, Country Risk Service, Risk Ratings Review, August 2021, at 30.

> *trends. The main focus of the ratings is on three risk categories to which clients can have direct exposure: sovereign risk, currency risk and banking sector risk. We also publish ratings for political risk and economic structure risk, as well as an overall country credit rating. The ratings are measured on a scale of 0-100. Higher scores indicate a higher level of risk. The scale is divided into ten overlapping bands: AAA, AA, A, BBB, BB, B, CCC, CC, C, D. In the Risk ratings review, ratings for a region are defined as the unweighted average of the ratings for all the countries being assessed in that region.*[28]

Figure 13 summarizes the country risk ratings for Canada and the U.S. as of August 2021.

Figure 13: Country Risk Ratings

	Canada	U.S.
Sovereign Risk Rating	A	AA
Currency Risk Rating	A	A
Banking Sector Risk Rating	AA	A
Political Risk Rating	AAA	AA
Economic Structure Risk Rating	A	A
Overall Country Risk Rating	A	A

This suggests that from a country risk perspective, Canada and the U.S. are highly comparable in a global context. This assessment is confirmed in country risk reports from Allianz indicating that both Canada and the U.S. were ranked AA1 as of January 2025.[29]

Despite the recent tariff tensions, the magnitude and significance of trade between the two countries reflects the high degree of integration between the two economies. According to the U.S. Department of State: "The United States and Canada enjoy the world's most comprehensive trading relationship, which supports millions of jobs in each country. Canada and the U.S. are each other's largest export markets, and Canada is the number one export market for more than 30 U.S. States."[30] Canada is currently the U.S.' 2nd largest goods trading partner overall with $773 billion in total (two-way) goods trade during 2023.[31] This is an average two-way trade of $US 2.1 billion per day; trade between the two countries continued at this level during the first eleven

28 Ibid, at 28.
29 Source: Country Risk Report Canada (allianz.com) , Country Risk Report United States (allianz.com).
30 U.S. Department of State, https://www.state.gov/u-s-relations-with-canada
31 https://www.census.gov/foreign-trade/balance/c1220.html

months of 2024. This is an indication of the high degree of integration between the two economies.

Exhibit CEA-2 presents several measures that reflect the overall economic and investment environment in Canada and the U.S. On balance, the economic and business environments of Canada and the U.S. are highly integrated and exhibit strong correlation across a variety of metrics, including GDP growth and government bond yields. From a business risk perspective, including overall business environment and competitiveness, Canada and the U.S. are ranked closely when compared against other developed and developing countries. Based on these macroeconomic indicators, there are no fundamental dissimilarities between Canada and the U.S. (in terms of economic growth, inflation, or government bond yields) that would cause a reasonable investor to have a materially different return expectation for a group of comparable risk utilities in the two countries. Our cost of capital analysis is framed by the conclusion that Canada and the U.S. have comparable macroeconomic and investment environments. We therefore consider both Canadian and U.S. proxy companies for our analysis.

F. Capital Market Conclusions

Interest rates on government and utility bonds have remained about the same as when the UARB approved the settlement in NSPI's previous GRA. This indicates that despite the uncertainties in the economy, the cost of utility capital has remained somewhat stable. Over the longer term, the utility industry faces complex structural challenges associated with climate change, decarbonization, cyber security, grid modernization and shifting consumer preferences. The electric utility industry is starting to see load growth due to electrification of buildings, demand for electric vehicle charging, and demand from data centers for artificial intelligence. While inflation has gradually declined to levels slightly above central bank targets, long-term interest rates in both Canada and the U.S. are projected to remain near current levels over the next two to three years, as shown in the Consensus Economics forecasts. We have specifically incorporated this economic outlook through the use of projected interest rates in the CAPM and Risk Premium models, and the forecast of GDP growth in the multi-stage DCF model.

SECTION 4:

SELECTION OF PROXY COMPANIES

Since ROE is a market-based concept and given that NSPI is not publicly-traded, it is necessary to establish a group of companies that are both publicly-traded and comparable to the Company's business and financial characteristics to serve as its "proxy" for purposes of the ROE estimation process. Even if NSPI's regulated electric utility operations made up the entirety of a publicly-traded entity, transitory events could bias that entity's market value in one way or another over a given period of time. A significant benefit of using a proxy group is that it provides the ability to mitigate the effects of anomalous events that may be associated with any one company. The proxy companies used in our ROE analyses possess a set of business and financial characteristics that are similar to NSPI's regulated electric utility operations and thus provide a reasonable basis for the derivation and assessment of ROE and capital structure estimates.

NSPI is an integrated electric utility that provides generation, transmission and distribution service to approximately 549,000 residential, commercial, and industrial customers in Nova Scotia. As of December 31, 2024, the Company had regulated net property, plant, and equipment of approximately $4.9 billion and delivered 10,442 GWh of power.[32] NSPI generated approximately 64 percent of its electricity supply from Company-owned generating plants in 2024, while purchasing the remaining 36 percent.[33]

We developed three proxy groups for the ROE analysis. The first proxy group is comprised of publicly-traded, regulated Canadian electric and natural gas utility companies. Recognizing there are few publicly-traded companies in the utility sector in Canada, the only screening criterion was an investment grade credit rating, which all companies in the sector have. Emera Inc. has been excluded from the Canadian proxy group because it is the parent company of NSPI. TC Energy (formerly TransCanada) has been excluded due to the risk profile of the TransCanada Mainline, which differs from electric utility operations. The following five companies comprise the Canadian Proxy Group.

[32] Data provided by NSPI.
[33] Data provided by NSPI.

Figure 14: Canadian Proxy Group

Company	Ticker
AltaGas Inc.	ALA
Canadian Utilities Limited	CU
Enbridge Inc.	ENB
Fortis Inc.	FTS
Hydro One Ltd.	H

The second proxy group is comprised of U.S. electric utility companies that would be considered by investors as generally comparable in risk to NSPI. To obtain companies of like-risk, we performed a number of screens to develop a group of companies that are primarily engaged in the provision of regulated electric utility service. Starting with the 36 domestic companies Value Line classifies as Electric Utilities, we further screened for companies that meet the following criteria:

a) Maintain credit ratings of at least BBB+ from S&P or Baa1 from Moody's;

b) Consistently pay quarterly cash dividends, and have not reduced or eliminated those dividends in the past two years;

c) Have positive earnings growth rate projections from at least two sources;

d) Have company-owned regulated generation assets in rate base;

e) Derived at least 70 percent of operating income from regulated operations in the period from 2021-2023;

f) Derived at least 90 percent of regulated operating income from electric utility service in the period from 2021-2023; and

g) Not involved in a merger or other significant transformative transaction during the evaluation period.

The following ten U.S. electric utility companies met the screening criteria:

Figure 15: U.S. Integrated Electric Proxy Group

Company	Ticker
Alliant Energy Corp.	LNT
American Electric Power Company	AEP
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy Inc.	EVRG
NextEra Energy, Inc.	NEE
OGE Energy Corporation	OGE
Pinnacle West Capital Corp.	PNW
Portland General Electric Company	POR
PPL Corporation	PPL

The third proxy group is comprised of the three Canadian investor-owned utilities that are primarily engaged in the provision of electricity (Canadian Utilities Limited, Fortis Inc. and Hydro One Ltd.) plus all ten U.S. electric utilities in Figure 16**.** This group is referred to as the North American Electric proxy group.

Figure 16: North American Electric Proxy Group

Company	Ticker
Canadian Utilities Ltd.	CU
Fortis Inc.	FTS
Hydro One Ltd.	H
Alliant Energy Corp.	LNT
American Electric Power Company	AEP
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy Inc.	EVRG
NextEra Energy, Inc.	NEE
OGE Energy Corporation	OGE
Pinnacle West Capital Corp.	PNW
Portland General Electric Company	POR
PPL Corporation	PPL

Exhibit CEA-3 provides additional information on the proxy group screening process.

Canadian regulators have adopted a pragmatic view of the use of U.S. data and proxy groups to estimate the allowed ROE for Canadian regulated utilities. The development of a proxy group comprised entirely of Canadian electric utilities is challenged by the small number of publicly-traded utilities in Canada and the fact that many of those Canadian companies derive a significant percentage of revenues and net income from operations other than regulated electric utility service. The continuing trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility holding companies, further blurs the distinction between a Canadian and U.S. utility company. Multiple regulatory authorities in Canada have recognized that Canadian utility companies are competing for capital in global financial markets and that Canadian data are limited by the small number of publicly-traded utilities. Regulators have also recognized the integrated nature of Canadian and U.S. financial markets, and the similarity of the utility regulatory regimes.

In particular, both the BCUC and the AUC have accepted the use of a North American proxy group comprised of utility companies in both Canada and the U.S. to set the authorized ROE for utilities under their jurisdiction. The BCUC explained its rationale for using a North American proxy group as follows:

> *For the reasons outlined above, we find the use of the Canadian proxy groups and US proxy groups alone to be inferior to that of using a North American proxy group which has a reasonable mix of both Canadian and US comparators, and the averaging of the results of these three groups to be a poor compromise. On balance, we find that having a proxy group of North American comparators trumps any jurisdictional or structural differences. In making this determination, we rely on the facts that financial and capital markets are highly integrated and that utility regulatory regimes in North America are sufficiently similar for the purpose of establishing a comparable ROE.*[34]

The BCUC decision is consistent with our experience that equity investors and credit analysts consider the utility industry as a North American industry, with Canadian companies competing for capital with similar risk companies in both countries.

The AUC also developed a set of screening criteria for purposes of selecting a proxy group used to estimate the cost of equity for Alberta's electric and gas utilities.[35] The large majority of companies chosen by the AUC for the comparator group (28 out of 33 companies, or almost 85

---

[34] British Columbia Utilities Commission, Decision and Order G-236-23, September 5, 2023, at 16.
[35] AUC Decision 27084-D02-2023, October 9, 2023, at para 99-104.

percent) were either U.S. electric or U.S. gas utilities (or both). In addition, several of the Canadian companies in the AUC's comparator group have significant U.S. operations, including Emera, Fortis, and Algonquin Power.

In Ontario, the OEB's recent generic cost of capital decision questioned the framework it established in 2009 that placed reliance on U.S. proxy group data to establish the ROE for Ontario's utilities.

> *The OEB acknowledges that its 2009 Report placed considerable weight on U.S.-based utility data in establishing reasonable expectations for returns that enable Ontario-based utilities to access capital. The expert reports filed by both the EDA (Nexus expert) and OEA (Concentric expert) in this proceeding have been responsive to the approach previously adopted by the OEB therein, notably the comparability of U.S. and Canadian utilities. While it may be relevant to consider U.S. utility ROE results, differences in structure and risk limit the ability to find truly comparable companies.*[36]

We recognize the challenges of finding comparable companies to Canadian utilities, but these challenges exist for any utility in Canada or the U.S. The NEB recognized these challenges and reinforced this view in its bellwether TQM decision.

> *In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's view that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008.*[37]

Since the NEB's 2009 decision, the utility industry has become even more of a North American industry from both an investor and allocation of capital viewpoint. Our view is that careful screening of a North American proxy group of companies remains the most reliable method for determining the cost of capital, and is consistent with how investors see the market.

[36] Decision and Order, March 25, 2025 at 37.
[37] RH-1-2008, March 2009, at 71.

SECTION 5:
METHODS FOR ESTIMATING THE RETURN ON EQUITY

Analysts use multiple approaches to estimate the cost of common equity. The required ROE can be estimated using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns. A consideration in determining the ROE is to ensure that the methodologies employed reasonably reflect investors' forward-looking views of financial markets in general, and the subject company (in the context of the proxy group) in particular.

No financial model can exactly pinpoint the correct ROE; rather, each test brings its own perspective and set of inputs that inform the estimate of the ROE. Consistent with the *Hope* standard, it is "the result reached, not the method employed, which is controlling."[38] Although each model brings a different perspective and adds depth to the analysis, each model also has its own inherent weaknesses and should not be relied upon individually without corroboration from other approaches. Regardless of which analyses are used to estimate the investor-required ROE, analysts must apply informed judgment to assess the reasonableness of results and to determine the appropriate weighting to apply to results under prevailing capital market conditions.

Other Canadian utility regulators, including the BCUC,[39] the OEB,[40] and the AUC,[41] have acknowledged the need to use multiple methodologies in determining a fair return on equity.

A. Discounted Cash Flow ("DCF") Model

The premise underlying the DCF model is that investors value a given investment according to the present value of its expected cash flow over time. The standard DCF model is shown in Formula [1]:

$$P = \frac{D_0(1+g)^1}{(1+r)^1} + \frac{D_1(1+g)^2}{(1+r)^2} + \cdots + \frac{D_{n-1}(1+g)^n}{(1+r)^n} \quad [1]$$

where:

38 See Hope Natural Gas v. Federal Power Commission.

39 British Columbia Utilities Commission, FortisBC Energy Inc., Application for its Common Equity Component and Return on Equity for 2016, Decision and Order G-129-16, August 10, 2016, at 47.

40 Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084, at 26.

41 Alberta Utilities Commission, 2018 Generic Cost of Capital, Decision 22570-D01-2018, at 59-94,

P = the current stock price
g = the dividend growth rate
D_n = the dividend in year n
r = the cost of common equity.

Assuming a constant growth rate in dividends, the model may be rearranged to compute the ROE, as shown in Formula [2]:

$$r = \frac{D}{P} + g \quad [2]$$

Stated otherwise, the cost of common equity is equal to the dividend yield plus the expected dividend growth rate.

1. Constant Growth DCF Model Assumptions

The Constant Growth DCF model requires the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate. As discussed later in the report, other forms of the DCF model do not rely on the assumption of constant growth in perpetuity.

2. Dividend Yield

As shown in equation [3], the dividend yield component of the DCF model is calculated as follows:

$$[3] \quad Y = \frac{D_0(1+0.5g)^1}{P_0}$$

One half year's growth rate is applied to the annual dividend rate to account for increases in quarterly dividends at different times throughout the year. It is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. This adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period and does not overstate the aggregated dividends to be paid during that time.

The dividend yields were calculated for each company in the respective proxy groups by dividing the current annualized dividend by the average stock price for each company for the 90 trading days ended January 31, 2025. Those dividend yields are multiplied by one-half the growth rate to reflect expected future dividend increases.

3. Growth Rate Estimates

In considering the appropriate growth rate for the DCF model, the most relied upon indicator of investors' expectations is analysts' estimates of future earnings growth. We have relied on earnings growth estimates from S&P Capital IQ Pro, the *Value Line Investment Survey*, Zacks Investment Research, and Seeking Alpha for the companies in the respective proxy groups. We rely on these multiple sources to best inform the overall estimate of earnings growth for each company. Those growth rates are shown in Exhibit CEA-4.

Investors typically rely on projected earnings growth rates rather than dividend growth rates for several reasons. First, although the DCF model is based on dividend growth rates, a company's dividend growth is derived from and can only be sustained by earnings growth. Second, in order to reduce the long-term growth rate to a single measure, as required in the Constant Growth DCF model, it is necessary to assume a constant payout ratio, and that earnings per share, dividends per share and book value per share grow at a constant rate. Third, earnings growth rates are less influenced by dividend decisions that companies may make in response to near-term changes in the business environment. Finally, analysts' forecasts of earnings growth are widely available, whereas dividend and book value growth rates are generally available only from Value Line.[42]

Some utility regulators in Canada have expressed concern that analysts' earnings growth rates may be overly optimistic. If optimism bias were present in analysts' earnings forecasts, it could create an upward bias in the estimated cost of capital that results from the DCF approach. In order to assess whether earnings growth rates are reasonable relative to GDP growth, Concentric compared the actual earnings and dividends per share growth rates for the companies in the three proxy groups for which the required data are available to GDP growth. These results are shown in Figure 17.

[42] Value Line is the only publication of which we are aware that projects dividend and book value growth rates. Those estimates represent the Value Line analyst's perspective on dividend and book value growth. In contrast, many of the earnings growth rates that are publicly available are consensus estimates with contributions provided by several analysts.

Figure 17: Utility Earnings, Dividend and GDP Growth Comparisons

	[1] Avg. EPS Growth Historical 2009-2024	[2] Avg. DPS Growth Historical 2009-2024	[3] CAGR GDP Growth 2009-2024	[4] Avg. EPS Growth Forecast	[5] Nominal GDP Growth Forecast
Canadian Proxy Group	5.93%	9.09%	4.41%	5.50%	4.04%
U.S. Electric Proxy Group	4.69%	4.75%	4.78%	6.76%	4.14%
North American Electric Proxy	4.78%	4.89%	4.75%	6.36%	4.12%
Average	5.13%	6.25%	4.65%	6.20%	4.10%

[1] Value Line, average compound annual growth rate in EPS of each company the proxy group
[2] Value Line, average compound annual growth rate in DPS of each company the proxy group
[3] Statistics Canada, Table: 36-10-0104-01 (formerly CANSIM 380-0064), 2009 to 2024 and
Bureau of Economic Analysis, Table 1.1.5. Gross Domestic Product.
Combined Proxy Group number is weighted average of Canadian and US results
[4] See Exhibit JMC-4 Constant DCF
[5] See Exhibit JMC-5 Multi-Stage DCF

This analysis shows important relationships based on fifteen years of history, which is a sufficient time-period to draw meaningful conclusions and to frame reasonable expectations for the future.

- Historically, dividend growth has tracked reasonably well with earnings growth, as would be expected, as earnings drive dividend growth. The exception is the Canadian proxy group, where dividends outpaced earnings growth over this period. This is primarily due to Enbridge, which had a significant increase in its payout ratio. We conclude that earnings growth is a reasonable (if not conservative) proxy for dividend growth, especially with a broad enough company sample.
- Both historical earnings and dividend growth generally exceeded GDP growth. The exception is the U.S. Electric proxy group, where historical GDP growth is approximately equal to both historical dividend growth and earnings growth. This should not be a surprise, as earnings for a healthy and well-managed utility can exceed the growth rate of the overall economy. There is no fundamental basis to assume that economy-wide GDP growth with a mix of macroeconomic, social, and business drivers serves as a limit on utility earnings growth.
- Looking to the future, it is not unreasonable to rely on analyst projections, as we and other experts commonly do, just because they exceed GDP growth. Over the historical period,

average dividend growth for the North American Electric proxy group exceeded historical GDP growth by 0.14 percent.

These relationships indicate the projected analyst growth rates are entirely reasonable by historical standards.

4. Multi-Stage DCF Model

In order to address some of the limiting assumptions underlying the Constant Growth form of the DCF model, our ROE analysis and recommendation relies on the results of a multi-period (three-stage) DCF Model. The Multi-stage DCF model tempers the assumption of constant growth in perpetuity with a three-stage approach based on near-term, transitional, and long-term growth rates.

The Multi-stage DCF model transitions from near-term growth (i.e., the average of Value Line, Zacks, S&P Capital IQ Pro and Seeking Alpha forecasts used in the Constant Growth model) for the first stage (years 1-5) to the long-term forecast of nominal GDP growth for the third stage (year 11 and beyond). The second, or transitional, stage connects near-term growth with long-term growth by changing the growth rate each year on a pro rata basis. In the terminal stage, the dividend cash flow then grows in perpetuity at the same rate as nominal GDP (or a total of 200 years). The return on equity is the internal rate of return based on the current average stock price and this stream of dividend payments. As we have shown above, GDP growth is conservative based on the historic earnings and dividend growth of the proxy group companies.

Nominal GDP growth rates for the proxy groups were developed using data for each country as reported by Consensus Economics, Inc. for the period from 2030-2034. These forecasts are based on real (constant dollar) growth rates and estimates for inflation. The inflation estimate was applied to the estimate of real GDP growth to develop the nominal (post-inflation) GDP growth rate. The estimates of nominal GDP growth are summarized in Figure 18.

Figure 18: Estimates of Nominal GDP Growth[43]

Source	Canada	U.S.
Real GDP Growth	1.9%	1.9%
Inflation	2.1%	2.2%
Nominal GDP Growth	**4.04%**	**4.14%**

5. DCF Results

The DCF results are shown in Figure 19 and in Exhibits CEA-4 and CEA-5. To mitigate any concern that short-term EPS growth rates may not be sustainable, we have relied on the results of the Multi-Stage DCF model, which tempers the short-term growth rate in Years 1-5 with projected GDP growth in Years 11-200. As summarized in Figure 22, the Multi-Stage DCF model produces an average cost of common equity of 9.6 percent for the Canadian Utility proxy group, 9.4 percent for the U.S. Electric proxy group, and 9.3 percent for the North American Electric Utility proxy group. These values include an adjustment of 50 basis points for flotation costs and financial flexibility.

Figure 19: 90-day Average Multi-Stage DCF Results

Proxy Group	
Canadian Utility	9.60%
U.S. Electric Utilities	9.35%
North American Electric Utilities	9.29%

43 Consensus Forecasts, for 2030-2034, October 7, 2024, at 3 (U.S.) and 29 (Canada).

As discussed in more detail in Section VI, we believe that the North American Electric utility proxy group is most comparable to NSPI from an investment perspective.

B. Capital Asset Pricing Model ("CAPM")

The CAPM method is based on the relationship between the required return of a security and the systematic risk of that security. As shown in Equation [4], the CAPM is defined by four components, each of which must be a forward-looking estimate:

[4] Ke = rf + β(rm – rf)

where:

Ke = the required ROE for a given security;

β = Beta of an individual security;

rf = the risk-free rate of return; and

rm = the required return for the market as a whole.

The term (rm – rf) represents the Market Risk Premium ("MRP"). According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by beta, which is defined as:

[5] $$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)}$$

where:

re = the rate of return for the individual security or portfolio.

The variance of the market return, noted in Equation [5], is a measure of the variability in the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, beta represents the risk of the security relative to the market.

1. Risk Free Rate

Our CAPM analysis relies on the 2026 through 2028 average *Consensus Economics* forecast of the 10-year government bond yield (shown in Figure 20) plus the average historical spread between 10-year and 30-year government debt. The use of a forecast yield is appropriate as it provides a forward-looking view of the ROE.

Figure 20: Long-term Forecast for 10-Year Government Bond Yields[44]

	2026	2027	2028	Average
Canada	3.2%	3.4%	3.5%	**3.37%**
U.S.	3.7%	3.7%	3.7%	**3.70%**

With an average spread between 10-year and 30-year government bond yields of 30 basis points in Canada and 44 basis points in the U.S.,[45] the corresponding longer-term forecast yield on 30-year government bonds over the period 2026–2028 is shown in Figure 21.

Figure 21: Risk Free Rate

	Canada	U.S.
October 2024 Consensus Forecast Average 2026-2028 Forecasts	3.37%	3.70%
Average Daily Spread between 10-year and 30-year government bonds (last 10 years)	0.30%	0.44%
Sum	**3.67%**	**4.14%**

2. Beta

We have employed several methods of measuring the beta coefficient for the Canadian and U.S. proxy group companies using estimates from both Value Line and Bloomberg. Value Line publishes the historical beta for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index. Bloomberg produces beta estimates based on parameters entered by the user. We have computed Bloomberg betas based on five years of weekly stock returns and using the S&P 500 or the S&P/TSX Composite as the market index. Both Value Line and Bloomberg provide adjusted betas to compensate for the tendency of

44 Consensus Forecasts by Consensus Economics Inc., Survey Date October 7, 2024, at 29 and 3.
45 Historical spreads were calculated using daily bond yields for the 10 year period ending January 31, 2025.

beta to revert toward the market mean of 1.0 over time. The betas used in our CAPM analyses for the proxy groups are shown in Figure 22.

Figure 22: Value Line and Bloomberg Betas

	Value Line	Bloomberg
Canadian Group	0.80	0.87
U.S. Electric Utility Group	0.97	0.92
North American Electric Group	0.95	0.88

There are two primary reasons to adjust raw betas. First, empirical studies have provided evidence that an individual company beta is more likely than not to move toward the market mean of 1.0 over time.[46] Second, adjusting beta serves a statistical purpose. Because betas are statistically estimated and have associated error terms, betas greater than 1.0 tend to have positive estimated errors and thus tend to overestimate future returns. Betas below the market average of 1.0 tend to have negative error terms and underestimate future returns. Consequently, it is necessary to adjust forecasted betas toward 1.0 to improve forecasts.[47] Because current stock prices reflect expected risk, one must use an expected beta to appropriately reflect investors' expectations. A raw beta reflects only where the stock price has been historically relative to the broad market and is an inferior proxy for the expected returns when compared to the adjusted beta.

Dr. Marshall Blume was among the first to study beta. Specifically, he studied four groups of betas, ranging from a very low beta group (averaging 0.50, and similar to the utility industry) to a very high beta group. Dr. Blume found that his adjustment best predicted future betas for each of the four risk groups over the next seven years. Dr. Blume found that a low beta portfolio that averaged 0.50 migrated towards the grand mean of all betas of 1.0 approximately in accordance with the Blume formula. This study provides empirical evidence that betas migrate towards 1.0 and do indeed exceed their long-term unadjusted averages. Given that the CAPM is intended to estimate the forward-looking cost of capital, it is important to reflect a forward view of beta and

46 Marshall E. Blume, The Journal of Finance, "On the Assessment of Risk," March 1971, Volume 26, No. 1, at 1-10, and Marshall E. Blume, The Journal of Finance, "Betas and Their Regression Tendencies," June 1975, Volume 30, No. 3, at 785-795.

47 Roger A. Morin, *New Regulatory Finance*, at 74.

its tendency to migrate towards the market mean over time, which is not limited to the long-term historical average of the industry beta.

In terms of how other Canadian jurisdictions have recently treated beta, Dr. Jonathan Lesser was retained by the BCUC to review the methodologies used to estimate the cost of capital as part of the 2021-2022 generic cost of capital proceeding in British Columbia. Dr. Lesser also recognized the merits of using Blume adjusted betas in the CAPM analysis.

> *Because regulators establishing the allowed ROE for a regulated utility are basing that allowed ROE on expected market conditions over an indefinite future, adjusted beta values are typically considered to be more appropriate when applying the CAPM.*[48]

In a follow-up interrogatory on this issue, Dr. Lesser further clarified his position:

> Does Dr. Lesser see merit in adjusting utility betas to anything other than the market value of one? If so, please explain.
>
> Response:
> *Dr. Lesser assumes the question is asking about methodologies that adjust raw beta values towards their theoretical long-term values. Dr. Lesser is not aware of beta adjustment methodologies that adjust raw beta values towards a value other than one.*[49]

Dr. Lesser further expanded this position in his response to a clarifying question by the Commission:

> Please confirm, or explain otherwise, if Dr. Lesser endorses the use of the Blume-adjusted Beta for utilities' ROE determination.
>
> Response:
> *I recommend the use of Blume-adjusted beta values. Furthermore, I recommend the use of the beta values reported by Value Line to ensure there is consistency amongst all CAPM estimates.*[50]

We agree with Dr. Lesser, and in our experience, Value Line and Bloomberg are the most commonly employed sources of beta for cost of capital analysis.

---

48 Regulated Utility Cost of Capital: Theory and Canadian Practice, Jonathan A. Lesser, Continental Economics, Inc., August 4, 2021, at 42.

49 British Columbia Utilities Commission – Generic Cost of Capital – Project No. 1599176 – BCUC Staff Consultant Response, Dr. Lesser Responses to FortisBC Set 1, November 30, 2021, 10.1.

50 Responses to British Columbia Utilities Commission Information Request No. 2 Generic Cost of Capital Prepared by Jonathan Lesser, Ph.D., June 10, 2022, 7.1.

The BCUC noted in its September 2023 Decision and Order that it had not previously accepted the use of Blume adjusted betas. However, the BCUC reversed its previous decisions on this issue, stating:

> *However, the Panel notes Mr. Coyne's explanation that Dr. Blume found that his adjustment was applicable to all betas, ranging from a low of 0.50 to a high of 1.53, and in Mr. Coyne's view, there is no reason to expect that regulated utilities would be an exception to this rule. Given the views of the two experts in this proceeding and since none of the parties object to Mr. Coyne's use of Blume-adjusted data, the Panel accepts the experts' recommendation to use the Blume-adjusted beta estimates for the proxy groups.*[51]

3. Market Risk Premium ("MRP")

Estimates of the MRP generally fall into two categories, *ex-post* (historical arithmetic average) and *ex-ante* (forward looking). The historical MRP is based on the arithmetic means of the equity market returns for large company stocks over the income only return on long-term government bonds, based on data from Kroll (formerly Duff & Phelps). In Canada, the historical MRP is based on return data from 1919-2023, while in the U.S., the historical MRP is calculated using return data from 1926-2023.

Because the U.S. and Canadian economies are highly integrated and capital flows freely across the border, the risk premiums for each country are highly correlated. Accordingly, it is reasonable to derive a single estimate of the MRP for Canada and the U.S., as provided in Figure 23.

Figure 23: Historical Market Risk Premia – Canada and U.S.

Canada	5.68%
United States	7.17%
Average	6.43%

We have previously used an average of forward-looking and historical MRPs in Canada, which was the approach taken by the BCUC in its September 2023 decision for FortisBC. In order to be consistent with our recent approach elsewhere in Canada, however, we have used only the

51 British Columbia Utilities Commission, Decision and Order G-236-23, September 5, 2023, at 75.

historical MRP in our CAPM analysis for NSPI. The historical MRP is substantially lower than the forward-looking MRP and is therefore a conservative estimate in the CAPM analysis.

4. CAPM Results

Our CAPM analysis for the integrated electric utilities produces an ROE estimate of 9.7 percent for the Canadian Utilities proxy group, 10.7 percent for the U.S. Electric Utilities proxy group, and 10.3 percent for the North American Electric proxy group.

Figure 24: CAPM Results (including flotation costs)

Proxy Group	
Canadian Utilities	9.71%
U.S. Electric Utilities	10.69%
North American Electric Utilities	10.32%

C. Flotation Costs and Financing Flexibility

It is common practice for Canadian regulators to approve an adjustment for flotation costs and financing flexibility, with 50 basis points being the norm (as discussed below). The adjustment for flotation costs compensates the equity holder for the costs associated with the sale of new issues of common equity. These costs include out-of-pocket expenditures for the preparation, filing, underwriting, as well as a discount to the share price, and other costs of issuance of common equity. An adjustment is also made to provide for financial flexibility such that there is adequate cushion to raise equity in challenging capital market conditions.

As the purpose of the allowed rate of return in a regulatory proceeding is to estimate the cost of capital the regulated company would incur to raise money in the "primary" markets, an estimate of the returns required by investors in the "secondary" markets must be adjusted for flotation costs in order to provide an estimate of the cost of capital that the regulated company requires. The adjustment also takes into account the need for financial flexibility, meaning that utilities are capital intensive businesses and must be able to access capital markets at all necessary times regardless of conditions in capital markets or the economy.

The practice of allowing a 50-basis point adjustment for flotation costs and financing flexibility is widespread across Canada. As shown in Figure 25, of the ten jurisdictions examined, seven have historically granted the 50-basis point adjustment. Only Quebec deviates from 50 basis points by allowing 30 to 40 basis points, and Manitoba and Saskatchewan, which have only Crown utilities, do not employ regular ROE analyses. In Nova Scotia, the Board's February 2023 order approving a settlement agreement did not specify whether flotation costs were included in the authorized ROE for Nova Scotia Power. The BCUC recently rejected an ROE adjustment for flotation costs and financing flexibility for FortisBC Energy, Inc. and FortisBC Inc. in its September 2023 decision, although it made some adjustment in the deemed equity ratio. In 2016, the BCUC accepted a 50-basis point adjustment for flotation and financing flexibility, but did not accept that the adjustment should automatically be applied to experts' analytical results. The AUC's October 2023 order in the GCOC proceeding for 2024 and beyond included an adjustment of 50 basis points. The OEB in its recent generic cost of capital decision reduced its previous 50 basis points to 25 basis points for flotation costs alone, absent a showing that a utility's actual flotation costs exceed that number,

Figure 25: Jurisdictional Comparison of Financing and Flexibility Adjustment

Jurisdiction	Adj.	Docket/Proceeding	Notes
Alberta	50 bps	2018 GCOC Decision 22570-D01-2018 and 2024 GCOC Decision 27084-D02-2023	Adjustment of 50 bps is normally included in the allowed return to account for administrative and equity issuance costs, any impact of underpricing a new issue, and the potential for dilution.
British Columbia	None	2023 GCOC Decision Stage 1	Has previously approved 50-bps adjustment in 2016 FEI Decision and 2013 GCOC Decision in Stage 1
Manitoba	N/A	N/A	N/A
New Brunswick	50 bps	2010 EG Decision	Accepted 50 bps as being the lower of two proposed adjustments presented.
Newfoundland and Labrador	50 bps	P.U. 13(2013), and P.U. 18(2018)	Accepted 50-bps adjustment
Nova Scotia	N/A	2023 NSUARB 12	The 2023 Nova Scotia Power rate application was resolved through a settlement agreement that specified an authorized ROE but did not indicate whether that return included flotation costs and/or financing flexibility.
Ontario	50 bps	EB-2009-0084	Base ROE value included a 50-bps adjustment for flotation and financing flexibility.
	25 bps	EB-2024-0063	25 bps for flotation costs.
Prince Edward Island	50 bps	Order UE19-08	Approved ROE included a 50-bps adjustment for flotation costs.
Saskatchewan	N/A	N/A	N/A
Quebec	30-40 bps	D-2011-182/R-3752-2011	Regie determined provision for flotation costs and other costs of accessing capital markets ranging from 30-40 bps, with a greater weighting at the lower end of the range.

For the above reasons, we have adjusted the results of our DCF and CAPM analyses by 50 basis points for flotation costs and financing flexibility.

D. Risk Premium Analysis

In general terms, the Risk Premium approach recognizes that equity is riskier than debt because equity investors bear the residual risk associated with ownership. Equity investors, therefore, require a greater return (i.e., a premium) than would a bondholder. The Risk Premium approach estimates the ROE as the sum of the Equity Risk Premium and the yield on a particular class of bonds.

ROE = RP + Y [6]

Where:

RP = Risk Premium (difference between allowed ROE and the 30-Year Treasury Yield) and

Y = Applicable bond yield.

Since the equity risk premium is not directly observable, it is typically estimated using a variety of approaches, some of which incorporate ex-ante, or forward-looking, estimates of the ROE and others that consider historical, or ex-post, estimates. For our Risk Premium analysis, we have relied on authorized returns from a large sample of U.S. vertically-integrated electric utility companies.

To estimate the relationship between risk premium and interest rates, we conducted a regression analysis using the following equation:

$RP = a + (b \times Y)$ [7]

Where:

RP = Risk Premium (difference between allowed ROEs and the 30-Year Treasury Yield);

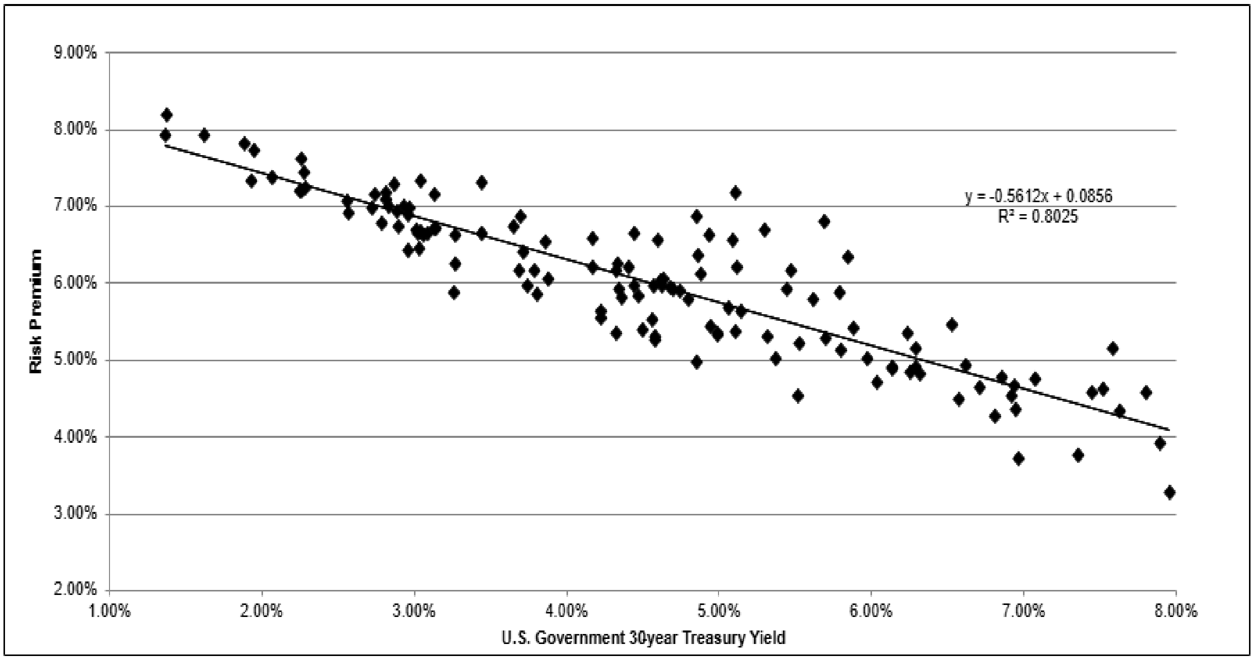
a = Intercept term;

b = Slope term; and

Y = 30-Year Treasury Yield.

Data regarding allowed ROEs were derived from 777 integrated electric utility company rate cases in the U.S. from January 1992 through January 31, 2025, as reported by Regulatory Research Associates.

Figure 26: Risk Premium Results



As illustrated by Figure , the risk premium varies with the level of the bond yield, and generally increases as the bond yields decrease, and vice versa. In order to apply this relationship to current and expected bond yields, we consider three estimates of the 30-year Treasury yield, including the current 30-day average, a near-term Blue Chip consensus forecast for Q2 2025 – Q2 2026, and a Blue Chip consensus forecast for 2026–2030. We find this 5-year result to be most applicable because investors typically have a multi-year view of their required returns on equity. Based on the regression coefficients in Exhibit CEA-9.1, which allow for the estimation of the risk premium at varying bond yields, the results of our U.S. Risk Premium analysis are summarized in Figure 27.

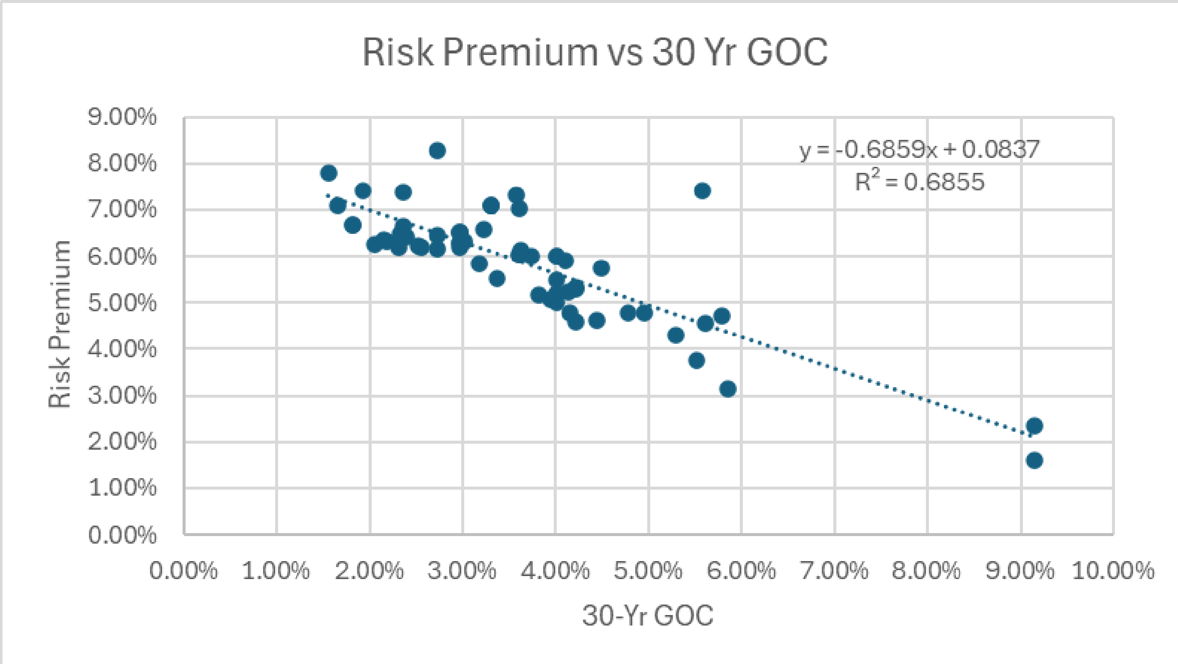
Figure 27: Risk Premium Results Using 30-Year Treasury Yield

	Using 30-Day Average Yield on 30-Year Treasury Bond	Using Q2 2025–Q2 2026 Forecast for Yield on 30-Year Treasury Bond[52]	Using 2026-2030 Forecast for Yield 30-Year Treasury Bond[53]
Yield	4.82%	4.66%	4.30%
Risk Premium	5.85%	5.95%	6.15%
Resulting ROE	10.68%	10.53%	10.45%

We also conducted a risk premium analysis based on approximately 60 Canadian decisions for electric and gas utilities from 1994 through 2024. As in the U.S., the regression analysis for Canada shows an inverse relationship between interest rates and the equity risk premium. Figure 28 shows the regression equation produced by this analysis. See also Exhibit CEA-9.2 for the full risk premium analysis for Canada.

52 Blue Chip Financial Forecasts, Vol. 44, No. 2, January 31, 2025, at 2.
53 Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14.

Figure 28: Risk Premium Results - Canada[54]



The Canadian risk premium analysis shows that the average equity risk premium in Canada since 1994 has been 5.87 percent. The results of the Canadian risk premium analysis, shown in Figure 29 below, support the reasonableness of our DCF and CAPM analyses for the North American proxy group companies. We have placed the most weight on the 9.53 percent result, which is based on the same projected risk-free rate as in our CAPM analysis for the period from 2026-2028.

[54] The two ROE decisions shown on the far-right side of the chart are from 1994, when interest rates were significantly higher than they are today, and the resulting equity risk premium was significantly lower.

Figure 29: Risk Premium Results - Canada

	Using 30-Day Average Yield on 30-Year GOC Bond[55]	Using 2026–2028 Forecast for Yield on 30-Year GOC Bond[56]	Using 2026-2030 Forecast for Yield 30-Year GOC Bond[57]
Yield	3.28%	3.67%	3.72%
Risk Premium	6.12%	5.86%	5.82%
Resulting ROE	9.40%	9.53%	9.54%

E. Comparison to Other Authorized ROEs

Authorized ROEs and common equity ratios for other investor-owned electric utilities in Canada and the U.S. are another relevant benchmark when setting authorized returns. Given the "opportunity cost" concept underlying a fair return, this is appropriate, because an investor would shift capital to a higher return for the same level of risk, if available. As shown in Figure 33**,** the average authorized ROE for Canadian investor-owned electric utilities is 9.11 percent, while in the U.S., the average authorized ROE for integrated electric utilities since January 2023 has been was 9.79 percent.[58] Importantly, unlike NSPI, none of the Canadian companies in Figure 30 own a significant amount of regulated generation.

55 Bloomberg Professional, as of December 31, 2024.
56 Consensus Economics, October 2024, at 29. We used the same forecast of government bond yields as in our CAPM analysis.
57 Consensus Economics, October 7, 2024, at 29.
58 Source: S&P Capital IQ Pro, Regulatory Research Associates.

1 **Figure 30: Authorized Electric ROEs and Equity Ratios**

	Generation	ROE	Equity Ratio
NSPI (existing)	Yes	9.00%	40.0%
NSPI (Concentric analysis)	Yes	9.90%	45.0%
NSPI (proposed)	Yes	9.00%	40.0%
Newfoundland Power	Minimal	8.60%	45.0%
Maritime Electric Company Ltd	Minimal	9.35%	40.0%
Ontario Electric Utilities	None	9.00%	40.0%
Alberta Electric Utilities	None	8.97%	37.0%
FortisBC Inc.	Yes	9.65%	41.0%
Canadian Electric Average		**9.11%**	**40.6%**
U.S. Electric Utilities[59]	Yes	9.79%	52.0%
U.S. Electric Proxy Group Average[60]	Yes	9.66%	51.1%

2

59 Source: SNL Financial. Figures are from January 1, 2024 through January 31, 2025, excluding limited issue riders and electric transmission and distribution cases.

60 Ibid.

SECTION 6:
CAPITAL STRUCTURE AND RISK ANALYSIS

A. NSPI's Deemed Common Equity Ratio

In February 2023, the Board approved the settlement agreement which included an increase in the deemed common equity ratio for NSPI from 37.5 percent to 40.0 percent for the purposes of establishing rates, with earnings in any given year determined on an actual five-quarter average equity thickness of up to 40.0 percent.[61] To consider the appropriate common equity ratio for the Company over the proposed rate period, we have examined the risk profile of NSPI.

B. Risk Analysis

Concentric examines risk from two primary perspectives: (1) financial risk; and (2) business risk. Financial risk primarily relates to the risk associated with the way in which a company has financed its business, as evidenced by the relative percentages of debt and equity in the capital structure. To the extent the company is more highly leveraged, it requires higher net income to cover its fixed interest obligations, which must be paid before there is any net income for shareholders. Business risk for a regulated utility encompasses both operational risk (e.g., economy of service territory, weather conditions, geographical diversity, etc.) and regulatory risk (e.g., opportunity for timely recovery of prudently incurred costs). Taken together, financial risk and business risk are the primary elements of investment risk that investors consider when establishing their return requirements.

In each risk category, Concentric further considers three perspectives:

a) Comparison of the risk profile of NSPI to other investor-owned electric utilities in Canada;

b) Comparison of the current risk profile of NSPI to a proxy group of comparable electric utilities in the United States; and

c) Comparison of NSPI's risk profile today to the circumstances at the time of the Company's 2021 GRA filing.

61 Decision 2023 NSUARB 12, M10431, issued February 2, 2023, at para. 271.

1. Financial Risk

a. Definition of Financial Risk

Financial risk exists to the extent a company incurs debt obligations in financing its operations. These fixed obligations increase the level of income which must be generated to cover interest payments before common stockholders receive any return, and they are considered by both debt and equity investors in addition to business risks. Fixed financial obligations also reduce a company's financial flexibility and its ability to respond to adverse economic circumstances and capital market conditions, such as those during the credit crisis and financial market disruptions of 2008/2009, and more recently in 2020 during the COVID-19 induced disruption in financial markets.

b. Implication of Capital Structure on Rate of Return

The capital structure relates to a company's financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations, and is a function of the percentage of debt (or financial leverage) in the capital structure. In that regard, as the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of financial leverage increases, the risk of financial distress for common equity holders (i.e., financial risk) also increases.[62] Since the capital structure can affect the company's overall level of risk, it is an important consideration in establishing a fair return.

c. Comparison to Other Investor-Owned Utilities

As explained in Section IV, we selected proxy groups consisting of Canadian, U.S. Electric, and North American Electric utilities for purposes of establishing our ROE recommendation for NSPI. In order to assess the reasonableness of the common equity ratio for NSPI, our analysis is based on a comparison to the common equity ratios of other investor-owned electric utilities in Canada and the U.S. at the operating company level because that is the level at which a regulated capital structure is established based on an evaluation of the business risk of the utility and related factors.

As shown in Figure 31, NSPI's deemed common equity ratio of 40.0 percent is generally in line with other investor-owned electric utilities in Canada except those in Alberta. However, many of

[62] See Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 45-46.

these companies own limited or no generation assets, while NSPI is an integrated electric utility, and therefore faces greater business risk, which justifies a higher deemed equity ratio. The average authorized common equity ratio for U.S. integrated electric utilities since January 2023 was 52.0 percent, or almost 12.0 percentage points greater than NSPI's current deemed common equity ratio of 40.0 percent.

Figure 31: Comparison of Deemed Common Equity Ratios

Operating Utility	Deemed Common Equity Ratio
NSPI (existing)	40.0%
NSPI (proposed)	40.0%
Alberta Electric Utilities	37.0%
FortisBC Electric	41.0%
Ontario Electric Utilities	40.0%
Maritime Electric	40.0%
Newfoundland Power	45.0%
Canadian Electric Average	**40.6%**
US Electric Utility Average[63]	**52.0%**

We also compared NSPI's deemed common equity ratio of 40.0 percent to the authorized equity ratios for the operating companies held by the Electric T&D proxy group that is used in our report for NSP Maritime Link. As shown in Figure 7 of that report, the average authorized equity ratio for those companies is approximately 49.0 percent, reflecting higher overall common equity ratios than NSPI, which owns substantial electric generation assets.

d. Assessment of Credit Metrics

Financial risk is also measured through other credit metrics, such as the ratio of Funds from Operations ("FFO") to debt and Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"), as well as interest coverage ratios that compare EBITDA and FFO to interest payments on long-term debt. As shown in Exhibit CEA-10, the S&P adjusted credit metrics for NSPI in 2023 were materially weaker than the companies in either the Canadian or

[63] S&P Global Market Intelligence, based on electric rate case decisions from January 1, 2023 through January 31, 2025, excluding decisions in Arkansas, Florida, Indiana and Michigan where the equity ratio includes zero cost items (such as accumulated deferred income taxes) that are typically excluded from rate base in other jurisdictions.

the U.S. Electric proxy groups. Figure 32 summarizes the key credit metrics for NSPI and the average credit metrics for the companies in the Canadian and the U.S. Electric proxy groups.

Figure 32: 2023 S&P Credit Metrics Comparison

Credit Metric	NSPI	Canadian	U.S. Electric
Debt to Capital Ratio	67.3%	55.8%	58.2%
FFO / Debt (%)	9.3%	13.1%	15.0%
Debt / EBITDA	7.01	5.78	5.28
EBITDA to Interest Coverage	3.05	3.90	4.26
FFO to Interest Coverage	2.87	4.19	4.82

As shown in Figure 36, compared to both the Canadian and U.S. proxy groups, NSPI has a lower FFO / Debt ratio, a higher Debt / EBITDA ratio, a lower EBITDA to interest coverage ratio, a lower FFO to Interest Coverage ratio, and a higher debt to capital ratio. All of NSPI's ratios are weaker than the Canadian and U.S. Electric proxy group averages. In fact, as shown in Exhibit CEA-10, NSPI's credit metrics (as measured by these five metrics) are weaker than every holding company in the U.S. Electric Proxy group.

Further, as an integrated electric utility, S&P assesses NSPI's financial risk using its medial volatility table, under which financial risk is considered "Significant" when FFO / Debt is between 13 and 21 percent, whereas T&D utilities are evaluated on the low volatility table, which requires FFO / Debt of only 9 to 13 percent to be considered "Significant." This change occurred in May 2016, when S&P moved NSPI at that time from the low volatility table to the medial volatility table. As a result, S&P's financial risk assessment of NSPI changed from "Intermediate" to "Significant," reflecting the substantial generation assets owned by NSPI, which S&P views as riskier than T&D utilities.[64]

Based on a comparison of the common equity ratios and credit metrics of NSPI to the companies in the two proxy groups, we conclude that NSPI has greater financial risk than both the Canadian proxy group and the U.S. Electric proxy group.

64 S&P Global Ratings, Nova Scotia Power Inc., May 25, 2016, at 2.

e. Change in NSPI's Credit Rating Since 2021

S&P Global downgraded NSPI by two notches to BBB- from BBB+ in February 2023,[65] and DBRS Morningstar downgraded NSPI to BBB (high) from A (low) in December 2022.[66] Both rating agencies cited concerns over heightened political intervention after the Province amended the Public Utilities Act in November 2022 to cap customer base rate increases at 1.8 percent over the period from 2022 through 2024 and to limit the allowed ROE and deemed equity ratio at 9.25 percent and 40.0 percent, respectively. S&P Global currently ranks NSPI's business risk as "Strong" and its financial risk as "Aggressive." The Company is only notch away from being below investment grade.

While noting the stable regulatory regime in Nova Scotia, S&P Global has previously expressed concern with the Company's high reliance on riskier coal-based generation, its limited geographic and regulatory diversity, and the limited cushion in its financial metrics.[67] Each of these factors has financial risk implications due to the potential impact on credit ratings; however, we consider these as operating and regulatory risks, and they are covered in more detail in that section of the report. In February 2024, S&P Global reaffirmed the BBB- rating (Outlook: Negative) for NSPI, noting that the Provincial government had proposed to allow the Company to recover $117 million in deferred fuel costs over the next 10 years and that the Company had been penalized $10 million for failing to meet the requirements for renewable energy resources, although the fine is under appeal.[68]

f. Conclusions on Financial Risk

The 40.0 percent deemed common equity ratio for NSPI is similar to the Canadian average of 40.6 percent for investor-owned electric utilities, despite the fact that the Company owns substantial regulated generation assets, which increases its risk profile, as discussed in the following section on business risk. By comparison to the U.S. Electric proxy group, NSPI's deemed equity ratio is substantially lower than the average of 51.1 percent.

NSPI's long-term issuer rating from S&P Global of BBB- is three notches below the U.S. Electric utility proxy group average of A-, and the Company has materially weaker credit metrics than its

65 S&P Global Ratings, Nova Scotia Power Inc., February 13, 2023, at 1.
66 DBRS Morningstar, Nova Scotia Power Inc., January 19, 2023, at 1.
67 S&P Global Ratings, Nova Scotia Power Inc., May 11, 2021, at 1.
68 S&P Global Ratings, Nova Scotia Power Inc., February 12, 2024, at 1-2.

Canadian or U.S. peers. Overall, NSPI has significantly more financial risk than the average North American electric utility.

2. Business Risk

a. Definition of Business Risk

Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including the fair return on, and of, its capital in a timely manner. Concentric includes operating risk and regulatory risk under this broad definition of business risk.

b. Business Risk Analysis

In order to assess NSPI's business risk, Concentric examined the following factors:

1) the generation ownership of NSPI relative to other investor-owned electric utilities, and in particular the percentage of thermal assets and the requirement for the Company to retire thermal generation and transition its generation profile to include more renewable resources;

2) macroeconomic and demographic trends in Nova Scotia;

3) operating risks associated with the Company's service territory, particularly the prevalence of severe weather conditions;

4) recovery of fuel and purchased power costs; and

5) competition from alternative fuels.

Where appropriate, we have examined changes since the Company's previous GRA filing.

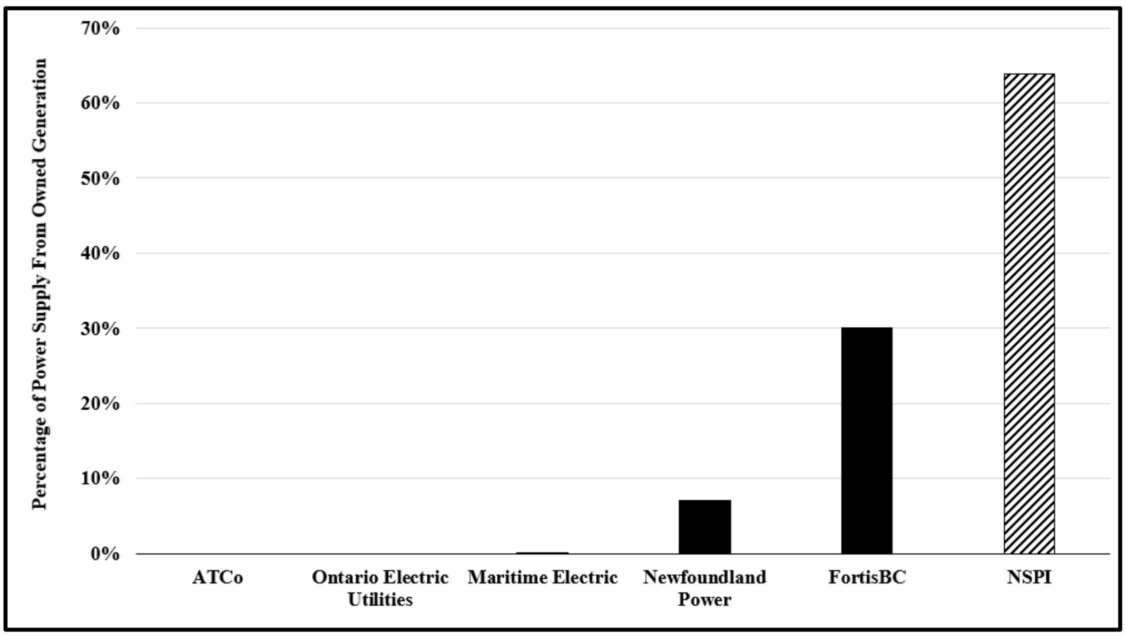
c. Generation Ownership

Unlike most other regulated electric utilities in Canada, NSPI owns substantial regulated generation assets. In 2024, NSPI derived 63.9 percent of its power supply from Company-owned generation facilities, while purchasing the remaining 36.1 percent from other suppliers.[69] Electric utilities in Ontario and Alberta are pure T&D utilities and do not own generation. Newfoundland

[69] This percentage does not include Maritime Link Base Blocks. If the ML Base Block is included, the percentage of Company-owned generation increases to 76.1%.

Power and Maritime Electric own a small amount of regulated generation as backup supply and for peaking purposes, but primarily rely on purchasing power from other sources. FortisBC generates approximately 30 percent of its electricity from company-owned hydro-electric plants and purchases the remainder.[70] In this regard, NSPI is unique among Canadian utilities. Figure 33 compares the portion of NSPI's power supply that is comprised of owned generation assets relative to other Canadian investor-owned utilities.

Figure 33: Percentage of Power Supply Comprised of Owned Generation



Utilities that own generation assets are considered to have higher business risk by credit rating agencies and equity investors. Moody's, for example, explains how they assess business risk and credit metrics for utilities as follows:[71]

> *There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology have different levels of business risk.*

[70] FortisBC, Annual Information Form for the Year Ended December 31, 2023, at 7.
[71] Moody's Ratings, "Rating Methodology: Regulated Electric and Gas Utilities," August 6, 2024, at 14.

> *Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing potential asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.*

Among U.S. electric utilities, generation ownership is much more common. We have included a generation ownership screen in selecting our U.S. Electric proxy group in order to make that group more comparable to NSPI on this important risk factor. Based on data from Regulatory Research Associates, the average authorized ROE for U.S. integrated electric utilities was 9.84 percent in 2024 compared to 9.53 percent for electric T&D only utilities.

In addition, the average authorized common equity ratio for integrated electric utilities in the U.S. was approximately 2.0 percent higher than for T&D utilities since January 2023. This highlights the greater risk of companies with regulated generation assets relative to those with T&D only assets.

One additional risk that NSPI bears due to its generation mix is carbon transition risk. As an owner of significant thermal generation assets (Lingan, a 607 MW thermal generating facility; Trenton, a 304 MW thermal generating facility; Point Aconi, a 168 MW thermal generating facility; and Point Tupper, a 150 MW thermal generating facility),[72] NSPI is subject to a variety of environmental policies at both the provincial and federal levels. These decarbonization initiatives create risk for the Company as it manages the transition from a substantially carbon-based generation portfolio to more renewable generation sources such as solar, wind, and hydro.

Protecting the environment is an increasing area of focus for both the provincial and federal governments. The throne speech for Premier Rankin's government in March 2021 committed to, among other things, accelerating the phase-out of coal for energy use, making Nova Scotia the first Canadian province to achieve carbon neutrality, as well as various energy efficiency programs.[73] While the throne speech for Premier Houston's government in October 2021 committed to ensuring that 80 percent of energy would be supplied by renewable energy in 2030,

[72] Source: Nova Scotia Power, see Figure 3 of 2024 10 Year System Outlook.
[73] Third Session of the 63rd General Assembly of the Nova Scotia Legislature, March 9, 2021, Speech from the Throne.

it did not specifically address the phase-out of coal for energy use.[74] However, Bill No. 57, the *Environmental Goals and Climate Change Reduction Act*, which was introduced in the Nova Scotia Legislature on October 27, 2021, specified a number of goals for the Province, including for 80 percent of electricity in the Province to be supplied by renewable energy by 2030 and a phase out of coal-fired electricity generation in Nova Scotia by 2030. In October 2023, the Province published its 2030 Clean Power Plan. The plan calls for the addition of new wind, solar, and natural gas capacity to the grid, as well as investments in battery storage, and a new transmission line to New Brunswick to improve reliability of the grid. The Province also announced that it was abandoning the proposed Atlantic Loop in its plan to decarbonize the electrical grid by 2030, according to the Natural Resources and Renewables Minister.[75]

Morningstar DBRS, which rates NSPI's debt, commented on the 2030 Clean Power Plan as follows:

> *Morningstar DBRS is encouraged that there is now a plan for NSPI to achieve its provincially mandated renewable generation targets, and there is alignment with the Province that substantial capital expenditures (capex) will be required. However, Morningstar DBRS expects these plans will require substantial funding support from both the Provincial and Federal governments under an ambitious time frame. Morningstar DBRS will continue to monitor the Company's progress, especially with the release of a Clean Electricity Solutions Task Force report expected early in 2024.*[76]

Specific environmental policies applicable to NSPI include: (1) the compelled closure of coal-fired generation by 2030, whether as a result of federal or provincial legislation,[77] (2) a carbon tax imposed by the federal government that is projected to hit $170 per tonne by 2030,[78] (3) a provincially mandated target of 40 percent of energy from renewable sources in 2020-2029,[79] and (4) a provincially mandated target of 80 percent of energy from renewable sources for each calendar year beginning with 2030.[80] Complying with these environmental policies will require the Company to successfully manage a transformation in the composition of its generation portfolio and transmission system, and expend substantial capital in the process. This amplifies

74 First Session of the 64th General Assembly of the Nova Scotia Legislature, October 12, 2021, Speech from the Throne.
75 CBC News, "N.S. abandons Atlantic Loop, will increase wind and solar energy projects for green electricity," October 11, 2023.
76 Morningstar DBRS, Rating Report Nova Scotia Power Inc., January 12, 2024, at 1-2.
77 Nova Scotia Power, 2020 MD&A, at 4.
78 Ibid.
79 Nova Scotia Power, 2023 Annual Information Form, at 11.
80 Renewable Electricity Regulations made under Section 5 of the Electricity Act S.N.S. 2004, Section 6B.

the importance of NSPI maintaining a constructive regulatory environment that supports the necessary investments to meet these federal and provincial goals on behalf of its customers.

NSPI has achieved a 60 percent reduction in coal utilization since 2005.[81] Further, NSPI is on track for a 92 percent reduction in carbon emissions by 2030 as compared to 2005 levels. However, NSPI was not able to comply with the provincial target of 40 percent of energy from renewable sources from 2020-2022, and was subsequently fined by the Nova Scotia Government the maximum amount of $10 million, which has been appealed by the Company. In 2023, however, NSPI met this target, with 43 percent of its electric sales coming from renewable resources.[82]

These risks are not generally faced by other Canadian investor-owned utilities, many of which own little, if any, generation. Further, as discussed in more detail later in this section, while the companies in the U.S. Electric proxy group do own regulated generation, those include relatively less coal-fired generation than NSPI owns, and a timeframe for reaching carbon reduction targets that is generally longer than NSPI's. Therefore, we conclude that NSPI faces substantial carbon transition risk, and more carbon transition risk than the proxy companies. In the 2021 GRA, NSPI proposed a decarbonization transition plan that included moving the net book value of its thermal units that will be retired over the next decade to a deferral account (the DDA) to be amortized over a relatively longer period to mitigate the rate impact on customers. The Board ultimately approved a settlement agreement that included this mechanism, with certain limitations, including "unrecovered NBV costs transferred upon the retirement of each asset within the scope of the DDA, and unrecovered decommissioning costs added when they are incurred", and "NS Power must meaningfully investigate the potential use of securitization as it relates to the DDA and file an initial report on this issue with its first annual DDA filing, due no later than April 30, 2025."[83] Our understanding is that NSPI intends to file for approval for the securitization of approximately $700 million of DDA assets later in 2025. If such securitization cannot be completed by January 1, 2026, NSPI is requesting that the depreciation expense and financing costs of these assets be deferred at the weighted average cost of capital. The potential securitization is intended to apply only to the net book value of these assets as of December 2025. Any subsequent sustaining capital investments and operating expenses required while these

81 Nova Scotia Power, 2020 Annual Information Form, at 7.
82 Nova Scotia Power, 2023 Annual Information Form, at 6.
83 Decision 2024 NSUARB 67, M11220, April 10, 2024, pp. 5-6.

assets remain used and useful will continue to be included in rate base and/or revenue requirement in the normal course of business. The DDA and proposed securitization have the potential to mitigate a meaningful degree of the Company's energy transition risks. NSPI's risk, however, remains higher than companies not facing similar challenges of meeting the Province's ambitious sustainability goals.

d. Macroeconomic and Demographic Trends

According to TD Economics, Nova Scotia's economic growth is expected to slow in 2025 and 2026 compared to 2024 levels, which were supported by increased spending in the public sector. Consumer spending has been supported by healthy job growth and real wage gains, and the new Provincial government has announced a one percent reduction in the HST, effective April 1, 2025, which is expected to provide further stimulus.[84] Population growth is expected to slow due to reduced inflows of non-permanent residents and as intra-provincial migration to Nova Scotia slows. The Federal government has reduced the number of foreign student study permit approvals by 30 percent compared to 2023 levels. Rapidly cooling population growth has placed downward pressure on the unemployment rate in the Province, which has fallen below the Canadian average, although this is not expected to persist. Approximately 70 percent of Nova Scotia's exports are to the U.S., making the Province's economy susceptible to tariff risk; however, only five percent of the Province's imports are from the U.S., which reduces the risk of inflation due to trade disputes. Unemployment in Nova Scotia is projected to increase from 6.4 percent in 2024 to 6.9 percent in 2026, while real GDP growth is forecast to slow from 1.9 percent in 2024 to 1.3 percent in 2026, lower than the national average of 1.7 percent forecast for 2026.

The Conference Board of Canada's ("CBC") most recent long-term outlook for Nova Scotia covers the period through 2045. The CBC observes that:[85]

a) Real GDP growth is expected to be modest in Nova Scotia over the long term, with average annual gains of 1.4 per cent between 2024 and 2045.

b) Consumer spending power will be limited by the reduced spending power of an aging population.

[84] TD Economics, Provincial Economic Forecast, December 16, 2024, at 9.
[85] Conference Board of Canada, "Dark Clouds in the Distance but Bright Spots Remain, Nova Scotia's Outlook to 2045," April 8, 2024, at 3.

c) The business investment outlook is weak, as no major capital projects are in the pipeline in the long term, and housing starts have slowed.

d) Nova Scotia's finances face structural challenges, as an older population will demand more government services while, at the same time, slowing down economic growth.

e) Manufacturing is one of the few bright spots on the industry side, with real output growth expected to average a healthy 2.8 per cent between 2024 and 2045.

Figure 34 compares Nova Scotia to Canada on a number of key macroeconomic indicators over the period from 2024-2045.

Figure 34: Key Economic Indicators – 2024-2045[86]

Economic Indicator	NS	Canada
Real GDP Growth	1.4%	2.3%
Labor Force	0.7%	0.9%
Population	0.5%	1.1%
Employment	0.9%	1.5%
Household Disposable Income	2.1%	2.9%
Retail Sales	3.2%	2.4%
Housing Starts	(11.2%)	(1.9%)

As shown in Figure 38, NSPI's projected macroeconomic factors are weaker than the national average with the exception of retail sales. In addition, the population of Nova Scotia is expected to expand at a slower rate than the national average over the intermediate to long term, which serves to limit growth opportunities for the electric utility.

These weak long-term economic and demographic trends place downward pressure on NSPI's electric load growth, which is offset by increased demand for electricity due to population growth, electrification of buildings, electric vehicle charging, and commercial and industrial customer usage. Load growth is also being affected by demand side management ("DSM") programs that reduce energy consumption in the province and by solar installation. For example, NSPI's load growth forecast estimates that DSM programs will reduce load growth by 699 GWh over the next ten years. Additionally, increased growth in distributed energy resources ("DERs") may further dampen the Company's volume growth prospects. As of December 2023, NSPI had

86 The Conference Board of Canada, "Dark Clouds in the Distance but Bright Spots Remain," Nova Scotia's Outlook to 2045, April 8, 2024.

over 70 MW of solar installed and the Company expects annual growth in solar installations of 10-15 percent per year, which would put solar capacity at around 200 MW by 2030. NSPI's load growth forecast projects that solar will reduce load growth by 627 GWh over the next ten years.

e. Operating Risks

One of the most important operating risks for NSPI is weather-related service disruptions. The Company's service territory is characterized by severe ice storms and wind conditions, including tropical storms and hurricanes. The need to address supply disruptions caused by severe weather conditions involves unanticipated and potentially volatile capital and operating costs. The Company was allowed to implement a storm rider on a pilot basis from 2023-2025.[87] This mechanism provides for recovery of storm costs beyond those covered in base rates. NSPI is seeking to continue the storm rider on a pilot basis in 2026-2027, which will help to mitigate the financial impacts and assist the Company in responding to storm related service outages. These mechanisms are increasingly common in storm-prone regions.

Another factor impacting NSPI's operating risk is the recent passage of the Energy Reform (2024) Act. The Act represents the potential for a significant shift in both the regulation and operations of the electric industry in the Province. As the provisions of the Act come into force, NSPI's historic role of control of the bulk power grid is intended to shift to the IESO, and greater competition will be introduced into the wholesale power market. The impacts on NSPI business and its operating risks will be determined as the Act's new policy direction is implemented, but creates uncertainty from an investor perspective.

f. Recovery of Fuel and Purchased Power Costs

NSPI recovers prudently incurred increases and/or decreases in its cost of fuel outside of general rate proceedings through periodic adjustments to customer rates via its Fuel Adjustment Mechanism ("FAM"). The Board first authorized NSPI to implement the FAM in 2007, finding that, among other things, it would enable the Board and other interested parties to receive more information on a timely basis regarding NSPI's fuel costs.[88] The Board conditioned its approval of NSPI's FAM on the implementation of a "meaningful audit process."[89] Accordingly, NSPI

87 NSUARB, Nova Scotia Power, February 2023, at para. 332.

88 Nova Scotia Utility and Review Board, 2007 NSUARB 174, NSUARB-P-887, Decision issued December 10, 2007, at para. 76 & 92.

89 Ibid, at para. 51.

NSEB IR-102, pdf pg. 477: DBRS says: "There were several positive developments for NSPI in 2024. In April, the NSUARB approved for the sale of $117 million of fuel-adjustment mechanism (FAM) regulatory assets from NSPI to the Province of Nova Scotia (the Province; rated A (high) with a Stabletrend). In September 2024, the federal government also finalized an agreement with NSPI, NSP Maritime Link Inc. (NSPML; Maritime Link Financing Trust rated (P) AAA with a Stable trend), and the Province for a federal loan guarantee of $500 million of debt to be issued by NSPML. Proceeds from this December 2024 issuance were transferred to the Company and applied against the FAM regulatory asset balance. These two transactions (1) will reduce debt at the Company by $617 million, (2) reduce regulatory lag for NSPI disposing of the balance in the FAM, and (3) reduce rate pressure on customers as the recovery is spread over a much longer period." and S&P says (pdf pg. 490) :Nova Scotia Power Inc. (NSPI) recently received a Canadian federal loan guarantee to securitize C$500 million of current and future fuel balances at NSPI; the company used proceeds toward reducing debt at NSPI. This follows the C$117 million NSPI received from the provincial government earlier in 2024 toward the deferred fuel cost recovery. S&P Global Ratings views these favorably because they reduced debt at NSPI while also reducing the regulatory lag associated with recovery of higher fuel costs in Nova Scotia, which in recent years pressured NSPI's credit measures." How was this factored into Concentric's analysis?

implemented a FAM, subject to external audits and associated regulatory proceedings every two years thereafter.

Fuel adjustment clauses are common across the regulated utility industry. The Board recognized the widespread nature of this regulatory mechanism before approving a FAM for NSPI, stating in 2005 that: "The Board recognizes that FAMs exist in many other jurisdictions and can, potentially, be a positive and useful regulatory tool."[90]

Credit rating agencies continue to identify NSPI's ability to recover its fuel costs as a credit challenge. DBRS and S&P Global have both indicated that the design of NSPI's FAM exposes the Company to greater regulatory lag. S&P Global noted that in 2024 NSPI was allowed by the Provincial government to place $117 million into a deferral account for recovery over the next 10 years.[91] However, S&P Global also noted that the Company has a remaining balance of deferred fuel costs of $278 million, which must be recovered from customers in future rate applications, placing additional upward pressure on customer bills according to the rating agency. As discussed in our report for NSP Maritime Link, this issue was resolved through a $500 million debt issuance in November 2024 (backed by a federal loan guarantee) to finance the amount owed by customers to NSPI for the deferred FAM balance.

The specific fuel and purchased power cost recovery mechanisms available to other Canadian investor-owned electric utilities are discussed in more detail later in this report. We conclude that the design of NSPI's FAM, including the bi-annual audit and the associated regulatory lag, translate into elevated risk on this factor relative to its Canadian and U.S. peers.[92]

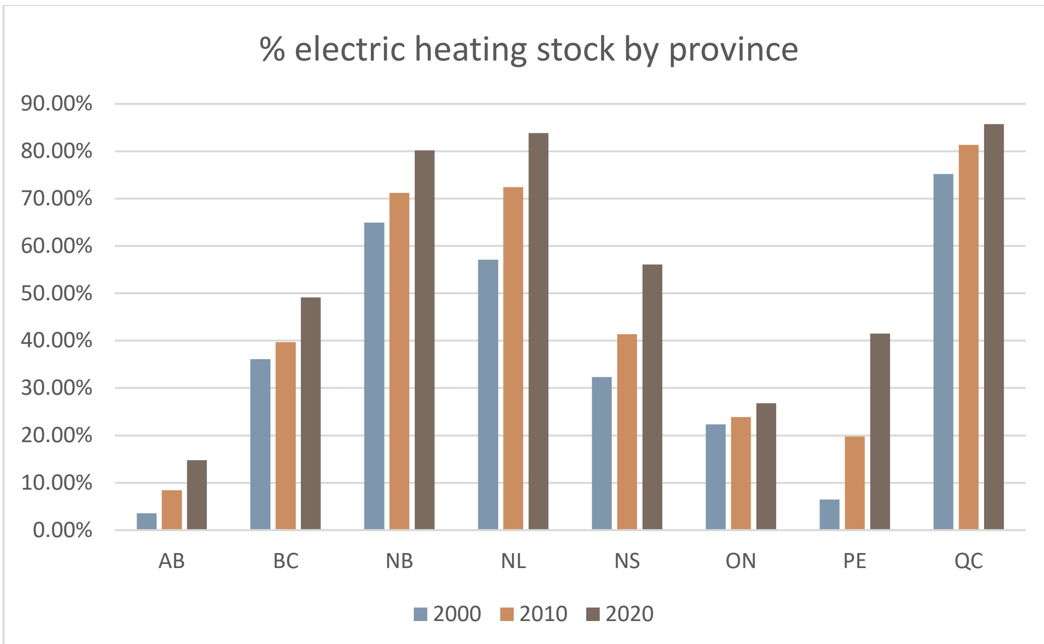
g. Alternative Fuel Risk

Although NSPI continues to face competition from alternative fuel sources, this risk is declining due to government policy that promotes electrification of buildings and increased purchases of electric vehicles. In 2020, approximately 51.1 percent of NSPI's residential customers used electricity for space heating, and that percentage increased to 60.2 percent in 2024.[93] Figure 35 shows the percentage of residential electric heating stock by province based on data from Natural

90 Ibid, at para. 66.
91 S&P Global Ratings, Nova Scotia Power Inc., February 12, 2024, at 1.
92 Concentric understands that there were no disallowances from the 2016/17 FAM Audit and minor disallowances from the 2018/19 FAM Audit, and the UARB has recognized the maturing of the FAM Process. There was, however, a $4 million disallowance from the 2020/21 FAM Audit.
93 Data provided by NSPI.

Resources Canada for the period from 2000-2020. The chart indicates that, in Nova Scotia, approximately 55 percent of the heating stock is electric as compared to slightly over 30 percent in 2000.

Figure 35: Electric Heating Stock by Province



Historically, volatility in the price of fuel oil combined with lower installation costs and moderate increases in the price of electricity have favored electric space heating. The increase in electric space heating market share has had a direct impact on the growth in NSPI's average electricity usage per residential customer and energy sales. In recent years, however, customers have increased their purchases of heat pumps, which had 43.6 percent penetration in 2024 as compared with only 6 percent in 2012.[94] Heat pumps play a dual role for a company with NSPI's market profile. On the one hand, conversions from other fuels (oil, propane, or gas) to electric heat pumps increase electric load. On the other hand, heat pumps that replace less efficient electric baseboard heating serve to reduce load (unless additional air conditioning load makes up for the displaced heating loss). As discussed in more detail later in this report, NSPI has relatively more exposure to these load risks than the proxy companies because it does not have protection against volumetric risk.

[94] Data provided by NSPI.

h. Regulatory Risk

There have been decisions by the UARB where operating and capital costs have been disallowed. Cost disallowances are always within the scope of utility regulation, but in Concentric's experience, significant disallowances are not the norm. For example, in a 2018 AMI decision, the Board approved recovery of the underlying cost of the retired meters over a five-year period, including debt costs, but not including an equity return. This decision is particularly relevant as NSPI will need to retire approximately $1 billion in thermal generation assets as part of the clean energy transition and recover the associated site restoration costs. Another example is the treatment of certain operating expenses that NSPI is not allowed to recover from customers, including executive compensation (which is capped by legislation), both short-term and long-term incentive compensation for all employees, and donations and sponsorships. These costs account for approximately 50 basis points of earned ROE for NSPI, and disallowance of the expenses results in the Company earning less than it otherwise would. A third example is the amortization of costs related to Hurricane Fiona in 2022. Although the UARB recognized these costs as being extraordinary and allowed NSPI to defer them, the Board required NSPI to begin amortizing the costs immediately, which effectively resulted in a disallowance of a portion of these costs despite the UARB's ruling that the costs were both prudent and extraordinary. In addition, under the Public Utilities Act, NSPI must meet annual performance standards. While this isn't necessarily a unique risk in and of itself, the magnitude of the potential administrative penalty that can be imposed each year if any of those standards are not met is significant. Section 52E of the Public Utilities Act provides for a maximum penalty of $25 million per year.

i. Political Risk

NSPI is also subject to significant political risk, as evidenced by the legislation that was passed following the hearing in the previous GRA but prior to the UARB's order, when the Provincial government placed a cap on the authorized ROE and equity ratio of NSPI that could be approved by the Board. Both DBRS and S&P Global have commented on the high degree of political risk that NSPI faces. In our experience, this level of political intervention is uncommon and causes investors (both debt and equity) to question whether NSPI will be able to recover its prudently incurred costs and earn its authorized ROE. This political risk is detrimental for both customers and the utility because it raises the Company's overall cost of capital.

j. Conclusions on Business Risk

As discussed in this Section, NSPI's risk profile is characterized by the following factors: 1) ownership of substantial regulated generation assets; 2) the need to retire a substantial amount of thermal generation assets and to make significant capital investments to transition its generation portfolio to a higher percentage of renewable resources by 2030; 3) a FAM that is subject to bi-annual audits, which contributes to regulatory lag, and the deferral of fuel cost variations over a three-year period; 4) volumetric risk that is not mitigated by a revenue decoupling mechanism, weather normalization clause or lost revenue adjustment mechanism; 5) weaker economic and demographic trends in its service territory compared to Canada overall; and 6) exposure to storms and severe weather, even though that risk has been mitigated by the approval of the storm rider, which was approved on a pilot basis for 2023-2025. NSPI is requesting that the storm cost rider be continued on a pilot basis in 2026-2027 as part of this GRA.

The business risk for NSPI remains elevated as in 2022 (the date of Company's previous GRA filing). In particular, from investors' perspective, the Company's decarbonization risk remains high as the timeline for retiring thermal generation assets and transitioning its generation portfolio to more renewable resources and to IESO ownership has become more imminent. Credit rating agencies are monitoring this situation closely and have identified the risks NSPI faces as it manages the energy transition.

3. Comparison to other Canadian Investor-Owned Electric Utilities

Concentric also compared the business risk of NSPI to six other Canadian investor-owned electric utilities: ATCO Electric; FortisAlberta; FortisBC Electric; Hydro One Networks; Maritime Electric; and Newfoundland Power.[95] In assessing the business risk of NSPI relative to other Canadian investor-owned electric utilities, Concentric considered the following factors:

a) Regulated generation ownership;

b) Recovery of fuel and purchased power costs;

c) Volume/demand risk;

95 Concentric did not include crown corporations in the risk comparison because crown corporations cannot be used for purposes of estimating the cost of equity since they are not publicly traded and no market data are available.

d) Regulatory environment; and

e) Capital cost recovery.

a. Regulated Generation Ownership

As discussed in the previous section, NSPI generated approximately 64 percent of its power supply from Company-owned generation resources in 2024. By comparison, electric utilities in Alberta and Ontario do not own regulated generation assets, and therefore have lower risk profiles as T&D utilities. FortisBC Electric derives approximately 30 percent of its power supply from company-owned generation and purchases the remaining 70 percent through a variety of power purchase agreements and spot market purchases.[96] Maritime Electric and Newfoundland Power both own limited generation assets, primarily as backup and peaking supply, and purchase the large majority of their power supply from other sources (i.e., Point Lepreau and off-island wind in the case of Maritime Electric, and Newfoundland and Labrador Hydro in the case of Newfoundland Power). On that basis, NSPI has greater risk associated with ownership of generation assets than other investor-owned electric utilities in Canada.

b. Recovery of Fuel and Purchased Power Costs

NSPI is the only Canadian investor-owned electric utility that owns significant regulated generation, and the Company has an annual FAM. While the FAM includes an incentive component whereby NSPI retains or absorbs 10 percent of the over- or under-recovered amount up to a maximum of $5 million, the operation of this incentive was suspended in connection with the approval by the UARB of NSPI's fuel stability plan (2020-2022), under which no fuel rate adjustments related to the under-recovery of fuel costs were allowed. The incentive was also suspended for the period 2017-2019 as a result of legislation enacted by the province. As noted previously, the provincial government has purchased a $117 million receivable to reduce deferred fuel cost.

The Alberta electric utilities, including ATCO Electric and FortisAlberta, are not responsible for the generation function, nor are electric utilities in Ontario, such as Hydro One Networks. FortisBC Electric has an annual fuel and purchased power cost recovery mechanism, and Maritime Electric has a monthly fuel and purchased power cost recovery mechanism. Newfoundland Power recovers changes in power supply costs through the Rate Stabilization

[96] FortisBC, Annual Information Form For the Year Ended December 31, 2020, at 7-9.

Account ("RSA"), which allows for recovery of variations in Newfoundland and Labrador Hydro's production costs. The RSA also recovers or credits, as appropriate, variations in Newfoundland Power's supply costs due to changes from test year energy and demand costs. Newfoundland Power's Energy Supply Cost Variance Clause captures changes in purchased power costs related to variances in customers' load requirements.

In summary, our conclusion is that NSPI has risk associated with recovery of variations and the timing of such recovery in fuel or purchased power costs at the upper end of other Canadian investor-owned electric utilities.

c. Volume/Demand Risk

NSPI does not have a mechanism to mitigate volume/demand risk due to changes in volume attributable to weather, economic conditions, or energy efficiency and conservation programs. The significance of this risk has increased for NSPI as more residential customers convert to electricity for space heating.

By comparison, among Canadian investor-owned electric utilities, FortisBC's electric utility operates under a revenue stabilization plan that includes full protection against volumetric risk (i.e., the difference between forecast and actual sales goes into a load variance deferral account). Newfoundland Power has a weather-related variance account that allows the Company to recover in a future period the difference between projected and actual revenues due to abnormal weather conditions in the test year. Maritime Electric has a weather normalization reserve that protects against changes in volume/demand, although that mechanism is currently under review. ATCO Electric Distribution and FortisAlberta both are subject to a performance-based regulation ("PBR") plan that adjusts revenues annually based on inflation less a productivity factor. These plans allow for an annual adjustment for changes in billing determinants through a "Q value." Q value represents the percentage change in billing determinants, and for electric distribution utilities under the price cap mechanism, this percentage change is calculated across all billing determinants, including energy, demand and the number of customers.[97] Hydro One Networks has a revenue decoupling mechanism as part of its Custom Incentive Regulation plan, and all electric distribution utilities in Ontario have fully decoupled rates for residential customers. In summary, NSPI has more volumetric risk than other investor-owned electric utilities in Canada

97 Decision 25864-D01-2020, ATCO Electric 2021 Annual Performance-Based Regulation Adjustment (December 18, 2020), pp. 5-6.

except for those in Alberta. This is particularly important because the percentage of NSPI's residential customers heating with electricity has increased to approximately 60 percent in 2024, and the DSM program operated by EfficiencyOne has increased target energy savings without a corresponding method to offset these lost revenues.

d. Regulatory Environment

UBS ranks regulatory jurisdictions in the U.S. and Canada for purposes of determining whether to apply valuation discounts or premiums to the utility stocks it covers. Specifically, UBS places regulatory jurisdictions into five tiers based on the following equally weighted criteria: (1) whether commissioners are elected or appointed, (2) allowed returns relative to 10-year Treasury notes, (3) mechanisms that reduce regulatory lag, (4) rate and customer bill levels, (5) the tendency to settle or litigate rate cases, and (6) a subjective "investor friendliness" factor.[98] UBS ranked Nova Scotia's regulatory environment in tier three out of five (with one being the best) in a December 2023 report.[99] UBS also placed Ontario, Newfoundland and Labrador, and Prince Edward Island in tier three. British Columbia was rated in tier one, while Alberta was rated in tier five.

Among credit rating agencies, S&P Global ranks the regulatory environment in Nova Scotia among the lowest in terms of credit supportiveness in North America (i.e., among the bottom three jurisdictions among 60 that are ranked.)[100] Similarly, in a January 2024 credit report for NSPI, DBRS Morningstar rates the regulatory environment for regulated utilities on eight criteria on a scale from Excellent to Poor. Figure 36 summarizes those factors for Nova Scotia. The ratings for Political Interference and Rate Freeze have each declined by one level since the December 2020 DBRS report that Concentric presented in its evidence in the previous GRA.

98 UBS Global Research, "North America Power & Utilities: Mind the Gap(s): 2021 Utility Outlook," December 14, 2020, at 5.
99 UBS Global Research, "2024 Outlook: A Year for Resolutions and Resolve," December 12, 2023, at 12.
100 S&P Global Ratings, North American Utilities Regulatory Jurisdictions Update, February 19, 2025, at 2.

Figure 36: DBRS Morningstar Rank of Nova Scotia Regulatory Environment[101]

Criteria	Score
Deemed Equity	Below Average
Allowed ROE	Good
Energy Cost Recovery	Below Average
Capital and Operating Cost Recovery	Good
Cost of Service vs. Incentive Rate Mechanism	Excellent
Political Interference	Poor
Stranded Cost Recovery	Good
Rate Freeze	Below Average

e. Capital Cost Recovery

NSPI files a capital budget with the Board annually, which includes the Company's capital budget for the upcoming year, as well as a five-year outlook. As part of that filing, the Board approves certain capital expenditures for the coming year. Similarly, Newfoundland Power, FortisBC Electric, and Maritime Electric also file for pre-approval of certain capital expenditures. Hydro One Networks operates under a performance-based regulation plan in Ontario, which includes a capital factor rate adjustment for both transmission and distribution segments that provides cash flow support to the capital program between rate cases.[102] In Alberta, the AUC approved the third generation PBR plan for distribution utilities for the period 2024-2028.[103] The new PBR plan continued the division of capital costs into two categories: Type 1 (capital tracker mechanism for extraordinary capital additions, subject to a true up) and the K-bar mechanism (for all other capital additions not included in Y, Z, or Type 1 treatment). The Type 1 capital criteria are restrictive (*i.e.*, must be extraordinary, not previously in rate base, and required by a third-party, *e.g.*, regulatory, or legislative authority).[104]

Electric utilities in Canada are not allowed to earn a cash return on Construction Work in Progress, but all utilities are permitted AFUDC. In summary, NSPI has similar risk associated with capital cost recovery as other investor-owned electric utilities in Canada except for those in Alberta, which have higher risk on certain capital costs.

101 DBRS Morningstar, Rating Report Nova Scotia Power, Inc., January 12, 2024, at 10.
102 Moody's Investors Service, Hydro One Inc., Credit Opinion, December 21, 2020, at 4.
103 AUC Decision 27388-D01-2023 (October 4, 2023).
104 AUC Decision 20414-D01-2016 (Errata) (February 6, 2017) at para 198.

f. Conclusions on Business Risk Compared to Other Canadian Electric Utilities

check how this compares to Concentric report in 2022 GRA

Concentric concludes that NSPI has greater business risk compared to other Canadian investor-owned electric utilities. In particular, factors contributing to this greater business risk include: 1) NSPI's ownership of regulated generation assets, and the need to transition from coal and gas-fired generation toward more renewable resources by 2030; 2) NSPI's lack of protection against volumetric risks; 3) NSPI's exposure to severe weather conditions, especially hurricanes and ice storms; 4) the aggressive DSM targets in the province; and 5) the risk of political intervention in the regulatory process in Nova Scotia. While the regulatory framework in Nova Scotia is generally supportive of maintaining NSPI's credit quality, there are certain aspects of the operating environment where the Company has greater business risk than other Canadian investor-owned electric utilities.

With regards to new generation, my understanding is that it will now be procured by the NSIESO and will be owned by IPPS (and perhaps NSP). Does this have any impact on NSP's business risk? Was this considered in the Concentric Report?

4. Comparison to U.S. Electric Utility Proxy Group

a. Regulated Electric Utility Operations

NSPI derives 100 percent of its operating income and revenues from regulated electric utility service. As shown in Exhibit CEA-11, the companies in the U.S. Electric utility proxy group derive approximately 97 percent of regulated income and regulated revenues from electric utility service. Similarly, about 97 percent of regulated assets are dedicated to electric utility operations. For this reason, the U.S. companies in the North American Electric proxy group are more representative of NSPI's electric utility operations than the Canadian proxy group companies, which generally derive lower percentages of operating income and revenues from electric utility service and have a lower percentage of assets dedicated to electric utility operations.

b. Credit Rating Agency View on U.S. Regulatory Framework

Some have argued in the past that U.S. utilities are riskier because the regulatory environment is more favorable in Canada than in the U.S. from the perspective of debt and equity investors. In September 2013, however, Moody's published a report discussing its evolving view of U.S. utility regulation. In that report, Moody's stated:

> *Based on our observations of trends and events, we propose to adopt a generally more favorable view of the relative credit supportiveness of the U.S. utility regulatory environment. Our updated view considers improving regulatory trends that include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, and generally fair and open relationships between utilities and regulators.*

***

> *Our revised view that the regulatory environment and timely recovery of costs is in most cases more reliable than we previously believed is expected to lead to a one notch upgrade of most regulated utilities in the U.S., with some exceptions. This evolving view is independent of the proposed changes in the methodology that are highlighted in the Summary section that follows, and would have taken place even if the 2009 methodology were to remain in place without modification.*[105]

More recently, a March 2019 report by equity analysts at Scotiabank indicated that they view the regulatory environments in Canada and the U.S. as being similar for regulated utilities. In explaining why they expect the valuations of Canadian and U.S. utilities to converge, Scotiabank observed:

> *Canadian and U.S. valuations should converge. Historically, the Canadian utilities have traded at a premium to their mid-cap U.S. peers.* ***We attribute this to the historical view that Canadian regulation was superior to U.S. regulation (we no longer have that view)*** *as well as to strong earnings growth in part due to M&A. As shown in Exhibit 19, based on forward consensus estimates, the Canadian names now trade at a 3x discount.*[106]

The Moody's and Scotiabank reports confirm Concentric's assessment of the comparability of the U.S. and Canadian regulatory environments.

c. Comparison to U.S. Electric Utility Proxy Group

As a preliminary matter, Concentric notes that from investors' perspective, both short-term and long-term risk are important. Regulation generally is better at addressing short-term risk, whereas long-term risk cannot be mitigated as effectively by regulation. For example, changes in competitive positioning vs. alternative fuels, shifts in service area demographics, or policy mandates impacting long-term business prospects may not be fully protected.

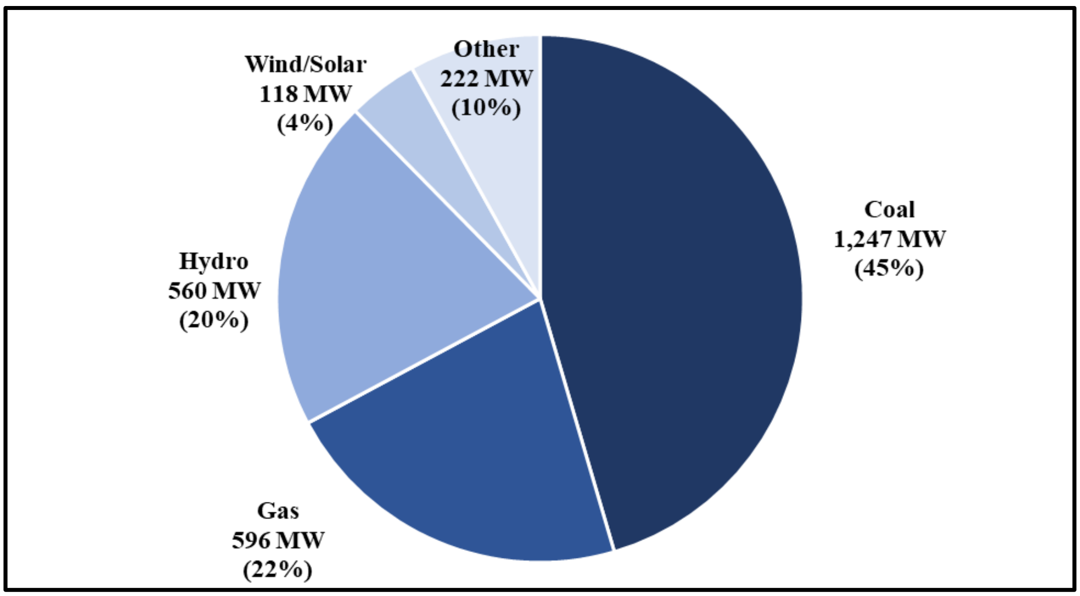
We have compared the business risk for NSPI to the U.S. Electric proxy group in two ways: (1) regulated generation risk, and (2) available ratemaking mechanisms.

105 Moody's Investors Service, "Proposed Refinements to the Regulated Utilities Rating Methodology and our Evolving View of US Utility Regulation," September 23, 2013, at 1.

106 Scotiabank Equity Research Spotlight, Energy Infrastructure, March 18, 2019, at 9. [Emphasis added.]

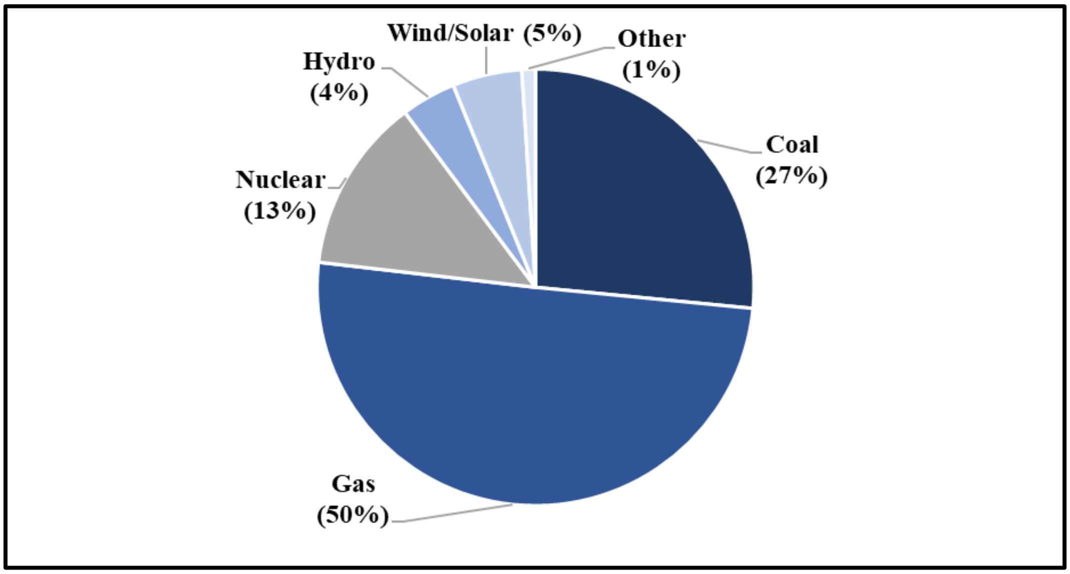
Regulated Generation Risk: NSPI owns substantial regulated generation assets and therefore has similar generation risk as the U.S. Electric proxy group operating companies. Of the 47 electric operating subsidiaries held by the U.S. Electric proxy group, 34 (i.e., approximately 72 percent) are vertically integrated. However, coal-fired generation comprises a large portion of NSPI's generation portfolio relative to the U.S. Electric proxy group, as shown in Figure 37 and Figure 38. On a percentage basis, NSPI owns more coal-fired generation assets than all but one company in the U.S. Electric proxy group (i.e., Evergy Inc.), although that percentage will steadily decrease as NSPI shuts down its coal-fired generation plants and transitions to renewable resources.

Figure 37: NSPI Generation Mix[107]



[107] Source: S&P Global Market Intelligence.

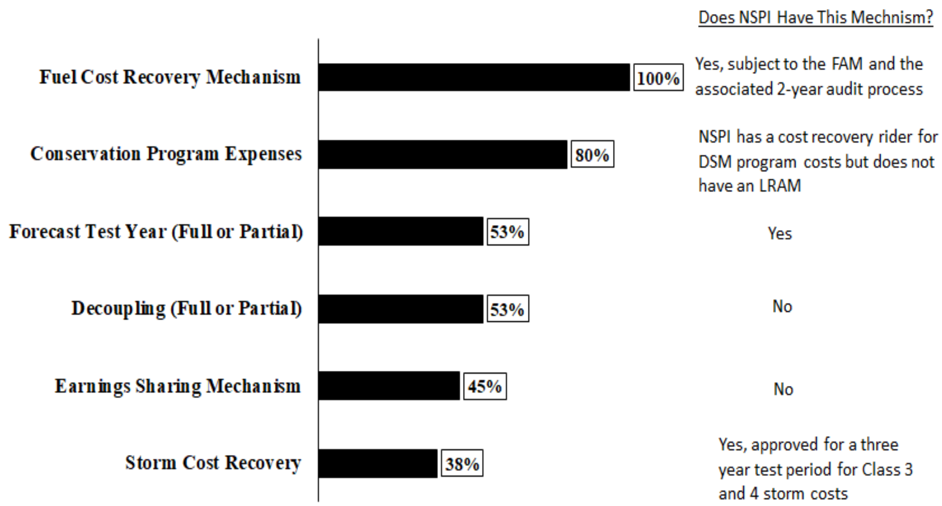
Figure 38: U.S. Electric Proxy Group Average Generation Mix[108]



Available Ratemaking Mechanisms: The companies in the U.S. Electric proxy group operate with a variety of ratemaking mechanisms that provide, on average, more risk insulation than is available to NSPI. Figure 45 identifies a variety of significant regulatory mechanisms and provides (1) the percentage of operating subsidiaries of the U.S. Electric proxy group that operate in jurisdictions employing those mechanisms, and (2) whether NSPI has access to those mechanisms. As summarized in Figure 39, the U.S. Electric proxy group companies generally have access to comparable ratemaking mechanisms to NSPI (e.g., 100 percent have a fuel cost recovery mechanism, 53 percent operate in jurisdictions that employ forecast test years) plus additional ratemaking mechanisms that are not available to NSPI (e.g., 53 percent have either full or partial revenue decoupling). Those additional ratemaking mechanisms are significant from a risk perspective because they provide a degree of protection to the proxy companies (e.g., from volumetric risk in the case of decoupling) that NSPI does not have.

108 Ibid.

Figure 39: Available Ratemaking Mechanisms for NSPI and U.S. Electric Proxy Group[109]



d. Conclusions on Business Risk of NSPI Compared to U.S. Electric Utility Proxy Group

Based on the business risk analysis, we conclude that NSPI has similar business risk to the U.S. Electric utility proxy group on many factors that affect the short and intermediate term variability of earnings and cash flows. For example, NSPI, like many of the U.S. Electric proxy group companies, owns regulated generation assets, has a FAM, and employs a forecast test year. However, multiple factors distinguish NSPI from the U.S. Electric proxy group companies from a risk perspective. For example, NSPI's relatively greater dependence on coal-fired electric generation exposes it to more carbon transition risk faster than the U.S. Electric proxy companies as it shifts its generation profile to include more renewable sources of power. Additionally, NSPI's lack of a decoupling mechanism means that it faces relatively greater volumetric risk than those companies in the U.S. Electric proxy group which operate in jurisdictions employing decoupling or weather normalization mechanisms (approximately one half), which is important given the warming climate and the fact that NSPI is a winter peaking utility operating in a jurisdiction with limited natural gas penetration. This is also particularly important considering that NSPI funds

109 Source: Regulatory Research Associates; Concentric research.

a DSM program for its customers (reducing its sales volumes) but is not allowed to recover lost revenues through an LRAM.

5. Risk Analysis Conclusions

Based on the results of the financial and business risk analyses discussed throughout this report, Concentric concludes that:

- NSPI's generation ownership distinguishes the Company from other investor-owned electric utilities in Canada.
- The business risk of NSPI remains elevated as it was at the time of the last GRA in 2022. In particular, the Company must comply with environmental requirements related to an accelerated decarbonization of its generation fleet by 2030. This transition from thermal generation to renewable resources is already underway but will continue to require substantial amounts of capital over the next five years and expose NSPI to risks such as renewable electricity standard and emission compliance.
- The business risk profile (including regulatory risk) of NSPI is higher than that of other Canadian investor-owned electric utilities. NSPI's business risk is also greater on average than the companies in the U.S. Electric proxy group.
- As reported by the Conference Board of Canada, the economy in Nova Scotia is generally projected to be weaker than Canada overall over the 2024-2045 period. In particular, GDP growth and population growth are both forecast to be lower than Canada overall, and the aging population is expected to cause more people to exit the workforce. These challenging demographic and macroeconomic trends in the Province also pressure electricity demand over the medium to longer-term.
- With the exception of a forecast test year and a pilot mechanism to recover storm costs, NSPI generally has greater regulatory risk than the operating companies in the Canadian and U.S. Electric utility proxy groups. As evidence of this greater risk, Concentric observes that the Company failed to earn its authorized ROE in each of 2022, 2023, and 2024. The Company experiences above average regulatory lag due to the operation of the FAM audit process, and NSPI does not have protection against volumetric risk through a revenue decoupling mechanism or weather normalization clause.
- Concentric's ROE and capital structure recommendations assume that the storm rider, which was approved for a three-year test period, is continued on a pilot basis in 2026-

2027. Absent approval of this proposal, NSPI has higher risk relative to the proxy groups on this factor. why would this make NSP risk higher relative to other Utilities (check above)?

- The financial risk of NSPI is greater than that of many companies in the Canadian proxy group and greater than the U.S. Electric utility proxy group, based on an analysis of deemed common equity ratios and key cash flow and interest coverage metrics.

Based on the foregoing considerations, Concentric concludes that an increase in the deemed common equity ratio for NSPI to 45.0 percent would be reasonable. This would place NSPI's common equity ratio at the upper end of electric utilities in Canada, comparable to that of Newfoundland Power (also 45 percent), which is appropriate given the Company's risk profile, but still well below the average of its U.S. peers of 51.1 percent. However, NSPI is requesting to maintain its current capital structure, which includes a deemed equity ratio of 40.0 percent. A supportive regulatory environment is critical for NSPI in terms of maintaining access to capital on reasonable terms particularly during this transition period as NSPI continues to work toward meeting the Province's ambitious environmental goals.

why should NSP equity ratio be in the upper end of Canadian electric utilities? where does a 40% equity ratio put NSP compared to other Canadian electric utilities?

SECTION 7:

OVERALL CONCLUSIONS AND RECOMMENDATIONS

For the reasons discussed throughout this report, it is appropriate to consider the CAPM using a historical market risk premium, the multi-stage DCF model and Risk Premium results for both Canada and the U.S. when establishing the authorized ROE for NSPI. The results of these models are summarized in Figure 40.

Figure 40: Summary of Results[110]

	Canadian Regulated Utilities	US Electric Utilities	North American Electric Utilities
CAPM – Historical MRP	9.71%	10.69%	10.32%
Multi-Stage DCF	9.60%	9.35%	9.29%
Risk Premium	9.54%	10.45%	10.00%
Average	**9.62%**	**10.16%**	**9.87%**

The average of all three methods for the North American Electric proxy group is 9.9 percent, within the range of 9.29 percent to 10.32 percent. Based on this analysis, we believe a reasonable estimate of NSPI's required ROE is 9.9 percent, which is supported by the average result for the North American Electric proxy group. However, NSPI is requesting to maintain its existing authorized ROE of 9.0 percent in order to mitigate the rate impact on customers of this GRA filing. The average for the Canadian proxy group, several of which have unregulated business activities and many of which do not own regulated generation and several of which have significant U.S. operations, is 9.6 percent.

NSPI is proposing to continue its deemed equity ratio of 40.0 percent. This request is reasonable, if not conservative, given the business and financial risks of NSPI, which distinguish the Company from other electric utilities in Canada and the U.S. As discussed previously in this report, there is an inter-relationship between the authorized ROE and the deemed capital structure. That is, firms with lower common equity ratios require higher rates of return to compensate shareholders for

[110] DCF results are based on 90-day average stock prices for proxy group companies. Results include 50 basis points for flotation costs and financial flexibility except for U.S. risk premium results.

the additional financial risks. If the deemed common equity ratio for NSPI is maintained at the current level of 40.0 percent, our ROE recommendation of 9.9 percent is understated based on market data for risk comparable companies in both Canada and the U.S., and more so at the Company's requested ROE of 9.0 percent.

Appendix 13A

Non-standard Meter Service

(AMI) Opt-Out Fee

Appendix 13A – Non-standard Meter Service (AMI) Opt-out Fee

1 Proposed Fee for Non-standard Meter Service

The Board approved NS Power's Advanced Metering Infrastructure (AMI) Project Application in June 2018. The Company filed its Revised AMI Compliance Filing on September 20, 2018, detailing the plan to inform customers about the opt-out1 process for AMI meter installation, and the estimated charges for opting out. In its December 6, 2018 Decision Letter, the Board directed as follows:

> NS Power is directed to use monthly fees of $4 for customers currently on a bi-monthly reading schedule and $22 for customers currently on a monthly reading schedule, respectively, as the approximate values in its communication to customers regarding the opt-out option, with the understanding that those numbers are rough estimates which remain to be verified during the next General Rate Application.[2]

In January 2022, the Company filed its GRA which included a proposed AMI opt-out charge of $3.67 per month for customers whose meters are currently read bi-monthly, and $22.01 per month for demand customers whose meters will continue to be read monthly. Although NS Power's GRA Settlement Agreement[3] included support from regulatory stakeholders for the proposed AMI opt-out fee, the Board did not approve the proposed AMI opt-out fee in its February 3, 2023 Decision. However, the Board Decision provided general direction, which the Company has addressed in **Section 1**.

In this Application, NS Power proposes a monthly opt-out charge according to the schedule outlined in **Table 1**.

Table 1 – Proposed Schedule of AMI Opt-out Fee Monthly Charges for 2026 and 2027

Standard Customer Meter Read Frequency	Proposed Opt-out Customer Meter Read Frequency	Proposed Opt-out Charge	
		in 2026	in 2027
Bi-monthly (6 times per year)	Semi-annually (twice per year)	$3.81 per month	$4.47 per month

[1] Customers who have chosen not to receive an AMI meter, or customers equipped with an AMI meter with the remote connection capability disabled, (i.e. customers that opt-out of over-the-air billing) are considered "AMI opt-out" customers for which NS Power providing non-standard meter service.
[2] M08349 – NSEB Decision, 2018 NSUARB 219, page 14, para 42. December 6, 2018.
[3] M10431, NS Power 2023-2024 GRA, Exhibit N-155, Schedule "A" Terms of Settlement, GRA Element "Misc. Charges (incl. AMI opt-out, […])," page 6 (PDF page 10). November 24, 2022.

Standard Customer Meter Read Frequency	Proposed Opt-out Customer Meter Read Frequency	Proposed Opt-out Charge	
		in 2026	in 2027
Monthly (12 times per year)	No change (12 times per year)	$22.89 per month	$26.79 per month

To reduce monthly charges for opt-out customers, and consistent with the approach proposed in the 2023-2024 GRA, NS Power will conduct semi-annual meter readings for customers whose meters are currently read bi-monthly (i.e. Domestic and Small General classes). For customer classes that include a monthly demand charge (i.e. General, Large General, Small Industrial, Medium Industrial, Large Industrial, and the Municipal Tariff), meters will continue to be read monthly to determine the monthly demand for customers. Reducing the frequency of manual meter readings in this way lowers the total required meter read hours by 64 percent and results in a total estimated cost savings of $1.2 million over 2026 and 2027. This reduction in read frequency also balances the need for reasonable accuracy of billed consumption while minimizing costs for opt-out customers.

NS Power's financial model for the opt-out charges is attached in **PR-02 Attachment 1**. The model includes the estimated incremental costs that will be incurred as a result of providing customers the option to retain non-standard meter service, such as the ongoing costs associated with reading the meters manually and facilitating and administering the process. NS Power has made the following changes to the AMI opt-out fee financial model since the last GRA:

- The addition of a 33 percent Meter Reader supervisor oversight factor;
- Removal of the opt-out communications costs;
- Updates to basic financial assumptions (e.g. WACC and labour rates);
- Workload volumes have been forecast based on actual numbers of opt-out customers to date and bi-annual read rates; and
- Travel times have been updated to reflect drive times between the actual location of opt-out customers, organized by meter route rather than generic travel time estimates.

These rates reflect an effort to minimize non-standard meter service costs while ensuring that actual costs for provisioning the service are fully recovered from opt-out customers as shown in **Table 2**.

Table 2 – AMI Opt-Out Model Assumptions

Opt-Out Charge Assumptions	2026	2027
Customer Opt-Out Percentage	2.9	2.0
Opt-Out Total Customer	16,340	11,089
Total Meter Reads Per Year	36,301	25,798
Time Required (Hours)	5,482	3,891
Expected Annual Cost ($ Million)[1]		
Total O&M	$0.73	$0.66
Depreciation, Carrying Costs, Tax	$0.11	$0.10
Total Annual Revenue Requirement ($ Million)	**$0.83**	**$0.77**
Monthly Charge (former bi-monthly read customers; now semi-annual)	**$3.81**	**$4.47**
Monthly Charge (monthly read customers)	**$22.89**	**$26.79**

[1] Numbers may not sum due to rounding.

These costs are incremental costs which would otherwise not be incurred by the Company as further described in the sections that follow.

2 Findings included in the Board's Decision under M10431

The NSEB's 2023-2024 GRA Decision provided general direction for pursuing available options:

> In considering NS Power's requested opt-out fee, the Board questions **whether all reasonable options have been explored to minimize or eliminate the proposed fee**. […]
>
> //
>
> In considering the requirement for an opt-out fee, the Board notes that **customers who opt-out of the smart meter program will still be paying for that capital project through costs that are embedded in rates**. […]
>
> Upon consideration of this issue, the Board is **not persuaded that the amount of the proposed opt-out fee, or the need for a fee, has been fully explored or justified**. It is incumbent upon NS Power to provide its customers with flexible options which could minimize the energy cost burden. That **flexibility could include monthly, bimonthly, semi-annual, or some other schedule of meter readings suitable for its customers.**

> […] NS Power **may seek approval at a later time, after it has acquired actual experience with opt-out costs** and has clearly demonstrated its experience with flexible customer options.[4] [emphasis added]

Each of these findings is addressed in the following subsections.

2.1 Options for Minimization or Elimination of Opt-Out Fees

NS Power has explored all reasonable options to minimize or eliminate the proposed fee.

2.1.1 Opt-Out Fees in Other Jurisdictions

Section 11 of the Company's AMI Project Application provided a summary of the separate charges implemented by utilities in other jurisdictions for non-standard meter service to recover the cost of serving those customers.[5] At the time of NS Power's 2017 AMI Application, the summary of charges from other jurisdictions ranged from $5.00 to $32.40 per month. The Company noted in its AMI Application that, in many instances, utilities in other jurisdictions implemented an initial fee in addition to a monthly charge, which has not been NS Power's approach in consideration of these fees. The Company has refreshed this jurisdictional review, using the same utilities included in its 2017 summary, and provided as **Appendix 13B**.

As of March 2025, opt-out fees implemented by utilities in other jurisdictions range from $2.50 to $34.05 per month; the median fee is $18.44 per month. All the utilities examined by NS Power in 2025 have implemented an initial or one-time fee (ranging from $22.60 to $126.27). The initial AMI opt-out fee generally covers administrative and processing costs (e.g. installation labour and materials, configuration of an analog or non-communicating meter, updating customer records). NS Power's non-standard meter service is primarily provided using AMI meters with the over-the-air (OTA) billing functionality turned off, which reduces the need for an initial fee to cover these costs. By excluding an initial fee for customers that opt-out of OTA billing, NS Power ensures those customers who choose to opt-out are not unduly burdened or penalized.

[4] M10431, NS Power 2023-2024 GRA, NSEB Decision
, February 3, 2023, pages 168-169, para. 433, 436-438.
[5] M08349 – Exhibit N-1, NS Power AMI Application, page 87-89. October 19, 2017.

In addition, approximately 41.5 percent of the total AMI project costs were for the AMI meters themselves.[6] Parsing project costs for AMI-metered customers based on whether they opted out of OTA billing unfairly increases these costs for customers receiving standard meter service. Since most non-standard meters are AMI meters, all customers should contribute to the capital investment in these meters. This approach minimizes costs for opt-out customers while providing fair and equitable service options and maintaining operational efficiency.

2.1.2 Economic Comparison of In-house versus Outsourced Meter Readings

In its Order dated December 6, 2018, the Board directed NS Power to explore the option of providing opt-out meter reading services by external contractor resources, including an economic comparison against provision via in-house resources.[7] In the 2023-2024 GRA, NS Power assessed whether cost savings could be achieved by engaging meter reading services of external contractor resources (provided in detail as **Appendix 12C**) through an RFP process and evaluation of external meter reading services. NS Power determined there were no cost savings to customers by outsourcing opt-out meter reading services and, in fact, external outsourcing would cost 25 percent more than keeping meter reading in house.

2.1.3 Regulation 5.1 – Post Card and Estimated Meter Reading

Customer-submitted meter reads, by post card or electronically, were raised in both the AMI Application and the 2023-2024 GRA as an option to reduce or eliminate an opt-out fee. Specifically, the Board's GRA Decision provided the following:

> Despite Mr. Drover stating that analog meters are complicated, provisions in Regulation 5.1 allow customers to take their own meter readings and send them to NS Power. In fact, NS Power's website includes a page titled "Send Your Meter Read", with an illustration on how to read the analog meter and an online form to submit the meter and account information. It is the Board's view that similar instructions can be developed for customers to read their digital meters and submit that information electronically or otherwise.[8]

[6] M11003 – NS Power, Approval of Authorization to Overspend Capital Work Order CI47124 – Advanced Metering Infrastructure in the amount of $11,219,295, Figure 1, PDF page 10-11. February 17, 2023.
[7] M08349 – NSEB Order, page 2, clause 2. December 6, 2018.
[8] M10431 – NSEB Decision, page 168, para. 435. February 3, 2023.

Customer-submitted meter reads are used only on an exception basis when NS Power is unable to obtain an on-site reading. Regulation 5.1 requires that the Company read a customer's meter following five consecutive bill estimations.[9] As the proposed opt-out fee includes reduced meter read frequency (from six to two manual reads per year), having one or both of those as a customer-submitted read can lead to inaccuracies, resulting in incorrect billing. The potential for inaccuracies is of even greater concern when customer-submitted meter reads are coupled with four bill estimations each year. Under Regulation 5.1, in rural areas where a post card meter reading has been adopted or the Company estimates the bill (in cases when a customer does not return the prepaid postage card), "an actual reading must be taken by the Company at least once within a twelve-month period for meters which are read bi-monthly and once within a six-month period for meters which are read monthly."[10] This provision is specifically intended to mitigate the potential for inaccuracies due to concurrent bill estimations and/or customer-submitted meter reads.

The majority of NS Power's non-standard meter service is provided through an AMI meter with the radio/over-the-air billing turned off. In contrast to legacy (analog) meters, AMI meters are digital; they cycle through various data points, which make it challenging to accurately capture consumption readings and increase the likelihood of unintentional errors in customer-submitted readings. In 2024, approximately 177 customer accounts submitted a post card or photo meter read; this represents less than 1 percent of the 18,140 customers that have opted out of AMI meters. Customer-submitted meter readings can also result in intentional misreporting, particularly in the absence of established regular and systematic utility-led verification processes. While Regulation 5.1 allows for customer-submitted readings, NS Power still needs to receive, verify, and process these readings, along with handling disputes and correcting errors.

For these reasons, customer-submitted meter reads are not a reasonable proxy for NS Power manual meter reads, and an associated opt-out fee to cover the costs associated with ensuring accurate and reliable meter readings is necessary.

2.2 Both AMI Project Capital Costs and Savings are Embedded in Rates

[9] Regulation 5.1 Meter Reading, "Estimated Meter Reading," page 40. January 1, 2017.
[10] Regulation 5.1 Meter Reading, "Estimated Meter Readings in Rural Areas," page 41.

The concept of non-participant[11] contributions to the AMI capital project costs, as these costs are embedded in rates, is based on the principle of shared infrastructure costs. Traditionally, when a utility undertakes a large-scale infrastructure project like AMI, the costs are spread across all customers to ensure that all customers who benefit from the infrastructure contribute to its cost. This approach is common in utility regulation to avoid disproportionately high costs for individual customers, to reduce undue financial burden on any single group(s) of customers, and to ensure that the utility can recover its investment. Regulatory boards often mandate that the costs of essential infrastructure projects be shared among all customers to ensure equitable cost distribution and to support the utility's financial health. Even if some customers opt out, the infrastructure (e.g. communication networks, data management systems) is still in place and must be funded.

Following the Company's implementation of the AMI project[12], OTA billing has become the standard meter reading service across Nova Scotia. NS Power's AMI Application was determined to be in the public interest by the Board, providing cost savings and benefits for all customers. When customers decide to opt-out of OTA billing, the overall benefits of the project (i.e. improved grid management, enhanced outage detection, and operational efficiencies) are diminished, potentially leading to higher operational costs and less effective service for all customers. The costs associated with manual meter reading for opt-out customers are also subsidized by the full rate base, further impacting the overall savings and efficiency gains of the AMI project.

Consistent with this, non-standard meter reading service for opt-out customers is a cost that would not otherwise be incurred. Opt-out meter reading is based on the forecast incremental cost to serve opt-out customers, and informed by the Company's actual experience with opt-out costs. It is treated as a pass-through to opt-out customers, where the revenue associated with the service offsets the cost of delivering the service and is no longer borne by other customers. Given that 99.97 percent of non-standard meters are AMI meters (as of December 2024), all customers should contribute to the capital investment in these meters and, as such, there will be no over-recovery associated with the proposed opt-out fee.

[11] In this case, customers that opt-out of AMI over-the-air billing
[12] Approximately 97 percent of AMI meters have been fully migrated to over-the-air meter reading and billing as of April 2025

NS Power has increasingly been asked by stakeholders to leverage its AMI data for various justifications and analyses. AMI data helps NS Power improve outage detection and management by using real-time data from smart meters to identify outage locations and restore power more efficiently. The Company identified several material benefits resulting from AMI meter data as part of its Rebuttal Evidence in the AMI Authorization to Overspend Application (M11003). The Board's November 2023 Decision provided:

> Second, the above revised NPV revenue requirement does not include several material benefits identified by NS Power it did not contemplate at the time of the original AMI Project application (and which were not included in the NPV analysis). These were identified in NS Power's Rebuttal Evidence at pp. 16-17, including:
>
> - Leveraging AMI usage data to assist with electrical service sizing for developers and apartment building owners for electric vehicle readiness, Heat Pump conversions, and generator capacity planning.
> - Leveraging AMI voltage data to support troubleshooting of customer power quality concerns. This results in a reduction of field work; AMI data can be used to reduce load checks by powerline technicians.
> - Using AMI remote disconnect and connect capabilities to manage power connections during on-site engineering assessments, rather than using an on-site powerline technician.
> - Proactive detection of unreported outages at vacant/seasonal properties. This reduces overtime costs, increases revenue and improves customer experience.
> - Using AMI Over-the-Air capabilities to enable bidirectional metering on AMI meters, reducing the need for on-site meter exchanges.
> - Enablement of cold load restoration plans.
> - Transformer loading and proactive maintenance – AMI data can be used to determine actual transformer loading, reducing unnecessary field scoping and overbuilt transformer capacity.
>
> Further, several benefits were identified in the development of the AMI Project but were not quantified as part of the NPV analysis, including load disaggregation customer insights, safety in the form of high temperature alarms, improved service reliability by reducing outage durations, carbon savings by using the AMI data to better understand feeder and transformer loading and the better integration of new electric loads like electric vehicles and heat pumps.
>
> **We are satisfied that the above points provide additional substantial benefits to customers and the utility**. They provide further support for approving the ATO application.
>
> //

> The Board also notes from various energy transition matters it has considered or is dealing with at the present time that the implementation of the AMI Project is an important development that will help facilitate various aspects dealing with the integration of renewables or distributed energy resources on the electric grid, assisting in the management of load and developing time-varying rates, which are all critically essential to the energy transition. Given the above reasons and considering the current legislative policy context, the Board agrees with NS Power's statement that without the implementation of the AMI Project, NS Power would be "well behind other North American utilities in implementing foundational technology to modernize the electrical system and adapt to a transforming energy industry".[13] [emphasis added]

This comprehensive use of AMI data underscores its value beyond just billing and meter reading, making it a critical component of modern utility operations.

2.3 The Company has Acquired Actual Experience with Opt-out Costs and Flexible Customer Options

As part of the approval process for NS Power's AMI roll-out, the NSEB required NS Power to track its costs and report annually on the customers choosing to opt out of AMI installation. [14]

NS Power has been providing the NSEB with the costs associated with opt-out fees (including capital costs, Customer Care expenses, and meter services) as part of its regular reporting requirements since May 2021. The fifth AMI Opt-out Report (2024 Report) has been included as **Appendix 13C**. As noted in that report, in 2024, the Meter Services expenses for opting out were approximately $1.1 million and Customer Care expenses were approximately $10,000, for a total of $1.11 million. Cumulatively, since 2019/2020, annual costs associated with opt-out services totalled $4.24 million, as summarized in **Table 3**.

Table 3 – Annual Costs Associated with Opt-out Services in Millions ($ Million)

Cost Category	2019/2020	2021	2022	2023	2024	Grand Total
Internal Labour	0.15	0.07	–	–	–	0.22
Consulting	0.18	0.00	–	–	–	0.18

[13] M11003 – NSEB Decision, 308688, pages 9-10. November 3, 2023.
[14] M08349, NS Power CI 47124 – AMI Project, Supplemental NSEB Decision, December 6, 2018, p. 14.

Cost Category	2019/2020	2021	2022	2023	2024	Grand Total
Total Labour[1]	**0.33**	**0.07**	–	–	–	**0.40**
Customer Care Expenses	0.35	0.15	0.03	0.01	0.01	0.55
Meter Services Expenses[2]	–	0.09	0.99	1.11	1.10	3.29
Grand Total	**0.68**	**0.31**	**1.02**	**1.12**	**1.11**	**4.24**

[1] These actual costs incurred are included in CI 47124 – AMI Project; no capital costs were incurred in 2022, 2023, or 2024.
[2] Meter Services expenses include carrying costs, depreciation and tax expenses

The Board also reviewed and assessed utility meter opt-out fees in the Halifax Regional Water Commission (HRWC, Halifax Water) 2016 AMI capital project (M07473). In its 2016 Application, HRWC proposed the introduction of meter reading charge at $50 per quarter[15] for customers choosing not to take service through an AMI meter. The Board approved the proposed fee for new customers of Halifax Water, in recognition that AMI meters were not the standard service meter at that time. In its Decision on HRWC's AMI project, dated October 6, 2016, the Board provided that, "in cases where AMI is the standard meter in use, and new customers refuse to use this standard AMI meter, there is an additional cost to HRWC and, accordingly, the proposed additional meter reading charge may be applied."[16]

The Company has developed the proposed opt-out fee using its experience tracking and annually reporting opt-out costs through its AMI Opt-out Report. NS Power submitted its first AMI opt-out cost model in its 2017 AMI Capital Project Application[17]. Since then, NS Power has filed successively refined and increasingly experience-based AMI Opt-Out Models in the AMI Application proceeding (M08349), AMI Compliance Filing (M08349), 2022-2024 GRA (M11431), and in this Application, which has been informed by five years' worth of opt-out cost tracking and annual reporting. Respectfully, in contrast, HRWC's $50 opt-out fee was developed in 2016, pre-dating the installation of any AMI meters for its customer base and using an estimate of incremental costs. In 2016, the Board approved HRWC's fee (for new customers only) and, in 2020, the Board approved Halifax Water's proposal to extend the same $50 fee to all customers

[15] In response to Board IR-9 in Halifax Water's AMI capital project, HRWC provided a breakdown of its proposed fee of $50, which was based on an estimate of what the incremental costs might be.
[16] Refer to pages 3-4 of the October 6, 2016, Board Decision (document: 249289) in M07473.
[17] M08349 – NS Power, Capital Work Order CI 47124 – AMI Project, Appendix G, PDF page 958. October 19, 2017.

having then achieved "the successful installation of AMI meters for approximately 98%"[18] of its customers, without any required revisions to opt-out fee model inputs or assumptions.

2.4 The Need, and Amount, of the Proposed Opt-out Fee has been Fully Explored and Justified

NS Power's position is closely aligned with the principles and justifications established by HRWC in its 2016 AMI opt-out proposal and, more recently, in its 2020 general rate application (M09589). HRWC's 2020 GRA proposed revisions to its Regulations extending the AMI opt-out fee ($50 per quarter) to all opt-out customers (both new and existing). Halifax Water highlighted that the 3 percent of customers who have not installed AMI meters has resulted in extra costs that would not otherwise exist, and in the absence of an opt-out fee those customers have neither an incentive to install AMI nor a consequence for refusal, and they continue to receive water service at the same cost as previous, which is ultimately subsidized by the rate base.[19]

HRWC's Post-Hearing Submission clarified that costs incurred to provide non-standard meter services should be borne by the customers that opt-out of the AMI meter service, particularly as it had successfully installed AMI meters for approximately 98 percent of Halifax Water's customers. HRWC reported that the remaining 2,000-2,500 customers with non-AMI meters were dispersed throughout Halifax, increasing travel times and distances required to read those meters, and therefore it is appropriate to charge these customers for the cost of providing the service of manual meter reads.[20]

NS Power serves approximately 555,000 customers dispersed throughout the province, including in rural areas which have a low-density population, and has approximately 18,140 customer opt-outs requiring, at a minimum, a combination of manual meter readings and bill estimations. If opt-out customers were billed in accordance with NS Power's proposed opt-out fee of $3.81 per month, in 2026, customers with meter reads currently on a bi-monthly cycle would pay $45.72 per year.

[18] M09589 – Post-Hearing Submission, page 27 (PDF page 28).
[19] Refer to HRWC's response to Board IR-57 in M09589, specifically page 2, lines 42-43 and 50-59, as filed on April 1, 2020.
[20] M09589 – HRWC General Rate Application, Post-Hearing Submission, page 27 (PDF page 28). July 2, 2020.

Customers currently on a monthly demand read cycle would pay $274.84 annually if billed the proposed opt-out fee of $22.89 per month, in 2026.

In its Decision dated August 27, 2020, the Board approved HRWC's proposal to extend its AMI opt-out fee to all customers and noted "that there was no opposition to the proposed Regulations […] including the proposed manual meter read fee in s.45A.[21]

Consistent with Halifax Water's proposed manual meter read fee Regulation (M09589), the Company's AMI Compliance Filing Reply Evidence provided:

> All parties appear to accept that an opt-out charge should apply. There are no comments before the Board suggesting that customers who decide to receive non-standard metering service should not be issued a charge. Synapse stated that, based on NS Power's filing, an opt-out charge in range of $10-$12 is reasonable.[22]

Like Halifax Water, the need for, and amount of, NS Power's proposed AMI opt-out fee is justified and is in line with existing precedent in the province.

---

[21] Refer to paragraphs 95 and 102 of the Board's August 27, 2020 Decision in M09589.
[22] M08349 – AMI Compliance Filing Reply Evidence, page 18. November 13, 2018.

CAD to USD conversion 1.4188

Region	Utility	Opt-out Meter Type	Initial Fee	Monthly Fee	Other Fees	Additional Information	Reference
Canada	BC Hydro	Radio-off Meter	$ 22.60	$ 20.00	$ 55.00	Eligibility limited to customers who need to replace their existing radio-off meter. If you already have a smart meter, you're not eligible to request a radio-off meter. "Other Fees" are applicable one-time, for swap to smart meter.	https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-meters/meter-choice.html?WT.mc_id=rd_meterchoices
		Legacy Meter	n/a	n/a	n/a	Discontinued	https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-meters/meter-choice.html?WT.mc_id=rd_meterchoices
	Fortis BC	Radio-off Meter (opt-in)	$ 88.00	$ 19.50	-	Monthly fee applies for each meter read	https://www.fortisbc.com/accounts-billing/meters-meter-readings/radio-off-option-for-advanced-meters
	Hydro Quebec	Non-communicating Meter	$ 85.00	$ 2.50	-	Revert to Smart Meter at no additional cost or exit fee	https://www.hydroquebec.com/data/documents-donnees/pdf/conditions-service-en.pdf
	EPCOR (Alberta)	Non-standard Meter	$ 87.18	$ 16.59	-	Eligibility criteria for non-standard meter opt-in applies; no exit fee	https://www.epcor.com/ca/en/ab/edmonton/account/meters/advanced-meters/power-meters.html
USA	Central Power Maine	Electro-mechanical or Solid State Meter	$ 56.75	$ 25.62	-	Discounted monthly fee may be available to income-qualified customers; no exit fee; additional $25 surcharge may apply based on a selection period	https://www.cmpco.com/documents/40117/115962041/sect12_7-1-2023.pdf/1cb953e3-d9df-b08f-ef37-8d61545e165f?t=1688043207697
		Smart Meter (no internal network interface card & no radio signal)	$ 28.38	$ 22.83	-	Discounted monthly fee may be available to income-qualified customers; no exit fee; additional $25 surcharge may apply based on a selection period	https://www.cmpco.com/documents/40117/115962041/sect12_7-1-2023.pdf/1cb953e3-d9df-b08f-ef37-8d61545e165f?t=1688043207697
	AEP Ohio	Non-standard Meter	$ 61.01	$ 34.05	-	Can request opt-out before installation date and waive the initial fee	https://www.aepohio.com/community/projects/smart-grid/smart-meters
	FPL Energy	Non-standard Meter	$ 126.27	$ 18.44	-	Delivered through a Rider (NSMR) described on page 19 of the Tariff Book (https://www.fpl.com/content/dam/fplgp/us/en/rates/pdf/electric-tariff-section8.pdf)	https://www.fpl.com/rates/meter-options.html
	Pacific Gas & Electric	Analog Meter	$ 106.41	$ 14.19	-	Discounted for customers qualifying for financial assistance ($10 initial, $5 monthly); all monthly charges are automatically discounted after 36 consecutive months	https://www.pge.com/en/save-energy-and-money/energy-saving-programs/smartmeter/opt-out-program.html
	San Diego Gas & Electric	Analog Meter	$ 106.41	$ 14.19	-	Discounted for income-qualified customers ($10 initial, $5 monthly); for all customers, monthly charge is billed for three years from opt-out date	https://www.sdge.com/residential/savings-center/smart-meters/smart-meter-opt-out
	Southern California Edison	Analog Meter	$ 70.94	$ 14.19	-	Discounted for income-qualified customers ($10 initial, $5 monthly)	https://www.sce.com/customer-service/my-account/smart-meters/opt-out
		Averages	**$ 76.27**	**$ 18.37**	**n/a**		
			$ 22.60	$ 2.50			
			$ 126.27	$ 34.05			

Bank of Canada Currency Converter

Conversions are based on Bank of Canada exchange rates, which are published each business day by 16:30 ET.

New Conversion

View data for the past:

1 Week | 2 Weeks | 1 Month | 3 Months | 6 Months | 1 Year

Canadian dollar → US dollar

Exchange rate summary		
Low	2025-02-26	0.6974
Average	2025-02-20 – 2025-02-26	0.7018
High	2025-02-20	0.7048

Results

Date	Value of 1.00 CAD in USD	CAD → USD	USD → CAD
2025-02-20	0.70 USD	0.7048	1.4188
2025-02-21	0.70 USD	0.7039	1.4207
2025-02-24	0.70 USD	0.7030	1.4225
2025-02-25	0.70 USD	0.6999	1.4287
2025-02-26	0.70 USD	0.6974	1.4339

Nova Scotia POWER
An Emera Company

PO Box 910 ● Halifax, Nova Scotia ● Canada ● B3J 2W5

Re: M08349 – CI 47124 – Advanced Metering Infrastructure (AMI) Project – Costs Associated with Opt-Out Services

The Nova Scotia Utility and Review Board (NSUARB, Board) approved Nova Scotia Power Incorporated's (NS Power, Company) application for Capital Work Order CI 47124, Advanced Metering Infrastructure (AMI) Project, on June 11, 2018 (AMI Decision).[1]

In its AMI Compliance Filing Decision dated December 6, 2018 (Compliance Filing Decision), the Board directed as follows:

> (1) In order to more fully pursue initiatives which could reduce opt-out costs, NS Power is directed to explore the option of providing opt-out meter reading services via external contractor resources. This analysis should include an economic comparison against provision via in-house resources.
>
> (2) To aid in transparently establishing any future opt-out charge, NS Power is directed to track and annually file its costs associated with opt-out services.[2]

On July 12, 2024, NS Power filed its fourth annual opt-out cost report. NS Power provides this fifth annual opt-out cost report in accordance with the Board's directives.

NS Power has installed more than 531,000 smart meters as of April 1, 2025. The Company provided the Board with monthly status updates from August 5, 2022 until December 6, 2024. In its December 17, 2024 Letter, the Board approved NS Power's request to discontinue the monthly update reports:

> The Board is satisfied that NS Power has essentially fulfilled the requirement under s. 3AB(1) of the Electricity Act and approves its request to discontinue the monthly update reports. The Board further notes NS Power's commitment to actively work towards completing remaining installations.[3]

As of April 1, 2025, approximately 97 percent of AMI meters have been migrated to fully automated meter reading and billing using AMI meter data, known as Over-the-Air (OTA) billing. All meters that are able to be migrated to OTA billing have been successfully

[1] M08349 – NS Power CI 47124 – AMI Project, NSUARB Decision, June 11, 2018.
[2] M08349 – NS Power CI 47124 – AMI Project, Supplemental NSUARB Decision, December 6, 2018, page 14.
[3] M10639 – NSUARB Letter, 317636. December 17, 2024.

transitioned. As new customers are added or previously opted-out customers choose to opt-in, we will coordinate these activities in parallel throughout 2025.

Opt-Out Meter Reading via External Contractor Resources

NS Power provided a full update on the RFP as part of its General Rate Application (GRA) M10431,[4] and has provided further details to address each of the findings outlined in the Board's M10431 Decision in Appendix 13A of the Company's Direct Evidence in the 2026-2027 GRA.

Costs Associated with Opt-Out Services

Up to December 31, 2024, NS Power has incurred costs in relation to opt-out services in three areas:

(1) Capital investment

(2) Customer care expenses for program roll out

(3) Meter reading costs for reading opt-out meters

Capital Investment

In order to provide an opt-out option to customers, a capital investment was required to modify various NS Power systems to support a new, non-standard meter service. Like many IT investments, this involved the design, build, integration, configuration, and testing of the systems required to support opt out service.

The capital costs to December 31, 2024 associated with these activities include both internal and external resources and are summarized below. These actual costs incurred are included in CI 47124 - AMI Project.[5] There were no capital costs incurred in 2022, 2023, or 2024.

Opt-out Capital Investment	2019/2020 ($M)	2021 ($M)
Internal Labour	0.15	0.07
Consulting	0.18	0
Total Labour	**0.33**	**0.07**

Customer Care Expenses

NS Power has approximately 18,140 customers who have opted out. These customers continue to have their meters read manually at the meter every other month, at no additional charge to the customer. NS Power completed a call out campaign to these

[4] M10431 2022 -2024 General Rate Application DE-03 – DE-04 page 116 of 121.

[5] M11003 NS Power CI 47124 – AMI Project Authorization to Overspend (ATO) Application, Exhibit N-1, February 17, 2023

customers in 2021/2022. In 2023 and 2024, Customer Care redirected their efforts to support the last of the AMI meter change outs that required coordination with customers to access the meters. NS Power received approximately 650 inbound calls from opt-out customers in 2024.

	2019/2020 ($M)	**2021 ($M)**	**2022 ($M)**	**2023 ($M)**	**2024 ($M)**
Customer Care Expenses	0.35	0.15	0.03	0.01	0.01

Meter Services Expenses

Opt-out customers in OTA-enabled areas require manual meter reading and receive non-standard meter service. In 2024, NS Power continued to read these opt-out customers per standard read frequency in accordance with current regulations. Going forward, NS Power continues to explore ways to reduce costs and consider flexible customer options; this is further detailed in Appendix 13A of the Direct Evidence in the 2026-2027 GRA. In 2024, NS Power completed approximately 100,000 manual reads for opt-out customers, that would otherwise be read OTA if they had AMI service, at a total cost of approximately $1.1 million.

	2019/2020 ($M)	**2021 ($M)**	**2022 ($M)**	**2023 ($M)**	**2024 ($M)**
Meter Services Expenses	–	0.09	0.99	1.11	1.10

Meter Services expenses in 2024 include carrying costs, depreciation and tax expenses.