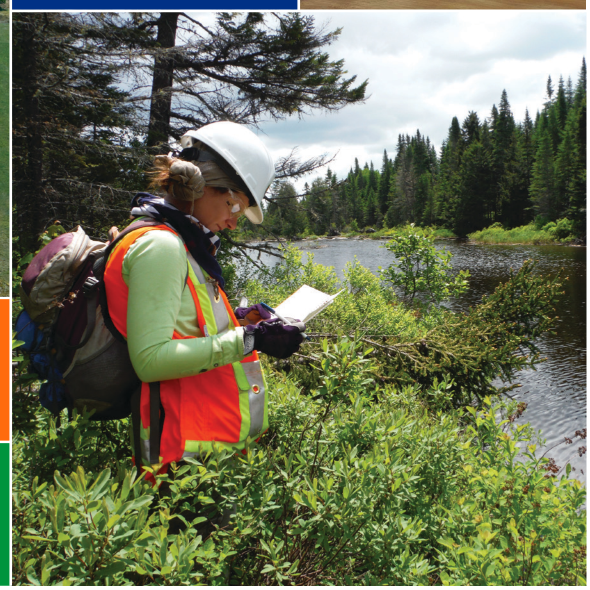
Energy East Project
Consolidated Application

Errata to Volumes 1, 2 and 10
and ESA Volumes 17 and 19

NEB Hearing Order OH-002-2016

July 2016



Submitted to:
The Secretary
National Energy Board
517 10th Ave SW
Calgary, Alberta T2R 0A8

TransCanada

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28 July 2016

National Energy Board
517 Tenth Avenue SW
Calgary, AB
T2R 0A8

Filed Electronically

Attention: Ms. Sheri Young, Secretary of the Board

Dear Ms. Young:

Re: Energy East Pipeline Ltd. (Energy East)
TransCanada PipeLines Limited (TransCanada)
Energy East Project and Asset Transfer Applications (Consolidated Application)
Consolidated Application Supplemental Report No. 1
Hearing Order OH-002-2016
Board File OF-Fac-Oil-E266-2014-01-02

On 17 May 2016, a Consolidated Application for the Energy East Project and Asset Transfer was filed with the Board.

Energy East has since identified various errata for the Consolidated Application and now provides replacement pages with black-lined revisions and related explanations for filing with the Board. The electronic files on the Board's website are being corrected. A replacement paper copy is attached.

If you have any questions, or require any further information, please contact the undersigned or Adrienne Menzies, Facilities Applications Manager, at (403) 920-5364 or adrienne_menzies@transcanada.com.

Yours truly,

Energy East Pipeline Ltd. and TransCanada PipeLines Limited

Original Signed by

Elizabeth Swanson
Associate General Counsel
Energy East Law

c.c. List of Intervenors in OH-002-2016

Enclosures

Errata

Consolidated Application and Consolidated ESA Errata

Table 1: Energy East Consolidated Application Errata

Volume	Section	PDF Pages	Exhibit Number	Description
Volume 1, Table of Contents	Consolidated Application Contents	329 of 339	A76903-3	Appendix 4A was added to Consolidated Application ESA List of Appendices for Volume 17. This appendix was filed in Energy East's fifth supplemental report (December 2015), but was inadvertently omitted from the Consolidated Application, as explained in Table 2.
Volume 1, Application and Project Overview	Contents	5 of 6	A76905-1	Corrections to reference documents in List of Appendices.
Volume 1, Application and Project Overview	Section 2, Project Overview	12 and 13 of 60	A76905-4	Corrections to reference documents.
Volume 1, Application and Project Overview	Section 2, Project Overview	59 of 60	A76905-4	Corrections to reference documents.
Volume 1, Application and Project Overview	Section 3, Project Justification and Benefits	3 of 16	A76905-5	Corrections to reference documents.
Volume 1, Application and Project Overview	Section 3, Project Justification and Benefits	11 of 16	A76905-5	Correction to data that was not revised during the consolidation to reflect information that was filed in the December 2015 application amendment.
Volume 1, Application and Project Overview	Appendix 1-3 Cover Page	1 of 115	A76905-9	For the reasons provided below, Appendix 1-3 cover page revised to show: • deletion of Concentric November 2015 Update report • addition of Concentric June 2016 black-lined consolidation report • deletion of Golder November 2015 Report • retention of Golder March 2016 Report
Volume 1, Application and Project Overview	Appendix 1-3, Concentric Report dated November 2015	1 of 115	A76905-9	Removed the Concentric Report dated November 2015 from the Consolidated Application in its entirety and replaced it with a black-lined version dated June 2016 that : • conforms references to the Consolidated Application • reflects information from the March 2016 Golder Report that was filed as Attachment D to the Concentric Report as a part of the Consolidated Application • reflects the Transportation Service Agreements that were included in the Consolidated Application

Table 1: Energy East Consolidated Application Errata (cont'd)

Volume	Section	PDF Pages	Exhibit Number	Description
Volume 1, Application and Project Overview	Appendix 1-3, Attachment A, Resumé of John J. Reed –	–	A76905-9	Inserted Attachment A: Resumé of John J. Reed that was inadvertently omitted from the Consolidated Application
Volume 1, Application and Project Overview	Appendix 1-3, Attachment C – Golder Associates Report: *Environmental and Socio-economic Assessment Update – Employment and Economy, November 2015*	55 to 99 of 115	A76905-9	Removed Golder Associates Report dated November 2015 contained as Attachment C to Appendix 1-3 of the Consolidated Application, as this report has been superseded by the March 2016 Golder Report that was filed as Attachment D to Appendix 1-3 of the Consolidated Application and will remain on the record.
Volume 2, Sale and Purchase of Mainline Assets	Section 1, Overview	7 of 8	A76906-2	Correction to data that was not revised during the consolidation to reflect information that was filed in the December 2015 application amendment.
Volume 2, Sale and Purchase of Mainline Assets	Section 2, Regulatory Standards	5 of 8	A76906-3	Wording correction for clarity.
Volume 2, Sale and Purchase of Mainline Assets	Section 2, Regulatory Standards	7 of 8	A76906-3	Correction to data that was not revised during the consolidation to reflect information that was filed in the December 2015 application amendment.
Volume 2, Sale and Purchase of Mainline Assets	Section 7, Third-Party Notification	5 of 6	A76906-8	Insertion of information that was filed in the December 2015 application amendment but was inadvertently omitted from the Consolidated Application.
Volume 2, Sale and Purchase of Mainline Assets	Appendix 2-7	1 to 3 of 3	A76907-7	Correction to data that was not revised during the consolidation to reflect information that was filed in the December 2015 application amendment.
Volume 10, Aboriginal Engagement	Section 6, Engagement Program Outcomes	3 of 6	A76968-7	Correction to data in sub-section 6.2.2 Saskatchewan.

Table 2: Energy East Consolidated ESA Errata

Consolidated Application Volume	Section	PDF Pages	NEB Exhibit Number	Explanation of Correction or Update
Volume 17, Part A, Marine Terminal Complex	Section 10	22 of 62	A77025-14	Added figure reference and removed "ERROR! Reference source not found."
Volume 17, Part A, Marine Terminal Complex	Section 11	30 and 31 of 68	A77025-16	Removed duplication of effects to be assessed.
Volume 17, Part B, Marine Shipping	Table of Contents	9 and 10 of 10	A77025-26	Added new page to Table of Contents for List of Appendices and reference to Appendix 4A, which inserted two pages into the document.
Volume 17, Part B, Marine Shipping	Section 4	31 of 54	A77025-30	Removed "ERROR! Reference source not found."
Volume 17, Part B, Marine Shipping	Section 4	35 of 54	A77025-30	Corrected spelling error.
Volume 17, Part B, Marine Shipping	Section 4, Appendix 4A	–	A77025-30	Added Appendix 4A – Modelling Underwater Sound Associated with Shipping in the Bay of Fundy, which was included in the fifth supplemental report (December 2015) but was inadvertently omitted from the Consolidated Application.
Volume 19: Accidents and Malfunctions	Table of Contents	8 of 272	A77029-2	Corrected table numbering from Table 4-29 to Table 4-37.
Volume 19: Accidents and Malfunctions	Section 5 Marine Component Assessment	238 to 242 of 272	A77029-2	Added sentence that was inadvertently omitted during development of the Consolidated Application. It was originally in the marine baseline section of Volume 19, Section 5.3.1, Marine Site Interest, and should have been moved to Section 5.4, Tanker Strikes on Marine Mammals.

Volume 1

Application and Project Overview

VOLUME 17: BIOPHYSICAL AND SOCIO ECONOMIC EFFECTS ASSESSMENT – NEW BRUNSWICK

Part A: Marine Terminal Complex

Appendix 2A	Figures – New Brunswick
Appendix 2B	Ground-level Concentrations at Sensitive Receptors
Appendix 3A	Glossary
Appendix 5A	Water Well Data Collected from NB Online Well Log System
Appendix 6A	Species of Management Concern in the New Brunswick RAA
Appendix 6B	Potential Watercourses in New Brunswick
Appendix 9A	SOMC That Might Occur in the LAA or RAA
Appendix 15A	Aboriginal Community Profiles and Literature Review – New Brunswick
Appendix 19A	Sensitive Receptor Maximum Ground-Level Concentrations – New Brunswick
Appendix 20A	Baseline Information
Appendix 20B	Change in Visual Value
Appendix 20C	Typical Tank Terminal Installation Light Simulation

Part B: Marine Shipping

~~NA~~Appendix 4A Modelling Underwater Sound Associated with Shipping in the Bay of Fundy

VOLUME 18: EFFECTS OF THE ENVIRONMENT ON THE PROJECT

NA

VOLUME 19: ACCIDENTS AND MALFUNCTIONS

Appendix 2A	Internal Corrosion Caused by Naphthenic Acids and Water and Sediment Concentrations
Appendix 2B	Modification Factors
Appendix 3A	Air Dispersion Modelling

VOLUME 20: ASSESSMENT SUMMARY AND CONCLUSIONS

NA

VOLUME 21: ENVIRONMENTAL PROTECTION PLANS

New Pipeline

Appendix A	Emergency Contacts
Appendix B	Contacts
Appendix C	Approvals/Permits Potentially Required for Pipeline Development
Appendix D	Industry Guidelines and Regulations
Appendix E	Typical Drawings
Appendix F	Contingency Plans

LIST OF APPENDICES

LIST OF FIGURES

LIST OF TABLES

For a breakdown of the main Project components by province, refer to Section 5.0, Provincial Profiles, of this Consolidated Application volume. See also Sections 2.5, 2.6, and 2.7 below for additional information on the respective new pipeline, conversion, and facility designs for the Project.

Volume 13 provides aerial overview and detailed route maps of the Energy East Pipeline.

2.2.3 Estimated Capital Cost

Table 2-1 provides a current estimate of the capital costs of the Project in 2013 dollars.

Table 2-1: Capital Cost Estimate (CA Rev. 0)

Component	Capital Cost ($ million)
Pipeline	
New Pipelines	6,439
Conversion Pipelines	1,950
Pump Stations	4,354
Tank Terminals and Delivery Meter Stations	1,880
Marine Terminals	1,025
Sub-total	**15,648**
Transfer Price for Gas Assets	1,478
AFUDC	2,220
Total	**19,346**

2.2.4 Project Justification

Energy East has commissioned independent expert reports on the economic, social and environmental effects of the Project and the overall public interest served by the Project, the Asset Transfer and the related but separate Eastern Mainline Project. The reports conclude that there will be positive benefits from the Project, the Asset Transfer and the EMP.

The reports are outlined in Volume 1, Section 3.3: Evidentiary Support for the Public Interest Determination, and are appended as follows:

- Conference Board of Canada (CBoC) – *Energy East Pipeline Project: Understanding the Economic Benefits for Canada and its Regions, October 2015* (Appendix 1-2)
- Concentric Energy Advisors, Inc. (Concentric) – *Direct Evidence of John J. Reed, ~~November 2015 Update~~June 2016* (Appendix 1-3)

- Roland Priddle – *The Energy East Project and the Canadian Public Interest: A Significant and Strategic Element of National Infrastructure, Updated November 2015* (see Appendix 1-4)

These reports reflect the current scope and cost of the Project, and augment third-party economic effects assessments of Energy East and the EMP that were prepared by Nichols Applied Management/Stantec Consulting Ltd. (Nichols) and Golder Associates Ltd. (Golder), respectively. The Nichols assessment is provided in Volume 16 of the consolidated ESA, while the Golder assessment is appended to the Concentric report in Appendix 1-3.[20]

2.2.5 Section 58 Exemption

To maintain the construction schedule and staged in-service dates for the Project, exemptions from the detailed route process are being sought under section 58 of the NEB Act as part of the Consolidated Application. The requested exemptions are for:

- temporary construction-related infrastructure
- activities and works in support of converting the required TransCanada gas assets to oil service
- pump stations along the Project's converted pipeline segments
- Hardisty D and Saint John tank terminals and related facilities

The activities and works proposed for relief under section 58 will only be undertaken on lands where the requisite land rights are in place and only then, after the Board has issued a CPCN for the entire Project and subject to any further regulatory direction, applicable pre-construction conditions have been satisfied.

2.3 CONSOLIDATED APPLICATION VOLUME 2 – SALE AND PURCHASE OF MAINLINE ASSETS

As described in Volume 2 of this Consolidated Application, TransCanada and Energy East, as general partner on behalf of Energy East Pipeline Limited Partnership, have entered into an agreement governing the transfer of the TransCanada gas assets, the Transfer Agreement. The assets proposed to be transferred include approximately 3,000 km of 1067 mm (NPS 42) pipeline.

[20] To reflect an increase in the estimated capital cost of the EMP, Golder refreshed the Statistics Canada Inter-Provincial Input-Output Model economic modelling in an additional report dated March ~~1~~ 2016. The March 2016 report is provided in Appendix 1-3 of this Consolidated Application (see Attachments~~ B to~~ D to the ~~Golder~~Concentric report).

Board's MH-001-2012 decision. Energy East intends to set-aside funds for the Project in a manner similar to the abandonment trust agreement provided for Keystone Pipeline (Canada).

For additional information on the ACE for Energy East, see Volume 3, Section 2.4.1.3: Decommissioning and Abandonment and to Appendix 3-5: Energy East Pipeline Draft Trust Agreement.

2.17.2 TransCanada Mainline

The Asset Transfer and addition of the EMP facilities will result in a net reduction to the ACE approved for the TransCanada Mainline. The estimated net impact of these two facility changes is a reduction of $362 million from the approved initial ACE of $2.38 billion.

For information on the effects of the Asset Transfer and EMP on the ACE for the TransCanada Mainline, refer to Section 4.4.3.1: Pipeline Abandonment Cost Implications.

2.17.3 Environmental Assessment

As decommissioning and abandonment are currently anticipated to occur in excess of 40 years into the future, a broad assessment was undertaken with respect to environmental impacts, informed by necessary assumptions. This assessment, including the determination of significance of any effects following mitigation and the significance of cumulative effects, is provided in the ESA (see ESA Volume 14, Section 8: Decommissioning and Abandonment).

2.18 SUPPORTING DOCUMENTS

Table 2-4 is a list of the supporting documents that are provided in this Consolidated Application volume.

Table 2-4: List of Appendices to Volume 1: Application, Overview and Justification

Consolidated Appendix No.	Consolidated Appendix Name
Appendix 1-1	Standards and Specifications (Industry and Company)
Appendix 1-2	Conference Board of Canada Report (October 2015)
Appendix 1-3	Concentric Report (~~November 2015~~June 2016) (Attachment~~s~~ – ~~October 2014 Golder Report, November 2015 Update and~~ March 2016 Golder Report~~Update~~)
Appendix 1-4	Priddle Report (November 2015) (Attachment – Footnote References)
Appendix 1-5	Placeholder – Update on TERMPOL Process (Q4 2016)
Appendix 1-6	Placeholder
Appendix 1-7	Placeholder

3.3 EVIDENTIARY SUPPORT FOR THE PUBLIC INTEREST DETERMINATION

In addition to their own evidence, TransCanada and Energy East retained independent experts to provide views regarding the economic, social and environmental effects of the Project and the overall public interest served by the Project, the Asset Transfer and the EMP. Each of these reports or assessments reflects the current scope and cost of the Project:[7]

- *Written Evidence of John J. Reed*, Concentric Energy Advisors, Inc.(~~November 2015~~June 2016) (Concentric Report)[8]
- *Energy East Pipeline Project: Understanding the Economic Benefits for Canada and its Regions* (The Conference Board of Canada, October 2015) (CBoC Report)[9]
- *The Energy East Project and the Canadian Public Interest: A significant and strategic element of national infrastructure* (Roland Priddle, November 2015) (Priddle Report)[10]
- *Supply and Market Study for Energy East Project* (IHS Inc., September 2015) (IHS Report)[11]
- Nichols Applied Management/Stantec Consulting Ltd., ESA Volume 16, Socio-economic Assessment (Stantec, October 2014)[12]
- Eastern Mainline Project – Environmental and Socio-economic Assessment – Section 6 (Employment and Economy) (Golder Associates, October 2014, November 2015 Update, and March 2016 Update)[13]

Collectively, this body of independent expert evidence demonstrates that achieving the Project through the Asset Transfer while continuing to meet firm gas service obligations through the limited addition of gas facilities proposed in the EMP is in the public interest. The conclusions of the experts are discussed in greater detail later in this section.

3.4 PUBLIC INTEREST OF THE PROJECT

Environmental, social and economic considerations are relevant to a determination of the public interest. So too, particularly in this case, is a consideration of the ways in

[7] These reports and assessments reflect a staged in-service date in fourth quarter 2020. Refer to Volume 7, Section 2.5: Construction Schedule. The earliest in-service date is currently scheduled for fourth quarter 2021.

[8] See Volume 1, Appendix 1-3: Concentric Report, June 2016~~November 2015~~.

[9] See Volume 1, Appendix 1-2: CBoC Report, October 2015.

[10] See Volume 1, Appendix 1-4: Priddle Report, November 2015.

[11] See Volume 3, Appendix 3-6: IHS Report, September 2015.

[12] See the Environmental and Socio-economic Assessment (Vol. 16, Socio-economic Assessment).

[13] See Volume 1, Appendix 1-3: Concentric Report, June 2016~~Attachment B (October 2014); Attachment C (November 2015), and~~ Attachment D (March 2016).

3.6 BENEFITS OF ASSET TRANSFER

Energy East proposes to acquire gas assets from the TransCanada Mainline. The transfer price equates to the net book value (NBV) of the transferred assets (approximately $~~743~~ 744 million) plus an estimated premium of $734 million over NBV, the Acquisition Premium, for a total price of approximately $1.5 billion.

The TransCanada gas assets to be transferred consist of portions of three lines on the TransCanada Mainline, comprised of:

- Prairies Line – Line 100-4, comprising 940 km of 1067 mm (NPS 42) pipeline starting at MLV-2 near Burstall, SK to MLV-41 east of Winnipeg, MB
- Northern Ontario Line – Line 100-4 with certain sections of Line 100-3, comprising 1,640 km of 1067 mm (NPS 42) pipeline starting at MLV-41 east of Winnipeg, MB to MLV-116 near North Bay, ON
- North Bay Shortcut Line – Line 1200-2, comprising 420 km of 1067 mm (NPS 42) pipeline starting at MLV-116 near North Bay, ON to MLV-1401 near Iroquois, ON

In addition to the Conference Board assessment noted above, TransCanada completed an evaluation of the impact on the Mainline's revenue requirement of transferring the three segments noted above, as well as the associated construction of the EMP. The analysis shows that on a NPV basis, the economic effect of the Mainline Asset Transfer and the EMP, when taken together, result in a benefit of more than $500 million to Mainline shippers, while meeting all firm transportation requirements.

A further analysis considers the potential benefits for the Eastern Triangle separately from the Mainline as whole; that analysis shows that of the $500 million benefit, on an NPV basis, there is at least a net benefit of $100 million to Eastern Triangle shippers.

In addition, TransCanada believes that these benefits can be achieved without impacts to either natural gas market prices or to the quality of firm service deliveries. Details of the analysis are provided in this Consolidated Application, Volume 2, Section 4.1.

3.7 OTHER BENEFITS

3.7.1 Concentric Energy Advisors

Energy East and TransCanada retained Concentric Energy Advisors (Concentric), a management consulting and financial advisory firm focused on the North American energy industry, to conduct a review of the Energy East and Eastern Mainline projects. Their review covered the following topics:

Appendix 1-3

Concentric Report (~~November 2015~~ June 2016) (Attachment: Golder March 2016 Technical Report Economic Impact Update - Eastern Mainline Project)

~~(Attachments – November 2015 Golder Report and March 2016 Golder Report on Economic and Employment Effects)~~

NATIONAL ENERGY BOARD

IN THE MATTER OF the *National Energy Board Act*, R.S.C. 1985, c. N-7, as amended, and the regulations made thereunder;

IN THE MATTER OF the *Canadian Environmental Assessment Act*, 2012, S.C. 2012, c. 37, as amended, and the regulations made thereunder;

AND IN THE MATTER OF an application by Energy East Pipeline Ltd. (Energy East), as general partner on behalf of the Energy East Pipeline Limited Partnership and the Canaport Energy East Marine Terminal Limited Partnership, for a Certificate of Public Convenience and Necessity and related approvals pursuant to Parts III and IV of the *National Energy Board Act* and Section 43 of the *Onshore Pipeline Regulations*;

AND IN THE MATTER OF an application by TransCanada PipeLines Limited and Energy East Pipeline Ltd. respecting the transfer of certain natural gas pipeline assets pursuant to Parts I, IV and V of the *National Energy Board Act*.

**TRANSCANADA PIPELINES LIMITED AND ENERGY EAST PIPELINE LTD.
ENERGY EAST PROJECT AND ASSET TRANSFER APPLICATIONS**

~~April~~ June 2016 Consolidation

**WRITTEN EVIDENCE OF JOHN J. REED
CONCENTRIC ENERGY ADVISORS, INC.**

To: The Secretary
National Energy Board
517 10th Avenue SW
Calgary, Alberta
T2R 0A8

TABLE OF CONTENTS

I. *INTRODUCTION*

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is John J. Reed. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q2. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A2. I am Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. ("Concentric"). Concentric is a management consulting firm specializing in financial and economic services to the energy industry.

Q3. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A3. I have more than thirty-five years of experience in the North American energy industry. Prior to my current position with Concentric, I served in executive positions with various consulting firms and as Chief Economist with Southern California Gas Company, North America's largest gas distribution utility. I have provided expert testimony on financial and economic matters on more than 150 occasions before the National Energy Board ("NEB" or "Board"), the Federal Energy Regulatory Commission ("FERC"), provincial and state utility regulatory agencies, various state and federal courts, and before arbitration panels in Canada and the United States. A copy of my résumé and a listing of the testimony I have sponsored is included as Attachment A.

Q4. IN WHICH CASES HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE BOARD?

A4. I have submitted evidence before the Board on behalf of the following parties in the following proceedings:

- Alberta-Northeast (GH-1-87)
- Alberta-Northeast (GH-2-87)
- Alberta-Northeast (GH-5-89)
- Independent Petroleum Association of Canada (RH-2-91)

- The Canadian Association of Petroleum Producers (RH-1-93)
- Maritimes & Northeast Pipeline (GH-6-96)
- Alliance Pipeline (GH-3-97)
- Maritimes & Northeast Pipeline (GH-3-2002)
- TransCanada PipeLines (RH-3-2004)
- Brunswick Pipeline (GH-1-2006)
- TransCanada PipeLines (RH-1-2007)
- Repsol Energy Canada (GH-1-2008)
- Maritimes & Northeast Pipeline (RH-4-2010)
- TransCanada PipeLines (RH-003-2011)
- Trans Mountain Pipeline (RH-001-2012)
- TransCanada PipeLines (RH-001-2013)
- NOVA Gas Transmission Ltd. (GH-001-2014)
- Trans Mountain Pipeline (OH-001-2014)
- TransCanada PipeLines (RH-001-2014)

In addition to testifying, I have worked with numerous entities in the Canadian energy industry during my career, assisting them with various strategic, regulatory and toll-related issues.

Q5. ON WHOSE BEHALF ARE YOU SPONSORING EVIDENCE IN THIS PROCEEDING?

A5. I am sponsoring evidence on behalf of Energy East Pipeline Ltd. ("Energy East") and TransCanada PipeLines Limited ("TransCanada").

Q6. WHAT IS THE PURPOSE OF YOUR EVIDENCE?

A6. The purpose of my evidence is to address economic and public interest aspects of (i) the application of Energy East for new crude oil pipeline and related facilities, (ii) the joint application of Energy East and TransCanada for the transfer of existing natural gas assets to oil service, and (iii) the application of TransCanada for the construction of certain gas facilities that will be part of the Mainline. While these are separate applications that have been filed with the Board, they contain related and overlapping information and, therefore, I will refer to them collectively as the "Application". My Written evidence addresses the following four issues:

- A review and assessment of whether the Energy East Pipeline Project ("Energy East Pipeline"), a new proposed crude oil pipeline, meets the Board's standards for economic and financial feasibility, which are important criteria for the determination of whether a project is in the public interest;
- Evaluate the terms and reasonableness of the proposed transfer of assets from the TransCanada natural gas transmission system ("Mainline") to Energy East ("Conversion Facilities");
- Evaluate whether the new gas pipeline facilities proposed to be constructed by TransCanada as part of the Mainline (*i.e.*, the Eastern Mainline Project ("EMP")) are needed, and whether there is a strong likelihood that the contracted demand charges on the EMP will be paid by gas shippers over the term of the contracts;
- Assess the overall Canadian public interest benefits, including the commercial, economic, supply and market benefits, associated with the Energy East Pipeline, the transfer of the Conversion Facilities and the construction of the EMP (collectively, the "Project").

Q7. WHAT INFORMATION CONTAINED IN THE APPLICATION HAVE YOU REVIEWED FOR THE DEVELOPMENT OF YOUR EVIDENCE?

A7. I have reviewed Volumes 1, 2, 3 and 11 of the original October 2014 Application and Volume 1 of the Application Amendment which is now contained in Volumes 1, 2, 3 and 11 of the May 2016 Consolidated Application. This review included the quantitative assessments of the benefits of the Project, including the studies prepared by The Conference Board of Canada ("Conference Board"), which has developed a report that evaluates the economic benefits of the Energy East Pipeline ("Updated Conference Board Report"), and by IHS, Inc. ("IHS"), which has developed a report that provides an independent assessment of the market for the products shipped, the supplies available to, and the oil industry benefits and impacts that are expected to result from the operation of the Energy East Pipeline ("Updated IHS Report"). I have also reviewed the reports prepared by Nichols Applied Management ("Nichols"), which produced the socioeconomic analysis included in the Application ("Nichols Report"), and by Golder Associates, Ltd. ("Golder"), which addresses the economic impact of the EMP ("Golder Report").[1]

I have formed the conclusions and opinions provided in this evidence based on a review of the materials noted above, as well as my experience in the energy industry generally, and my experience in the Canadian energy industry specifically.

II. ***PROJECT OVERVIEW***

Q8. WHAT FACILITIES ARE BEING PROPOSED IN THE APPLICATION?

A8. Energy East is proposing to construct and operate a 4,500 km crude oil pipeline system from Hardisty, Alberta to Saint John, New Brunswick. The pipeline will transport up to 1.1 million barrels per day ("bpd") of crude oil and is scheduled to be in-service by the end of 2020. The Energy East Pipeline includes the acquisition of existing natural gas facilities from TransCanada and the conversion of those facilities to oil service, in addition to the construction of new oil pipeline and related facilities. The preliminary scope of the Energy East Pipeline includes:

- Converting approximately 3,000 km of 1,067 mm (NPS 42) of existing gas pipelines to oil service;
- Constructing new mainline oil pipeline segments totaling approximately 1,500 km of 1,067 mm (NPS 42) pipe;
- Installing laterals and terminal interconnection pipelines; and
- Construction of a new marine terminal at Saint John, NB.

Currently, approximately 3,800 km of the proposed pipeline length is projected to be located either within an existing right-of-way ("ROW") or alongside existing linear disturbances such as pipelines, railways, roads, and electrical power lines. The remaining length, or about 700 km, is projected to be installed in new ROW.

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[1] ~~The Golder Report is found at NEB Filing ID: A4D8R4 and ~~Aan Updated Golder Report, dated March 2016 is attached to this Evidence. ~~as Attachment C. The economic analyses associated with the EMP described in the Golder Report will not be updated until first quarter of 2016 and therefore have not been updated in this Evidence.~~

The Conversion Facilities will consist of converting approximately 3,000 km of existing Mainline facilities from the Alberta/Saskatchewan border to a point near the Mainline's existing interconnection with Iroquois Gas Transmission System, including the portion from North Bay Junction to Iroquois ("North Bay Shortcut").

For the EMP, TransCanada is proposing to construct additional facilities consisting of approximately 279 km (of 914 mm (NPS 36), 6450 kPa) pipeline looping along the existing Montreal Line and nine additional 11 MW compressor units at existing locations.

Q9. HOW MUCH OF THE PROPOSED NEW OIL CAPACITY IS CURRENTLY UNDER CONTRACT?

A9. Energy East currently has committed, long-term contracts of 995,000 bpd for firm service with terms that average 19 years. Of that volume, ~~725~~845,000 bpd has a contract delivery point of either a Quebec refinery or Saint John. The remaining ~~270~~150,000 bpd under contract is subject to ongoing commercial discussions with shippers related to an election to deliver to Saint John or continued evaluation of other delivery options. In addition, it has reserved 90,000 bpd for uncommitted spot service. This evidence utilizes the 995,000 bpd based on executed TSAs and the ongoing commercial discussions. The fixed demand charge revenue referred to within this evidence is also calculated from the 995,000 bpd contract level.

Q10. IS ENERGY EAST SEEKING APPROVAL FOR THE TOLLS AND TARIFF IN THE APPLICATION?

A10. No. Energy East is only seeking approval for its tolling methodology, not approval of specific tolls which will be determined at a later time. Energy East addresses all of the matters regarding Part IV of the NEB Act in Volume 3, Section 2 of the Consolidated Application~~ and Volume 1, Section 7 of the Application Amendment~~.

III. ***Executive Summary***

Q11. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE PROJECT.

A11. Based on my review of the Application, my understanding of the requirements of Section 52 and 74 of the NEB Act, the Board's Filing Manual, and the policy and precedent from past Board decisions, it is my opinion that the overall economic benefits of the Project far exceed any potential economic burdens of the Project, and that the Project is fully consistent with the public interest. Specifically:

- In my consideration of the public interest, I have evaluated and considered the economic impacts associated with each of the components of the Project – the Conversion Facilities, the EMP and the construction of new oil pipeline facilities. Because of the interrelated nature of these components of the Project relative to one another, my opinion regarding the public interest is based on the totality of the Project.
- The Project provides an opportunity for Canada to maximize the benefits from the development of its natural resources, providing substantial economic benefits that would not be attainable absent the Project, without resulting in economic burdens on natural gas shippers.
- The transfer of the Conversion Facilities from gas to oil service substantially reduces the aggregate cost and environmental impact that would otherwise be required if all new oil pipeline facilities were to be constructed; the terms of the proposed transfer are reasonable and make a significant contribution to providing net benefits to gas shippers across the Mainline.
- Without the transfer of the Conversion Facilities, the Energy East Pipeline would not be economic and access to new oil markets would be constrained, resulting in market inefficiency and the potential loss of billions of dollars, which in my view, is inconsistent with the public interest.
- The proposed Energy East Pipeline clearly meets the standards that the Board has previously evaluated in regard to economic and financial feasibility.
  - There is projected to be sufficient crude oil supply for the pipeline, and there is clear and substantial demand for committed oil transportation service from large, credit-worthy shippers capable of funding the financial obligations of such service over the 20-year contract terms.

- The optionality provided by the new oil pipeline, in conjunction with the sufficient take-away capacity for the delivered crude oil, is projected to alleviate significant market constraints that currently exist, providing substantial benefits to the Western Canadian oil industry, Eastern Canadian refineries in Quebec and New Brunswick through a secure source of competitively priced domestic crude oil, and to the entire Canadian economy; the energy industry benefits that are derived from the development of the Energy East Pipeline are expected to exceed $204 billion.
- The facilities are reasonably sized based on the long-term commitments made by the shippers, and the capacity on the facilities has been efficiently and fairly allocated to the shippers that value this capacity most highly; the new facilities will be used and useful, and the demand charges for the capacity are highly likely to be paid.

• The Energy East Pipeline will also promote a competitive market environment for oil transportation service.

- The pipeline will provide oil shippers with increased options for marketing their products, providing broader market access by allowing shippers the ability to access the North American and overseas markets.
- The negotiated tolling methodology proposed by Energy East is consistent with what the Board has approved for other oil pipelines, and reasonably apportions risks between shippers and Energy East, including the fact that Energy East will be at risk for any future underutilization.
- The agreements executed by Energy East and its shippers were negotiated in an open and competitive process, and promote productive efficiency by reasonably allocating development and operating risks among the parties.

• The Energy East Pipeline would provide substantial federal and provincial macroeconomic benefits totaling over $136 billion over the first 20 years in service, which includes a projected $~~4.5~~6.0 billion in gas corridor economic impact benefits associated with the construction phase of the EMP as well.

• I have considered from an economic perspective whether the public interest is better served if the Conversion Facilities are used in oil or gas service. I have concluded that neither the service quality nor the cost of firm Mainline gas service is expected to be harmed by the transfer of the Conversion Facilities as a result of the commitments made by Energy East and TransCanada, including the construction of the EMP. Regardless, the transfer of the Conversion Facilities represents a higher and better use for those existing Mainline facilities.

- The gas facilities to be transferred to oil service in the Prairies and Northern Ontario Line segments are not projected to be required to continue to provide firm transportation services, and thus are more appropriately applied to a higher and better use.
- While TransCanada would otherwise be unable to meet its existing and projected firm service commitments in the Eastern Triangle absent the construction of any new gas facilities, such a potential scenario would not occur with the EMP, and thus in my view is not a public interest concern.
- TransCanada has committed to construct the EMP, which would encompass sufficient natural gas facilities in the Eastern Triangle to permit all of the Mainline's current and projected firm transportation service requirements to be met after the transfer of the Conversion Facilities and includes 50 TJ/d of Additional Capacity; the EMP was designed after TransCanada determined firm service requirements through Open Seasons, and based on a comprehensive forecast of future firm service levels.
- Based on the currently known firm service commitments by shippers on the Mainline, and all else being equal, there is projected to be a tolling benefit for Mainline shippers as a result of the transfer of the Conversion Facilities and construction of the EMP. There is projected to be an over $500 million reduction (on a net present value basis) in the Mainline revenue requirement over the 2018 to 2050 period as a result of the transfer of the Conversion Facilities and the construction of the EMP; the transfer, the repurposing of these assets as oil transportation facilities, and the construction of the EMP, represents the least cost means of meeting both gas and oil shippers' needs.

IV. *OVERALL PUBLIC INTEREST CONSIDERATION*

Q12. IS THE PUBLIC INTEREST AN IMPORTANT CONSIDERATION FOR THE BOARD IN ITS DETERMINATION OF WHETHER NEW FACILITIES SHOULD BE APPROVED, AND WHETHER AN APPLICANT'S PROPOSAL PRODUCES JUST AND REASONABLE TOLLS?

A12. Yes. The Board has stated that its purpose is to regulate in the Canadian public interest. Specifically:

> The NEB's purpose is to promote safety and security, environmental protection and efficient energy infrastructure and

> markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade.[2]

Q13. WHAT IS YOUR UNDERSTANDING OF THE BOARD'S DEFINITION OF THE PUBLIC INTEREST?

A13. It is my understanding that the Board has defined the Canadian public interest as:

> …inclusive of all Canadians and refers to a balance of economic, environmental and social interests that changes as society's values and preferences evolve over time. As a regulator, the Board must estimate the overall public good a project may create and its potential negative aspects, weigh its various impacts, and make a decision.[3]

In the past, a Chair of the Board has also stated:

> Although there is no precise definition of the public interest, it is clear that the public interest embodies the concept of "the greatest good for the greatest number".[4]

A Board Member recently highlighted the evolving nature of how public interest is defined:

> Each public interest decision is considered and weighed differently by independent panel members on the basis of diverse factors including economic feasibility of physical facilities, public consultations, Aboriginal matters, land matters, environmental and socio-economic matters, tolling and such other factors as the assigned panel considers relevant to the matter.[5]

In that same speech, two Board decisions were noted that demonstrated the "independence and wide range of considerations given by individual panels to arrive at a public interest determination." For example, in the Board's decision in GH-1-2006 in approving the Emera Brunswick Pipeline, the Board balanced

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[2] NEB website, "What is the NEB's Mandate?"; *see*, http://www.neb-one.gc.ca/clf-nsi/rthnb/whwrndrgvrnnc/nbfctsht-eng.html; accessed September 12, 2014.

[3] *See, e.g.*, NEB, Reasons for Decision, GH-1-2006, p. 10; NEB, Strategic Plan; NEB, "NEB Perspective on Economic Regulation," presented by Kenneth Bateman, June 5, 2011, p. 8.

[4] NEB, The Regulator's Role – Promoting the Public Interest, presented by Kenneth Vollman, May 24, 2000.

[5] NEB, NEB Perspective on Economic Regulation, presented by Kenneth Bateman, June 5, 2011, p. 9.

local, regional and national considerations in making its public interest determination. In OH-1-2009, the Board focused on economic impact of the proposed Keystone XL Pipeline project, finding that the project was in the public interest because the long-term benefits outweighed the burdens:

> There are typically both benefits and burdens associated with each application and the Board must apply its reasoned judgment, based upon a considered analysis of the evidence properly before it, to come to its final determination.
>
> …..
>
> In weighing the benefits and burdens for this Project, the Board has determined that the benefits of the Keystone XL Pipeline outweigh the burdens.[6]

For purposes of my evidence, and the determination as to whether, in my opinion, the Application is consistent with the public interest, I have relied upon the standard set forth by the Board in OH-1-2009 for my examination of the benefits and burdens of the Project in its entirety. While I understand that there are separate applications, and that the Board could attempt to address the benefits and burdens of each application separately, the interdependencies between the elements of the Project have led me to conclude that it is only by examining the public interest considerations of the Project as a whole that the Board can determine if any or all of its elements are in the public interest. Addressing these issues separately may not produce an optimal, feasible or consistent result. By undertaking a comprehensive examination of the public interest issues of the Project, the Board can evaluate the potential benefits and burdens of all elements of the Project in a consistent framework, and balance any competing interests in addressing whether the Project, taken as a whole, is in the public interest.

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[6] NEB, Reasons for Decision, OH-1-2009, pp. 78-79.

Q14. HAS THE BOARD IDENTIFIED A SPECIFIC SET OF CRITERIA THAT ARE APPLICABLE IN ALL CASES FOR PURPOSES OF EVALUATING THE PUBLIC INTEREST?

A14. No. The Board has been clear in its belief that a uniform set of criteria does not exist with which all projects can be evaluated to determine the public interest:

> …there are no firm criteria for determining the public interest that will be appropriate to every situation. Like "just and reasonable" and "public convenience and necessity", the criteria of public interest in any given situation are understood rather than defined and it may well not serve any purpose to attempt to define these terms too precisely. Instead, it must be left to the Board to weigh the benefits and burdens of the case in front of it.[7]

Therefore, while the Board has defined the public interest, it has also recognized that each project is different and therefore the Board must review the circumstances on a case by case basis.

Q15. IN THE CURRENT CIRCUMSTANCES, ENERGY EAST AND TRANSCANADA ARE SEEKING APPROVALS IN THE APPLICATION PURSUANT TO BOTH SECTION 52 AND SECTION 74 OF THE NEB ACT. HAS THE BOARD PREVIOUSLY LINKED ITS PUBLIC INTEREST FINDING IN A SECTION 74 APPLICATION TO ITS FINDING IN A SECTION 52 APPLICATION?

A15. Yes. In MH-1-2006, the Board approved the transfer of existing Mainline natural gas facilities to oil service for the TransCanada Keystone Pipeline GP Ltd. project ("Keystone Pipeline"), finding that doing so was in the public interest. However, the Board indicated that its public interest determination was conditional on a subsequent finding that the construction and operation of the proposed Keystone Pipeline was also in the public interest:

> The Board notes that this approval of the Transfer Application, including the rate base treatment, has no effect unless further regulatory approvals, including those required for the section 52

[7] NEB, Reasons for Decision, GH-1-2006, p. 10.

> and 21 applications by TransCanada Keystone Pipeline GP Ltd. are received.[8]

Considering that TransCanada and Energy East are seeking both Section 74 and Section 52 approvals in the Application, and are filing for approval of the Project in its entirety, it is my understanding that the public interest standard is the test that the Board would apply in evaluating the reasonableness of the Application – for the transfer of gas assets to oil service, the construction and operation of new oil facilities, and the construction and operation of new gas facilities – in these proceedings.

V. <u>FINANCIAL AND ECONOMIC FEASIBILITY OF THE ENERGY EAST PIPELINE</u>

A. Standards for Evaluating Financial and Economic Feasibility

Q16. HOW HAS THE BOARD TRADITIONALLY ASSESSED THE FINANCIAL AND ECONOMIC FEASIBILITY OF A PROPOSED PROJECT?

A16. Section 52 of the NEB Act states that when considering an application for a certificate:

> The Board shall have regard to all considerations that appear to it to be relevant, and may have regard to the following:
>
> (a) the availability of oil, gas or any other commodity to the pipeline;
> (b) the existence of markets, actual or potential;
> (c) the economic feasibility of the pipeline;
> (d) the financial responsibility and financial structure of the applicant, the methods of financing the pipeline and the extent to which Canadians will have an opportunity of participating in the financing, engineering and construction of the pipeline; and
> (e) any public interest that in the Board's opinion may be affected by the granting or the refusing of the application.

[8] *Id*., p. 59.

In practice, the Board's standard for determining if a project is economically feasible – criterion (c) above – has been the presentation of satisfactory evidence that criteria (a), (b) and (d) above have been met.

The Board has also commented expansively in past decisions on the criteria it uses when considering the economic feasibility of new pipeline projects. For example, in GH-1-2004, the Board stated:

> The National Energy Board takes the following criteria into consideration when considering economic feasibility for facilities built under the *National Energy Board Act*:
>
> - the availability of markets for the gas flowing on the pipeline (will the gas be purchased?);
> - the availability of downstream pipeline capacity (will there be sufficient pipeline capacity to move the gas from the end of the [Project] to ultimate markets?);[9]
> - the long-term gas supply which is available to the pipeline (is there sufficient gas to be transported?);
> - the contractual commitments underpinning the project (will the fixed cost component of the pipeline tolls be paid?); and
> - the ability of the project to be financed (will investors fund the pipeline?).[10]

In addition, in GH-3-97, the Board stated:

> …this assessment includes an evaluation of: (i) the availability of long-term gas supply, (ii) the long-term outlook for gas markets, (iii) the contractual commitments underpinning the proposal, and (iv) project financing.[11]

The Board's threshold criteria for economic feasibility are also reflected, in more abbreviated terms, in Guide A, Section A.3 of its Filing Manual, which states:

> The overall purpose for filing information on facility economics is to demonstrate that the applied-for facilities will be used, will be

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9 In addition to land delivery points at Montreal, Quebec City and Saint John, Canaport Energy East Marine Terminal will have capacity to load 2.3 million bpd.

10 NEB, Reasons for Decision, GH-1-2004, Volume 2, Chapter 7.

11 NEB, Reasons for Decision, GH-3-97, p. 12.

> useful, and that demand charges will be paid and that sufficient funds will be available for abandonment requirements.[12]

Q17. DO YOU MAKE A DISTINCTION BETWEEN FINANCIAL AND ECONOMIC FEASIBILITY?

A17. Yes. For purposes of my evaluation, I have distinguished between financial and economic feasibility. Specifically, I have used the term "financial feasibility" to refer to the commercial matters, focusing on the Board's criteria regarding the ability of a project to be financed and whether a project's fixed charges are likely to be paid. I use the term "economic feasibility" to mean the justification and need for a project within an industry context, centering on the Board's criterion that a project be used and useful. Specifically, economic feasibility is dependent on whether adequate supply exists, whether there is market demand for a project, and sufficient takeaway capacity at the end of the pipeline. Both financial and economic feasibility depend on the level of shipper support for a project.

Q18. ARE THERE OTHER STANDARDS USED BY THE BOARD TO EVALUATE THE FINANCIAL AND ECONOMIC FEASIBILITY OF A PROJECT?

A18. Yes. While not addressed in every proceeding, there are a number of other standards that the Board has applied in assessing the financial and economic feasibility of a proposed project. In terms of financial feasibility, the Board also has considered: (i) the reasonableness of risk apportionment in the project's commercial terms, and (ii) the competitiveness of a project, and its effect on the market. In certain cases, the Board has placed considerable weight on these factors.[13] With regard to economic feasibility, the Board also commonly evaluates whether a project has been sized correctly.

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[12] NEB Filing Manual, Guide A, Section A.3, p. 4A-62.

[13] For example, I am aware that in GH-5-89 the Board discussed the concept of economic feasibility as a standard it considers to evaluate a proposed pipeline project.

Accordingly, in my evidence herein, I have also addressed the Project in terms of each of these additional criteria.

B. Financial Feasibility of the Energy East Pipeline

Q19. IS THE TOLLING METHODOLOGY SET FORTH IN THE TSAs, WHICH ALSO INCLUDES THE TERMS AND CONDITIONS OF SERVICE, RELEVANT TO AN ASSESSMENT OF THE PROJECT'S FINANCIAL FEASIBILITY?

A19. Yes. While Energy East is not seeking Board approval of the specific tolls in this proceeding, it is seeking approval of the tolling methodology. The TSAs that Energy East and its shippers have executed, which include the tolling methodology and the terms and conditions of service, specifically relate to the financial feasibility of the Energy East Pipeline.

Q20. HOW DOES THE TOLLING METHODOLOGY SUPPORT THE FINANCIAL FEASIBILITY OF THE ENERGY EAST PIPELINE?

A20. As discussed, one criterion for financial feasibility is the ability of the fixed charges for the proposed project to be paid. The tolling methodology for the Energy East Pipeline has been designed so that an integrated, market-based set of tolls is applicable to all service, and the tolling framework will apply for 20 years, thus establishing predictable and stable tolls over the life of the TSAs. As described in Volume 3, Section 2 of the Consolidated Application~~ and as updated in Volume 1, Section 7 of the Application Amendment~~, committed shippers have agreed to pay fixed charges totaling approximately $42 billion over the terms of their contracts.[14]

Energy East was able to garner the support of financially strong and viable shippers as indicated by their ability to meet TransCanada's credit worthiness standards and requirements, and have committed to significant long-term firm

[14] Consolidated Application, Vol. 3, Section 2~~ and Application Amendment, Volume 1, Section 7~~.

service on the pipeline. This revenue, from shippers that have met TransCanada's credit worthiness standards, should be more than sufficient to pay the estimated fixed costs of the oil pipeline. In addition, the variable toll component will be set at a level each year that is designed to recover the operation and maintenance costs of the oil pipeline, as well as provide for the funding of an abandonment reserve fund in accordance with reasonable industry practice.

The proposed tolling methodology is consistent with the new market for oil pipeline services in that it offers firm transportation service under committed long-term contracts while still reserving capacity for spot service at a premium to the committed service, thus being responsive to shipper requests for long-term toll stability and predictability. Moreover, the negotiated tolling methodology for the Energy East Pipeline is similar to other negotiated tolling methodologies for new oil pipelines that the Board in the past has found to be just and reasonable and not unduly discriminatory. Thus, based on all of these factors, in my view, the proposed tolling methodology is reasonable, competitive and consistent with the Board's financial feasibility standard in terms of the likelihood of the fixed charges of the Energy East Pipeline to be paid going forward.

Q21. IN ADDITION TO THE SIGNED AGREEMENTS FOR FIRM SERVICE, ARE THERE REASONS TO BELIEVE THAT SPOT SERVICE WILL ALSO CONTRIBUTE TO THE FINANCIAL FEASIBILITY OF THE PROJECT?

A21. Yes. Because the Energy East Pipeline's financial feasibility is underpinned by long-term contracts with committed shippers, spot service is not necessary for financial feasibility. However, the availability of spot service also increases the potential benefits of the project. Energy East proposes to reserve 90,000 bpd for spot service. The toll for spot service will be a maximum of 170 percent of the shortest term toll offered to committed shippers for each route. Consequently, the possibility of increased revenues from uncommitted volumes that can also contribute to the fixed cost recovery associated with the pipeline further supports the financial feasibility.

Q22. YOU MENTIONED RISK APPORTIONMENT AS ANOTHER COMPONENT OF THE BOARD'S FINANCIAL FEASIBILITY EVALUATION. ARE THE COMMERCIAL TERMS AND CONDITIONS IN THE TSAs CONSISTENT WITH REASONABLE RISK APPORTIONMENT?

A22. Yes. The TSAs reflect a negotiated agreement between Energy East and the committed shippers that includes an agreement to share the risks if the pipeline costs exceed the pre-construction estimates. In addition, because Energy East will be charging a negotiated toll over the life of the TSAs, Energy East's firm shippers will not be at risk for any underutilization of the proposed facilities for the duration of these firm contracts. In its decision in GH-3-97, the Board stated that it considered a pipeline being "at-risk" to be a significant public interest consideration:

> In its application, Alliance declared itself to be "at-risk" with respect to any underutilization of the applied-for facilities… This fact addresses one potentially significant public interest consideration.[15]

I agree with the Board's assessment that risk apportionment is a significant public interest consideration, and in my view, the facts in this case represent a reasonable apportionment of the risk between Energy East and its shippers, both during the development phase, as well as throughout the term of its commercial operation. Limiting overall risk through the use of negotiated agreements, and by Energy East sharing the remaining risk from cost overruns is particularly responsive to the Board's consideration noted above. Energy East will retain and manage other risks like counterparty credit risk and unforeseen service interruptions. Consequently, I believe the risk apportionment of the commercial terms for the Energy East Pipeline are consistent with the public interest.

[15] NEB, Reasons for Decision, GH-3-97, p. 13.

Q23. THE ABILITY OF A PROJECT TO BE FINANCED WAS ANOTHER CRITERION OF THE BOARD FOR EVALUATING FINANCIAL FEASIBILITY. WHAT HAVE YOU CONCLUDED REGARDING WHETHER THE PROJECT IS LIKELY TO BE FINANCEABLE?

A23. As discussed in the Application, Energy East Pipeline's financing will be provided mostly by TransCanada. TransCanada expects to finance its current capital program through predictable cash flows generated from operations, new senior debt, as well as through subordinated capital in the form of additional preferred shares and hybrid securities, the issuance of common shares and portfolio management, which includes an intended dropdown of all of its U.S. natural gas pipeline assets into its master limited partnership, TC PipeLines LP.[16] Moreover, based on the strength of the long-term TSAs executed by credit-worthy shippers, it is my opinion that the Energy East Pipeline would be likely to obtain outside financing on a stand-alone basis if it were not being financed by TransCanada. Based on my understanding of the project's economics, risk apportionment and the level of shipper support, I have concluded that the pipeline will be able to secure capital on reasonable terms, which is consistent with it being financially feasible.

C. Economic Feasibility of the Energy East Pipeline

Q24. AS PREVIOUSLY DISCUSSED, THE BOARD HAS CONSIDERED AVAILABILITY OF SUPPLY, MARKET DEMAND, PROJECT SIZING AND THE EXISTENCE OF SUFFICIENT TAKE-AWAY CAPACITY IN EVALUATING ECONOMIC FEASIBILITY, CORRECT?

A24. Yes.

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[16] Consolidated Application, Volume 3, Commercial, Section 4, Financing.

Q25. WILL THE PIPELINE HAVE ACCESS TO LONG-TERM CRUDE OIL SUPPLY?

A25. Yes. As discussed in the Updated IHS Report, crude oil production in western Canada is projected to grow from 3.7 MMb/d in 2014 to 5.9 MMb/d in 2030. The majority of this supply growth comes from oil sands, with most growth provided by heavy crude oil. Therefore, even if all four of the currently proposed major new crude oil pipelines[17] are in fact built, the market can fully absorb the new pipeline capacity over time through production growth.

Q26. IN YOUR VIEW, DO THE TSAs THAT ENERGY EAST HAS EXECUTED DEMONSTRATE A MARKET DEMAND FOR THE ENERGY EAST PIPELINE?

A26. Yes. In my opinion, the executed TSAs, which are long-term contractual commitments for 995,000 bpd underpinning the Energy East Pipeline, clearly demonstrate that there is market demand and a need for oil pipeline capacity from western Canada. This is consistent with the Board's findings in OH-1-95:

> The Board considers the existence of long-term transportation service agreements to be strong evidence of the need for the Express Pipeline. The fact that market participants have made financial commitments to Express provides the Board with comfort that the Express Pipeline will access profitable markets for western Canadian crude oil producers and that the pipeline will be used and useful.[18]

Moreover, considering the large, long-term contractual commitments of the shippers on the Energy East Pipeline, the pipeline can reasonably be expected to be utilized at a high load factor.[19] For example, assuming a shipper with a negotiated firm take-or-pay commitment of 50,000 bpd for 20 years at a negotiated toll of $8.00/barrel, this would result in a financial obligation over the

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17 These four crude oil pipeline projects are: the Trans Mountain Expansion, Northern Gateway, Keystone XL, and Energy East.

18 NEB, Reasons for Decision, OH-1-95, p. 46.

19 A high load factor pipeline is a pipeline that is used at a high rate on a relatively constant basis.

term of the contract of approximately $2.9 billion dollars for that shipper.[20] It can reasonably be assumed that such a large, long-term financial commitment by a shipper is not going to be made lightly or without a plan to transport oil.

As noted by the Board in GH-3-97, such large financial commitments are consistent with both demonstrating adequate supplies and market demand:

> The Board is also of the view that the financial commitments that shippers have made to pay $8.2 billion in demand charges on the Alliance system over the first 15 years of operation provides a powerful incentive for shippers to acquire adequate gas supplies. These companies, backed by their lenders, have made expert determinations that they will have access to adequate gas supplies in order to utilize their capacity entitlements on the Alliance Project.
>
> .....
>
> The financial commitments of the Alliance shippers to the Project provide strong evidence that the market will be adequate. The Board recognizes the shippers' business expertise and their confidence that the market opportunities merit the investments to which they have committed.[21]

These same conclusions for Energy East can reasonably be drawn from the facts presented in the Application, including the fact that, as noted previously, Energy East’s firm shippers have committed to pay approximately $42 billion in demand charges over the initial 20 year term of the TSAs. The firm shipper commitments represent large financial obligations and provide a strong incentive for shippers to utilize the Energy East Pipeline at a very high load factor.

Q27. HAS THE CAPACITY ON THE ENERGY EAST PIPELINE BEEN EFFICIENTLY ALLOCATED?

A27. Yes. Pursuant to the open, transparent and non-discriminatory open season process, capacity has been awarded to shippers that value it the most, which is consistent with allocative efficiency, *i.e.*, assigning resources to those that most

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[20] $8.00/bbl x 50,000 bbls x 365 days x 20 years = $2.92 Billion.

[21] NEB, Reasons for Decision, GH-3-97, pp. 19, 26.

value those resources. Thus, the capacity rights on the pipeline have been allocated to those shippers in an economically efficient manner. In addition, shippers also will be able to trade their rights on a short or longer-term basis in an informal secondary market. This, along with the spot service that Energy East will offer, will ensure that capacity is allocated to shippers who most highly value it on an ongoing basis during the lifetime of the pipeline.[22]

Q28. DO YOU BELIEVE THAT THE OPEN SEASON PROCESS WAS REASONABLE?

A28. Yes. Energy East provided two transparent, fair and balanced open season processes for shippers, giving them sufficient time and information to make an informed decision, and an equal opportunity to participate. Leading up to the first open season process, Energy East consulted and negotiated with potential shippers to establish the agreed upon tolls. In addition, a second open season process was conducted in July, 2014 and an additional 90,000 bpd were contracted. The successful result of the open season processes, resulting in an increase in the initial capacity of the pipeline from 525,000 bpd to 1,100,000 bpd demonstrates that the process was reasonable.[23]

Q29. IN ADDITION TO RESPONDING TO MARKET DEMAND, WILL THE ENERGY EAST PIPELINE ALSO ENHANCE MARKET DIVERSIFICATION FOR CANADIAN OIL PRODUCERS?

A29. Yes. The Energy East Pipeline will provide additional needed transportation capacity to deliver growing oil production in western Canada to eastern Canadian and eastern U.S. markets, since both markets depend on expensive crude oil imported from foreign markets. In addition, Canadian oil currently is exported almost exclusively to U.S. markets. With U.S. oil production increasing, developing overseas markets for Canadian oil is vital to ensuring that Canadian

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22 Consolidated Application, Volume 3, Commercial, Section 2, Transportation Terms and Tolls~~ and Application Amendment, Volume 1, Section 7~~.

23 *Id*, p 2-2.

oil producers will receive full value for their production and, in turn, ensures that Canadians will receive maximum benefits from the development and sale of these natural resources. The pipeline provides oil producers with the opportunity to market their products to overseas markets, and at the same time, provides a price lift for all Canadian oil producers with the creation of a new and higher-value outlet for Canadian oil. With the ability to sell Canadian oil to offshore markets via the Atlantic Ocean, shippers have the opportunity to reach the most attractive markets through firm and spot service that is competitively and predictably priced. As is true for virtually all commodity markets, the elimination of binding constraints (which can be logistical, contractual, and financial) on the ability of products to reach the highest value markets produces economic gains for producers, eliminates price distortions that can otherwise lead to inefficient use of the commodity, and helps promote economically efficient investment decisions for producers and consumers.

Q30. IS THE SIZING OF THE ENERGY EAST PIPELINE CONSISTENT WITH THE BOARD'S ECONOMIC FEASIBILITY STANDARDS?

A30. Yes. As discussed, a consideration of the Board has been the appropriate sizing of proposed facilities, such that productive efficiency is promoted, *i.e.*, ensuring that the total cost of meeting the market demand is minimized, which includes ensuring that new capacity is not added when the market will not support the total cost of such capacity. As noted, the pipeline has been sized to meet the firm contractual demand of 995,000 bpd, plus a reasonable amount of uncommitted spot service (90,000 bpd). Through its original open season process, 905,000 bpd were contracted and in 2015 an additional 90,000 bpd were contracted. More than 90 percent of Energy East Pipeline's firm capacity is subscribed at this time, and as discussed, Energy East is at-risk for the unsubscribed capacity, meaning shippers will not be liable for any unsubscribed capacity. In addition, the TSAs, which provide effective and equitable risk sharing for construction cost changes, and the fixed toll structure, which provides a strong incentive to manage costs after commercial operation is achieved, both are consistent with the promotion of productive efficiency.

Accordingly, the need for and sizing of the pipeline is appropriate for the demand and market for new oil transportation services, and clearly promote productive efficiency, which the Board has also recognized as a goal of effective regulation.

Q31. IN ASSESSING A PROPOSED PROJECT'S FINANCIAL AND ECONOMIC FEASIBILITY, IS IT THE BOARD'S PRACTICE TO CONSIDER OTHER COMPETING PROJECTS?

A31. Yes, in the sense that the Board often examines whether a proposed project is developed in a manner that is consistent with competitive market principles. However, while the Board sometimes considers the competitive framework in which a project is being proposed, it does not typically assess or consider the relative merits of competing projects. In OH-1-2007, the Board stated:

> It was suggested by the CEP in final argument that the Board should consider the public interest broadly enough to review this application in comparison or conjunction with other proposed projects. The Board does not however have a practice of hearing facilities applications on a comparative basis and has, in the case of *Sable*, determined that it is not under a statutory obligation to hold comparative hearings.[24]

In other words, the Board does not have a practice of picking winners and losers. In assessing a project's financial and economic feasibility, the Board evaluates the effect that a project would have on market competition and intervenes only in instances where competitive market forces may be unable to be effective. When no unreasonable adverse effect on competition is anticipated, it has been the Board's view that the market should decide if the project is eventually built. The Board has reiterated this position on a number of occasions in past decisions. For example, in OH-1-2009, the Board stated:

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[24] NEB, Reasons for Decision, OH-1-2007, p. 14.

> In general, the public interest is served by allowing competitive forces to work, except where there are costs that outweigh the benefits.[25]

In addition, the Board concluded in GH-1-2004 that, "[o]ur approval gives Mackenzie gas an opportunity to compete. Denial would block that opportunity indefinitely."[26]

The Energy East Pipeline is one of a group of pipelines that is being proposed to meet the market's need for additional pipeline capacity. However, the financial and economic feasibility of the Energy East Pipeline does not depend on the success or failure of any of those other projects, and the Board's past standards do not suggest that a comparison of the Energy East Pipeline to those other projects is appropriate. It is my understanding that Energy East, and its shippers, are fully prepared to proceed once the Board has made the appropriate recommendation to the Governor in Council, and the requisite approvals are issued, without regard to whether other projects move forward or not.

Q32. IN YOUR OPINION, WILL THE ENERGY EAST PIPELINE BE CONSISTENT WITH THE COMPETITIVE CONTEXT OF THE MARKET?

A32. Yes. The Energy East Pipeline is fully consistent with the promotion of an efficient and competitive oil transportation market. As noted by the Board in past decisions, the public interest is best served by allowing competitive forces to work. The Energy East Pipeline will promote competition by giving shippers enhanced options for marketing their products, providing broader market access by allowing shippers the ability to access not only the North American market, but also overseas markets. As noted by the Board in the Keystone XL Pipeline decision:

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[25] NEB, Reasons for Decision, OH-1-2009, p. 32.

[26] NEB, Reasons for Decision, Volume 2, Chapter 7, GH-1-2004.

> Moreover, the Board is of the view that all western Canadian producers are likely to benefit from the Keystone XL Pipeline over the longer term, through broader market access, greater customer choice and efficiencies gained through competition among pipelines.[27]

The Energy East Pipeline will provide these same benefits to the market by creating new capacity for oil market participants and enabling a greater level of competition among pipelines for uncommitted production.

Based on the analysis discussed in the Updated IHS Report, there is a potential for some level of underutilization of the region's aggregate pipeline capacity during the 2021-2033 period if all of the currently proposed crude oil pipeline projects proceed as planned. However, that does not indicate that the Energy East Pipeline, or any of the other proposed projects, are not economically feasible.

Q33. WHY IS THE RISK OF UNDERUTILIZED PIPELINE CAPACITY NOT A CONCERN OR AN INDICATION THAT ONE OR MORE OF THE PROPOSED PIPELINES IS NOT NEEDED?

A33. Shippers want access to multiple markets and see a benefit in the flexibility of being able to go to a market that offers the highest netback at any point in time, especially when market dynamics are unpredictable. As discussed, shippers have made very large financial commitments to transport oil on the pipeline because they require long-term, assured pipeline transportation to refineries and maritime markets that can be accessed through docks in eastern Canada.

In addition, the balance between supply and take-away pipeline capacity shown in the Updated IHS Report indicates that crude oil supply is expected to grow to meet the full take-away capacity that is built, such that even if all proposed pipeline projects proceed as planned, the new capacity will be fully absorbed by 2033. Even in the case in which all of the proposed oil pipelines were to be

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[27] NEB, Reasons for Decision, OH-1-2009, p. 33.

constructed, in the intervening 15 years or so, the new capacity provided by these pipelines will promote market competition and higher netbacks to producers and will provide producers with the opportunity to develop new supply areas confidently. In addition, the Updated IHS Report, which assumes that all four of the large crude oil pipeline projects currently in development come on-line by 2021, is not an actual forecast of pipeline capacity; rather, it is a simplifying assumption made by IHS in order to estimate the netback benefits of the Energy East Pipeline. If other projects do not go forward, the need for the Energy East Pipeline will be even greater.

Having sufficient pipeline capacity is a very important issue. As seen in the market from 2011 to early 2013, insufficient pipeline capacity has resulted in severe price discounting for Western Canadian crude supplies. Inadequate pipeline access for Alberta producers led to large price discounts for Canadian crude, which, in aggregate, reduced producer revenues by between US$14 billion and US$19 billion in 2013. In 2014, IHS estimated total reduced producer revenues of US$3 to US$9 billion. Those foregone producer revenues should be compared against the much lower costs to shippers of holding some excess capacity.

Given that highly asymmetrical cost/benefit relationship, shippers can be seen as making a rational economic decision by committing to Energy East and other projects on an unconditional basis, even if some temporary excess capacity may result if all projects are developed as planned and on schedule. In addition, it is my opinion that the public interest considerations should take into account a new dynamic in oil markets. The need for new pipeline facilities is not simply the difference between projected supply and current take-away capacity. The market also needs: (i) flexibility; (ii) diversity of market access; (iii) the ability to manage risk associated with competing in multiple markets; and (iv) the ability to manage development and operational risk.

Q34. PLEASE EXPLAIN HOW THESE ADDITIONAL ISSUES CONTRIBUTE TO THE NEED FOR NEW OIL PIPELINE CAPACITY.

A34. As discussed in the Updated IHS Report, Canadian crude production has historically relied on refining markets in Canada, the U.S. Midwest and the Pacific Northwest, which have been accessed by a relatively small number of pipelines with dedicated markets. However, the significant expansion of Western Canadian crude production, combined with the increase in U.S. crude production and relatively stable refining demand, has led to a new market structure in which producers have sought access to an expanded set of market options for their production, and to transportation infrastructure that can access those markets. In order to accommodate these demands for greater market access, the Canadian oil pipeline network needs to be reconfigured to go beyond its traditional role of providing crude supply to refineries in the interior of the continent, and also provide greater access to Eastern Canada and the U.S. East Coast that currently depend on expensive crude oil imported from foreign markets.

The development of a more diversified "portfolio" approach to marketing also reflects the fact that different markets offer significantly different netbacks to producers, and that the relative attractiveness of markets can change quickly as supply and demand fundamentals shift. A portfolio approach to marketing requires that the transportation infrastructure be able to accommodate shifts in market preferences, which in turn creates value through having the option and ability to redirect flows as markets change. The willingness of shippers to commit to take-or-pay fixed charges for pipeline capacity to multiple markets makes economic sense when viewed in this context, and providing that optionality enables Canadian producers and resource owners to maximize the value they derive from oil production. Shippers also recognize that there are risks that some projects may not be developed as planned or on schedule, and that even after commercial operation is achieved, some amount of capacity may not be fully available at all times. Overall, oil transportation costs are small in comparison to the value of the product that is being shipped.

All of these facts contribute to the demand for additional oil pipeline capacity and justify the economics of holding and paying for capacity that may not be used every day of the year. Accordingly, in my view, the Energy East Pipeline is consistent with the new market dynamics regarding the need for pipeline transportation optionality and flexibility, and will not result in an unreasonable degree of underutilization on existing or new oil pipeline assets.

Q35. DOES THE BOARD ALSO CONSIDER BOTH THE CURRENT AND FUTURE REQUIREMENTS FOR TRANSPORTATION SERVICE WHEN EVALUATING A PROJECT?

A35. Yes. In its decision regarding Keystone XL in OH-1-2009, the Board was clear that in the development of pipelines, both current and future requirements for transportation service must be taken into consideration.

> The Board is of the view, however, that prudent design must consider both the current and future requirements for transportation service over the life of a Project to achieve the objective of efficiency. The Board is satisfied that the Keystone XL Pipeline, as proposed, reflects a reasonable balance of both the current and anticipated requirements of shippers over the longer term, given the supply potential of the WCSB and the size of the USGC market.[28]

These views are also relevant to the Board's evaluation of the current set of proposed oil pipelines, including Energy East. Some level of optionality in capacity markets promotes economic efficiency, reflects the likelihood of future additional demand and does not detract from the economic feasibility of the pipeline. In circumstances where shippers have demonstrated their willingness to pay for this optionality over the long term, it is consistent with the public interest to permit pipeline developers to build to meet current and future requirements, and to allow some measure of optionality or inter-market swing capacity.

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[28] NEB, Reasons for Decision, OH-1-2009, p. 18.

D. Projected Economic Benefits of the Energy East Pipeline

Q36. IS THE ENERGY EAST PIPELINE PROJECTED TO PRODUCE SUBSTANTIAL ECONOMIC BENEFITS FOR CANADA?

A36. Yes. Based on the studies that have been conducted, there are projected to be substantial and broad macroeconomic and energy industry benefits for Canada as a whole, as well as for oil producers in the WCSB in particular. Specifically, according to the Updated Conference Board Report and Nichols Report, the Energy East Pipeline and EMP would provide substantial macroeconomic benefits at the federal and provincial levels totaling over $136 billion,[29] including:

- An estimated 168,711 full-time equivalent ("FTE") person-years of employment during the development phase with Ontario, Quebec and New Brunswick capturing approximately 77 percent of those employment benefits, and another 91,984 FTE person-years of employment during the first 20 years of operation with Ontario, Quebec and the Prairies (defined as Alberta, Saskatchewan and Manitoba) receiving 89 percent of the benefit;[30]
- $55.5 billion in total estimated GDP effects in Canada between 2013 and 2040;
- $10.3 billion in incremental government revenues from the construction and operation of the Energy East Pipeline over the first 25 years of operation;
- $70.6 billion in income taxes and royalty payments at the federal and provincial level as a result of higher netbacks to oil producers; and
- $48.3 million annually in incremental property tax revenue of in Alberta, Manitoba, New Brunswick, Ontario, Quebec and Saskatchewan, collectively. [31]

The Updated IHS Report notes that the Energy East Pipeline will allow Western Canadian heavy crude oil to compete with Mexican and South American heavy

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[29] All of the benefits discussed as quantified by the Conference Board Report are in 2013 dollars.

[30] Energy East Pipeline Project: Understanding the Economic Benefits for Canada and its Regions, the Conference Board of Canada, Table 1.

[31] The incremental property tax revenue estimate has not been updated since the original Application. That information was not available at the time this Evidence was prepared; however, given the small size of this component of the total federal and provincial benefits, it is unlikely that an update would even have a rounding effect on the total benefits.

crude supplies that currently supply heavy crude refineries in the U.S. Gulf Coast.[32]

Q37. IS THE ENERGY EAST PIPELINE PROJECTED TO ALSO PROVIDE BENEFITS TO CANADIAN OIL PRODUCERS AND OTHER MARKET PARTICIPANTS THAT ARE NOT FIRM SHIPPERS ON THE PROPOSED PIPELINE?

A37. Yes. Oil is actively traded in large, highly liquid multinational markets in which arbitrage opportunities are quickly exploited such that "the law of one price" prevails. In such markets, prices are established by the economics of the marginal supplier and the marginal consumer. Infrastructure developments, which improve the efficiency of the market or economically remove constraints, serve to increase the total economic welfare of all participants. By providing greater access for Canadian producers to a large, valuable market that is not easily accessible with the current infrastructure, the Energy East Pipeline would allow the entire Canadian producer community to profit from higher prices. In this market, relieving delivery constraints to a higher-value market is functionally equivalent to a sudden rise in demand from a large new market, lifting prices for producers that would otherwise be constrained in reaching the higher-value market.

Specifically, the Updated IHS Report concludes that development of the Energy East Pipeline, along with other planned major crude oil pipelines, will result in higher oil prices for the market as a whole as compared to a Reference scenario in which these projects are not built. Based on its 2015 Supply Outlook, IHS estimates that total producer revenue benefits attributable to all the planned major pipelines can be expected to be C$663 billion (US$590 billion)[33] through 2040. The estimated benefits attributable to the market access provided by Energy East equates to approximately C$161 billion to C$217 billion (US$142 billion to

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[32] Supply and Market Study for Energy East Project, IHS, Appendix D – Possible Markets from Energy East, September 2015.

[33] In constant 2014 dollar terms.

US$193 billion). If only Energy East is constructed, netback benefits of C$204 billion (US$183 billion) would be attributable to the Project.

In addition, the Energy East Pipeline is expected to produce benefits for refiners in New Brunswick by reducing their cost of accessing crude, including the substitution of pipeline transport of crude for rail transport, which IHS has reported is expected to represent a $9.00 per barrel savings. These lower feedstock costs should enable Eastern Canadian refineries to reduce their dependence on foreign crude sources, and improve the competitiveness of these refineries, enhancing their long-term economic viability.

Q38. WILL THE ENERGY EAST PIPELINE ALSO ENHANCE THE QUALITY AND VALUE OF SERVICE TO OIL SHIPPERS?

A38. Yes. With the Energy East Pipeline, committed shippers will be able to gain firm access to capacity for 20 years and the option to renew their contracts for an additional term. In addition, shippers will have access to the 90,000 bpd reserved for spot capacity. The Energy East Pipeline will facilitate shippers' ability to arrange long-term business with confidence since, under the terms of the contracts, shippers will have stable and predictable tolls for 20 years. As a result, the Energy East Pipeline will enhance the capacity, quality and reliability of transportation service options available to the market.

VI. Transfer of Assets – Conversion of Gas to Oil Service

Q39. PLEASE DESCRIBE THE CONVERSION FACILITIES, *i.e.*, THOSE FACILITIES TO BE TRANSFERRED TO ENERGY EAST AND CONVERTED FROM GAS TO OIL SERVICE.

A39. As described in Volume 2, Section 1 of the Consolidated Application~~ and in Volume 1, Section 4 of the Application Amendment~~, for purposes of the proposed transfer transaction, there are three design areas: the Prairies, the Northern

Ontario Line, and the Eastern Triangle, each with a set of assets that will be transferred from gas service to oil service. Specifically:

- Prairies Line: 940 km of Line 100-4, which is comprised of 1,067 mm pipe (NPS 42) between MLV 2 near Burstall, Saskatchewan and Station 41 near Ile des Chenes, Manitoba;
- Northern Ontario Line: 1,640 km of Line 100-4 (NPS 42) and portions of Line 100-3 (NPS 42) between Station 41 near Ile des Chenes, Manitoba and Station 116 near North Bay Junction, Ontario; and
- Eastern Triangle: 420 km of Line 1200-2, which is the 1,067 mm pipe (NPS 42) that is part of the North Bay Short Cut from North Bay Junction to Iroquois Junction in Ontario.

Q40. WHAT ARE THE FACTORS THAT THE BOARD CONSIDERS IN DETERMINING THE REASONABLENESS OF AN APPLICATION TO TRANSFER FACILITIES?

A40. Section 74 of the NEB Act governs the transfer of pipeline assets. The Board has stated that the regulatory standard applicable to any application to transfer facilities is the public interest. The Board must consider all factors that are relevant to the public interest, including but not limited to, the interests of gas and oil shippers, producers and consumers. In MH-1-2006, the Board stated:

> The Board is of the view that Parliament has provided it with explicit guidance in the Act as to the test it should apply to requests for relief under section 74. Part 1 of the NEB Act establishes the Board and sets out the Board's powers. The Board is of the view that section 12, when considered in accordance with principles of legislative interpretation suggested by Driedger and the Supreme Court, requires the Board to assess the Transfer Application on the basis of the public interest. To achieve this mandate, *it is therefore necessary for the Board to consider matters beyond adverse results to gas pipeline shippers*.[34]

Within the Filing Manual, Guide R relates to transfer of Ownership, Lease or Amalgamation pursuant to Section 74:

[34] NEB, Reasons for Decision, MH-1-2006, pp. 15-16; emphasis added.

> When the pipeline is already regulated by the Board an Order or a Certificate of Public Convenience and Necessity would have been issued once the Board had determined that the facilities:
>
> - Would be constructed and operated in a safe and an environmentally sound manner, and
> - Were required for the present and future public convenience and necessity.
>
> As a result, when a transaction involving the sale, conveyance, lease, purchase or amalgamation of an NEB-regulated pipeline is to occur, the Board needs assurance that, notwithstanding any changes in operation or configuration that are expected to occur, it would continue to be in the public interest to operate the facilities.

Although the public interest standard has been previously challenged as the appropriate test for evaluating a transfer of pipeline assets, the Board has explicitly rejected the notion that a transfer should be approved only if it could be shown that there is no harm to gas shippers:

> Furthermore, adopting the proposed no harm test would be contrary to the long list of Board and Court authorities that have decided that the Board has wide discretion to determine what is relevant to the exercise of its mandate. If the Board adopted the narrow interpretation urged by the parties in favour of the no harm test, it would oblige the Board to automatically favour the interests of shippers, excluding other persons and other public interest factors, thus sterilizing the broader mandate granted the NEB by Parliament. While gas shippers' interests are very important in this case, it is not the only factor that the Board must consider. The Board is charged with considering all of the factors that are relevant to the public interest, in each case.[35]

Q41. HOW HAVE YOU EVALUATED THE PUBLIC INTEREST ASSOCIATED WITH THE PROPOSED ASSET TRANSFER OF THE CONVERSION FACILITIES?

A41. The ultimate determination required is whether the public interest is better served if the Conversion Facilities are used in oil or gas service. This determination requires an assessment of the effect of the transfer of Conversion Facilities on the

[35] NEB, Reasons for Decision, MH-1-2006, pp. 15-16.

quality and cost of meeting demand for oil service, and the effect on the quality and cost of meeting demand for gas service. The impact on the quality and cost of meeting the demand for gas service is also very much affected by TransCanada's proposal for new replacement gas facilities that will enable the Mainline to continue to meet all of its existing and reasonably foreseeable firm service obligations. As previously stated, I have concluded that the public interest issues associated with the proposed conversion can only be fully evaluated if they are considered as part of the broader evaluation of the public interest issues associated with the entire Project. In essence, this evaluation asks and answers the question of whether the transfer puts the Conversion Facilities to a higher and better use and that the benefits of the transfer outweigh the burdens of doing so. In this instance, the question as to whether this represents a higher and better use involves a consideration of economic, environmental, social, political and other factors, and rests on a determination as to whether the net effects of the transfer promote the public interest or are detrimental to it.

A. Quality of Firm Service

Q42. WHAT ARE THE ECONOMIC ASPECTS OF THE PUBLIC INTEREST RELATED TO THE QUALITY OF GAS SERVICE THAT ARISE FROM THE TRANSFER OF CONVERSION FACILITIES TO ENERGY EAST?

A42. The primary concern with respect to the quality of natural gas service is that the firm service that has been contracted by shippers is maintained at all times after the transfer of the Conversion Facilities. With respect to gas service, there may be public interest detriments if the quality of existing and anticipated firm natural gas service is eroded post-transfer.

Q43. HAS THE BOARD PREVIOUSLY DEFINED A STANDARD FOR ASSESSING THE ADEQUACY OF PIPELINE CAPACITY RELATIVE TO A TRANSFER OF ASSETS?

A43. Yes. In the MH-1-2006 decision, the Board defined the standard for assessing whether there is adequate pipeline capacity as follows:

> The Board is of the view that the relevant consideration for determining adequate capacity for the Mainline is the pipeline's *__ability to meet anticipated requests for firm service__*.[36]

In that same decision, in discussing the public interest standard that it applies to transfer applications, the Board concluded that, "[g]as shippers are only entitled to service for which they have contracted; they are not entitled to specific facilities."[37] In addition, the Board also concluded that it would be wasteful and an inefficient use of resources to require that pipeline capacity be retained for peak requirements for which shippers had declined to contract, and that it would be in the public interest to provide a productive alternative use of underutilized assets.[38]

Interruptible service on the Mainline arises from the availability of pipeline capacity not used in firm service. Capacity also could become available from time to time as a result of ambient temperatures or from the nature of establishing the design capacity, which is based upon the loss of a critical unit. Interruptible service, which is characterized as a discretionary service on the Mainline, is exactly that – discretionary – meaning that its availability, and thus quality, can and does vary with the utilization of firm capacity. Thus, interruptible service has no minimum quality of service, but rather is available only from time to time depending on the level and utilization of firm contracting on the Mainline relative to the capacity available on a particular path.

[36] NEB, Reasons for Decision, MH-1-2006, p. 48; emphasis added.

[37] *Id*., p. 55.

[38] *Id*., pp. 51, 55, 58.

Q44. IF THE CONVERSION FACILITIES ARE TRANSFERRED TO ENERGY EAST, WILL EXISTING OR ANTICIPATED FIRM SERVICE ON THE MAINLINE BE DEGRADED OR ERODED?

A44. No. TransCanada has taken a number of reasonable steps to ensure that firm service on the Mainline will not be degraded or eroded if the Conversion Facilities are transferred to Energy East to be used in oil service. These steps include conducting open seasons for firm service on the Mainline, conducting a forecast of future Mainline requirements, and proposing the construction of additional new Mainline facilities in the Eastern Triangle so that all current firm commitments are able to continue to be met post-transfer plus 50 TJ/d of Additional Capacity. In addition, the facilities in the Eastern Triangle will continue to be expandable through reasonable compression additions and further looping to accommodate future requests for firm service.

Q45. DO YOU AGREE THAT THE TERMS OF THE AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION, INC., UNION GAS LIMITED, GAZ METRO LIMITED PARTNERSHIP AND TRANSCANADA (THE LDC ENERGY EAST AGREEMENT)[39] AS EXPLAINED IN VOLUME 1, SECTION 4.4 OF THE APPLICATION AMENDMENT IS IMPORTANT TO THE SUCCESS OF THE PROJECT?

A45. Yes. As noted, the LDC Energy East Agreement is a result of several years of negotiations and represents a balance of interests and compromises. The LDC Energy East Agreement provides benefits for all Eastern Triangle shippers and for Western Mainline shippers in that the Project is more likely to be realized as a result of reducing or eliminating opposition to the Project.

[39] The LDC Energy East Agreement was signed by the parties on October 30, 2015 and filed with the Board on November 5, 2015.

Q46. PLEASE DESCRIBE THE MAINLINE OPEN SEASON THAT TRANSCANADA CONDUCTED TO ASSESS THE DEMAND FROM GAS SHIPPERS FOR PIPELINE CAPACITY.

A46. As discussed in Volume 2, Section 4 of the Consolidated Application~~ and updated in Volume 1, Section 5.4 of the Application Amendment~~, TransCanada conducted an open season, which closed in January 2014 for service starting November 2016 ("2016 NCOS"), to offer gas shippers the opportunity to sign firm transportation contracts on the Mainline for incremental firm service requirements, or for shippers that wished to "firm up" short-term firm or interruptible service that they had been using. An additional open season was conducted and closed in January, 2015 for service beginning November 1, 2017 ("2017 NCOS").

Further, as also described in Volume 2, Section 4 of the Consolidated Application ~~and updated in Volume 1, Section 5.4 of the Application Amendment~~, in order to determine the appropriate amount of capacity required to meet existing firm service requirements and accommodate new firm service requests, TransCanada held two Capacity Management Open Seasons, which provided shippers an opportunity to reduce contractual commitments that would contribute to the need for new facilities. TransCanada sought the turnback of firm transportation service that might aid in reducing or eliminating the incremental facilities required as a result of the 2016 NCOS and 2017 NCOS. TransCanada also invoked the Term-up Provision in relation to EMP in early 2015, resulting in a small decrease to the firm service requirements.

In my opinion, the 2016 NCOS, the 2017 NCOS and the and the Capacity Management Open Seasons were appropriate processes by which TransCanada was able to offer its capacity to all interested parties on a non-discriminatory, open-access basis, and by which TransCanada was able to reasonably determine what facilities were needed to meet its existing and new firm service commitments.

Q47. HAVE CHANGES IN NORTH AMERICAN GAS MARKETS IMPACTED SHIPPERS' SOURCE OF SUPPLY AND CONTRACTING OF THE MAINLINE?

A47. Yes. Over the past few years, North American gas markets have changed significantly due to the increased availability of shale gas in the United States. Very large new supply sources such as the Marcellus Shale and Utica Shale have caused major structural changes in the North American market in general, and changes on the Mainline in particular. In fact, the rapid, unexpected growth in shale gas production in the Utica and Marcellus basins of the U.S., which are situated very close to TransCanada's domestic and export markets on the eastern portion of its system, has fundamentally disrupted many gas markets traditionally served by the Mainline.

Specifically, as the production of shale gas has substantially increased in the past few years, natural gas prices have declined from levels experienced when supply was not as abundant. While lower gas prices have tended to reduce exploration and development activity in traditional basins, and increase demand, supply has continued to increase nonetheless. This increased availability of U.S. shale gas close to consuming markets has caused a reduction in demand for WCSB supply, which in turn has contributed to a reduction in long-haul contracting on TransCanada's Mainline. Further, the location of new supply has altered the historical pattern of pipeline flows. TransCanada explains the effects of new supply on the Eastern Triangle as follows:

- Rapid growth of new gas supply sources in the Marcellus and Utica shale plays in the US northeast adjacent to the Eastern Triangle has reduced, and will continue to reduce, the export demand requirements from the Eastern Triangle.
- Expected new pipeline infrastructure within the northeastern US region, is forecast to reduce the quantity of natural gas supplied to the markets in this region via TransCanada's Iroquois export point. These changes are expected to cause the Iroquois point to reverse flow such that natural gas is imported into Canada.

- The continuation of these trends will obviate the need for additional firm transportation capacity in the Affected Area beyond what will be added by the Eastern Mainline Project.
- TransCanada's Eastern Mainline Project will not only meet the near and medium term market demand, it will facilitate increased gas imports into the Eastern Triangle along the most direct path, thereby enhancing regional security of supply over the long term.[40]

Q48. DO YOU BELIEVE THAT THESE STRUCTURAL CHANGES IN THE NORTH AMERICAN GAS MARKET AFFECT THE ECONOMIC ASPECTS OF THE PUBLIC INTEREST ASSOCIATED WITH THE CONVERSION FACILITIES BEING TRANSFERRED TO OIL SERVICE?

A48. Yes. In my view, these structural changes that have transformed the North American gas market, significantly affect the economic aspects of the public interest associated with the Conversion Facilities being transferred to oil service. The Board has specifically recognized that changes in the North American gas market have been affecting the economic viability of the Mainline. In its RH-03-2011 decision, the Board stated:

> Changes in the business environment of natural gas supply, markets and contracting practices have affected the long-term economic viability of the Mainline. Continued low prices for natural gas have led to a decline in drilling in the WCSB, which in turn resulted in less gas delivered onto the western section of the Mainline. This, coupled with a decrease in the number of long-haul FT contracts, has led to lower throughput on the Mainline. Increasing tolls, in part caused by the drop in long-haul FT contracts, have also negatively affected the Mainline's ability to attract volumes.[41]

In that same decision, the Board also anticipated the possibility that the competitive environment in which the Mainline operates might cause TransCanada to consider alternative uses for the Mainline when it stated:

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[40] Consolidated Application, Vol. 2, Section 4, pp. 4-~~10~~ 11 to 4-12~~and updated in the Application Amendment, Volume 1, Section 5.4.3~~.

[41] NEB, Reasons for Decision, RH-03-2011, p. 8.

> The Mainline faces increased competitive risk. Accordingly, we have provided the Mainline with the tools to respond to this risk, coupled with regulatory oversight and regulatory process flexibility to effect changes as appropriate. *We find this to be important regardless of what the future holds in terms of whether all or part of the facilities continue to provide gas service*.
>
> …..
>
> Therefore, we find that the transfer of accumulated depreciation would have an uncertain, but potentially significant impact if, in the future, part of the Mainline is redeployed for oil service.[42]

Considering the existing and projected market circumstances, there is a very low probability that there would be a shortage of Mainline capacity from the WCSB in the future if the Conversion Facilities are transferred to oil service. Accordingly, in my opinion, it is not in the public interest to retain the Conversion Facilities in gas service when the use of the Conversion Facilities in oil service clearly provides timely access to oil markets and produces substantial benefits by alleviating the currently constrained oil supply in western Canada.

Q49. BASED ON THE CHANGING MARKET CONDITIONS, HAS TRANSCANADA UNDERTAKEN ANY ANALYSIS TO ASSESS THE FIRM SERVICE REQUIREMENTS ON THE MAINLINE AFTER THE TRANSFER OF THE CONVERSION FACILITIES TO ENERGY EAST?

A49. Yes. As described in Volume 2, Section 5 of the Consolidated Application~~ and as updated in Volume 1, Section 5.4.3 of the Application Amendment~~, TransCanada has developed a throughput forecast that incorporates an outlook for the broader North American gas market (supply, demand and infrastructure assumptions), but focuses on the key factors that impact throughput on the Mainline system. Total firm service requirements in the Eastern Triangle are not expected to increase, with growth in domestic LDC and power generation markets largely being offset by reductions in export markets.

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[42] *Id*., pp. 3, 65; emphasis added.

Q50. WILL THE MAINLINE HAVE SUFFICIENT CAPACITY TO MEET ITS FIRM REQUIREMENTS ACROSS THE SYSTEM AFTER THE CONVERSION FACILITIES ARE TRANSFERRED?

A50. Yes. TransCanada expects to have sufficient capacity to continue meeting its firm service requirements on the Prairies Line and the Northern Ontario Line, without any facilities additions, after the transfer of the Conversion Facilities is completed. In terms of the Eastern Triangle, as described in Volume 2, Section 4 of the Consolidated Application~~ and as updated in Volume 1, Section 5.4 of the Application Amendment~~, TransCanada has developed a planning basis for the amount of firm service requirements in that portion of the system as of March 1, 2019. Specifically, the expected firm service requirements of 2,664 TJ/d are based on the 2016 NCOS and 2017 NCOS. Without the EMP, there would be a contractual firm capacity shortfall of approximately 658 TJ/d. This amount, in addition to the agreed to 50 TJ/d as per the LDC Energy East Agreement, brings the total additional capacity shortfall to 708 TJ/day. Therefore, in order to serve the currently known going forward requirement for firm capacity, TransCanada is proposing to add additional gas facilities required to meet a maximum of 708 TJ/d of firm requirements.

Based on TransCanada's forecast of firm service requirements, the proposed construction provides for the ability to meet all current firm service, and all 2016 and 2017 NCOS firm service requests, assuming full renewal of existing FT commitments. Once EMP is constructed and in service, if some of the current FT service is not renewed, and is not resold to others in the near term, the planned new gas facilities would also enable TransCanada to provide a small amount of future firm service, and expand availability of IT and STFT service until the new facilities once again become fully contracted. As noted above, total demand for Mainline transportation services in the Eastern Triangle is not forecasted to increase overall beyond current demand levels as a result of anticipated offsetting decreases in exports to the Northeast U.S.

Q51. WHAT ARE THE FACILITIES THAT TRANSCANADA IS PROPOSING TO CONSTRUCT AS PART OF THE EMP?

A51. As described in Volume 2, Section 4 of the Consolidated Application~~ and as updated in Volume 1, Sections 5.4 and 6.5 of the Application Amendment~~, TransCanada is proposing to construct as part of the EMP approximately 279 km of additional gas pipeline along the Montreal Line from Markham, Ontario to a location near the existing Iroquois export point. TransCanada is also proposing to construct additional compression at existing locations, which would be sufficient to enable the deactivation of a number of compressor units installed in the 1960s and 1970s along the Montreal Line. The deactivation of these units will address obsolescence and reliability issues, while at the same time meeting the long-term firm service requirements in the Eastern Triangle in a cost effective manner. The proposed EMP facilities are not a new version of the Eastern Triangle facilities that are being transferred to Energy East. Rather, as discussed below, the EMP facilities have been designed to be responsive to current and anticipated future requests for firm service in the Eastern Triangle, and to minimize the environmental impact associated with the construction of the Project from an overall perspective.

Since the majority of bids received in the 2016 and 2017 NCOS were for short-haul transportation through Parkway, TransCanada determined that the proposed new gas facilities provide the shortest distance between emerging supply and the market. For that reason, TransCanada determined that the most efficient expansion of the Mainline to meet the anticipated firm contractual requirements going forward would be to expand the Montreal Line so that gas delivered at Parkway (or elsewhere in southern Ontario) can be delivered most directly to eastern markets. Overall, this design enhances the net benefits of the Project.

Q52. SHOULD THE BOARD BE CONCERNED ABOUT THE EFFECT OF THE FACILITIES CONVERSION ON THE AMOUNT OF INTERRUPTIBLE CAPACITY AVAILABLE TO THE MARKET?

A52. Not to any significant degree. As discussed in the LDC Agreement the "Design Requirement" will meet all firm service requirements, plus 50 TJ/d of Additional Capacity. The Board has previously determined that the relevant consideration for assessing whether there is adequate pipeline capacity is the pipeline's ability to meet anticipated requests for firm service, and that gas shippers are only entitled to service for which they contract, not specific facilities. Gas pipeline facilities that are used for contract carriage, not common carriage, are designed and constructed to meet the current and reasonably foreseeable capacity requirements of the firm shippers and are only built when those facilities are adequately supported by long-term contracts for firm service. The additional non-contracted 50 TJ/d will be available to all shippers.

Q53. WHAT IS YOUR CONCLUSION WITH RESPECT TO THE QUALITY OF FIRM SERVICE THAT WILL BE PROVIDED ON THE MAINLINE POST-TRANSFER?

A53. Based on my review of the materials in this proceeding, in my opinion, so long as the EMP is approved, the quality of contracted firm gas transportation service on the Mainline will not be reduced by the asset transfer of the Conversion Facilities. As discussed, TransCanada's Mainline throughput forecast reflects that the existing ex-WCSB gas pipeline capacity, after the Conversion Facilities are transferred to oil service and with the construction of the EMP, is sufficient to meet the demand for firm ex-WCSB gas pipeline capacity and Eastern Triangle firm gas pipeline capacity.

B. Transfer Price/Impact on Mainline Tolls

Q54. DOES THE BOARD HAVE A POLICY FOR THE PRICING OF ASSETS PURCHASED FROM AN AFFILIATED COMPANY?

A54. Yes. The Board's *Oil Pipeline Uniform Accounting Regulations* ("OPUAR") and the *Gas Pipeline Uniform Accounting Regulations* ("GPUAR") both use a Net Book Value ("NBV") standard and stipulate that where facilities are purchased from an affiliated company, the original cost of the facilities and accumulated depreciation is recorded in the accounts of the purchasing company.[43] In addition, a transfer at NBV from one regulated utility to another ensures that one customer group is not being favored at the expense of another, and that the consolidated entity is not making an excessive return through the transfer of assets to an affiliate at greater than NBV. In its decision approving the transfer of Mainline assets to Keystone Pipeline, the Board determined that NBV was the appropriate price for the transfer of assets between affiliates.[44]

Q55. AT WHAT PRICE IS TRANSCANADA PROPOSING TO TRANSFER THE CONVERSION FACILITIES TO ENERGY EAST?

A55. As noted previously, for purposes of the proposed transfer transaction, there are three design areas: the Prairies, the Northern Ontario Line, and the Eastern Triangle, each with a set of assets that will be transferred from gas service to oil service. The transfer price that has been agreed to by Energy East and TransCanada for the Conversion Facilities reflects the NBV of the Conversion Facilities, as of the transfer date, plus an acquisition premium of $734 million (the "Acquisition Premium"). It is also my understanding that as a result of negotiations between Energy East and its shippers, it was agreed that the cost of the Acquisition Premium would be paid by Energy East shippers and Energy East. The $1 billion to be borne by the oil shippers would be included as part of rate base for purposes of determining final toll calculations for the oil facilities and

[43] Oil Pipeline Uniform Account Regulations, C.R.C., c 1058, Section 15 (4); Gas Pipeline Uniform Account Regulations, SOR/83-190, Section 15 (4).

[44] Reasons for Decision, MH-1-2006, p. 53.

will be recovered over the life of the project. In contrast, the $500 million contribution from Energy East would be excluded from the negotiated toll calculation for the initial 20-year contract period, and this amount would be deferred and placed at risk for future recovery subsequent to the initial 20-year term of the negotiated tolls. As discussed in more detail below, this treatment results in Energy East and the initial oil shippers splitting the cost of the purchase in excess of NBV, provides for toll benefits to all of TransCanada's firm service shippers, and does not allow TransCanada to earn an excess return on the sale of the Conversion Facilities.

Q56. WHY DID TRANSCANADA DECIDE TO PRICE THE TRANSFER OF THE EASTERN TRIANGLE FACILITIES AT MORE THAN NBV IN THIS CASE?

A56. The amount to be paid by Energy East over NBV for the Conversion Facilities is proposed to be allocated to reduce Mainline rate base in the Eastern Triangle, which will offset the effects of the transfer and the costs of the new facilities that TransCanada will need to construct in order to meet the anticipated firm service requirements of the Eastern Triangle shippers. The proposed Acquisition Premium will be used to achieve a NPV benefit for Eastern Triangle shippers relative to what otherwise would have occurred absent the transfer of the Conversion Facilities. In my view, this represents a reasonable resolution of the various interests of Energy East, the oil shippers and the Mainline shippers.

Q57. WOULD THE TRANSFER OF ASSETS AT MORE THAN NBV ALLOW TRANSCANADA TO EARN AN EXCESSIVE RETURN?

A57. No. The sale amount in excess of NBV will be recorded by TransCanada as a reduction to the Mainline rate base to offset the costs associated with the EMP. The balance of the deferred gain will be amortized to reduce the revenue requirement from the date of the final asset transfer to the end of 2030.

Q58. WHAT IMPACT WILL THE TRANSFER, COMBINED WITH CONSTRUCTION OF THE EMP, HAVE ON THE MAINLINE TOLLS?

A58. With the construction of the EMP, abandonment costs are projected to decline. In total, there is projected to be a net reduction in costs associated with firm transportation on the Mainline. Specifically, the transfer of the Conversion Facilities, plus the addition of the EMP facilities, is projected to result in a net reduction to the Mainline's abandonment cost estimate on a net present value basis of approximately $208 million through 2050.[45] In contrast, transfer of the Conversion Facilities is projected to cause Mainline fuel costs to increase assuming no changes are made to compressor efficiencies. The net present value of these increased fuel costs through 2050 equates to approximately $54 million.[46] Regardless, all else being equal, there is no anticipated toll increase that would result from the transfer and the construction of the EMP prior to 2018. As part of the recent RH-001-2014 Decision, TransCanada tolls for firm services are fixed for the 2015–2017 period, and under review for possible adjustment for the 2018–2020 period.

Q59. ARE THERE ECONOMIC BENEFITS PROJECTED SPECIFICALLY ASSOCIATED WITH THE EMP?

A59. Yes. As discussed in the Golder Report, there will be over $~~4.5~~<u>6</u> billion in gas corridor economic impact benefits associated with the construction phase of the EMP (the benefits of the operation phase is expected to be minimal). These benefits include an increase in economic output of $~~2.39~~<u>3.12</u> billion, an increase in GDP of $~~1.18~~<u>1.54</u> billion, an increase in total labour income of $~~0.7~~<u>1.0</u> billion, an increase in tax revenues of $~~311.6~~<u>435.2</u> million, and an increase in employment of ~~9,687~~<u>13,011</u> full time equivalent positions.

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45 <u>Consolidated</u> Application~~ Amendment~~, Volume ~~1~~<u>2</u>, ~~Section 5.4.4,~~ Table ~~5-14~~<u>4-16</u>. The discount rate of 8.69 percent is sourced from the LDC Energy East Agreement in Appendix A.

46 *Id.*

Q60. OVERALL, WHAT IS THE PROJECTED NET IMPACT OF THE TRANSFER OF THE CONVERSION FACILITIES AND CONSTRUCTION OF THE EMP ON THE MAINLINE REVENUE REQUIREMENT?

A60. As described in Consolidated Application~~ Amendment~~, Volume ~~1~~2, Sections ~~5.~~4.4 through ~~5.~~4.7, the overall result is a positive net present value benefit for Mainline shippers of over $500 million, and a total cost reduction for Mainline shippers during the 2018-2050 time period of $200 million as shown in Table 1:

Table 1: Projected Changes in Aggregate 2018 to 2050 Mainline Revenue Requirement (in $Millions)[47]

	Total	**NPV**
Transfer	$ (5,278)	$ (352)
New Gas Facilities	$ 5,574	
Abandonment Cost	$ (655)	$ (208)
Fuel Cost	$ 162	$ 54
Total	**$ (197)**	**$ (506)**

As noted, as part of the recent RH-001-2014 Decision, TransCanada tolls for firm services are fixed for the 2015–2017 period, and under review for possible adjustment for the 2018–2020 period. Additionally, in accordance with the LDC Energy East Agreement, tolls for the 2018 to 2020 period will be established without the effect of the Asset Transfer and the Eastern Mainline Project. As such, there will be no toll impact associated with the proposed Asset Transfer and the addition of the Eastern Mainline Project on the Mainline prior to 2021.

[47] Consolidated Application~~ Amendment~~, Volume 2~~1~~, ~~Section 5.4,~~ Table ~~5~~4-9 and Table ~~5~~4-~~14~~16.

VII. *PUBLIC INTEREST EVALUATION*

Q61. IN YOUR OPINION, IS THE OVERALL PROJECT CONSISTENT WITH THE PUBLIC INTEREST?

A61. Yes. Based on my review of the three components of the Application – the construction of new oil facilities, the transfer of existing gas facilities to oil service, and the construction of new gas facilities – and the facts and analyses presented in this application, it is my opinion that, from an economic perspective, and consistent with the Board's prior standard for evaluating public interest, that the benefits of the proposed Project are substantial and outweigh any potential economic burdens. Therefore, I believe that the overall Project is consistent with the Public Interest.

First, the Project will provide numerous and substantial benefits to WCSB oil producers and consumers and to federal, provincial and local governments, including:

- Enhanced quality and value of service for the new oil pipeline's firm shippers;
- Enhanced access of Canadian oil producers to Eastern Canada, including Montreal, Quebec City, and Saint John, New Brunswick, the U.S. East Coast, the U.S. Gulf Coast, and overseas markets, providing essential market diversification;
- Lower costs as compared with rail transportation, and improved competitiveness for refineries located in Quebec and New Brunswick;
- Higher prices/netbacks to Canadian oil producers as quantified in the Updated IHS Report;
- The reduction in the likelihood of recurring price discounts for Canadian crude, based on the existence of paths to multiple markets, and flexibility to target the highest netback markets;
- Promotion of competition among oil pipelines;
- Increased flexibility and optionality in the entire oil pipeline transportation system;
- Promotion of economic efficiency in pipeline transport markets (both productive and allocative); and

- Substantial macroeconomic benefits in local, provincial and federal economies as identified in the Updated Conference Board Report, the Nichols Report, and the Golder Report.

In addition, it is my opinion that the transfer of the Conversion Facilities to oil service, and the construction of the EMP, are in the public interest. The asset transfer of the Conversion Facilities represents a higher and better use for currently underutilized Mainline gas transmission facilities. While absent the EMP, the quality of firm service for natural gas shippers may have been degraded as a result of the transfer that is not the case assuming the construction of the EMP. In my view, the asset transfer of the Conversion Facilities together with the EMP facilitates numerous benefits for both natural gas and oil shippers that would not be possible absent the transfer of the gas facilities to oil service:

- results in a major reduction in capital expenditures for the overall Project due to use of existing gas pipeline for oil service;
- absent the transfer of the Conversion Facilities, the Energy East Pipeline would not be economic, resulting in access to new oil markets being constrained, and in market inefficiency;
- the transfer of the Conversion Facilities reduces construction time and environmental impact compared to constructing a new oil pipeline;
- the facilities associated with the EMP are closer to and can accommodate increasing gas flows from Dawn, Niagara and Chippawa, which are consistent with current market trends and shippers' current preferences for gas supply;
- as discussed in the Golder Report, there will be over $~~4.5~~6 billion in gas corridor economic impact benefits associated with the construction phase of the EMP, including an increase in economic output of $~~2.39~~3.12 billion, an increase in GDP of $1.~~18~~54 billion, an increase in total labour income of $~~0.7~~1.0 billion, an increase in tax revenues of $~~311.6~~435.2 million, and an increase in employment of ~~9,687~~13,011 full time equivalent positions.[48]

I consider all of these benefits as important considerations regarding the public interest determination by the Board in this proceeding.

[48] These benefits are also included within the Conference Board Report.

In summary, the overall Project continues to provide firm shippers on the Mainline with reliable firm service, while at the same time creating an opportunity for Western Canadian oil producers to expand and gain access to new diverse markets to maximize the netbacks for their crude, and achieve flexibility in marketing the large production increases that are expected through 2030, which will also enhance the prospects of downstream refiners. All of these factors support a finding that the proposed transfer of the Conversion Facilities from gas to oil service, the construction of the EMP, and the construction of the Energy East pipeline are in the Canadian public interest.

Q62. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR WRITTEN EVIDENCE.

A62. The Application fully meets and conforms to the standards the Board has established for finding that a proposed project is financially and economically feasible. In addition, the Project is fully consistent with the market's preferences for a market-based structure for service on Energy East and on oil pipelines generally.

The Project also provides extensive socio-economic benefits to Canadians across the country, including: residents of the areas through which the pipeline crosses, suppliers in many provinces, local, provincial and federal governments and the overall Canadian economy. The Project allows Canada to maximize the benefits it derives from the development of natural resources, and provides a feasible and efficient means of addressing the asymmetrical risk of too much/too little oil pipeline capacity. Energy East's development does not hinge on the success or failure of any other planned oil pipeline projects; the shipper commitments are not contingent on what happens with other projects, and shippers have provided clear and convincing support for the development of this expanded path to high-value markets. The Board can, and should, place considerable weight on the willingness of shippers that have met TransCanada's credit worthiness standards and the Project sponsor to underwrite the cost of this project for up to 20 years. Taken together, I believe that these facts provide a compelling case for concluding that the Project is feasible, beneficial, and consistent with the public interest.

The transfer of the Conversion Facilities from gas service to oil service is a higher and better use for underutilized Mainline facilities that are not fully contracted for firm service, nor which are likely to be in the foreseeable future. Without the transfer of the Mainline facilities, the Project would not be economic and access to new oil markets would be constrained, resulting in market inefficiency and the potential loss of billions of dollars of benefits to producers, provincial governments and the Canadian public.

TransCanada's gas throughput forecast demonstrates that the Mainline will have sufficient capacity to continue meeting firm service requirements on the Prairies Line and the Northern Ontario Line after the Asset Transfer is completed, and TransCanada's planning assumptions for the Eastern Triangle, and the new facilities to be added as part of the EMP, indicate that TransCanada will be able to continue meeting all current and projected firm service requirements on the Eastern Triangle. Finally, the financial terms of the proposed asset transfer help to mitigate potential adverse tolling impacts on TransCanada's gas shippers, and balances the interests of oil shippers, gas shippers and TransCanada/Energy East. For all of these reasons, I have concluded that the Application meets the Board's standards for finding that the Project promotes the public interest.

On November 6, 2015, United States President, Barack Obama, rejected TransCanada's proposed Keystone XL Oil pipeline, which would have carried approximately 800,000 bpd from the Canadian oil sands to refineries in the Gulf Coast. The rejection of Keystone XL Oil Pipeline does not change my overall conclusions that the proposed project is financially and economically feasible and that Project provides extensive socio-economic benefits to Canadians.

Q63. DOES THIS CONCLUDE YOUR WRITTEN EVIDENCE?

A63. Yes.

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 35 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 150 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join Concentric as Chairman and Chief Executive Officer.

REPRESENTATIVE PROJECT EXPERIENCE

EXECUTIVE MANAGEMENT

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 25 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

FINANCIAL AND ECONOMIC ADVISORY SERVICES

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Provided expert testimony on more than 200 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Has been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets and served on a "Blue Ribbon" panel established by the Province of New Brunswick regarding the future of natural gas distribution service in that province.

RESOURCE PROCUREMENT, CONTRACTING AND ANALYSIS

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

STRATEGIC PLANNING AND UTILITY RESTRUCTURING

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies, pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to most of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Chairman and Chief Executive Officer

CE Capital Advisors (2004 – Present)
Chairman, President, and Chief Executive Officer

Navigant Consulting, Inc. (1997 – 2002)
President, Navigant Energy Capital (2000 – 2002)
Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988 – 1997)
Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983 – 1988)
Vice President

Stone & Webster Management Consultants, Inc. (1981 – 1983)
Senior Consultant
Consultant

Southern California Gas Company (1976 – 1981)
Corporate Economist
Financial Analyst
Treasury Analyst

EDUCATION AND CERTIFICATION

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, 24, 79 and 99 Licenses

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BOARDS OF DIRECTORS (PAST AND PRESENT)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

AFFILIATIONS

American Gas Association
Energy Bar Association

Guild of Gas Managers
International Association of Energy Economists
National Association of Business Economists
New England Gas Association
Society of Gas Lighters

ARTICLES AND PUBLICATIONS

"Maximizing U.S. federal loan guarantees for new nuclear energy," *Bulletin of the Atomic Scientists* (with John C. Slocum), July 29, 2009
"Smart Decoupling – Dealing with unfunded mandates in performance-based ratemaking," *Public Utilities Fortnightly*, May 2012

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alaska Public Utilities Commission				
Chugach Electric	12/86	Chugach Electric	Docket No. U-86-11	Cost Allocation
Chugach Electric	6/87	Enstar Natural Gas Company	Docket No. U-87-2	Tariff Design
Chugach Electric	12/87	Enstar Natural Gas Company	Docket No. U-87-42	Gas Transportation
Chugach Electric	11/87, 2/88	Chugach Electric	Docket No. U-87-35	Cost of Capital
Alberta Utilities Commission				
Alberta Utilities (AltaLink, EPCOR, ATCO, ENMAX, FortisAlberta, Alta Gas)	1/13	Alberta Utilities	Application 1566373, Proceeding ID 20	Stranded Costs
Arizona Corporation Commission				
Tucson Electric Power	7/12	Tucson Electric Power	Docket No. E-01933A-12-0291	Cost of Capital
UNS Energy and Fortis Inc.	1/14	UNS Energy, Fortis Inc	Docket No. E-04230A-00011 and Docket No. E-01933A-14-0011	Merger
California Energy Commission				
Southern California Gas Co.	8/80	Southern California Gas Co.	Docket No. 80-BR-3	Gas Price Forecasting
California Public Utility Commission				
Southern California Gas Co.	3/80	Southern California Gas Co.	TY 1981 G.R.C.	Cost of Service, Inflation
Pacific Gas Transmission Co.	10/91, 11/91	Pacific Gas & Electric Co.	App. 89-04-033	Rate Design
Pacific Gas Transmission Co.	7/92	Southern California Gas Co.	A. 92-04-031	Rate Design
Colorado Public Utilities Commission				
AMAX Molybdenum	2/90	Commission Rulemaking	Docket No. 89R-702G	Gas Transportation
AMAX Molybdenum	11/90	Commission Rulemaking	Docket No. 90R-508G	Gas Transportation
Xcel Energy	8/04	Xcel Energy	Docket No. 031-134E	Cost of Debt
CT Dept. of Public Utilities Control				
Connecticut Natural Gas	12/88	Connecticut Natural Gas	Docket No. 88-08-15	Gas Purchasing Practices
United Illuminating	3/99	United Illuminating	Docket No. 99-03-04	Nuclear Plant Valuation

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Southern Connecticut Gas	2/04	Southern Connecticut Gas	Docket No. 00-12-08	Gas Purchasing Practices
Southern Connecticut Gas	4/05	Southern Connecticut Gas	Docket No. 05-03-17	LNG/Trunkline
Southern Connecticut Gas	5/06	Southern Connecticut Gas	Docket No. 05-03-17PH01	LNG/Trunkline
Southern Connecticut Gas	8/08	Southern Connecticut Gas	Docket No. 06-05-04	Peaking Service Agreement
District Of Columbia PSC				
Potomac Electric Power Company	3/99, 5/99, 7/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts
Fed'l Energy Regulatory Commission				
Safe Harbor Water Power Corp.	8/82	Safe Harbor Water Power Corp.		Wholesale Electric Rate Increase
Western Gas Interstate Company	5/84	Western Gas Interstate Company	Docket No. RP84-77	Load Fcst. Working Capital
Southern Union Gas	4/87, 5/87	El Paso Natural Gas Company	Docket No. RP87-16-000	Take-or-Pay Costs
Connecticut Natural Gas	11/87	Penn-York Energy Corporation	Docket No. RP87-78-000	Cost Alloc./Rate Design
AMAX Magnesium	12/88, 1/89	Questar Pipeline Company	Docket No. RP88-93-000	Cost Alloc./Rate Design
Western Gas Interstate Company	6/89	Western Gas Interstate Company	Docket No. RP89-179-000	Cost Alloc./Rate Design, Open-Access Transportation
Associated CD Customers	12/89	CNG Transmission	Docket No. RP88-211-000	Cost Alloc./Rate Design
Utah Industrial Group	9/90	Questar Pipeline Company	Docket No. RP88-93-000, Phase II	Cost Alloc./Rate Design
Iroquois Gas Trans. System	8/90	Iroquois Gas Transmission System	Docket No. CP89-634-000/001; CP89-815-000	Gas Markets, Rate Design, Cost of Capital, Capital Structure
Boston Edison Company	1/91	Boston Edison Company	Docket No. ER91-243-000	Electric Generation Markets
Cincinnati Gas and Electric Co., Union Light, Heat and Power Company, Lawrenceburg Gas Company	7/91	Texas Gas Transmission Corp.	Docket No. RP90-104-000, RP88-115-000, RP90-192-000	Cost Alloc./Rate Design Comparability of Svc.
Ocean State Power II	7/91	Ocean State Power II	ER89-563-000	Competitive Market Analysis, Self-dealing

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Brooklyn Union/PSE&G	7/91	Texas Eastern	RP88-67, et al	Market Power, Comparability of Service
Northern Distributor Group	9/92, 11/92	Northern Natural Gas Company	RP92-1-000, et al	Cost of Service
Canadian Association of Petroleum Producers and Alberta Pet. Marketing Comm.	10/92. 7/97	Lakehead Pipe Line Co. L.P.	IS92-27-000	Cost Allocation, Rate Design
Colonial Gas, Providence Gas	7/93, 8/93	Algonquin Gas Transmission	RP93-14	Cost Allocation, Rate Design
Iroquois Gas Transmission	94	Iroquois Gas Transmission	RP94-72-000	Cost of Service and Rate Design
Transco Customer Group	1/94	Transcontinental Gas Pipeline Corporation	Docket No. RP92-137-000	Rate Design, Firm to Wellhead
Pacific Gas Transmission	2/94, 3/95	Pacific Gas Transmission	Docket No. RP94-149-000	Rolled-In vs. Incremental Rates; rate design
Tennessee GSR Group	1/95, 3/95, 1/96	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs
PG&E and SoCal Gas	8/96, 9/96	El Paso Natural Gas Company	RP92-18-000	Stranded Costs
Iroquois Gas Transmission System, L.P.	97	Iroquois Gas Transmission System, L.P.	RP97-126-000	Cost of Service, Rate Design
BEC Energy - Commonwealth Energy System	2/99	Boston Edison Company/ Commonwealth Energy System	EC99-33-000	Market Power Analysis – Merger
Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	10/00	Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	Docket No. EC01-7-000	Market Power 203/205 Filing
Wyckoff Gas Storage	12/02	Wyckoff Gas Storage	CP03-33-000	Need for Storage Project
Indicated Shippers/Producers	10/03	Northern Natural Gas	Docket No. RP98-39-029	Ad Valorem Tax Treatment
Maritimes & Northeast Pipeline	6/04	Maritimes & Northeast Pipeline	Docket No. RP04-360-000	Rolled-In Rates
ISO New England	8/04 2/05	ISO New England	Docket No. ER03-563-030	Cost of New Entry
Transwestern Pipeline Company, LLC	9/06	Transwestern Pipeline Company, LLC	Docket No. RP06-614-000	

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Portland Natural Gas Transmission System	6/08	Portland Natural Gas Transmission System	Docket No. RP08-306-000	Market Assessment, natural gas transportation; rate setting
Portland Natural Gas Transmission System	5/10, 3/11, 4/11	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Business risks; extraordinary and non-recurring events pertaining to discretionary revenues
Morris Energy	7/10	Morris Energy	Docket No. RP10-79-000	Affidavit re: Impact of Preferential Rate
Florida Public Service Commission				
Florida Power and Light Co.	10/07	Florida Power & Light Co.	Docket No. 070650-EI	Need for new nuclear plant
Florida Power and Light Co.	5/08	Florida Power & Light Co.	Docket No. 080009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/09	Florida Power & Light Co.	Docket No. 080677-EI	Benchmarking in support of ROE
Florida Power and Light Co.	3/09, 5/09, 8/09	Florida Power & Light Co.	Docket No. 090009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/10; 5/10, 8/10	Florida Power & Light Co.	Docket No. 100009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/11, 7/11	Florida Power & Light Co.	Docket No. 110009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/12 7/12	Florida Power & Light Co.	Docket No. 120009-EI	New Nuclear cost recovery , prudence
Florida Power and Light Co.	3/12 8/12	Florida Power & Light Co.	Docket No. 120015-EI	Benchmarking in support of ROE
Florida Power and Light Co.	3/13, 7/13	Florida Power & Light Co.	Docket No. 130009	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/14	Florida Power & Light Co.	Docket No. 140009	New Nuclear cost recovery, prudence
Florida Senate Committee on Communication, Energy and Utilities				
Florida Power and Light Co.	2/09	Florida Power & Light Co.		Securitization

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Hawaii Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/00	Hawaiian Electric Light Company, Inc.	Docket No. 99-0207	Standby Charge
Illinois Commerce Commission				
Renewables Suppliers (Algonquin Power Co., EDP Renewables North America, Invenergy, NextEra Energy Resources)	3/14	Renewables Suppliers	Docket No. 13-0546	Application for Rehearing and Reconsideration; long-term purchase power agreements
WE Energies Corporation	8/14	WE Energies/Integrys	Docket No. 14-0496	Merger Application
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/01	Northern Indiana Public Service Company	Cause No. 41746	Valuation of Electric Generating Facilities
Northern Indiana Public Service Company	01/08, 03/08	Northern Indiana Public Service Company	Cause No. 43396	Asset Valuation
Northern Indiana Public Service Company	08/08	Northern Indiana Public Service Company	Cause No. 43526	Fair Market Value Assessment
Iowa Utilities Board				
Interstate Power and Light	7/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. SPU-05-15	Sale of Nuclear Plant
Interstate Power and Light	5/07	City of Everly, Iowa	Docket No. SPU-06-5	Municipalization
Interstate Power and Light	5/07	City of Kalona, Iowa	Docket No. SPU-06-6	Municipalization
Interstate Power and Light	5/07	City of Wellman, Iowa	Docket No. SPU-06-10	Municipalization
Interstate Power and Light	5/07	City of Terril, Iowa	Docket No. SPU-06-8	Municipalization
Interstate Power and Light	5/07	City of Rolfe, Iowa	Docket No. SPU-06-7	Municipalization
Maine Public Utility Commission				
Northern Utilities	5/96	Granite State and PNGTS	Docket No. 95-480, 95-481	Transportation Service and PBR
Maryland Public Service Commission				
Eastalco Aluminum	3/82	Potomac Edison	Docket No. 7604	Cost Allocation

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Potomac Electric Power Company	8/99	Potomac Electric Power Company	Docket No. 8796	Stranded Cost & Price Protection
Mass. Department of Public Utilities				
Haverhill Gas	5/82	Haverhill Gas	Docket No. DPU #1115	Cost of Capital
New England Energy Group	1/87	Commission Investigation		Gas Transportation Rates
Energy Consortium of Mass.	9/87	Commonwealth Gas Company	Docket No. DPU-87-122	Cost Alloc./Rate Design
Mass. Institute of Technology	12/88	Middleton Municipal Light	DPU #88-91	Cost Alloc./Rate Design
Energy Consortium of Mass.	3/89	Boston Gas	DPU #88-67	Rate Design
PG&E Bechtel Generating Co./ Constellation Holdings	10/91	Commission Investigation	DPU #91-131	Valuation of Environmental Externalities
Coalition of Non-Utility Generators		Cambridge Electric Light Co. & Commonwealth Electric Co.	DPU 91-234 EFSC 91-4	Integrated Resource Management
The Berkshire Gas Company Essex County Gas Company Fitchburg Gas and Elec. Light Co.	5/92	The Berkshire Gas Company Essex County Gas Company Fitchburg Gas & Elec. Light Co.	DPU #92-154	Gas Purchase Contract Approval
Boston Edison Company	7/92	Boston Edison	DPU #92-130	Least Cost Planning
Boston Edison Company	7/92	The Williams/Newcorp Generating Co.	DPU #92-146	RFP Evaluation
Boston Edison Company	7/92	West Lynn Cogeneration	DPU #92-142	RFP Evaluation
Boston Edison Company	7/92	L'Energia Corp.	DPU #92-167	RFP Evaluation
Boston Edison Company	7/92	DLS Energy, Inc.	DPU #92-153	RFP Evaluation
Boston Edison Company	7/92	CMS Generation Co.	DPU #92-166	RFP Evaluation
Boston Edison Company	7/92	Concord Energy	DPU #92-144	RFP Evaluation
The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Company	11/93	The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Co.	DPU #93-187	Gas Purchase Contract Approval
Bay State Gas Company	10/93	Bay State Gas Company	Docket No. 93-129	Integrated Resource Planning
Boston Edison Company	94	Boston Edison	DPU #94-49	Surplus Capacity
Hudson Light & Power Department	4/95	Hudson Light & Power Dept.	DPU #94-176	Stranded Costs
Essex County Gas Company	5/96	Essex County Gas Company	Docket No. 96-70	Unbundled Rates
Boston Edison Company	8/97	Boston Edison Company	D.P.U. No. 97-63	Holding Company Corporate Structure
Berkshire Gas Company	6/98	Berkshire Gas Mergeco Gas Co.	D.T.E. 98-87	Merge approval

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Eastern Edison Company	8/98	Montaup Electric Company	D.T.E. 98-83	Marketing for divestiture of its generation business.
Boston Edison Company	98	Boston Edison Company	D.T.E. 97-113	Fossil Generation Divestiture
Boston Edison Company	2/99	Boston Edison Company	D.T.E. 98-119	Nuclear Generation Divestiture
Eastern Edison Company	12/98	Montaup Electric Company	D.T.E. 99-9	Sale of Nuclear Plant
NStar	9/07, 12/07	NStar, Bay State Gas, Fitchburg G&E, NE Gas, W. MA Electric	DPU 07-50	Decoupling, risk
NStar	6/11	NStar, Northeast Utilities	DPU 10-170	Merger approval
Mass. Energy Facilities Siting Council				
Mass. Institute of Technology	1/89	M.M.W.E.C.	EFSC-88-1	Least-Cost Planning
Boston Edison Company	9/90	Boston Edison	EFSC-90-12	Electric Generation Mkts
Silver City Energy Ltd. Partnership	11/91	Silver City Energy	D.P.U. 91-100	State Policies; Need for Facility
Michigan Public Service Commission				
Detroit Edison Company	9/98	Detroit Edison Company	Case No. U-11726	Market Value of Generation Assets
Consumers Energy Company	8/06, 1/07	Consumers Energy Company	Case No. U-14992	Sale of Nuclear Plant
WE Energies	12/11	Wisconsin Electric Power Co	Case No. U-16830	Economic Benefits/Prudence
Consumer Energy Company	6/2013	Consumers Energy Company	Case No. U-17429	Certificate of Need, Integrated Resource Plan
WE Energies	08/14	WE Energies/Integrys	Case No. U-17682	Merger Application
Minnesota Public Utilities Commission				
Xcel Energy/No. States Power	9/04	Xcel Energy/No. States Power	Docket No. G002/GR-04-1511	NRG Impacts
Interstate Power and Light	8/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. E001/PA-05-1272	Sale of Nuclear Plant
Northern States Power Company d/b/a Xcel Energy	11/05	Northern States Power Company	Docket No. E002/GR-05-1428	NRG Impacts on Debt Costs
Northern States Power Company d/b/a Xcel Energy	09/06, 10/06, 11/06	NSP v. Excelsior	Docket No. E6472/M-05-1993	PPA, Financial Impacts

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Northern States Power Company d/b/a Xcel Energy	11/06	Northern States Power Company	Docket No. G002/GR-06-1429	Return on Equity
Northern States Power	11/08, 05/09	Northern States Power Company	Docket No. E002/GR-08-1065	Return on Equity
Northern States Power	11/09 6/10	Northern States Power Company	Docket No. G002/GR-09-1153	Return on Equity
Northern States Power	11/10, 5/11	Northern States Power Company	Docket No. E002/GR-10-971	Return on Equity
Missouri Public Service Commission				
Missouri Gas Energy	1/03 04/03	Missouri Gas Energy	Case No. GR-2001-382	Gas Purchasing Practices; Prudence
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case Nos. ER-2004-0034 HR-2004-0024	Cost of Capital, Capital Structure
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case No. GR-2004-0072	Cost of Capital, Capital Structure
Missouri Gas Energy	11/05 2/06 7/06	Missouri Gas Energy	Case Nos. GR-2002-348 GR-2003-0330	Capacity Planning
Missouri Gas Energy	11/10, 1/11	KCP&L	Case No. ER-2010-0355	Natural Gas DSM
Missouri Gas Energy	11/10, 1/11	KCP&L GMO	Case No. ER-2010-0356	Natural Gas DSM
Laclede Gas Company	5/11	Laclede Gas Company	Case No. CG-2011-0098	Affiliate Pricing Standards
Union Electric Company d/b/a Ameren Missouri	2/12, 8/12	Union Electric Company	Case. No. ER-2012-0166	ROE/earnings attrition/regulatory lag
Union Electric Company d/b/a Ameren Missouri	08/14	Noranda Aluminum Inc.	Case No. EC-2014-0223	Ratemaking; regulatory and economic policy
Montana Public Service Commission				
Great Falls Gas Company	10/82	Great Falls Gas Company	Docket No. 82-4-25	Gas Rate Adjust. Clause
Nat. Energy Board of Canada				
Alberta-Northeast	2/87	Alberta Northeast Gas Export Project	Docket No. GH-1-87	Gas Export Markets
Alberta-Northeast	11/87	TransCanada Pipeline	Docket No. GH-2-87	Gas Export Markets
Alberta-Northeast	1/90	TransCanada Pipeline	Docket No. GH-5-89	Gas Export Markets

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Indep. Petroleum Association of Canada	1/92	Interprovincial Pipe Line, Inc.	RH-2-91	Pipeline Valuation, Toll
The Canadian Association of Petroleum Producers	11/93	Transmountain Pipe Line	RH-1-93	Cost of Capital
Alliance Pipeline L.P.	6/97	Alliance Pipeline L.P.	GH-3-97	Market Study
Maritimes & Northeast Pipeline	97	Sable Offshore Energy Project	GH-6-96	Market Study
Maritimes & Northeast Pipeline	2/02	Maritimes & Northeast Pipeline	GH-3-2002	Natural Gas Demand Analysis
TransCanada Pipelines	8/04	TransCanada Pipelines	RH-3-2004	Toll Design
Brunswick Pipeline	5/06	Brunswick Pipeline	GH-1-2006	Market Study
TransCanada Pipelines Ltd.	12/06, 04/07	TransCanada Pipelines Ltd.: Gros Cacouna Receipt Point Application	RH-1-2007	Toll Design
Repsol Energy Canada Ltd	3/08	Repsol Energy Canada Ltd	GH-1-2008	Market Study
Maritimes & Northeast Pipeline	7/10	Maritimes & Northeast Pipeline	RH-4-2010	Regulatory policy, toll development
TransCanada Pipelines Ltd	9/11, 5/12	TransCanada Pipelines Ltd.	RH-3-2011	Business Services and Tolls Application
Trans Mountain Pipeline LLC	6/12, 1/13	Trans Mountain Pipeline LLC	RH-1-2012	Toll Design
TransCanada Pipelines Ltd	8/13	TransCanada Pipelines Ltd	RE-001-2013	Toll Design
NOVA Gas Transmission Ltd	11/13	NOVA Gas Transmission Ltd	OF-Fac-Gas-N081-2013-10 01	Toll Design
Trans Mountain Pipeline LLC	12/13	Trans Mountain Pipeline LLC	OF-Fac-Oil-T260-2013-03 01	Economic and Financial Feasibility and Project Benefits
New Brunswick Energy and Utilities Board				
Atlantic Wallboard/JD Irving Co	1/08	Enbridge Gas New Brunswick	MCTN #298600	Rate Setting for EGNB
Atlantic Wallboard/Flakeboard	09/09, 6/10, 7/10	Enbridge Gas New Brunswick	NBEUB 2009-017	Rate Setting for EGNB
Atlantic Wallboard/Flakeboard	1/14	Enbridge Gas New Brunswick	NBEUB Matter 225	Rate Setting for EGNB
NH Public Utilities Commission				
Bus & Industry Association	6/89	P.S. Co. of New Hampshire	Docket No. DR89-091	Fuel Costs
Bus & Industry Association	5/90	Northeast Utilities	Docket No. DR89-244	Merger & Acq. Issues
Eastern Utilities Associates	6/90	Eastern Utilities Associates	Docket No. DF89-085	Merger & Acq. Issues

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
EnergyNorth Natural Gas	12/90	EnergyNorth Natural Gas	Docket No. DE90-166	Gas Purchasing Practices
EnergyNorth Natural Gas	7/90	EnergyNorth Natural Gas	Docket No. DR90-187	Special Contracts, Discounted Rates
Northern Utilities, Inc.	12/91	Commission Investigation	Docket No. DR91-172	Generic Discounted Rates
Public Service Co. of New Hampshire	7/14	Public Service Co. of NH	Docket No. DE 11-250	Prudence
New Jersey Board of Public Utilities				
Hilton/Golden Nugget	12/83	Atlantic Electric	B.P.U. 832-154	Line Extension Policies
Golden Nugget	3/87	Atlantic Electric	B.P.U. No. 837-658	Line Extension Policies
New Jersey Natural Gas	2/89	New Jersey Natural Gas	B.P.U. GR89030335J	Cost Alloc./Rate Design
New Jersey Natural Gas	1/91	New Jersey Natural Gas	B.P.U. GR90080786J	Cost Alloc./Rate Design
New Jersey Natural Gas	8/91	New Jersey Natural Gas	B.P.U. GR91081393J	Rate Design; Weather Norm. Clause
New Jersey Natural Gas	4/93	New Jersey Natural Gas	B.P.U. GR93040114J	Cost Alloc./Rate Design
South Jersey Gas	4/94	South Jersey Gas	BRC Dock No. GR080334	Revised levelized gas adjustment
New Jersey Utilities Association	9/96	Commission Investigation	BPU AX96070530	PBOP Cost Recovery
Morris Energy Group	11/09	Public Service Electric & Gas	BPU GR 09050422	Discriminatory Rates
New Jersey American Water Co.	4/10	New Jersey American Water Co.	BPU WR 1040260	Tariff Rates and Revisions
Electric Customer Group	01/11	Generic Stakeholder Proceeding	BPU GR10100761 and ER10100762	Natural gas ratemaking standards and pricing
New Mexico Public Service Commission				
Gas Company of New Mexico	11/83	Public Service Co. of New Mexico	Docket No. 1835	Cost Alloc./Rate Design
Southwestern Public Service Co., New Mexico	12/12	SPS New Mexico	Case No. 12-00350-UT	Rate Case, Return on Equity
New York Public Service Commission				
Iroquois Gas. Transmission	12/86	Iroquois Gas Transmission System	Case No. 70363	Gas Markets
Brooklyn Union Gas Company	8/95	Brooklyn Union Gas Company	Case No. 95-6-0761	Panel on Industry Directions

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Central Hudson, ConEdison and Niagara Mohawk	9/00	Central Hudson, ConEdison and Niagara Mohawk	Case No. 96-E-0909 Case No. 96-E-0897 Case No. 94-E-0098 Case No. 94-E-0099	Section 70, Approval of New Facilities
Central Hudson, New York State Electric & Gas, Rochester Gas & Electric	5/01	Joint Petition of NiMo, NYSEG, RG&E, Central Hudson, Constellation and Nine Mile Point	Case No. 01-E-0011	Section 70, Rebuttal Testimony
Rochester Gas & Electric	12/03	Rochester Gas & Electric	Case No. 03-E-1231	Sale of Nuclear Plant
Rochester Gas & Electric	01/04	Rochester Gas & Electric	Case No. 03-E-0765 Case No. 02-E-0198 Case No. 03-E-0766	Sale of Nuclear Plant; Ratemaking Treatment of Sale
Rochester Gas and Electric and NY State Electric & Gas Corp	2/10	Rochester Gas & Electric NY State Electric & Gas Corp	Case No. 09-E-0715 Case No. 09-E-0716 Case No. 09-E-0717 Case No. 09-E-0718	Depreciation policy
Nova Scotia Utility and Review Board				
Nova Scotia Power	9/12	Nova Scotia Power	Docket No. P-893	Audit Reply
Nova Scotia Power	8/14	Nova Scotia Power	Docket No. P-887	Audit Reply
Oklahoma Corporation Commission				
Oklahoma Natural Gas Company	6/98	Oklahoma Natural Gas Company	Case PUD No. 980000177	Storage issues
Oklahoma Gas & Electric Company	9/05	Oklahoma Gas & Electric Company	Cause No. PUD 200500151	Prudence of McLain Acquisition
Oklahoma Gas & Electric Company	03/08	Oklahoma Gas & Electric Company	Cause No. PUD 200800086	Acquisition of Redbud generating facility
Oklahoma Gas & Electric Company	08/14	Oklahoma Gas & Electric Company	Cause No. PUD 201400229	Integrated Resource Plan
Ontario Energy Board				
Market Hub Partners Canada, L.P.	5/06	Natural Gas Electric Interface Roundtable	File No. EB-2005-0551	Market-based Rates For Storage

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Pennsylvania Public Utility Commission				
ATOC	4/95	Equitrans	Docket No. R-00943272	Rate Design, unbundling
ATOC	3/96 4/96	Equitrans	Docket No. P-00940886	Rate Design, unbundling
Rhode Island Public Utilities Commission				
Newport Electric	7/81	Newport Electric	Docket No. 1599	Rate Attrition
South County Gas	9/82	South County Gas	Docket No. 1671	Cost of Capital
New England Energy Group	7/86	Providence Gas Company	Docket No. 1844	Cost Alloc./Rate Design
Providence Gas	8/88	Providence Gas Company	Docket No. 1914	Load Forecast., Least-Cost Planning
Providence Gas Company and The Valley Gas Company	1/01 3/02	Providence Gas Company and The Valley Gas Company	Docket No. 1673 and 1736	Gas Cost Mitigation Strategy
The New England Gas Company	3/03	New England Gas Company	Docket No. 3459	Cost of Capital
Texas Public Utility Commission				
Southwestern Electric	5/83	Southwestern Electric		Cost of Capital, CWIP
P.U.C. General Counsel	11/90	Texas Utilities Electric Company	Docket No. 9300	Gas Purchasing Practices, Prudence
Oncor Electric Delivery Company	8/07	Oncor Electric Delivery Company	Docket No. 34040	Regulatory Policy, Rate of Return, Return of Capital and Consolidated Tax Adjustment
Oncor Electric Delivery Company	6/08	Oncor Electric Delivery Company	Docket No.35717	Regulatory policy
Oncor Electric Delivery Company	10/08, 11/08	Oncor, TCC, TNC, ETT, LCRA TSC, Sharyland, STEC, TNMP	Docket No. 35665	Competitive Renewable Energy Zone
CenterPoint Energy	6/10 10/10	CenterPoint Energy/Houston Electric	Docket No. 38339	Regulatory policy, risk, consolidated taxes
Oncor Electric Delivery Company	1/11	Oncor Electric Delivery Company	Docket No. 38929	Regulatory policy, risk
Cross Texas Transmission	08/12 11/12	Cross Texas Transmission	Docket No. 40604	Return on Equity
Southwestern Public Service	11/12	Southwestern Public Service	Docket No. 40824	Return on Equity
Lone Star Transmission	5/14	Lone Star Transmission	Docket No. 42469	Return on Equity, Debt, Cost of Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Texas Railroad Commission				
Western Gas Interstate Company	1/85	Southern Union Gas Company	Docket 5238	Cost of Service
Atmos Pipeline Texas	9/10; 1/11	Atmos Pipeline Texas	GUD 10000	Ratemaking Policy, risk
Texas State Legislature				
CenterPoint Energy	4/13	Association of Electric Companies of Texas	SB 1364	Consolidated Tax Adjustment Clause Legislation
Utah Public Service Commission				
AMAX Magnesium	1/88	Mountain Fuel Supply Company	Case No. 86-057-07	Cost Alloc./Rate Design
AMAX Magnesium	4/88	Utah P&L/Pacific P&L	Case No. 87-035-27	Merger & Acquisition
Utah Industrial Group	7/90 8/90	Mountain Fuel Supply	Case No. 89-057-15	Gas Transportation Rates
AMAX Magnesium	9/90	Utah Power & Light	Case No. 89-035-06	Energy Balancing Account
AMAX Magnesium	8/90	Utah Power & Light	Case No. 90-035-06	Electric Service Priorities
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Benchmarking in support of ROE
Vermont Public Service Board				
Green Mountain Power	8/82	Green Mountain Power	Docket No. 4570	Rate Attrition
Green Mountain Power	12/97	Green Mountain Power	Docket No. 5983	Cost of Service
Green Mountain Power	7/98, 9/00	Green Mountain Power	Docket No. 6107	Rate development
Wisconsin Public Service Commission				
WEC & WICOR	11/99	WEC	Docket No. 9401-YO-100 Docket No. 9402-YO-101	Approval to Acquire the Stock of WICOR
Wisconsin Electric Power Company	1/07	Wisconsin Electric Power Co.	Docket No. 6630-EI-113	Sale of Nuclear Plant
Wisconsin Electric Power Company	10/09	Wisconsin Electric Power Co.	Docket No. 6630-CE-302	CPCN Application for wind project
Northern States Power Wisconsin	10/13	Xcel Energy (dba Northern States Power Wisconsin)	Docket No. 4220-UR-119	Fuel Cost Adjustments
Wisconsin Electric Power Company	11/1/13	Wisconsin Electric Power Co.	Docket No. 6630-FR-104	Fuel Cost Adjustment

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
WE Energy	08/14	WE Energy/Integrys	Docket No. 9400-YO-100	Merger approval

ATTACHMENT A
EXPERT TESTIMONY OF JOHN J. REED
COURTS AND ARBITRATION

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
American Arbitration Association				
Michael Polsky	3/91	M. Polsky vs. Indeck Energy		Corporate Valuation, Damages
ProGas Limited	7/92	ProGas Limited v. Texas Eastern		Gas Contract Arbitration
Attala Generating Company	12/03	Attala Generating Co v. Attala Energy Co.	Case No. 16-Y-198-00228-03	Power Project Valuation; Breach of Contract; Damages
Nevada Power Company	4/08	Nevada Power v. Nevada Cogeneration Assoc. #2		Power Purchase Agreement
Sensata Technologies, Inc./EMS Engineered Materials Solutions, LLC	1/11	Sensata Technologies, Inc./EMS Engineered Materials Solutions, LLC v. Pepco Energy Services	Case No. 11-198-Y-00848-10	Change in usage dispute/damages
Commonwealth of Massachusetts, Appellate Tax Board				
NStar Electric Company	8/14	NStar Electric Company		Valuation Methodology
Commonwealth of Massachusetts, Suffolk Superior Court				
John Hancock	1/84	Trinity Church v. John Hancock	C.A. No. 4452	Damages Quantification
State of Colorado District Court, County of Garfield				
Questar Corporation, et al	11/00	Questar Corporation, et al.	Case No. 00CV129-A	Partnership Fiduciary Duties
State of Delaware, Court of Chancery, New Castle County				
Wilmington Trust Company	11/05	Calpine Corporation vs. Bank Of New York and Wilmington Trust Company	C.A. No. 1669-N	Bond Indenture Covenants
Illinois Appellate Court, Fifth Division				
Norweb, plc	8/02	Indeck No. America v. Norweb	Docket No. 97 CH 07291	Breach of Contract; Power Plant Valuation

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Independent Arbitration Panel				
Alberta Northeast Gas Limited	2/98	ProGas Ltd., Canadian Forest Oil Ltd., AEC Oil & Gas		
Ocean State Power	9/02	Ocean State Power vs. ProGas Ltd.	2001/2002 Arbitration	Gas Price Arbitration
Ocean State Power	2/03	Ocean State Power vs. ProGas Ltd.	2002/2003 Arbitration	Gas Price Arbitration
Ocean State Power	6/04	Ocean State Power vs. ProGas Ltd.	2003/2004 Arbitration	Gas Price Arbitration
Shell Canada Limited	7/05	Shell Canada Limited and Nova Scotia Power Inc.		Gas Contract Price Arbitration
International Court of Arbitration				
Wisconsin Gas Company, Inc.	2/97	Wisconsin Gas Co. vs. Pan-Alberta	Case No. 9322/CK	Contract Arbitration
Minnegasco, A Division of NorAm Energy Corp.	3/97	Minnegasco vs. Pan-Alberta	Case No. 9357/CK	Contract Arbitration
Utilicorp United Inc.	4/97	Utilicorp vs. Pan-Alberta	Case No. 9373/CK	Contract Arbitration
IES Utilities	97	IES vs. Pan-Alberta	Case No. 9374/CK	Contract Arbitration
State of New Jersey, Mercer County Superior Court				
Transamerica Corp., et. al.	7/07, 10/07	IMO Industries Inc. vs. Transamerica Corp., et. al.	Docket No. L-2140-03	Breach-Related Damages, Enterprise Value
State of New York, Nassau County Supreme Court				
Steel Los III, LP	6/08	Steel Los II, LP & Associated Brook, Corp v. Power Authority of State of NY	Index No. 5662/05	Property seizure
Province of Alberta, Court of Queen's Bench				
Alberta Northeast Gas Limited	5/07	Cargill Gas Marketing Ltd. vs. Alberta Northeast Gas Limited	Action No. 0501-03291	Gas Contracting Practices

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
State of Rhode Island, Providence City Court				
Aquidneck Energy	5/87	Laroche vs. Newport		Least-Cost Planning
State of Texas Hutchinson County Court				
Western Gas Interstate	5/85	State of Texas vs. Western Gas Interstate Co.	Case No. 14,843	Cost of Service
State of Texas District Court of Nueces County				
Northwestern National Insurance Company	11/11	ASARCO LLC	No. 01-2680-D	Damages
State of Utah Third District Court				
PacifiCorp & Holme, Roberts & Owen, LLP	1/07	USA Power & Spring Canyon Energy vs. PacifiCorp. et. al.	Civil No. 050903412	Breach-Related Damages
U.S. Bankruptcy Court, District of New Hampshire				
EUA Power Corporation	7/92	EUA Power Corporation	Case No. BK-91-10525-JEY	Pre-Petition Solvency
U.S. Bankruptcy Court, District Of New Jersey				
Ponderosa Pine Energy Partners, Ltd.	7/05	Ponderosa Pine Energy Partners, Ltd.	Case No. 05-21444	Forward Contract Bankruptcy Treatment
U.S. Bankruptcy Court, No. District of New York				
Cayuga Energy, NYSEG Solutions, The Energy Network	09/09	Cayuga Energy, NYSEG Solutions, The Energy Network	Case No. 06-60073-6-sdg	Going concern
U.S. Bankruptcy Court, So. District Of New York				
Johns Manville	5/04	Enron Energy Mktg. v. Johns Manville; Enron No. America v. Johns Manville	Case No. 01-16034 (AJG)	Breach of Contract; Damages

ATTACHMENT A
EXPERT TESTIMONY OF JOHN J. REED
COURTS AND ARBITRATION

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U.S. Bankruptcy Court, Northern District Of Texas				
Southern Maryland Electric Cooperative, Inc. and Potomac Electric Power Company	11/04	Mirant Corporation, et al. v. SMECO	Case No. 03-4659; Adversary No. 04-4073	PPA Interpretation; Leasing
U. S. Court of Federal Claims				
Boston Edison Company	7/06, 11/06	Boston Edison v. Department of Energy	No. 99-447C No. 03-2626C	Spent Nuclear Fuel Litigation
Consolidated Edison of New York	08/07	Consolidated Edison of New York, Inc. and subsidiaries v. United States	No. 06-305T	Leasing, tax dispute
Consolidated Edison Company	2/08, 6/08	Consolidated Edison Company v. United States	No. 04-0033C	SNF Expert Report
Vermont Yankee Nuclear Power Corporation	6/08	Vermont Yankee Nuclear Power Corporation	No. 03-2663C	SNF Expert Report
U. S. District Court, Boulder County, Colorado				
KN Energy, Inc.	3/93	KN Energy vs. Colorado GasMark, Inc.	Case No. 92 CV 1474	Gas Contract Interpretation
U. S. District Court, Northern California				
Pacific Gas & Electric Co./PGT PG&E/PGT Pipeline Exp. Project	4/97	Norcen Energy Resources Limited	Case No. C94-0911 VRW	Fraud Claim
U. S. District Court, District of Connecticut				
Constellation Power Source, Inc.	12/04	Constellation Power Source, Inc. v. Select Energy, Inc.	Civil Action 304 CV 983 (RNC)	ISO Structure, Breach of Contract

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U.S. District Court, Northern District of Illinois, Eastern Division				
U.S. Securities and Exchange Commission	4/12	U.S. Securities and Exchange Commission v. Thomas Fisher, Kathleen Halloran, and George Behrens	Case No. 07 C 4483	Prudence, PBR
U. S. District Court, Massachusetts				
Eastern Utilities Associates & Donald F. Pardus	3/94	NECO Enterprises Inc. vs. Eastern Utilities Associates	Civil Action No. 92-10355-RCL	Seabrook Power Sales
U. S. District Court, Montana				
KN Energy, Inc.	9/92	KN Energy v. Freeport MacMoRan	Docket No. CV 91-40-BLG-RWA	Gas Contract Settlement
U.S. District Court, New Hampshire				
Portland Natural Gas Transmission and Maritimes & Northeast Pipeline	9/03	Public Service Company of New Hampshire vs. PNGTS and M&NE Pipeline	Docket No. C-02-105-B	Impairment of Electric Transmission Right-of-Way
U. S. District Court, Southern District of New York				
Central Hudson Gas & Electric	11/99, 8/00	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Electric restructuring, environmental impacts
Consolidated Edison	3/02	Consolidated Edison v. Northeast Utilities	Case No. 01 Civ. 1893 (JGK) (HP)	Industry Standards for Due Diligence
Merrill Lynch & Company	1/05	Merrill Lynch v. Allegheny Energy, Inc.	Civil Action 02 CV 7689 (HB)	Due Diligence, Breach of Contract, Damages

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U. S. District Court, Eastern District of Virginia				
Aquila, Inc.	1/05, 2/05	VPEM v. Aquila, Inc.	Civil Action 304 CV 411	Breach of Contract, Damages
U. S. District Court, Portland Maine				
ACEC Maine, Inc. et al.	10/91	CIT Financial vs. ACEC Maine	Docket No. 90-0304-B	Project Valuation
Combustion Engineering	1/92	Combustion Eng. vs. Miller Hydro	Docket No. 89-0168P	Output Modeling; Project Valuation
U.S. Securities and Exchange Commission				
Eastern Utilities Association	10/92	EUA Power Corporation	File No. 70-8034	Value of EUA Power
Council of the District of Columbia Committee on Consumer and Regulatory Affairs				
Potomac Electric Power Co.	7/99	Potomac Electric Power Co.	Bill 13-284	Utility restructuring

March 2016

TECHNICAL REPORT

Economic Impact Update Eastern Mainline Project

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REPORT

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1.0 PROJECT PURPOSE AND IMPACT ESTIMATION APPROACH

TransCanada PipeLines Limited (TransCanada) proposes to construct and operate a new natural gas pipeline, as well as modify five existing compressor station facilities between the existing Mainline Valve (MLV) 132 near Markham, Ontario and the existing MLV 145 near the community of Brouseville, Ontario. The pipeline and facilities are known collectively as the Eastern Mainline Project (the Project). The Project route will generally follow a portion of the right-of-way (ROW) of the existing Canadian Mainline pipeline.

TransCanada commissioned Golder Associates Ltd. (Golder) to estimate the economic effects of the construction of the Project on the Canadian, Ontario and other provincial economies. An Economic Impact Technical Report (Golder 2014b) was included in the Application to the National Energy Board (NEB) under sections 52 and 58 of the *National Energy Board Act* for a Certificate of Public Convenience and Necessity. This Economic Impact Update report incorporates revised expenditure estimates for the Project that reflect modifications to its scope and changes in its labour, goods and services costs. The Project scope changes include minor pipeline route adjustments and additional pipeline length.

The length of the pipeline is now 278.6 km, approximately 33.2 km longer than the design outlined in the Application to the NEB (TransCanada PipeLines Limited 2014). There are no changes to the proposed expansion of compression facilities at the five existing compressor stations and no changes to the technical details of the Project's compression facility additions. The Amended NEB Application included an ESA Amendment (Golder 2015).

This Economic Impact Analysis used estimates of the Project's direct expenditures and input-output (I-O) economic impact modelling to predict the Project's economic effects. The analytical approach included the following key elements.

- Use of Statistics Canada's Inter-Provincial Input-Output Model (IPIO Model or IPIOM) to assist in calculating the Project's economic impact on the Canadian, Ontario and other provincial economies.
- Use of the Conference Board of Canada's national and provincial forecasting models to estimate the tax revenue effects of the Project.
- Use of a TransCanada supplied Class 5 estimate of expenditures for Project construction.[1] TransCanada provided the expenditure data by pipeline and compressor station components of the Project and further dis-aggregated the data by key expenditure categories for each component.
- 'Shocking' of Statistics Canada's IPIO Model with the proposed expenditures.
- Exclusion of certain expenditures from the modelling that have no economic effects (e.g. land acquisition expenditures, which are a transfer of economic assets between parties).

Only the economic impact of the Project's construction phase was analyzed as the incremental economic impact of the Project's operation phase is viewed as nominal because the Project replaces the existing natural gas transport service offered by the Canadian Mainline pipeline. The Project will enable TransCanada to continue to meet its commercial obligations along the proposed route following the proposed transfer of certain Canadian

[1] The economic impact input-output modelling is based upon a capital expenditure estimate for the Project dated July 2015.

Mainline facilities to Energy East Pipeline Ltd. (Energy East) and the subsequent conversion of the transferred facilities to the transport of crude oil. TransCanada estimates the incremental direct employment of the Project during its operation phase as 5 full-time equivalents (FTE) on an annual basis. The annual incremental direct GDP during the operation phase would be largely limited to the labour income associated with these 5 operators.

The potential economic effects of the Project's construction phase were assessed using the following indicators:

- employment;
- economic output;
- Gross Domestic Product (GDP);
- labour income; and
- tax revenue.

Construction of temporary infrastructure is scheduled to begin in Q3 2017, with construction of the pipeline sections scheduled to begin in Q1 2018 and continue through to March 2019, with a revised in-service date of March 2019 (TransCanada PipeLines Limited 2015). Project design and construction planning work started in October 2013. The economic impact of expenditures associated with the planning and engineering design is included in the analysis.

The revised cost estimate used in the economic impact modelling is approximately $1.652 billion[2], which includes expenditures for engineering design, building the pipeline, and adding new compressor units to existing compressor stations. This estimate includes assumptions for cost escalation and contingency. Construction of the pipeline and compressor station additions will occur only in Ontario, but the Project will source some goods and services from other provinces and internationally.

The input-output modelling undertaken for this analysis generated estimates of the Project's direct, indirect and induced effects on the Canadian, Ontario and other provincial economies. These effects are incremental as the Project's spending on construction related goods, materials, services and labour would not occur in the absence of the Project. The Project's direct economic effects are amplified through the local and provincial economies and also the national economy via the indirect economic effects flowing from the Project's direct spending on goods and services (for example, increased construction activity will lift demand for utilities, transportation, financial, and insurance services) and via the induced effects from the spending on consumer and personal services that is supported by Project related wages and salaries.

The modelling for this analysis included "shocking" the IPIOM with the injection of Project construction phase expenditures into the Canadian economy. To analyze the impact of major construction projects, input-output model runs or shocks are structured for analytical purposes as either an increase in the output (total revenues) of one or more construction related industries or an increase in the expenditures on a given basket of goods and services (typically referred to as a commodity shock).

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[2] All expenditures and dollar impacts are reported in 2013 Canadian dollars ($CAN). This cost estimate excludes certain expenditures that will not have an effect from an economic impact perspective, such as land acquisition.

To analyze the economic impact of the construction phase of this Project, a commodity shock modelling approach was used, and the standard production function for engineering construction in the model, which includes expenditures for labour, pumps and compressors, steel pipes, measuring and controlling devices, and engineering and related services, was modified to take account of the Project's expenditure estimates thereby creating a Project-specific production function for designing and constructing the pipeline. The expenditures would include the costs for the work of tradespersons, engineers, and equipment operators, for equipment leasing services and for the many smaller capital items and materials involved in pipeline construction. The IPIO Model was run using the increase in expenditures on these goods and services within the Canadian economy due to the spending of the Project.

The industry production functions in the IPIOM incorporate interprovincial and international imports so the modelling results incorporate only effects associated with Project consumed goods and services that are produced within Canada. This feature also allows for consideration of effects on a province, i.e., only effects associated with goods and services produced within a province.

The impact estimates are current as of July 2015, but are subject to change as the Project design is refined in response to various internal and external-to-TransCanada processes.

2.0 ECONOMIC IMPACT ESTIMATION RESULTS

This section presents the results of the economic impact analysis of the construction phase of the Project. The employment, labour income, GDP, economic output and tax revenue results are shown for Canada, Ontario and other provinces.

2.1 Employment

An estimated direct employment of 6,470 FTE jobs[3] are expected to be supported through Project spending on engineering design and construction of the pipeline and compressor station additions (Table 2-1).[4] The construction work would occur in Ontario, so the direct employment effects at the national level are equivalent to those that occur in Ontario. The types of jobs in construction fieldwork would include, but not be limited to, welders and welder helpers (approximately 20%), labourers (approximately 20%), equipment operators, (approximately 25%), oilers (approximately 5%), and mechanics (approximately 3%).

[3] Employment effects are reported in FTE (full-time equivalent) job units. The employment unit of FTE job takes into account the number of hours worked in one year by full-time, part-time and temporary employees and self-employed persons. The FTE job unit transforms the different employment categories into one unit based on overall averages of full-time hours worked in one year in the business and government sectors. FTE jobs include both the employee and self-employed jobs, but the FTE transformation only applies to employee jobs. Person-year (PY) is an alternative term with the same meaning. The FTE job unit is used herein because many industries are represented in the modelling and they have an array of full-time, part-time and temporary employment attachment structures. The use of the annual FTE job unit provides a consistent approach across industries to portraying employment activity. It should be noted that a FTE job represents a typical employment period in terms of hours worked for one year, and, in and of itself, a FTE job should not be interpreted as a permanent or long-term, sustaining job unit of measurement. Within an operation phase situation, an estimate of FTE jobs can be used to help determine an estimate of the number of 'permanent' or 'long-term' jobs of a project or program. The short-term structure of construction employment precludes assigning an estimate of 'permanent' or 'long-term' jobs to a project or program.

[4] As the Project's expenditures are reported in 2013 $CAN and the version of the IPIOM used for this analysis incorporates 2010 $CAN, the model's estimated employment effects for the Project were reduced by 12.1%, the estimated change in annual labour income over the 2010-2013 period, to estimate the amount of Project supported employment.

All of the direct employment for construction is expected to be filled by Ontario residents and the modelling estimates reflect this expectation. However, the awarding of contracts for construction may result in firms from Quebec and Alberta supplying a portion of the construction services, so some direct workers may be Quebec and/or Alberta residents.

Indirect employment in Ontario and other provinces is expected to be stimulated through Project expenditures on materials, goods and services produced in Canada. This is employment connected to the production of materials, goods and services purchased by the prime contractor(s) and TransCanada for designing and constructing the Project. The indirect employment within Canada supported by Project spending during the construction phase is anticipated to be an estimated 3,144 FTE jobs, and the majority would be based in Ontario, 2,609 FTE jobs (83%).

Only a small portion of the supplier industry employment is expected to occur in other provinces; 242 FTE jobs (8%) in Quebec, 117 FTEs (4%) in Alberta, 79 FTE jobs (2%) in BC and 97 FTE jobs (3%) in the other provinces and the Northwest Territories. The focus of indirect employment in Ontario is due to the combination of pipeline construction wholly taking place in this province along with the relatively large industrial supply sector that is present in the province.

The construction phase induced employment effect is anticipated to be largely taking place in Ontario because the bulk of the direct and indirect employment is seen as occurring there. The induced employment would mainly be in retail outlets and service businesses in Ontario that are patronized by the households of the workers in either direct or indirect employment supported by Project spending. The Project's induced employment effect is estimated as 3,397 FTE jobs within Canada, and 2,774 of these FTE jobs (82%) would be based in Ontario.

The total employment effect over the Project's construction phase is expected to be an estimated 13,011 FTE jobs in Canada, and, the vast majority (91%), 11,854 FTE jobs are expected to occur in Ontario. Table 2-1 displays the estimated employment impacts of the construction phase.

Table 2-1: Employment Effects of the Construction Phase in Canada, Ontario and the other Provinces and Territories

	Canada (FTE jobs)	Ontario (FTE jobs)	Other provinces and territories (FTE jobs)
Direct	6,470	6,470	0
Indirect	3,144	2,609	535
Induced	3,397	2,774	623
Total	13,011	11,854	1,157

Note: Totals may not correspond with the sum of the separate figures due to rounding.

Source: Conference Board of Canada and Statistics Canada 2015.

The top five supplier industries are projected to account for almost half (48.0%) of indirect employment in Ontario, which is the province that accounts for the largest portion of the Project's indirect employment. The Wholesale Trade industry is expected to account for the largest share of indirect employment in Ontario, followed by two technical service industries. The industries accounting for the larger share of the Project's indirect employment in Ontario are as follows:

- Wholesale trade – 404 FTE jobs (15.5%);
- Other professional, scientific and technical services – 346 FTE jobs (13.3%);

- Architectural, engineering and related services – 231 FTE jobs (8.8%);
- Retail trade – 140 FTE jobs (5.4%);
- Legal, accounting and related services – 133 FTE jobs (5.1%);
- Other administrative and support services – 101 FTE jobs (3.9%);
- Steel product manufacturing – 98 FTE jobs (3.7%); and
- Truck transportation – 93 FTE jobs (3.5%).

These are logical impact modelling results because Project construction will require steel products, design and ongoing engineering services will be required throughout the construction period and there will be a need for a wide array of construction materials and goods distributed through various wholesalers.

The IPIOM forecasts a small amount of indirect employment in Quebec (242 FTE jobs), mainly in the Wholesale Trade, Other Professional, Scientific and Technical Services, Truck Transportation, and Steel product manufacturing industries.

2.2 Labour Income

The Project's labour income effects tightly correspond with the preceding employment effects. The Project is expected to generate approximately three-fifths of a billion dollars ($597.8 million) in additional direct labour income and this effect is anticipated to wholly occur in Ontario (Table 2-2). The Project is relatively labour intensive as more than a third (36%) of its economic output is accounted for by its direct labour income, i.e., its direct labour spend.

The average annual compensation of direct employees (who are expected to be located in Ontario) is projected to be relatively high, approximately $92,500 per direct employment FTE job, which reflects the higher wage and benefits compensation levels of the industrial projects construction sector. The average annual compensation would be lower for the Project supported indirect and induced employment, $74,000 per indirect employment FTE job and $58,500 per induced employment FTE job for the Ontario-based indirect employment.

Taking account of the direct, indirect and induced employment effects, the Project would account for over a billion dollars ($1,029 million) of employment income in Canada, and Ontario is forecasted to account for 92.7% of the Canadian total. Table 2-2 presents the estimated labour income effects of the construction phase.

Table 2-2: Labour Income Effects of the Construction Phase in Canada, Ontario and other Provinces and Territories

	Canada ($ millions)	Ontario ($ millions)	Other provinces and territories ($ millions)
Direct	597.8	597.8	0
Indirect	232.1	192.9	39.2
Induced	198.8	163.1	35.7
Total	1,028.7	953.8	74.9

Note: Totals may not correspond with the sum of the separate figures due to rounding.

Source: Conference Board of Canada and Statistics Canada 2015.

2.3 Economic Output and Gross Domestic Product (GDP)

The direct economic output encompasses Project expenditures on direct labour, materials, goods and services to build the Project, and includes expenditures on major items such as pipe. The direct economic output associated with the industries constructing the new pipeline is expected to be $1,651.9 million, and this would cover labour costs for engineering, project management, and on-site construction activities, direct Project expenditures on materials, goods and services and the net returns of the companies building the pipeline.

The indirect output of the Project is associated with expenditures on multiple rounds of upstream purchases of materials, goods and services used to make the domestically produced materials, goods and services directly used by the Project. The Project's indirect output in Canada is expected to amount to $756.6 million and $588.8 million in Ontario (77.8%). Most indirect output, i.e., the gross revenues all along the goods and services supply chain, would come from Ontario and 51 industries in this province are expected to have 10 or more FTE jobs linked to the Project's indirect effects. The remainder of the Project's indirect economic output is spread mainly through three other provinces, $65.0 million (8.6%) in Quebec, $55.7 million (7.4%) in Alberta and $15.4 million (2.0%) in BC.

The scope of the direct business opportunity for Canadian producers of materials, goods and services is represented by the planned direct expenditures of the Project for acquisition of items in these commodity categories. A large portion of the anticipated Project expenditure would be managed through contracts and sub-contracts directed to suppliers of materials, goods and services. There would likely be one or two prime contractors for the engineering and construction aspects, and they in turn would be letting many contracts and sub-contracts for specialized trades, professional services and many other items. These specialized service contracts could include the following:

- engineering, various including civil, structural, pipeline, environmental and geotechnical;
- surveying;
- various excavation services, including clearing, grading and trenching;
- various baselay services, including bending, welding, lowering, back filling, coating, hydrostatic testing pipe and clean-up;
- horizontal directional drilling; and
- valve assembly, installation and testing.

TransCanada's procurement practices and general economic conditions especially in the province of Ontario would affect the level of interest expressed by local and regional supplier enterprises and, consequently, the extent to which the local economies in Ontario can maximize their shares of the economic benefits of the Project. The actual share captured by businesses in each community or region of Ontario is not currently known and would depend on local capacity and capabilities at the time TransCanada is seeking materials, goods or services and the interest of local enterprises in pursuing these opportunities. There would be contracting for various goods, including:

- 36 inch (914 mm) OD pipeline;
- 11 MW compressor unit additions;

- Valve Assemblies (e.g., cross-over valves); and
- Pre-Fabricated Elbows.

Although the extent of spending on locally produced goods and services would depend on their availability, quality and price competitiveness, the proximity of the Project to suppliers to major industrial enterprises is expected to lead to significant sourcing of materials, goods and services from Ontario.

The total output of the Project in Canada is estimated as $3,117.6 million, which is the sum of the Project's direct, indirect and induced output (Table 2-3).[5]

There would be Project expenditures on imported goods and services as well, currently estimated at almost $500 million. Iron and steel pipes and other iron and steel products (such as valves), pumps and compressors, and measuring and controlling devices are anticipated to be the main categories of imported items.

The majority of GDP or value added is composed of labour income and operating surplus, which is gross profit income, and is the beneficial macroeconomic effect of the Project. GDP does not include revenues from sales of intermediate inputs. The estimated direct GDP contribution of the Project in Canada is $761.2 million, and would be primarily due to the Project expenditures on wages and salaries for workers to design and construct the Project. The direct GDP effect is expected to be fully focused on Ontario, and again this is due to the construction activity wholly taking place in this province.

The Project's total GDP effect would be over a billion dollars in both Canada and Ontario, $1,539.7 million and $1,387.9 million, respectively. Ontario is expected to have a more than 90.1% share of the total GDP associated with the Project, and this effect is due to the Project's location, the province's large industrial supply sector, and the household spending associated with direct and indirect employment largely occurring in Ontario. Table 2-3 displays the estimated economic output and GDP effects of the Project's construction phase.

Table 2-3: Economic Output and GDP Effects of the Construction Phase in Canada, Ontario and the other Provinces and Territories

	Economic Output			GDP		
	Canada ($ millions)	Ontario ($ millions)	Other provinces and territories ($ millions)	Canada ($ millions)	Ontario ($ millions)	Other provinces and territories ($ millions)
Direct	1,651.9	1,651.9	-	761.2	761.2	-
Indirect	756.6	588.8	167.8	367.3	287.3	80.0
Induced	709.1	571.5	137.6	411.1	339.4	71.7
Total	3,117.6	2,812.2	305.4	1,539.7	1,387.9	151.8

Note: Totals may not correspond with the sum of the separate figures due to rounding.

Source: Conference Board of Canada and Statistics Canada 2015.

[5] A caution in regard to interpreting economic output results is that there is some double counting of output effects in the results for this indicator (i.e., revenues from sales of both intermediate and final products are reflected in the output figure). Economic output is equivalent to total revenues so this indicator represents a measure of the overall business opportunity presented by a project. The total GDP indicator is a more accurate representation of a project's overall economic contribution as total GDP represents the sum of the value added in the economy at each level of effect (direct, indirect and induced).

2.4 Tax Revenue

The total tax revenue derived from the Project's construction phase in Canada is expected to amount to an estimated $435.2 million. For every $1 of direct economic output, the Project would generate $0.26 in tax revenues.

Almost half of the total tax revenues associated with the Project, $194.5 million (45%), is anticipated to accrue to the Ontario government; a result that reflects all pipeline construction occurring in this province and the large share of sourcing of materials, goods and services by Ontario suppliers. The Federal Government is expected to take in 52% of the total tax revenues, an estimated $225.8 million. Property taxation as a pipeline would not be applied until the operation phase. An estimate of property tax revenues due to the Project at the local government level for the construction phase was therefore not made.

Personal income taxes are the main tax revenue source to the Canadian governments from the Project's construction phase, a forecasted $197.1 million (45%), and the main source for the Ontario Government, $68.0 million (35%). This result reflects the relatively high labour intensity of the Project, 36% of its direct economic output is accounted for by expenditures on direct labour. Table 2-4 presents the government tax revenue impact for Canada, Ontario and the other provinces and territories.

Table 2-4: Tax Revenue by Tax Type of the Construction Phase in Canada, Ontario and the other Provinces and Territories

	Canada ($ millions)	Ontario ($ millions)	Other provinces and territories ($ millions)
Federal Government	**225.8**	**102.1**	**123.7**
Personal Income Tax	123.3	47.4	75.9
Corporate Income Tax	57.4	22.1	35.3
Indirect tax[6]	28.5	26.2	2.3
Other tax	16.6	6.4	10.2
Provincial Governments	**209.3**	**194.5**	**14.8**
Personal Income Tax	73.8	68.0	5.8
Corporate Income Tax	56.7	54.3	2.4
Indirect tax	69.3	63.4	5.9
Other tax	9.4	8.7	0.7
Total tax Revenues	**435.2**	**296.6**	**138.6**
Personal Income Tax	197.1	115.4	81.7
Corporate Income Tax	114.2	76.4	37.8
Indirect tax	97.9	89.7	8.2
Other tax	26.0	15.1	10.9

Note: Totals may not correspond with the sum of the separate figures due to rounding.

Source: Conference Board of Canada and Statistics Canada 2015.

[6] The estimated taxes include taxes on products (HST, GST, PST, federal excise taxes, import duties, and fuel taxes) and taxes on factors of production (capital taxes, land transfer taxes, and property taxes).

3.0 LOCAL ECONOMIC IMPACTS

3.1 Employment

The Project is wholly located in southern Ontario and is anticipated to have a demand for direct labour in engineering design and pipeline and compressor station construction totalling an estimated 6,470 FTE jobs. A wide range of occupations would be drawn upon to design and build the Project including pipeline engineers, welders, weld inspectors, horizontal directional drill (HDD) operators, truck drivers, heavy equipment operators, pipeline construction supervisors, health and safety officers, semi-skilled labourers (such as welder's helper) and general construction labourers. The start of the pipeline is near Markham, within the populous Greater Toronto Area and it traverses or is near a few mid-sized and small cities, including Kingston, Oshawa, Pickering, Whitby, Belleville and Brockville.

Most workers would be hired directly by companies contracting to TransCanada or companies acting as subcontractors to the primary contractors. These workers have not yet been hired so the precise distribution of Project employment by residence is not known, but the location of the pipeline in southern Ontario, with its large, diverse labour force, points to most or all of the Project's construction workers being sourced from these communities, including its Greater Toronto Area communities.

In 2011, the socio-economic Local Study Area (LSA) defined for the Environmental and Socio-economic assessment of the Project (Golder 2015) had a labour force of 625,525 workers and the Regional Study Area (RSA) had a labour force of 1,286,800 workers. The Project's effects on the local labour markets would depend on the capacity of the local labour force to meet Project labour demand while the overall local labour market stays in balance. The local capacity is defined as the number of qualified unemployed persons within the LSA or RSA in excess of a 5% natural rate of unemployment.[7] For example, if the baseline unemployment rate in the LSA is 7% for the occupations required for direct, indirect and induced positions and the Project hires persons with those occupations from the local population, then the labour market would remain in balance up to the point that its unemployment rate is equal to approximately 5%.

The definition of labour market capacity does not include persons who are employed. However, labour force capacity is dynamic in that some employed members of the local labour force would leave their jobs to take a Project position and, in turn, these vacancies would either be filled by local persons or eventually by in-migrating workers who relieve the local labour scarcity.[8]

[7] The Conference Board of Canada (2007) estimated the natural rate of unemployment in Ontario as 5.2%. The natural rate of unemployment is the level of unemployment in an economy that is operating at full capacity and its wage increases are gradual and not inflationary. There is unemployment in this scenario because of the time required to find a job, some job seekers will hold out for a higher wage or a certain job and some persons are unwilling to move to accept new employment for a variety of reasons. Local hiring in excess of approximately 5% unemployment would give rise to adverse labour market effects such as persistent labour shortages, reduction in service levels, and delay in completing work. If the unemployment rate is below the natural rate of unemployment, there would be no capacity in the local labour supply to help meet the Project labour demand and, at the same time, sustain a balanced labour market.

[8] This characterization of the local labour force capacity as the pool of unemployed persons has limitations as an area's participation rate also influences this capacity. Some persons may have withdrawn from a labour force because of poor employment prospects or for other reasons and the potential of attractive employment opportunities may draw them back into the local labour force. The pool of unemployed persons seeking work would likely expand with the advent of a major project generating a range of direct, indirect and induced employment opportunities.

The current unemployment rates for the LSA and RSA are not known, but the 2015 unemployment rate for the Kingston-Pembroke economic region was 7.2% (Statistics Canada 2016).[9] With an unemployment rate similar to this rate in the LSA and RSA and taking account of a 5% natural rate of unemployment, the capacity of the labour force in the LSA above the 5% natural rate of unemployment would be approximately 13,750 workers and the capacity would be approximately 28,000 workers in the RSA. The Project would have specific occupational needs for the pipeline construction work, but there would also be more general occupational needs for the indirect and induced labour demand associated with the Project.

The economic benefit of the Project is expected to extend beyond the LSA and RSA. For example, because of the proximity of the Project's western terminus within the Greater Toronto Area, there would be an even larger pool of labour to draw from than is represented within the LSA or the RSA (i.e., available labour force members in Peel, Halton and Toronto can be drawn on as well because of the Project's proximity to these communities and their labour forces). The Toronto Census Metropolitan Area (CMA) had a labour force of about 3.5 million and a 7.1% unemployment rate in 2015 (Statistics Canada 2016).

There would be indirect employment associated with the Project, i.e., workers would also be hired by companies supplying goods and services to the Project's contractors, and by companies further upstream that are supplying inputs to the direct suppliers. The largest share (83%) of the indirect employment supported by the Project's spending on materials, goods and services is anticipated to be based in Ontario, an estimated 2,609 FTE jobs. Most suppliers are foreseen to be coming from southern Ontario because of its large industrial supply base and the attraction for Project contractors of sourcing from local or regional suppliers that are offering price and quality competitive products and services that can be delivered on a timely basis to Project construction locations.

Given the expected sourcing of direct and indirect labour needs from southern Ontario, the workers associated with the retail, finance, professional service, food and personal service operations who cater to the household requirements of the direct and indirect employment supported by the Project would largely be located in the same communities as the residences of this direct and indirect employment. There are an expected 2,774 FTE jobs in Ontario linked to the induced economic activity generated by the Project.

3.2 Goods and Services Procurement

Almost the whole of the anticipated Project expenditure would be managed through contracts and sub-contracts directed to suppliers of goods and services. There would likely be one or two prime contractors for the construction aspects and several prime contractors for the engineering. These prime contractors would be issuing many contracts and sub-contracts for specialized trades and professional services. These service contracts could include the following:

- engineering (including civil, structural, pipeline, environmental and geotechnical);
- surveying;
- various excavation services, including clearing, grading and trenching;

[9] The 2015 unemployment rate for Ontario was 6.8% (Statistics Canada 2016). Based on data from the Census of Canada, the 2011 unemployment rate in the LSA was estimated as 8.2%, and the 2011 unemployment rate in the RSA was estimated as 7.8%. The 2011 unemployment rate in Ontario as a whole was slightly higher, 8.3% (Golder 2015).

- various baselay services, including bending, welding, lowering, back filling coating, hydrostatic testing pipe and clean-up;
- horizontal directional drilling; and
- valve assembly, installation and testing.

TransCanada's procurement practices and local and regional economic conditions would affect the level of interest expressed by local and regional suppliers and, consequently, the extent to which the economies of the LSA and RSA communities can maximize their shares of Project economic benefits. The actual share of Project expenditures on goods and services captured by local and regional businesses is not known at this juncture and would depend on local capacity and capabilities at the time TransCanada is seeking goods or services and the interest of local and regional enterprises in pursuing these opportunities. The Project is expected to contract for various goods, including:

- aerial gas coolers;
- NPS 36" pipe;
- valve assemblies;
- cross-over valve assemblies; and
- pre-fabricated elbows.

Although the extent of spending on locally produced goods would depend on their availability, quality and price competitiveness, the proximity of the Project to the Greater Toronto Area and its very large industrial supply base is expected to lead to significant sourcing of goods and services from southern Ontario in general and the Greater Toronto Area in particular. The Toronto Region Board of Trade has observed that "The Toronto region is the national leader by employment size in many important clusters, including Business Services, Financial Services, Publishing, Automotive, Processed Food, and Education and Knowledge Creation. It has a strong and diverse labour force, with nearly three-quarters of its population of working age and the region produces almost half of the province's economic output and almost 20 percent of the country's" (Toronto Region Board of Trade 2014).

3.3 Tax Revenue

Property taxation would be the primary source of tax revenues from the Project at the local government level. The assessed value of the Project's real property at the Project site would increase as construction gets underway and facilities are established. Property taxation as a pipeline would not be applied until the operation phase. An estimate of property tax revenues due to the Project at the local government level for the construction phase was therefore not made. For the operation phase, the Project is expected to pay property taxes of approximately $8 million per year that would accrue to the municipalities and counties along the route.

4.0 LIMITATIONS

The following are the study's limitations.

- Final expenditure estimates for the Project may differ from the amounts presented in this report.
- Input-output models are linear and do not factor in economies of scale, i.e., they assume that a given change in the demand for a commodity will translate into a proportional change in production.
- Input-output models do not take into account the amount of time required for economic changes to occur. Economic adjustments resulting from a change in demand are assumed to happen immediately.
- Input-output models assume there are no capacity constraints and that an increase in the demand for labour will result in an increase in employment (rather than simply re-deploying workers).
- There is not a specific North American Industry Classification System ("NAICS") code for pipeline construction in the IPIOM so the Project was modelled as a commodity shock, which creates a project-specific production function.
- The IPIOM is based on a "snapshot" of the Canadian and provincial economies in 2010 so the model reflects relationships between industries from that year.
- While use of the IPIOM has limitations, its commodity and industry relationships are based on a very large database accumulated over several years and the model have been found to generate impact estimates that are indicative of realized economic impacts. Nevertheless, the reported impacts are estimates and are accurate to probably no better than +/- 15%.

5.0 CLOSURE

Please contact Derek De Biasio at 604-296-7035 if you have any questions or would like additional information.

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Volume 2

Sale and Purchase of Mainline Assets

The analysis undertaken by TransCanada does not indicate that Mainline shippers will be exposed to incremental costs or even that they will be revenue neutral as a result of the transfer of the Conversion Facilities. It indicates that Mainline shippers will achieve an economic benefit as a result of the transfer.

The combined effect of removal of the Conversion Facilities from the Mainline rate base and the construction of the EMP results in an estimated savings to Mainline shippers, on a net present value basis, of over $~~900~~ 500 million calculated to ~~2030~~ 2050. Of this amount, ~~the estimated benefit for shippers in the Eastern Triangle is approximately $500 million~~ over $400 million is a benefit to western Mainline shippers and at least $100 million is a benefit to Eastern Trianggle shippers over the same period.

TransCanada proposes to deduct the transfer price (estimated to be approximately $1.5 billion at the time of transfer) from the Mainline rate base. Of the transfer price, $~~500~~ 734 million represents an amount in excess of NBV or an Acquisition Premium. TransCanada will assign the Acquisition Premium to the Eastern Triangle rate base ~~to provide benefits to the Eastern Mainline Project~~ as specified in the LDC Energy East Agreement.

Energy East proposes that the full amount of the purchase price will then be recognized by it initially as Oil Plant Under Construction at the date of transfer and subsequently as Oil Plant in Service in the Energy East rate base when the Conversion Facilities are put into oil service. The NBV of the Conversion Facilities plus ~~$250 million~~ a portion of the Acquisition Premium up to a maximum of $1 billion will be recovered in Energy East tolls over the life of the Project. ~~The remaining $250 million of the Acquisition Premium will be not be included in the calculation of tolls until subsequent to the initial 20 year term of the negotiated toll.~~

1.3 ORGANIZATION OF THE TRANSFER APPLICATION

The remaining sections of this Transfer Application discuss:

- the applicable regulatory standards to be applied to the Transfer Application (Section 2)
- terms of the proposed transfer (Section 3)
- potential effects of the transfer on the TransCanada Mainline shippers (Section 4)
- gas supply and markets (Section 5)
- system design for the Eastern Mainline Project (Section 6)
- third-party consultation (Section 7)
- public interest in Asset Transfer (Section 8)

demonstrated that they are not necessary and where TransCanada had proposed an alternative use for the facilities that the Board had found to be in the public interest.[19]

The used and useful standard also was the subject of much discussion in the Mainline RH-003-2011 case where it, along with prudence, was accepted by the Board as a criterion that determines the opportunity for cost recovery.[20]

It is the position of the Applicants that in the circumstances of this case, it is in the public interest to transfer the currently used and useful Conversion Facilities from gas service to oil service. The Conversion Facilities will be converted to a higher and better use in oil service, while Mainline gas shippers receive economic benefits.

2.4 NO ACQUIRED RIGHTS

The NEB has accepted and adopted the principle of "no acquired rights," by which it is meant that customers do not gain proprietary rights to services or facilities of a pipeline, or entitlement to a degree of toll protection, simply because of their past patronage, absent a current firm contractual right. When contracting with a pipeline, shippers purchase a service from the pipeline (e.g., transportation or storage service) and not an ownership interest in the facilities. As a result, by purchasing service from a pipeline, shippers are in no way granted an entitlement to future protection of toll levels or availability of capacity.

Recent examples of the application of the "no acquired rights" principle include the RH-003-2011 Decision on the TransCanada Mainline Restructuring, where the Board held that shippers' costs and benefits do not extend beyond a contract under which service was requested and made available,[21] and the MH-1-2006 Decision on the initial transfer of TransCanada Mainline facilities from gas service to oil service.[22]

The "no acquired rights" principle means that Mainline gas shippers do not have any proprietary rights to existing Mainline capacity that is not currently contracted, or to the facilities that could provide that ~~contracted~~ capacity.

2.5 FIRM SERVICE IS THE MEASURE OF POST-TRANSFER REMAINING MAINLINE CAPACITY

Among the factors to be weighed in the assessment of the public interest of the proposed facilities transfer is the anticipated demand for gas transportation capacity on the Mainline, and the impact that the transfer of the Facilities could have on the ability of the Mainline to meet that demand.

19 Ibid.

20 RH-003-2011 Decision, pages 37–40.

21 RH-003-2011 Decision, page 2.

22 MH-1-2006 Decision, page 5

In the MH-1-2006 case, the Board approved NBV as the appropriate transfer price for the facilities sold by TransCanada to Keystone for conversion from gas service to oil service. While the NBV transfer price was uncontested, the NEB found it to be appropriate since it accorded with existing practices and principles, and with the OPUARs and the GPUARs.[29]

In the case of the Mainline and Energy East, the Asset Transfer is between affiliated corporations at a price of approximately $1.5 billion (Transfer Price) that exceeds the NBV of the Conversion Facilities by $~~500~~ 734 million. TransCanada proposes to provide additional economic benefit to Mainline shippers by allocating the acquisition premium ($~~500~~ 734 million) as a reduction of Eastern Triangle rate base to be amortized ~~over a 15-year period~~ to 2030. The Board has recognized that where there is an Acquisition Premium, its disposition is at the discretion of the pipeline.[30]

In recognition of the fact that TransCanada has committed to assign the full amount of the Acquisition Premium to the benefit of Mainline shippers, TransCanada and Energy East submit that the Board should find that the negotiated Transfer Price is just and reasonable and provides no undue benefit to either affiliated company. Accordingly, the Board should approve the Applicants' requests for exemptions from the GPUAR and OPUAR to permit the Asset Transfer at the negotiated Transfer Price, to credit the Acquisition Premium to the Eastern Triangle rate base and to amortize the Acquisition Premium to 2030.

2.7 CONCLUSION

TransCanada's Canadian federally regulated pipeline systems exist and operate within the legal framework established by the NEB Act and the regulatory standards and principles recognized and applied by the Board. These standards continue to be applicable and should inform and govern the decision of the Board on the Application. The overarching regulatory standard applicable to this Transfer Application is the public interest.

29 MH-1-2006 Decision, Chapter 5: The Transfer at Net Book Value, pages 53–54.

30 Atco Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board), 2006 S.C.J. No. 4.

Specifically, TransCanada negotiated the LDC Energy East Agreement which was precipitated by and is responsive to the concerns raised by Ontario and Quebec natural gas customers. Additionally, the 2017 NCOS and commercial processes also addressed a number of concerns identified by Mainline shippers.

The following additional discussions with stakeholders occurred subsequent to the October 2014 filing of the Application:

- On 9 September 2015, the LDC Agreement – Term Sheet was presented at a Tolls Task Force (TTF) meeting in Winnipeg.
- On 12 November 2015, the LDC Definitive Agreement and a summary of anticipated amendments to this Application were presented at a TTF meeting in Toronto.
- Individual meetings were also held with some Mainline stakeholders.

At the 12 November 2015 TTF meeting, TransCanada asked stakeholders to provide comments or concerns regarding the Application Amendment by 26 November 2015, and to provide any comments outside the confidential TTF forum so they could be described to the NEB. Centra Gas Manitoba was the only party to comment, expressing opposition to the Energy East Adjustment.

TransCanada believes that the 2017 NCOS and commercial processes, the LDC Agreement, and the changes to the timing, scope and cost of the Eastern Mainline Project have otherwise addressed concerns of Mainline shippers.

TransCanada anticipates that this proceeding will provide an opportunity for understanding and addressing any third party commercial concerns to the extent that they remain.

Appendix 2-7

Revenue Requirement – Assumptions

1.0 REVENUE REQUIREMENT FOR ASSET TRANSFER AND EASTERN MAINLINE PROJECT

The following assumptions were used in the calculation of the annual incremental revenue requirement impact of transferring Mainline facilities to Energy East and the addition of the Eastern Mainline Project facilities including the ~~deactivation~~ retirement[1] of electric compressor units along the Montreal line.

Rate Base: The transferred assets will be removed from gas service and transferred to Energy East in March ~~31, 2016~~ 2018 and March ~~31, 2017~~ 2019 with a reduction to rate base in these months equivalent to the net book value of the facilities and ~~a gain on sale of $500 million~~ the Acquisition Premium. Rate base will be increased by the cost of the Eastern Mainline Project facilities and the cost of ~~deactivating~~ retiring the electric compressor units. In addition, rate base is reduced by the carrying value of associated line pack gas.

Return: Return is determined by applying a forecast rate of return to the change in rate base. The rate of return is based on a return on common equity (ROE) of 10.1 per cent on a deemed common equity ratio of 40 per cent, with the balance consisting of funded and unfunded debt. A new debt issuance of $~~675~~650 million at an interest rate of ~~6.5~~4.75% has been assumed in July 2018.

Depreciation: Depreciation expense reflects the incremental change in gas plant in service and the respective depreciation rates for each segment. The depreciation rates used are consistent with the RH-3-2011 decision as noted below:

- Western Mainline - Prairies pipeline assets – 1.83%
- Western Mainline - NOL pipeline assets – 4.24%
- Eastern Triangle pipeline assets – 1.71%
- Eastern Triangle compression assets – 3.47%

With respect to ~~the NOL segment,~~calculating the depreciation expense savings for the NOL and Prairies segments, the incremental depreciation impact stops when ~~the net book value reaches zero in~~ total depreciation savings equate to the allocation of the transfer price for the respective segments. This is 2021 for the NOL and 2028 for the Prairies.

[1] Retirement is used as a general term for an asset being removed from pipeline service as noted in section 36(1) of the Gas Pipeline Uniform Accounting Regulations.

Income Tax: Income tax expense is impacted by the change in equity return, depreciation, CCA and the ~~gain on sale of assets~~ Acquisition Premium. The UCC tax pools, used to calculate CCA, are reduced by the ~~sales proceeds~~transfer price of the transferred facilities and increased by the cost of the Eastern Mainline Project facilities. As the ~~gain~~ Acquisition Premium is amortized and included in the revenue requirement a corresponding reduction to income tax is realized. An income tax rate of ~~25.937~~ 26.850 per cent is assumed for the period.

OM&A: Reductions in OM&A costs are the result of field operation synergies realized from co-locating Energy East assets along or adjacent to the Mainline right of way and efficiencies in head office support services which are currently allocated to the Mainline and other TransCanada business units.

Compressor Overhaul: Overhaul costs associated with the nine new compressor units are not expected to be incurred for approximately ~~13~~10 years following installation. When these costs are incurred they are included in rate base and amortized at a rate of 7.87% (approximately 12.7 years). Overhaul costs of $2 million/unit have been included in the ~~The~~ revenue requirement ~~impact of these costs prior to 2030 is negligible and was therefore not factored into this analysis~~ over a 12 year cycle starting in 2029.

Property Tax: Property taxes are expected to be reduced as the result of removing approximately 3,000 kilometers of pipeline from gas transportation service and adding ~~254~~280 kilometers of the Eastern Mainline Project to gas transportation service. The estimate was determined based on changes to kilometers of pipe within each province. Property taxes are assumed to escalate by 3% annually.

Pipeline Integrity: Future pipeline integrity costs are impacted by the removal of 3,000 km of pipeline from gas service and by incremental integrity work on the NOL and ~~Montreal line~~ EMP.

Fuel Tax: Fuel tax is charged on fuel gas consumed in Saskatchewan and Manitoba. Removal of pipeline assets from gas service in these two provinces will result in higher fuel gas consumption and a corresponding increase in fuel tax. ~~The total increase in fuel tax over the period 2016 to 2030 is forecast to be minimal (approximately $200 thousand).~~

Electric Costs: The ~~deactivation~~retirement of ~~[~~13~~]~~ electric compressor units will reduce the electric costs incurred annually.

Avoided Maintenance Capital: This is the maintenance capital expected to be incurred on the 13 electric compressor units that will be avoided when these units are ~~deactivated~~retired. Avoided maintenance costs result in lower return, depreciation and income taxes calculated using the same parameters stated above.

Volume 10

Aboriginal Engagement

- the potential effects of the Project on watercourses, native prairie and heritage resources
- involvement in construction monitoring and reclamation plans
- economic development and participation, including capacity funding, community investment, employment, training and vendor opportunities during construction and operations, and opportunities for Project revenue sharing

6.2.2 Saskatchewan

Energy East has engaged ~~23~~24 First Nation and Métis communities and organizations in Saskatchewan since engagement efforts began in April 2013. The issues of interest and concern identified include:

- pipeline safety and integrity, the nature of the product, the potential effects on the environment in the event of a spill and emergency response planning
- the protection of resources, including Qu'Appelle and Round lakes
- the adequacy of engagement by the Crown, the NEB and Energy East
- the potential effects of the Project on the environment, including on surface and groundwater quality, fish, wildlife, traditional land and resource use activities and community interests, species at risk, and on the health of community members
- economic development and participation, including capacity funding, community investment, and employment, training and vendor opportunities during construction and operations
- the need for abandonment and decommissioning plans and corporate responsibility for all TransCanada facilities within the region over the lifetime of a project

6.2.3 Manitoba

Energy East has engaged 20 First Nation and Métis communities and organizations in Manitoba since engagement efforts began in April 2013 and the issues of interest and concern identified include:

- potential effects of the Project on the environment and, in particular, the potential effects of the proposed Assiniboine River crossing
- the potential effects of the Project on traditional use of lands, waters and resources, and on lands within the Sand Hills and Whiteshell Provincial Park
- the potential effects of spills and community participation in environmental protection and emergency response
- the potential effects of the Project on Treaty rights
- the adequacy of provincial and federal Crown consultation on the Project and the need for a meaningful engagement process that addresses the unique historic circumstances of the Métis and First Nations within the region

ESA Volume 17

Biophysical and Socio Economic Effects Assessment – New Brunswick

Benthic habitat surveys were conducted in the PDA in July 2015. High bottom turbidity resulted in poor quality of the underwater video in the area. The predominant substrate type observed along all six transects was sand with gravel/cobble and shell hache. Occasional rubble and boulders were observed along transects 3, 4 and 6. Three metal lobster traps and three tires were also observed on transects 4, 5 and 6 outside the footprint of the marine terminal. Two American lobsters , one hermit crab (not identified to species) and one unidentified fish were observed along transects 4 and 6 outside the footprint of the marine terminal. Macroalgae throughout the area was uncommon but occasionally observed; for example, patches of rockweed (*Fucus* sp.).

Results from the 2013 benthic invertebrate grab samples in the area revealed that the benthic communities at all sample locations (see Figure 10-2) were dominated by annelids (primarily polychaetes). Polychaetes accounted for between 80 and 90% of the communities at J2, J13, and S13 and comprised between 43% and 72% at the remaining stations. Station S9 contained a large proportion of bivalves (primarily *Nucula proxima*) which accounted for 44% of the individuals found. Bivalves comprised between 11% and 23% of benthic communities at stations J1, J2, J8, J10, J12, and S14A. Crustaceans (primarily barnacles, amphipods, and cumaceans) comprised greater than 10% of the organisms found at stations J8, J10, J12, and J14. Gastropods were observed in relatively low numbers at all stations. Organisms listed under the 'other' category primarily included nematodes, nemerteans and sipunculids. These 'other' organisms comprised between 11% and 23% of the benthos found at stations J1, J10, J12, J15, and S14A. In general, stations J2, J13, and S13 were the most heavily dominated by annelid taxa, suggesting that the communities in these areas are less complex and might be indicative of environmental stress. Station J12 exhibited the least dominance by any one taxa group, suggesting that the community at this location was more stable, complex and potentially less impacted by environmental stressors.

In 2015 sediment samples for infaunal benthic invertebrate analysis were collected from three stations within the anticipated dredge area of the PDA (see Figure 10-2~~Error! Reference source not found.).~~ The benthic communities at each sample site were dominated by annelids (primarily polychaetes). Molluscs and arthropods were the second or third most abundant taxonomic groups, and most were bivalves, barnacles, cumaceans and amphipods. Less abundant taxa within the samples included nematodes, chordates, foraminifera and sipunculids. Taxonomic diversity was lower in sample SS2 than in samples SS8 and SS9. Sample SS9 had the highest number of individual organisms, followed by SS8 and SS2. These variations in diversity and number of organisms may be attributed to the difference in sediment composition among the three sampling sites. Site SS2 was predominately fine sediment with a high silt fraction, whereas SS8 and SS9 were predominately coarser sediment that contained more sand and gravel and lesser amounts of silt and clay.

FIELD SURVEY RESULTS

A total of 34 marine bird species were recorded during the surveys, including detection of one SOMC. Du ring the survey periods, the habitat in the PDA was primarily used by small numbers of feeding and wintering dabbling and diving ducks (primarily black scoter and common eider) and cormorant species, which were present throughout the year.

Gull species, such as herring gull and great black-backed gull were recorded on every survey visit, and are present in the PDA year-round. Iceland gull were recorded foraging in the PDA during the winter and early spring. Several species of shorebirds were observed in low numbers near the PDA, including spotted sandpiper (*Actitis macularius*), killdeer (*Charadrius vociferus*), purple sandpiper, whimbrel (*Numenius phaeopus*), and semipalmated plover. Double-crested cormorant were recorded in small numbers, passing by the PDA during fall migration months (August through November), and using the habitat within the PDA for foraging.

Harlequin duck was the only SOMC recoded during field surveys; this species was observed on five of the 27 surveys completed. This is consistent with past records of small numbers of harlequin ducks observed in the Anthonys Cove to Mispec area.

11.3 Potential Effects

11.3.1 Potential Effects and Measurable Parameters

Potential effects of the Project on marine wildlife and wildlife habitat were identified and evaluated based on the following:

- The interaction could cause a measurable change in the VC and/or has an identified regulatory threshold that could be exceeded by project development (construction or operations).
- The interaction could affect the persistence and viability of the VC in the RAA.
- The interaction could directly or indirectly affect a SAR whose *population or habitat are provincially or federally managed or protected (*e.g.*, Species at Risk Act, Migratory Birds Convention Act*, New Brunswick *Species at Risk Act*).
- The interaction has been identified as an effect of concern by regulators and other stakeholders as a key effect on a particular VC, identified as an effect of concern based on the professional judgment of those conducting the assessment, or could be specific to a particular region.

Based on this review and knowledge of the Project and its associated activities, the following project-specific effects on marine wildlife and wildlife habitat including SAR or SOMC are assessed:

- change in marine wildlife behavior – sensory disturbance caused by:
- construction of the marine terminal complex (e.g., pile driving, use of barges and support vessels for installation of the trestle and berth facilities and dredging); or
- the operation of the marine terminal complex and vessel loading/hoteling, could interact with marine wildlife and wildlife habitat
- change in health of marine wildlife – primarily related to sensory disturbance caused by:

- construction of the marine terminal complex (e.g., pile driving, use of barges and support vessels for installation of the trestle and berth facilities and dredging); or
- the operation of the marine terminal complex and vessel loading/hoteling, could interact with marine wildlife and wildlife habitat

To adequately characterize the potential effects of the Project on marine wildlife and wildlife habitat, measurable parameters are used to represent each type of predicted effect. Effective parameters are preferably measurable and quantifiable (e.g., underwater sound level). However, some effects on marine wildlife lack defined parameters to measure effects and are therefore qualitative and rely primarily on professional judgment and past project experience.

Table 11-4 summarizes the potential effects, measurable parameters, and rationale for each selection for the marine wildlife and wildlife habitat VC.

Table 11-4 Potential Effects and Measurable Parameters for Marine Wildlife and Wildlife Habitat

Potential Project Effect	Rationale for Inclusion of the Potential Project Effect in the Assessment	Measurable Parameter(s) for the Effect	Rationale for Selection of the Measurable Parameter
Change in behaviour	Marine terminal complex construction and operation has the potential to affect marine wildlife behavior.	• Underwater sound level • Potential for behavioural change due to in air sound or light	Construction of the marine components of the Project has potential to produce sound and light levels at magnitudes that could trigger behavioural changes to marine wildlife.
Change in health	Marine terminal complex construction and operation has the potential to affect marine wildlife health.	• Underwater sound level • Potential for injury or mortality due to in air sound or light	Construction of the marine components of the Project has potential to produce sound and light levels that could cause physical injury or mortality to marine wildlife.

11.3.2 Effects Assessment

Project activities associated with the marine terminal complex have potential to directly and indirectly affect marine wildlife and wildlife habitat by way of in-air and underwater noise, and night-lighting. Specifically, these Project activities have the potential to result in the following effects:

- change in behaviour
- change in health

Potential interactions between Project activities and marine wildlife and wildlife habitat are presented in Table 11-5. The effects of marine shipping associated with the Project, including berthing, on marine wildlife and wildlife habitat are assessed in Volume 17, Part B, Section 4.3. Effects related to collisions between vessels and marine mammals are addressed with accidents and malfunctions in Volume 19.

List of Appendices

Abbreviations

µPa .... micro Pascal
AHDs .... acoustic harassment devices
AQMG .... Air Quality Model Guideline
CAAQS .... Canadian Ambient Air Quality Standards
CAC .... criteria air contaminant
CALPUFF .... California Puff Modelling System
CO .... carbon monoxide
COSEWIC .... Committee on the Status of Endangered Wildlife in Canada
CRA .... commercial, recreational, aboriginal
CWS .... Canadian Wildlife Services
dB .... decibel
DFO .... Fisheries and Oceans Canada
EEDI .... Energy Efficiency Design Index
Energy East .... Energy East Pipeline Ltd.
ESA .... environmental and socio-economic assessment
ESRD .... Alberta Environment and Sustainable Resource Development
GHG .... greenhouse gas
H_2S .... hydrogen sulphide
Hz .... hertz
IMO .... International Maritime Organization
kHz .... kilohertz
KI .... key indicator
km .... kilometre
LAA .... local assessment area
LFA .... lobster fishing area
LNG .... liquefied natural gas
m .... metre
MARPOL .... International Convention for the Prevention of Pollution from Ships
MBCA .... *Migratory Birds Convention Act*
MCTS .... Marine Communications and Traffic Service
MT .... metric tonne
NA-ECA .... North American Emission Control Area
NAFO .... Northwest Atlantic Fisheries Organization
NB .... New Brunswick
NBDELG .... New Brunswick Department of Environment and Local Government
NEB .... National Energy Board
nm .... nautical mile
NO .... nitrogen oxide
NO_2 .... nitrogen dioxide

NOAA .... National Oceanic and Atmospheric Administration
NO_X .... nitrogen oxides
OGV .... ocean-going vessel
OLM .... ozone limiting method
OMECC .... Ontario Ministry of the Environment and Climate Change
PDA .... project development area
PM_{10} .... particulate matter with diameters less than 10 µg
$PM_{2.5}$ .... particulate matter with diameters less than 2.5 µg
Project .... Energy East Project
RAA .... regional assessment area
RMS .... root mean square
SAR .... species at risk
SARA .... *Species at Risk Act*
SCR .... selective catalytic reduction
SEL .... sound exposure level
SFA .... scallop fishing area
SNCR .... selective non-catalytic reduction
SO_2 .... sulphur dioxide
SOMC… .... species of management concern
SO_X .... oxides of sulphur
SPA .... scallop production area
SPL .... sound pressure level
SPM .... single point mooring
TDR .... technical data report
TERMPOL .... Technical Review Process of Marine Terminal Systems and Transshipment Sites
TSP .... total suspended particulate matter
TSS .... total suspended solids
U.S. EPA .... United States Environmental Protection Agency
VC .... valued component
VLCC .... very large crude carrier
VOC .... volatile organic compounds

4.5.2 Significance Thresholds for Residual Effects

Residual effects are characterized based on several criteria and on the expected effectiveness of mitigation measures.

A significant adverse residual effect on marine wildlife and wildlife habitat is one that:

- affects populations in such a way as to cause a decline in abundance or change in distribution such that the populations in the assessment area will not be sustainable

All applicable legislation and regulations (i.e., *Fisheries Act*, SARA, MBCA, NB SARA) were also considered to be an essential part of the framework for the assessment of residual effects on marine wildlife and wildlife habitat.

4.5.3 Assessment of Residual Effects

CHANGE IN BEHAVIOUR

MARINE MAMMALS

Changes in behaviour as a result of underwater noise from marine shipping depend on the magnitude and duration of the noise, the areal extent of the underwater noise, and the species, the individual, and their activity (Richardson et al. 1995; Southall et al. 2007). Underwater acoustic modelling (see Section 4.3.2) was used to predict the sound levels produced by vessels transiting to and from the marine terminal. To determine the potential residual effects from that underwater noise, the sound levels were compared to a behavioural disruption threshold established by the NOAA. DFO has not adopted regulatory thresholds for assessing the effects of underwater noise on marine mammals; therefore, thresholds established by NOAA are considered in this assessment. ~~(see Section 4.3.2**Error! Reference source not found.**). ~~NOAA is currently developing new behavioural disruption thresholds; however, these are not yet available (NOAA 2013, 2015). Therefore, the current, interim behavioural disruption thresholds (160 dB_{RMS} re 1 µPa for pulsed noise and 120 dB_{RMS} re 1 µPa for nonpulse noise for both pinnipeds and cetaceans [NOAA n.d.]) are used in this assessment. Project-related shipping will create underwater noise that may cause changes in marine mammal behaviour, including SOMC. See Table 4-8 for the estimated areal extent of underwater noise above the behavioural disruption threshold, based on acoustic modelling conducted for the Project.

blue whales off the coast of California had no responses to loud anthropogenic noise at the scales examined. Research suggests that marine mammals recover or return to normal behaviour once noise that can cause changes in behaviour ceases (Southall et al. 2007). Current fin, humpback, and minke whale distributions (see Figure 4-3 to Figure 4-5) have areas of high densities outside of the shipping lanes. Vessel speed mitigation will reduce the extent of underwater noise above the behavioural disruption threshold and therefore the number of marine mammals exposed to that noise.

There is also potential for underwater noise from marine shipping to reduce communication space or cause masking, which limits the ability of marine mammals to communicate and detect natural sounds (Nowacek et al. 2003; Richardson et al. 1995). North Atlantic right whales in and around Stellwagen Bank National Marine Sanctuary in Massachusetts Bay, Gulf of Maine had a greater than or equal to 38% loss of communication space (i.e., the area around an individual where communication with conspecifics can occur) due to shipping noise compared to hypothesized historic ambient noise levels (Hatch et al. 2012). In the same area, communication space was reduced to an average of 80% for fin whales, 92% for humpback whales and 23% for right whales as a result of a passing commercial vessel (Clark (2009). The reason for the larger reduction in communication space for right whales, relative to fin and humpback whales, was because right whale calls are not as loud to begin with (Clark et al. 2009). Hermannsen et al. (2014) found changes in the hearing range of harbour porpoise as a result of large tanker traffic, although this occurred in areas that were shallower than those in which Project-related shipping would occur and overlap with the distribution of harbour porpoise within the RAA.

It is expected that marine mammals exposed to noise above the behavioural disruption threshold will resume normal activity once the noise ceases (Southall et al. 2007). Marine mammals within 11.2 km of a Project-related tanker will be exposed to underwater noise that could cause changes in behaviour for 12 minutes to 48 minutes (depending on location and season) approximately every 16 hours.

Changes in marine mammal behaviour can occur at varying levels of underwater noise, and depend on the species, the individual, and their activity. North Atlantic right whale call amplitude was found to increase linearly with increases in background noise from 92 dB to142 dB (in the 20 Hz to 8 kHz range) (Parks et al. (2011). When North Atlantic right whales were exposed to tanker noise between 129 dB and 142 dB re 1 µPa (with most energy from 50 Hz to 500 Hz), there was no major change in dive behaviour (Norwacek et al. 2003). Fin whales in the Northeast Atlantic and Mediterranean Sea changed call characteristics as a result of tanker noise; this may compensate for the effects of masking but result in increased energetic costs (Castellote et al. 2012).

Fin whales in Californian waters did not change foraging patterns when exposed to noise exceeding 140 dB re 1 µPa within the study area (Croll et al. 2001). Migrating humpback whales off the coast of Australia changed path and dive behaviour when exposed to noise from 2 to 2.1 kHz and source levels of 148 dB to153 dB at 1 m RMS (Dunlope et al. 2013). Changes in behaviour as a result of anthropogenic noise are difficult to predict and vary considerably (Southall et al. 2007).

Although the current interim behavioural disruption thresholds are under evaluation (NOAA n.d.) likely provide a overestimate for changes in behaviour because the potential for a change in marine mammal behaviour is dependent on a variety of variables.

APPENDIX 4A Modelling Underwater Sound Associated with Shipping in the Bay of Fundy

JASCO APPLIED SCIENCES

Modelling Underwater Sound Associated with Shipping in the Bay of Fundy

Submitted to:
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Stantec Consulting Ltd.
Subconsultant agreement: 01 May 2014

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1. Introduction

1.1. Project Overview

The Energy East Project involves construction of a pipeline system to transport crude oil from Alberta and Saskatchewan to delivery points in Quebec and New Brunswick. As part of this project, TransCanada PipeLines Limited has proposed to operate a terminal on the north shore of the Bay of Fundy at Mispec Point, approximately 9 km southeast of the city of Saint John, New Brunswick (Figure 1). The Canaport Marine Terminal would include a two-berth fixed structure, and would load Suezmax oil carriers and Very Large Crude Carriers (VLCC) destined for international markets.

This report describes a modelling study carried out by JASCO Applied Sciences (JASCO) for Stantec Consulting to predict underwater noise levels associated with shipping operations to and from the Canaport Marine Terminal. A total of six scenarios were modelled for two separate times of year (February and August) and for operation of two types of carriers (Suezmax and VLCC) and associated support tugs. The modelling methodology accounts for source characteristics and for environmental properties in the area, including seasonal variations in water column properties. Model results are presented as root-mean-square (rms) sound pressure levels (SPLs) and 24-hour sound exposure levels (SELs).

Section 1.2 presents background information on underwater acoustic modelling and the sound level thresholds used to assess potential impacts on marine mammals. Section 2 outlines the scenarios modelled. Section 3 discusses the methodology for estimating the source levels and modelling the sound propagation and describes the environmental parameters used by the propagation models. Section 4 presents the model results in two formats: tables of distances to sound level thresholds and sound field contour maps showing the directivity of the various sound level threshold contours. Finally, Section 5 presents an analysis of the results.

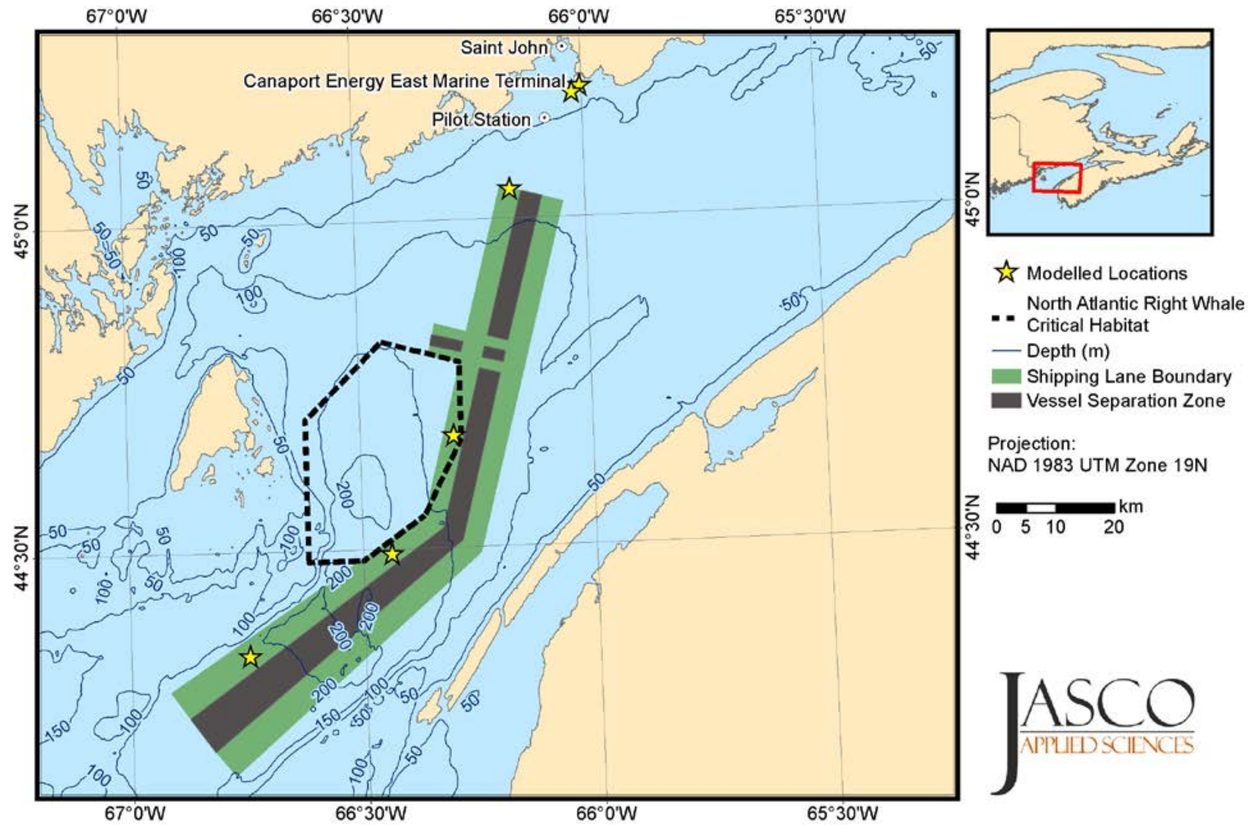

Figure 1. Modelled site locations near proposed Canaport Energy East Marine Terminal at Mispec Point, NB.

1.2. Background

1.2.1. Transmission Loss

The propagation of sound through the environment is modelled by predicting the transmission loss—a measure, in decibels (dB), of the decrease in sound level between a source and a receiver some distance away. Geometric spreading of acoustic waves is the dominant transmission loss mechanism. Transmission loss also occurs when the sound is absorbed and scattered by the seawater and absorbed, scattered, and reflected at the water surface and within the seabed. Transmission loss is dependent on the sound frequency and the acoustic properties of the environment including the underwater sound speed (which changes with depth and water properties), the bathymetry, and the geoacoustic properties of the seafloor.

If the transmission loss at a given frequency is known, then the sound level received at a location (received level, RL) equals the source level (SL) minus the transmission loss (TL) that occurs between the source and that location:

$$RL = SL - TL \tag{1}$$

Where SL is the effective SPL or SEL of the source at a reference distance of 1 m (dB re 1 µPa @ 1 m and dB re 1 µPa^2·s @ 1 m, respectively), RL is SPL or SEL received at the given location (dB re 1 µPa or dB re 1 µPa^2·s, respectively), and TL is the transmission loss (dB re 1 m) that occurs between the source and that location.

1.2.2. Impulsive and Continuous Sound

Anthropogenic and environmental noise can be classified into two general categories: impulsive and continuous. Impulsive noise, such as noise from impact pile driving, is characterized by brief, intermittent acoustic events with rapid (i.e., within a few seconds) onset and decay back to ambient levels. Continuous noise, such as propeller noise from a ship, is characterized by gradual changes in the sound level over time.

1.2.3. Acoustic Metrics

Underwater sound amplitude is measured in decibels (dB) relative to a fixed reference pressure of p_0 = 1 μPa. Because the sound levels of impulsive noise are not generally proportional to the instantaneous acoustic pressure, several sound level metrics are commonly used to evaluate sound levels of impulsive noise and their effects on marine life. The following sound metrics may also be referenced in the assessment of continuous noise (Section 1.2.5).

The zero-to-peak SPL, or peak SPL (dB re 1 μPa), is the maximum instantaneous sound pressure level in a stated frequency band attained by an acoustic pressure signal, $p(t)$:

$$\text{peak SPL} = 10\log_{10}\left[\frac{\max\left(\left|p^2(t)\right|\right)}{p_0^2}\right] \tag{2}$$

The peak SPL metric is commonly quoted for impulsive sounds, but it does not account for the duration or bandwidth of the noise. At high intensities, the peak SPL can be a valid criterion for assessing whether a sound is potentially injurious; however, because the peak SPL does not account for the duration of a noise event, it is a poor indicator of perceived loudness.

The root-mean square (rms) SPL (dB re 1 μPa) is the rms pressure level in a stated frequency band over a time window (T, s) containing the acoustic event:

$$\text{rms SPL} = 10\log_{10}\left(\frac{1}{T}\int_T p^2(t)dt \Big/ p_0^2\right) \tag{3}$$

The rms SPL is a measure of the average pressure or of the effective pressure over the duration of an acoustic event, such as the emission of one acoustic pulse or sweep. Because the window length, T, is the divisor, events more spread out in time have a lower rms SPL for the same total acoustic energy density.

The sound exposure level (SEL, dB re 1 μPa^2·s) is a measure of the total acoustic energy received over a period of time, and is calculated is by taking the dB level of the integrated sound power over a specified time period, T:

$$SEL = 10\log_{10}\left(\int_T p^2(t)dt \Big/ \left(p_0^2 T_0\right)\right) \tag{4}$$

where T_0 is a reference time interval of 1 s. The SEL represents the total acoustic energy received at some location during an acoustic event; it measures the total sound energy to which an organism at that location would be exposed.

SEL can be calculated over time periods containing multiple acoustic events. The SEL over multiple events (dB re 1 µPa^2•s) is computed by summing (in linear units) the SELs of the N individual events:

$$\mathrm{SEL_N} = 10\log_{10}\left(\sum_{i=1}^{N} 10^{\frac{\mathrm{SEL}_i}{10}}\right) \tag{5}$$

1.2.4. Marine Mammal Auditory Weighting Functions

The potential for sound to affect marine animals depends in part on how well the animal can hear it. Sounds are less likely to disturb or injure animals if they are at frequencies that the animals cannot hear well, although sound pressure can cause physical injury through non-auditory mechanisms (i.e., barotrauma) if it is high enough. For sound levels below such extremes, frequency weighting can be applied to scale the importance of sound components at particular frequencies in a manner reflective of an animal's sensitivity to those frequencies (Nedwell and Turnpenny 1998, Nedwell et al. 2007).

Auditory weighting functions for marine mammals were proposed by Southall et al. (2007). They are referred to as M-weighting functions. Functions were defined for five functional hearing groups of marine mammals:

- Low-frequency cetaceans (LFCs)—mysticetes (baleen whales)
- Mid-frequency cetaceans (MFCs)—some odontocetes (toothed whales)
- High-frequency cetaceans (HFCs)—odontocetes specialized for using high-frequencies
- Pinnipeds in water—seals, sea lions, and walrus
- Pinnipeds in air (not addressed here)

The M-weighting functions have unity gain (0 dB) through the passband and their high and low frequency roll-offs are approximately –12 dB per octave. The amplitude response in the frequency domain of each M-weighting function is defined by:

$$G(f) = -20\log_{10}\left[\left(1+\frac{a^2}{f^2}\right)\left(1+\frac{f^2}{b^2}\right)\right] \tag{6}$$

where $G(f)$ is the weighting function amplitude (in dB) at the frequency f (in Hz), and a and b are the estimated lower and upper hearing limits, respectively, which control the roll-off and passband of the weighting function. The parameters a and b are defined uniquely for each functional hearing group (Table 1).

Finneran and Jenkins (2012) suggested updates to the cetacean M-weighting functions by merging them with equal-loudness weighting functions. In a draft report, the U.S. National Oceanic and Atmospheric Administration (NOAA 2013) suggested further modifications to the low-frequency cetacean function and also recommended splitting the pinnipeds in water hearing group into two families: phocids (i.e., true seals) and otariids (i.e., sea lions and fur seals). Each auditory weighting function recommended by NOAA (2013) is a merge of two functions:

$$\begin{aligned} G_1(f) &= K_1 - 20\log_{10}\left[\left(1+\frac{a_1^2}{f^2}\right)\left(1+\frac{f^2}{b_1^2}\right)\right] \\ G_2(f) &= K_2 - 20\log_{10}\left[\left(1+\frac{a_2^2}{f^2}\right)\left(1+\frac{f^2}{b_2^2}\right)\right] \end{aligned} \tag{7}$$

where, in general, G_1 is the M-weighting function defined by Southall et al. (2007; Equation 6) and G_2 is the equal-loudness function defined by Finneran and Jenkins (2012). K_1 and K_2 normalize the functions to the same reference frequency. The NOAA-recommended auditory weighting function is equal to the higher of the two functions at each frequency; generally, G_1 applies at low frequencies and G_2 applies at high frequencies. For the mid- and high-frequency cetacean groups, the parameters are as defined by Southall et al. (a_1 and b_1) and Finneran and Jenkins (a_2 and b_2). For the low-frequency cetacean group, the parameters are modified from those previously defined. For pinnipeds in water, new G_1 parameters are defined separately for phocid and otariid pinnipeds in water and the G_2 function is omitted. The phocid weighting function has a wider frequency range than the otariid function (Table 1). The auditory weighting functions recommended by Southall et al. (2007) and NOAA (2013) are shown in Figure 2. The use of weighting functions in addressing proposed NOAA criteria is discussed further in Section 1.2.5.

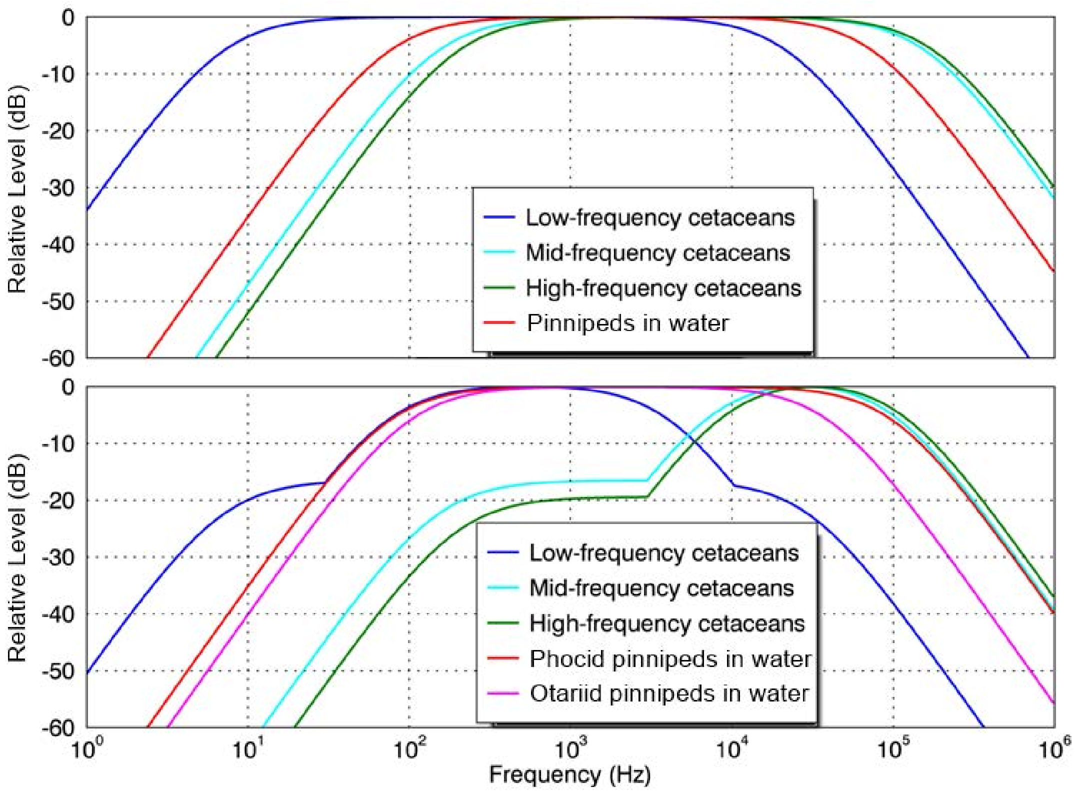

Figure 2. Auditory weighting functions for functional marine mammal hearing groups as recommended by (top) Southall et al. (2007) and (bottom) NOAA (2013).

Table 1. Parameters for the auditory weighting functions recommended by Southall et al. (2007) and NOAA (2013).

Functional hearing group	Southall et al.		NOAA					
	a (Hz)	b (Hz)	K_1 (dB)	a_1 (Hz)	b_1 (Hz)	K_2 (dB)	a_2 (Hz)	b_2 (Hz)
Low-frequency cetaceans (LFC)	7	22,000	−16.5	7	30,000	0.3	75	4,000
Mid-frequency cetaceans (MFC)	150	160,000	−16.5	150	160,000	1.4	7,829	95,520
High-frequency cetaceans (HFC)	200	180,000	−19.4	200	180,000	1.4	9,480	108,820
Pinnipeds in water (Pw)	75	75,000	–	–	–	–	–	–
Phocid pinnipeds in water (PPw)	–	–	0	75	100,000	–	–	–
Otariid pinnipeds in water (OPw)	–	–	0	100	40,000	–	–	–

1.2.5. Marine Mammal Noise Exposure Criteria

Modelling results are provided for the following assessment criteria for underwater noise:

- Current interim NMFS acoustic criteria for behavioural disruption, and
- Criteria proposed in the NOAA Draft Acoustic Guidelines (NOAA 2013) released in December 2013.

The U.S. National Marine Fisheries Service (NMFS) has defined potential disturbance or behavioural disruption for both pinnipeds and cetaceans:

- 160 dB re 1 μPa rms SPL for impulsive sounds, and
- 120 dB re 1 μPa rms SPL for continuous sounds (NMFS 2014).

Expressed in rms SPLs, the criteria account for the energy and duration of the acoustic event. They do not, however, account for exposure duration, frequency composition of the sound, repetition rate, or the hearing ability of the animals.

In December 2013, NOAA released Draft Acoustic Guidelines (NOAA 2013), which are currently under review. The guidelines include peak SPL thresholds and cumulative SEL injury thresholds; under the U.S. regulatory system, a *take* is defined to occur when a marine mammal is exposed to sound levels that exceed these thresholds. The NOAA Draft Acoustic Guidelines stipulate that the SELs must be calculated from the level accumulated at the animal's location(s) over a specific accumulation period. Furthermore, the SEL must be frequency-weighted for the applicable marine mammal functional hearing group and compared to thresholds specific to each group.

The accumulation period for computation of the SEL under the NOAA Draft Acoustic Guidelines depends on the duration of the activity, movement of the source and animal, and the ability to model such movement. Where animal and/or source movement can be modelled, the accumulation period is the lesser of the length of the activity and 24 h. If the source and animal movements cannot be modelled in the assessment, a 1-hour accumulation time is proposed as a simplified approach. For a stationary source, however, the guidelines state that this suggested accumulation time could be inappropriate for marine mammals that show fidelity to a particular site, as they may stay nearby for longer times.

The auditory weighting functions and thresholds proposed by NOAA (2013) are based primarily on two studies: Southall et al. (2007) and Finneran and Jenkins (2012). While closely related, the weighting functions and thresholds proposed in the NOAA Draft Acoustic Guidelines differ from those in both of these studies. As previously discussed, NOAA proposes auditory weighting functions and thresholds for five marine mammal hearing groups: low-, mid-, and high-frequency cetaceans, and two classes of pinnipeds in water—phocids and otariids (Section 1.2.4). The NOAA Draft Acoustic Guidelines thresholds for the onset of permanent hearing threshold shift (PTS) are given in Table 2. The definition of behavioural thresholds requires additional research and assessment, and is not addressed in the Draft Acoustic Guidelines (NMFS 2014, Lucke et al. 2014).

Table 2. Peak sound pressure level (SPL, dB re 1 μPa) and M-weighted sound exposure level (SEL, dB re 1 $\mu Pa^2 \cdot s$) dual acoustic thresholds for permanent hearing threshold shift (PTS) from impulsive and non-impulsive sounds proposed by the NOAA Draft Acoustic Guidelines (NOAA 2013, Tab. 6).

Functional hearing group	Impulsive		Non-impulsive	
	Peak SPL	Weighted SEL	Peak SPL	Weighted SEL
Low-frequency cetaceans	230	187	230	198
Mid-frequency cetaceans	230	187	230	198
High-frequency cetaceans	201	161	201	180
Phocid pinnipeds underwater	235	192	235	197
Otariid pinnipeds underwater	235	215	235	220

2. Modelled Scenarios

Underwater sound fields associated with shipping operations were modelled for the following scenarios, placed along the approximate route of an outbound carrier (Figure 3, Table 3):

- Carrier docking/undocking: Tug-assisted docking/undocking operations near the terminal (Site 1, Figure 3) were modelled assuming three support tugs for a Suezmax carrier and four support tugs for a VLCC (see Section 3.1 for details). It was assumed that carriers will not be equipped with thrusters or will not use thrusters if installed, so that the contribution to the overall sound field from the carrier is expected to be negligible during docking and undocking. Only the sound generated by the tugs was modelled for docking/undocking scenarios.
- Carrier transit between the terminal and the pilot station: A carrier and one escort tug transiting at 6 kts were modelled for a site between the terminal and the pilot station (Site 2, Figure 3).
- Carrier transit at full speed: A carrier transiting at 15 kts was modelled for three sites in the outbound shipping lane in the Bay of Fundy (Sites 3, 5, and 6, Figure 3).
- Carrier transit through the North Atlantic right whale critical habitat: A carrier transiting at either 10 kts (summer) or 15 kts (winter) (see Section 3.1.1) was modelled for a site in the outbound shipping lane where it passes through the North Atlantic right whale critical habitat (Site 4, Figure 3).

The underwater sound field was modelled for a Suezmax carrier and a VLCC for each of the transit scenarios (Section 3.1).

The distance over which sound propagates depends on the water column sound speed profile, which varies over the course of a year. In order to bracket this variability, each scenario was modelled using sound speed profiles from February and August, representing the likely best and worst cases for sound propagation, respectively (Section 3.3.3).

Assessment of SELs as per the NOAA draft criteria (Section 1.2.5) requires that SELs be integrated over an appropriate area and time period. A sample shipping scenarios was assembled to estimate SELs from the series of carrier and tug operations involved in undocking of a single carrier and transit to the end of the outbound shipping lane (Figure 4, Table 4). SELs were estimated for a Suezmax carrier and a VLCC, for both February and August sound speed profiles. Carriers will be running auxiliary engines only during the 20–31 h spent at berth before undocking (Fidell 2014), and will generate negligible amounts of noise during this time; as such, time spent at dock before undocking was not included in the scenario. The scenario takes into account the site- and source-specific sound fields associated with each activity, source movement, and the expected or likely frequency and/or duration of noise emission. Animal movement was not modelled.

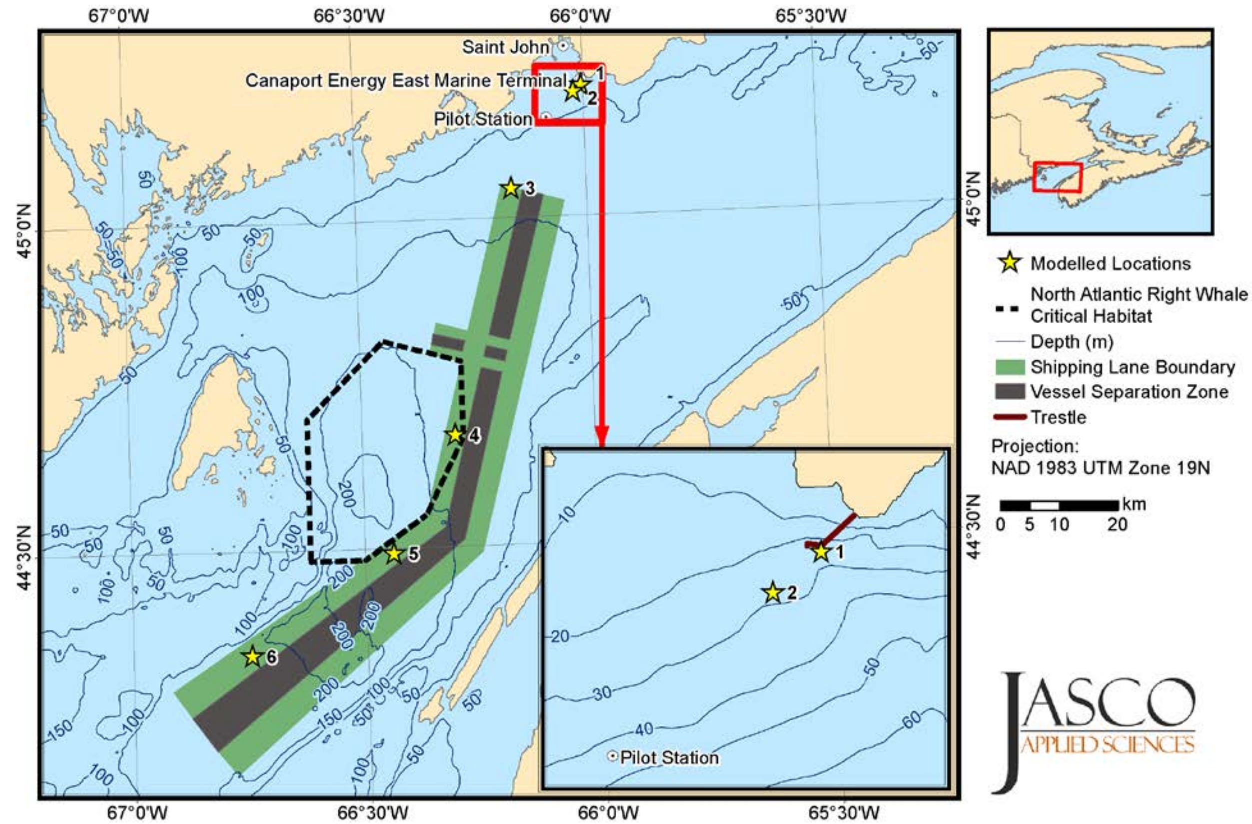

Figure 3. Locations of modelled sites. Inshore sites are shown in greater detail in the inset. Site numbers correspond to those in Table 3.

Table 3. Locations and operations for modelled scenarios. Easting and northing are in Universal Transverse Mercator (UTM) Zone 19N. Water depths are given in metres below the mean water level.

Site	Longitude	Latitude	Easting (m)	Northing (m)	Approximate depth (m)	Operations
1	66°0.198'W	45°12.054'N	735358	5009638	25	Docking/undocking
2	66°1.260'W	45°11.460'N	734009	5008486	28	Carrier + tug transit, 6 kts
3	66°9.708'W	45°2.796'N	723512	4992046	87	Carrier transit, 15 kts
4	66°17.982'W	44°40.350'N	714035	4950118	130	Carrier transit, 10 kts (summer) or 15 kts (winter)
5	66°26.352'W	44°29.664'N	703599	4929977	195	Carrier transit, 15 kts
6	66°44.862'W	44°20.598'N	679533	4912471	196	Carrier transit, 15 kts

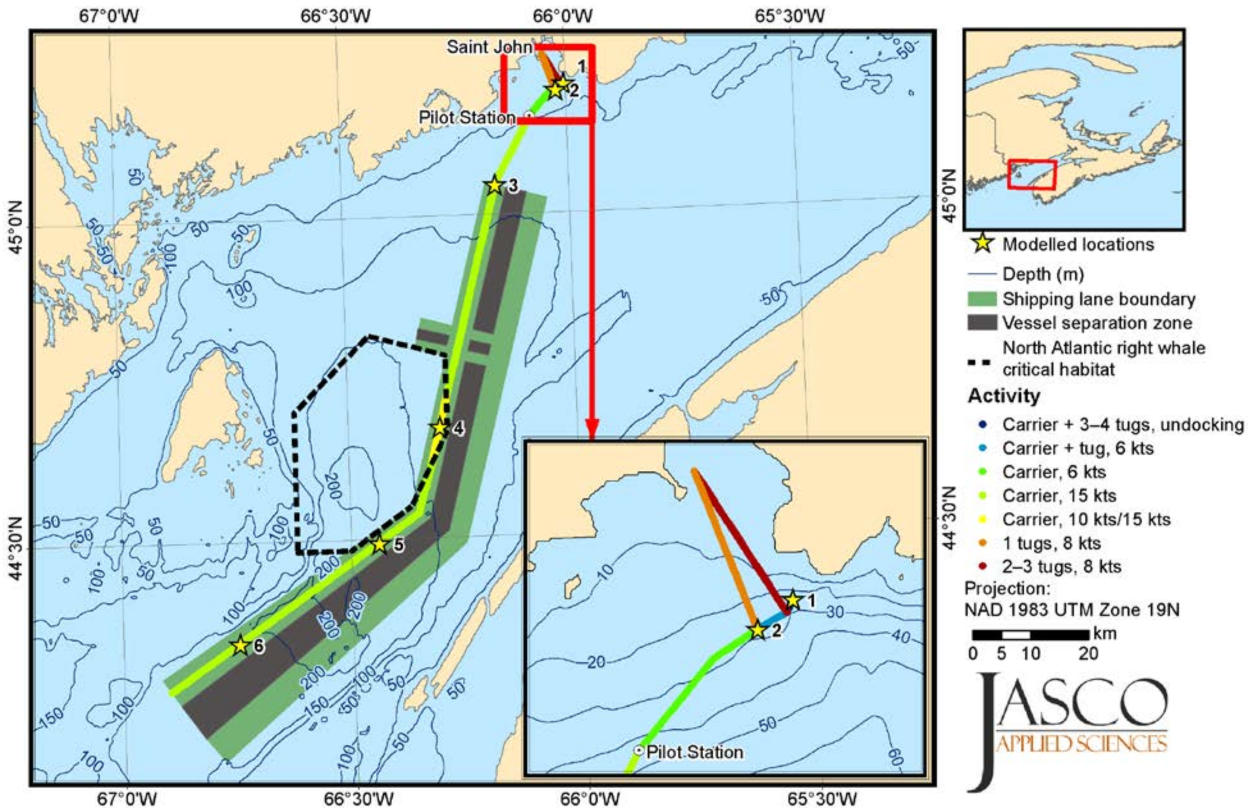

Figure 4. Vessel tracks used to compute 24-hour sound exposure levels (SELs). Ranges for the numbers of tugs reflect the fact that VLCCs require one more support tug for docking and undocking than Suezmax carriers do. Transit speed through the North Atlantic right whale critical habitat is 10 kts in summer and 15 kts in winter.

Table 4. Vessel activities and tracks used to compute 24-hour sound exposure levels (SELs). Activities are listed in approximate order of occurrence for an outgoing carrier, and may overlap in some cases. Transit speed through the marine park depends on the season. BP = bollard pull.

Activity	Vessels		Distance (km)	Speed (km/h (kts))	Time (h)
	Suezmax	VLCC			
Undocking	Carrier + 3 tugs (2 × 70 t BP, 1 × 50 t BP)	Carrier + 4 tugs (3 × 70 t BP, 1 × 50 t BP)	0.6	5.6 (3.0)	0.10
Tug transit to home port	2 tugs (1 × 70 t BP, 1 × 50 t BP)	3 tugs (2 × 70 t BP, 1 × 50 t BP)	6.5	14.8 (8.0)	0.44
Escorted transit	Carrier + tug (70 t BP)	Carrier + tug (70 t BP)	1.3	11.1 (6.0)	0.12
Tug transit to home port	Tug (70 t BP)	Tug (70 t BP)	6.5	14.8 (8.0)	0.44
Transit to pilot station	Carrier	Carrier	6.5	11.1 (6.0)	0.59
Transit to N end of marine park	Carrier	Carrier	50.9	27.8 (15.0)	1.83
Transit through marine park (winter)	Carrier	Carrier	11.8	27.8 (15.0)	0.43
Transit through marine park (summer)	Carrier	Carrier	11.8	18.5 (10.0)	0.64
Transit to end of shipping lane	Carrier	Carrier	61.8	27.8 (15.0)	2.23

3. Methods

Underwater sound fields for the vessel sources were modelled with JASCO's Marine Operations Noise Model (MONM), using parameters specific to the environment. The following sub-sections describe the methodology and parameters used to estimate source levels and sound propagation.

3.1. Source Levels

Source levels for each of the vessels listed in Section 2 were derived from published measurements and empirical models. In each case, source levels were estimated for 1/3-octave-bands from 10–31,623 Hz. The approaches used and the resulting levels are presented in the sub-sections below.

3.1.1. Carriers

Ships visiting the proposed Canaport Marine Terminal will include Suezmax carriers and VLCCs, with the smaller Suezmax carrier making up the bulk of visiting vessels (Fidell 2014). Typical specifications for the two carrier types are shown in Table 5. Ships are expected to transit at 15 kts to the pilot boarding station, then at 6 kts to the turning areas immediately in front of the berths (Moffatt and Nichol 2014). Ship speed will be reduced to 10 kts within the Grand Manan critical habitat during summer and fall (Canadian Coast Guard 2014). Docking and undocking will be carried out with the assistance of tugs, as discussed in Section 3.1.2.

Source levels for the carriers were based on published measurements of three crude oil carriers under normal operating conditions in Santa Barbara Channel (McKenna et al. 2012). The average transiting speed for these oil carriers was 13.5 kts; the average source levels for these measurements were presented in standard 1/3-octave-bands ranging from 20 to 800 Hz. Based on measurements from Arveson and Vendittis (2000), who measured a modern cargo ship with transiting speeds from 8–16 kts, 1/3-octave-band source levels were extrapolated to lower frequencies (10–20 Hz) and to higher frequencies (1–31.6 kHz). Table 6 lists specifications for the surrogate vessels.

The 1/3-octave-band source levels for the surrogate vessels were adjusted to the carrier specifications and transit speeds using the power-law equation of Ross (1976):

$$S(f,V,L) = S_0(f) + c_V 10\log\left(\frac{V}{V_0}\right) + c_L 10\log\left(\frac{L}{L_0}\right) \quad (8)$$

where S is the source spectrum level, f is the frequency, S_0, V_0, and L_0 are the reference source level spectra, speed, and length, respectively. The constants, c_V and c_L, are taken to be 6 and 2, respectively (Wales and Heitmeyer 2002). The resulting 1/3-octave-band source levels for transit speeds of 6, 10, and 15 kts are shown in Figure 5.

Since the dominant source of underwater noise from shipping is generally propeller cavitation (Ross 1976, §8.6), the source depth was estimated based on the drafts and propeller diameters (Table 5). The source of radiated noise was assumed to be at a point midway between the shaft and the top of the propeller disk; therefore, we used the following equation (Gray and Greeley 1980) to estimate the source depth, Zs:

$$Z_s = D - 0.85 \times d \quad (9)$$

where D is the vessel draft and d is the propeller diameter. The resulting source depths, based on the design draft of the carriers, are 9 m for the Suezmax carrier and 13 m for the VLCC.

It was assumed that carriers will not be equipped with thrusters or will not use thrusters during docking/undocking when being assisted by tugs, and will thus contribute only minimally to the overall noise field. As such, only noise from assisting tugs was included in docking/undocking scenarios

(Sections 2 and 3.1.2). Similarly, carriers will generally run only auxiliary engines while at berth (Fidell 2014).

Table 5. Specifications assumed in modelling of source levels for carriers (Antonopoulos 2012, Fidell 2014, and Moffat and Nichol 2014).

Vessel	Length (m)	Breadth (m)	Draft (m)	Maximum power (kW)	Propeller diameter (m)
Suezmax	274	50	16	21,727	8
VLCC	332	60	21	29,400	10

Table 6. Information on surrogate vessels used for deriving source levels for the acoustic model.

Type	Vessel	Size (m)			Power (kW)	Speed (kts)	Broadband SL (dB re 1 μPa @ 1 m)
		Length	Breadth	Draft			
Crude oil carrier*	*Singapore Voyager*	241.0	42.0	14.0	11,931	12.6	180.5
	NS Century	243.0	42.0	14.4	13,721	12.8	
	Chemtrans Sky	229.0	32.0	11.7	9,694	14.6	
Cargo ship**	*Overseas Harriette*	172.9	22.8	10.2	8,352	8–16	178.2–192.1

* Source level measurements from McKenna et al. (2012).
** Source level measurements from Arveson and Venditis (2000).

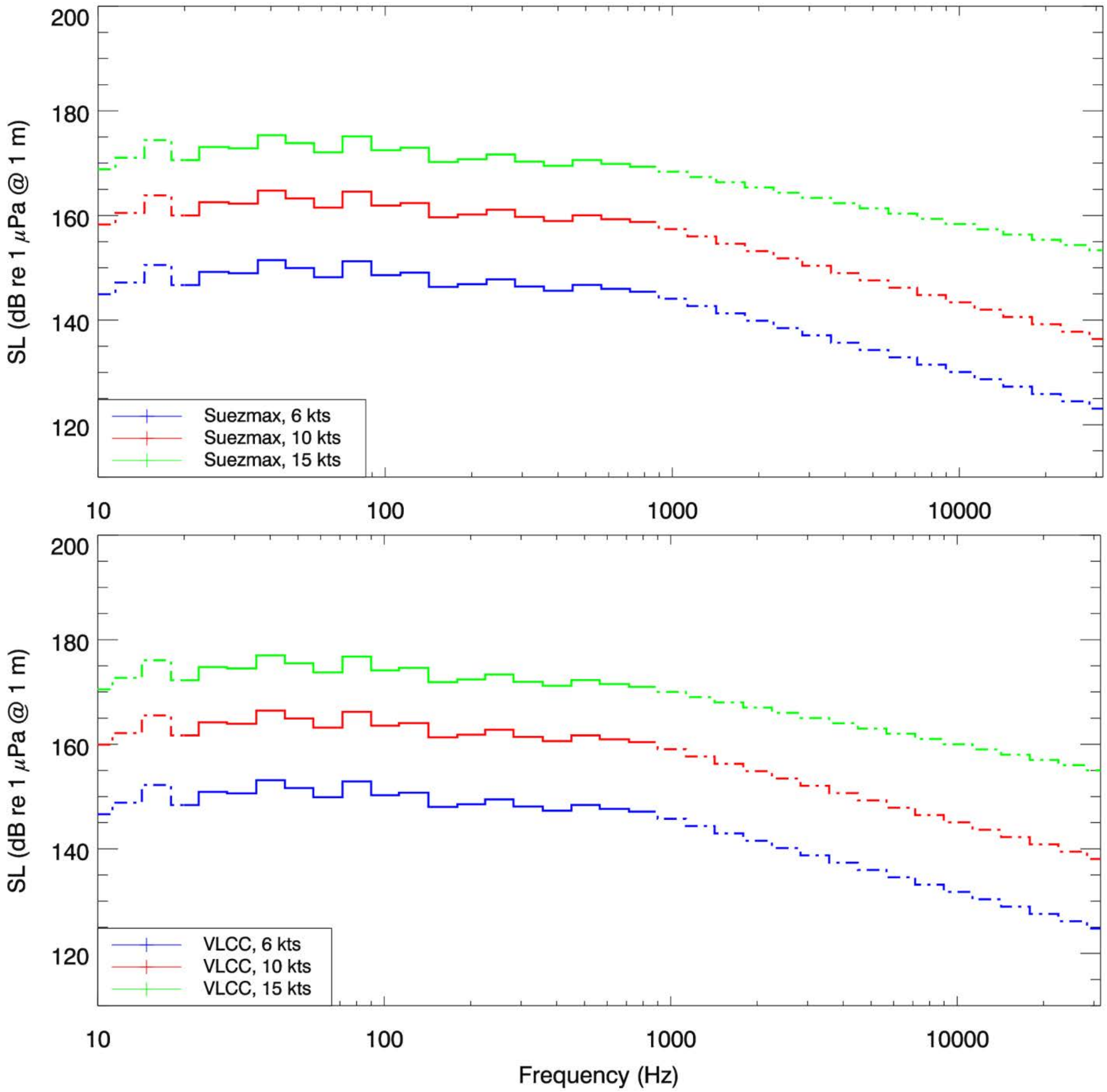

Figure 5. Estimated source levels (SLs) for a (top) Suezmax carrier and (bottom) VLCC transiting at three different speeds. Extrapolated levels below 20 Hz and above 800 Hz are shown as dot-dashed lines.

3.1.2. Tugs

A tug will be employed to escort carriers transiting between the terminal and the point where the carrier transit route crosses the Saint John-Digby ferry route approximately 2 km southwest of the terminal (Figure 3, Section 2). Two additional tugs will assist with docking and undocking of Suezmax vessels; three additional tugs (for a total of four tugs) are anticipated for VLCCs (Moffatt and Nichol 2014). All tugs are expected to use Z drives; initial tug requirements specify a bollard pull of 50 t for one of the tugs and 70 t for the remaining support vessels (Moffatt and Nichol 2014).

Source levels were estimated from the *Britoil 51*, an offshore tug with a bollard pull of 90 t (Table 7; Hannay et al. 2004). Estimated source levels for escort tugs transiting and maneuvering a carrier to the berth were derived from *Britoil 51* source levels for half-speed (6.5 kts) transit and anchor pulling, respectively, using Equation 8 and an additional power correction:

$$S(f,V,L,P) = S_0(f) + c_V 10\log\left(\frac{V}{V_0}\right) + c_L 10\log\left(\frac{L}{L_0}\right) + 10\log\left(\frac{P}{P_0}\right) \tag{10}$$

The additional term reflects the fact that a tug's power rating is based not only on its length (and hence the power needed for propulsion), but also on its designed towing capability. Dimensions and power ratings for the two tugs were based on those of two existing St. John Harbour tugs (Table 7). Because source levels above 10 kHz for the surrogate tug were unavailable, modelled source levels were extrapolated to 31.6 kHz based on an empirical relationship that describes the typical high-frequency trend of source spectrum levels for surface vessels (Ross 1976):

$$S(f) \propto -20\log f, \qquad f \geq 100\ \text{Hz} \tag{11}$$

where *S* is the source spectrum level (dB re 1 µPa^2/Hz @ 1 m) at frequencies above 100 Hz. The source levels were then reduced by 5 dB to reflect the reduction in cavitation noise associated with Z-drive systems (Spence et al. 2007); the resulting 1/3-octave-band source levels are shown in Figure 6.

The estimated source depths for the tugs, from Equation 9 and Table 7, were 1.5 m for the higher-powered tug and 3 m for the lower-powered tug. Because the distribution of tugs with respect to each other or to the carrier being escorted will vary, identical source co-ordinates (easting and northing) were used for all vessels included in a given scenario (Section 2); vessel-specific source depths were used. Although this conservative approach leads to slight increases in sound levels at ranges close to the sources (i.e., a fraction of the real separation of the sources), the effects become negligible at ranges relevant to marine mammal noise exposure criteria.

Table 7. Specifications of the vessels used to estimate source levels for tugs operating at or near the terminal.

Vessel	Length (m)	Breadth (m)	Draft (m)	Maximum power (kW)	Bollard pull (t)	Propulsion	Propeller diameter (m)
Atlantic Bear	30.8	11.1	3.88	4,258	72	2 Z-drive propellers	2.8
Atlantic Hemlock	29.5	11.1	4.78	2,986	50	2 Z-drive propellers	2.1
Britoil 51	45.0	11.8	4.5	4,922	90	2 fixed-pitch propellers, 1 bow thruster	3.2

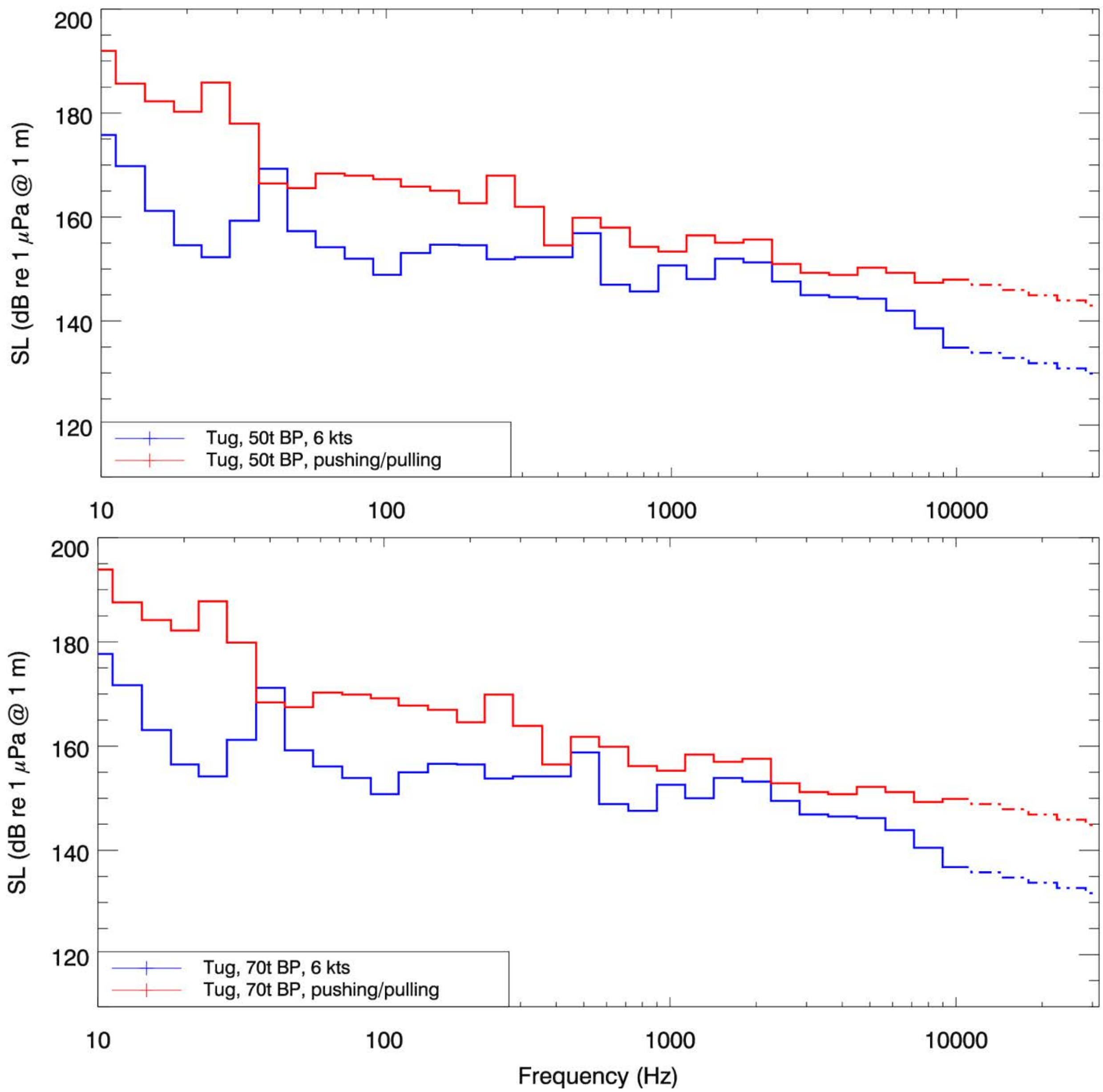

Figure 6. Estimated source levels (SLs) for carrier escort tugs with (top) 50 t and (bottom) 70 t of bollard pull transiting and pushing/pulling. Extrapolated levels above 10 kHz are shown as dot-dashed lines.

3.2. Sound Propagation Model

Underwater sound propagation (i.e., transmission loss) was predicted with JASCO's Marine Operations Noise Model (MONM). MONM computes acoustic propagation via a wide-angle parabolic equation solution to the acoustic wave equation (Collins 1993) based on a version of the U.S. Naval Research Laboratory's Range-dependent Acoustic Model (RAM), which has been modified to account for an elastic seabed (Zhang and Tindle 1995). The parabolic equation method has been extensively benchmarked and is widely employed in the underwater acoustics community (Collins et al. 1996). MONM accounts for the additional reflection loss at the seabed due to partial conversion of incident compressional waves to shear waves at the seabed and sub-bottom interfaces, and it includes wave attenuations in all layers. MONM incorporates the following site-specific environmental properties: a bathymetric grid of the modelled area, underwater sound speed as a function of depth, and a geoacoustic profile based on the overall stratified composition of the seafloor. MONM's predictions have been validated against experimental data from several underwater acoustic measurement programs conducted by JASCO (Hannay and Racca 2005, Aerts et al. 2008, Funk et al. 2008, Ireland et al. 2009, O'Neill et al. 2010, Warner et al. 2010).

MONM computes acoustic fields in three dimensions by modelling transmission loss within two-dimensional (2-D) vertical planes aligned along radials covering a 360° swath from the source, an approach commonly referred to as *N*×2-D. These vertical radial planes are separated by an angular step size of $\Delta\theta$, yielding $N = 360°/\Delta\theta$ number of planes (Figure 7).

MONM treats frequency dependence by computing acoustic transmission loss at the centre frequencies of 1/3-octave-bands. Sufficiently many 1/3-octave-bands, starting at 10 Hz, are modelled to include the majority of acoustic energy emitted by the source. At each centre frequency, the transmission loss is modelled within each of the *N* vertical planes as a function of depth and range from the source. The 1/3-octave-band received levels are computed by subtracting the band transmission loss values from the source level in that frequency band. Composite broadband received levels are then computed by summing the received 1/3-octave-band levels.

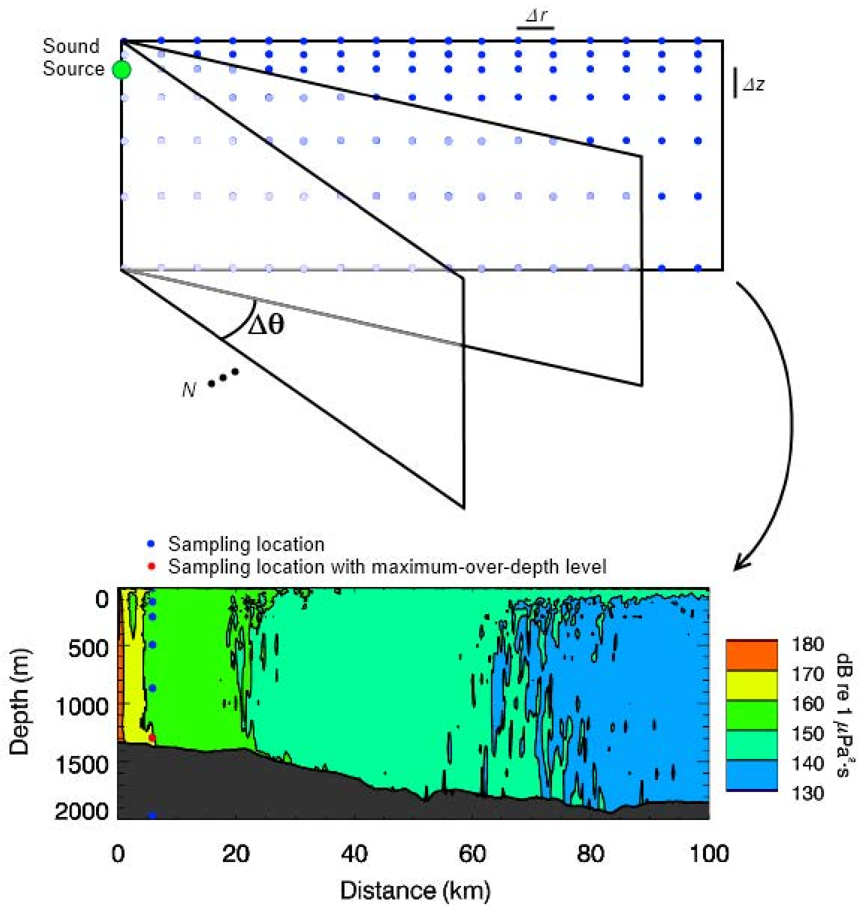

Figure 7. Representation of *N*×2-D and maximum-over-depth approaches.

The frequency-dependent transmission loss computed by MONM may be corrected to account for the attenuation of acoustic energy by molecular absorption in seawater. The volumetric sound absorption is quantified by an attenuation coefficient, expressed in units of decibels per kilometre (dB/km). The absorption coefficient depends on the temperature, salinity, and pressure of the water as well as the sound frequency. In general, the absorption coefficient increases with the square of frequency. The absorption of acoustic wave energy has a noticeable effect (> 0.05 dB/km) at frequencies above 1 kHz.

For example, at 10 kHz the absorption loss over 10 km distance can exceed 10 dB. This coefficient for seawater can be computed according to the formulae of François and Garrison (1982a, 1982b), which consider the contributions of pure seawater, magnesium sulfate, and boric acid. The formula applies to all oceanic conditions and frequencies from 200 Hz to 1 MHz. For this project, absorption coefficients were computed and applied for all modelled frequencies (Section 3.3.4). Because of the computational expense associated with parabolic equation modelling at frequencies at or above several kHz and the relative importance of absorption at such frequencies, the TL in each frequency band between 6.3 and 31.6 kHz was approximated from the TL computed at 5 kHz by applying the correct frequency-dependent absorption coefficient in each band.

The received sound field within each vertical radial plane is sampled at various ranges from the source, generally with a fixed radial step size, out to a maximum range of interest. For this study, the sound field at each site was modelled over an area of ~ 60 × 60 km centred on the source, with a horizontal separation of Δr = 5 m between receiver points along the modelled radials and a horizontal angular resolution of $\Delta\theta$ = 5°.

At each sampling range along the radial plane, the sound field is sampled at various depths, where step sizes are chosen to provide increased coverage near the depth of the source and at depths of interest in terms of the sound speed profile. Receiver depths for this study span the entire water column over the modelled areas, from 2 m to a maximum of 300 m, with step sizes that increased from Δz = 2 to 50 m with increasing depth. For mapping and computing distances to isopleths, the received level at a given sampling location is taken as the maximum value that occurs over all receiver depths at that location, i.e., the maximum-over-depth received level.

3.2.1. 24-hour SEL

Cumulative sound exposure levels (SELs) for undocking and transit of a single carrier were estimated based on the vessels tracks, speeds, and activities outlined in Section 2. Each track segment was assigned a sound field from the per-site modelling, based on the activity and environment. Multiple copies of the appropriate sound fields were made at 50 m intervals along the tracks. The individual fields were then summed, including a correction factor to account for the vessel speed along the track, thus yielding the total field over the operation. Contours and threshold ranges for the estimated field were then calculated as for the single-site cases.

3.3. Environmental Parameters

3.3.1. Bathymetry

Water depths throughout the modelled area were extracted from digital bathymetry for the Gulf of Maine (Roworth and Signell 1998). These bathymetry data have a resolution of 15 arc-seconds (~ 330 × 460 m at the studied latitude). The vertical datum is mean sea level. Bathymetry for a 200 × 200 km area was extracted and re-gridded onto a Universal Transverse Mercator (UTM) Zone 19 coordinate projection with a regular grid spacing of 50 × 50 m. Contours derived from the bathymetry grid are shown in Figure 1 and Figure 3.

3.3.2. Geoacoustic Properties

Sound propagation in shallow water is strongly influenced by the geoacoustic parameters of the seafloor, including the density, the compressional wave (P-wave) speed, the shear wave (S-wave) speed, the compressional wave attenuation, and the shear wave attenuation of seabed sediments and bedrock. A variety of sediments is found in the Bay of Fundy, ranging from clay to boulders. Three broad sediment categories occur within study area (Osler 1994, Fader et al. 2004):

- Scotian Shelf Drift: Glacial till, comprised of poorly sorted sediments; dominantly sandy, but contains abundant silt and clay
- Sambro Sand: Thin veneer of silty sand, locally with larger proportions of coarser material
- LaHave Clay: Silty clay to clayey silt

Where they occur, Sambro Sand and LaHave Clay overlie Scotian Shelf Drift, which in turn overlies the bedrock throughout the Bay of Fundy. The overall sediment thickness in the study area varies from approximately 140 m east of Grand Manan Island to 170 m in the vicinity of Site 6 (Whittaker et al. 2013), and the dominant bedrock type is sandstone (King and MacLean 1974, Davis and Brown 1996).

Scotian Shelf Drift is the dominant surficial sediment type in the study area (Fader et al. 2004), and surficial sediment samples collected in the vicinity of Sites 3–6 show varying amounts of gravel, sand, silt, and clay (Bershard and Weiss 1976, Hathaway 1977). Sites 1 and 2 lie within a region of LaHave Clay (Fader et al. 2004), but a nearby surface sediment sample (Bershad and Weiss 1976) found a large proportion of sand, suggesting that the layer of clay may be thin and/or patchy in this area. As such, Scotian Shelf Drift was taken to be the main sediment type for all six modelling sites.

Based on the above information, a simplified geoacoustic profile was constructed assuming 150 m of Scotian Shelf Drift over sandstone. The geoacoustic properties of the sediment layer were estimated from the parameters provided by Osler (1994) and the empirical formulas presented by Hamilton (1980) and Buckingham (2005). The parameters for the sandstone layer were taken from the values reported by Osler (1994). The resulting profile is shown in Table 8.

Table 8. Estimated geoacoustic profile. Within each depth range, each parameter varies linearly within the stated range.

Depth below seafloor (m)	Material	Density (g/cm^3)	P-wave speed (m/s)	P-wave attenuation (dB/λ)	S-wave speed (m/s)	S-wave attenuation (dB/λ)
0–20	Scotian Shelf Drift	2.05–2.06	1,670–1,870	0.40–1.02	420	0.85
20–50		2.06–2.08	1,870–,2000	1.02–1.31		
50–100		2.08	2,000–2,120	1.31–1.57		
100–150		2.08	2,120–2,210	1.57–1.74		
> 150	Sandstone	2.30	2,300	0.02		

3.3.3. Sound Speed Profiles

The sound speed profiles for the modelled sites were derived from temperature and salinity profiles from the U.S. Naval Oceanographic Office's *Generalized Digital Environmental Model V 3.0* (GDEM; Teague et al. 1990, Carnes 2009). GDEM provides an ocean climatology of temperature and salinity for the world's oceans on a latitude-longitude grid with 0.25° resolution, with a temporal resolution of one month, based on global historical observations from the U.S. Navy's Master Oceanographic Observational Data Set (MOODS). The climatology profiles include 78 fixed depth points to a maximum depth of 6,800 m (where the ocean is that deep). The GDEM temperature-salinity profiles were converted to sound speed profiles according to the equations of Coppens (1981):

$$c(z,T,S,\phi) = 1449.05 + 45.7t - 5.21t^2 - 0.23t^3 + \left(1.333 - 0.126t + 0.009t^2\right)\left(S - 35\right) + \Delta \quad (12)$$

$$\Delta = 16.3Z + 0.18Z^2, \quad Z = \frac{z}{1000}\left[1 - 0.0026\cos(2\phi)\right], \quad t = \frac{T}{10}$$

where z is water depth (m), T is temperature (°C), S is salinity (psu), and ϕ is latitude (radians).

Two sound speed profiles were selected for each model scenario, in order to bracket seasonal variability in sound propagation resulting from changes in the water column sound speed. During the winter, sound speeds in the area of interest generally increase with depth (Figure 8), leading to refraction of sound back toward the sea surface, a situation favourable for longer-range sound propagation. In contrast, near-surface sound speed profiles in the area become largely downward-propagating during the summer (Figure 8). Based on this, the February (winter) and August (summer) sound speed profiles were selected as most and least favourable to sound propagation, respectively. Temperature and salinity profiles for each modelling site were extracted using the nearest GDEM grid point with adequate depth coverage; for Sites 1–4 this was one grid point south or west of the grid point geographically closest to the source. In the case of the three deepest Sites (Sites 4–6), GDEM profiles reasonably close to the source locations had a vertical extent 20–30 m less than the maximum bottom depth in the modelling area. These profiles were extended assuming a constant sound speed gradient below the maximum depth in the GDEM profile. The resulting profiles are shown in Figure 9.

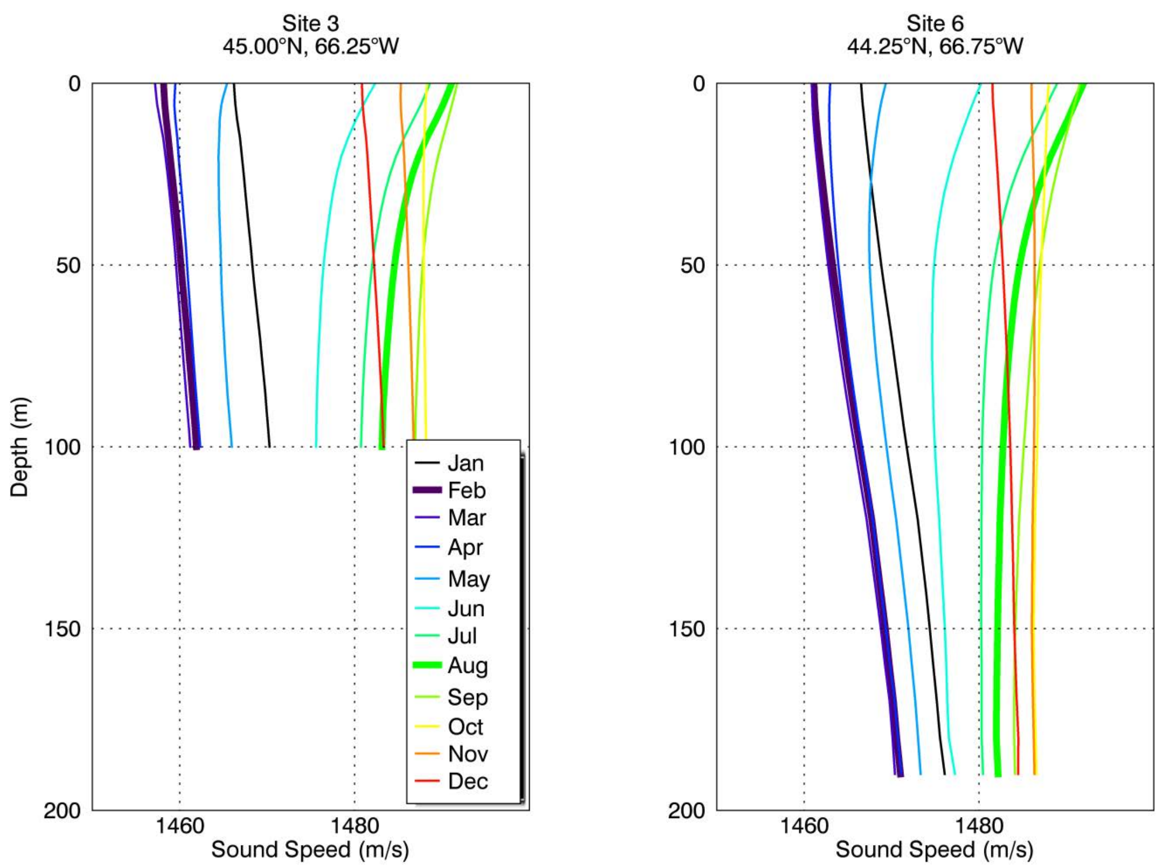

Figure 8. Mean monthly sound speed profiles in the vicinity of modelling Sites 3 and 6 (Figure 3, Table 3). The profiles were derived from data obtained from *GDEM V 3.0* (Teague et al. 1990, Carnes 2009).

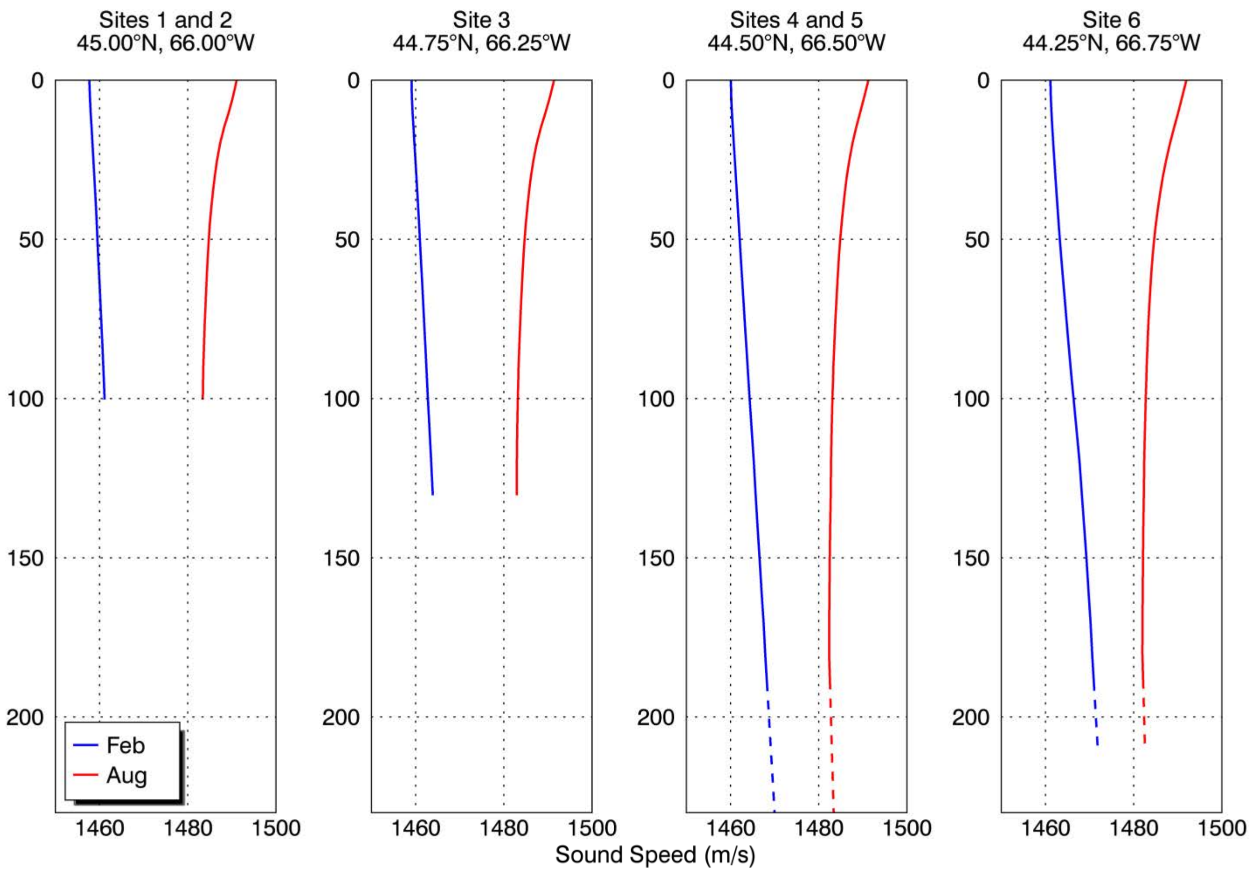

Figure 9. Mean monthly sound speed profiles used for the modelling scenarios in Table 3, derived from data obtained from GDEM V 3.0 (Teague et al. 1990, Carnes 2009). The extrapolated portions of the profiles for Sites 4–6 are shown as dashed lines.

3.3.4. Seawater Absorption

The absorption coefficient was estimated for each 1/3-octave-band modelled using the equations of François and Garrison (1982a,b; Section 3.2) assuming a depth of 10 m and average temperature and salinity values from GDEM (Section 3.3.3): T = 3.25°C and S = 32.08 psu for February; T = 11.06°C and S = 32.11 psu for August. The resulting frequency-dependent absorption coefficients are shown in Figure 10.

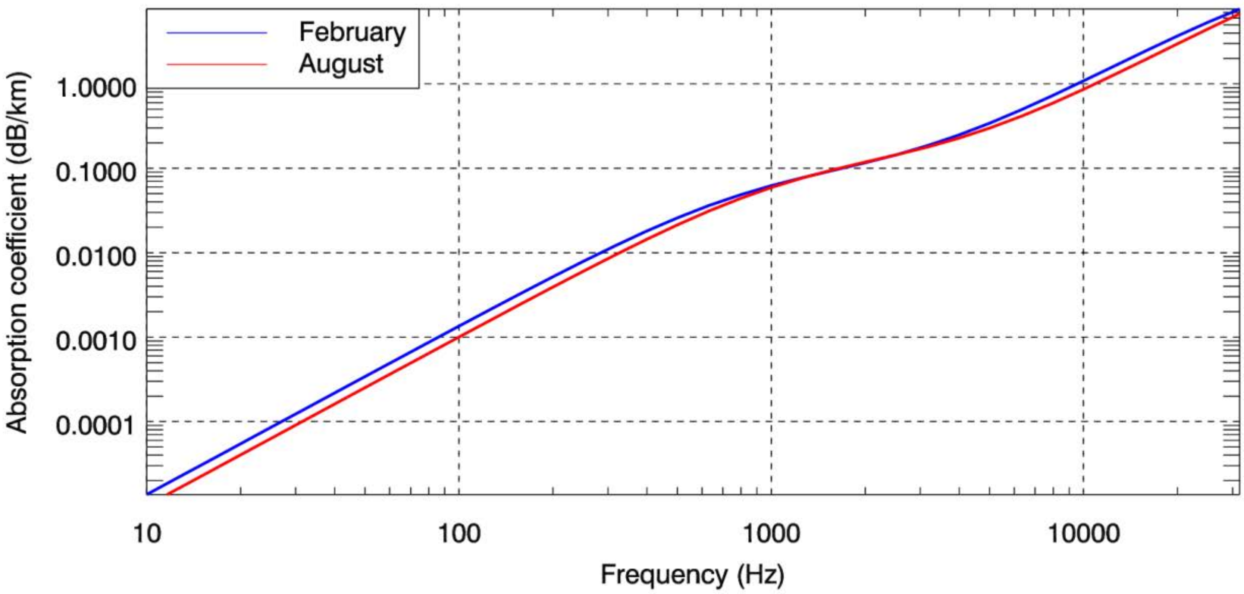

Figure 10. Absorption coefficient, from the equations of François and Garrison (1982a,b), for February and August.

4. Results

4.1. Root-Mean-Square Sound Pressure Levels

Predicted maximum-over-depth underwater sound fields are presented in two formats: tables of distances to 120–190 dB re 1 µPa rms SPL, and contour maps showing the directivity and range to various sound levels. The tabulated distances are reported in terms of the 95th percentile radius ($R_{95\%}$), defined as the maximum range at which the given sound level was encountered after exclusion of the 5% farthest such points. The farthest points are excluded to account for the fact that the maximum-over-depth sound field footprint may not be circular and, along a few azimuths, may extend far beyond the main ensonification zone because of variations in the environment. Regardless of the geometric shape of the maximum-over-depth footprint, $R_{95\%}$ is the predicted range encompassing at least 95% of the area (in the horizontal plane) that would be exposed to sound at or above that level.

Distances ($R_{95\%}$) to received SPLs of 120–190 dB re 1 µPa for Suezmax carrier operations are shown in Table 9 and Table 10 for the February and August water column sound speed profiles, respectively. Distances for VLCC operations are shown in Table 11 and Table 12. The maximum range modelled was 30 km. For the purposes of generating sound field maps and computing radii, the N×2-D sound field output by MONM (Section 3.2) was interpolated to a rectangular grid with a horizontal resolution of 10 m.

Contour maps of the rms SPL sound fields for each VLCC scenario are shown in Figure 11 through Figure 16 for the February sound speed profile. Maps for the VLCC with an August sound speed profile and for the Suezmax carrier for both sound speed profiles are in Appendix A.

Table 9. 95% ($R_{95\%}$) horizontal distances (in km) from the source to modelled maximum-over-depth unweighted broadband rms sound pressure levels (SPLs; 10 Hz to 31.6 kHz) for Suezmax operations in February. Horizontal grid resolution is 10 m.

Scenario	rms SPL (dB re 1 µPa)			
	190	180	160	120
Site 1, docking/undocking, 3 tugs	< 0.01	< 0.01	0.02	3.11
Site 2, carrier transit with tug, 6 kts	----	----	< 0.01	0.84
Site 3, carrier transit, 15 kts	----	< 0.01	0.02	7.73
Site 4, carrier transit, 15 kts	----	< 0.01	0.02	7.49
Site 5, carrier transit, 15 kts	----	< 0.01	0.02	7.49
Site 6, carrier transit, 15 kts	----	< 0.01	0.02	7.92

Table 10. 95% ($R_{95\%}$) horizontal distances (in km) from the source to modelled maximum-over depth unweighted broadband rms sound pressure levels (SPLs; 10 Hz to 31.6 kHz) for Suezmax operations in August. Horizontal grid resolution is 10 m.

Scenario	rms SPL (dB re 1 µPa)			
	190	180	160	120
Site 1, docking/undocking, 3 tugs	< 0.01	< 0.01	0.02	2.89
Site 2, carrier transit with tug, 6 kts	----	----	< 0.01	0.79
Site 3, carrier transit, 15 kts	----	< 0.01	0.02	6.70
Site 4, carrier transit, 10 kts	----	----	< 0.01	1.84
Site 5, carrier transit, 15 kts	----	< 0.01	0.02	6.57
Site 6, carrier transit, 15 kts	----	< 0.01	0.02	6.84

Table 11. 95% ($R_{95\%}$) horizontal distances (in km) from the source to modelled maximum-over depth unweighted broadband rms sound pressure levels (SPLs; 10 Hz to 31.6 kHz) for VLCC operations in February. Horizontal grid resolution is 10 m.

Scenario	rms SPL (dB re 1 µPa)			
	190	180	160	120
Site 1, docking/undocking, 4 tugs	< 0.01	< 0.01	0.02	3.49
Site 2, carrier transit with tug, 6 kts	----	----	< 0.01	0.88
Site 3, carrier transit, 15 kts	----	< 0.01	0.03	10.89
Site 4, carrier transit, 15 kts	----	< 0.01	0.03	10.31
Site 5, carrier transit, 15 kts	----	< 0.01	0.02	10.79
Site 6, carrier transit, 15 kts	----	< 0.01	0.03	11.20

Table 12. 95% ($R_{95\%}$) horizontal distances (in km) from the source to modelled maximum-over depth unweighted broadband rms sound pressure levels (SPLs; 10 Hz to 31.6 kHz) for VLCC operations in August. Horizontal grid resolution is 10 m.

Scenario	rms SPL (dB re 1 µPa)			
	190	180	160	120
Site 1, docking/undocking, 4 tugs	< 0.01	< 0.01	0.02	3.22
Site 2, carrier transit with tug, 6 kts	----	----	< 0.01	0.84
Site 3, carrier transit, 15 kts	----	< 0.01	0.03	8.53
Site 4, carrier transit, 10 kts	----	----	< 0.01	2.52
Site 5, carrier transit, 15 kts	----	< 0.01	0.02	9.07
Site 6, carrier transit, 15 kts	----	< 0.01	0.02	8.79

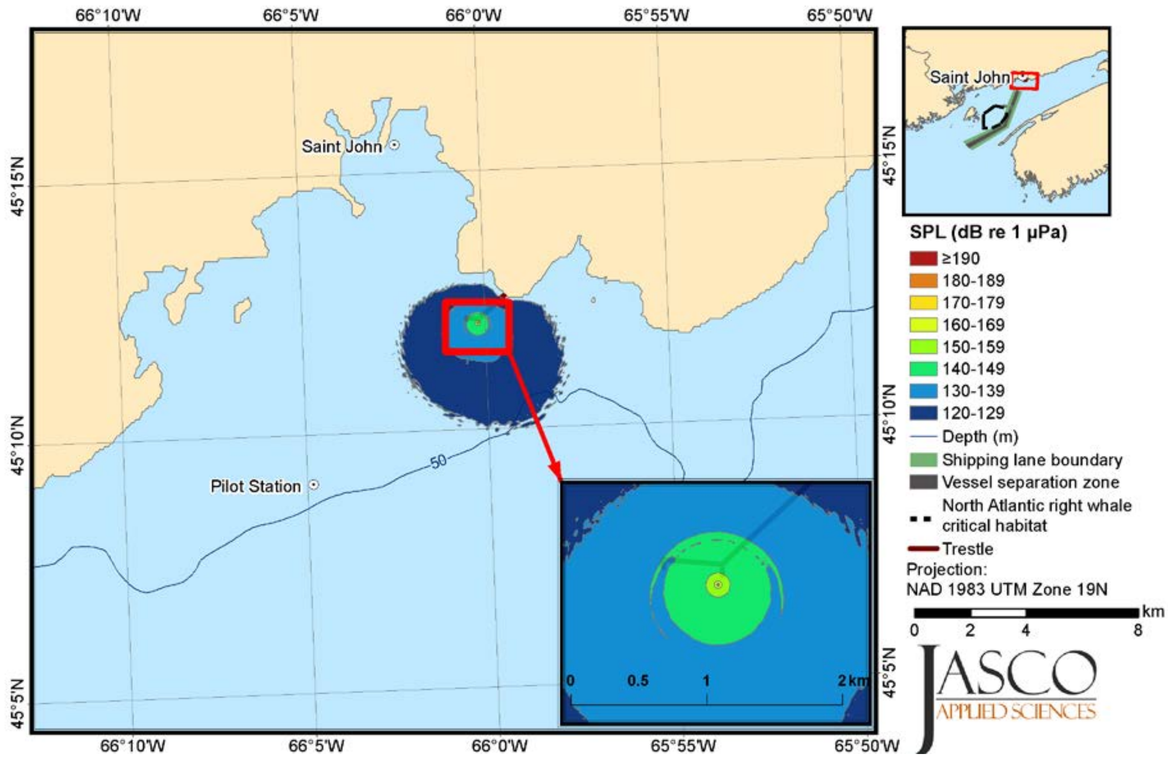

Figure 11. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for VLCC docking/undocking with four tugs at Site 1 in February.

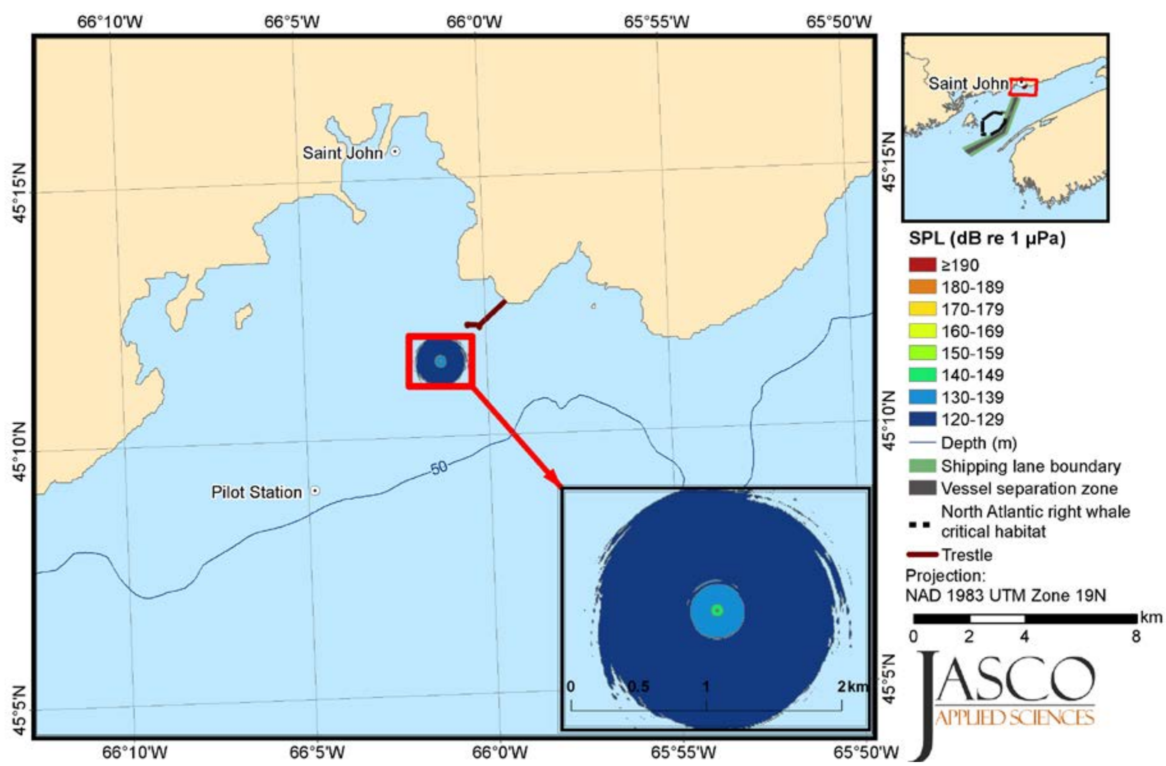

Figure 12. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for VLCC transit with one tug at 6 kts at Site 2 in February.

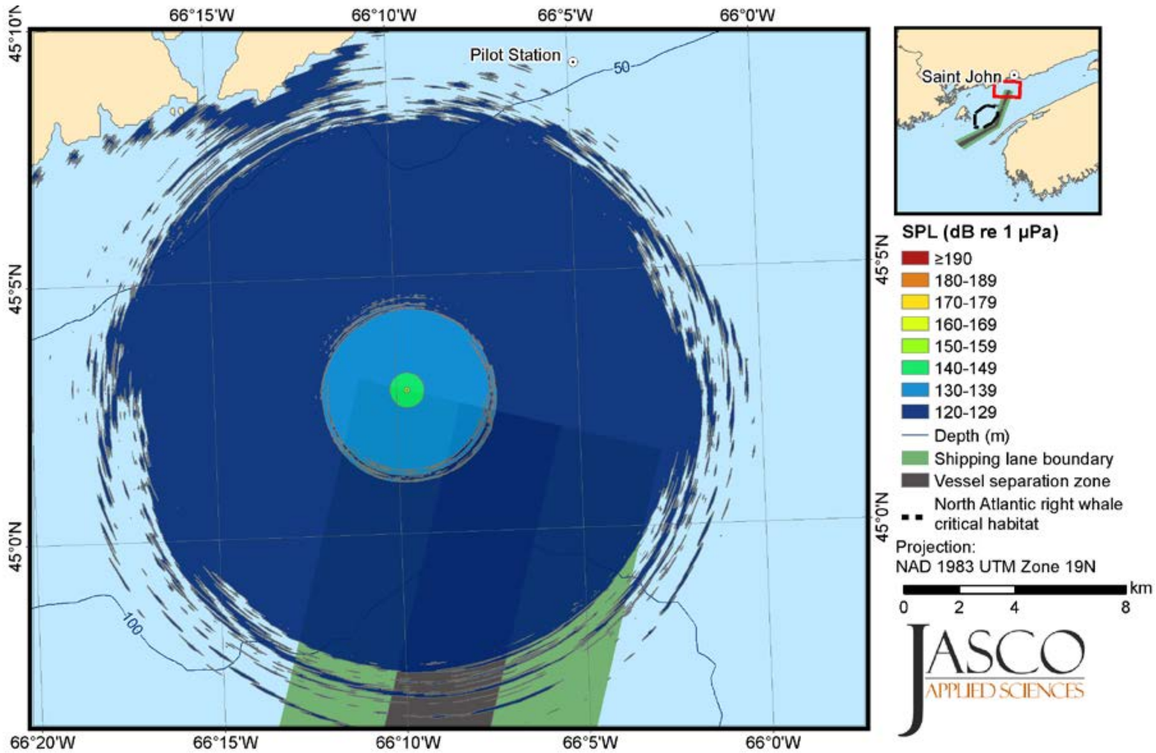

Figure 13. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for VLCC transit at 15 kts at Site 3 in February.

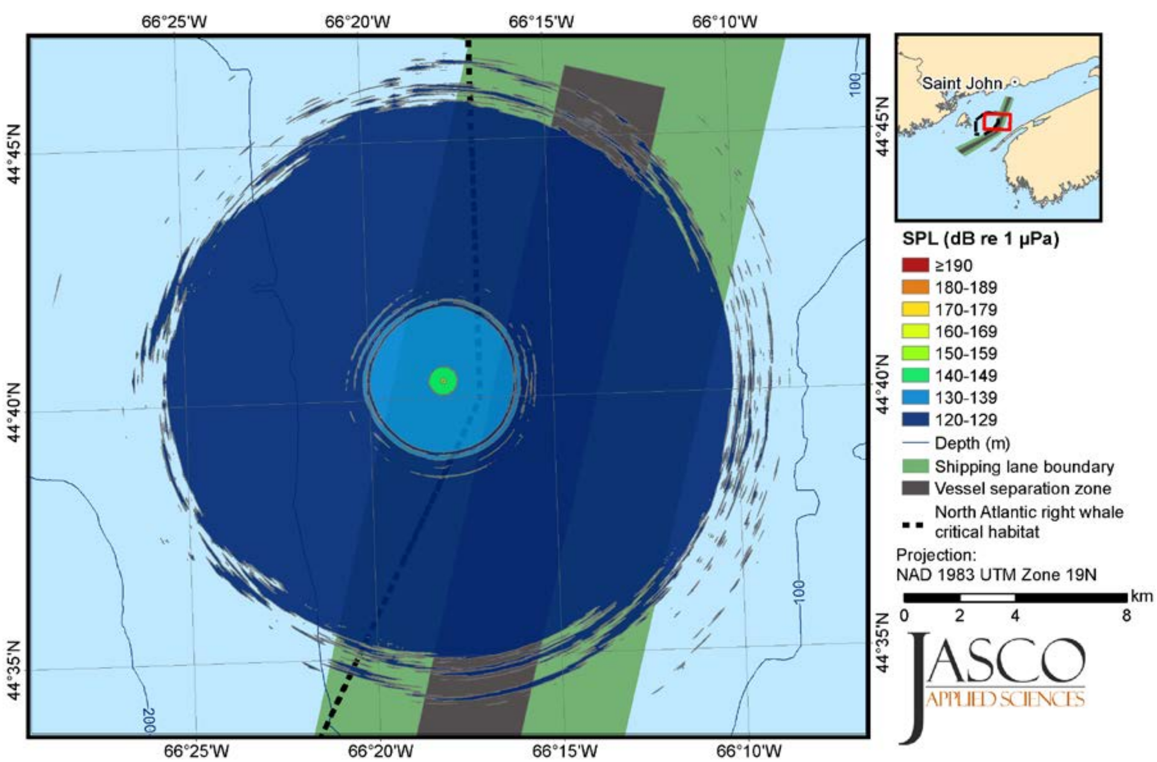

Figure 14. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for VLCC transit at 15 kts at Site 4 in February.

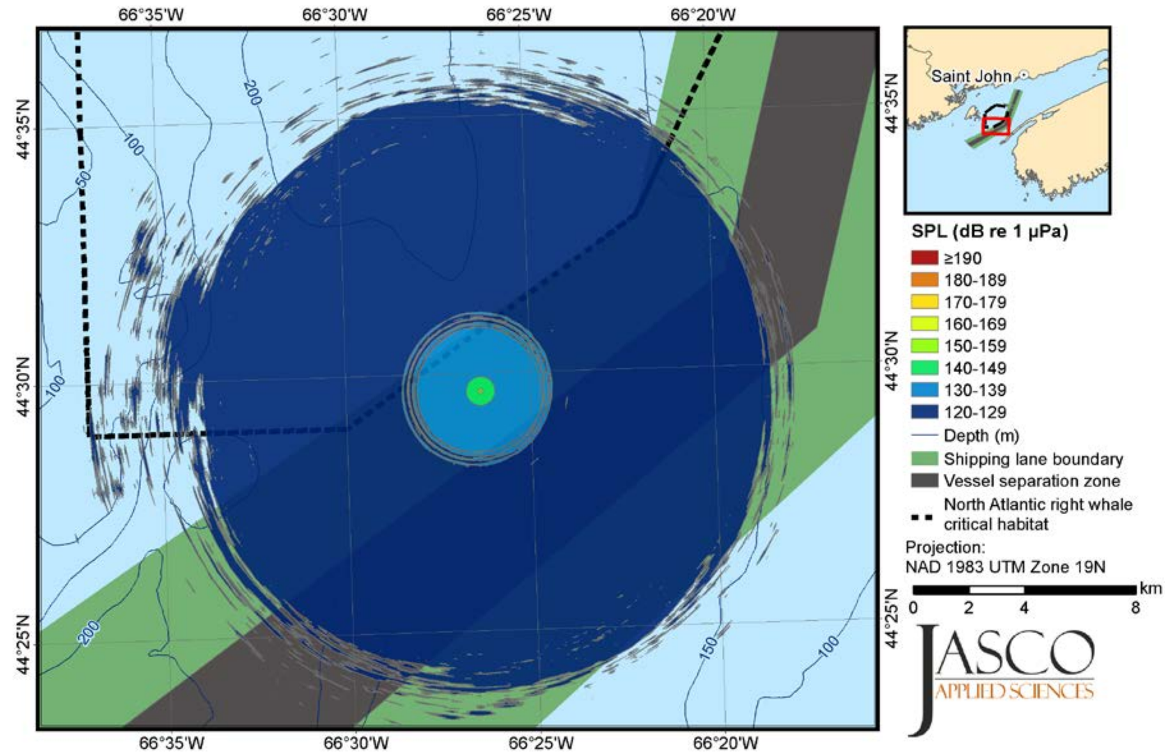

Figure 15. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for VLCC transit at 15 kts at Site 5 in February.

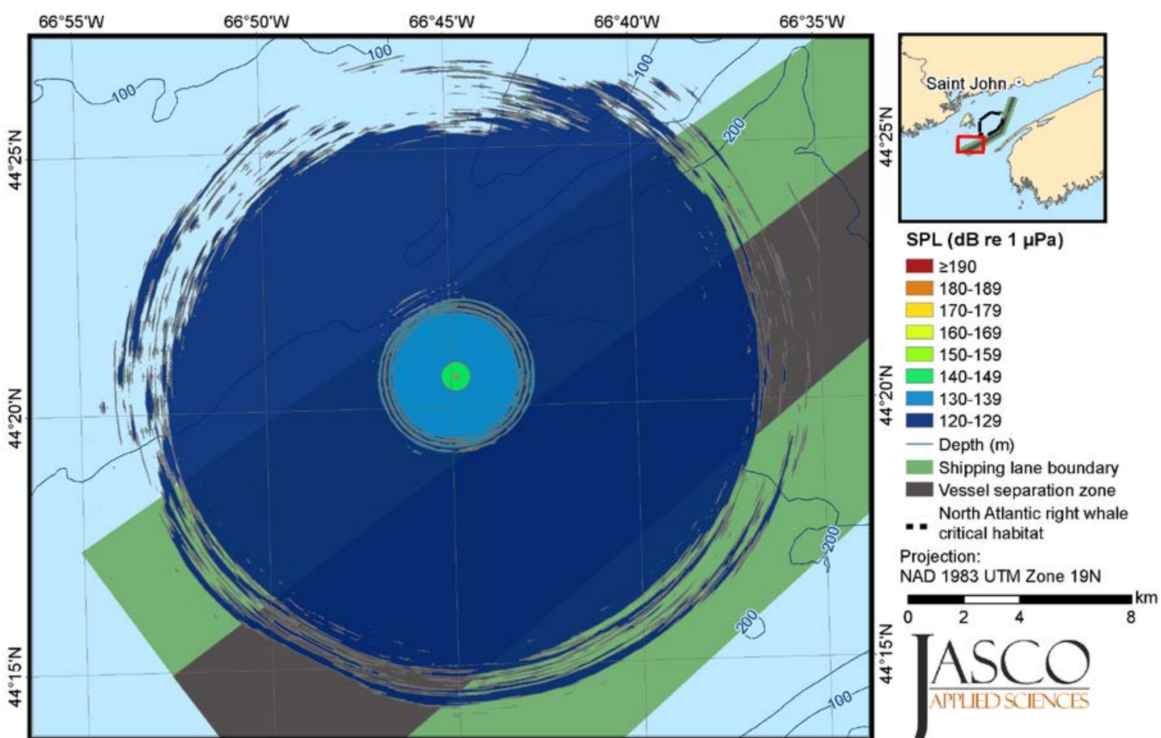

Figure 16. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for VLCC transit at 15 kts at Site 6 in February.

4.2. 24-hour SEL

The maximum-over-depth, per-second SELs from MONM were M-weighted, replicated at appropriate spatial intervals, and summed as described in Section 3.2.1 to generate estimates of the SELs for undocking and transit of a single carrier, as outlined in Section 2. Contour maps of unweighted SEL for each of the four vessel transit scenarios are shown in Figure 17 through Figure 20; distances for M-weighted SELs are smaller. NOAA thresholds for PTS (Table 2, Section 1.2.5) were not achieved anywhere in the modelled grid for any of the functional hearing groups.

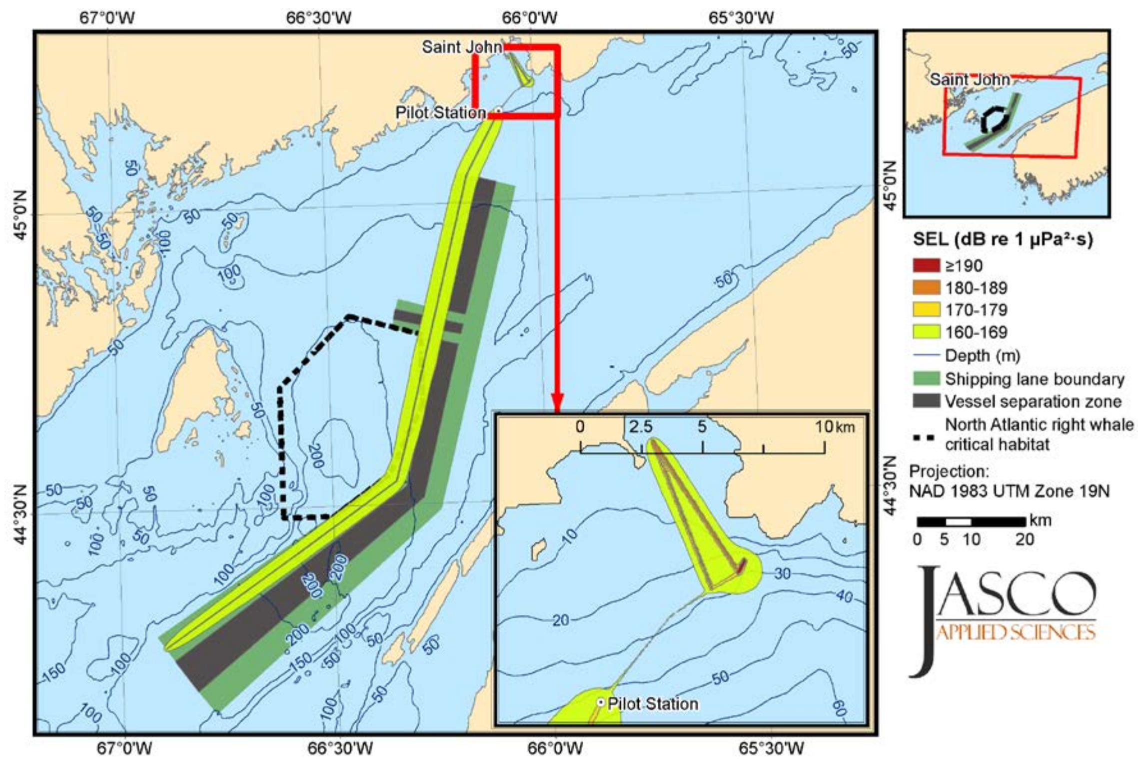

Figure 17. Maximum-over-depth unweighted sound exposure levels (SELs) for Suezmax operations in February.

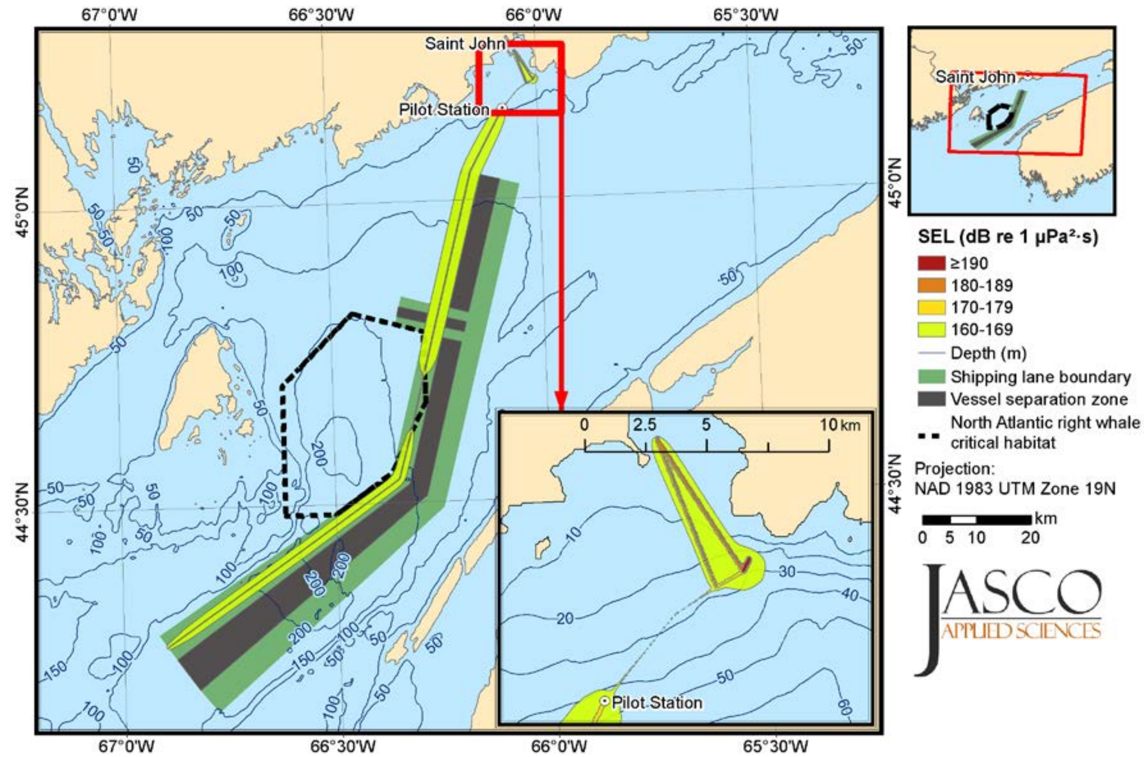

Figure 18. Maximum-over-depth unweighted sound exposure levels (SELs) for Suezmax operations in August.

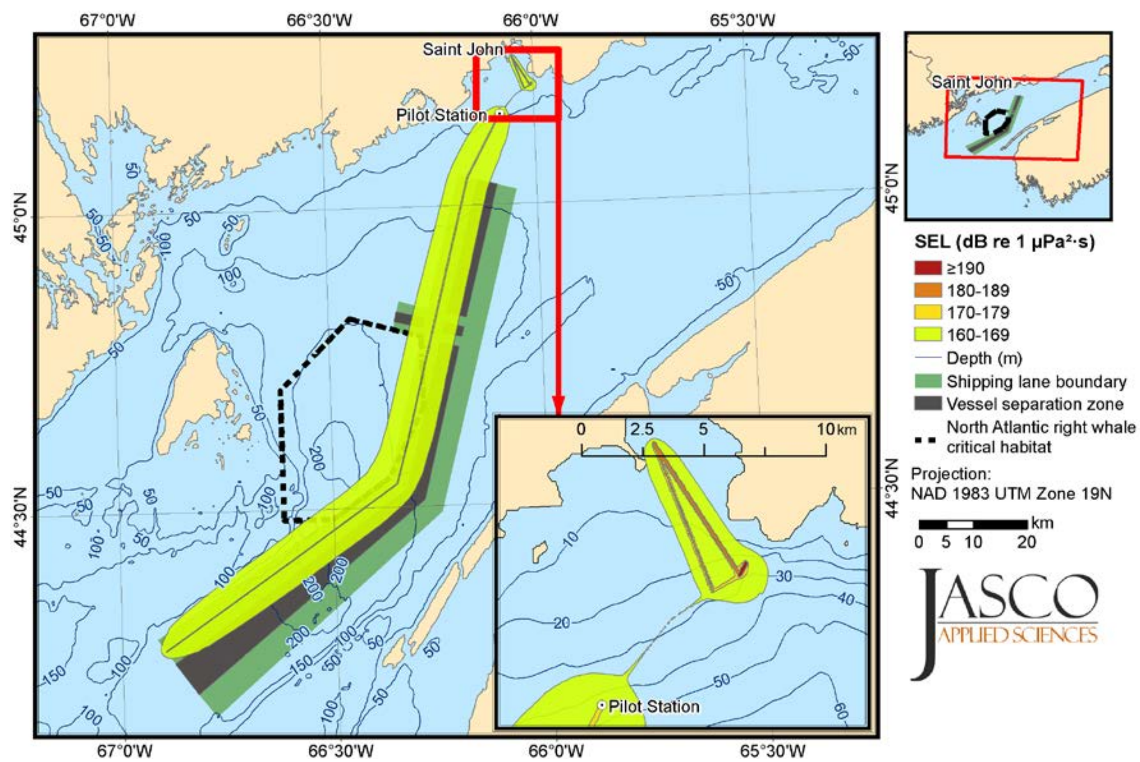

Figure 19. Maximum-over-depth unweighted sound exposure levels (SELs) for VLCC operations in February.

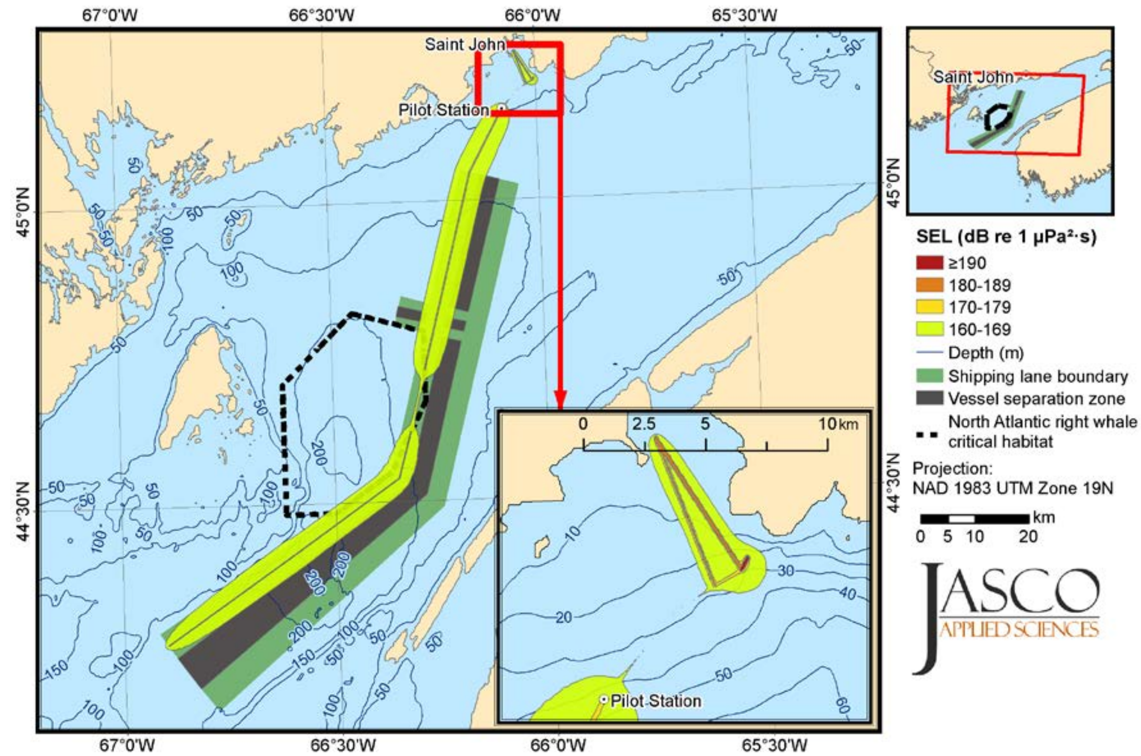

Figure 20. Maximum-over-depth unweighted sound exposure levels (SELs) for VLCC operations in August.

5. Discussion

A modelling study was carried out to predict underwater sound levels associated with shipping in the vicinity of the proposed Canaport Marine Terminal near Saint John, NB. Underwater noise estimates were made for six sites and two carrier types (Section 2, Table 3), taking into account both source characteristics (Section 3.1) and site-specific environmental parameters (Section 3.3). To account for seasonal changes in sound propagation, two sound speed profiles were considered (Section 3.3.3).

Ranges to the 120 dB re 1 μPa root-mean-square (rms) sound pressure level (SPL) isopleth were greater for the Very Large Crude Carrier (VLCC) than for the Suezmax carrier (Table 13), as expected given the VLCC's higher power rating (Section 3.1.1). For a given vessel class, distances were larger for the winter sound speed profile than for the summer profile (Table 13, Figure 21), reflecting the tendency of the winter sound speed profile to refract sound away from the sediments (Section 3.3.3).

Carrier transit at full-speed generated the longest distances to the 120 dB re 1 μPa rms SPL isopleth, up to 11 km for a VLCC in February (Table 13). Reducing transit speeds to 10 kts in the North Atlantic right whale critical habitat in August reduced received levels considerably. Distances associated with docking and undocking were 2.9–3.5 km. While broadband source levels for manoeuvering tugs were higher than those for carrier transit (Section 3.1), transmission loss is relatively high in the shallow waters immediately around the terminal, particularly for the low frequencies that are dominant in the tug source level spectra (Figure 6).

Consistent with the single-site results, sound exposure levels (SELs) for the full vessel transit scenario (Section 2) were larger for the VLCC and for the February sound speed profile, than for the Suezmax and/or the August profile (Figure 17 through Figure 20). SELs at or above NOAA thresholds for PTS (NOAA 2013) did not, however, occur for any of the operational scenarios or functional hearing groups modelled.

Table 13. Summary of distances ($R_{95\%}$, km) to the 120 dB re 1 μPa rms SPL isopleth for the vessel operation scenarios modelled. Horizontal grid resolution is 10 m.

Scenario	Distance (km)			
	Suezmax, February	Suezmax, August	VLCC, February	VLCC, August
Site 1, docking/undocking	3.11	2.89	3.49	3.22
Site 2, carrier transit with tug, 6 kts	0.84	0.79	0.88	0.84
Site 3, carrier transit, 15 kts	7.73	6.70	10.89	8.53
Site 4, carrier transit, 10 kts (summer) or 15 kts (winter)	7.49	1.84	10.31	2.52
Site 5, carrier transit, 15 kts	7.49	6.57	10.79	9.07
Site 6, carrier transit, 15 kts	7.92	6.84	11.20	8.79

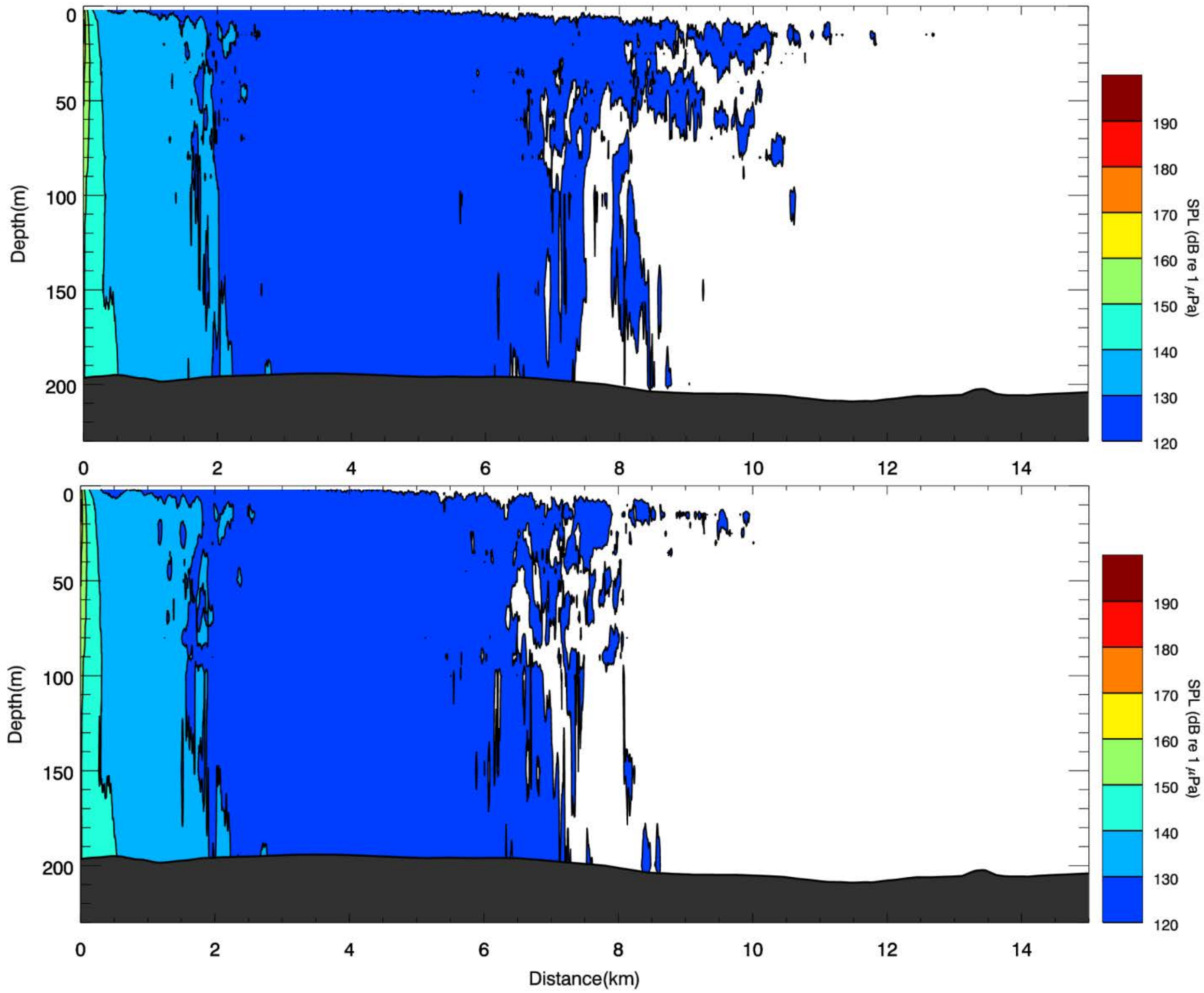

Figure 21. Root-mean-square (rms) sound pressure levels (SPLs) for VLCC transit at 15 kts at Site 6 for the months of (top panel) February and (bottom panel) August. Levels are shown along a radial extending due east from the source location.

Glossary

1/3-octave-band
Non-overlapping passbands that are one-third of an octave wide (where an octave is a doubling of frequency). Three adjacent 1/3-octave-bands make up one octave. One-third-octave-bands become wider with increasing frequency.

absorption
The conversion of sound waves into heat, which is captured by insulation.

attenuation
The acoustic energy loss due to absorption and scattering.

auditory weighting function (frequency-weighting function)
Auditory weighting functions account for marine mammal hearing sensitivity. They are applied to sound measurements to emphasize frequencies that an animal hears well and de-emphasize frequencies they hear less well or not at all (Southall et al. 2007, Finneran and Jenkins 2012, NOAA 2013)

azimuth
A horizontal angle relative to a reference direction, often magnetic north or the direction of travel.

bandwidth
The range of frequencies over which a sound occurs. Broadband refers to a source that produces sound over a broad range of frequencies (e.g., seismic airguns, vessels) whereas narrowband sources produce sounds over a narrow frequency range (e.g., sonar) (ANSI/ASA S1.13-2005 R2010).

bollard pull (BP)
A measure of a vessel's pulling power defined as the force exerted under full power on a shore-mounted bollard through a tow-line. Commonly measured in a practical test, but sometimes simulated or estimated. Unit: ton (t).

broadband sound level
The total sound pressure level measured over a specified frequency range. If the frequency range is unspecified, it refers to the entire measurement range.

cavitation
A rapid formation and collapse of vapor in water, most often caused by a rapid pressure drop.

cetacean
Member of the order *Cetacea* of aquatic, mostly marine mammals. Includes whales, dolphins, and porpoises.

compressional wave
A mechanical vibration wave where the direction of particle motion is parallel to the direction of propagation. Sometimes referred to as a primary wave, or P-wave.

continuous sounds
Sounds that gradually vary in intensity with time, for example, sound from a transiting ship.

decibel
A logarithmic unit of the ratio of a quantity to a reference quantity of the same kind. Symbol: dB.

ensonification
Exposure to sound.

frequency
The rate of oscillation of a periodic function measured in units of cycles-per-unit-time. The reciprocal of the period. Unit: hertz (Hz). Symbol: *f*. For example, 1 Hz = 1 cycle per second.

functional hearing group
Grouping of marine mammal species with similar estimated hearing ranges.

geoacoustic
Relating to the acoustic properties of the seabed.

hearing threshold
The sound pressure level that is barely audible for a given individual in the absence of significant background noise during a specific percentage of experimental trials.

high-frequency cetacean (HFC)
The functional hearing group that represents odontocetes specialized for using high-frequencies.

low-frequency cetacean (LFC)
The functional hearing group that represents mysticetes (baleen whales).

mid-frequency cetacean (MFC)
The functional hearing group that represents some odontocetes (dolphins, toothed whales, beaked whales, and bottlenose whales).

M-weighting
The process of band-pass filtering loud sounds to reduce the importance of inaudible or less-audible frequencies for broad classes of marine mammals. “Generalized frequency weightings for various functional hearing groups of marine mammals, allowing for their functional bandwidths and appropriate in characterizing auditory effects of strong sounds” (Southall et al. 2007).

mysticete
Member of the *Mysteceti*, a suborder of the order *Cetacea*. The toothless or baleen whales (also called whalebone whales). Mysticetes are characterized by having baleen plates to filter food from water. They are not known to echolocate, but use sound for communication. Includes the rorquals (*Balaenopteridae*), right whales (*Balaenidae*), and the gray whale (*Eschrichtius robustus*).

noise
Unwanted sound that interferes with detecting other sounds.

non-impulsive sound
Sound that is broadband, narrowband or tonal, brief or prolonged, continuous or intermittent, and typically does not have a high peak pressure with rapid rise time (typically only small fluctuations in decibel level) that impulsive signals have (ANSI/ASA S3.20-1995 R2008). For example, marine vessels, aircraft, machinery, construction, and vibratory pile driving.

odontocete
Member of the *Odontoceti*, a suborder of the order *Cetacea*. The toothed whales, including sperm whales, killer whales, belugas, narwhals, dolphins, and porpoises, which are able to echolocate.

otariid
Member of the *Otariidae*, one of the three taxa of *Pinnipedia*. The eared seals, commonly called sea lions and fur seals, which use their large fore flippers for propulsion.

parabolic equation method
A computationally-efficient solution to the acoustic wave equation that is used to model transmission loss. The parabolic equation approximation omits effects of back-scattered sound, simplifying the computation of transmission loss. The effect of back-scattered sound is negligible for most ocean-acoustic propagation problems.

peak sound pressure level (peak SPL)
The maximum instantaneous sound pressure level, in a stated frequency band, within a stated period. Also called zero-to-peak sound pressure level. Unit: decibel (dB).

permanent threshold shift (PTS)
A permanent loss of hearing sensitivity due to excessive noise exposure. PTS is considered auditory injury.

phocid
Member of the *Phocidae*, one of the three taxa of *Pinnipedia*. The true seals or earless seals, which are more adapted to aquatic life than otariids and use their hind flippers for propulsion.

pinniped
Member of the *Pinnipedia*. Includes phocids (true seals or earless seals), otariids (eared seals or fur seals and sea lions), and walrus.

point source
A source that radiates sound as if from a single point (ANSI S1.1-1994 R2004).

pressure, acoustic
The deviation from the ambient hydrostatic pressure caused by a sound wave. Also called overpressure. Unit: pascal (Pa). Symbol: p.

pressure, hydrostatic
The pressure at any given depth in a static liquid that is the result of the weight of the liquid acting on a unit area at that depth, plus any pressure acting on the surface of the liquid. Unit: pascal (Pa).

rms
root mean square.

rms sound pressure level (rms SPL)
The root-mean-square average of the instantaneous sound pressure as measured over some specified time interval. For continuous sound, the time interval is one second. *See also* SPL.

shear wave
A mechanical vibration wave where the direction of particle motion is perpendicular to the direction of propagation. Sometimes referred to as a secondary wave or S-wave. Shear waves propagate only in solid media, such as sediments or rock. Shear waves in the seabed can be converted to compressional waves in water at the water-seabed interface.

sound
A time-varying pressure disturbance generated by mechanical vibration waves travelling through a fluid medium such as air or water.

sound exposure
Time integral of squared, instantaneous frequency-weighted sound pressure over a stated time interval or event. Unit: pascal-squared second ($Pa^2 \cdot s$) (ANSI S1.1-1994 R2004).

sound exposure level (SEL)
A measure of the total sound energy in one or more pulses. Unit: dB re 1 $\mu Pa^2 \cdot s$.

sound field
Region containing sound waves (ANSI S1.1-1994 R2004).

sound pressure level (SPL)
The decibel ratio of the time-mean-square sound pressure, in a stated frequency band, to the square of the reference sound pressure (ANSI S1.1-1994 R2004). A measure of sound level that represents only the pressure component of the sound and does not account for the duration of the sound. Unit: decibel (dB).

For sound in water, the reference sound pressure is one micropascal (p_0 = 1 μPa) and the unit for SPL is dB re 1 μPa:

$$\text{SPL} = 10\log_{10}\left(p^2/p_0^2\right) = 20\log_{10}\left(p/p_0\right)$$

Unless otherwise stated, SPL refers to the root-mean-square sound pressure level (rms SPL).

sound speed profile
The speed of sound in the water column as a function of depth below the water surface.

source level (SL)
The sound pressure level measured 1 metre from a theoretical point source that radiates the same total sound power as the actual source. Unit: dB re 1 μPa @ 1 m.

spectrum
An acoustic signal represented in terms of its power (or energy) distribution versus frequency.

transmission loss (TL)
The decibel reduction in sound level that results from sound spreading away from an acoustic source, subject to the influence of the surrounding environment. Also referred to as propagation loss.

wavelength
Distance over which a wave completes one oscillation cycle. Unit: metre (m). Symbol: λ.

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Appendix A. Sound Field Maps

Contour maps of the rms SPL sound fields for Suezmax carrier operations in February and August and for VLCC operations in August are shown in Sections A.1–A.3. Results for VLCC operations in February are presented in Section 4.1.

A.1. Suezmax Carrier, February

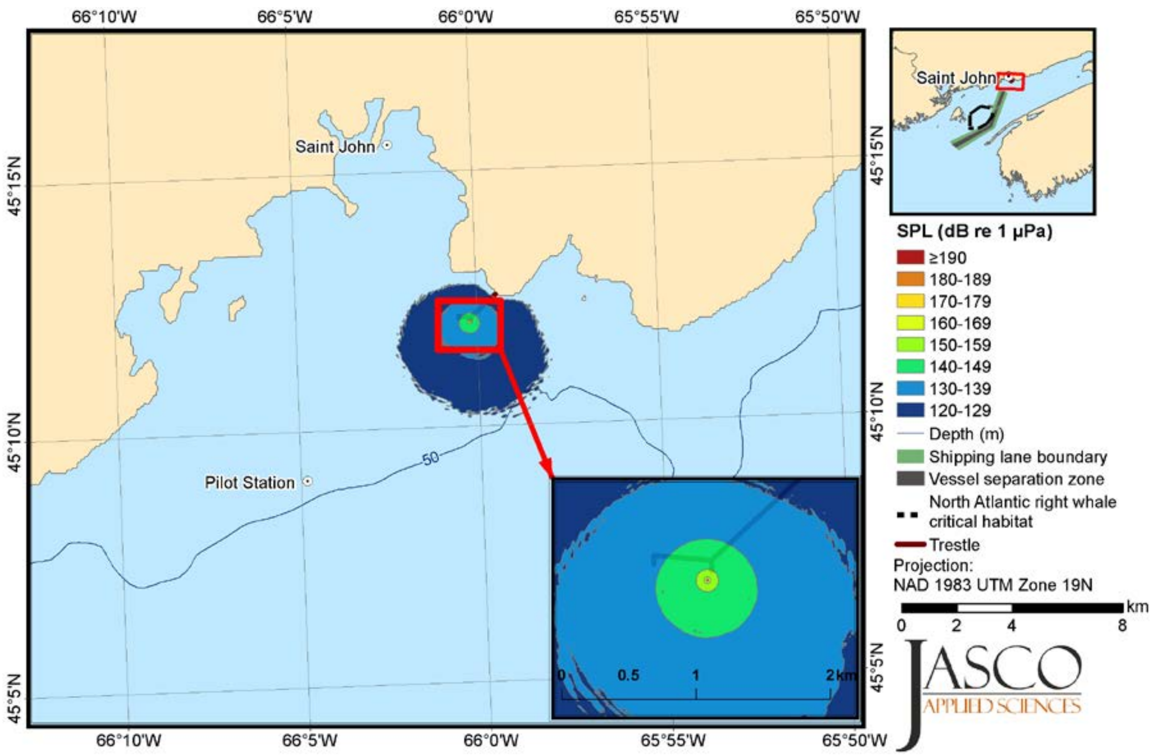

Figure A-1. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for Suezmax docking/undocking with three tugs at Site 1 in February.

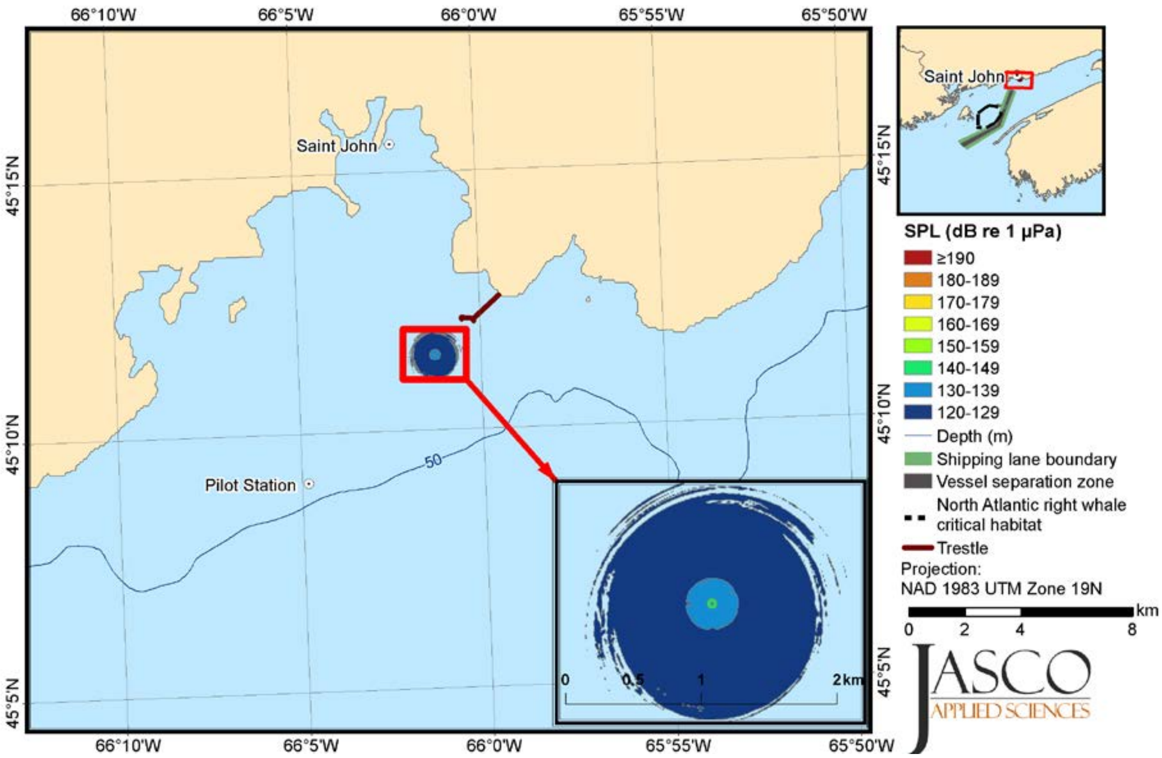

Figure A-2. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for Suezmax transit with one tug at 6 kts at Site 2 in February.

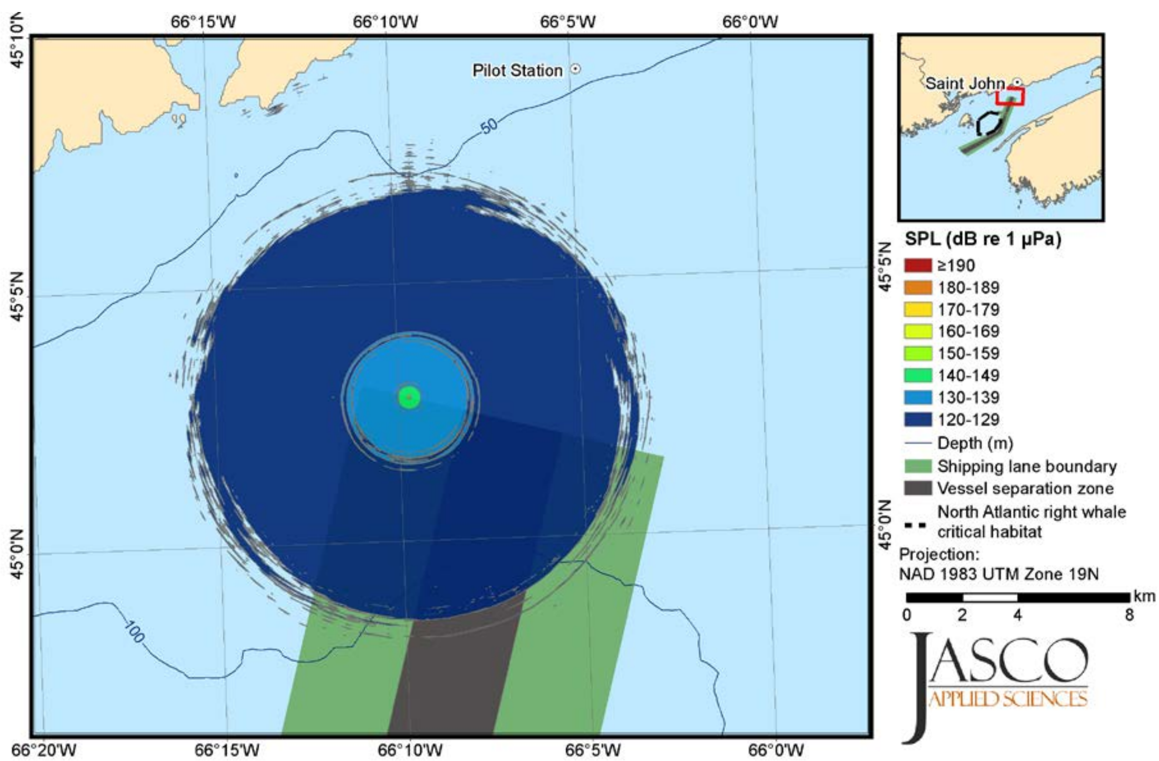

Figure A-3. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for Suezmax transit at 15 kts at Site 3 in February.

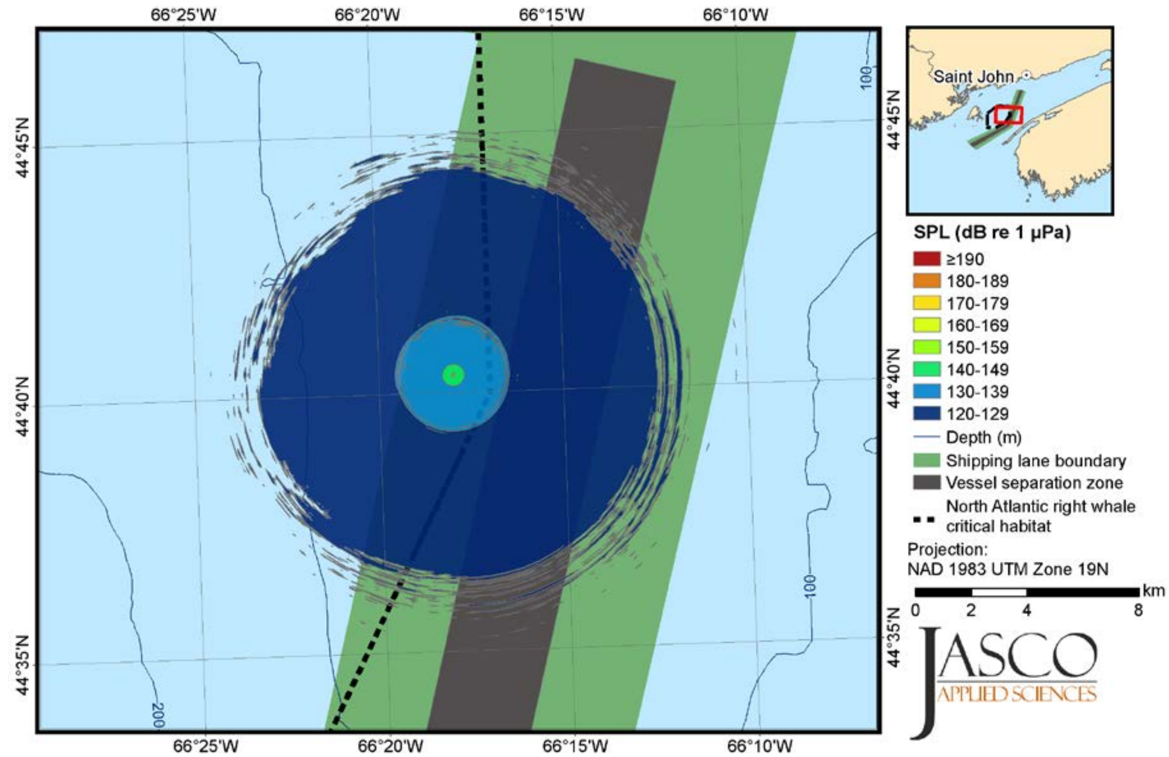

Figure A-4. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for Suezmax transit at 15 kts at Site 4 in February.

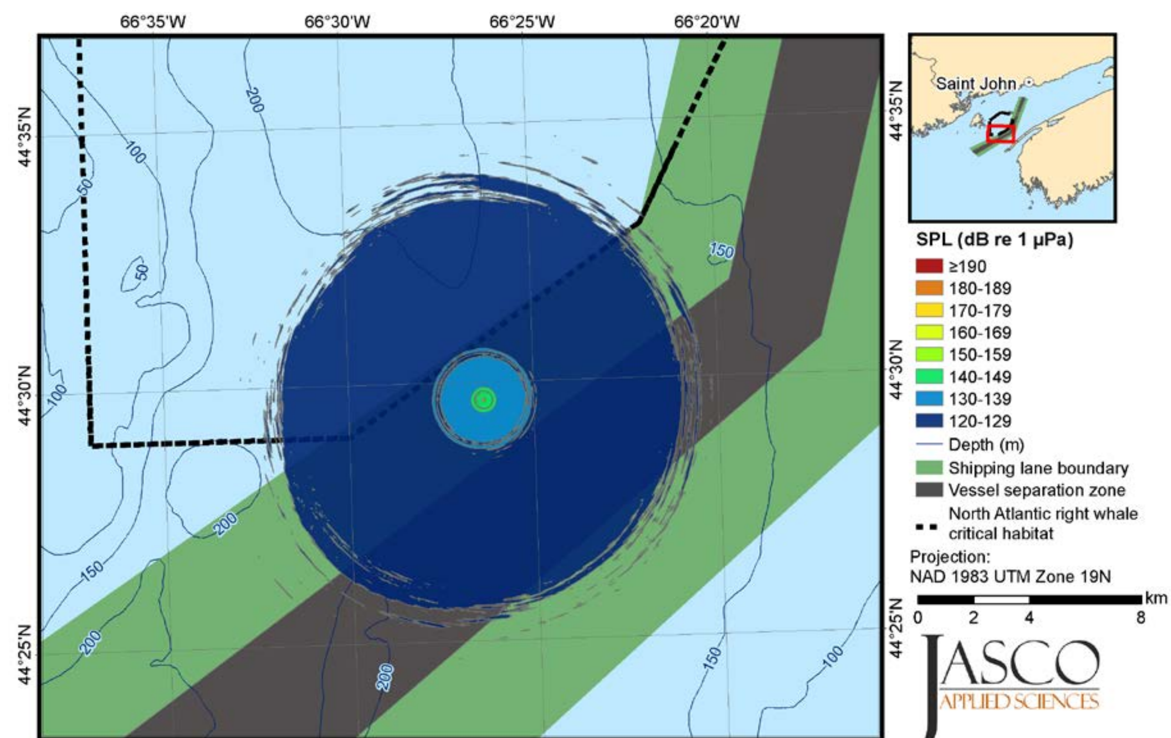

Figure A-5. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for Suezmax transit at 15 kts at Site 5 in February.

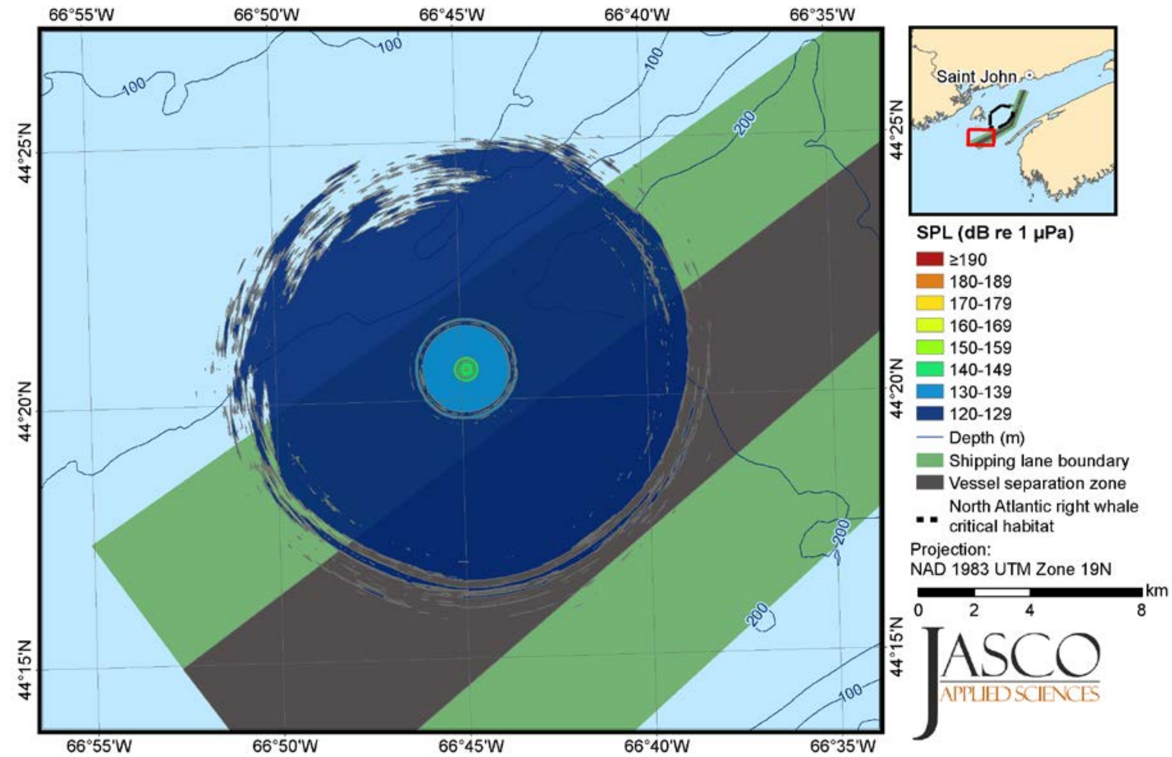

Figure A-6. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for Suezmax transit at 15 kts at Site 6 in February.

A.2. Suezmax Carrier, August

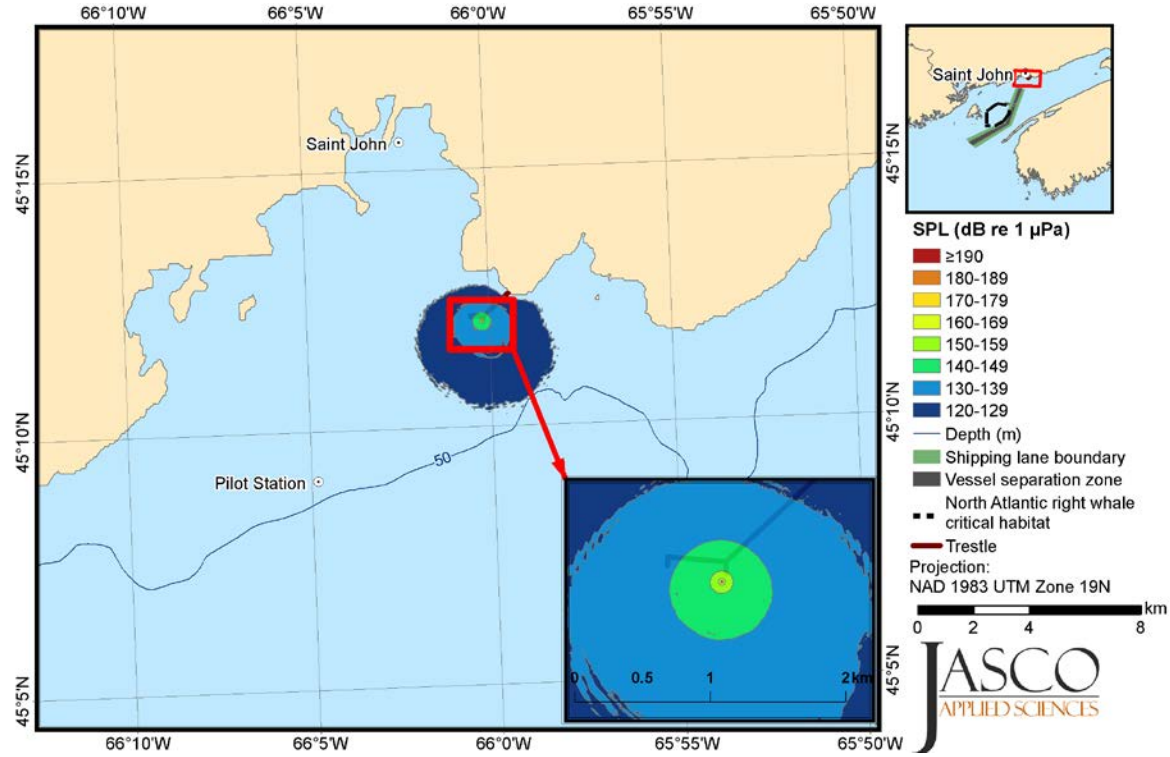

Figure A-7. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for Suezmax docking/undocking with three tugs at Site 1 in August.

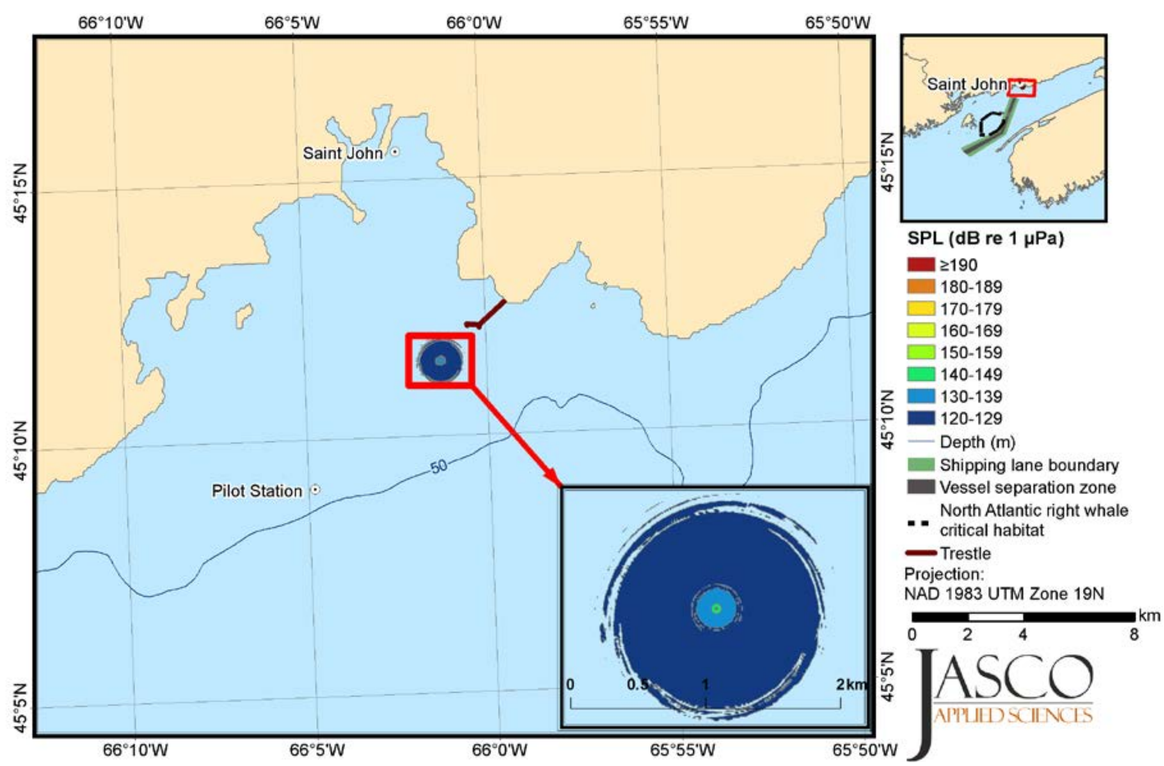

Figure A-8. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for Suezmax transit with one tug at 6 kts at Site 2 in August.

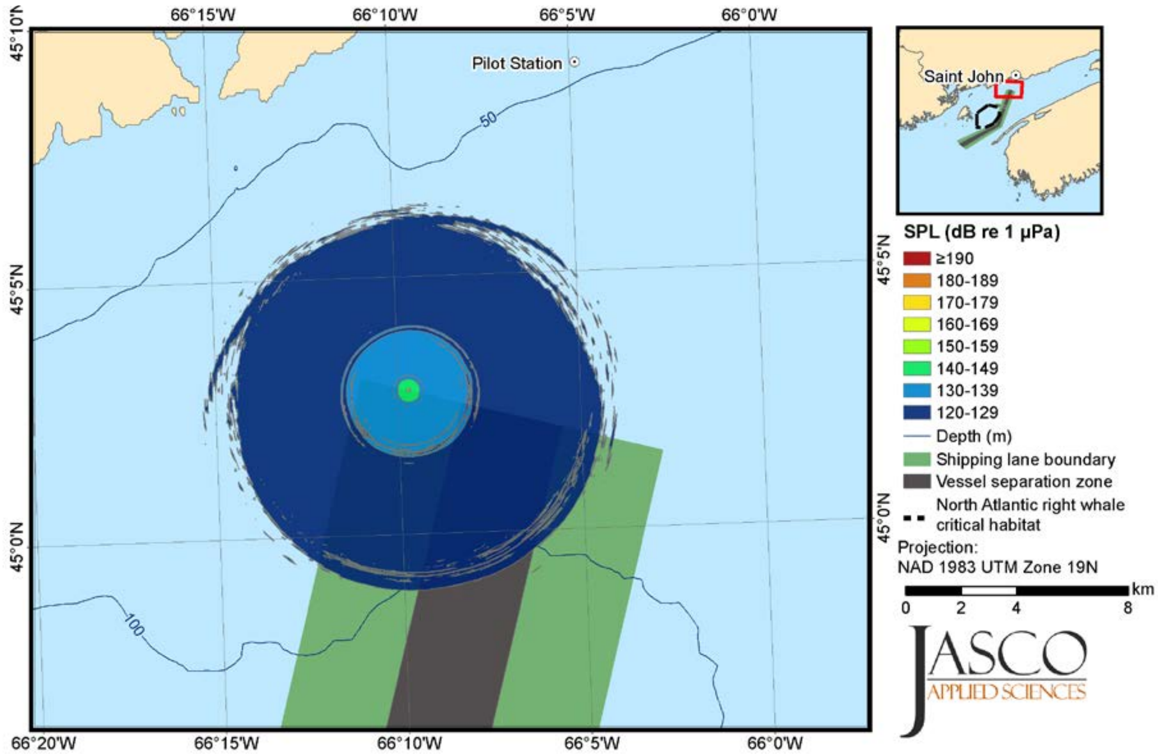

Figure A-9. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for Suezmax transit at 15 kts at Site 3 in August.

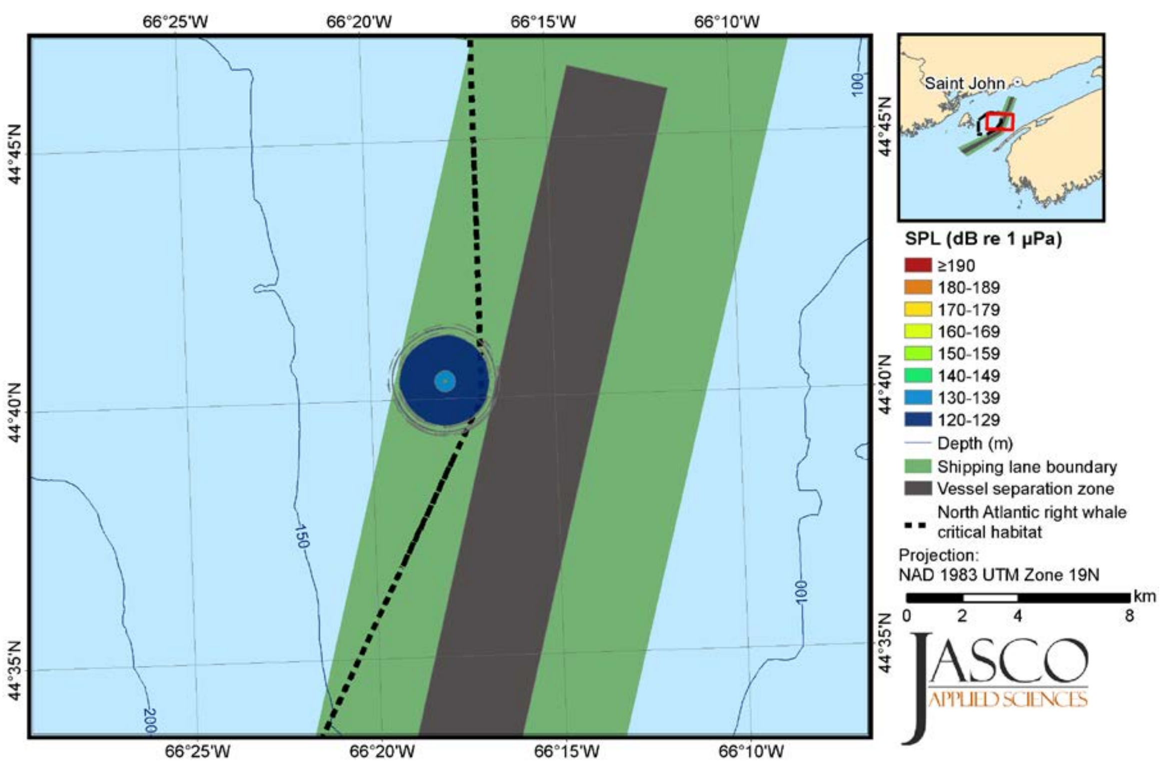

Figure A-10. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for Suezmax transit at 10 kts at Site 4 in August.

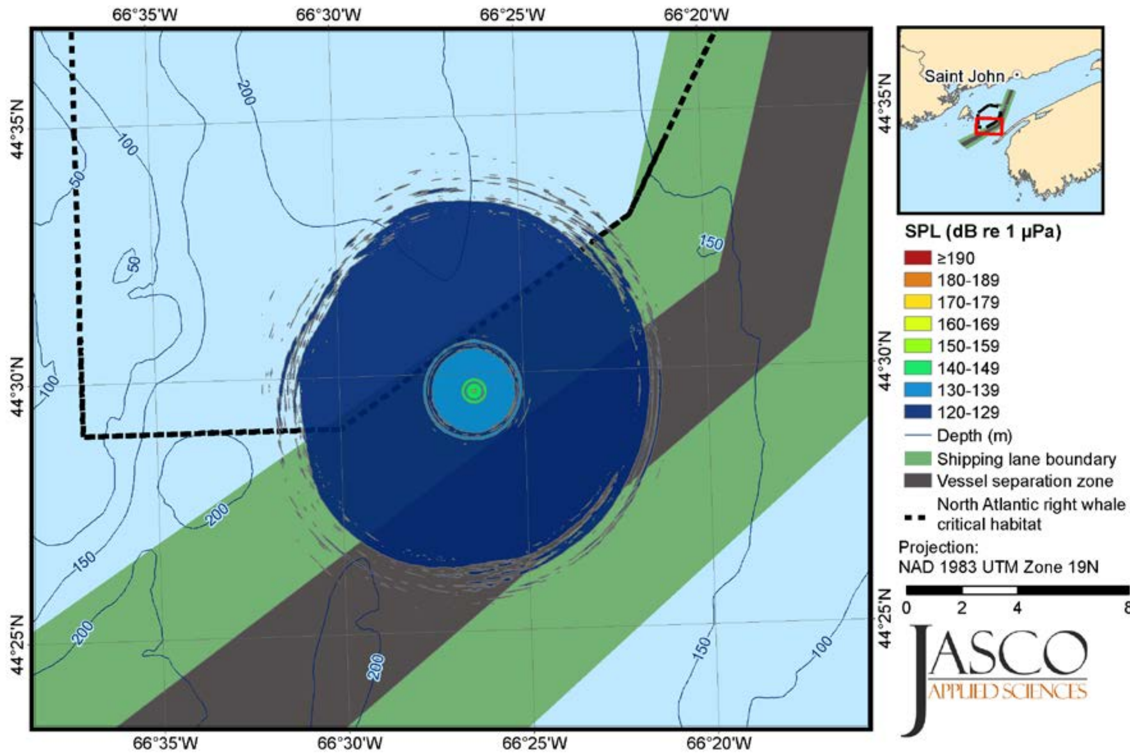

Figure A-11. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for Suezmax transit at 15 kts at Site 5 in August.

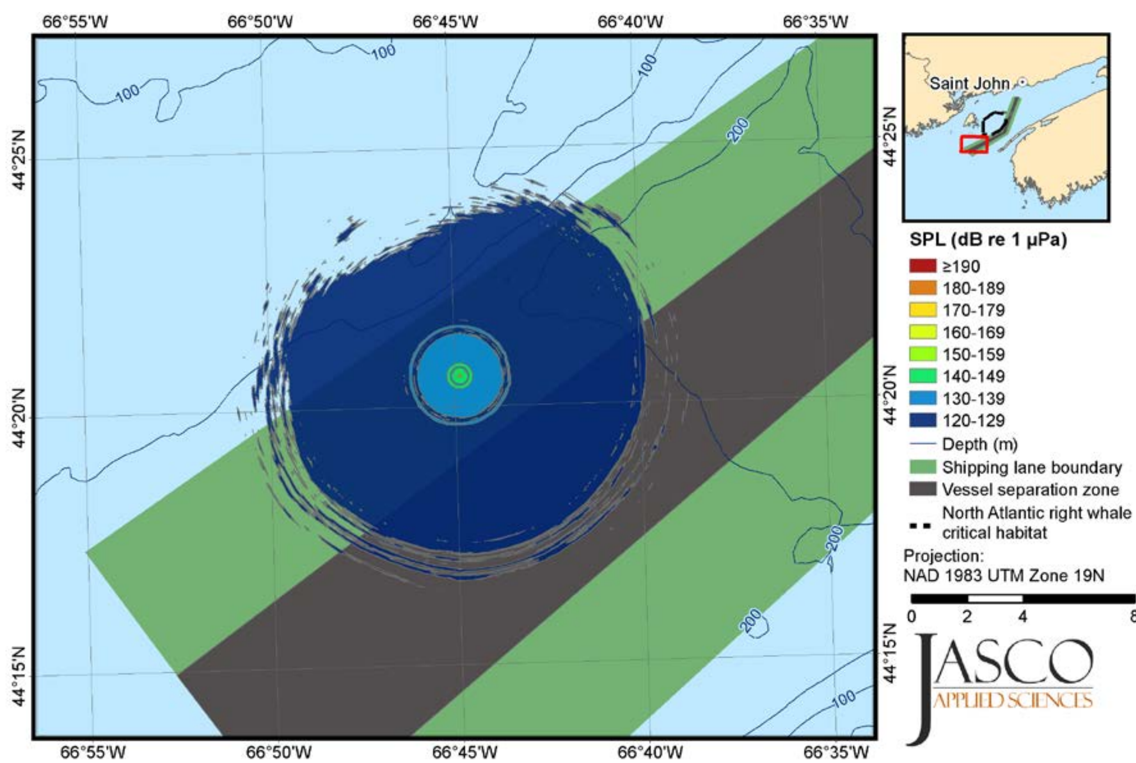

Figure A-12. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for Suezmax transit at 15 kts at Site 6 in August.

A.3. VLCC, August

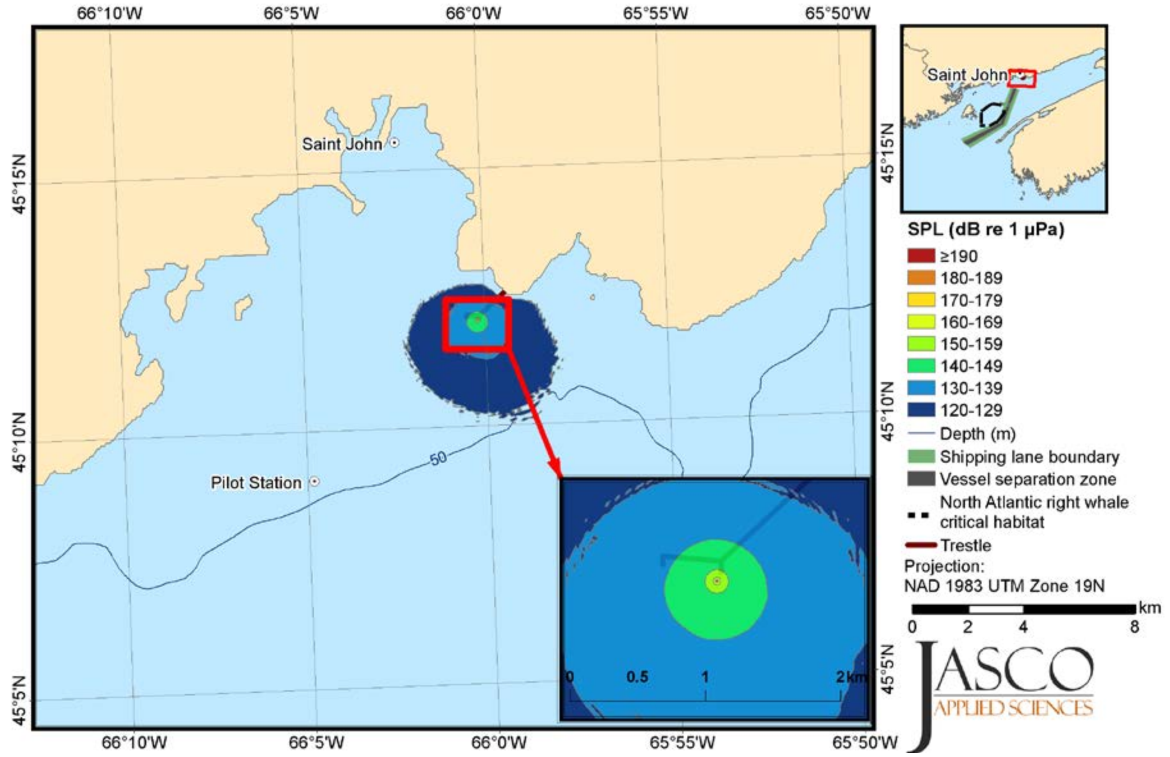

Figure A-13. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for VLCC docking/undocking with four tugs at Site 1 in August.

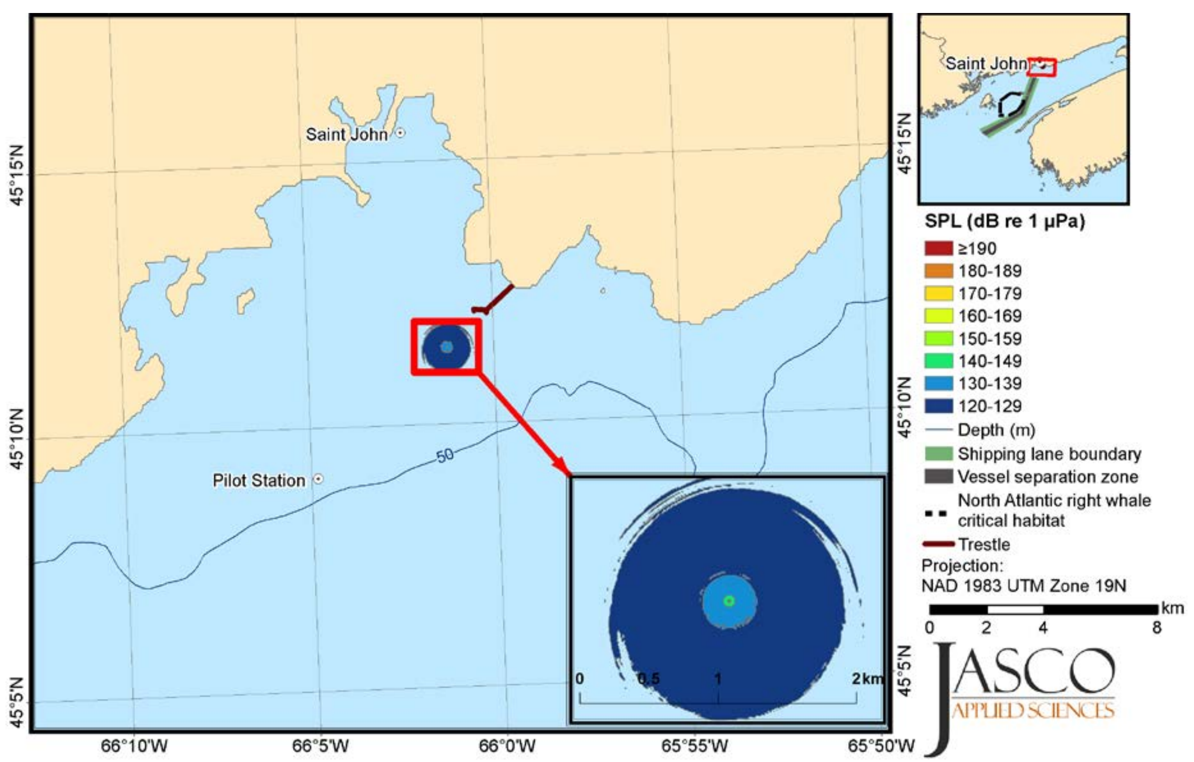

Figure A-14. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for VLCC transit with one tug at 6 kts at Site 2 in August.

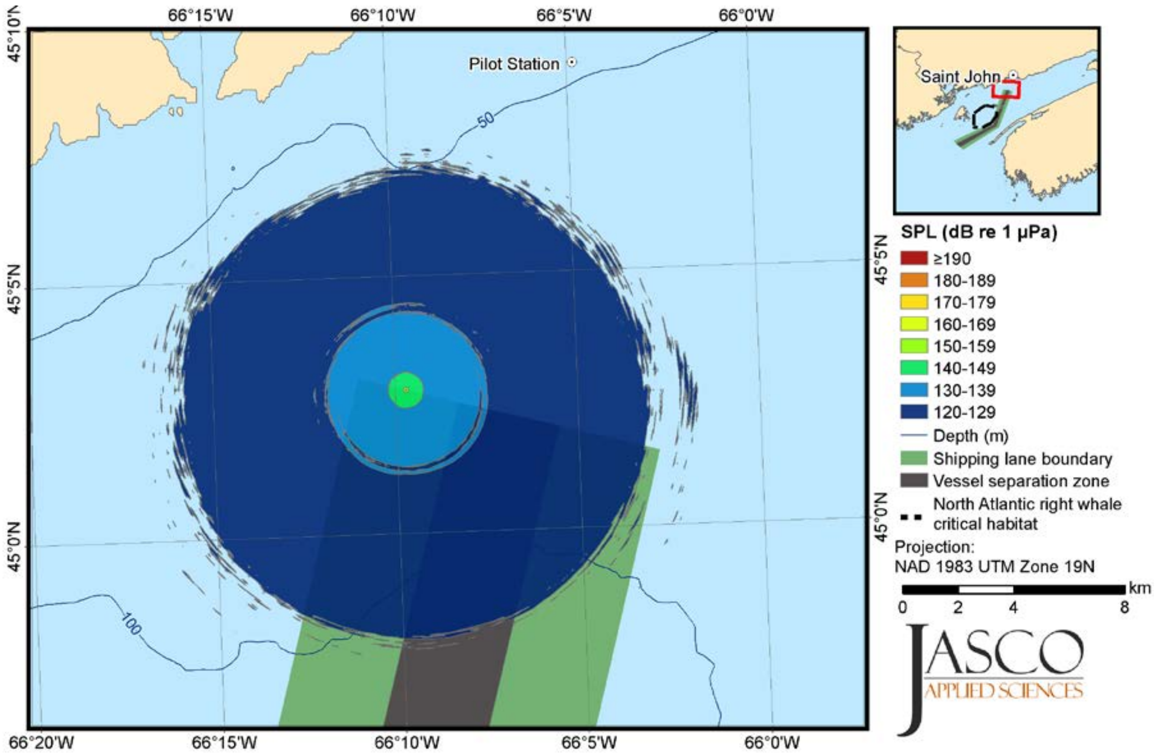

Figure A-15. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for VLCC transit at 15 kts at Site 3 in August.

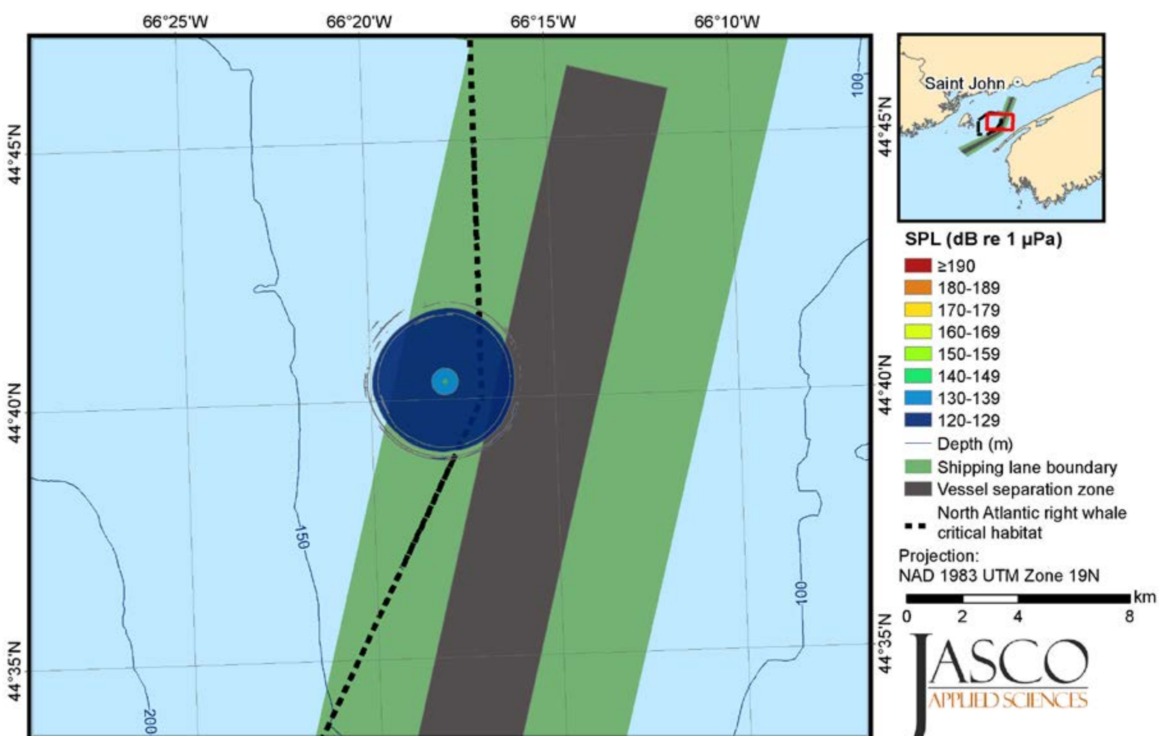

Figure A-16. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for VLCC transit at 10 kts at Site 4 in August.

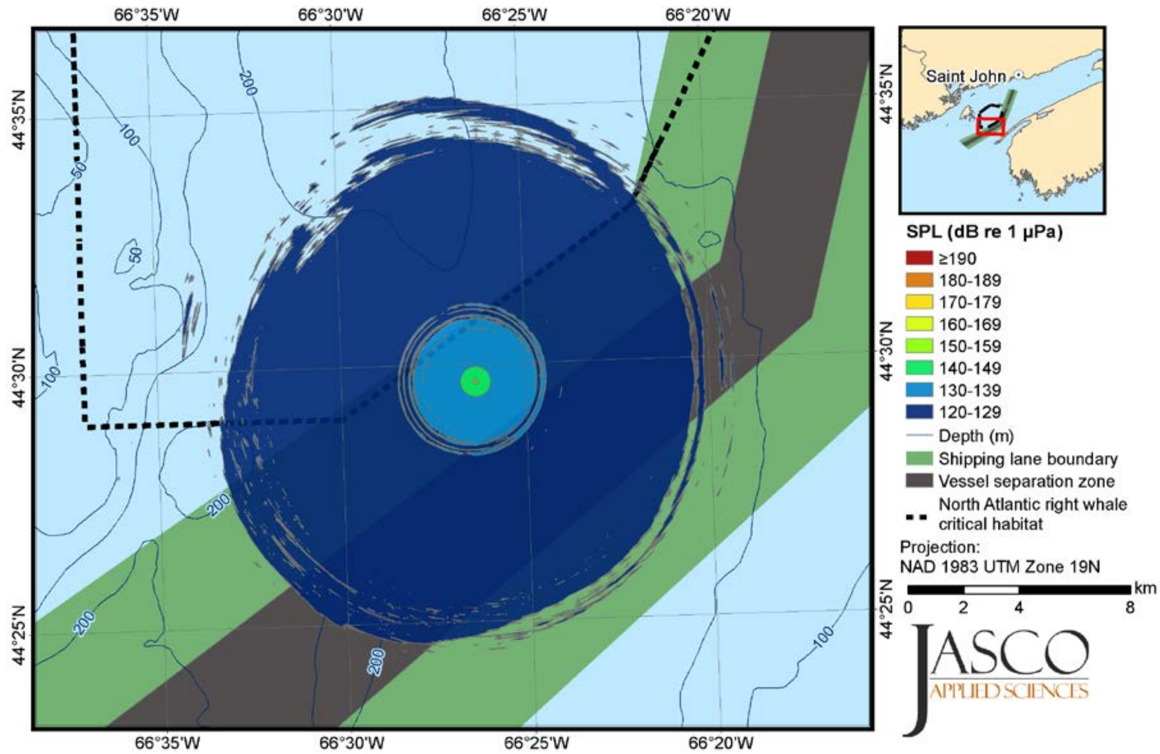

Figure A-17. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for VLCC transit at 15 kts at Site 5 in August.

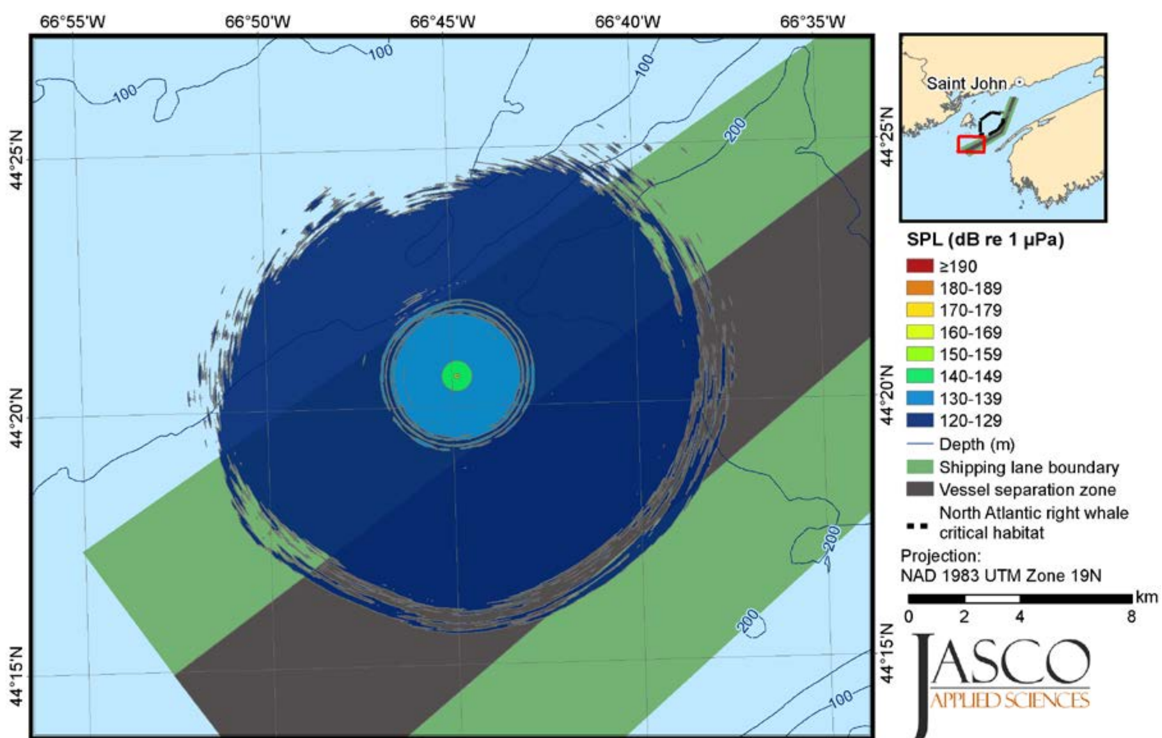

Figure A-18. Maximum-over-depth root-mean-square (rms) sound pressure levels (SPLs) for VLCC transit at 15 kts at Site 6 in August.

ESA Volume 19

Accidents and Malfunctions

The Bay of Fundy Traffic Separation Scheme shipping lanes were re-routed in 2003 to avoid areas of high use by North Atlantic right whales (Transport Canada 2002) (see Marine Wildlife and Wildlife Habitat TDR, Volume 22). It has been estimated that the probability of interaction between vessels and right whales in the outbound traffic lane has been reduced by an average of 90% (Vanderlaan et al. 2008 as cited in DFO 2014). The designated shipping lanes also avoid the main high-density areas of fin whales; humpback whales; and minke whales (see Marine Wildlife and Wildlife Habitat TDR, Volume 22).

Seasonal tanker speed reductions in management areas have been successful in reducing North Atlantic right whale mortality along the US east coast (Laist et al. 2014). To reduce the probability of a tanker strike, recommended mitigation measures include following the Canadian Coast Guard Notice to Mariners guidelines in North Atlantic right whale critical habitat. These guidelines recommend a speed reduction to 10 knots or less from June to December within critical habitat, as well as having an onboard look-out to watch for marine mammals. (DFO 2015).

With the implementation of reduced tanker speeds and using approved shipping lanes, there is a low likelihood of a tanker strike as a result of increased tanker traffic associated with the Project.

5.5 Conclusion

Accidental events have the potential to affect marine resources near the marine terminal. These events may include oil spills from the terminal or tankers, or tanker strikes with marine mammals.

Accidental spills have the potential to affect marine species directly through ingestion, breathing, and dermal exposure, and result in physiological effects over time. Proper planning will limit the risk of accidental events occurring, and equipment and response plans will be in place before the start of Project operations. Contingency, response and management plans for spills will avoid and limit potential effects.

Tanker strikes with marine mammals may occur as result of marine shipping. With the implementation of mitigation measures including following the Canadian Coast Guard Notice to Mariners guidelines in North Atlantic right whale critical habitat) and using of existing shipping lanes there is a low likelihood of a tanker strike as a result of increased tanker traffic associated with the Project.

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