October 31, 2017

Dear [REDACTED],

Re: Your request for access to information under Part II of the Access to Information and Protection of Privacy Act (File # NR-87-2017)

On October 3, 2017, the Department of Natural Resources received your request for access to the following records/information:

A copy of the following briefing notes: Power supply for Labrador interconnected system customers Minister meeting with BP (June 19) Statoil Bonaventure 0-96 Exploration Well Review of Environmental Regulatory Processes To provide a Muskrat Falls project summary and update (July 24) To provide an overview of the Gull Island Project and recent update on market opportunities Overview of New England market opportunities and Nalcor’s activity in the region Mitigation of Oil Seepage in the Shoal Point area Background information on energy issues in the New England States to inform discussions at the 2017 NEG/ECP Conference To provide information on Eastern Canadian provinces' current energy issues which may be raised during NEG meeting Minister Meeting with Quebec Minister of Energy and Natural Resources (August 7) Big Brother Mining Corporation’s mineral exploration application and George River Caribou Herd Assessment of the Voisey’s Bay Underground Mine project by the Independent Engineer Meeting with BP (August 29) Taxation of the Hydroelectric Generating Plant in the town of Bishop’s Falls

I am pleased to inform you that a decision has been made by the Department of Natural Resources, confirmed by the Deputy Minister, to provide access to parts of the requested information.
Access to portions of the remaining information contained within the records, has been refused in accordance with the following exceptions to disclosure, as specified in the Access to Information and Protection of Privacy Act (the Act):

Section 29(1)(a)
The head of a public body may refuse to disclose to an applicant information that would reveal advice, proposals, recommendations, analyses or policy options developed by or for a public body or minister;

Section 30(1)(a)
The head of a public body may refuse to disclose to an applicant information that is subject to solicitor and client privilege or litigation privilege of a public body.

Section 34(1)(a)(i)
The head of a public body may refuse to disclose information to an applicant if the disclosure could reasonably be expected to harm the conduct by the government of the province of relations between that government and the following or their agencies: the government of Canada or a province.

Section 35(1)(d)
The head of a public body may refuse to disclose to an applicant information which could reasonably be expected to disclose information, the disclosure of which could reasonably be expected to result in the premature disclosure of a proposal or project or in significant loss or gain to a third party;

Section 35(1)(g)
The head of a public body may refuse to disclose to an applicant information which could reasonably be expected to disclose information, the disclosure of which could reasonably be expected to prejudice the financial or economic interest of the government of the province to manage the economy of the province;

Section 39(1)(a)(ii)
The head of a public body shall refuse to disclose to an applicant information that would reveal commercial, financial, labour relations, scientific or technical information of a third party;

Section 39(1)(b)
The head of a public body shall refuse to disclose to an applicant information that is supplied, implicitly or explicitly, in confidence;

Section 39(1)(c)(i)
The head of a public body shall refuse to disclose to an applicant information the
disclosure of which could reasonably be expected to harm significantly the competitive position or interfere significantly with the negotiating position of the third party;

Section 39(1)(c)(ii)
The head of a public body shall refuse to disclose to an applicant information the disclosure of which could reasonably be expected to result in similar information no longer being supplied to the public body when it is in the public interest that similar information continue to be supplied;

Section 39(1)(c)(iii)
The head of a public body shall refuse to disclose to an applicant information the disclosure of which could reasonably be expected to result in undue financial loss or gain to any person

As required by 8(2) of the Act, we have severed information that is unable to be disclosed and have provided you with as much information as possible; in accordance with your request for a copy of the records, the records have been included with this correspondence.

As set out in section 42 of the Act you may ask the Information and Privacy Commissioner to review the department’s decision to provide access to the requested information. A request to the Commissioner must be made in writing within 15 business days of the date of this letter or within a longer period that may be allowed by the Commissioner. Your request should identify your concerns with the department’s response and why you are requesting a review.

The request for review may be addressed to the Information and Privacy Commissioner is as follows:

Office of the Information and Privacy Commissioner
2 Canada Drive
P.O. Box 13004, Stn. A
St. John’s, NL. A1B 3V8

Telephone: (709) 729-6309
Toll-Free: 1-877-729-6309
Facsimile: (709) 729-6500

Pursuant to section 52 of the Act, you may also appeal directly to the Supreme Court Trial Division within 15 business days after receiving the department’s decision.

Please be advised that responsive records will be published following a 72 hour period after the response is sent electronically to you or five business days in the case where
records are mailed to you. It is the goal to have the responsive records posted to the Completed Access to Information Requests website within one business day following the applicable period of time. Please note that requests for personal information will not be posted online.

For further details about how an access to information request is processed, please refer to the Access to Information Policy and Procedures Manual at http://www.atipp.gov.nl.ca/info/index.html.

If you have any questions regarding the processing of your request, please feel free to contact me by telephone at 729-0463 or rhynes@gov.nl.ca.

Sincerely,

Rod Hynes
ATIPP Coordinator
Decision/Direction Note
Department of Natural Resources

Title: Assessment of the Voisey's Bay Underground Mine Project by the Independent Engineer

Decision/Direction Required:
- Whether to issue a Work Task Order (WTO) to initiate an assessment of the progress of the underground mine project by the independent engineer as allowed for in the Development Agreement (DA).

- It is recommended that S.29(1)(a)

Background and Current Status:
- VNL operates the Voisey's Bay mine and Long Harbour nickel processing plant subject to conditions of the Voisey's Bay Development Agreement (DA).

- The Fifth Amendment to the DA included a commitment to develop the post-ovoid underground mine such that continuous operation at Voisey's Bay is maintained. The amendment included milestones, based on the schedule in the FEL-2 (prefeasibility) study. Each milestone has a cure period attached, and government has the option of applying remedies including suspension of export, and in the case of Start of Blasting, monetary liquidated damages.

- The commitment to construction of the underground mine was secured through S.35(1)(d) security that was built up through the Contingent Unprocessed Nickel Charge. On sanction of the project in July 2015, the security was reduced by S.35(1)(d) and now includes as letters of credit and as a General Security Agreement and Collateral Realty Mortgage.

- The 5th Amendment committed VNL to milestones associated with construction including:
  - Sanction – June 30, 2015
  - Preparation for Construction (award of contracts, opening of project office) – December 31, 2015
  - Start of Construction – June 30, 2016
  - Start of Blasting (for underground mine development) – S.35(1)(d)
  - Start of Mining (first production) – December 31, 2019

- VNL approached government in May 2015 indicating that they needed to revise the schedule as defined by the milestones in the 5th Amendment. This was followed by a formal letter on May 29, 2015.

- Per MC2015-0257, NR sent VNL a letter on July 2, 2015 providing limited waivers of remedies applying to milestones for underground mine development as defined in the 5th Amendment.

- The letter contains the following provisions:
  - Acceptance of a revised schedule ("Optimized Schedule") for development of the underground mine.
  - Provision of waivers for Preparation for Construction and Start of Construction milestones as defined in the DA (i.e. government will not suspend export of nickel concentrate if the milestones are not achieved by the milestone dates, if diligent progress is maintained).
Acceptance of a revised milestone date for Start of Blasting for underground development (changed from [redacted]), but with remedies remaining in place if the revised milestone date is missed.

The Independent Engineer is to rely upon the Optimized Schedule when assessing if Vale NL is "proceeding diligently" with the Underground Mine when preparing the Engineer's Assessment in relation to the Underground Mine.

The milestones and remedies are, apart from the dates of sanction and first production, confidential due to commercial sensitivity and are redacted from the 5th Amendment.

The Preparation for Construction and Start of Construction milestones were achieved in mid-2016.

On November 7, 2016, VNL met with NR officials to inform them that their new execution strategy is to delay start of underground development until [redacted] to facilitate better control of construction execution and expenditures. VNL indicated that first production of ore is still expected in 2020 and that additional concentrate export allowance is not being requested.

On March 15, 2017, VNL wrote to request that the Milestone Date for Start of Blasting be waived to [redacted].

On July 14, 2017, the CEO of Vale Canada, Jennifer Maki, informed the Minister that Vale SA is not satisfied with the Base Metals Business (BMB) performance and has ordered that a 60 day review of the business be undertaken, including the Voisey's Bay underground mine project. No large contracts will be entered into until the review is complete, including the contract for starting underground development at Voisey's Bay.

Analysis:

The DA considers and estimates the damages to the Province should Vale not meet its commitment to construct the underground mine. These considerations within the Development Agreement include the Contingent Unprocessed Nickel Charge (Article 4.3A - currently $400 million in security) and Liquidated Damages (Article 15.9 - [redacted]), mentioned above.

The DA allows for an assessment by an independent engineer to evaluate whether the underground mine is being developed diligently in accordance with the DA. The related section of the DA is attached.

A contract is in place with Knowles Consultancy Services, dated June 2015, as independent engineer for the underground mine project. This would be the first assessment done. Knowles were also independent engineers for the Long Harbour construction and performed 14 assessments of that project.

There is $40,000 in professional services under Mineral Development's budget in 2017 for assessments by the independent engineer. The cost of the independent assessment is
shared equally by Vale and NR. NR's share of the cost of an assessment is typically $7,500 to $15,000.

- To have an assessment done, a Work Task Order (WTO) must be sent to Knowles and copied to Vale. The WTO has been prepared and was typically signed in the past at the ADM level.

Alternatives:

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Prepared/Approved by: A. Smith / P. Canning
Ministerial Approval: Received from Hon. Siobhan Coady

August 23, 2017

Attachment: Article 15.4 of the Development Agreement
15.4 Underground Mine Completion - Engineer’s Assessments.

The Engineer shall issue an Engineer’s Assessment in relation to Underground Mine:
(a) semi-annually as at February 28th and August 31st of each year until the start of mining at the Underground Mine, unless otherwise agreed by the parties; and
(b) otherwise as requested by the Government or the Proponent from time to time, which request shall be in writing and given to the Engineer and the other party.

Such Engineer’s Assessment shall include (among other things) the Engineer’s independent assessment as to: (i) whether the Proponent is proceeding diligently with the completion of the FEL 3 study with the intent of meeting the Milestone set forth in Section 4.6A(d), (ii) whether the Proponent is proceeding diligently with the Overall Progress on the Underground Mine, with the intent of achieving the start of mining by 31 December 2019 and, if not, the Engineer’s assessment of the date on which the start of mining would likely occur, based on reasonable assumptions, (iii) whether the Proponent has met or failed to meet any of the Milestones set forth in Section 4.6A by the applicable Milestone Date, and (iv) whether Overall Progress has reached a percentage completion that would trigger the reduction of the Contingent Unprocessed Nickel Charge in accordance with Section 4.3A.2. Such Engineer’s Assessment shall be delivered to the Government and the Proponent within 30 days of (1) the dates referred to in subparagraph (a), or (2) the date of a request made under subparagraph (b). The Proponent shall make available to the Engineer all such data concerning the engineering and construction of the Underground Mine as may be required to permit the Engineer to issue such Engineer’s Assessment (including the Proponent’s monthly progress reports) and shall provide a copy of the same to the Government if so requested.
Information Note

Department of Natural Resources

Title: Power supply for Labrador interconnected system customers

Issue: To summarize Labrador interconnected system power supply issues and options

Background: Labrador West (Labrador City, Wabush) Power Supply

- NL Hydro supplies power to western Labrador primarily via two 230 kilovolt (kV) transmission lines carrying electricity from the Churchill Falls generating station to the Wabush terminal station for regional distribution. The power currently available to Labrador West is a function of the capacity limits of these transmission lines, which is less than the 535 megawatts (MW) of generation available to NL Hydro from Churchill Falls generating station.

- The transmission limit of the lines is 345 MW with all equipment in service (“non-firm” limit). If one of the two lines is out of service for any reason, then the limit of the lines is 257 MW in the winter and 185 MW in the summer (“firm limits”).

Analysis

- The Labrador West coincident peak load at any moment in 2016 was 317 MW. Individual customer’s loads peaked at different times including 245 MW for IOC and 81 MW for the towns, which means the combined “non-coincident peak” was 326 MW.

- A return of the Wabush Mines operation to its pre-shut down level (~50 MW) or other similar scale load growth from another mine or large new data centres can be expected to require additional power supply. NL Hydro indicates that town load has grown since the Wabush Mines shut down in part due to data center expansion.

- Data centers consume significant quantities of power. Various media have reported that several new data centres in the US each consume 100 MW.

- Data centres are proving to be interested in expanding operations into Labrador where average industrial (i.e. large scale) customer rates are now approximately 2.6 cents per kilowatt hour, which is among the lowest in North America.

- While new mining operations are long-term infrastructure-heavy projects with major employment benefits, data centers are highly mobile operations that employ comparatively few people as they are primarily automated computer servers requiring cooling fans.
Background: Labrador East (HVGB, North West River, Shetshatshiu) Power Supply

- Hydro owns and operates a 269 km 138 kilovolt (kV) transmission line (TL240) in Labrador that runs from the Churchill Falls Generating Station to provide electricity to customers in the Happy Valley-Goose Bay (HVGB) area. Hydro also operates a 25 MW diesel combustion turbine in HVGB whose primary function is to provide voltage support to the transmission line and back-up generation if the transmission line is out of service for repair. When all Labrador East equipment is in service, the limit of the transmission system is 80 MW.

- The combustion turbine operates in synchronous condenser mode on a continuous basis, from the middle of October until the end of May to maintain voltage levels in the HVGB area.

- The combustion turbine is currently out of service due to an oil leak discovered in December 2016. While it ran in synchronous condenser mode all winter, it is being shipped to the United States for repair and overhaul. It is expected back in service in fall 2017. The PUB has approved Hydro’s application for the work.

Analysis

- The actual electrical load on the Labrador East system was approximately 80 MW in 2016 including 9 MW for Muskrat Falls construction and 71 MW for NLH’s remaining customers.

- Similar to Labrador West, there is potential for new load growth in the region including from new data centres.

- NLH is considering the most cost-effective short term and long term supply options for Labrador East. There are several options under consideration including

Actions being Taken

- NR will continue to work with NLH to identify issues and options for supplying Labrador interconnected customers.
Meeting Note
Department of Natural Resources
BP
Tuesday, June 20, 2017
4:00 PM
Minister’s Boardroom

Attendees:  
BP:  
Rob O’Connor, Exploration Manager, Canada  
Anita Perry, VP, Communications & External Affairs, Regional Manager NS  
See Attachment 1 for biographies.

NR:  
Minister Siobhan Coady  
Gordon McIntosh  
Wes Foote  
Lynn Sullivan

Purpose of Meeting:
• No formal meeting agenda has been provided. Officials may wish to discuss: 1) BP’s interests in the NL offshore; 2) the new generic offshore royalty regime and competitiveness review; and 3) CEAA 2012 and Responsible Authority for Assessment.

Background:
• BP (formerly British Petroleum) is one of the world’s largest integrated oil and gas companies. Headquartered in London, UK, BP has approximately 74,500 employees worldwide and is active in 72 countries. Through its two primary operating segments, upstream and downstream petroleum, BP is involved in the exploration, development and production of energy sources as well as refining, processing, transportation and energy trading activities. BP also has interests in renewable energy with activities focused on biofuels and wind.

• BP Canada Energy Group (BP Canada) is subsidiary of BP with offices in Calgary, Alberta and Halifax, Nova Scotia. BP Canada’s interests include:
  o Alberta Oil Sands - Interests in three oil sands assets (Sunrise, Pike and Terre de Grace) in the Athabasca region of northeast Alberta.
  o Beaufort Sea - 100% interest in two other exploration blocks. BP is exploring the area under a joint operating agreement with ExxonMobil Canada and Imperial.
  o Nova Scotia Offshore - 50% interest and operator in four exploration licences with partner Hess (also 50% interest). BP is the operator of the exploration program.
  o NL Offshore - Interests in six exploration licences in the Flemish Pass Basin, three exploration licences in the Orphan Basin and a significant discovery licence in the Labrador offshore. See Agenda Item #1 and Attachment 2 for additional information.

• For the period November 2014 to December 2016, BP was party to the supply offtake agreement with North Atlantic Refining LLP (NARL). Under the agreement, BP supplied the refinery with crude oil for processing and received the majority of refined petroleum products under fixed margin pricing terms. The arrangement helped support the new refinery ownership during transition of operations following acquisition. The agreement has expired although disputes between BP and NARL that arose during the contract period have been continuing
through arbitrations.

- See Attachment 3 for an overview of BP’s latest financial and operational results.

**Agenda Item #1 – BP’s Interests in the NL Offshore**
- BP may discuss its interests and any planned/potential activities in the NL Offshore.

**Analysis:**
- In the eastern offshore region, BP and its partners have interests in six exploration licences in the Flemish Pass Basin and three exploration licences in the Orphan Basin with a total work commitment of $1.24 billion of which BP’s share is approximately $403 million.
  - **Flemish Pass Basin:**
    - In the 2011 Call for Bids, BP Canada (with its working interest partners) was awarded two land parcels for a total bid commitment of $347.77 million. BP’s share is $34.78 million.
    - In the 2015 Call for Bids, BP Canada (with its working interest partners) was awarded three land parcels for a total bid commitment of $466.56 million. BP’s share is $153.96 million.
    - In the 2016 Call for Bids, BP Canada (with its working interest partners) was awarded one land parcel for a total bid commitment of $12.2 million. BP’s share is $7.32 million.
  - **Orphan Basin:**
    - In the 2016 Call for Bids, BP Canada (with its working interest partners) was awarded three land parcels in the Orphan Basin for a total bid commitment of $413.61 million. BP’s share is $206.8 million.

- BP Canada holds a 0.8662% interest in the Hopedale E-33 significant discovery license (SDL 203) in the Labrador offshore region. BP Canada is partnered with 13 other companies on this licence which has not seen any significant activity since 1987.

- Further information on BP’s land/licence interests in the NL offshore including a map of parcel locations are included in Attachment 2.

**Potential Speaking Points:**
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**Proposed Action:**
- No proposed actions at this time.
Agenda Item #2 – New Generic Offshore Royalty Regime (GORR) and Competitiveness Review

- BP may wish discuss the new NL generic offshore oil royalty.

Analysis:

- Commencing in 2014, NR and its strategic energy advisor Wood Mackenzie worked with the Department of Finance and Nalcor Energy to develop a GORR framework. The GORR is based on project cost recovery and profitability with royalty rates linked to a project revenue to cost ratio calculation referred to as the R factor. The royalty framework is included in Attachment 4.

- NR led targeted and industry-specific stakeholder consultations on the new royalty in 2015. Consultation groups included existing and potential new entrant upstream oil companies, the Canadian Association of Petroleum Producers (CAPP), the Newfoundland and Labrador Oil and Gas Industries Association (NOIA), the St. John’s Board of Trade, the Labrador and Aboriginal Affairs Office and Nunatsiavut Government, the Governments of Nova Scotia and Canada as well as the C-NLOPB. BP Canada Energy ULC is a member of CAPP.

- The new GORR framework was publicly released on November 2, 2015 in advance of the 2015 land sale. Royalty finalization requires regulations development and final approvals.

- Since November 2015, discussions continued with CAPP on the new royalty.

- Government issued OC2017-138 on May 2, 2017, which approved the new royalty framework under the oil royalty regulations. These regulations will be implemented November of 2017. The Department of Natural Resources will review Newfoundland and Labrador’s global competitiveness respecting the Ball of Value.
NR officials have drafted a scope of work based on input from NR’s internal sources and previous work as well as input from CAPP. Further discussion with stakeholders is required.

Potential Speaking Points:

Proposed Action:
- No proposed actions at this time.

Agenda Item #3 – CEAA 2012 and Responsible Authority for Assessment

Analysis:
- Changes to the federal environmental assessment process have resulted in certain activities proposed in the Canada-NL offshore area becoming subject to the Canadian Environmental Assessment Act, 2012 (CEAA 2012). These changes have resulted in responsibility for conducting environmental assessment under CEAA 2012 resting with the Canadian Environmental Assessment Agency (CEAA), while responsibility for carrying out the regulatory review, which must also include consideration of environmental factors, resting with the C-NLOPB.

- In February 2016, the Energy Safety and Security Act (ESSA) received royal assent. This legislation was introduced to modernize safety and security for Canada’s offshore and nuclear industries, ensure a world-class regulatory system and strengthen safety and environmental protection. While the majority of the ESSA is not related to federal environmental assessment, it includes provisions that amend the Accord Acts to provide the C-NLOPB with the necessary tools and authorities to enable them to conduct environmental assessments under CEAA 2012.

- The Minister of Environment and Climate Change Canada is currently reviewing the federal environmental assessment processes associated with the CEAA 2012. In August 2016, a four-person Expert Panel was established to conduct a review including stakeholder and public engagement and to submit a report to the federal Minister. On April 5, 2017, the Expert Panel delivered its report to the federal Minister.

- The Panel is of the view that environmental assessments must move beyond a sole emphasis focused on the bio-physical environment to encompass all impacts likely to result from a project. As such, they recommend that "environmental assessments" be referred to as "impact assessments" governed by four fundamental principles namely that they be transparent, inclusive, informed and meaningful.

- Of the 49 recommendations contained in the report, the Panel has recommended that a single authority having the mandate to conduct and decide upon impact assessments on behalf of
the federal government and that this new federal authority be established as a quasi-judicial tribunal empowered to undertake a full range of facilitation and dispute resolution processes.

- This recommendation would appear to go against the NL’s position that the C-NLOPB should be the sole regulatory authority conducting environmental assessments in the Canada-NL offshore area. Designating the C-NLOPB as a responsible authority would also be in keeping with the Atlantic Accord Agreement principle of Joint Management of the offshore industry by both the Governments of Canada and Newfoundland and Labrador. The C-NLOPB was established under this joint management agreement for the purpose of interpreting and applying the provisions of the Accord Act to all activities of operators in the Canada-NL offshore area and to oversee operator compliance with those provisions including those related to environmental protection.

- The Minister of Environment and Climate Change Canada will consider the recommendations in the Panel’s Report and identify next steps to improve federal environmental assessment processes. Minister Coady responded to the Expert Panel Report on April 26, 2017 reiterating the province’s position as articulated in previous correspondence that the C-NLOPB is best positioned to conduct environmental assessments in the NL offshore and should be designated as responsible authority under CEAA 2012. A federal response to the report recommendations is not expected later this month.

**Potential Speaking Points:**

- The C-NLOPB is the primary regulator of the Canada-NL offshore area.

- The C-NLOPB, as the responsible authority, would be in keeping with the Atlantic Accord principle of Joint Management of the offshore industry by Canada and NL.

- The C-NLOPB, as the responsible authority, would reduce regulatory overlap and duplication by allowing the requirements of CEAA 2012 and the Accord Acts to be met by one regulator through a single process.

- The C-NLOPB has the relevant technical expertise and experience to conduct environmental assessments and review the impacts of offshore oil and gas activities.

**Proposed Action:**

- NR has corresponded with Minister McKenna on several occasions expressing grave concerns that decision making of an authority outside of our region has the ability to impact our economy and that the C-NLOPB is best suited to carry out assessments in the Canada-NL offshore region. NL will continue to stress the importance of the principles of joint management inherent under the Accord Acts and reiterate its position that the Accord Act amendments proclaimed in February 2016 respecting the C-NLOPB as Regulatory Authority be acted upon.

- The Department of Municipal Affairs and Environment has reviewed the Panel’s Report and has responded on behalf of the Province. Presently a conference bilateral call with Minister Mckenna and Ministers Joyce and Coady is being scheduled.
Attachment 1 – Biographies

Rob O’Connor
Exploration Manager, Canada, BP

Rob O’Connor was born in San Francisco, California and grew up in the city of Palo Alto, California. He holds a BS degree in Geology from the University of California at Davis, and an MS degree in Geophysics from Stanford University.

Rob’s current role is Exploration Manager for BP, leading the active offshore exploration projects in Nova Scotia, Newfoundland and the Beaufort Sea. Prior to joining the oil industry, Rob worked in technical roles with the US Geological Survey and the Geophysics Division of the New Zealand Government. In 1989, Rob joined Arco as an Exploration Geophysicist. With BP and Arco, Rob has worked in a variety of exploration and development roles in West Africa, the southern and central North Sea, Algeria, Azerbaijan, and the Black Sea. His most recent role was that of Regional Exploration Manager in the Gulf of Mexico, leading Regional subsurface studies in both the Gulf, and along the Atlantic Margin of North America.

Rob currently lives in Houston, Texas.

Anita Perry
Vice President
Communications & External Affairs
Regional Manager Nova Scotia
BP Canada

Anita Perry is Vice President of Communications and External Affairs and Nova Scotia Regional Manager for BP Canada. She leads all external relations including: government, media and community relations for BP in Canada. Anita is also leading all external relations for BP in Nova Scotia in support of BP Exploration (Canada) Limited’s Scotian Basin exploration project.

Before joining BP Canada, Anita worked with major Canadian corporations leading external communications, public affairs and investor relations communications. Early in her career, Anita worked for politicians at the municipal, provincial and federal levels as an Advisor.

A native of Prince Edward Island, Anita’s career and education have taken her to many parts of Canada; including Moncton, Ottawa, Toronto, Yellowknife, Regina, Calgary and Halifax. She obtained her Bachelor of Arts at the University of Regina majoring in Political Science and Economics.
Attachment 2 – BP Interests in NL Offshore

**BP Exploration Licence Interests – Flemish Pass Basin:**

<table>
<thead>
<tr>
<th>Licence</th>
<th>Call for Bids Year</th>
<th>Interest Holders</th>
<th>Effective Date/ Term</th>
<th>Total Bid (Million $)</th>
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</thead>
<tbody>
<tr>
<td>EL 1125</td>
<td>2011</td>
<td>Statoil Canada Ltd. (40%) Chevron Canada Ltd. (40%) BP Canada Energy Group ULC (10%) Anadarko (10%)</td>
<td>Jan. 15, 2012 9 years</td>
<td>$202.17</td>
</tr>
<tr>
<td>EL 1126</td>
<td>2011</td>
<td>Statoil Canada Ltd. (40%) Chevron Canada Ltd. (40%) BP Canada Energy Group ULC (10%) Anadarko (10%)</td>
<td>Jan. 15, 2012 9 years</td>
<td>$145.60</td>
</tr>
<tr>
<td>EL 1140</td>
<td>2015</td>
<td>Statoil Canada Ltd. (34%) ExxonMobil Canada Ltd. (33%) BP Canada Energy Group ULC (33%)</td>
<td>Jan. 15, 2016 9 years</td>
<td>$225.16</td>
</tr>
<tr>
<td>EL 1141</td>
<td>2015</td>
<td>Statoil Canada Ltd. (34%) ExxonMobil Canada Ltd. (33%) BP Canada Energy Group ULC (33%)</td>
<td>Jan. 15, 2016 9 years</td>
<td>$206.26</td>
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<tr>
<td>EL 1142</td>
<td>2015</td>
<td>Statoil Canada Ltd. (34%) ExxonMobil Canada Ltd. (33%) BP Canada Energy Group ULC (33%)</td>
<td>Jan. 15, 2016 9 years</td>
<td>$35.14</td>
</tr>
<tr>
<td>EL 1149</td>
<td>2016</td>
<td>BP Canada Energy Group ULC (60%) Noble Energy Canada LLC (40%)</td>
<td>Jan. 15, 2017 9 years</td>
<td>$12.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td></td>
<td><strong>$826.53</strong></td>
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**BP Exploration Licence Interests – Orphan Basin:**

<table>
<thead>
<tr>
<th>Licence</th>
<th>Call for Bids Year</th>
<th>Interest Holders</th>
<th>Effective Date/ Term</th>
<th>Total Bid (Million $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EL 1145</td>
<td>2016</td>
<td>BP Canada Energy Group ULC (50%) Hess Canada Oil &amp; Gas ULC (25%) Noble Energy Canada LLC (25%)</td>
<td>Jan. 15, 2017 9 years</td>
<td>$276.31</td>
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<tr>
<td>EL 1146</td>
<td>2016</td>
<td>BP Canada Energy Group ULC (50%) Hess Canada Oil &amp; Gas ULC (25%) Noble Energy Canada LLC (25%)</td>
<td>Jan. 15, 2017 9 years</td>
<td>$12.05</td>
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<td>EL 1148</td>
<td>2016</td>
<td>BP Canada Energy Group ULC (50%) Hess Canada Oil &amp; Gas ULC (25%) Noble Energy Canada LLC (25%)</td>
<td>Jan. 15, 2017 9 years</td>
<td>$125.25</td>
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<td><strong>Total</strong></td>
<td></td>
<td></td>
<td></td>
<td><strong>$413.61</strong></td>
</tr>
</tbody>
</table>

1. In addition to the exploration licenses outlined above, BP also has a 0.8662% interest in the Hopedale E-33 significant discovery licence in the offshore Labrador region. This licence has an effective date of August 4, 1987 and is held with 13 other interest holder partners. This licence area has not seen any recent significant activity.
Map 1 – Eastern Newfoundland Region Licence Information (C-NLOPB)
Potential copyright material

If you wish to obtain a copy please contact the ATIPP Office at (709) 729-7072 or atipoffice@gov.nl.ca.
Attachment 3 – BP Financial & Operational Indicators

<table>
<thead>
<tr>
<th></th>
<th>Q4 2016</th>
<th>Q4 2015</th>
<th>2016</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Financial</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Revenue1 Million US$</td>
<td>$52,121</td>
<td>$49,233</td>
<td>$186,606</td>
<td>$225,982</td>
</tr>
<tr>
<td>Net Earnings Million US$</td>
<td>$497</td>
<td>($3,307)</td>
<td>$115</td>
<td>($6,482)</td>
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<tr>
<td>Net Earnings per Share US$</td>
<td>$0.03</td>
<td>($0.18)</td>
<td>$0.01</td>
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</tr>
<tr>
<td>Cash flow from Operations Million US$</td>
<td>$2,428</td>
<td>$5,806</td>
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<tr>
<td>Total Assets2 Million US$</td>
<td>$263,316</td>
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<tr>
<td>Total Liabilities3 Million US$</td>
<td>$166,473</td>
<td>$163,445</td>
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<tr>
<td>Total Shareholders’ Equity2 Million US$</td>
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<td>$98,387</td>
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<tr>
<td>Total Capital Investment3 Million US$</td>
<td>$7,573</td>
<td>$6,116</td>
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<tr>
<td>Upstream Million US$</td>
<td>$5,852</td>
<td>$4,570</td>
<td>$16,048</td>
<td>$16,306</td>
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<tr>
<td>Operations</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Upstream Production4 1000 boe/day5</td>
<td>2,186</td>
<td>2,314</td>
<td>2,208</td>
<td>2,220</td>
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<tr>
<td>Refinery Throughput 1000 barrels/day</td>
<td>1,644</td>
<td>1,714</td>
<td>1,685</td>
<td>1,705</td>
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<tr>
<td>Refinery Availability Percent</td>
<td>94.9%</td>
<td>95.5%</td>
<td>95.3%</td>
<td>94.7%</td>
</tr>
</tbody>
</table>

1. Total revenue and other income.
2. As of the end of the quarter.
3. Capital Investment on an accrual basis comprises additions to property, plant and equipment, intangible assets and investments in joint ventures and associates, and reflects consideration payable in business combinations and includes inorganic and organic capital expenditures. Inorganic capital expenditure comprises consideration in business combinations and certain other significant investments made by the group.
4. Excludes Russia production.
5. Thousand barrels of oil equivalent per day.
6. Numbers may not sum to totals due to rounding.

NL Discussion:

- On November 9, 2016, BP (50%), in partnership with Hess (25%) and Noble Energy (25%), was awarded three parcels in the Eastern Newfoundland region. BP (60%) was also awarded a fourth parcel in the same region in partnership with Noble Energy (40%).

Financial/Operations Discussion:

- BP reported net earnings of US$497 million in Q4 2016 compared to a net loss of US$3,307 million in Q4 2015. BP reported net earnings of US$115 million for full year 2016 compared to a net loss of US$6,482 million for full year 2015. Earnings for both periods were affected by:
  - Earnings were positivity impacted by lower cash and non-cash costs and higher upstream realizations compared to one year ago.
  - Earnings were negatively impacted by weaker refining margins and a higher level of turnaround activity compared to one year ago.
  - Affecting both full year 2016 and Q4 2016 were charges associated with the Deepwater Horizon accident and oil spill following the settlement of claims in 2015.

- Production for Q4 2016 was 5.5% lower than Q4 2015 mainly due to entitlement and portfolio impacts. Production for 2016 was 2,208 mboe/day, compared to 2,220 mboe/day for 2015. Q1 2017 reported production is expected to be higher than Q4 2016 reflecting the impact of the Abu Dhabi concession renewal. BP expects full-year 2017 production to be higher than 2016. Production will depend on the timing of project start-ups, acquisition and divestment activities, OPEC quotas and entitlement impacts.
• Total capital expenditure in Q4 2016 was US$7.6 billion, compared with US$6.1 billion Q4 2015. Capital expenditures were US$19.4 for 2016 comparable to US$19.5 billion for 2015. BP’s organic capital expenditure was $16.0 billion for 2016 (excludes consideration for the renewal of 10% of the Abu Dhabi ADCO onshore oil concession). This was well below the original guidance of US$17-$19 billion for the year.

• In relation to the Gulf of Mexico oil spill, the total cumulative pre-tax charge for the incident is US$62.6 billion. The charge taken for Q4 2016 was US$800 million pre-tax. Significant progress was made in Q4 2016 and BP is moving towards completion of the process for resolving Business Economic Loss claims. Amounts to resolve the claims are expected to be substantially paid this year.

• Divestment proceeds were US$0.5 billion for Q4 2016 compared to US$0.2 billion for the same period in 2015. For the full year 2016, proceeds were US$2.6 billion in addition to $0.6 billion received in relation to the sale of 20% from its shareholding in Castrol India Limited for a total of $3.2 billion for the year, compared with $2.8 billion in 2015. In 2017, divestments are expected to be in the range of US$4.5-$5.5 billion.

Other Discuss and Outlook:

• For the 2017-2021 period, BP expects capital expenditure to be within the range of US$15-US$17 billion per year. BP will continue to focus on costs and capital discipline and seek further improvements throughout the BP Group.

• In the Upstream segment, capital spending for the 2017-2021 period is expected to be focused on select investment and range between $13 and $14 billion per year. Approximately 60% will be allocated to major projects, less than 10% towards exploration, less than 10% towards maintenance and the remaining towards infill drilling.

• Since 2014, BP has reduced its cash costs by US$7 billion (US$4 billion in the Upstream), a year ahead of plan due to working smarter, simpler and in a more standardized way. BP will continue to reduce costs and expect to continue to transform and modernize its organization by driving continuous improvement across every part of the BP Group.

• Since 2014, BP has reduced its capital and cash costs by US$9 billion in the Upstream by working with the supply chain, reducing the size of its organization and being disciplined with every dollar. BP has reduced its workforce by one third and is now 36% less than the peak in 2013.

• BP has 17.8 billion barrels of oil equivalent reserves, equal to 14.7 years of reserve life.

• Since 2010, BP has delivered approximately US$75 billion of divestments. Going forward, divestments will be focused on the midstream, downstream and infrastructure.
Information Note
Department of Natural Resources

Title: Statoil Bonaventure O-96 Exploration Well

Issue: Preliminary Results of the Statoil Bonaventure O-96 Exploration Well

Background and Current Status:
- Statoil spud the Bonaventure O-96 well on May 21, 2017 using the semi-submersible rig, West Aquarius on contract from Seadrill. Statoil Canada Ltd. (Operator) 65% and Husky Oil Operations Ltd. 35% are the interest owners.

- The well was drilled on Significant Discovery License (SDL) 1047 in the Flemish Pass basin in about 1112 m of water depth. The well is located approximately 30 km north of the high impact discovery wells of Bay du Nord C-78/C-78z (see Map).

NOTE: Information used in this information note has been submitted to the Canada-Newfoundland and Labrador Offshore Petroleum Board by the Operator on a confidential basis and, pursuant to section 119 of the Canada-Newfoundland and Labrador Atlantic Accord Implementation Act, is privileged and must not knowingly be disclosed.

Analysis:

Action Being Taken:
- Department staff will liaise with C-NLOPB officials as further updates become available.

Prepared/Approved by: J. Agbakwuru / P. Molloy / W. Foote
Ministerial Approval: Received from Hon. Siobhan Coady

June 22, 2017
Information Note
Department of Natural Resources

Title: Review of Environmental and Regulatory Processes

Issue: Government of Canada discussion paper on review of environmental and regulatory processes.

Background and Current Status:

- The Government of Canada (GoC) has committed to reviewing and modernizing environmental assessment and regulatory processes. After extensive public consultations, Expert Panel reports and Parliamentary studies conducted over the last 12 months, on June 30, 2017, the GoC released a discussion paper (attached) outlining potential reforms being considered to rebuild trust and modernize Canada’s environmental and regulatory processes. This includes a review of the Canadian Environmental Assessment Act, 2012 (CEAA 2012), the National Energy Board Act, the Fisheries Act, and the Navigation Protection Act.

- The proposed reforms are based on the guiding principles of fair, predictable and transparent environmental assessment and regulatory process; participation of indigenous peoples; inclusive and meaningful public engagement; timely, evidence-based decisions; and utilizing the one project – one assessment approach.

- Key measures being considered include:
  - Establishing a single government agency responsible for assessments of federally designated projects. The review would go beyond environmental impacts to also consider social, health and economic aspects of a project and require a gender-based analysis. Joint assessments will be undertaken with the life cycle regulator for major energy transmission, nuclear and offshore oil and gas projects.
  - Requiring an early planning phase to foster greater collaboration and engagement between proponents, Indigenous peoples, stakeholders, the public and federal and provincial governments.
  - Early and regular engagement and partnership with Indigenous peoples based on recognition of Indigenous rights and interests from the outset.
  - Restoring lost protections and incorporating modern safeguards to the Fisheries Act and the Navigation Protection Act.

- The discussion paper is open to public comment until August 27, 2017.

- Of key importance to the province is the designation of the C-NLOPB as a Responsible Authority (RA) for the purpose of environmental assessments. On October 17, 2016, Minister Coady wrote Minister McKenna (Environment and Climate Change Canada) requesting that the C-NLOPB be designated RA. In addition, in December 2016, the Minister submitted a written comment to the Expert Panel to review federal environmental assessment processes indicating that the C-NLOPB is best suited to conduct environmental assessments in the NL offshore area. The Minister also reiterated similar messages to the May 5th deadline for comments on the Expert Panel Report followed up with correspondence to Minister McKenna.

Analysis:

- It has been the position of NL that the C-NLOPB should be so designated as the RA for conducting environmental assessments in the offshore area. The C-NLOPB possesses the experience and technical expertise and is the best placed regulator to conduct environmental assessments. The Accord Acts explicitly mandate the C-NLOPB with the administration of offshore oil and gas exploration and development on behalf of each government. This
mandate includes protection of the environment which was the responsibility of the C-NLOPB, as RA, until federal amendments unilaterally removed such designation in 2010.

- Currently, the Canadian Environmental Assessment Agency is the RA for environmental assessments in the Atlantic offshore. Amendments to the Accord Acts in February 2016 set out the C-NLOPB’s responsibilities as RA; however, in order to come into force the designation as RA requires amendments to the regulations promulgated under CEAA 2012. As previously mentioned, Minister Coady has written Minister McKenna requesting that this be fast-tracked. This position has been also taken by Nova Scotia whose Accord legislation was also amended in 2016 regarding RA designation for the CNSOPB.

- The discussion paper makes a number of references to offshore oil and gas and offshore regulators (below). These references appear to indicate that the GoC is open to the concept of the C-NLOPB in some form of governance role and having responsibilities for environmental assessment activities in the offshore.

  o “Our government recognizes that some elements of the current system are working and should continue to form part of improved environmental assessment and regulatory processes, including decisions with enforceable conditions, legislated timelines, tools for federal-provincial cooperation and a strong role for expert regulators in energy transmission, nuclear and offshore oil and gas”

  o “Our proposal recognizes constitutional jurisdiction and the strength of regimes that are in place among provincial, territorial and Indigenous partners, as well as existing co-management frameworks used in the North and Canada’s offshore regions”

  o “For major energy transmission, nuclear, and offshore oil and gas projects, the agency and life-cycle regulators would jointly conduct impact assessments as part of a single, integrated review process”

  o “Relying on the life-cycle regulators (i.e. National Energy Board, Canadian Nuclear Safety Commission, Offshore Petroleum Boards) for the assessment of non-designated projects (e.g. delineation wells in the offshore)”

  o “Maintain authority for the National Energy Board, the Canadian Nuclear Safety Commission and the Offshore Petroleum Boards to integrate impact assessment conditions stemming from a joint assessment under their responsibility for regulatory compliance, monitoring and enforcement”

Action Being Taken:
- The GoC is accepting comments on the discussion paper until August 27, 2017 in preparation for the introduction of federal legislation to modernize EA and the NEB expected expected to be introduced before the end of the calendar year. The Government of NL will continue to put forth its position that the C-NLOPB should be so designated as the RA for conducting environmental assessments in the offshore area.

Prepared/Approved by: C. Carter / W. Foote
Ministerial Approval: Received from Hon. Siobhan Coady

July 25, 2017
Potential copyright material

If you wish to obtain a copy please contact the ATIPP Office at (709) 729-7072 or atippoffice@gov.nl.ca.
Overview: To provide an overview of the Gull Island Project and recent update on market opportunities.

Background and Current Status:
- The Gull Island project is Phase 2 of the Lower Churchill Project with a planned capacity of 2,250 MW and an average energy output of 11.9 TWh per year. Gull Island is on the Churchill River downstream from the 5,428 megawatt Churchill Falls generating station and upstream from the Muskrat Falls hydroelectric station construction site.

- As the Muskrat Falls Project will meet domestic market requirements for the foreseeable future, Gull Island output would be dedicated to export and serving any new NL large-scale load growth.

- Significant technical work has been completed on the Gull Island project, including: technical studies and an environmental assessment for generation; assessment of potential transmission routes; aboriginal agreement with Innu Nation; a water management agreement with Churchill Falls (Labrador) Corporation Limited; and of extensive hydrological data and analysis.

- The Gull Island project is of interest to policy makers in the northeast region as it is the main alternative large hydro supplier to Hydro Quebec’s resources.

- Multiple market options and market access options for Gull Island are being assessed for potential feasibility. One of the primary considerations will be availability of a long-term contract to enable financing. Market options include: Ontario (ON); the Maritimes; and New England.

Analysis:

Ontario
- In July 2015, ON and NL Energy Ministers announced the creation of the interprovincial, Ontario – Newfoundland and Labrador Interprovincial Electricity Trade (ONLIET) Working Group to study the potential for firm clean electricity trade opportunities between both provinces.

- The working group includes provincial government officials from ON and NL, and representatives from Ontario’s Independent Electricity System Operator (IESO) and Nalcor.
Maritime Provinces

- Potential markets for Gull Island power include Nova Scotia (NS) and New Brunswick (NB) as they generate a high proportion of their electricity from coal and fuel oil and the new federal carbon tax policy is motivating these provinces to consider their options for phasing out these high-carbon emitting plants in the 2030-2040 timeframe.

- Federal Budget 2016 allocated $2.5 million over two years for the Regional Electricity Cooperation and Strategic Infrastructure (RECSI) to facilitate regional dialogues and studies to identify the most promising electricity infrastructure projects for achieving significant regional greenhouse gas (GHG) reductions. Funding of $470,000 is allocated to the Atlantic region, and NL is participating in this work.

- NL is also participating in the Atlantic Clean Energy Partnership announced by Atlantic Premiers in April 2017. The intent of the Atlantic Energy Partnership is work regionally and with the federal government to focus on identifying potential enhancements to electricity generation and transmission infrastructure, the promotion of energy efficiency, as well as the demonstration, deployment, adoption, and export of clean energy technologies.

New England

- The New England market serves over 14 million people and is facing: 1) excessive reliance on natural gas; 2) retirement of non-gas-fired generation, and 3) aggressive greenhouse gas emission reduction targets and state renewable portfolio standards.

- In July of 2016, Massachusetts passed the Clean Energy Bill requiring procurement of 1,600 MW of offshore wind and 9.45 terawatt hours (TWh) of clean energy annually, including hydro and land-based wind. Contracts will be executed by December 2022.

- In anticipation of Massachusetts issuing a request for proposal, on January 11, 2017, Emera Inc. issued a news release soliciting partners to bundle their clean energy generation with Emera’s transmission on its proposed Atlantic Link for delivery into New England. The Atlantic Link will be a 350-mile submarine high-voltage DC transmission line delivering energy from NB to Massachusetts.

On the RFP closing date July 27, 2017, Emera announced it had formally proposed the 1,000 MW line in response to the RFP. The news release noted that generation suppliers included Nalcor Energy with 1.1 terawatt hours of hydropower annually. No further details were given on Nalcor’s involvement.

Nalcor views the Atlantic Link as an opportunity... Future opportunities related to the New England market could include the Gull Island project.
NL Generation and Transmission:
- Current export is driven by access to Nalcor's 265 MW transmission reservation through Quebec and the amounts of surplus energy available on the Labrador interconnected system. Nalcor indicates it can deliver varying amounts of supply from now to post-2041 when the Churchill Falls contract will expire. Until mid-2020's, NL can provide 100-250 MW (1.2-4 TWh/year), weighted more heavily to the summer season.

- In the long-term beyond the mid-2020's, new generation at Gull Island and/or smaller hydro and wind generation could provide more than 2,000 MW (11.9 TWh/year). With the Churchill Falls Renewal Contract expiring in 2041, additional supply ranging from 4,000 MW (25 TWh/year) could be available for export.

Prepared/Approved by: C. Boland/C. Snook/J. Cowan
Ministerial Approval: Received from Hon. Siobhan Coady

July 27, 2017
Information Note  
Department of Natural Resources

Title: Mitigation of Oil Seepage in the Shoal Point Area on the Port au Port Peninsula

Issue: To provide some history of seepage in the area and a summary of the recommendations of the report prepared by AMEC for the Department of Municipal Affairs and Environment (MAE) on an oil seep reported on Shoal Point for the Minister’s visit to the region on July 26 and 27, 2017

Background and Current Status

- The presence of surface hydrocarbons along the coastline in Port au Port Bay was first reported by Alexander Murray (first government geologist for Newfoundland) in his 1865 Report of Activities to the Newfoundland government.

- The first known drilling for hydrocarbons on the Port au Port Peninsula took place on land in 1898. In that year and intermittently up to 1901, records indicate the Western Oil Company Limited (from New Brunswick) drilled at least four shallow holes at Shoal Point which reportedly produced anywhere from 10 to 20 barrels of oil per day.

- In 1928, subsea seeps were reported in the General report of the Government geologist as follows: “I have no doubt that a submarine seepage does exist, for on the occasion of my visit, I was able to stand and watch the waves breaking in, each one of which would, on receding, leave a characteristic oily foam amongst the beach boulders”.

- The last episode of historic drilling commenced in 1965, when British Newfoundland Exploration Limited (Brinex) and Golden Eagle Oil and Gas Limited undertook a joint exploration program throughout the Port au Port Peninsula. Two wells were drilled, Shoal Point #1 and Shoal Point #2 with both encountering non-commercial oil shows.

- On behalf of MAE, AMEC Foster Wheeler investigated an oil seep which had been identified in a face book posting in early 2015. As a result, AMEC was retained by MAE to remediate oil seepage along the western shore of Shoal Point. In November 2015, a repair project was implemented in an attempt to temporarily stop the seep. In May of 2016, it was reported that the oil seepage had resumed.

- A Science Panel was assembled by Environment Canada in June 2015 to examine a request from MAE to assess the seepage. Based on areal reconnaissance, it was concluded that the seep was very small in volume and intermittent. It was noted that a sheen of 50 parts per million can be seen with the naked eye and that ships are allowed to discharge up to 15 ppm. At that time there was no issue related to birds however later in the year, Piping Plovers would be in the area.

- On a related matter, a paper presented at the 2017 GAC Annual General Meeting titled “Investigation into the impact of a leaking oil exploration well on the scallop fishery in Port au Port Bay, Newfoundland” concluded “No evidence of hydrocarbon or metal contamination in the sediments, water, or mussels was detected. These results suggest the decline of the scallop fishery in Port au Port Bay cannot be explained by petroleum hydrocarbons from the leaking oil exploration well.”
Analysis

- In 2016, AMEC Foster Wheeler was retained again by MAE to further investigate the ongoing oil seepage at Shoal Point. AMEC, in its 2017 report, identified 3 options for consideration: (1) Monitoring, (2) Capping ($300k), and (3) Well abandonment ($1M+). It is stated that the probability of reduced oil seepage increases with the cost but even the $1 million option states “Seeps may recur and continue”.

- In the context of oil seeps being noted along the point for more than a century, it seems unlikely that the suspected effects are a recent phenomenon.

- DNR staff provided comments on the draft of the AMEC report and with regard to options for future actions, additional data collection was suggested. With sufficient data on seep frequency, location, volume, duration, seasonality, tide effects, whether there are more seeps in the same general area, etc. a more effective cost benefit analysis can be performed. Suggestions for gathering additional data include:
  
  - Tasking ServiceNL field personnel to include regular site visits to the location to collect a sample and to record and photograph current conditions;
  
  - Take advantage of any available fly overs to gather aerial photos, slick visibility etc;
  
  - Review and analyze historic and current aerial photos of the area and note presence, location and extent or absence of slicks;

- It is probable that, even if successful, plugging any of the old well casings could cause the oil seep to migrate and emerge at surface elsewhere along the coast.

- On July 7, 2017, the Deputy Minister of MAE wrote his counterpart in Natural Resources (NR) requesting that NR assume the lead role in the development of a long term strategy to address concerns related to the Shoal Point wells and onshore orphaned and abandoned wells in general. The memo also made reference to seeking funding from the Federal Government similar to that obtained recently from Alberta related to well abandonment and reclamation.

Action Being Taken:

- Department staff will continue to liaise with MAE as further updates become available.

Prepared/Approved by:  J. Agbakwuru / P. Molloy / W. Foote
Ministerial Approval: Received from Hon. Siobhan Coady

July 26, 2017
Port au Port Peninsula Showing Location of Seeps and Documented Wells.
Overview: Overview of New England market opportunities and Nalcor’s activity in the region.

Background:
- NL has electricity resources in both the short and long term that can enable export to New England. A number of generation and transmission development scenarios are under consideration by Nalcor Energy.

- Presently, generation exists in Labrador that is being exported via the Hydro Quebec transmission system to external markets. Over the medium term, the Muskrat Falls project and associated transmission links will enable additional exports via the Maritimes. Over the longer term, additional exports could be realized with new transmission links from NL to Quebec or the Maritimes to enable Gull Island’s 2,250 megawatts (MW) capacity to be developed along with new wind generation.

New England Market
- The New England wholesale energy market serves a population of approximately 14.7 million that was valued at approximately $5.4 billion in 2016, down from $6 billion in 2015, primarily due to record low 2016 natural gas prices.

- In 2016, New England had approximately 30,500 MW of installed electricity generating capacity and imported approximately 17% of its energy needs. Electricity demand peaks in the summer, with a smaller peak occurring in the winter.

- New England is transitioning its power generation resource mix from coal and oil to natural gas. In 2016, generation consisted of 49% natural gas, 31% nuclear, 10% renewables, 7% hydro, and 3% oil and coal.

- The market is currently facing supply challenges including: (1) excessive reliance on natural gas generation, (2) upcoming retirements of non-gas-fired generation (up to 9,400 MW by 2020), (3) and aggressive greenhouse gas (GHG) emission reduction targets and state renewable portfolio standards (RPS), which require electricity suppliers to purchase a portion of their power from renewable sources.

- Accessing additional generation resources in higher load areas, such as Massachusetts and Connecticut, has also presented New England transmission challenges. Since 2002, New England has invested $8.4 billion in transmission, with a further $4 billion planned by 2022.

- Maine, New Hampshire, and Rhode Island presently exclude large-scale hydro power from their RPS. Vermont recognizes large-scale hydropower as renewable and so does Connecticut in limited circumstances. Massachusetts enacted its Energy Diversity Act in 2016, requiring utilities to procure 1,600 MW of offshore wind power and 1,200 MW of hydropower or other renewable resources, as discussed in more detail below.

New England’s Tri-State RFP
- In recent years, the New England states have worked towards large long-term procurement of clean energy resources, including large hydro imports, and associated new transmission infrastructure.
On November 12, 2015, the MA and CT state governments along with electric utilities from those states and RI, issued the Clean Energy joint procurement RFP.

The RFP sought bids on new Class 1 renewable energy projects of at least 20 MW and large-scale hydro power projects constructed after January 1, 2003. Class 1 renewables include wind, solar, small hydro, biomass and fuel cells. Hydroelectric power can also be used to balance or support wind generation. The overall solicitation was for approximately 5 TWh annually. The RFP also invited bids for transmission projects in recognition that some generation projects submitted may require new transmission.

Massachusetts Energy Diversity Act

On August 8, 2016, Massachusetts enacted its, Energy Diversity Act, requiring utilities solicit 15-20 year long-term contracts to procure 1,600 MW of offshore wind power and another 1,200 MW of hydropower or other renewable resources, including land-based wind or solar.

Nalcor supported the development of this act, and delivered a presentation to the MA House Joint Committee on Telecommunications, Utilities and Energy. Nalcor viewed this bill as important to NL, as it would allow import of Canadian hydropower and support long-term contracts for new supply, which is critical for Gull Island development.

In anticipation of Massachusetts issuing a request for proposal, on January 11, 2017, Emera Inc. issued a news release soliciting partners to bundle their clean energy generation with Emera’s transmission on its proposed Atlantic Link for delivery into New England. The Atlantic Link will be a 350-mile submarine high-voltage DC transmission line delivering energy from NB to Massachusetts.

On the RFP closing date July 27, 2017, Emera announced it had formally proposed the 1,000 MW line in response to the RFP. The news release noted that generation suppliers included Nalcor Energy with 1.1 terawatt hours of hydropower annually. No further details were given on Nalcor’s involvement.

Nalcor views the Atlantic Link as an opportunity

Future opportunities related to the New England market could include the Gull Island project.

On June 29, 2017, Massachusetts issued a request for proposals to procure a total of 400 MW of offshore wind energy generation. The submission due date is December 20, 2017 and a subsequent wind solicitation will be issued by June 29, 2019.

Near and Long-Term Opportunities
• Following the completion of the Muskrat Falls Project, including the associated transmission assets, the island of Newfoundland will be connected for the first time with the North American grid. This will allow Nalcor to maximize the value from provincial electricity resources by exporting excess electricity to other regions of Canada and the US.

• Nalcor indicates there is near-term potential to increase the value of its existing and committed surplus energy by using Nalcor’s existing transmission assets. At present, Nalcor has been assessing

• In the longer term, there are opportunities to continue building markets for developing of Gull Island. Potential business case scenarios could involve

• In addition to New England markets, NR and NL Hydro are also working with the federal and Atlantic Canadian governments and utilities to determine the best opportunities for new electricity infrastructure to reduce carbon emissions in the region.

Prepared/Approved by: C. Boland/C. Snook/J. Cowan
Ministerial Approval: Received from Hon. Siobhan Coady

July 27, 2017
Background Note – Muskrat Fall Project Overview
Department of Natural Resources

Issue: To provide a Muskrat Falls Project Summary and Update

Background and Current Status:

Project Description

- The Muskrat Falls Project includes:
  - Muskrat Falls Hydroelectric Generating Facility – 824 megawatts (MW);
  - Labrador Transmission Assets (LTA) – two 250 km 315 kV HVac transmission lines from Muskrat Falls to Churchill Falls with a capacity of 900 MW; and
  - Labrador-Island Transmission Link (LIL) – between Muskrat Falls and Soldiers Pond (1,100 km ±350 kV 900 MW HVdc bi-pole transmission line).

- In conjunction with the Muskrat Falls Project, the 500 MW Maritime Link transmission link will enable export and import of electricity between the Island and Nova Scotia. This includes approximately 350 km of overland transmission line and two subsea cables spanning 170 km beneath the Cabot Strait between the island and Nova Scotia.

- In return for building the Maritime Link and providing Nalcor with transmission service on the Maritime Link and through the Maritimes, an affiliate of Emera Inc. will receive 20% of the energy from Muskrat Falls to supply the Nova Scotia electricity system. The Maritime Link will be owned and operated by NSP Maritime Link Inc., a wholly-owned subsidiary of Emera Newfoundland and Labrador. After 35 years, ownership transfers to Nalcor.

Muskrat Falls Project Cost and Progress (June 2017 Update)

- Muskrat Falls was originally projected to cost $6.2 billion ($7.4 billion including financing costs). On June 23, 2017, Nalcor revised the Muskrat Falls Project baseline information, indicating the project is now forecasted to cost $10.1 billion ($12.7 billion including financing costs). The breakdown is as follows:

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<th>June 2017 (Cost in $ billions)</th>
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<td>Projected Cost with Financing</td>
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<tr>
<td></td>
<td>$12.7</td>
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</table>

- As of the end of May 2017, $6.853 billion was spent and $8.105 billion is committed. Expenditures include: $3.244 billion on the Muskrat Falls Generating Facility, $0.8 billion on LTA and $2.809 billion on LIL.

- Nalcor anticipates the LTA will be complete by the fall of 2017 and LIL will be complete mid-2018 compared to mid-2017 anticipated at sanction. As of May 2017, Muskrat Falls Generation was 66 percent completed; the LTA was 95 percent completed; and the LIL was 81 percent completed. Altogether, 75 percent of construction had been completed on the overall project. First power from the Muskrat Falls Generating Facility is now expected in the fall of 2019 compared to the fall of 2017 anticipated at sanction. Full power is expected mid-2020 compared to mid-2018 anticipated at sanction.
• Nalcor’s June 2017 update advised that in 2021, electricity rates for Island domestic customers are forecasted to rise to 22.89 cents per kilowatt hour unless Government takes action to mitigate the rate increases. At sanction, rates were estimated to be 15.12 cents by 2021.

• Government has committed to offset electricity rate increases through the sale of excess power; has directed Nalcor CEO Stan Marshall to identify other opportunities to bring rates closer to those predicted at project sanction, and secured an additional $2.9 billion federal loan guarantee.

• As of June 23, 2017, some key areas of progress with the Muskrat Falls Project include:
  o LTA – All transmission construction in Labrador nearing completion.
  o LIL – Completed marine cable installation, road construction, and access clearing.
  o Muskrat Falls Generation – Spillway operational, river diverted and cofferedam completed; North Spur stabilization work completed; 73 percent of required concrete in place; and the North Dam work has commenced.

Industrial and Employment Benefits of the Muskrat Falls Project

• During May 2017, 5,876 people were working on the Muskrat Falls Project. Of those:
  o 5,097 were residents of NL (87 percent of total persons employed).
  o 4,583 people were working directly in Labrador.
  o 1,068 people were Labrador residents (approximately 23 percent) of which, 426 self-identified as a member of a Labrador Aboriginal group (approximately 40 percent).
  o 634 women were working on all project components, comprising approximately 11 percent of the total workforce. Of these, 590 were NL residents.

• Muskrat Falls Project expenditures totaled more than $166 million in May 2017, including more than $48 million to NL businesses. In addition, from January 2013 to the end of the reporting period in May 2017, over $2 billion had been spent with NL-based companies.

Project Oversight

• Several project oversight mechanisms are in place to provide oversight of the project and meet the conditions for the federal loan guarantee. These include:
  o Independent Engineer – MHW Canada Inc. has been retained to ensure compliance with the terms of the federal loan guarantee.
  o Nalcor Oversight – In addition to its Board of Directors, Nalcor has established an internal audit committee and expanded the role of its external independent auditor.
  o NL Government Oversight – The NL Government established the Muskrat Falls Project Oversight Committee (MFOC) comprising senior officials from Natural Resources, Finance, Justice, Executive Council and chaired by the Clerk of the Executive Council. On April 10, 2017, the Provincial Government appointed four independent members. The Committee is supported by a working group representing expertise in the areas of law, engineering, project management, accounting and auditing. Quarterly updates have been provided to the public since July 2014.

• In December 2015, the Government of Newfoundland Labrador, through the MFOC, engaged Ernst & Young, LLP (EY) to conduct an independent review of the reasonableness of the MF Project cost and schedule forecast, the key associated risks and identification of opportunities for remediation or corrective action if necessary.

• EY’s Interim Report was released on April 12, 2016, and concluded that the September 2015 Muskrat Falls Project forecast was not reasonable. Government intends to action all EY recommendations including strengthening project governance and expanding oversight. EY is continuing to work on its final report on the project cost and schedule.
Astaldi Canada Contract

- Astaldi Canada is responsible for the execution of the contract for the Muskrat Falls powerhouse, intake and spillway.

- In mid-2016 Nalcor Energy negotiated a bridge agreement with Astaldi laying out firm production targets, expectations of the contractor and financial incentives over several months to continue construction progress on the powerhouse and intake at Muskrat Falls until a final commercial agreement could be reached. This occurred in December 2016 and finalized performance-based agreements while settling all prior claims. This added $270 million to the construction costs and it was also noted that Astaldi is performing above the 2017 plan.

Maritime Link

- On July 20, 2016, Emera announced it had replaced one of the Maritime Link’s major contractors, Abengoa S.A. due to ongoing global creditor protection proceedings hampering Abengoa’s ability to perform its work. The two contractors selected to replace Abengoa were the Emera subsidiary Emera Utility Services and Rokstad Power, headquartered in B.C.


North Spur

- There have been concerns raised by individuals and groups in and outside Labrador regarding the stability of the North Spur. Communities such as Happy Valley – Goose Bay and Mud Lake have also expressed concerns regarding emergency flood plans in the event of a dam breach.

- The North Spur has been studied by multiple geoscience and geotechnical engineers since 1965; and Nalcor and contractor SNC Lavelin (SNC) regularly review the related engineering work and engage third-party experts to complete the external validation. Extensive field investigations have also been completed to support the engineering design and validated through independent reviews. The design solution has been addressed in more than 30 engineering studies and the geotechnical conditions are well understood by Nalcor and its engineering consultants. In 2013, a design review was completed by three different external expert panels and the design has been further validated through independent reviews by MWH Canada (the project’s independent engineer) as well as Hatch Ltd.

- The Muskrat Falls facility is being built to industry standards of dam safety and construction. It will be monitored to meet the Dam Safety Guidelines as outlined by the Canadian Dam Association (CDA) and includes daily, weekly and monthly inspections, as well as ongoing monitoring and analysis of instrumentation. There is also an established Dam Safety Program for the project developed by the SNC Engineering team which is active today. In February 2017, a dam safety audit of the Dam Safety Management Plan, which is in place at the Muskrat Falls Construction Site, was performed by Hatch Ltd. The results of the audit indicated that the dam safety management program at the site, which is in compliance with the CDA guiding principles, meets and exceeds industry best practices.

Mud Lake

- In May 2017, Mud Lake, Labrador, was flooded requiring residents to evacuate the community and with many blaming Nalcor for the incident. CBC News has reported that Halifax-based lawyer Ray Wagner met with Mud Lake residents in June to discuss a potential class action lawsuit against Nalcor. In July he stated he still has to draft a claim but expects to file it before the end of summer.
• In June, Government recruited an independent expert to lead the assessment of the cause of the flooding. Karl-Erich Lindenschmidt is an associate professor at the University of Saskatchewan’s school of Environment and Sustainability and Global Institute for Water Security. In July, Government contracted the services of an engineering consultant to work with him. KGS Group - Consulting Engineers (KGS) is a Winnipeg-based company that specializes in hydroelectric and water resources. The terms of reference ask that they provide an explanation of why flooding occurred, what measures are needed to prevent future flooding and how residents can get advance warning if there is a problem. Traditional knowledge of residents will also be taken into account. The report is expected to be completed by September 2017.

**Methylmercury**

• Methylmercury concerns about the Muskrat Falls Project have been raised by various parties since the project was announced. The Federal/Provincial Joint Review Panel was created in 2011 to ensure that the Lower Churchill Project environmental assessment satisfied their respective legislative requirements. The panel recommended that, if the Project was approved, a regionally-integrated cumulative effects assessment be done as well as the establishment of protected areas. In March 2016, F/P experts and other consultants participated in a scientific workshop to examine the science surrounding the issue.

• The Nunatsiavut Government (NG) partnered with Harvard University (Dr. Elsie Sunderland) to do their own study whose conclusions suggested higher-than-expected levels in Lake Melville, before flooding. In April 2016 they released more information suggesting that methylmercury levels could rise significantly if only partial clearing took place. Dr. Sunderland attended the above noted workshop and was in contact with government officials, however, confusion arose when Harvard stated “that’s not the sort of work that Prof. Sunderland does or would do”. The Minister of Environment and Climate Change reached out to Harvard to seek clarification regarding their stance on Dr. Sunderland’s current and future research on methylmercury.

• In November 2015, the NG started the “Make Muskrat Right” campaign asking the province, among other things, to commit to full reservoir clearing. Since then numerous protests have taken place. In October 2016 the Premier met with Indigenous leaders resulting in an agreement for further independent assessment by establishing an Independent Expert Advisory Committee. Government created the methylmercury Monitoring Plan while Nalcor drafted the methylmercury Environmental Effects Monitoring Plan to create baselines for monitoring and mitigation.

*Prepared/Approved by: R. Montague/C. Snook/J. Cowan
Ministerial Approval: Received from Hon. Siobhan Coady

July 27, 2017*
Overview: Background information on energy issues in the New England states to inform discussions at the 2017 NEG/ECP Conference.

Background and Current Status:
- From 2000 to 2016, New England has transitioned its electricity generation mix from oil and coal (from 40% down to 3% in 2016) to natural gas (from 15% increasing to 49% in 2016). This resulted in 2016 electricity generation consisting of 49% natural gas, 31% nuclear, 10% renewables, 7% hydro, and 3% oil and coal.

- According to the US Energy Information Administration, as of April 2017, residential electricity customers in New England states paid some of the highest average electricity rates in the US.

<table>
<thead>
<tr>
<th>New England State</th>
<th>Rank</th>
<th>Average Residential Electricity Rate (cents/kWh)</th>
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<tbody>
<tr>
<td>Massachusetts</td>
<td>3rd</td>
<td>20.70</td>
</tr>
<tr>
<td>Connecticut</td>
<td>4th</td>
<td>20.12</td>
</tr>
<tr>
<td>New Hampshire</td>
<td>6th</td>
<td>19.01</td>
</tr>
<tr>
<td>Vermont</td>
<td>7th</td>
<td>17.72</td>
</tr>
<tr>
<td>Maine</td>
<td>9th</td>
<td>16.05</td>
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- New England’s wholesale electricity market serves approximately 14.7 million and was valued at $US5.4 billion in 2016, down from $6 billion in 2015. The 2016 market value was the lowest in 13 years, due to a warmer winter and low natural gas prices.

- New England energy efficiency policies and growth in solar photovoltaics are slowing peak electricity demand growth and flattening energy use. The New England market is nevertheless facing several challenges.

- As a large portion of the region uses natural gas for power generation; electricity rates are largely impacted by fluctuations in natural gas prices. There is also a potential supply shortage related to the upcoming retirements of non-gas-fired generation (up to 10,200 MW by 2020).

- New England states are promoting greenhouse gas (GHG) reductions on a state-by-state basis, and at the regional level, through a combination of legislative mandates (e.g., CT, MA, RI) and aspirational, non-binding goals (e.g., ME, NH, VT and the NEG/ECP). Half of the New England states presently exclude large-scale hydro power from their renewable portfolio standards (RPS). Exceptions include Vermont, Maine and Connecticut (in limited circumstances).

- Accessing additional generation resources in higher load areas, such as Maine and Connecticut, has presented transmission challenges for New England. Since 2002, $8 billion has been invested in transmission in New England, with $4 billion planned through 2020.

Maine:
- In 2016, nearly two-thirds of Maine’s net electricity generation came from renewable energy resources, with 25 per cent from hydroelectricity, 24 per cent from biomass (mainly wood products), and 14 per cent from wind.
• Maine has one of the highest renewable standards in the U.S., requiring that 40 per cent of total retail electricity sales must come from renewable resources by 2017.

• Maine has identified five key energy issues it will need to address in the short to long term: (i) decreasing electricity prices and overall energy costs; (ii) extending natural gas services and transmission infrastructure to residential, commercial and industrial customers; (iii) strengthening energy efficiency, conservation and weather-proofing of the building envelope, and fostering renewable energy use; (iv) reducing oil use by 50 per cent by 2050; and, (v) preparing an energy assurance and emergency preparedness and response plan.

• Since 2012, a number of different politicians have introduced bills designed to lower electricity costs in Maine by removing a 100 MW cap on renewable energy credits for hydropower. These bills have been unsuccessful in removing the cap. Governor LePage has advocated that removing the cap would allow Maine to access cheaper power from Canada. Maine has also advocated for additional natural gas infrastructure projects to facilitate a stable supply and end bottlenecks.

New Hampshire:
• In 2016, 56 per cent of New Hampshire’s net electricity generation came from nuclear power, with 25 per cent from natural gas. In 2016, for the first time, New Hampshire obtained more net electricity generation from wind (2.3% of generation) than from coal (2.2% of generation).

• By 2025, NH electric utilities must obtain at least 25 per cent of their electricity supplies from renewable sources.

• On September 1, 2014, the Office of Energy and Planning (OEP) released a 10 year Energy Strategy. The Strategy addressed energy efficiency, grid modernization, renewable energy, alternative fuel choices, and transportation options.

Massachusetts:
• In 2016, MA generated 66% of its electricity from natural gas and 5% of its electricity from coal. Further, in 2016, solar photovoltaic facilities, including the state's largest community solar project, comprised 88% of the new utility-scale generating capacity installed in Massachusetts.

• In 2015, 27% of Massachusetts' households used fuel oil to meet their primary home heating needs, more than five times higher than the nationwide average of 5.1%.

• On August 8, 2016, Massachusetts enacted its Energy Diversity Act, requiring utilities solicit 15-20 year long-term contracts to procure 1,600 MW of offshore wind power and another 1,200 MW of hydropower or other renewable resources, including land-based wind or solar.

• On March 31, 2017, Massachusetts issued a request for proposals to procure clean energy generation including hydro totally 9,450,000 MWh a year. On the RFP closing date of July 27, 2017, Emera announced it had submitted a proposal for a sub-sea 1,000 MW transmission line from NB to Boston including 1.1 terawatt hours of hydro power annually from Nalcor Energy.

• Further, on June 29, 2017, Massachusetts issued a request for proposals to procure a total of 400 MW of offshore wind generation. The submission due date is December 20, 2017. Massachusetts will issue a subsequent wind solicitation by June 29, 2019.
Connecticut:
- Connecticut's (CT) renewable portfolio standard sets a goal of obtaining 23 per cent of the state's electricity from renewable energy resources by 2020, plus another 4 per cent from conservation and energy from industrial heat. In 2015, 46 per cent of CT's net electricity generation came from the Millstone nuclear station.

- In July 2013, CT Governor Malloy signed two new pieces of energy legislation. The first expanded the state's natural gas distribution system. In response, regulated natural gas companies filed proposals to connect thousands of households. The second bill changed CT's renewable energy policy to boost Canadian hydropower imports.

- By increasing the availability of natural gas as an alternative to costlier oil energy and relying more on hydropower from Canada, Governor Malloy noted that CT is putting downward pressure on energy prices. The cost of electricity in CT has been among the highest in the US.

Vermont:
- Vermont produces less than 35% of the electricity it consumes and depends on power from the New England grid and Canada. In 2016, nearly all of Vermont's in-state net electricity generation was produced by renewable energy, including hydroelectric, biomass, wind, and solar resources.

- Vermont issued an updated Vermont Comprehensive Energy Plan (CEP) and an Electric Plan in January 2016. The plan is to be updated every six years thereafter.

- The update CEP reaffirms Vermont's goal of achieving 90 per cent of its total energy needs from renewable sources by 2050 and includes a statutory target of 25 per cent by 2025. Other detailed goals include reducing total energy consumption per capita by 15 per cent by 2025, end-use goals for 2025 of 10 per cent renewable transportation and 67 per cent, GHG reduction goals of 40 per cent below 1990 levels by 2035 and 90 per cent below 1990 levels by 2050.

Rhode Island:
- In 2016, natural gas fueled 96 per cent of Rhode Island's (RI) net electricity generation. RI is the second-lowest emitter of carbon dioxide in the US. It does not have any coal-fired electricity generation.

- The first U.S. offshore wind facility, with five 6 MW turbines three miles off RI's Block Island, began operations in May 2017.

- RI law requires energy suppliers to include 16 per cent renewable energy in the electricity generation mix by the end of 2019. The American Council for an Energy Efficient Economy rated RI in 6th place in overall scoring in 2013 and 2nd in energy efficiency programs and policies in the US.

Prepared/Approved by: C. Boland/C. Snook/J. Cowan
Ministerial Approval: Received from Hon. Siobhan Coady

July 27, 2017
NEG/ECP – Background Note – Current Energy Issues in the Eastern Canadian Provinces
Department of Natural Resources

**Issue:** To provide background information on Eastern Canadian provinces’ current energy issues which may be raised during the 2017 NEG/ECP meeting.

**Background and Current Status:**
- Since 2005, the four Atlantic provinces (NL, NS, NB and PEI) have collectively led Canada in GHG reductions, achieving 24% in reductions from 2005 levels. These reductions are expected to continue, with the federal government projecting that collectively, Atlantic Canada will surpass a 30% reduction from 2005 levels by 2030.

- Federal Budget 2016 allocated $2.5 million over two years for the Regional Electricity Cooperation and Strategic Infrastructure (RECSI) to facilitate regional dialogues and studies to identify the most promising electricity infrastructure projects for achieving significant regional greenhouse gas (GHG) reductions: $470,000 is allocated to the Atlantic region.

- In April 2017, Atlantic Premiers announced the Atlantic Clean Energy Partnership (the Partnership). The intent of the Partnership is to work regionally and with the federal government to focus on identifying potential enhancements to electricity generation and transmission infrastructure, the promotion of energy efficiency, as well as the demonstration, deployment, adoption, and export of clean energy technologies.

- While taking regional and provincial factors into consideration, the Partnership can enhance collaborative efforts to accelerate the adoption of clean growth opportunities in the Atlantic energy sector. This can lead to further GHG reductions, while enhancing economic growth, creating clean jobs and driving innovation in the transition to a low-carbon economy. QC is not included in the Partnership.

- The Canadian Free Trade Agreement includes a regulatory framework governing electricity transmission. This provides specific rules and builds on the principles of open access and non-discrimination that were outlined in the Canadian Energy Strategy. In addition to the development of these rules, the Government of Newfoundland and Labrador has agreed, at the request of other provinces, territories and the Federal Government, to engage with QC to discuss electricity transmission.

**Quebec’s Priorities/Issues:**
- On April 11, 2016, QC unveiled its energy policy for 2016-2030, entitled "Politique énergétique 2030, L’énergie des Québécois – Source de croissance" (Energy Policy 2030, The Energy of Quebeckers – a Source of Growth). The policy aims to set a clear vision of energy development in QC as well as address the concerns of certain stakeholders. Its objectives are to: promote a low carbon economy; optimally enhance energy resources; encourage responsible consumption; exploit the full potential of energy efficiency; and stimulate the chain of technological and social innovation. The policy identifies five major targets to be met by 2030: increase energy efficiency by 15%; reduce the amount of petroleum products consumption by 40%; eliminate the use of thermal coal-based energy; increase total renewable energy production by 25%; and increase bioenergy production by 50%.
• Public hearings are underway in the US for approval of the construction of the Northern Pass transmission line that would bring electricity to southern New Hampshire (NH) from QC. The Northern Pass Transmission project is a 400 km line from QC through the White Mountains of NH; 96 kms of the lines will be buried. It will cost $2.8 billion dollars, but HQ would assume only $607 million of the total and generate $200 million dollars a year in profits. On July 21, 2016, ISO New England officially determined that the Northern Pass project can reliably interconnect with the regional electric grid, and will not have an adverse effect on the reliability or operating characteristics of the regional grid and its participants. It is scheduled to be online by 2019. NH electricity rates are among the highest in the US.

• On May 30, 2016, QC released its Strategic Environmental Assessment (SEA) Report of its entire hydrocarbons sector, including for Anticosti Island. This assessment was used to formulate recommendations for social, environmental, economic, security, transportation and emissions of greenhouse gases. Among the key findings, the modernization of the legislative and regulatory framework governing hydrocarbons in QC is required. In December 2016 QC passed Bill 106 which creates a new agency to promote QC’s transition to cleaner energy yet also lays out a framework for oil and gas development in the Canadian province.

• The proposed Energy East pipeline has faced fierce opposition in QC and according to a March 2016 national poll by Forum Research, only 38 per cent of Quebecers supported the pipeline project, the lowest level of support in the country. In early August 2016, QC officials refused to issue permits for geological testing of the riverbed of the St. Lawrence River to TransCanada Corp. The testing would determine how to cross the Ottawa River, near the junction with the St. Lawrence River. In January 2016, the mayors of the greater Montreal area came out in opposition to the Energy East Pipeline project based on public concerns regarding possible environmental impacts. In June 2016, the First Nations of QC officially opposed the pipeline. In March 2016, a coalition of QC environmental groups filed a court motion against the project.

• In July 2017, QC and NL agreed to explore opportunities that support greater economic and community development along the shared border of the two provinces. The provinces have targeted two issues of common interest that would benefit from greater interprovincial cooperation: the development of the Labrador Trough and the extension of Highway 138 on the lower North shore of Québec.

New Brunswick’s Priorities/Issues:
• On January 26, 2017, President Donald Trump signed an executive action to move forward on a controversial Keystone XL Pipeline Project. Analysts are divided on what impact the apparent revival of the Alberta-to-Texas Keystone XL pipeline will have on the Energy East project that would go from Alberta to Canada's east coast. The construction of Energy East, a 415 km pipeline system, will represent a $6.5 billion investment into the NB economy. This will support over 3,771 full-time direct and spin-off jobs per year in NB and create activity for local companies and generate additional tax revenues for all levels of governments.

• On June 15th, 2017, the Canadian Nuclear Safety Commission, an independent federal nuclear regulator, announced a five-year power reactor operating licence was granted to NB
Power for the Point Lepreau Nuclear Generating Station. The Point Lepreau Nuclear Generating Station has a capacity of 660 MW and is a base load contributor to the NB electrical grid. It produces enough non-emitting electricity to power more than 333,000 homes per year. Point Lepreau is a major component of the generating assets that will contribute to NB’s goal of having as much as 75 per cent of the electricity used in NB coming from clean, renewable or non-emitting sources by 2020.

- NS based Emera is soliciting participants in its 1000 MW Atlantic Link project in anticipation of a Massachusetts request for proposals for clean energy in early 2017. The proposed Atlantic Link Project involves installation of approximately 350 miles of subsea HVdc (high voltage direct current) transmission cable – entering the water near an existing electric substation at Coleson Cove, New Brunswick and coming ashore at a proposed site near the Pilgrim nuclear generating station at Plymouth, MA (Pilgrim is scheduled to retire in mid-2019).

Nova Scotia’s Priorities / Issues:
- On January 21, 2016, NS granted regulatory approvals for the $100 million Alton Natural Gas Storage facility project in Colchester County to store natural gas in three underground salt caverns near Stewiacke, NS. Environmental concerns focus on the release of salty water from drilling the underground caverns into the Shubenacadie River system. The approval comes after 18 months of consultations with the First Nations.

- On January 27, 2016, Nova Scotia Power (NSP) said that it has exceeded its 25% renewable energy target in 2015. NS now generates 26.6% of its electricity from sources such as wind, hydro, tidal and biomass. The most rapid growth has come from wind farms, which jumped from supplying 1% to 10% of the province’s electricity. Hydro accounts for 9.8% of the province’s electricity supply today, but is forecast to hit 22% in 2020. Ten years ago, more than 80% of NS’s electricity was generated by burning coal. This has dropped to 56% and is forecast to decline to 45% by 2020.

- On August 3, 2016, the Nova Scotia Utility and Review Board approved a 62.5 km natural gas pipeline that will connect with a recently approved liquefied natural gas facility in Cape Breton being constructed by Bear Head LNG at Point Tupper. LNG produced at the facility will be transported by LNG vessels to overseas markets.

- On April 25th 2017, Energy Minister Samson announced that seven projects will receive funding from the Smart Energy Innovation Program. This program will provide NS researchers and early-stage businesses support to develop and sell sustainable energy solutions. The successful projects will look at integrating renewable energy into the grid, as well as ways to store and manage energy efficiently. A total of up to $700,000 in funding is available from Innovacorp and the Department of Energy.

- In conjunction with the Muskrat Falls Project, the 500 MW Maritime Link will enable export and import of electricity between the Island and NS. This includes approximately 350 km of overland transmission line and two subsea cables spanning 170 km beneath the Cabot
Strait between the island and NS. In return for building the Maritime Link and providing
Nalcor with transmission service on the Maritime Link and through the Maritimes, Emera Inc.
will receive 20 per cent of the energy from Muskrat Falls to supply the NS electricity system.

**Prince Edward Island’s Priorities / Issues:**

- PEI has been converting the heat systems for a number of facilities from oil to biomass since 2012. In that time, they have cumulatively displaced approximately 2.4 million litres of fuel oil. When all the biomass heating plants currently covered by contracts are operational in 2016, they will displace approximately 3.3 million litres of fuel oil per year and reduce greenhouse gas emissions by approximately 9,000 tonnes per year.

- On April 29, 2016, PE’s Energy Minister announced that Maritime Electric’s plan to add two new underwater electric cables between PE and NB has received provincial and federal environmental approval and that work would begin immediately. The cables will allow Maritime Electric to import up to 360 MW of electricity, bolstering the 200 MW cables installed four decades ago that are currently serving PE by shipping power over from NB. The cost of the project is estimated to be upwards of $140 million. The federal government has provided $50 million, with the rest coming from PE. The cables will be owned by the province and leased to Maritime Electric. According to Maritime Electric. The project has been facing delays as power was initially expected in January 2017.

- On March 17, 2017, PEI released a 10-year energy strategy to reduce energy use, establish cleaner and locally produced energy sources and moderate future energy price increases. The Provincial Energy Strategy addresses four key areas identified to take action to determine PEI’s energy future: Energy Efficiency and Conservation, Power Generation and Management, Biomass and Heating, Transportation. The energy strategy will result in energy savings for Islanders and greater self-sufficiency by reducing our reliance on imported fossil fuels. It will also translate into good jobs and economic opportunity with an increase in retrofitting projects and more energy produced locally.

**Prepared/Approved by:** A. Philpott/C. Boland/J. Cowan

**Ministerial Approval:** Received from Hon. Siobhan Coady

**July 31, 2017**
Meeting Note
Department of Natural Resources
Meeting with Quebec’s Minister of Energy and Natural Resources
August 13, 2017 - 4:15 p.m.
Algonquin Resort – St. Andrews by the Sea, NB

Attendees:
Honourable Siobhan Coady, Minister of Natural Resources, Newfoundland and Labrador
Honourable Pierre Arcand, Minister of Energy and Natural Resources, Quebec

NL: Gordon McIntosh, Deputy Minister, Department of Natural Resources
QC: Robert Keating, Deputy Minister of Energy and Natural Resources
        Julien Marcotte, Political Advisor

Purpose of Meeting:
• To provide for a bilateral meeting between Minister Coady and Minister Arcand at the Energy
  and Mines Ministers’ Conference.

Background:
• On July 19, 2017, the Premiers of Quebec and Newfoundland and Labrador announced that
  they agreed to explore opportunities that support greater economic and community
  development along the shared border of the two provinces.

• The provinces have targeted two issues of common interest that would benefit from greater
  interprovincial cooperation: the development of the Labrador Trough and the extension of
  Highway 138 on the lower North shore of Québec.

Potential Agenda Item #1 - Mining
• Both Newfoundland and Labrador and Quebec have large mineral industries that are major
  contributors to their respective economies:
  o According to Natural Resources Canada (NRCan), Newfoundland and Labrador has a
    2016 preliminary mineral production value of approximately $2.65 billion and is dominated
    by iron ore ($1.68 billion), nickel ($659 million) and copper ($228 million).
  o Quebec has a 2016 preliminary mineral production value of $6.44 billion, with the majority
    of value coming from gold ($2.71 billion), nickel ($660 million), copper ($271 million), and
    zinc ($231 million).

• The Labrador Trough is a geological belt with significant deposits of iron ore spanning parts
  of Labrador and northern Quebec. Some deposits are in production and some in
  development. The region is a potential long-term iron ore source capable of competing with
  Australia and Brazil, who currently have a strong influence on global prices. There are
  developments on both sides of the border that may require interaction and cooperation
  between Newfoundland and Labrador and Quebec. Labrador-based projects, such as those
  by Tata Steel, Tacora Resources (Wabush Mines) and Alderon (Kami Iron Ore Project) also
  have spin-off activity on the Quebec side of the border as these projects ship out from Sept-
  Îles and the Quebec North Shore and Labrador (QNS&L) railway.
• There are two Newfoundland and Labrador iron ore operators that could potentially benefit from the signing of an agreement for increased cooperation regarding mineral development:
  o Tata Steel Minerals Canada Limited’s (TATA) operation includes multiple iron ore deposits that either span or are in close proximity to the border of Labrador and Quebec. The Fleming 7N deposit straddles the Labrador and Quebec border, Howse and Kivivic deposits are in Labrador whereas the Goodwood and Sunny deposits are in Quebec.
  o The Iron Ore Company of Canada (IOC) produces iron ore in Labrador at its Carol Lake Project and ships product via the Quebec North Shore and Labrador Railway (approximately 420 km) to their loading facility in Sept-Îles, Quebec, for shipping to markets.

• The geology on either side of the Labrador and Quebec border is similar, thus mineral discoveries on the Quebec side should indicate favourable potential on the Labrador side as well. Both Newfoundland and Labrador and Quebec have supports in place to assist in mineral exploration:
  o Newfoundland and Labrador offers financial assistance through its Mineral Incentive Program (MIP), with a budget of $1.7 million. Part of MIP is the Junior Exploration Assistance Program with program goals to grow the mineral inventory of Newfoundland and Labrador through the discovery of new mineral districts, occurrences, prospects and deposits.
  o Quebec relaunched its Plan Nord in 2014 to help promote the potential for industries such as mining, energy, tourism, social and cultural development. The Plan Nord works to ensure that favourable conditions are in place to attract investors interested in developing mining projects with economic potential for Quebec. Plan Nord will invest $1.3 billion in infrastructure and other projects (mostly public geoscience) over the next five years.
  o Quebec has developed a unique model, known as SIDEX - The Diversification of Exploration Investment Partnership - to stimulate its mineral exploration sector. SIDEX is an institutional fund that mainly invests in the share capital of companies. In 16 years of operation, SIDEX has provided $84 million to 230 projects.

• Tata Steel’s project (and potentially others in the future) will source iron ore from mines on both sides of the border.

• Working cooperatively with Quebec can improve transportation resources available to existing operators such as IOC and TATA that have components of their operations in both provinces. Taking a regional approach to infrastructure planning could be more efficient and avoid duplication of services that would be more cost effective.

• Prior to the decline in iron ore prices, proposed mine development in the Labrador Trough would have exceeded existing rail capacity.

• The Geological Survey of Newfoundland and Labrador (GSNL) has a long history of cooperation with its Quebec Geological Survey counterparts. Directors meet regularly as part
of the Committee of Provincial and Territorial Geologists and the National Geological Surveys Committee.

- The GSNL has contributed to recent Federal-Provincial projects under the Geoscience for Energy and Minerals 2 program. These projects are coordinated by the Federal Geological Survey of Canada, but involve Provincial Surveys in cross-border geological mapping. Provincial involvement is primarily supported through the Federal program budget.

Potential Speaking Points:
- The Minister may wish to indicate that Newfoundland and Labrador is open to collaboration with Quebec on issues of mutual benefit that affect the mining sector in both provinces including rail and port issues.

Potential Agenda Item #2 - Canada Free Trade Agreement (CFTA)
- On-going negotiations during 2016/2017 among all jurisdictions in Canada (including the federal government) towards the CFTA saw Newfoundland and Labrador propose specific rules and dispute resolution for electricity transmission within Canada.

- At the July 2016 meeting of the Council of the Federation (COF), Newfoundland and Labrador and Quebec, with the support of all provinces and territories (PTs), reached an agreement whereby specific rules on electricity transmission would be negotiated prior to the signing of the CFTA. At that time, it was further agreed that the rules would not come into force for at least 24 months until Newfoundland and Labrador and Quebec undertook a bilateral process to identify mutually beneficial options with regard to the electricity sector.

- Accordingly, specific rules on electricity transmission are included in the CFTA in an Annex that will enter into force if Quebec or Newfoundland and Labrador provide written notice to the Internal Trade Secretariat of such entry into force no earlier than 24 months, but no later than 36 months, after the effective date of the CFTA - July 1, 2017. S.29(1)(a)

- Currently, the DM Committee established to oversee engagement with Quebec is preparing recommendations on how to proceed with the bilateral process. S.29(1)(a)

Potential Speaking Points:
- The Minister may wish to indicate that she is looking forward to beginning bilateral discussions with Quebec on the CFTA transmission rules.

Prepared by/Approved by: A. Philpott/C. Boland/A. Smith (with IIAS)/J. Cowan
Ministerial Approval:

August 11, 2017
Information Note
Department of Fisheries and Land Resources
Department of Natural Resources

**Title:** Big Brother Mining Corporation’s Mineral Exploration Application (E170247) and George River Caribou Herd

**Issue:** The George River Caribou Herd (GRCH) has declined to 1 per cent of peak historical abundance and has been assessed as Endangered by the Committee on the Status of Endangered Wildlife in Canada (COSEWIC). Mineral Exploration Request E170247 is within the core habitat of the GRCH. The proposed exploration program may impact the GRCH and options for potential future mineral development are limited under the Canadian Species at Risk Act (SARA) and Endangered Species Act (ESA).

**Background and Current Status:**
- Big Brother Mining Corporation (Big Brother) initially obtained mineral licences under the Mineral Act for areas in northwestern Labrador (Appendix A). These licences were transferred to Maximos, but Big Brother is proposing to carry out exploration work.
- Big Brother filed an application with the Department of Natural Resources (NR) on July 18, 2017 to carry out mineral exploration within Maximos’ mineral licences. The proposed work includes diamond drilling, three fly camps, three fuel caches, water use, prospecting and geological mapping at various locations within the licences.
- Big Brother has cited that it is investing approximately $3.5 million for this proposed exploration program.
- Fisheries and Land Resources (FLR) received the referral on July 18, 2017 and initiated a review of the application.
  - On July 21, 2017 FLR recommended the application be referred to COSEWIC.
  - NR immediately notified Big Brother about FLR’s concerns.
- The GRCH population has declined to 1% of its peak abundance and currently is estimated at less than 9,000 individuals and declining. The herd has been assessed as “Endangered” by the COSEWIC.
Endangered designation would immediately prevent the disturbance, harassment or killing of individuals as well as the destruction of the animals’ habitat. Further protection measures stemming from recovery programs will likely prohibit development activities within the core range, or Critical Habitat of the herd. Big Brother’s mineral exploration proposal is located within core range, which has a proven annual occupancy by the GRCH during late spring to late fall (Appendix B).

The Province is planning

Big Brother has suggested

Big Brother has also suggested

Analysis:

The proposed drill site is located within core range occupied by GRCH from late spring to late fall.

Big Brother has suggested

Approving a mineral exploration program in this area may

The proposed mineral exploration may also be viewed as

Caribou collar locations for years 2011-2015 within ten kilometers of the proposed drill site have been outlined across the Julian calendar to demonstrate maximum and minimum occupation of GRCH in this location (Appendix B).

Maximum annual occupancy of GRCH within ten kilometers of the proposed drill site occurs between early April and late May and late July through October. The proponent’s time period of operations is mid-August to late September, coinciding with peak occupancy of GRCH.
The mitigation measures proposed by Big Brother.

Action Being Taken:

Prepared/Approved by: W. Barney / B. Adams / S. Moores / H. Rafuse / K. Sheppard/ P. Canning

Ministerial Approval: Received from Hon. Siobhan Coady

August 17, 2017
Appendix A – Mineral tenure and prosed exploration work activities
Appendix B:

Distribution density of caribou derived from collar data
Julian day calendar of collared GRC activity within 10 km of proposed drill site
Meeting Note
Department of Natural Resources
BP
Wednesday, September 6, 2017
10:30 – 11:30 AM
Enterprise Centre
Exploration Drive, Bridge of Don
Aberdeen, AB23 8GX

Attendees:  
BP:
Tim Smith, VP Communications and External Affairs
Dave Lynch, VP Reservoir Development

[NR:
Minister Siobhan Coady
Gordon McIntosh
Wes Foote

Purpose of Meeting:
• No formal meeting agenda has been provided. Officials may wish to discuss BP’s North Sea experience including targeted extensions and potential application in NL.

Background:
• BP (formerly British Petroleum) is one of the world’s largest integrated oil and gas companies. Headquartered in London, UK, BP has approximately 74,500 employees worldwide and is active in 72 countries

• Through its two primary operating segments, upstream and downstream petroleum, BP is involved in the exploration, development and production of energy sources as well as refining, processing, transportation and energy trading activities. BP also has interests in renewable energy with activities focused on biofuels and wind.

• In 2016, BP merged with Det norske to create Norway’s largest independent oil and gas business, Aker BP. BP became a 30% shareholder in the company.

• BP Canada Energy Group (BP Canada) is subsidiary of BP with offices in Calgary, Alberta and Halifax, Nova Scotia. BP Canada’s interests include:
  o Alberta Oil Sands - Interests in three oil sands assets (Sunrise, Pike and Terre de Grace) in the Athabasca region of northeast Alberta.
  o Beaufort Sea - 100% interest in two exploration blocks. BP is exploring the area under a joint operating agreement with ExxonMobil Canada and Imperial.
  o Nova Scotia Offshore - 50% interest and operator in four exploration licences with partner Hess.
  o NL Offshore - Interests in six exploration licences in the Flemish Pass Basin, three exploration licences in the Orphan Basin and a significant discovery licence in the Labrador offshore. See Attachment 2 for additional information.

• For the period November 2014 to December 2016, BP was party to the supply offtake
agreement with North Atlantic Refining LLP (NARL). Under the agreement, BP supplied the refinery with crude oil for processing and received the majority of refined petroleum products under fixed margin pricing terms. The arrangement helped support the new refinery ownership during transition of operations following acquisition. The agreement has expired although disputes between BP and NARL that arose during the contract period have been continuing through arbitrations.

- See Attachment 3 for an overview of BP’s latest financial and operational results.

**Agenda Item #1 – BP’s North Sea experience including targeted extensions and potential application in NL**

- BP has been active in the North Sea since 1964 and considers it a growth region. BP can bring its proven track record, technical and technological knowledge, and efficiencies in the North Sea to Newfoundland.

**Analysis:**

- BP’s first major oil discovery was in 1970 in the North Sea’s Forties field, located 180 km east of Aberdeen, Scotland. Having 2.5 billion barrels of recoverable oil, it turned the North Sea into a globally significant oil and gas region. BP sold the field to Apache in 2003. To date, BP has produced more than 5 billion barrels of oil equivalent.

- BP has been successful at reducing costs in the North Sea and making the North Sea a more attractive place to invest. In 2014, it cost $30 to produce one barrel of oil. Today it costs $16-17 and they aim to lower the cost to $12/barrel. This allows them to produce and sustain oil production at $50/bbl Brent crude prices.

- BP estimates their North Sea resources to be 2 billion barrels of oil and expect to double their production by 2020 to 200,000 bbls/d. This will be achieved through major projects including the new Glen Lyon Floating Production Storage and Offloading (FPSO) vessel extending and expanding recovery from the Schiehallion and Loyal oil fields located West of Shetland, the second-phase development of the giant Clair field, Clair Ridge, and bringing the Culzean gas field online.

- Discovered in 1977, 75 km west of the Shetland Islands, the Clair field is the largest oilfield on the UK Continental Shelf, with an estimated 8 billion barrels of oil in place.
  
  - Given its challenging reservoir characteristics (poor reservoir and oil quality, sub-commercial flow rates) and the technological limits at the time, it wasn’t drilled extensively until the mid-1990s and a development plan wasn’t approved until 2001. Production began 28 years after its discovery in 2005.
  
  - Given its large size, it is being developed in a phased approach with the first phase producing 300 million barrels and the second phase, Clair Ridge, expected to have first oil in 2018 and recover 640 million barrels. A third phase may be possible.
  
  - It produces 22-25 API oil from a 600 m thick fractured Devonian to Carboniferous fluvial/lacustrine sandstones that are fault bounded and overlie and onlap a topographic basement high. The basement high is thought to be a rotated footwall block related to a major NE-SW trending extensional fault that was first activated in the Devonian and segmented by NW-SE trending faults. The field has a 15% recovery factor.
Partners in the field are BP 28.6%, Royal Dutch Shell 28%, ConocoPhillips 24%, and Chevron 19.4%.

- The Schiehallion and Loyal fields, west of the Shetlands, have an estimated 850 million barrels of oil. After 15 years of operating in harsh conditions and producing nearly 400 million barrels, the original FPSO needed to be replaced by the new Glen Lyon FPSO.

- In 2017, BP will participate in up to 6 exploration wells in the UK and will drill approximately 50 development wells over the next 3-4 years.

- The North Sea provides a challenging environment with severe metocean conditions (wind, waves, current).

Potential Speaking Points:
- Discuss the similarities between both regions in terms of water depth, metocean conditions, environmental and regulatory processes.

Proposed Action:
- No proposed actions at this time.

Prepared / Approved by: P. Parsons/A. Krakowka/J. Petrovic/N. Abundo/W. Foote
Ministerial Approval: Received from Hon. Siobhan Coady

August 30, 2017
Attachment 1 – Biographies
Attachment 2 – BP Interests in NL Offshore

BP Exploration Licence Interests – Flemish Pass Basin:

<table>
<thead>
<tr>
<th>Licence</th>
<th>Call for Bids Year</th>
<th>Interest Holders</th>
<th>Effective Date/ Term</th>
<th>Total Bid (Million $)</th>
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<tr>
<td>EL 1125</td>
<td>2011</td>
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<td>Chevron Canada Ltd. (40%)</td>
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<td></td>
<td>Anadarko (10%)</td>
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<td>EL 1126</td>
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<td>Chevron Canada Ltd. (40%)</td>
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<td>BP Canada Energy Group ULC (10%)</td>
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<td>Anadarko (10%)</td>
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<tr>
<td>EL 1140</td>
<td>2015</td>
<td>Statoil Canada Ltd. (34%)</td>
<td>Jan. 15, 2016</td>
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<td></td>
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<td>ExxonMobil Canada Ltd. (33%)</td>
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<td>EL 1142</td>
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<td>$826.53</td>
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BP Exploration Licence Interests – Orphan Basin:

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<tr>
<th>Licence</th>
<th>Call for Bids Year</th>
<th>Interest Holders</th>
<th>Effective Date/ Term</th>
<th>Total Bid (Million $)</th>
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</thead>
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<td>EL 1145</td>
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<td>Hess Canada Oil &amp; Gas (25%)</td>
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<tr>
<td></td>
<td></td>
<td>Noble Energy Canada INC (25%)</td>
<td></td>
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</tr>
<tr>
<td>EL 1146</td>
<td>2016</td>
<td>BP Canada Energy Group (50%)</td>
<td>Jan. 15, 2017</td>
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<td>Hess Canada Oil &amp; Gas (25%)</td>
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<tr>
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<td></td>
<td>Noble Energy Canada INC (25%)</td>
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<tr>
<td>EL 1148</td>
<td>2016</td>
<td>BP Canada Energy Group (50%)</td>
<td>Jan. 15, 2017</td>
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<td></td>
<td></td>
<td>Hess Canada Oil &amp; Gas (25%)</td>
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<tr>
<td></td>
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<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td>$413.61</td>
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</tbody>
</table>

1. In addition to the exploration licenses outlined above, BP also has a 0.8662% interest in the Hopedale E-33 significant discovery licence in the offshore Labrador region. This licence has an effective date of August 4, 1987 and is held with 13 other interest holder partners. This licence area has not seen any recent significant activity.
Map 1 – Eastern Newfoundland Region Licence Information (C-NLOPB)
Potential copyright material

If you wish to obtain a copy please contact the ATIPP Office at (709) 729-7072 or atipoffice@gov.nl.ca.
## Attachment 3 – BP Financial & Operational Indicators

<table>
<thead>
<tr>
<th></th>
<th></th>
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</tr>
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<tbody>
<tr>
<td>Revenue(^1)</td>
<td>Million US$</td>
<td>$57,366</td>
<td>$47,276</td>
<td>$113,752</td>
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<tr>
<td>Net Earnings(^2)</td>
<td>Million US$</td>
<td>$144</td>
<td>($1,419)</td>
<td>$1,593</td>
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<tr>
<td>Net Earnings per Share(^3)</td>
<td>US$</td>
<td>$0.07</td>
<td>($0.08)</td>
<td>$0.08</td>
</tr>
<tr>
<td>Cash flow from Operations(^4)</td>
<td>Million US$</td>
<td>$4,890</td>
<td>$3,883</td>
<td>$7,004</td>
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<tr>
<td>Total Assets(^5)</td>
<td>Million US$</td>
<td>$263,115</td>
<td>$263,136</td>
<td>Same as Q2 2017</td>
</tr>
<tr>
<td>Total Liabilities(^5)</td>
<td>Million US$</td>
<td>$164,654</td>
<td>$169,028</td>
<td>Same as Q2 2017</td>
</tr>
<tr>
<td>Total Shareholders’ Equity(^5)</td>
<td>Million US$</td>
<td>$98,461</td>
<td>$94,108</td>
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<tr>
<td>Total Capital Investment(^6)</td>
<td>Million US$</td>
<td>$4,488</td>
<td>$4,487</td>
<td>$8,556</td>
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<tr>
<td>Upstream</td>
<td>Million US$</td>
<td>$3,810</td>
<td>$3,717</td>
<td>$6,790</td>
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<tr>
<td>Downstream</td>
<td>Million US$</td>
<td>$465</td>
<td>$450</td>
<td>$937</td>
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<tr>
<td>Other Business and Corporate</td>
<td>Million US$</td>
<td>$73</td>
<td>$38</td>
<td>$159</td>
</tr>
<tr>
<td>Operations</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upstream Production(^7)</td>
<td>mboe/day(^8)</td>
<td>2,431</td>
<td>2,212</td>
<td>2,410</td>
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<tr>
<td>Refinery Throughput</td>
<td>mbbls/day(^9)</td>
<td>1,688</td>
<td>1,704</td>
<td>1,682</td>
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<tr>
<td>Refinery Availability</td>
<td>Percent</td>
<td>94.5%</td>
<td>95.7%</td>
<td>94.8%</td>
</tr>
</tbody>
</table>

1. Total revenue and other income.
2. Income/(loss) attributable to BP shareholders.
3. Basic earnings per ordinary share.
4. Net cash from operating activities.
5. As of the end of the quarter.
6. Capital Investment are on a cash basis and include inorganic and organic expenditures. Inorganic capital comprise consideration in business combinations and certain other significant investments made by the group.
7. Production volumes do not include Rosenft.
8. Thousand barrels of oil equivalent per day.
9. Thousand barrels per day.
10. Numbers may not sum to totals due to rounding.

**Financial/Operations Discussion:**

- BP reported net earnings of US$144 million in Q2 2017 compared to a net loss of US$1.4 million in Q2 2016. Year-to-Date (YTD) 2017 net earnings were US$1.6 billion, higher compared to a net loss for YTD 2016 of US$2.0 billion. Earnings were:
  - Positivity impacted by higher upstream liquids and gas realizations, the impact of the Abu Dhabi concession renewal, continued fuels marketing growth and increased refining commercial optimization and higher production.
  - Negatively impacted by higher depreciation, depletion and amortization expenses and exploration write-offs, a lower contribution from oil supply and trading and a higher level of turnaround activity in the Downstream.

- Production for Q2 2016 was 2,431 mboe/day, 9.9% higher than Q2 2016 mainly due to the ramp-up of major projects. In Q3 2017, BP expects production to be broadly flat with Q2 2017 with the continued ramp-up of major projects offset by seasonal turnaround and maintenance activities. YTD 2017 production was 2,410 mboe/day, higher compared to YTD 2016 of 2,265 mboe/day.

- From 2016-2021, BP expects to add more than 1 million boe/day, with 800 mboe/day expected to come from major projects and 200 mboe/day from portfolio additions.

- Total capital expenditures for Q2 2017 were US$4.9, on par with Q2 2016. Organic capital expenditure in Q2 2017 was US$4.3 billion, compared with US$4.2 billion Q2 2016. Inorganic capital expenditure for Q2 2017 was US$0.1 billion, compared with US$0.3 billion in Q2 2016. BP expects 2018-2021 organic capital expenditure to be between US$15-$17 billion per year.
However, BP stated that if prices were to go below US$50/barrel, the company would take measures to further increase capital efficiency towards a sustainable lower investment frame.

- Payments related to the Gulf of Mexico oil spill totaled US$2.0 billion in Q2 2017 and US$4.3 billion for YTD 2017. Payments are expected to be considerably lower in the second half and the 2017 full-year estimate is unchanged at $4.5-5.5 billion.

- Divestment proceeds were US$0.5 billion for Q2 2017 compared to US$0.4 billion for Q2 2016. In 2017, divestments are expected to be in the range of US$4.5-$5.5 billion, with proceeds weighted towards the second half of the year. In the long term, BP expects US$2-$3 billion in divestments per year.

- BP stated that OECD inventories appear to be declining and moving towards a more balanced position. However, uncertainties remain around the timing of when the market will balance and around the longer term outlook.

Other Discussion:

- **Upstream:**
  - In Egypt, achieved first gas production from the Taurus and Libra fields ahead of schedule.
  - In Senegal, BP along with joint venture partner Kosmos Energy announced the Yakaar gas discovery located at Cayar Offshore Profond block.
  - In Trinidad:
    - BP sanctioned the Angelin offshore gas project.
    - The Juniper facility is now in final commissioning with start-up expected in Q3 2017.
    - BP made two gas discoveries with the Savannah and Macadamia exploration wells. These discoveries may support future developments.
  - In North Sea, achieved first oil from the redeveloped Schiehallion Area, following completion of the Quad 204 project.
  - In India, BP and Reliance Industries announced the development of the R-Series deep water gas project in Block KG D6. This is the first of three planned projects in the block.
  - Project start-up for Khazzan Phase 1 in Oman, Persephone off the coast of Western Australia, and Zohr in Egypt remains on track for the second half of this year.
  - BP decided to exit some exploration assets in Angola, leading to higher exploration write-offs in the second quarter.

- **Downstream:**
  - BP signed an agreement to be the exclusive premium brand sold by Kroger, the largest supermarket chain in the US.
  - In China, BP announced the company’s intention to divest 50% working interest in the Shanghai SECCO Petrochemical Company Limited joint venture. This transaction is subject to regulatory approvals.
  - In India, signed a memorandum of understanding with Reliance Industries to jointly explore options to develop differentiated retail and aviation fuels, mobility and advanced low carbon energy businesses.
  - In Q3 2017, BP expects a similar level of industry refining margins and that North American heavy crude oil differentials will remain under pressure.

- **Rosneft (BP holds 19.75% working interest):**
  - Rosneft completed the acquisition of a 100% interest in the Kondaneft project that is developing four licence areas in the Khanty-Mansiysk Autonomous District in West Siberia.
  - Rosneft completed the transaction for the sale of a 20% interest in its Verkhechonskneftegaz subsidiary to the Beijing Gas Group.
Title: Taxation of the Hydroelectric Generating Plant in the Town of Bishop’s Falls

Decision/Direction Required:

- Whether to pay the outstanding taxes of $121,106 for the Hydroelectric Generating Plant, using the total assessed value of the property and the applicable mill rates for 2015, 2016 and 2017.

Background and Current Status:

- In December 2008, Abitibi closed its mill in Grand Falls-Windsor (GFW) and the Province expropriated Abitibi’s assets in the region. This included dams and generation stations in Bishop’s Falls, GFW, Star Lake and Buchans (the Exploits Generation (EG) Assets). The hydroelectric plants in Bishop’s Falls and GFW fall within municipal boundaries.

- In order to offset the associated loss of municipal revenue, Government approved transitional grants under the Department of Municipal Affairs’ (now MAE) Special Assistance Program to towns that had been receiving grants in lieu of taxes (GIL) from Abitibi. The Special Assistance grants were phased out over three fiscal years (2009-10 to 2011-12).

- Prior to the closure of the mill, the Town of Bishop’s Falls (Town) received an annual GIL of approximately $110,000 from Abitibi. Following that, Government’s total transitional funding to the Town was $218,900 (Year 1 – $110,000, Year 2 – $72,600, and Year 3 – $36,300).

- Since 2009, Nalcor has held the operating license for the EG Assets on behalf of the Province. Newfoundland and Labrador Hydro (NLH) operates it on behalf of Nalcor and the Province.

- As Crown corporations, Nalcor and NLH are generally not subject to municipal taxation pursuant to the Crown Corporation Local Taxation Act. An exception to this is found in the Municipalities Act, 1999 which contemplates that both the Crown and Crown Agents can be taxed for water and sewer as indicated in ss. 131(7). Without an order from the Lieutenant Governor-in-Council or a statute stating otherwise, Nalcor and NLH are not required to pay other municipal taxes (with the exception of water and sewer tax).

- Most towns in the province receive less than $1,000 for water and sewer taxes from NLH offices and facilities. The exceptions are St. John’s (about $20,000, as the Headquarters is located there); Grand Falls-Windsor (GFW) ($31,796 paid in 2015 and 2016), the office in Bishop’s Falls that is independent of the plant (about $12,000); and Stephenville (about $3,000). Three other Towns (Nain, Hawke’s Bay and Mary’s Harbour) receive just over $1,000 annually. The entire water and sewer bill for NLH for all cities and towns is less than $50,000 annually.
Analysis:

- The hydroelectric plant in Bishop’s Falls is connected to the municipal water supply via a 3/4 inch line and the water is used only for drinking and washroom facilities. The plant is an unattended station remotely operated from GFW. When on site, the number of personnel generally ranges between one and ten persons for maintenance and operations.

- In February 2012, the Town issued an invoice to NR for $200,000 for water and sewer tax. In April 2012, the Minister of MAE responded to the Town indicating that the rate charged did not appear to be equitable with commercial property classes from a usage/consumption perspective. The minimum water/sewer tax established for other commercial properties in the Town is $430.

- While there were discussions between the Town, MAE and NR between 2012 and 2014, there was no resolution.

- Therefore, to address the issue, in August 2014, Water and Sewage Tax Rate for the Hydroelectric Generating Plant located in the Town of Bishop’s Falls Regulations, as per subsection 131(8) of the Municipalities Act, 1999 were enacted. This established a water and sewer tax rate at the same mill rate applied to all other commercial properties and that the water and sewage tax rate would be this mill rate multiplied by the assessed value of the plant. This reduced the mill rate from 11 mills to 6 mills in 2015.

- The Town sent an invoice to NLH on August 26, 2014 covering taxes owed for the 2012-2014 period. The Town quoted an assessed value of $8.8 million, which when multiplied by the new commercial mill rate (6 mills) amounted to $155,000 for the three years. From documents provided by the Municipal Assessment Agency (MAA), this total assessed value included the land, building, dam and crane values.

- NLH contends that the assessed value should only be based on the building.

- Nalcor advises that the Town is no longer pursuing the invoices for 2012 - 2014, however, the Town has documented three outstanding invoices totaling $121,106, with the following breakdown: 2015 ($52,931), 2016 ($34,696) and 2017 ($33,479). These are all based on the total assessed value of the property. (See Annex A).
• NLH notes it is willing to pay the outstanding taxation amount that Government determines to be appropriate on the Bishop’s Falls plant.

Alternatives:
Prepared/Approved by: B. Waseem/L. Combden/C. Snook/J. Cowan (NR); in consultation C. Orsborn/T. Kelly/D. Spurrell/J. Chippett (MAE), JPS, and MAA
Ministerial Approval: Rec. from Hon. Siobhan Coady

August 31, 2017
ANNEX A

Table 1: Breakdown of Assessed Value (2015-2017)

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Assessed Value</th>
<th>Building Value</th>
<th>Land Value</th>
<th>Dam Value</th>
<th>Crane Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>$8,131,300</td>
<td>$2,252,700</td>
<td>$168,600</td>
<td>$5,422,800</td>
<td>$287,200</td>
</tr>
<tr>
<td>2013</td>
<td>$8,821,900</td>
<td>$2,550,200</td>
<td>$168,600</td>
<td>$5,795,600</td>
<td>$307,500</td>
</tr>
<tr>
<td>2014</td>
<td>$8,821,900</td>
<td>$2,550,200</td>
<td>$168,600</td>
<td>$5,795,600</td>
<td>$307,500</td>
</tr>
<tr>
<td>2015</td>
<td>$8,821,900</td>
<td>$2,550,200</td>
<td>$168,600</td>
<td>$5,795,600</td>
<td>$307,500</td>
</tr>
<tr>
<td>2016</td>
<td>$5,782,600*</td>
<td>$1,589,400</td>
<td>$168,600</td>
<td>$3,821,900</td>
<td>$202,700</td>
</tr>
<tr>
<td>2017</td>
<td>$5,579,900</td>
<td>$1,589,400</td>
<td>$168,600</td>
<td>$3,821,900</td>
<td>-**</td>
</tr>
</tbody>
</table>

*Reduction in 2016 assessed value is due to valuation at market value, instead of reproduction value, due to the Special Purpose Property (SPP) Regulations being struck down in 2015.

**The Crane was removed from the assessed value for 2017.

---

Table 2: Taxes Owing to the Town based on Assessed Value of Bishop’s Falls Building Only (2015-2017)

<table>
<thead>
<tr>
<th>Year</th>
<th>Building Value Only</th>
<th>Mill Rate</th>
<th>Taxes Owing</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>$2,550,200</td>
<td>6 mills</td>
<td>$15,301</td>
</tr>
<tr>
<td>2016</td>
<td>$1,589,400*</td>
<td>6 mills</td>
<td>$9,536</td>
</tr>
<tr>
<td>2017</td>
<td>$1,589,400</td>
<td>6 mills</td>
<td>$9,536</td>
</tr>
<tr>
<td>Total</td>
<td>-</td>
<td>-</td>
<td>$34,373</td>
</tr>
</tbody>
</table>

*Reduction in 2016 assessed value is due to valuation at market value, instead of reproduction value, due to the SPP Regulations being struck down in 2015.
Table 3: Taxes Owing to the Town of Bishop’s Falls based on Total Assessed Value of Property (2015-2017)

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Assessed Value</th>
<th>Mill Rate</th>
<th>Taxes Owing</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>8,821,900</td>
<td>6 mills</td>
<td>$52,931</td>
</tr>
<tr>
<td>2016</td>
<td>5,782,600*</td>
<td>6 mills</td>
<td>$34,696</td>
</tr>
<tr>
<td>2017</td>
<td>$5,579,900</td>
<td>6 mils</td>
<td>$33,479</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>$121,106</td>
</tr>
</tbody>
</table>

*Reduction in 2016 assessed value is due to valuation at market value, instead of reproduction value, due to the SPP Regulations being struck down in 2015.