1 INTRODUCTION

British Columbia Hydro and Power Authority (BC Hydro) proposes to construct and operate the Site C Clean Energy Project (the Project). As further described below, an environmental assessment of the Project is being conducted pursuant to the *Canadian Environmental Assessment Act, 2012*, S.C., 2012, c. 19 (CEAA 2012) and the B.C. *Environmental Assessment Act*, S.B.C., 2002, c. 43 (BCEAA).

On September 5, 2012, in accordance with CEAA 2012, BCEAA and the “Agreement to Conduct a Cooperative Environmental Assessment, Including the Establishment of a Joint Review Panel, of the Site C Clean Energy Project” dated February 8, 2012, as amended in August 2012 (the BC/Canada Agreement), the “Site C Clean Energy Project Environmental Impact Statement Guidelines” (the EIS Guidelines) were issued by the Minister of Environment of Canada and the Executive Director of the Environmental Assessment Office of British Columbia (The Minister of Environment of Canada and the Executive Director of the BCEAO, 2012).

1.1 Guiding Principles

The following principles are set out on page 1 of the EIS Guidelines:

*Environmental Assessment*

Environmental Assessment (EA) is a comprehensive process to identify and evaluate the potential effects of a proposed major project and ways to avoid or mitigate adverse effects.

*Public Participation*

The overall objective of public participation is best achieved when all parties have a clear understanding of the proposed project as early as possible in the review process. The public will be provided with opportunities to participate in the environmental assessment process.

*Aboriginal Consultation*

BCEAO and Canada are committed to working constructively with Aboriginal groups to ensure that the Crown fulfills its duties of consultation and accommodation. The proponent must ensure that it engages with Aboriginal groups that may be affected by the project, or that have asserted or established Aboriginal rights or treaty rights in the project area, as early as possible in the project planning process.”

The EIS Guidelines go on to state:

“An environmental assessment conducted in accordance with the agreement between the Ministers of Environment of BC and Canada with respect to the environmental assessment of the Project and with these EIS Guidelines, which have been developed under that Agreement, will meet the objectives of these principles.”
1.1.1 Comprehensive Environmental Assessment

This Environmental Impact Statement contains a record of a comprehensive environmental assessment of the Project that:

- Meets the requirements of the EIS Guidelines
- Is sufficient for the purpose of public hearings to be conducted by a Joint Review Panel
- Provides the basis upon which the Minister of Environment of Canada can make a decision under Section 52 of CEAA 2012
- Provides the basis upon which the Ministers of Environment and of Forests, Lands and Natural Resource Operations of British Columbia can make a decision under Section 17(3) of BCEAA
- Demonstrates that if the Project will result in significant adverse effects, it can be justified by the benefits of the Project and the need for the Project

1.1.2 Public Participation

This EIS demonstrates that the public has been provided with information about the Project and afforded an opportunity to provide input since 2007, four years prior to the commencement of the environmental assessment. This EIS also demonstrates that, to date, the public has been afforded the opportunity to participate in the assessment in accordance with BC/Canada Agreement and the EIS Guidelines.

1.1.3 Aboriginal Consultation

This EIS demonstrates that BC Hydro has engaged with Aboriginal groups that may be affected by the Project, or that have asserted or established Aboriginal rights or treaty rights in the project area, as early as possible in the project planning process. In particular, BC Hydro commenced engagement with those Aboriginal groups in 2007, four years prior to the commencement of the environmental assessment.

1.1.4 Sustainability

This EIS demonstrates that globally recognized principles and practices for corporate social responsibility and sustainability have been incorporated into the planning of the Project: modifying designs to minimize footprint and avoid effects where possible; developing mitigation measures and compensation plans, often in consultation with the public and stakeholders to reduce effects; working with Aboriginal groups and local communities to reach benefit sharing agreements and partnerships that would foster economic development.

1.2 Purpose of this Environmental Impact Statement

In May 2011, BC Hydro submitted the “Project Description Report – Site C Clean Energy Project” (BC Hydro 2011) (the Project Description Report) to the Executive Director (the Executive Director) of the British Columbia Environmental Assessment Office (the BCEAO) and to the Canadian Environmental Assessment Agency (the CEA Agency).

The Project will:
Site C Clean Energy Project Environmental Impact Statement
Volume 1: Introduction, Project Planning, and Description
Section 1: Introduction

1. Have an installed energy generating capacity of up to 1,100 MW
2. Require two new 500 kV transmission lines adjacent to two existing 138 kV transmission lines along approximately 77 km of existing and widened right-of-way
3. Require a realignment of portions of Highway 29
4. Require the creation of new quarries and the expansion of existing sand, gravel and stone quarries

Each of these are or may be reviewable under the Environmental Assessment Act, S.B.C., 2002, c. 43 (BCEAA) and the Reviewable Projects Regulation.

Prior to the enactment of CEAA 2012, federal agencies concluded that the Project will require:

1. Approval under the Navigable Waters Protection Act, R.S.C., 1985, c. N-22
2. Authorization under the Fisheries Act, R.S.C., 1985, c. F-14

Each of these requirements in turn engaged a requirement for an environmental assessment under the Canadian Environmental Assessment Act, S.C., 1992, c. 37 (CEAA) and the Law List Regulations, SOR/94-636.

The Minister of Environment of Canada and the Minister of Environment of British Columbia agreed to a cooperative environmental assessment of the Project and entered into the BC/Canada Agreement. The purpose of that agreement is set out in its preamble:

“WHEREAS the federal Minister of Environment and the provincial Minister of Environment has determined that a cooperative environmental assessment including a joint review panel for the Site C Clean Energy Project will avoid unnecessary duplication and delays that could arise from individual reviews by each government; and agree to establish a joint review panel for the Site C Clean Energy Project; …”

Under CEAA 2012 (and formerly under CEAA), the Minister of Environment of Canada or the federal responsible authority, as the case may be, and under BCEAA, the Minister of Environment of British Columbia or the Executive Director, as the case may be, each has the duty to i) ensure that, where the environmental assessment of a project is required, an assessment is conducted, and ii) determine the scope of the assessment required to meet the statutory requirements and purposes of CEAA 2012 and of BCEAA, respectively. In order to ensure that they would meet their respective statutory obligations and that an environmental assessment of the Project would be conducted in a manner that would meet the statutory requirements and purposes, the BC/Canada Agreement provides for a process for the development of draft EIS Guidelines, requires the Executive Director and the Minister of Environment of Canada to determine whether the EIS Guidelines are adequate and, when they have made that determination, to finalize and issue the EIS Guidelines.

On September 5, 2012, upon completion of the process for development, review, and finalization of the EIS Guidelines prescribed in the BC/Canada Agreement, the Executive Director and the Minister of Environment for Canada issued the EIS Guidelines to
BC Hydro. On page xi of the EIS Guidelines, the Minister of Environment of Canada and the Executive Director state the following:

“For the purposes of the environmental assessment under CEAA and to serve as the Environmental Assessment Certificate (EAC) Application for the Project, the Proponent must provide an EIS. In this document, the information which must be included in the EIS is identified.”

The purpose of this EIS is to provide the information that the Minister of Environment of Canada and the Executive Director have identified in the EIS Guidelines as required.

1.3 Presentation and Organization of the Environmental Impact Statement

The information required by the EIS Guidelines is set out in this EIS in five volumes and their appendices.

To the extent possible, the EIS is organized in a manner that parallels the organization of the EIS Guidelines. While there is some variation, the concordance between the contents of this EIS and the EIS Guidelines is demonstrated in detail in the Table of Concordance and is summarized below.

Note that Section 27 of the EIS Guidelines contains a series of references for the Guidelines themselves. Those references are not reproduced in the EIS. Also note that Section 28 of the EIS Guidelines contains a requirement to include a series of technical data reports and other documentation used to support the content of the EIS. Technical data reports and other documentation are appended to each of the volumes described below.

1.3.1 Volume 1: Introduction, Project Planning, and Description

In Volume 1 of the EIS, the information required by the following sections of the EIS Guidelines is set out:

• Section 1 of the EIS Guidelines: Guiding Principles, Purpose of the Environmental Impact Statement, Presentation, and Organization of this EIS
• Section 2 of the EIS Guidelines: Proponent Description
• Section 3 of the EIS Guidelines: Project Overview
• Section 4 of the EIS Guidelines: Need for, Purpose of, Alternatives to, and Alternative Means of Carrying out the Project
• Section 5 of the EIS Guidelines: Project Benefits
• Section 6 of the EIS Guidelines: Assessment Process
• Section 7 of the EIS Guidelines: Information Distribution and Consultation
1.3.2 **Volume 2: Assessment Methodology and Environmental Effects**

In Volume 2 of the EIS, the information required by the following sections of the EIS Guidelines is set out:

- Section 8 of the EIS Guidelines: Effects Assessment Methodology
  - In Volume 2 of this EIS, the methods used in compliance with the requirements set out in Section 8 of the EIS Guidelines are described
  - In addition, the specific methods used to conduct technical studies and to assess the potential effects of the Project on the valued components (VCs) are further detailed in the corresponding technical data reports appended to this EIS and in the discussion of the potential effects of the Project on each of the VCs

- Section 9 of the EIS Guidelines: Environmental Background
- Section 10 of the EIS Guidelines: Fish and Fish Habitat Effects Assessment
- Section 11 of the EIS Guidelines: Vegetation and Ecological Communities Effects Assessment
- Section 12 of the EIS Guidelines: Wildlife Resources Effects Assessment
- Section 13 of the EIS Guidelines: Greenhouse Gases Effects Assessment

1.3.3 **Volume 3: Economic Effects Assessment**

In Volume 3 of the EIS, the information required by the following sections of the EIS Guidelines is set out:

- Section 14 of the EIS Guidelines: Economics Effects Assessment
- Section 15 of the EIS Guidelines: Traditional Lands and Resource Use Effects Assessment
- Section 16 of the EIS Guidelines: Land and Resource Use Effects Assessment

1.3.4 **Volume 4: Social, Heritage Resources, and Health Effects Assessments**

In Volume 4 of the EIS, the information required by the following sections of the EIS Guidelines is set out:

- Section 17 of the EIS Guidelines: Social Effects Assessment
- Section 18 of the EIS Guidelines: Heritage Resources Effects Assessment
- Section 19 of the EIS Guidelines: Health Effects Assessment

1.3.5 **Volume 5: Aboriginal Interests and Information, Federal Information, and Environmental Management Plans**

In Volume 5 of the EIS, the information required by the following sections of the EIS Guidelines is set out:

- Section 20 of the EIS Guidelines: Asserted or Established Aboriginal Rights and Treaty Rights, Aboriginal Interests, and Information Requirements
• Section 21 of the EIS Guidelines: Summary of Proposed Environmental Management Plans

• Section 22 of the EIS Guidelines: Compliance Reporting

• Section 23 of the EIS Guidelines: Requirements for the Federal Environmental Assessment:
  o In Volume 5 of this EIS, compliance with particular requirements imposed by, or typically found in environmental assessments conducted under, CEAA is demonstrated. This is achieved in Volume 5 by:
    ▪ Discussion of specific assessments conducted in compliance with particular requirements
    ▪ Reference to other parts of this EIS where particular federal requirements are met

• Section 24 of the EIS Guidelines: Summary of Potential Residual Effects of the Project

• Section 25 of the EIS Guidelines: Complete Lists of Mitigation and Follow-up Measures

• Section 26 of the EIS Guidelines: Conclusion

References

Literature Cited


2 PROPOONENT DESCRIPTION

BC Hydro is a Crown corporation owned by the Province of British Columbia.

BC Hydro’s mandate is to generate, manufacture, conserve, purchase, and sell electricity to meet the needs of its customers. BC Hydro serves 95% of B.C.’s population, delivering electricity safely and reliably to approximately 1.9 million customers. Ninety per cent of BC Hydro customer accounts are residential, with the remainder either commercial or industrial.

As the largest electric utility in British Columbia, BC Hydro operates an integrated system with 31 hydroelectric facilities and three thermal generating plants, totalling approximately 12,000 MW of installed generating capacity (Figure 2.1). The hydroelectric facilities provide over 95% of the total electricity generated and are located in the Peace, Columbia, and Coastal regions of B.C. BC Hydro’s own generation is complemented by additional electricity purchased from Independent Power Producers in the province to meet customers’ annual needs.

BC Hydro delivers electricity to its customers through a network of over 75,000 km of transmission and distribution lines, approximately 300 substations, 900,000 utility poles, and 325,000 individual transformers. The system connects with other transmission systems in British Columbia, Alberta, and Washington State, which improves the overall reliability of the system and provides opportunities for trade.

BC Hydro is responsible for planning, building, operating, and maintaining its inventory of generation facilities and transmission and distribution assets. This responsibility includes obtaining all appropriate regulatory approvals for enhancements, reinforcements, and sustaining growth investments of these publicly owned assets.

The legislation that enables BC Hydro to carry out its mandate is the Hydro and Power Authority Act. Under the Utilities Commission Act, the British Columbia Utilities Commission regulates public utilities, including BC Hydro.

In addition, the BC Hydro Public Power Legacy and Heritage Contract Act ensures public ownership of BC Hydro’s transmission and distribution systems, all of BC Hydro’s existing generation and storage assets, and any future increases to the capacity and energy capability of these facilities. The Clean Energy Act, S.B.C., 2010, c. 22, updated several elements and targets included in the 2007 BC Energy Plan, and provides statutory guidance for how BC Hydro is to meet the Province’s energy objectives.
## 2.1 Contact Information

<table>
<thead>
<tr>
<th>Name of Corporation</th>
<th>BC Hydro and Power Authority</th>
</tr>
</thead>
<tbody>
<tr>
<td>Address</td>
<td>Corporate Office</td>
</tr>
<tr>
<td></td>
<td>333 Dunsmuir Street</td>
</tr>
<tr>
<td></td>
<td>Vancouver, BC V6B 5R3</td>
</tr>
<tr>
<td>President and Chief Executive Officer</td>
<td>Charles Reid</td>
</tr>
<tr>
<td>Executive Vice-President Site C Clean Energy Project</td>
<td>Susan Yurkovich</td>
</tr>
<tr>
<td>Principal Contact for the Environmental Assessment</td>
<td>Danielle Melchior</td>
</tr>
<tr>
<td></td>
<td>Director, Site C Environmental Assessment and Regulatory</td>
</tr>
<tr>
<td></td>
<td>Phone: 604 699-7344</td>
</tr>
<tr>
<td></td>
<td>Fax: 604 623-4333</td>
</tr>
<tr>
<td></td>
<td>Email: <a href="mailto:sitec@bchydro.com">sitec@bchydro.com</a></td>
</tr>
<tr>
<td>Company Website</td>
<td><a href="http://www.bchydro.com">http://www.bchydro.com</a></td>
</tr>
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<td>Project Website</td>
<td><a href="http://www.bchydro.com/sitec">http://www.bchydro.com/sitec</a></td>
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</tbody>
</table>
3 PROJECT OVERVIEW

3.1 Project Governance Process

3.1.1 Multi-staged Decision-Making Process

Consistent with best practices for large infrastructure projects, BC Hydro adopted a multi-stage approach for the planning and evaluation of the Project. This approach provides multiple decision-making points during project development and focuses on specific deliverables and objectives at each stage.

Stage 1, Review of Project Feasibility, took place from 2004 to 2007. During this stage, BC Hydro conducted a review of project feasibility, with a view to determining if there was enough potential to address key impacts, and whether it was in the best interests of ratepayers to move to the next stage of project planning and development. Specifically, BC Hydro reviewed existing studies and historical information, including information relating to engineering, project costs, and environment, as well as previous consultations.

The review concluded that it would be prudent to continue to investigate Site C as a potential resource option to address the growing electricity supply gap within the province. It was also determined that further review of the Project, including updating some previous technical studies, would provide important information about benefits, issues, costs, and potential mitigation options (BC Hydro 2007).

BC Hydro moved to Stage 2, Consultation and Technical Review, following direction by the Province in the BC Energy Plan. Stage 2 work, which commenced in the fall of 2007, included consultations with the public, stakeholders, communities, Aboriginal groups, and property owners, as well as preliminary discussions with the Province of Alberta and the Northwest Territories.

BC Hydro also initiated field studies to better understand current conditions related to the physical, biological, and socio-economic environment, and to gather engineering and technical information regarding the design, construction, and operation of the Project. Based on the Stage 2 key findings, BC Hydro recommended proceeding to the next stage of project planning and development, including an environmental and regulatory review (BC Hydro 2009).

BC Hydro entered Stage 3, the Environmental and Regulatory Review stage, in April 2010, following a decision by the Province to advance the Project to the next stage of development. BC Hydro filed its Project Description in May 2011 and it was accepted by the federal and provincial governments in August 2011, formally initiating the environmental assessment process.

Should the project receive environmental certification at the end of Stage 3, Stage 4 would include a decision by the BC Hydro Board of Directors and the Province to proceed to full project construction.

Stage 5, Construction, is the final stage, involving an approximate seven-year construction period with one additional year for final project commissioning, site reclamation, and demobilization.
3.1.2 Governance Structure and Implementation of Corporate Policies

The mechanism used to ensure that the Project implements and respects BC Hydro’s corporate policies is through the Project’s governance structure.

As a business unit within BC Hydro, the Project is headed by an Executive Vice-President who reports directly to BC Hydro’s President and Chief Executive Officer (CEO). Governance oversight is provided by the:

- BC Hydro Board of Directors, which is appointed by British Columbia’s Lieutenant Governor in Council and oversees the conduct of BC Hydro, supervises management, and ensures that all major issues affecting BC Hydro are given proper consideration. Day-to-day leadership and management of BC Hydro is delegated to the President and CEO.

- Site C Project subcommittee of the Board, which includes the Board Chair, President and CEO, three additional board members, and the Site C Executive Vice-President.

- BC Hydro Executive Team, which is led by the President and CEO and includes the Site C Executive Vice-President, and executives for each business unit and corporate services group at BC Hydro.

Technical Advisory Board

For the design of large-scale hydroelectric projects such as the Project, it is typical industry practice to retain external advisory review boards to provide independent due diligence, opinions, and advice on the technical aspects of the project design.

The Project has an established international Technical Advisory Board that has provided technical advice on the project engineering and design. The members of the Site C Technical Advisory Board are globally recognized for their technical knowledge and experience with the design of hydroelectric projects around the world.

The Technical Advisory Board meets twice per year to review key design milestones and will continue to provide input to the project as it progresses through implementation and final design.

BC Hydro, through its governance structure, is responsible and accountable for the implementation of mitigation measures for the Project, including the oversight of contractors’ obligations.

3.1.3 Corporate and Management Structure: Insurance and Liability

The Board of Directors is accountable for all risks incurred by BC Hydro and its subsidiaries. Authority for risk management is delegated to the Chief Executive Officer. The Chief Risk Officer is charged with the development of the enterprise risk management framework across all of BC Hydro, which provides the basis for consistent application of risk management practices. The Board of Directors and BC Hydro management regularly review and discuss the risk profile of the organization, and consider the nature and amount of risk incurred in the pursuit of the organization’s objectives.

BC Hydro also manages significant risks in conformity with the provisions of the international standard ISO 31000, Risk management – Principles and guidelines, or in
conformity with other externally recognized standards appropriate to the risk being managed.

During construction of the Project, BC Hydro would put in place a construction insurance program that would include, but not be limited to, the following:

- Course of Construction Insurance, to cover damage to the project during construction
- Professional Liability, covering claims arising from errors and omissions
- Wrap-up Liability, to cover third-party liability during construction

In addition, where applicable, BC Hydro may transfer various risks through contracts with insurance service providers.

Project risks during operations, to the extent that they are not covered by BC Hydro’s insurance program, are self-insured and managed through a comprehensive dam safety management system involving dam safety professionals and experts. Dams are continually monitored, and conditions are compared against national and international best practices. Interim risk management plans and capital upgrade programs are initiated as required.

### 3.1.4 Site C Clean Energy Project Charter

A Project Charter for the Project was approved by the BC Hydro Board of Directors in May 2011. It includes the following Vision, Mission and Objectives (Table 3.1).

#### Vision

Through the construction of the Project, BC Hydro will deliver a modern project that will:

- Support our clean energy objectives, of electricity self-sufficiency, job creation and greenhouse gas reduction
- Facilitate the development of clean energy projects by providing additional capacity to back up intermittent resources, such as wind, run-of-river hydro and solar

#### Mission

To design and construct a clean and renewable hydroelectric generation facility that will:

- Produce and deliver electricity in an environmentally and socially responsible manner
- Recognize the impacts of electricity generation and identify and incorporate options for mitigation that minimize effects
- Be best in class for engineering and environmental design and safety
- Build relationships and encourage participation and input from the public, local governments and stakeholders
- Build relationships with Aboriginal groups, and ensure meaningful consultation occurs in all stages of project development
- Employ a best practices standard in working with private property owners to minimize disruption, to ensure property owner input is thoroughly considered in project planning and to conduct work in a manner that demonstrates a respectful attitude towards the property and property rights of others
- Provide value to ratepayers by ensuring a competitive cost structure and maintaining the Project as a Heritage asset

### Objectives

The objectives are outlined in Table 3.1.

#### Table 3.1 Site C Clean Energy Project Charter Objectives

<table>
<thead>
<tr>
<th>Project Objectives</th>
<th>Description</th>
</tr>
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<tbody>
<tr>
<td>Provide reliable capacity</td>
<td>Maximize capacity available from Site C while meeting owner’s requirements</td>
</tr>
<tr>
<td>Deliver low cost energy</td>
<td>Maximize energy available from Site C while meeting owner’s requirements</td>
</tr>
<tr>
<td></td>
<td>Minimize project unit energy cost (UEC) while meeting owner’s requirements</td>
</tr>
<tr>
<td>Ensure a long term source of energy and capacity</td>
<td>Maximize project life within owner’s requirements</td>
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<tr>
<td></td>
<td>Retain public ownership of energy supply</td>
</tr>
<tr>
<td>Support Clean Energy Objectives</td>
<td>Maintain BC generation as &gt;=93% clean</td>
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<tr>
<td></td>
<td>Low life-cycle GHG emissions from project</td>
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<tr>
<td></td>
<td>Aids in integration of other intermittent renewable resources</td>
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<tr>
<td></td>
<td>Contribute to BC’s self-sufficiency goals</td>
</tr>
<tr>
<td>Public and worker safety</td>
<td>Achieve zero fatalities and zero serious injuries</td>
</tr>
<tr>
<td></td>
<td>Include safety in the design of all project components</td>
</tr>
<tr>
<td></td>
<td>Meet or exceed BC Hydro’s worker safety standards</td>
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<tr>
<td></td>
<td>Integrate job-safety planning into day-to-day work for all project activities</td>
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<tr>
<td>Ensure that the Crown’s duty to consult Aboriginal groups is met</td>
<td>Consult Aboriginal groups with a focus on impact assessment, mitigation, and where applicable, accommodation</td>
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<tr>
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<td>Identify opportunities for Aboriginal participation in the project</td>
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<tr>
<td>Environmental Leadership</td>
<td>Meet or exceed environmental requirements defined by legislation, regulation and government directives</td>
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<tr>
<td>Optimize existing BC Hydro assets on Peace River system</td>
<td>Increase value of Williston Reservoir storage and regulation</td>
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<td>Maintain operational and maintenance flexibility at existing BC Hydro generation facilities on the Peace River</td>
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<tr>
<td>Project Objectives</td>
<td>Description</td>
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<td>--------------------------------------------------------</td>
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<tr>
<td>Follow best practice in public process</td>
<td>• Undertake thorough, best practice consultation with the public, communities and stakeholders</td>
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<td>• Employ a best practices standard in working with private property owners to minimize disruption, to ensure input is thoroughly considered in project planning</td>
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<tr>
<td>Provide lasting economic and social benefits for</td>
<td>• Create construction-related jobs and business opportunities</td>
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<tr>
<td>northern communities, Aboriginal groups and the</td>
<td>• Consult and work with communities about regional benefits such as upgrades to infrastructure including roads, bridges and parks</td>
</tr>
<tr>
<td>province</td>
<td>• Work with Aboriginal communities to identify and create opportunities for skills training, jobs and economic development</td>
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excavations, and worker accommodation, as well as items with long lead times such as
the turbines and generators.

An overview of the month-by-month schedules for construction of the Project
components is provided in Volume 1 Section 4 Project Description. These schedules
were based on project planning at the time of preparation of the Environmental Impact
Statement and may change as a result of procurement and project planning
advancements.

References

Literature Cited

BC Hydro 2007. Peace River Site C Hydro Project, An option to help close B.C.’s growing
electricity gap, Summary: Stage 1 Review of Project Feasibility, December 2007. Report

BC Hydro 2009. Peace River Site C Hydro Project, Stage 2 Report: Consultation and Technical
4 PROJECT DESCRIPTION

4.1 Project Location

The Project is a proposed third dam and hydroelectric generating station on the Peace River in northeast B.C., Canada. The Peace River arises in the Rocky Mountain Trench in north-central B.C. and flows east across the provincial border into Alberta and, after turning north and joining the Athabasca and Mackenzie rivers, drains into the Arctic Ocean (Figure 4.1). The Project would be located approximately 62 river kilometres upstream from where the Peace River crosses the B.C. – Alberta border, and approximately 1,300 river kilometres upstream from where the Slave River crosses the Alberta – Northwest Territory border.

The dam would be located about 7 km southwest of Fort St. John at Universal Transverse Mercator (UTM) coordinates 629422E, 6229749N (Zone 10N NAD 83) (latitude and longitude of N 56°11′42.27″, W 120°54′51.02″, respectively). The 83 km long reservoir would extend upstream from the dam, west past Hudson’s Hope to the Peace Canyon Dam. The general location of the Project is shown in Figure 4.2.

4.1.1 Natural Elements

The geology in the Peace River region in the area of the proposed Project generally consists of flat to gently dipping sedimentary rocks of Cretaceous age that are about 70 million years old. The eastern slopes of the Rocky Mountains contain some limestone deposits, formed from marine sediments laid down about 200 million years ago. These formations also contain coal, petroleum, and natural gas deposits. To the west, interbedded shales and sandstone occur near the surface. The overburden, up to 400 m thick, consists of layers of till and gravel alternating with sands, silts, and clays.

The region’s upland areas are characterized by a rolling topography, with streams and rivers cutting through the overburden and rock to create valleys. Where the overburden consists primarily of silts and clays, the valley slopes are prone to erosion. The upland plateau is, for the most part, at an elevation of 700 m. Along the Peace River, the valley bottom is at an elevation of approximately 450 m at Hudson’s Hope, gradually sloping to an elevation of 410 m at the proposed dam site. The width of the valley varies from about 1 km to 5 km. The north bank of the river has prominent terraces, while the south bank is generally more steeply sloped. For more detail, see Volume 2 Section 11.2 Geology, Terrain, and Soils.

The major tributaries to the Peace River in the proposed reservoir area are Lynx Creek, Farrell Creek, Halfway River, Cache Creek, and the Moberly River (Figure 4.2). The Peace River and its tributaries support a diverse fish community that supports clear-water and turbid-water sport fish such as suckers, minnows, and sculpins. See Volume 2 Section 12 for more information about fish and fish habitat. Natural lakes occur sporadically in the uplands, with the largest being Moberly, Charlie, and Boudreau lakes. Groundwater generally flows towards the Peace River, which acts as a regional groundwater discharge point. See Volume 2 Section 11.4 Surface Water Regime and Volume 2 Section 11.6 Groundwater Regime for more detail on these topics. The rivers and lakes provide recreational opportunities that are discussed in Volume 3 Section 25 Outdoor Recreation and Tourism.
The climate, topography, and vegetation of the Peace River region in B.C. are more similar to Canada’s boreal forests and northern plains than they are to the rest of B.C. The Project is located within the moist, wet boreal white and black spruce subzone of the Peace lowlands eco-section. Within this subzone, the dominant tree cover is trembling aspen, with a mix of deciduous and coniferous forests in the valleys and moist depressions and on north-facing slopes. Grasslands, mostly cultivated, are prevalent in the uplands. Wetlands, muskeg, and riparian areas add to the variety of habitats in the region. See Volume 2 Section 13 Vegetation and Ecological Communities for more detail. This region supports populations of ungulates (e.g., mule deer, elk, moose, and white-tailed deer), fur-bearing mammals, birds, reptiles, amphibians, and insects. See Volume 2 Section 14 Wildlife Resources for more detail.

4.1.2 Human Elements

Archaeological and ethnographic sources indicate that Aboriginal peoples have lived in the Peace River region for thousands of years. Evidence from Charlie Lake Cave, near Fort St. John, dates to approximately 10,500 years ago, although it is assumed that Aboriginal people were living in the area for some time before this (Driver et al. 1996, Driver 1999, Fladmark et al. 1988). Based on the ethnographic record, the Dane-Zaa (also referred to as Beaver) and Tse Keh Nay (also referred to as Sekani) have used and occupied the region the longest (e.g., Jenness 1937). The languages of both the Dane-Zaa and Tse Keh Nay are Part of the Athapaskan language family (Krauss and Golla 1981:67). The Algonquian Cree arrived at the beginning of the fur trade era (Ridington 1981).

According to ethnographic sources, the Dane-Zaa used and occupied lands adjacent to the Peace River, from the Peace River Canyon to Lake Athabasca (Ridington 1981). The Tsay Keh Nay used and occupied the basins of the Parsnip and Finlay rivers, and the valley of the Peace as far downstream as the modern town of Peace River (Denniston 1981, Jenness 1932). The Algonquian Cree settled into the lower and middle Peace River areas of the traditional Dane-Zaa lands following their arrival in the area in the mid- to late 19th century (Ridington 1981).

The first contact with European explorers and fur traders occurred in the late 1790s, as shown on the historic timeline in Figure 4.3. With the Peace River corridor being an important link in the travel route between the Canadian northern plains and the coast, Fort St. John became one of a few established trading posts along this route in the following decades. By the mid-1800s, people began creating more permanent settlements in other parts of the Peace River region.

Around 1860, the Peace River region experienced the first of many successive waves of resource development. First came a minor gold rush, followed in the early 1900s by land settlement for farming and ranching. Land clearing for agricultural expansion led to the growth of a small forestry industry. The discovery of coal, also in the early 1900s, was followed by periods of oil and gas exploration in the 1920s and 1930s.

In response to increasing development and settlement of the northern regions of western Canada and starting in the late 1800s, First Nations and the federal government negotiated Treaty 8. That treaty defined Aboriginal rights to lands and resources within the area described in Section 4.1.2.1 Aboriginal Lands, including the Peace River region in what is now British Columbia.
The next wave of development in the 1940s and 1950s focused on developing major infrastructure to connect the Peace region to the rest of B.C. and Canada, including the Alaska Highway, provincial highway connections south to Prince George, a railway, and an airport just east of Fort St. John. During this period, the region became an important transportation corridor and service centre for northern development. Between the late 1950s and 1990s, several industrial facilities for processing oil, gas, and wood were developed in the region. Exploration activities for oil and gas continued, along with the construction and operation of several pipelines. In 1967, the W.A.C. Bennett Dam, located at the head of the Peace River Canyon, was completed, followed by the Peace Canyon Dam in 1980. Another wave of resource development activity began in the late 2000s with the extraction and processing of shale gas from the Montney Formation, the development of several wind farms, and the resurgence of coal mining around Tumbler Ridge.

The region’s population has grown along with the waves of resource development. The 2010 population estimate for Fort St. John and Taylor is about 21,300, with the total population for the region estimated at just over 59,300.

4.1.2.1 Aboriginal Lands

The Project lies within the tract of land described in the following excerpt from Treaty 8 and illustrated in Figure 4.4.

"AND WHEREAS, the said Commissioners have proceeded to negotiate a treaty with the Cree, Beaver, Chipewyan and other Indians, inhabiting the district hereinafter defined and described, and the same has been agreed upon and concluded by the respective bands at the dates mentioned hereunder, the said Indians DO HEREBY CEDE, RELEASE, SURRENDER AND YIELD UP to the Government of the Dominion of Canada, for Her Majesty the Queen and Her successors for ever, all their rights, titles and privileges whatsoever, to the lands included within the following limits, that is to say:

Commencing at the source of the main branch of the Red Deer River in Alberta, thence due west to the central range of the Rocky Mountains, thence northwesterly along the said range to the point where it intersects the 60th parallel of north latitude, thence east along said parallel to the point where it intersects Hay River, thence northeasterly down said river to the south shore of Great Slave Lake, thence along the said shore northeasterly (and including such rights to the islands in said lakes as the Indians mentioned in the treaty may possess), and thence easterly and northeasterly along the south shores of Christie's Bay and McLeod's Bay to old Fort Reliance near the mouth of Lockhart's River, thence southeasterly in a straight line to and including Black Lake, thence southwesterly up the stream from Cree Lake, thence including said lake southwesterly along the height of land between the Athabasca and Churchill Rivers to where it intersects the northern boundary of Treaty Six, and along the said boundary easterly, northerly and southwesterly, to the place of commencement.
AND ALSO the said Indian rights, titles and privileges whatsoever to all other lands wherever situated in the Northwest Territories, British Columbia, or in any other portion of the Dominion of Canada.

TO HAVE AND TO HOLD the same to Her Majesty the Queen and Her successors for ever.

And Her Majesty the Queen HEREBY AGREES with the said Indians that they shall have right to pursue their usual vocations of hunting, trapping and fishing throughout the tract surrendered as heretofore described, subject to such regulations as may from time to time be made by the Government of the country, acting under the authority of Her Majesty, and saving and excepting such tracts as may be required or taken up from time to time for settlement, mining, lumbering, trading or other purposes.”

Treaty 8 covers 841,487 km² in what is now the northern half of Alberta, the northeast quarter of British Columbia, the northwest corner of Saskatchewan, and the area south of Hay River and Great Slave Lake in the Northwest Territories. Forty First Nations are signatories or adherents to Treaty 8 and many of them have Indian Reserves held for their use and benefit within the boundaries of Treaty 8. Also located within the boundaries of Treaty 8 are several Métis communities.

4.1.2.2 Nearby Communities

First Nation communities located within 100 km of the Project (Figure 4.5) include First Nation Reserves held by Saulteau First Nations (approximately 60 km southwest of the dam site and 12 km from the nearest project component), West Moberly First Nations (approximately 75 km southwest of the dam site and 15 km from the nearest project component), Halfway River First Nation (approximately 67 km northwest of the dam site and 25 km from the nearest project component), Blueberry River First Nations (approximately 58 km north of the dam site and 42 km from the nearest project component), and Doig River First Nation (approximately 50 km north of the dam site and 42 km from the nearest project component).

Municipalities in the vicinity of the Project include the City of Fort St. John (approximately 7 km northwest of the dam site), the District of Taylor (approximately 16 km downstream of the dam site), the District of Hudson’s Hope (approximately 64 km upstream of the dam site and adjacent to the proposed reservoir), the District of Chetwynd (approximately 70 km to the south of the dam site), and the City of Dawson Creek (approximately 65 km to the southeast of the dam site).

4.1.3 Land Ownership

Land ownership in the vicinity of the Project is shown in Figure 4.6. The majority of land consists of surveyed or unsurveyed provincial Crown land. South of the proposed reservoir, within the transmission corridor, is a small area of privately owned land. Along the length of the proposed reservoir there are several BC Hydro-owned and privately owned parcels within the Peace River valley and on the north bank of the Peace River. There is no directly affected federally owned land near the Project.
Since 1957, the Province has held a flood reserve over Crown land lying within the proposed area of the reservoir (Figure 4.7). This notation prevents the construction of permanent structures and exploration for oil and gas, and is discussed in more detail in Volume 1 Section 6 Alternative Means of Carrying Out the Project. Within and around the Project activity zone, other tenures and rights exist for activities that include agriculture, grazing, forestry, oil and gas exploration and production, guiding, and trapping. These tenures are described in more detail in Volume 3 Economic and Land and Resource Use Effects Assessment.

4.1.4 Environmentally Sensitive Areas and Parks

The closest ecological reserve to the Project, Cecil Lake, is located 28 km northeast of Fort St. John and lies outside the Project activity zone. It is a land-based 129-ha area with vegetation and topography that is representative of the ecosystems in the Peace River area of the Alberta plateau. Approximately 11 km southwest of the ecological reserve, also outside the Project activity zone, is a 440-ha area designated by the international ornithology community as an Important Bird Area. The Province has not established any Wildlife Management Areas in northeast B.C.

The locations of wetlands and identified ungulate winter range (established under the Forests and Range Practices Act) are shown in Figure 4.8. The habitats of provincially or federally listed species are described in Volume 2 Section 13 Vegetation and Ecological Communities and Volume 2 Section 14 Wildlife Resources.

The locations of the following provincial, regional and municipal parks are shown in Figure 4.8.

- Provincial parks:
  - Beatton and Beatton River
  - Butler Ridge
  - Charlie Lake
  - Moberly Lake
  - Pine Le Moray
  - Taylor Landing
  - Kiskatinaw

- Regional parks:
  - Montney Centennial
  - Spencer Tuck

- Municipal parks:
  - Alwin Holland
  - Peace Island

The two municipal parks are located directly on the Peace River and in close proximity to the Project. Alwin Holland Park will be partially inundated by the proposed Site C reservoir.
A new proposed protected area, Peace River Boudreau Lakes, was recommended by the 1999 Dawson Creek and 1997 Fort St. John land and resource management planning processes; however, to date, the area has not been formally designated by the Province.

The Peace Moberly Tract is described in the 2006 Peace Moberly Tract Draft Sustainable Resource Management Plan (see reference below) as an area of land approximately 1,090 km² in size and lying between Moberly Lake and the Peace River. The Peace Moberly Tract lies within a greater area identified by the Saulteau and West Moberly First Nations as an ‘Area of Critical Community Interest’. The ‘Area of Critical Community Interest’ is in proximity to the Saulteau and West Moberly First Nations’ reserves and provides access for cultural activities and for hunting, trapping, and fishing.

4.1.5 Current Land Use and Management Designations

Current land use is a reflection of traditional uses and historic settlement patterns in combination with more recent activities involving resource extraction and processing and community development. Human activities are conducted within a context of management objectives articulated in provincial and local government plans and zoning.

As illustrated in Figure 4.9, the majority of land surrounding the Project activity zone is in the provincial Agricultural Land Reserve. In addition to farming and ranching, allowable uses within this Reserve include mineral exploration; oil and gas exploration and development; transportation, utility, and communication corridors; recreational developments; and forest management. The Project activity zone is also within the Peace Forest District, which includes the Fort St. John and Dawson Creek Timber Supply Areas and one Tree Farm Licence. The forested areas and lakes to the west and south of the project area are used for hunting, trapping, guiding, and outdoor recreation, and have been identified by the Saulteau and West Moberly First Nations as an ‘Area of Critical Community Interest’. The Province is managing these multiple uses on Crown land from the perspective of integrating environmental and conservation values with resource development, as described in the Land and Resource Management Plans developed in the late 1990s. See Volume 3 Economic and Land and Resource Use Effects Assessment for more information about land use.

Within municipal boundaries, the dominant uses of land include residential and commercial development, light industrial development, and roads, supported by institutional facilities for health, education, and safety. Outside municipal and First Nation reserve boundaries, rural residential development tends to be clustered along roads and historic settlement areas.

The location of the transportation and municipal infrastructure that supports economic development and human settlement in the region is identified in Figure 4.10. The highways through this region are used by local, commercial, and industrial traffic, as well as by tourists travelling to northern B.C., Alberta, and Alaska.

4.2 Project Evolution

The design of the Project has evolved since the 1982 British Columbia Utilities Commission (BCUC) application. Table 4.1 lists design changes that were made to avoid or mitigate potential effects of the Project.
The following subsections describe the components of the Project and the activities during construction and operation of the Project incorporating the design changes listed in Table 4.1. The effects assessments and the proposed mitigation measures described in this Environmental Impact Statement are for the Project components and activities described in Sections 4.3, 4.4, and 4.5 and therefore do not double-count the avoidance and mitigation of potential effects achieved by the design changes listed in Table 4.1.

Table 4.1  
List of Design Changes Since the 1982 BCUC Application to Avoid or Mitigate Potential Environmental Effects

<table>
<thead>
<tr>
<th>Project Component</th>
<th>Valued Component</th>
<th>Effects Avoided or Mitigated</th>
<th>Avoidance or Mitigation Measure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dam, generating station and spillways</td>
<td>Wildlife Resources</td>
<td>Loss of wildlife habitat</td>
<td>Maximize relocation of surplus excavated material upstream of dam</td>
</tr>
<tr>
<td></td>
<td>Wildlife Resources</td>
<td>Loss of wildlife habitat</td>
<td>Reduction of footprint and disruption of wetland habitat and clearing by relocating worker accommodation</td>
</tr>
<tr>
<td></td>
<td>Wildlife Resources</td>
<td>Loss of wildlife habitat</td>
<td>Minimize footprint on big island downstream of dam</td>
</tr>
<tr>
<td></td>
<td>Fish and Fish Habitat</td>
<td>Dissolved gas supersaturation</td>
<td>Spillway design modified to minimize dissolved gas</td>
</tr>
<tr>
<td>Reservoir</td>
<td>Community Infrastructure and Services</td>
<td>Erosion of slopes at Hudson's Hope</td>
<td>Extended shoreline protection</td>
</tr>
<tr>
<td>Highway 29 realignments</td>
<td>Community Infrastructure and Services</td>
<td>Potential erosion by reservoir</td>
<td>Realign Highway 29 at Dry Creek and Farrell Creek east</td>
</tr>
<tr>
<td>Agriculture</td>
<td>Loss of agricultural land</td>
<td>Selection of alignment at Lynx Creek that includes a portion of Millar Road</td>
<td></td>
</tr>
<tr>
<td>Quarried and excavated construction materials</td>
<td>Wildlife Resources</td>
<td>Loss of bat hibernacula</td>
<td>Elimination of Tea Creek from consideration as a source of temporary riprap</td>
</tr>
<tr>
<td></td>
<td>Human Health</td>
<td>Reducing heavy truck traffic on public roads – lower risk to human safety, less noise and dust</td>
<td>Selection of a conveyor for transporting till from 85th Avenue Industrial Lands to dam site area</td>
</tr>
<tr>
<td>Wildlife Resources</td>
<td>disturbance to caribou</td>
<td></td>
<td>Restriction on blasting at West Pine quarry to no greater than historical levels during the periods January 16 to March 31 and May 15 to June 14 each year</td>
</tr>
<tr>
<td>Transportation</td>
<td>Traffic congestion in Hudson's Hope and on Highway 29</td>
<td>Source permanent riprap for dam, generating station, and spillways from West Pine Quarry as opposed to Portage Mountain Quarry</td>
<td></td>
</tr>
<tr>
<td>Minerals and Aggregates</td>
<td>Use of aggregate in project area</td>
<td>Source aggregate for Highway 29 realignment from areas that would be inundated</td>
<td></td>
</tr>
</tbody>
</table>

NOTE:
* Valued components are described in Volume 2 Section 10 Effects Assessment Methodology.

Two further changes were made to the design of the Project after the commencement of the effects assessment.
The transmission line right-of-way requirements were reduced by changing the design and the sequencing of construction of the two 500 kV transmission lines so that the two existing 138 kV transmission lines could be removed. This sequencing is described in Section 4.3.3; however, the effects assessment is based on the greater width of right-of-way.

The capacity of the Stage 2 diversion works described in Section 4.4.3 was increased by increasing the diameter of the diversion tunnels. Volume 2 Section 11.4 Surface Water Regime describes the changes to upstream and downstream water levels during Stage 2 diversion based on the smaller diameter tunnels. The effects assessment is based on the changes described in Volume 2 Section 11.4 Surface Water Regime, except that the description of the effects of the environment on the Project contained in Volume 5 Section 37 Requirements for the Federal Environmental Assessment is based on the larger diameter tunnels.

### 4.3 Project Components

The components of the Project are:

- Dam, generating station, and spillways
- Reservoir
- Substation and transmission lines to Peace Canyon Dam
- Highway 29 realignment
- Quarried and excavated construction materials
- Worker accommodation
- Road and rail access

These components are described in the following subsections. Design and planning of the Project have continued since submission of the Project Description Report (BC Hydro 2011). The descriptions provided below supersede the descriptions contained in the Project Description Report (BC Hydro 2011). The locations of the Project components and activities are shown in Figure 4.11.

Alternative means of carrying out the Project are described in Volume 1 Section 6.0 Alternative means of Carrying out the Project. Alternatives that were considered for some of the Project components are described in the following subsections.

### 4.3.1 Dam, Generating Station, and Spillways

The general arrangement of the dam, generating station, and spillways is shown in Figure 4.12 and an artist’s rendition is shown in Figure 4.13.

From north to south, the main components of the dam, generating station, and spillways are:

- The left (north) bank stabilization, a large excavation to remove unstable materials from the bank above the earthfill dam and flatten the slope for long-term stability
- Two diversion tunnels used for river diversion during construction
The earthfill dam across the river valley abutting onto bedrock on the north bank and a buttress of roller compacted concrete (RCC) on the south bank

The RCC buttress that would support the south wall of the valley and provide an abutment for the earthfill dam and the foundation for the generating station and spillways

The generating station, consisting of power intakes, penstocks (large pipes that convey the water from the intakes to the powerhouse) and powerhouse

A spillway with seven gates and a free overflow auxiliary spillway to discharge inflows that exceed the capacity of the generating station

A lined approach channel to convey water from the reservoir to the power intakes and the spillways

Three 500 kV transmission lines to conduct electricity from the generating station to the substation and transmission lines, which would connect the Project to the bulk transmission system at Peace Canyon Dam

The earthfill dam, RCC buttress, power intakes, spillway headworks and associated training walls would impound the reservoir. These structures would be designed and constructed to international and Canadian standards to withstand the normal loads (including self-weight, reservoir and tailwater loads; internal water pressures due to seepage, ice, temperatures; and the interaction between the bedrock and the structures, as well as loads resulting from extreme floods and earthquakes).

An understanding of the consequences of dam failure underlies several principles in the Canadian Dam Association (CDA) Dam Safety Guidelines (CDA 2007) and is used to establish two principle design criteria, the inflow design flood, and the earthquake design ground motion. BC Hydro has adopted the highest dam classification for Site C. This results in the highest standard for the inflow design flood and earthquake design ground motion.

The inflow design flood adopted for Site C is the probable maximum flood, which is defined as the most severe flood that may reasonably be expected to occur at a particular location. Derivation of the probable maximum flood is described in Volume 5 Section 37 Requirements for the Federal Environmental Assessment.

The earthquake design ground motion adopted for Site C has an annual exceedance frequency of 1 in 10,000. Volume 2 Section 11.2 Geology, Terrain, and Soils provides information on the regional and site-specific seismic hazard assessment.

### 4.3.1.1 Earthfill Dam

#### 4.3.1.1.1 General Description

An earthfill dam has been selected as the best dam type for the geological conditions at Site C. A cross-section of the earthfill dam is shown in Figure 4.14. The design of the earthfill dam is conventional and there are many precedents around the world. In fact, the International Commission on Large Dams' World Register of Dams (ICOLD 2011) lists 443 earthfill dams with heights equal to or greater than the height of the proposed earthfill dam at Site C. The design and performance of earthfill dams is well understood. The dam would have a central impervious core with filters on each side of the core,
gravel drains on the downstream side of the core and outer shells of sands and gravels. The characteristics of the materials used to construct the dam are described in Section 4.3.1.1.2.

Weathered rock and colluvium would be removed from the abutments of the dam. In the riverbed, the shells of the dam would be founded on alluvium that overlies bedrock on the floor of the valley. The impervious core would be founded in a core trench excavated into the shale bedrock. Cement grout would be pumped into a curtain of closely spaced holes drilled along the floor of the core trench to a depth of about 20 m in the riverbed and about 30 m in the north abutment to seal joints and other discontinuities.

Table 4.2 lists some earthfill dams that have been constructed on bedrock with similar characteristics as the bedrock at Site C. Two of these dams, Mangla and Karkheh, are located in highly seismic areas and have a maximum design earthquake (MDE) of 0.4 g compared to 0.25 g at Site C.

<table>
<thead>
<tr>
<th>Name (Country)</th>
<th>Year Constructed</th>
<th>Height (m)</th>
<th>Foundation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bath County Upper Dam (USA)</td>
<td>1985</td>
<td>146</td>
<td>Shale interbedded with sandstone and siltstone</td>
</tr>
<tr>
<td>Mangla Dam (Pakistan)</td>
<td>1967</td>
<td>136</td>
<td>Claystone and siltstone of Siwalik (fresh water deposited) formations with bedding planes up to 1 m thick and bentonite seams. Strength of claystone very similar to shale at Site C.</td>
</tr>
<tr>
<td>Karkheh Dam (Iran)</td>
<td>2000</td>
<td>128</td>
<td>Shale</td>
</tr>
<tr>
<td>Ramganga Dam (India)</td>
<td>1970</td>
<td>126</td>
<td>Siwalik formation with alternate bands of shale and sandstone with occasional thin bands of siltstone</td>
</tr>
<tr>
<td>Jennings Randolph (USA)</td>
<td>1985</td>
<td>90</td>
<td>Shale</td>
</tr>
<tr>
<td>Zahara (Spain)</td>
<td>1994</td>
<td>80</td>
<td>Shale</td>
</tr>
<tr>
<td>Oahe (USA)</td>
<td>1948</td>
<td>75</td>
<td>Shale</td>
</tr>
<tr>
<td>Gardiner (Canada)</td>
<td>1967</td>
<td>64</td>
<td>Bearspaw formation comprising sandstone and clay shale with bentonite lenses</td>
</tr>
<tr>
<td>Garrison USA</td>
<td>1953</td>
<td>64</td>
<td>Shale</td>
</tr>
<tr>
<td>Goi (Japan)</td>
<td>1995</td>
<td>57</td>
<td>Shale</td>
</tr>
<tr>
<td>Balderhead (UK)</td>
<td>1964</td>
<td>48</td>
<td>Shale</td>
</tr>
<tr>
<td>Beltzville (USA)</td>
<td>1969</td>
<td>52</td>
<td>Shale</td>
</tr>
<tr>
<td>Cowanesque (USA)</td>
<td>1980</td>
<td>46</td>
<td>Calcareous and shaley sandstone with thick beds of shale</td>
</tr>
<tr>
<td>Aabach (Germany)</td>
<td>1981</td>
<td>45</td>
<td>Shale</td>
</tr>
<tr>
<td>Chatfield (USA)</td>
<td>1975</td>
<td>45</td>
<td>Shale</td>
</tr>
<tr>
<td>Waco (USA)</td>
<td>1965</td>
<td>43</td>
<td>Shale with bentonite seams</td>
</tr>
<tr>
<td>Tioga Hammond (USA)</td>
<td>1979</td>
<td>43</td>
<td>Shale</td>
</tr>
<tr>
<td>Kamenik (Bulgaria)</td>
<td>1994</td>
<td>40</td>
<td>Shale</td>
</tr>
</tbody>
</table>
Any seepage through the impervious core would be intercepted by the free-draining filter and drain layers downstream of the core, and conducted to the toe of the dam by a drainage blanket. The gradation of the filters and drains would be designed so that fine material could not be eroded from the core or filters by seepage. The filters would be processed as described in Section 4.4.3 to meet the required gradation.

Drainage tunnels in both the left and right abutments would intercept seepage through the abutment rock.

The upper part of the upstream face of the dam would be protected from wave erosion by riprap on a bedding of finer rock.

The earthfill dam would be approximately 1,050 m in length. The design elevation of the dam crest (i.e., the top of the dam) would be 469.4 m, approximately 60 m above the present river level, providing a freeboard of 7.6 m above the maximum normal reservoir level (elevation 461.8 m). The selected freeboard is large enough to provide protection from the following environmental factors:

- With the maximum normal reservoir level:
  - Set-up and waves generated by the wind with an annual exceedance frequency of 1 in 1,000 years coming from the direction that results in the highest waves
  - Landslide-generated waves
  - Seismic seiche and settlements due to the earthquake design ground motion
  - Freezing of the impervious core
  - Malfunction of spillway gates

- With the reservoir at the maximum flood level (elevation 466.3 m) during passage of the inflow design flood:
  - Seiche and waves generated by the wind with an annual exceedance frequency of 1 in 100 years coming from the direction that results in the highest waves

Please refer to Volume 5 Section 37 Requirements for the Federal Environmental Assessment for a discussion of the effects of the environment on the Project.

The dam would have a crest width of approximately 10 m and would be constructed higher than the design elevation to allow for settlement of the earthfill.

As described in Section 4.4.3, the foundation of the earthfill dam would be isolated from the river by cofferdams so that the construction would take place in the dry. As shown in Figure 4.14, the upstream and downstream cofferdams would be incorporated into the earthfill dam. The space between the upstream cofferdam and the upstream shell of the dam would be filled with surplus materials from the excavations required to construct the Project structures.

### 4.3.1.1.2 Materials Used to Construct the Earthfill Dam

Preliminary gradations of various fill materials for the dam are shown on Figure 4.15. These gradations may be refined during detailed design.

Extensive investigations have been undertaken to identify suitable sources of materials for construction of the earthfill dam (see Section 4.3.5.4). These investigations included
laboratory testing to confirm the properties of the proposed source of earthfill material described below.

Impervious core (Zone 1 Figure 4.14) would be:

- Glacial till sourced from the 85th Avenue Industrial Lands (see Section 4.3.5.2) with maximum particle size up to 150 mm and containing a minimum of 20% silt and clay, i.e., 20% finer than 0.075 mm
- Free of any organics
- Placed within 2% of its optimum moisture content as determined by standard Proctor compaction tests
- Placed in a manner to prevent segregation in layers a maximum of 300 mm thick and compacted by a vibratory or pneumatic roller to a minimum dry density equal to 98% of standard Proctor maximum dry density
- Placed only when temperatures are above freezing
- Protected from freezing during winter, and any frozen material would be removed prior to placing new material the following season
- Would have permeability equal to or less than $1 \times 10^{-6}$ cm/s after compaction
- Internally stable

As conventional for large earthfill dams, the final placement and compaction requirements – including layer thickness, compactor type, and number of roller passes required to achieve the specified density – would be confirmed by a test fill completed prior to placement in the dam.

In the vicinity of the left abutment and at the contact with the RCC buttress, impervious core material with a higher plasticity would be selected. It would be placed at or above optimum moisture content, and the layer thickness reduced to 150 mm to provide the best contact.

Based on the following testing, the 85th Avenue Industrial Lands was confirmed to be the best source of impervious material for use in the core of the earthfill dam:

- Soil classification tests (sieve, hydrometer, specific gravity, moisture content, and Atterberg limits)
- Double hydrometer
- Standard Proctor compaction
- Consolidation
- Triaxial shear strength
- Permeability
- Assessment of internal instability in a large permeameter
- Sand castle
- Hole erosion test
• Mineralogical testing X-ray diffraction, X-ray fluorescence, and scanning electron microscope

Fine filter (Zone 2A Figure 4.14) would be:

• Granular free-draining material sourced from the dam site area with a maximum size of 10 mm and containing a maximum of 5% silt and clay
• Well graded and within its specified gradation limits (D15 of fine filter less than 0.7 mm)
• Free of any organics
• Placed in a manner to prevent segregation in layers a maximum of 500 mm thick and compacted by a vibratory roller to a minimum of 70% relative density

The fine filter material particles would have to be sound and durable, and conventional concrete aggregate testing for fine aggregates have been completed on the material. The following tests were performed on samples of granular material from the dam site area to confirm that suitable fine filter could be produced from the materials available at site:

• Specific gravity and water absorption
• Magnesium sulphate soundness test
• Mineralogical testing
• Organic impurities
• Petrographic number

Coarse filter (Zone 2B Figure 4.14) would be:

• Free-draining material sourced from the dam site area with maximum size of 50 mm and containing a maximum of 2% fines
• Well graded within its specified gradation limits (D15 of coarse filter to be equal to or less than 5 times D85 of fine filter)
• Free of any organics
• Placed in a manner to prevent segregation in layers a maximum of 500 mm thick and compacted by a vibratory roller to a minimum of 70% relative density

The coarse filter material particles would have to be sound and durable, and conventional concrete aggregate testing for aggregates have been completed on the material. The following tests were performed on samples of granular material from the dam site to confirm that suitable coarse filter could be produced from the materials available at site:

• Specific gravity and water absorption
• Magnesium sulphate soundness test
• Los Angeles abrasion test
• Micro-deval test
• Mineralogical testing
Site C Clean Energy Project Environmental Impact Statement  
Volume 1: Introduction, Project Planning, and Description  
Section 4: Project Description

• Organic impurities
• Petrographic number

Shell material (Zone 3 Figure 4.14) would be:
• Granular free-draining material sourced from the dam site area with maximum size 200 mm and containing less than 5% silt and clay fines  
• Well graded within its specified gradation limits ($D_{15}$ of shell material to be equal to or less than 5 times $D_{85}$ of coarse filter)  
• Free of any organics  
• Placed in a manner to prevent segregation in layers a maximum of 600 mm thick and compacted by a vibratory roller to a minimum of 80% relative density

Shell material would be the granular material sourced from the required excavations or from the right bank terrace in the dam site area. The following tests were performed on samples of granular material from the dam site to confirm that it would be suitable for shell material:
• Gradations  
• The same tests as listed for coarse filters

Riprap bedding (Zone 5D Figure 4.14) would be:
• Hard, sound and durable fine rock sourced from the West Pine Quarry (see Section 4.3.5.2) with a maximum size of 250 mm and minimum size of 40 mm  
• Well graded between its maximum and minimum size ($D_{15}$ of riprap bedding material equal to or less than five times $D_{85}$ of shell material)  
• Placed in a manner to prevent segregation in layers a maximum of 600 mm thick and compacted by a vibratory roller to a minimum of 80% relative density

The material quality would be the same as the riprap; the tests undertaken to demonstrate the suitability of the material in the West Pine Quarry for riprap listed below also apply to riprap bedding.

The riprap (Zone 6D Figure 4.14) would be:
• Hard, sound, and durable fine rock sourced from the West Pine Quarry (see Section 4.3.5.2) with a maximum size of 1,100 mm and minimum size of 300 mm  
• Well graded between its maximum and minimum size ($D_{15}$ of riprap to be equal to or less than five times $D_{85}$ of riprap bedding material)  
• Carefully dumped and dressed in place with a backhoe

The following tests were performed on samples of rock from the West Pine Quarry to confirm that suitable riprap and riprap bedding could be obtained from the quarry:
• Petrographic analysis (thin section and aggregate type)  
• Specific gravity and water absorption  
• Los Angeles abrasion
4.3.1.2 Approach Channel

The approach channel would convey water from the reservoir to the generating station and spillways. The depth of water in the approach channel would vary from 24 m to 26 m below the maximum normal reservoir level. The approach channel would be approximately 200 m wide and 900 m (measured along the centreline) from the inlet to the end of the spillways. The approach channel would have an impervious lining to reduce seepage into the underlying bedrock. The majority of the lining would be impervious fill covered by bedding and riprap. In high velocity areas, such as adjacent to the power intakes and spillway headworks, the lining would be RCC or reinforced concrete. Discontinuities exposed in excavated rock surfaces would be sealed before placing the impervious fill lining. The approach channel would be divided into two sections by an 8 m high berm running down the middle of the channel. This berm would enable either section of the approach channel to be dewatered for inspection, maintenance, and repair of the approach channel lining with the reservoir drawn down to an elevation of 440 m.

During final design, the use of manufactured geomembranes, such as low density polyethylene for the approach channel lining instead of impervious fill, would be investigated. If manufactured geomembranes are found to be suitable, the amount of glacial till required from the 85th Avenue Industrial Lands would be reduced from that shown in Section 4.3.5.

4.3.1.3 RCC Buttress

As shown in Figure 4.16, the RCC buttress would extend from upstream of the core of the earthfill dam to the downstream end of the spillways. The buttress is divided into the following four major sections:

- Core buttress, which forms the south abutment of the earthfill dam at the core
- Dam buttress, which forms the south abutment of the downstream shell of the earthfill dam
- Powerhouse buttress, which supports the generating station
- Spillway buttress, which supports the spillways

Permanently exposed surfaces of the buttress would be faced with conventional concrete designed for exposure to the climatic conditions at site. As shown in Figure 4.16, a drainage gallery would run through the dam, power, and spillway buttresses, and would be connected to a deep drainage tunnel by a curtain of drilled drain holes. A grout curtain would extend along the south face of the buttress to seal discontinuities in the rock and reduce the seepage into the drainage system.
The buttress would transfer the water load in the approach channel and the loads from swelling of the bedrock in the valley wall down to the bedrock in the riverbed level by compression in the inclined buttress.

A cross-section of the core buttress is shown in Figure 4.17. The core buttress would be about 133 m long, 4 m greater than the maximum width of the impervious core of the earthfill dam plus the width of the fine and coarse filters. The height of the buttress would be about 65 m. The contact with the earthfill dam would be angled in the downstream direction so that any downstream movement of the earthfill dam would compress the contact. The contact would be faced with conventional concrete and finished to provide a flat surface for sealing the impervious core of the earthfill dam. A grout curtain beneath the core buttress would connect the earthfill dam grout curtain to the grout curtain along the south face of the buttress.

A cross-section of the 230 m long dam buttress is shown in Figure 4.18. The dam buttress would have a maximum height of 69 m. The height of the dam fill on the downstream side would vary with the slope of the downstream face of the earthfill dam. There would be no special treatment of the RCC face in contact with the gravel fill of the downstream shell of the earthfill dam.

A cross-section of the 170 m long powerhouse buttress is shown in Figure 4.19. The powerhouse buttress provides the foundation for the generating station. The powerhouse buttress would have a maximum height of 56 m to the underside of the power intakes.

A cross-section of the 200 m long spillway buttress is shown in Figure 4.20. The spillway buttress would provide the foundation for the spillways. The spillway buttress would have a maximum height of 60 m to the underside of the spillway headworks.

The vertical face of the core and dam buttress, the power intakes, and the spillway headworks, and associated training walls would form the north side of the approach channel.

4.3.1.4 Generating Station

The generating station would consist of six power intakes, six penstocks, and a six-unit powerhouse (Figure 4.19 and Figure 4.21). The intakes and penstocks would convey water from the approach channel to the turbines located in the powerhouse.

The power intakes would be constructed from reinforced concrete. As shown in Figure 4.19, the intakes would have a bell mouth intake to gradually accelerate the flow from the approach channel to the penstock. There would be a transition from the rectangular shape of the intake water passage to the circular shape of the penstock. Each intake would have a trashrack on the upstream face to prevent large debris from passing through the turbines. Each intake would be equipped with a vertical service gate and hoist capable of closing against full turbine flow in the event of an emergency. The intake gates would be used to seal the intake so that the penstock and turbine could be emptied for routine inspection and maintenance. Slots would be provided in the intakes so that a bulkhead gate could be installed to enable the intake to be emptied, so that gate guides could be inspected and maintained in the dry. The bulkhead gate would be installed using the gantry crane with the intake gate closed so that there would be no flow through the intake.
The penstocks would convey water from the intakes to the turbines. The penstocks would be fabricated from steel plate and would have an internal diameter of about 10.2 m. The lower bend shown in Figure 4.19 would reduce to the inlet diameter of the turbine, which would be about 8.6 m. A flexible coupling would connect each penstock to the turbine inlets.

The powerhouse would contain six generating units with a combined installed capacity of up to 1,100 MW. As shown in Figure 4.12, the powerhouse would be located immediately upstream of the spillways. As shown in Figure 4.19, the generating station would consist of a reinforced concrete substructure and a structural steel superstructure clad with painted insulated metal siding.

Vertical axis Francis turbines would be used. The output of the turbines would be controlled by high pressure hydraulic governors. Slots would be provided at the ends of the draft tubes so that stoplogs could be installed to enable the draft tube to be emptied so that the turbine could be inspected and maintained in the dry. The stoplogs would be installed using the gantry crane on the draft tube deck when the turbine shuts down so that there would be no flow through the turbine.

Two sumps would be located at the bottom of the superstructure. These sumps would contain the pumps required for emptying the turbines for inspection and for discharging building drainage, which would be pumped through an oil/water separator before discharging into the river.

The generators would be air cooled. Each generator would be connected to a three-phase transformer located on the draft tube deck. The transformers would step up the generator voltage to the 500 kV transmission voltage. Containment systems would be provided under each transformer with a capacity greater than the volume of oil contained in each transformer. Drainage water from the containment systems would pass through an oil/water separator before discharge to the river.

Each pair of transformers would be connected to a 500 kV transmission line via switchgear located between the transformers. The switchgear would enable either or both of the transformers to be connected to the transmission line. The switchgear would be insulated with sulphur hexafluoride (SF$_6$) gas.

Three 500 kV transmission lines would connect the three pairs of units to the substation south of the approach channel.

The powerhouse would contain all of the ancillary mechanical and electrical equipment and systems required to support operation and maintenance of the generating equipment.

All discharges from the generating station would be conveyed to the river downstream of the dam by the tailrace (see Figure 4.12), which would be protected from erosion by riprap.

### 4.3.1.5 Spillways

As shown on Figure 4.12 and Figure 4.21, there would be a gated service spillway and a free overflow auxiliary spillway.

The gated spillway would be separated into two separate compartments by a central concrete dividing wall, which would allow one compartment to be isolated and dewatered.
for inspection, maintenance, and, if necessary, repairs while the other compartment remained in service.

The reinforced concrete headworks structure would be equipped with seven radial gates to control the discharges (water releases) from the reservoir. Spillway discharges would be conveyed by a concrete chute into a two-stage stilling basin to dissipate the energy and minimize the erosion of the riverbed during large discharges. The spillway controls would be designed so that spillway gates would open in the event of an outage of the powerplant to provide downstream flows.

As shown in Figure 4.20, underslides would be provided in several of the spillway bays. These sluices would be used during reservoir filling and to draw the reservoir down in the unlikely event that repairs are required in the approach channel.

The free overflow auxiliary spillway would provide additional spill capacity in the unlikely event that some of the spillway gates become inoperable during an emergency. The auxiliary spillway would consist of an ungated concrete overflow section and a concrete chute and stilling basin.

The spillways would have the following discharge capacities:

- 10,100 m³/s at the maximum normal reservoir level
- 17,300 m³/s at the maximum flood level

The spillway would be designed to maximize energy dissipation while minimizing the potential for dissolved gas supersaturation.

All discharges from the generating station and spillways would be conveyed to the river downstream of the dam by the discharge channel (see Figure 4.12), which would be protected from erosion by riprap.

### 4.3.2 Reservoir

The Project would create an 83 km long reservoir that would be on average two to three times the width of the current river, which is up to approximately 1 km wide. The reservoir would be a maximum of 55 m deep at the deepest section of the river at the earthfill dam.

Table 4.3 lists key reservoir levels. The normal operating range between the maximum normal reservoir level and the minimum normal reservoir level would be 1.8 m.

#### Table 4.3 Key Reservoir Levels

<table>
<thead>
<tr>
<th>Reservoir Level</th>
<th>Elevation (m)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum flood level</td>
<td>466.3</td>
<td>Peak reservoir level during passage of the inflow design flood</td>
</tr>
<tr>
<td>Maximum normal reservoir level</td>
<td>461.8</td>
<td>Not exceeded during normal operation</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Only exceeded for short periods during large floods (annual probability less than 1 in 1,000)</td>
</tr>
<tr>
<td>Minimum normal reservoir level</td>
<td>460.0</td>
<td>Never below this level during normal operation</td>
</tr>
<tr>
<td>Minimum operating level</td>
<td>455.0</td>
<td>Lowest level at which the generating station could be operated if the reservoir had to be drawn down for any reason</td>
</tr>
<tr>
<td>Drawdown level</td>
<td>442.0</td>
<td>The lowest level that the reservoir can be drawn down to and pass upstream flow of 1,600 m³/s through the spillway underslides</td>
</tr>
</tbody>
</table>
Figure 4.22 shows water surface profiles from Peace Canyon Dam to Site C Dam for the existing river and the reservoir for the maximum discharge from Peace Canyon Dam, with the mean annual flow from the tributaries between Peace Canyon and Site C. It can be seen that the reservoir would back up to the tailrace of the Peace Canyon Dam. Figure 4.22 shows how the depth of water increases relative to the existing river levels downstream from Peace Canyon Dam to Site C. The reservoir bathymetry showing the water depths in the reservoir based on LiDAR mapping of the existing topography is contained in Figure 4.23.

Figure 4.24 shows surface area and volume plotted against elevation. The reservoir would have a maximum surface area of approximately 9,330 ha and a volume of approximately 2,310 million m$^3$ at the maximum normal reservoir level. The reservoir would have a minimum surface area of approximately 9,030 ha and a volume of approximately 2,145 million m$^3$ at the minimum normal reservoir level. The normal operating range would provide an active storage volume of 165 million m$^3$. The average residence time of the water in the Site C reservoir would be 22 days.

In addition to the flooding of the Peace River, the lower reaches of several tributaries would be flooded. Table 4.4 presents the increase in surface area and extent of flooding as a result of the Project at the maximum normal reservoir level and the minimum normal reservoir level.

<table>
<thead>
<tr>
<th>River or Tributary</th>
<th>Extent of Flooding (km)</th>
<th>Surface Area (ha)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>461.8</td>
<td>460.0</td>
</tr>
<tr>
<td>Halfway River</td>
<td>15.3</td>
<td>14.5</td>
</tr>
<tr>
<td>Lynx Creek</td>
<td>1.3</td>
<td>1.1</td>
</tr>
<tr>
<td>Farrell Creek</td>
<td>3.6</td>
<td>3.3</td>
</tr>
<tr>
<td>Cache Creek</td>
<td>9.0</td>
<td>8.7</td>
</tr>
<tr>
<td>Wilder Creek</td>
<td>3.2</td>
<td>3.0</td>
</tr>
<tr>
<td>Tea Creek</td>
<td>1.2</td>
<td>1.1</td>
</tr>
<tr>
<td>Moberly River</td>
<td>11.6</td>
<td>11.2</td>
</tr>
</tbody>
</table>

As described in Volume 2 Appendix B Geology, Terrain Stability, and Soil, Part 2 Preliminary Reservoir Impact Lines, shoreline protection beneath Part of the community of Hudson’s Hope would be constructed prior to filling the reservoir.

4.3.3 Substation and Transmission Line to Peace Canyon

4.3.3.1 General Description

As shown in Figure 4.12, the Site C generating station would be connected by three 500 kV transmission lines to a new substation located to the southeast of the generating station. Two new 500 kV alternating current transmission lines would connect the new Site C substation to the existing Peace Canyon substation, which is the point of interconnection for the Project to the bulk transmission system, a distance of approximately 77 km. These lines would be located within and immediately adjacent to an existing right-of-way as shown on Figure 4.25 and Figure 4.26. This right-of-way is currently occupied by two 138 kV transmission lines, which run from the G.M. Shrum generating station at W.A.C. Bennett Dam to supply power to Fort St. John and Taylor. As shown on Figure 4.26:
West of Jackfish Lake Road, the new 500 kV transmission lines would be constructed within the existing 118 m wide right-of-way. To accommodate these transmission lines, the total existing right-of-way would be cleared, extending the clearing by 72 m. A one-time clearing extent up to 14 m beyond the right-of-way would be required to remove any danger trees.

East of Jackfish Lake Road, to accommodate the Project access road (see Section 4.3.7) and the new 500 kV transmission lines, the right-of-way would be increased by 34 m. In some areas, it may be possible to reduce the additional widening to 17 m. To accommodate these transmission lines and the Project access road, the clearing extent would be increased between 89 m and 106 m, depending on the road alignment. As a result of the widened right-of-way, no one-time danger tree clearing is required east of Jackfish Lake Road.

The Site C substation would include 500 kV to 138 kV step-down transformers to provide service to Fort St. John and Taylor, and allow for the removal of the 138 kV lines. The advantages of connecting Fort St. John and Taylor to the new Site C substation would be:

- Improvements in system reliability, as they would be connected to the transmission system at a much closer point
- Reduction in transmission system energy losses for the supply to Fort St. John and Taylor

The first of the new 500 kV lines would be constructed along the north side of the existing 138 kV lines from Peace Canyon to the Site C substation (see Figure 4.26). After commissioning of the first new 500 kV line and the substation, the 138 kV lines to Fort St. John and Taylor would be connected to the transformers in the Site C substation. The existing 138 kV lines between G.M. Shrum and the Site C substation would then be decommissioned and removed. The second of the new 500 kV lines would then be constructed in the portion of the right-of-way previously occupied by the 138 kV lines. Some portions of the 138 kV lines in the vicinity of G.M. Shrum may remain in-service for local needs.

The substation would have space to allow for additional connections to Fort St. John and Taylor in the future at either 138 kV or 230 kV.

One or two microwave and communications towers approximately 20 m high would be constructed near the Septimus Siding for system communications. A second tower may be required on the north bank to provide the required coverage. The communications equipment installed would be compatible with the new generation system communication equipment that BC Hydro will be installing in the Project area in the future. These communications upgrades would proceed whether or not the Project proceeds.

Access roads would be required for the construction of the transmission lines and maintenance during operation (see Section 4.3.7).

### 4.3.3.2 Transmission Line Alternatives Considered

In addition to the proposed route, BC Hydro considered the following two alternative routes for connecting the Site C substation to the Peace Canyon substation:
4.3.3.2.1 Alternative 1 – North Transmission Corridor

BC Hydro considered locating two 500 kV transmission lines adjacent to the existing 138 kV transmission line. However, because of the geotechnical risk posed by unstable slopes near river crossings, a transmission corridor for the 500 kV lines would be located further north (Figure 4.27). While a corridor on the north side of the Peace River might be technically feasible, it would involve the acquisition of new rights-of-way on approximately 135 parcels of Crown and private land. A potentially feasible route would be 5 km to 10 km longer than the existing corridor on the south side. Total area of this right-of-way would be 1,263 ha.

BC Hydro did not believe there was adequate justification to pursue this alternative further because:

- Of the increased cost of the transmission line
- It would require the acquisition of rights on 135 parcels of land totaling 1,263 ha while BC Hydro already has a right-of-way on the south bank
- Widening of the existing right-of-way would have lesser environmental effects

4.3.3.2.2 Alternative 2 – Submarine Transmission Cable Connection between Site C and Peace Canyon

BC Hydro examined the concept of connecting Site C to the Peace Canyon station through two 500 kV alternating current submarine cables along the reservoir bottom. Each transmission circuit would be made up of three submarine cables, six in total would be required.

The cables would have to be laid on a stable surface and for maintenance requirements, BC Hydro requires a separation between cables of at least 100 m. The separation would be required so that each cable could be raised to the surface for inspection and repair if necessary and then lowered back to the bottom of the reservoir without any risk of contacting other cables. Therefore, a total width of over 600 m would be required to lay the cables.

Voltage compensation would be required because the cables would be 70 km in length. Series compensation stations would be required at both Site C and Peace Canyon.

Issues with this alternative included:

- The cost of submarine cables would be in the order of eight to 10 times greater than overhead lines
- Volume 2 Appendix B Geology, Terrain Stability, and Soil, Part 2 Preliminary Reservoir Impact Lines discusses the stability of the reservoir shoreline. To avoid the risk of burying or damaging the submarine cables, they would have to be routed to avoid areas where slides into the reservoir or materials from the eroding shoreline could reach them. The risk is that it may not be possible to raise a buried cable to the surface for inspection and repair. To avoid the risk associated with the reservoir slopes it would be necessary to lay the cables on flat surfaces such as riverbank
terraces or along the existing river channel, which would increase the length of the cables. There are a number of locations where the width of the valley floor is either insufficient to lay the cables or to avoid high banks, where slope stability and erosion would pose a risk to the reliability of the lines. These locations include: river kilometer 45 to 46, Attachie, and river kilometer 84 to 85.

- The transmission line would have to be completed prior to reservoir filling so that it would be ready to accept power when the generating station is commissioned and enters into service. Delays to the in-service date so that the cables could be laid from the reservoir surface would cost in the order of hundreds of millions of dollars, due to accumulated interest, and would not be an economically feasible option. The cables would be laid on dry land (e.g., on terraces) prior to reservoir filling, except where it would be necessary to lay the cables in the river to avoid the slope issues described above. Submarine cables are typically laid at sea or on large lakes by specialized cable laying vessels. Since the Peace River in British Columbia is not navigable for large vessels, it would not be possible to use such a vessel for Site C. Therefore, the in-river portion of the cables would have to be laid by a barge fabricated from modular units that could be shipped by road or rail.

- Road and rail capacity would limit the spool diameter and the length of cable that could be transported to the site for laying by barge or on land. This would require multiple cable splices, which would decrease the reliability of the cables.

In summary, the alternative of connecting Site C to Peace Canyon substations through submarine cables is uneconomic, with higher risks and lower reliability.

4.3.4 Highway 29 Realignments

4.3.4.1 General Description

Highway 29 connects Hudson’s Hope to Fort St. John and runs along the north side of the Peace River. It is a two-lane rural arterial undivided highway under the jurisdiction of the BC Ministry of Transportation and Infrastructure (BCMOTI).

Segments of the highway would be flooded by the Site C reservoir, resulting in the need to realign approximately 30 km of existing highway at Lynx Creek, Dry Creek, Farrell Creek, Halfway River, and Cache Creek. A section east of Farrell Creek that would not be flooded by the reservoir would need to be relocated further away from the reservoir shoreline due to the effects of long-term erosion and potential instability (see Volume 2 Appendix B Geology, Terrain Stability, and Soil, Part 2 Preliminary Reservoir Impact Lines). The alignments, including bridge cross-sections, are shown on Figure 4.28 through Figure 4.33. The lengths of each segment of the highway relocation, including causeway and bridge lengths, are given in Table 4.5.
Table 4.5 Highway 29 Realignment Segments and Respective Watercourse Crossing Lengths

<table>
<thead>
<tr>
<th>Segment</th>
<th>Total Length of Segment (km)</th>
<th>Causeway Length (m)</th>
<th>Bridge Length (m)</th>
<th>Number of Piers</th>
<th>Bridge Span</th>
<th>Figure Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lynx Creek</td>
<td>8.0</td>
<td>290</td>
<td>160</td>
<td>1</td>
<td>2</td>
<td>Figure 4.28</td>
</tr>
<tr>
<td>Dry Creek</td>
<td>1.5</td>
<td>N/A</td>
<td>11 m pipe-arch culvert</td>
<td>1</td>
<td>N/A</td>
<td>Figure 4.29</td>
</tr>
<tr>
<td>Farrell Creek</td>
<td>2.0</td>
<td>150</td>
<td>170</td>
<td>N/A</td>
<td>2</td>
<td>Figure 4.30</td>
</tr>
<tr>
<td>Farrell Creek East</td>
<td>6.0</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Figure 4.31</td>
</tr>
<tr>
<td>Halfway River</td>
<td>6.0</td>
<td>640</td>
<td>305</td>
<td>3</td>
<td>4</td>
<td>Figure 4.32</td>
</tr>
<tr>
<td>Cache Creek</td>
<td>8.5</td>
<td>240</td>
<td>200</td>
<td>1</td>
<td>2</td>
<td>Figure 4.33</td>
</tr>
</tbody>
</table>

NOTE: N/A – not applicable

Where required, navigable clearance envelopes would be 8 m high by 25 m wide.

Existing local roads within the realigned segments would be connected to the new highway alignment. Private and commercial driveways would be re-established. Driveway locations would be determined in consultation with private property owners and to the approval of BCMOTI.

4.3.4.2 Alternative Highway Alignments Considered

A number of highway alignment alternatives were developed for each of the segments. A multiple account evaluation process was undertaken to evaluate the alternatives for each segment. Characteristics evaluated included the relative safety, environmental effects (including those on fish, wildlife, and habitat), social effects (including those on property, heritage, and agriculture), and costs of each alternative. The process included workshops in which the characteristics of each alternative were ranked. Workshop participants included representatives of BC Hydro, the Site C Integrated Engineering Team, BCMOTI, and highway design consultants.

Each alignment had two options for crossing the watercourse:

- A short bridge plus a causeway
- A long bridge

BCMOTI preferred the short bridge options due to lower long-term maintenance costs, so the long bridge options were dropped.

4.3.4.2.1 Lynx Creek Alternatives

Four alignments for the Lynx Creek section were initially considered (BC Hydro, 2009). During public consultation in 2008, property owners expressed a preference for using the existing Millar Road, so two additional alignments using Millar Road were added.

The alignments considered were:

- Three in an inland corridor, located along the toe of the slope along the west side of the terrace
• One along the reservoir
• Two in a central corridor using a portion of Millar Road

The alignment shown in Figure 4.28 was selected as the preferred alternative. Even though it would have higher cost than the next highest ranked alternative, which was in the inland corridor, this alignment would:
• Utilize a portion of the existing Millar Road alignment and therefore reduce requirements for private property
• Affect fewer fields and a relatively small forested area, resulting in reduced potential adverse effects on the natural habitat
• Require minimal to no in-stream works on the Lynx Creek segment and therefore would have minimal adverse effects on aquatic or riparian habitat
• Have lower potential for collisions between vehicles and wildlife
• Have lower potential agricultural effects

4.3.4.2.2 Halfway River

Three alignments for the Halfway River section were considered (BC Hydro 2009). The overriding design consideration at Halfway River is the potential effect of a landslide-generated wave (see Volume 2 Appendix B Geology, Terrain Stability, and Soil, Part 2 Preliminary Reservoir Impact Lines), which affects the vertical road alignment and the design of the bridge.

The alignments considered were:
• One inland, located along the toe of the slope on the west side of the terrace
• One along the reservoir shoreline
• One using the inland alignment north of the river, crossing the river at an angle, and using the reservoir shoreline alignment south of the river

The alignment shown in Figure 4.32 was selected because it was the lowest overall cost and was considered to have a reasonable balance between the environmental and social factors.

4.3.4.2.3 Cache Creek

Two alignments for the Cache Creek section were considered (BC Hydro 2009). The alignments considered were:
• One along the reservoir shoreline
• One inland located along the toe of the slope on the west side of the terrace

The alignment shown in Figure 4.33 was selected because it has:
• Lower cost
• Less private land requirements
• Less severed actively farmed land
• Less agricultural land required for the right-of-way
• Fewer geotechnical issues

4.3.5 Quarried and Excavated Construction Materials

4.3.5.1 General Description
A variety of quarried and excavated materials would be required for construction of the dam, generating station and spillways, Highway 29 realignments, access roads and the Hudson’s Hope shoreline protection. These materials would be sourced from various locations in the Project vicinity, as shown in Figure 4.11.

In the following descriptions, off-site materials refers to materials that are excavated at and transported from a location away from the construction site (off-site) to the site where the materials would be used to construct a Project component. Except where noted otherwise, off-site materials would be transported from the sources to the construction sites by highway-rated trucks on public roads.

In the following descriptions, on-site materials refers to materials that would be sourced at the construction site, and come from excavations required for construction of the Project component or from a location within the boundaries of the site.

The approximate quantities of material to be used in the Project from each source are shown in Table 4.6 and Table 4.7. The quantities of unsuitable and surplus materials are shown in Table 4.8 and Table 4.9. The volume of unsuitable material and the total volume excavated may vary depending on the yield of the quarries, thickness of topsoil, occurrence of zones of material with gradations or moisture contents outside of the required specifications, and the like. For the purpose of the environmental assessment, reasonable but conservative assumptions (i.e., to give higher quantities) have been made.

4.3.5.2 Off-Site Sources
Development plans for the following off-site quarry and excavated materials sources describing the locations, boundaries and haul routes are provided in the following parts of Volume 1 Appendix C Draft Construction Materials Development Plans:

• Part 1 – Impervious Till Core Material Source Development Plan (85th Avenue Industrial Lands)
• Part 2 – Wuthrich Quarry Development Plan
• Part 3 – West Pine Quarry Development Plan
• Part 4 – Portage Mountain Quarry Development Plan
• Part 5 – Del Rio Pit Development Plan

The dimensions of the quarries and the excavated materials sources will depend on the method of development adopted by the contractors. Refer to the quarry and excavated materials development plans for potential development methods and dimensions.
<table>
<thead>
<tr>
<th>Material Description</th>
<th>West Pine Quarry</th>
<th>Wuthrich Quarry</th>
<th>85th Avenue Industrial Lands</th>
<th>Dam Site Area</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Impervious</td>
<td>N/A</td>
<td>N/A</td>
<td>2,921</td>
<td>414</td>
<td>3,335</td>
</tr>
<tr>
<td>Filters and drains</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>1,599</td>
<td>1,599</td>
</tr>
<tr>
<td>Shell and granular</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>12,616</td>
<td>12,616</td>
</tr>
<tr>
<td>Dam random fill</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>1,832</td>
<td>1,832</td>
</tr>
<tr>
<td>On-site access road</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>3,733</td>
<td>3,733</td>
</tr>
<tr>
<td>Permanent riprap and bedding</td>
<td>869</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>869</td>
</tr>
<tr>
<td>Temporary riprap and bedding</td>
<td>N/A</td>
<td>350</td>
<td>N/A</td>
<td>N/A</td>
<td>350</td>
</tr>
<tr>
<td>RCC and concrete aggregates</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>4,244</td>
<td>4,244</td>
</tr>
<tr>
<td>Total</td>
<td>869</td>
<td>350</td>
<td>2,921</td>
<td>24,438</td>
<td>28,578</td>
</tr>
</tbody>
</table>

NOTE:
N/A – not applicable
### Table 4.7  Approximate Quantities of Materials for Highway 29, Access Roads, and Hudson’s Hope Shoreline Protection

<table>
<thead>
<tr>
<th>Material Description</th>
<th>Portage Mountain Quarry</th>
<th>Inundated Areas Along Reservoir</th>
<th>Road Alignment Excavation</th>
<th>Dam Site Area</th>
<th>Del Rio Pit</th>
<th>Commercial Pits</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>North bank – Highway 29 realignment, access roads and reservoir shoreline protection during filling</td>
<td>Riprap and bedding</td>
<td>447</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>447</td>
</tr>
<tr>
<td>Granular aggregates (processed)</td>
<td>N/A</td>
<td>484</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>484</td>
<td></td>
</tr>
<tr>
<td>Fill and borrow</td>
<td>N/A</td>
<td>9,381</td>
<td>830</td>
<td>N/A</td>
<td>N/A</td>
<td>7</td>
<td>10,218</td>
</tr>
<tr>
<td>Concrete aggregates</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>South bank – access roads</td>
<td>Riprap and bedding</td>
<td>2</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>2</td>
</tr>
<tr>
<td>Granular aggregates (processed)</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>50</td>
<td>464</td>
<td>514</td>
</tr>
<tr>
<td>Fill and borrow</td>
<td>N/A</td>
<td>N/A</td>
<td>301</td>
<td>118</td>
<td>200</td>
<td>77</td>
<td>697</td>
</tr>
<tr>
<td>Concrete aggregates</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>16</td>
<td>16</td>
</tr>
<tr>
<td>Hudson’s Hope shoreline protection</td>
<td>Riprap and bedding</td>
<td>172</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>172</td>
</tr>
<tr>
<td>Granular aggregates (processed)</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Fill and borrow</td>
<td>N/A</td>
<td>N/A</td>
<td>306</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>306</td>
</tr>
<tr>
<td>Total</td>
<td>621</td>
<td>9,381</td>
<td>1,437</td>
<td>118</td>
<td>250</td>
<td>1,060</td>
<td>12,868</td>
</tr>
</tbody>
</table>

**NOTE:**
N/A – not applicable
## Table 4.8 Approximate Quantities of Unsuitable and Surplus Material for Dam, Generating Station, and Spillways

<table>
<thead>
<tr>
<th>Material Description</th>
<th>Volume Placed (1,000 Placed m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>West Pine Quarry</td>
</tr>
<tr>
<td>Surplus⁹</td>
<td>1,150</td>
</tr>
<tr>
<td>Unsuitable⁵</td>
<td>N/A</td>
</tr>
<tr>
<td>Stripping and overburden</td>
<td>242</td>
</tr>
<tr>
<td>Total</td>
<td>1,392</td>
</tr>
</tbody>
</table>

**NOTES:**

⁹ Surplus materials at West Pine and Wuthrich would be stockpiled for usage by BCMOTI or by others; unsuitable material at the 85th Avenue Industrial Lands would be used for final landscaping.

⁵ Unsuitable materials for construction would be relocated as described in Section 4.3.2.3.

N/A – not applicable
## Table 4.9 Approximate Quantities of Unsuitable and Surplus Materials for Highway 29, Access Roads, and Hudson’s Hope Shoreline Protection

<table>
<thead>
<tr>
<th>Material Description</th>
<th>Volume Placed (1,000 Placed m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Portage Mountain Quarry</td>
</tr>
<tr>
<td>Surplus*</td>
<td>463</td>
</tr>
<tr>
<td>Unsuitable</td>
<td>N/A</td>
</tr>
<tr>
<td>Stripping and overburden</td>
<td>33</td>
</tr>
<tr>
<td>Total</td>
<td>498</td>
</tr>
</tbody>
</table>

**NOTES:**
- * Surplus material at Portage Mountain and other gravel pits would be stockpiled for usage by BCMOTI or by others
- N/A – not applicable
4.3.5.2.1 85th Avenue Industrial Lands

The 85th Avenue Industrial Lands is a 96 ha parcel of land located in the Peace River Regional District, adjacent to the City of Fort St. John. BC Hydro owns all parcels of land within the site. All impervious material (i.e., glacial till) required for the construction of the earthfill dam core and the approach channel lining would be excavated from the 85th Avenue Industrial Lands. The impervious core in the closure section of the Stage 2 upstream cofferdam (see Section 4.4.3.3) may also be sourced from the 85th Avenue Industrial Lands depending on the suitability of material available on-site.

A conveyor would transport material from 85th Avenue Industrial Lands to the dam site area. The conveyor would off-load materials into a large hopper or to a stockpile close to the hopper. Trucks would then be loaded directly from the hopper or by front-end loader from the stockpile and transport the material to the placing location within the dam site.

4.3.5.2.2 Wuthrich Quarry

Temporary riprap and bedding material would be required for construction of parts of cofferdams, for lining parts of the inlet and outlet channels of the diversion tunnels, and for the erosion protection of the access road along the north bank of the river (see Section 4.3.7). The source of this temporary riprap would be the Wuthrich Quarry, which is an existing BCMOTI quarry located approximately 7 km northwest of Fort St. John. Further development by BC Hydro would expand the area that has been excavated by BCMOTI, but would be within the current boundaries of the quarry.

Riprap and bedding material would be transported from Wuthrich Quarry to the dam site by highway trucks on existing public roads.

4.3.5.2.3 West Pine Quarry

Permanent riprap and bedding material would be required for the upstream face of the dam, approach channel lining, containment dikes, cofferdams, some parts of the diversion tunnel inlet and outlet channels, the tailrace, and the discharge channel. The source of this permanent riprap and bedding material is the West Pine Quarry, located on provincial Crown land approximately 75 km southwest of Chetwynd along Highway 97 (approximately 160 km from the Project site).

There are currently two transportation options under consideration for the permanent riprap and bedding material:

1. Use the existing railway siding at the quarry and haul the material to the site by rail; one train per day would be required. Riprap and bedding would be unloaded at the Septimus Siding in the dam site area and moved to a stockpile. An extension of the siding may be required within the quarry. Due to breakage during extra handling. More rock would have to be quarried with this option.

2. Haul the material directly to the dam site area using highway-rated haul trucks, using both existing public roads and the Project access road (see Section 4.3.7) The transportation option would be selected by the contractor(s) using the riprap and bedding. For the purposes of environmental assessment, the trucking option has been assumed, as while it has less quarrying it has the greater footprint.
4.3.5.2.4 Portage Mountain

Permanent riprap and bedding material for the Hudson’s Hope shoreline protection, for the areas along the reservoir requiring protection during reservoir filling, and for Highway 29 construction would be sourced from Portage Mountain, 16 km southwest of Hudson’s Hope. Portage Mountain is currently undeveloped.

Excavated material would be transported from the quarry to the construction site using highway haul trucks via the access roads described in the development plan and existing public roads.

4.3.5.2.5 Del Rio Pit

Some of the gravel required for the construction of the Project access road and upgrades to the Jackfish Lake Road and other roads on the south bank would come from the Del Rio Pit, an existing gravel source operated by the BCMOTI. The pit is located 50 km north of Chetwynd, B.C., along Jackfish Lake Road, west onto Douglas Road and then onto Del Rio Pit Road.

The License of Occupation on Crown lands for the gravel reserve spans approximately 142 ha and is traversed by the 138 kV transmission line right-of-way.

4.3.5.2.6 Inundated Areas

Potential aggregate sources along the Peace River and tributary river valleys were identified. At each of the Highway 29 segments requiring realignment or upgrading, and for the Hudson’s Hope shoreline protection, the closest sources within the area that would be flooded by the proposed reservoir have been identified as off-site sources for the required construction materials.

Where the sources would be at shallow depth after reservoir impoundment, opportunities for enhancement of fish habitat by contouring and habitat complexing would be explored.

4.3.5.2.7 Commercial Pits

Materials sourced from local commercial pits for construction of Highway 29 would include aggregates for the asphalt pavement and concrete.

Some fill for the Hudson’s Hope shoreline protection could be sourced from local commercial pits.

Materials from commercial pits for the Project would be extracted under the terms of the development and other permits for those pits held by the pit owners.

4.3.5.2.8 Area E

Area E has been identified as a contingency pit for gravel to be used for road construction on the south bank or for construction of the earthfill dam. The identified area could provide up to one million m³ of gravel. Area E is adjacent to the Teko Pit, located just west of the confluence of the Peace and Pine rivers. This pit is operated by BCMOTI (east of the rail line) and by CN (west of the rail line).

The access road from this area is very steep and, if required, gravel could be hauled by rail from the siding in the Teko Pit to the Septimus Siding.
4.3.5.3  On-Site Sources

4.3.5.3.1  Highway 29 and Hudson’s Hope Shoreline Protection

Materials from excavations required for highway realignment that are suitable as fill would be used for the highway embankments.

As described in Volume 2 Appendix B Geology, Terrain Stability, and Soil, Part 2 Preliminary Reservoir Impact Lines, the Hudson’s Hope shoreline protection would be a combination of a berm and slope flattening. Suitable material from the slope flattening excavation would be used for construction of the berm.

4.3.5.3.2  Dam, Generating Station, and Spillways

Impervious material for construction of cofferdams and lining of disposal areas would be sourced from required excavations and from a source on the north bank outside the limits of the north bank stabilization excavation.

About 40% of the fine filter for the earthfill dam would come from a source on the north bank of the river, and the remainder from the south bank terrace downstream of the dam.

All of the gravel excavated for the construction of the dam, generating station, and spillways would be used for construction.

Aggregates for concrete and RCC and gravel for the shell of the dam would be sourced from the south bank terrace downstream of the dam.

4.3.5.4  Alternative Off-Site Material Sources Considered

The following subsections describe alternative off-site sources of materials that were considered and provide the rationale as to why these sources are not proposed for use in construction of the Project.

4.3.5.4.1  Dam, Generating Station, and Spillways

Impervious Material

Reconnaissance studies concluded that suitable impervious material was likely to be found on the north side of the Peace River close to the dam site area, and was unlikely to be found on the south side.

Geotechnical investigations were carried out on the north side of the river in 2009 and 2010 to identify potential sources of impervious core material. The 2009 investigation focused on understanding the surficial geology and stratification of the area, and identified the most promising source areas for further investigations. The 2009 investigations consisted of:

- 104 auger holes (up to 35 m depth, 125 mm diameter)
- 7 test pits (up to 5.2 m depth)
- Laboratory testing on representative samples
Additional investigations were carried out in 2010 to further define the potential sources. The 2010 investigations consisted of:

- 15 sonic drill holes (up to 29 m depth and 120 mm diameter)
- 8 test pits (up to 8.3 m depth)
- 6 piezometers installed for groundwater level monitoring
- Laboratory testing on representative samples

Of the potential sources investigated on the north bank, the 85th Avenue Industrial Lands were selected as the source of the impervious fill because it:

- Is close to the dam site area
- Has best gradation and plasticity
- Would require minimal moisture conditioning, as it has an average natural moisture content that is 1.3% dry of average optimum moisture content
- Can be compacted to a high density with an average dry density of 2,094 kg/m$^3$
- Standard Proctor maximum dry density
- Has the highest shear strength, varying from 32 to 35 degrees
- Is a more consistent product and in greater thickness, meaning that little material would be wasted
- Has less topsoil cover

### 4.3.5.4.2 Temporary Riprap

Tea Creek, located 6 km upstream of the dam on the north bank, was originally considered as the source for temporary riprap for the dam site. The haul distance to the dam is approximately 12 km by existing roads. The deposit is made up of sandstone outcrops of the Dunvegan formation on a bedrock ledge above Tea Creek. The rock, which includes thinly bedded planes of fine-grained sandstone overlain with overburden materials, is approximately 20 m thick.

The area was preliminarily assessed for environmental effects and a resident bat population was discovered residing along the outcrop. Other potential effects included the existence of rare species of plants, haul routes on agricultural lands, and the effect on farm operations and residences within 0.9 km to the east and 2.5 km upstream on Tea Creek. Because of these considerations, Wuthrich Quarry was selected as the source of temporary riprap.

### 4.3.5.4.3 Permanent Riprap

The Portage Mountain Quarry was considered as an alternate source of permanent riprap. Haul routes from Portage Mountain to the dam site area would be through Hudson’s Hope:

- East along Highway 29 to the Alaska Highway, through Fort St. John and via the Old Fort Road
• South on Highway 29 through Moberly to Jackfish Lake Road and via the Project access road; due to the restricted capacity of Hudson’s Hope Bridge, the load size would be limited, potentially increasing the number of trucks.

Due to the potential effect on traffic, this option was dropped, even though it would be $10 million cheaper than using material from the West Pine Quarry. Of particular concern were the long hills on Highway 29 where trucks hauling riprap would cause considerable delays.

4.3.5.4.4 Highway 29 and Hudson’s Hope Shoreline Protection

Other potential riprap sources near to Highway 29 and Hudson’s Hope are the Castle formation and the Pringle formation, both on Bullhead Mountain, approximately 6 km north of Portage Mountain. The thinly bedded rock outcrops would result in a lower potential yield than at Portage Mountain, which would increase the cost of production and generate a larger footprint than on Portage Mountain in order to produce the same volume of material. The absorption, specific gravity, and soundness results are below those acceptable for use as riprap. An access road capable of supporting haul units would be required to be constructed for approximately 4 km to the better of the two locations at the Pringle prospect. Therefore, the Bullhead Mountain sources are no longer being considered as potential sources of riprap.

4.3.6 Worker Accommodation

BC Hydro is planning for provision of worker accommodation during the construction phase. The operation phase annual average workforce is predominantly of a regular, long-term nature that would be easily accommodated in local communities.

BC Hydro estimates it will generate approximately 10,000 person-years of direct employment during the construction period. The estimated average annual construction phase workforce on-site would be between 800 and 1,700 workers (with contingency, up to 2,100 workers). Approximately 90% of the workforce would be required for construction activities at the dam site. About 10% of the workforce would be required for off-site construction activities, including Highway 29 realignment, Hudson’s Hope shoreline protection construction, road works, clearing, material transport, and transmission line construction. The workforce for the Project is expected to be composed of existing local residents, new local residents, and workers from outside the region who will maintain their permanent residence outside the region.

Worker accommodation planning is informed by the following objectives and considerations:

• Safety for public and workers
• Workforce attraction, retention, and well-being of workers and their families
• Project construction productivity, cost, and schedule
• Managing social and housing market effects in nearby communities, including opportunities to leave a beneficial housing legacy
• Support for new workers and their families who choose to move to the region
4.3.6.1 In-community Accommodation

BC Hydro is planning to build approximately 40 new permanent housing units for use by the construction workforce in the Fort St. John area. Following the construction period, these houses would become part of the long-term housing stock in the area. The development approach of the new housing would be focused on two key objectives:

- Provide housing suitable for Site C workers and their families during construction
- Provide housing suitable for community affordable housing post-construction

4.3.6.2 Temporary Accommodation – Dam Site

Temporary accommodations during the construction phase are planned for the dam site, in the form of camp facilities, on both the north and south banks of the Peace River in close proximity to the work sites. Temporary accommodations would be removed at the end of the construction phase and sites would be reclaimed.

The camp housing would largely consist of prefabricated units. Where possible, workers would be housed in the north or south camp, based on the location of their work site. This would minimize the transport of workers through active construction areas, which would benefit worker safety, site productivity, and cost.

Camp facilities and utilities would be designed, constructed, operated, decommissioned, and permitted to be compliant with all applicable regulations.

The north bank camp is planned to be built in Year 1 and to operate through to the end of the construction phase, with capacity for approximately 500 persons. The south bank camp is planned to be built later in Year 1 and to operate through to the end of the construction phase as required. The south bank camp would be built with a base capacity for 500 workers, with capacity to be expanded to a potential peak capacity for up to approximately 1,200 persons. Both camps utilities and infrastructure would be planned to accommodate the potential peak occupancy including contingency.

Camp facilities would be generally self-sufficient and typically include:

- Dormitories
- Washing and laundry
- Kitchen and dining
- Recreation and leisure
- General services (e.g., medical, first aid, commissary)
- Fire protection system
- Water supply, treatment, and distribution
- Waste water management
- Solid waste management system (including use of the regional landfill)
- Security system
- Telecommunications
- Grid electricity and other fuel supply
4.3.6.3 Temporary Accommodation – Regional Locations

BC Hydro is considering two general locations away from the dam site area for accommodation to support construction activities. The need for these camps, and the size and operating period for each camp, would be determined during the construction phase based on project scheduling and local alternative accommodation options. The sites could include temporary camp units and RV spaces. Local site selection would be done to find a suitable and permissible site, which could be on BC Hydro-owned land, Crown land, or leased private land. Camp facilities and utilities would be designed, constructed, operated, decommissioned, and permitted to be compliant with all applicable regulations. The general areas where these facilities may be placed are based on the location of the construction work sites outside of the dam site area:

- General vicinity of Hudson’s Hope
- General vicinity of the upper Jackfish Lake Road area (north of Chetwynd)

4.3.6.4 RV Parks

BC Hydro may secure use of dedicated long-stay RV spaces. These would likely be within the Fort St. John–Taylor and Hudson’s Hope areas, to provide workers with another housing option. BC Hydro would seek an operator, such as the private sector or the local governments, to supply RV spaces, and would require the sites to be built and operated in compliance with all applicable regulations.

4.3.7 Road And Rail Access

Temporary and permanent access roads would be required for the construction and operation phases of the Project, respectively. Where feasible, existing access roads would be used and upgraded as required.

The design for new construction and upgrades to public roads would be in accordance with applicable British Columbia and Canadian guidelines, codes, supplements, and technical circulars. Upgrades to the provincial and municipal public roads would meet or exceed existing conditions. Design criteria would be established and approved by the relevant jurisdictional authority. Temporary construction service roads would be designed in accordance with applicable standards for operational equipment and other applicable guidelines.

Refer to Volume 4 Appendix B Project Traffic Analyses Report for information on Project-related traffic along each route.
Sections 4.3.7.1 and 4.3.7.2 describe the access to the dam site area from the north and south banks, respectively, and Section 4.3.7.3 describes the main access roads within the dam site area.

4.3.7.1 North Bank Access to Dam Site Area

Figure 4.34 shows the permanent and temporary access roads to the north side of the dam site area. Access to the north side of the dam site area from Fort St. John and the Alaska Highway (Highway 97) would be via existing municipal and provincial public roads. Upgrades to the existing roads would include:

1. Hard-surfacing of 240 Road and the portion of 269 Road south of the intersection with 240 Road
2. Realigning a portion of Old Fort Road south of 240 Road, as shown on Figure 4.34
3. Improving public safety on 271 Road between the Wuthrich Quarry and Highway 97 by widening the shoulders or adding a paved path
4. Improving public safety on Old Fort Road north of 240 Road by widening the shoulders or adding a paved path
5. Potentially improving the Old Fort Road cross-section between 240 Road and the realigned segment, and from the end of the realigned segment to the Howe Pit entrance

The total length of required upgrades 1 and 2 above would be about 3.8 km, and the total length of upgrades 3, 4, and 5 above would be up to 7.6 km, depending on the results of an in-service road safety audit, consultation with the public and BCMOTI, and final design considerations. All upgrades to the existing roads listed above would be within the existing rights-of-way.

Access to the dam site from Old Fort Road and 269 Road would be controlled 24 hours a day, seven days a week throughout the construction period, so that only authorized traffic would be able to access the dam site area.

A conveyor would be installed to transport impervious material from the 85th Avenue Industrial Lands to the dam site area.

4.3.7.2 South Bank Access to Dam Site Area

4.3.7.2.1 General Description

Existing road networks on the south bank of the Peace River include the partially paved Jackfish Lake Road and an unpaved network of rail, transmission, oil and gas, and forest service roads.

Access to the south side of the dam site area from Chetwynd and the Alaska Highway would be via Highway 29, Jackfish Lake Road, and a new 33 km Project access road alongside the existing transmission line corridor (see Figure 4.35). Access to the dam site area via the Project access road would be controlled 24 hours a day, seven days a week throughout the construction period, so that only authorized traffic would use the road. After construction, the Project access road would remain in service to provide access to the eastern half of the transmission line and an alternate access to
the dam, generating station, and spillways. While this would be a private road, others
would be able to use the Project access road. Discussions would be held with applicable
agencies, stakeholders, and First Nations to determine whether enforceable restrictions
could be put on the road, or whether this would provide an opportunity to decommission
other roads in the vicinity.

As shown on Figure 4.35, the CN Rail line to Fort St. John passes through the dam site
area on the south bank. A new 2 km siding would be constructed on the north side of the
CN Rail line at the existing Septimus Siding.

The current network of unpaved resource roads would be upgraded to provide access to
the dam site area during the first year of construction, including isolated widening and
localized grading, and road base repairs along the 53 km of unpaved resource roads.

Upgrades to about 31 km of the unpaved portion of Jackfish Lake Road would be
undertaken in Year 3, prior to hauling of riprap from the West Pine Quarry to the dam
site area. These upgrades would include road base strengthening and hard surfacing,
which may require the widening of some sections.

In consultation with BCMOTI, BC Hydro would examine the feasibility, issues, and risks,
and costs and schedule for widening the shoulders along the first 30 km of Jackfish Lake
Road to meet current BCMOTI rural collector standards, potentially including two 1.5 m
wide paved shoulders.

4.3.7.2.2 Alternate Access Routes Considered

BC Hydro conducted a multiple account evaluation to determine the preferred south
bank access road. This process considered the relative safety, environmental effects,
social effects, and costs of various options, and was similar to that used for the
Highway 29 alternatives (see Section 4.3.4.2).

The following alternative alignments for the Project access from Jackfish Lake Road to
the dam site area were considered:

- Alignments 1 and 2, predominantly following the existing 138 kV transmission line
  right-of-way, with a slight variation at the western end. Alignment 1 follows the
  transmission line for its whole length, while alignment 2 follows Jackfish Lake Road
  west from the point where the road meets the transmission line.
- Alignments 3 and 5, following existing resource development roads and then the
  transmission line corridor
- Alignment 4, following existing resource development roads and then a new
  undeveloped route to the dam site area

Alignments 1 and 2 are the shortest, most direct routes. Alignments 2 and 3 had the highest safety rating of the five alignments. Alignments 4 and 5 are more costly than the other three options, and have a greater effect on aquatic and riparian habitat.

Alignments 1, 2 and 3 all had very similar ratings for the social and environmental
indicators, with the exception of safety as noted above.

Based on the above considerations, alignment 2 as shown in Figure 4.35 was selected.
4.3.7.3 Access Roads Within Dam Site Area

As shown on Figure 4.34, the main access roads within the dam site area connecting to Fort St. John would be:

- Along the north bank of the river (the river road) to Old Fort Road
- The north bank access road to 269 Road

As shown on Figure 4.35, the main access road within the dam site area connecting to Chetwynd via the Project access road would be the Septimus Siding road.

Within the dam site area, the contractors would construct many access roads for excavation, relocation of surplus excavated materials, construction of the dam, generating station, and spillways, and for interconnecting the temporary facilities described in Section 4.4.3. The location and routing of these roads would depend on the contractors’ methods, sequences, and detailed planning for undertaking the work, and would vary from year to year. Therefore, only the main roads that would be used for construction and remain in place for operations are described herein.

The river road would run along the edge of the river on the north bank, connecting Old Fort Road to the downstream end of the diversion tunnels. This road would provide the primary construction access to the dam site area from the east. Excavation of the north bank slope would cut the existing single access road that currently traverses the slope via a series of switchbacks. Until access roads can be established across the north bank excavation, the river road would be the only low-level access to the diversion works and area within the north bank Stage 1 cofferdams (see Section 4.4.3.2). The road would be constructed from gravel and protected from erosion by riprap from the Wuthrich Quarry. After construction, the road would remain as a secondary access to the dam from the north bank.

The north bank access road would connect 269 Road to the upper level of the north bank in the dam site area. This would provide access to the north bank camp, warehouse, and contractors’ work areas. After completion of the first stage of the north bank excavation, it would connect to temporary roads constructed over the north bank excavation and provide access to the river level. On completion of the Project, this road would become the permanent access across the north bank slope and earthfill dam to the generating station (see Figure 4.12).

4.3.7.4 Transmission Line Corridor Access

There is existing road access along most of the proposed route for the transmission lines as a result of construction and maintenance of the existing 138 kV transmission lines and other developments in the area. Some additional access roads may be required to individual structures and work sites.

4.3.7.5 Reservoir Preparation Access

Access required for reservoir clearing is described in Volume 1 Appendix A Vegetation, Clearing, and Debris Management Plan.
For construction access to the Hudson's Hope shoreline protection:

1. The intersection of Highway 29 and Canyon Drive would be reviewed to confirm estimated traffic delays resulting from construction, and options for mitigating any traffic delays to westbound traffic would be considered, such as:
   a. Construction of a dedicated left-hand turn slot, or
   b. Changing intersection priority by revising pavement markings and signing

2. A paved brake check area would be installed on Canyon Drive before the start of the 10% grade. Use of the brake check would be mandatory for all trucks hauling riprap from Portage Mountain.

3. Opportunities for constructing either arrestor beds or runaway lanes or both on Canyon Drive above Hudson's Hope would be explored and installed if feasible.

### 4.4 Construction

The construction activities described in the following subsections are based on the construction planning and assumptions made for the 2010 project cost estimate. Activities may be somewhat different depending on final design and procurement, including contractors' preferences for equipment, sequencing of activities and construction means and methods. However, the types of activities that might be used have been identified and all construction activities would be carried out in accordance with the Project Construction Environmental Management Program described in Volume 5 Section 35 Summary of Environmental Management Plans, with legal requirements applicable to those activities, and with the terms of permits issued with respect to those activities. The work would be contracted on the basis that contractors must commit to compliance with the Project Construction Environmental Management Program described in Volume 5 Section 35 Summary of Environmental Management Plans, legal requirements and the terms of all permits. All construction contracts would contain terms mandating compliance with the commitments made in the contractor's proposal or tender, as applicable.

Each of the following subsections describing construction activities should be read with the understanding that the work described therein would:

- Be conducted in compliance with a decision statement issued by the Minister of Environment of Canada
- Not commence until after an Environmental Assessment Certificate has been issued
- Not commence until the permits, licences, authorizations, and approvals necessary to conduct that activity have been obtained
- Be performed in accordance with the terms of those permits, licences, authorizations, and approvals, and the Construction Environmental Management Program described in Volume 5 Section 35 Summary of Environmental Management Plans

Sections 4.4.1 and 4.4.2 describe typical construction activities that are common to multiple project components. They are described separately to avoid the duplication of information.
Current protocols for ice management on the Peace River would be unaffected by
construction of the Project.

4.4.1 Site Preparation

4.4.1.1 Clearing

Generally, areas where major earthworks would be carried out, such as in the dam site
area, Highway 29 realignment, new all-season access roads, and construction material
source areas would require the complete removal of vegetation, including stumps, i.e.,
clearing and grubbing. The transmission lines would have a combination of clearing with
and without stump removal. The reservoir has a number of clearing treatments
prescribed, including some retention of vegetation depending on location and other
external factors.

The clearing and debris management plan for the Project is described in Volume 1
Appendix A Vegetation, Clearing and Debris Management Plan and describes the areas
that would be cleared.

4.4.1.2 Grubbing

Grubbing would be carried out in areas where construction activities or quarrying would
subsequently be carried out.

4.4.1.3 Stripping

Stripping of topsoil would generally be done with a tracked bulldozer, and the material
would be either stockpiled on-site for use during reclamation or hauled to another
location for storage.

4.4.1.4 Contaminated Sites

Volume 2 Appendix B Geology, Terrain Stability, and Soil, Part 3 Contaminated Sites
Report describes the assessments of potentially contaminated sites undertaken prior to
filing this Environmental Impact Statement. Potential contaminated sites would be further
assessed prior to the commencement of site preparation activities. Confirmed
contaminated sites would be remediated as Part of site preparation.

4.4.1.5 Infrastructure

All infrastructure components such as public utilities and oil and gas structures and
buildings would be inventoried and the necessary plans prepared for protection or
relocation.

4.4.1.6 Fencing

The perimeter of the dam site area would be fenced and gated as required to prevent
unauthorized access.

4.4.1.7 Helipad

Helipad(s) would be constructed on the south bank for emergency evacuation.
4.4.2 Typical Road and Highway Construction Activities

4.4.2.1 General Activities

General activities would include site preparation as described in Section 4.4.1 and construction of temporary facilities (site offices, utilities, workshops, storage, testing laboratories, vehicle storage and maintenance facilities, hazardous materials storage, fuel storage, and refuelling sites).

4.4.2.2 Gravel Production

Gravel pit development and operation would be required to produce roadway aggregates. Gravel for embankments would be excavated and hauled to the embankment location by trucks. Materials for road sub-base, base, and asphalt would be produced by crushing and screening gravel in the gravel pit to provide the specified gradations.

4.4.2.3 Road and Highway Grading

Grading would include all excavation for roadbeds and drainage works, embankment and causeway construction, and granular aggregate placement to form the roadbed. Unsuitable or surplus excavated material would be disposed of within the proposed right-of-way or designated waste areas.

Winter access roadbeds would be constructed mainly from snow and ice, with a minimal amount of soil to assist the freezing of the road, or to provide a more durable surface.

4.4.2.4 Drainage

Drainage works would include ditching, culvert installation, and placement of riprap and bedding. Temporary works, such as diversion of existing watercourses through cofferdams, may be required to facilitate road and bridge construction.

4.4.2.5 Bridge Construction

Bridge works would include driving piles in dry and wet conditions, placing concrete fill and columns for foundation, placing approach works, erecting girders, and placing the bridge deck. Bridge works would also include placement of bridge end fills, and placement of riprap and bedding. Concrete could be provided from existing commercial sources. Concrete batch plants may also be established and would include water supply, cement, and fly-ash storage and facilities for mixing concrete.

Temporary bridges and water crossings may include winter crossings, abutment bridges, and pile bridges. Winter crossings may be snow or gravel-covered box culverts. Abutment bridges would include modified railway flatbed cars, or steel girders and timber deck placed on timber crib or concrete abutment footings. Pile bridges would include pipe pile piers installed into the riverbed, with a timber deck supported on structural steel girders.

4.4.2.6 Finishing

Finishing of highways and roads would include the construction of a running surface consisting of gravel, sealcoat, or asphalt pavement. Depending on the running
surface and conditions, finishing may also include pavement markings, roadside barrier placement, new and relocated signage, electrical installations, fencing, and landscaping. Asphalt paving would require the establishment of an asphalt plant.

### 4.4.2.7 Traffic Management

In addition to the Project Traffic Management Plan outlined in Volume 5 Section 35 Summary of Environmental Management Plans, traffic management during construction would be in accordance with either the BC Standard Specifications for Highway Construction, the Forest Practice Code – Forest Road Engineering Guidebook, or the latest version of the BCMOTI Traffic Management Guidelines for Work On Roadways. Standard traffic control measures would be used for guiding traffic during construction.

### 4.4.2.8 Reclamation and Decommissioning

All temporary construction areas, including laydown areas and temporary access roads, would be deactivated and reclaimed on completion of construction. Abandoned sections of highways and roads would be reclaimed through pavement removal, scarifying of road base, drainage restoration, and landscaping. Reclaimed asphalt would be disposed of or recycled for use elsewhere in the Project. Existing roads and bridges may require widening, brushing, signage, or other improvements to meet the Project needs.

### 4.4.3 Dam, Generating Station, and Spillways

Construction of the dam, generating station, and spillways and of construction-supporting infrastructure such as worker camps, construction offices, temporary facilities and site access roads would take place within the bounds of the dam site area (Figure 4.36). Within the dam site area, environmental protection zones and restricted activity zones would be established to minimize or avoid potential construction effects in those areas. Construction activities would not be conducted within the environmental protection zones, while restricted construction activities would be conducted within the restricted activity zones. These zones currently include:

- Restricted activity zones along the north shore of the Peace River, with the construction of the north bank access road and the access road to the end of the conveyor from the 85th Avenue Industrial Lands the only permitted activities
- Restricted activity zone at the southeast corner, with the construction of the access road from the Septimus Siding the only permitted activity

Figure 4.37 depicts key construction activities and their respective locations within the dam site area.

The construction of the dam, generating station, and spillways can be categorized into four key stages:

- Preliminary works
- Stage 1 – river channelization (Figure 4.38)
- Stage 2 – river diversion (Figure 4.39)
Reservoir filling and commissioning

The total construction period would be eight years. The current schedule of key construction activities is summarized in Figure 4.40.

4.4.3.1 Preliminary Works

The first construction activities would be site preparation, construction of some temporary access roads, and construction and setup of the temporary facilities required for construction of the permanent works. The dam, generating station, and spillways would be constructed under several contracts. Each contractor would be responsible for setting up their own temporary facilities; therefore, this stage of the project would overlap the subsequent stages.

Excavation of the upper Part of the north bank would commence early in this stage and continue to the end of construction (see Section 4.4.3.3 for a description of activities for the excavation of the north bank).

4.4.3.1.1 Temporary Facilities

After site preparation, levelling ground and placing gravel for the development of temporary facilities, parking areas, staging, and laydown areas would be required. This section describes the temporary facilities that would be set up in the dam site area.

4.4.3.1.2 Utilities

Utilities such as water supply (potable and non-potable), sewer, natural gas, electricity and telecommunications would be installed on-site.

On the north bank of the dam site area, electricity would be provided by one or more connections to the existing BC Hydro 25 kV distribution system, which includes duct banks along the Alaska Highway and overhead lines on wood poles. Where it is not possible to use existing duct banks, new duct banks would be constructed. The overhead lines would be upgraded from single phase to three phase by the addition of a three phase cross arm and lines. Some wood poles would be replaced.

The preferred route would follow a duct bank from the Fort St. John substation and then via existing poles along 81 Avenue, 100 Street, 85 Avenue, Old Fort Road, and 240 Road to the point-of-interconnection.

The alternative route would follow duct banks from the Fort St. John substation to the terminus pole at 81 Avenue and 87 Street, then northwest along the Alaska Highway to a terminus pole at the Alaska Highway and 242 Road and then via existing poles along Old Fort Road and 240 Road to the point-of-interconnection. No duct banks exist from 81 Avenue and 87 Street to the Alaska Highway and 242 Road; therefore, new duct banks would be constructed.

A temporary 138 kV substation would provide temporary construction power on the south bank of the dam site area. The temporary substation would be connected to the existing 138 kV transmission line that crosses the dam site area and would supply 25 kV power to the construction facilities. Construction of the substation would require site preparation and grading, installation of grounding, fencing, concrete footings and electrical equipment, and testing and commissioning. Alternatively, one or more 138 kV/25 kV mobile substations could be used. After energization of the new Site C
substation, the temporary facilities on the south bank would be decommissioned and removed. The equipment would be redeployed to other BC Hydro site(s).

Backup diesel generators would be provided in case of power failures and to provide power prior to the interconnection of the substations to the BC Hydro system.

4.4.3.1.3 Dam Site Temporary Worker Accommodation

Construction of the north bank camp would commence within the first few months after construction commencement. Construction of the south bank camp would commence approximately six to eight months later.

4.4.3.1.4 Waste Treatment and Management Facilities

Waste water treatment facilities would be constructed within the dam site area to treat the waste water from the camps and other temporary buildings. Hazardous waste (including lubricants, antifreeze, etc.) and solid waste would be collected and disposed of.

4.4.3.1.5 Installation and Operation of Temporary Facilities

After site preparation, temporary construction facilities would be erected and installed on-site, including: site offices, workshops, laboratories and testing facilities, storage facilities, fabrication shops, safety, first aid and security facilities, and vehicle maintenance facilities. These facilities would likely comprise prefabricated structures, containers and trailers, but could also include structures requiring erection of structural steel members, cladding and roofing, construction of concrete base slabs, and wood frame construction.

4.4.3.1.6 Explosive Storage

It is anticipated that about one-third of the rock that would be excavated can be broken (ripped) with heavy equipment. However, drilling and blasting would be required for rock that is too hard to rip. Drilling and blasting may be required for excavation of the diversion tunnels (although mechanical excavation by road headers may be an economic option, depending on contractor experience and preference).

Packaged explosives such as dynamite and detonators would be stored on-site in explosives magazines constructed at designated areas, a safe distance from other facilities. The explosives would be transported to the site, unloaded, and stored in the magazines. When required, explosives would be loaded and transported to the excavations requiring drilling and blasting.

Blasting agents such as ammonium nitrate fuel oil would likely be used for bulk excavations such as the approach channel and foundation of the roller compacted concrete buttress. The components (ammonium nitrate and fuel oil) would be stored separately and only mixed together when placed in the blast holes. Licensed facilities would be used for the maintenance and repair of the trucks that deliver and mix the blasting agents.

4.4.3.1.7 Fuel Storage and Refuelling Sites

Fuel required for all construction equipment would be stored in fuel tanks at a designated location called a tank farm. The tank farm would likely comprise steel fuel
storage tanks, erected above ground. The tanks may be constructed on footings or may
be placed directly on the levelled natural ground. Bulk fuel would be delivered to the site
by road or rail, and transferred from the delivery trucks or tankers into the storage tanks
at the tank farm. Spill containment would be provided at the tank farm. Refuelling would
not take place adjacent to a body of water unless the area was contained by a dike or
other structure. All fuel delivery vehicles would be equipped with spill kits.

4.4.3.1.8 Truck Washing Stations
Truck washing stations would be established at designated locations on both banks.
Trucks used to deliver and batch concrete would be washed independently from all other
trucks and would have their own designated washing sites. Water used at all of the truck
washing sites would be collected and treated.

4.4.3.1.9 Aggregate and Filter Processing Plants
Aggregate (sand, gravel, and crushed stone) would be required for production of
concrete and roller compacted concrete, and for the filters in the earthfill dam. Aggregate
and filter materials would be processed from sand and gravel excavated from various
sources within the dam site area to meet the required specification. Aggregate and filter
material processing plants would be located close to the sand and gravel sources.
Material would be excavated from the sources and trucked to the processing plant(s),
where they would be stockpiled. The gravels would then be put through a crusher to
break up the larger stones. Once crushed, the sand and gravel would be screened,
washed, and sorted into stockpiles of specified material size. Trucks would be loaded
and would then transport the processed materials to their required location for use.
Waste water from washing would be collected and treated. Dust generated in the
processing operations or as a result of stockpiling would be controlled.

4.4.3.1.10 Concrete Batch Plants
Concrete batch plants would be established on both banks. The plants would include
storage facilities for cement, fly-ash, and other additives. The batch plants would have
bins for all of the materials required to produce concrete (sand, various sizes of
aggregates, cement, fly-ash, and water) and would mix the materials to produce the
concrete. Waste water from the batch plants would be collected and treated.
Conventional concrete would be deposited into mixer trucks or into buckets loaded onto
flatbed trucks, which would transport the concrete to the required locations on-site,
where the concrete would be placed, vibrated, and ultimately cured.
Roller compacted concrete (RCC) would likely be transported from the batching plant to
the buttress and approach channel via a conveyor system. Trucks may also be used if
required. The RCC would be dumped from the conveyor onto trucks, which in turn would
transport the RCC directly to where it would be placed. After the trucks had dumped the
RCC, it would be spread with bulldozers to the approximate lift (layer) height and
subsequently compacted using vibratory and drum rollers. Waste water from the batch
plants would be collected and treated.

4.4.3.1.11 Relocation of Surplus Excavated Materials
Much of the material excavated for construction of the dam, generating station, and
spillways would be unsuitable for construction or would be surplus to construction
requirements, and would need to be relocated. The areas shown on Figure 4.37, Figure 4.38 and Figure 4.39 have been designated for relocation of unsuitable and surplus excavated material. Table 4.10 summarizes the source of material, relocation area, and approximate embankment volume.

<table>
<thead>
<tr>
<th>Area</th>
<th>Material Source</th>
<th>Embankment Volume (million m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>L3</td>
<td>North bank excavations</td>
<td>10.9</td>
</tr>
<tr>
<td>L5</td>
<td>North bank excavations</td>
<td>7.7</td>
</tr>
<tr>
<td>L6</td>
<td>North bank excavations</td>
<td>1.4</td>
</tr>
<tr>
<td>R5a</td>
<td>South bank excavations</td>
<td>6.3</td>
</tr>
<tr>
<td>R5b</td>
<td>South bank excavations</td>
<td>1.3</td>
</tr>
<tr>
<td>R6</td>
<td>South bank excavations</td>
<td>1.5</td>
</tr>
</tbody>
</table>

Work on developing the areas outside of the riparian zones would commence as Part of the preliminary works. Areas within the riparian zones would be developed as Part of Stage 1. The areas would be used until completion of the Project.

Area L3 would be cleared and grubbed as Part of the site preparation activities. The remaining areas would require clearing and grubbing in riparian zones. Areas L5, L6, and R5 would all require construction of retention berms to retain the relocated material and isolate it from the river.

The retention dikes would be gravel berms constructed from excavated river gravels. The inside face of the gravel berms (i.e., the slope not exposed to the river) and bottom of the retention areas would be lined with impervious material such as glacial till or lacustrine material coming from on-site locations. In addition, a capping layer of impervious material would be overlaid on the relocated materials. This lining and capping material would minimize infiltration through the relocated materials, and mitigate possible acidic drainage and metal leaching from the shale bedrock or other surplus excavated materials (see Volume 2 Appendix B Geology, Terrain Stability, and Soil, Part 4 Acid Rock Drainage and Metal Leaching Management Plan). Riprap would be placed on the outer faces of the retention dikes to prevent erosion by the river.

Surplus excavated material would be transported via truck to these locations, dumped, and spread to the ultimate design elevations and slopes. Areas L5 and R5 and the area between the upstream face of the completed earthfill dam and the upstream cofferdam would ultimately be completely inundated with water when the reservoir is impounded near the end of construction.

In order to haul excavated materials to Area R5a, a temporary construction access bridge would be required across the lowest reach of the Moberly River. The temporary access bridge would have a clear span over the main channel of the Moberly River. This crossing is temporary as it would only be used for transportation of surplus materials to Area R5a and would be removed before filling of the reservoir.

### 4.4.3.2 Stage 1 – River Channelization

Work on Stage 1 would commence after receipt of the applicable federal authorizations. The north and south bank Stage 1 cofferdams shown on Figure 4.38 would confine the river to its main channel.
SITE C CLEAN ENERGY PROJECT
ENVIRONMENTAL IMPACT STATEMENT
VOLUME 1: INTRODUCTION, PROJECT PLANNING, AND DESCRIPTION
SECTION 4: PROJECT DESCRIPTION

4.4.3.2.1 North Bank Stage 1 Cofferdams

The Stage 1 cofferdams on the north bank would include the cofferdams around the diversion tunnel inlet and outlet locations, as well as along the shore of the central island between these two locations, in order to isolate the north side of the river and enable construction activities on the north bank of the river to commence. These cofferdams would be constructed in riparian zones that would require clearing and grubbing.

Gravel from local sources in or near the river would be excavated for cofferdam construction. Gravel extraction would be done, keeping a berm of gravel between the extraction area and the river to provide isolation. The gravel fill would be placed to construct the cofferdams and riprap from off-site locations would be transported via truck to the site and placed on the slopes of the cofferdams for erosion control. In order to prevent seepage under the gravel cofferdams, a vertical cut-off would be installed through the cofferdams to provide an impermeable barrier. The cut-offs would be either a slurry trench wall or a steel secant pile wall.

Slurry trench walls would be a trench about 1 m wide, excavated through the cofferdam and the alluvium in the riverbed down to bedrock. During excavation, the sides of the trench would be supported by thick, dense slurry of bentonite clay and water. The trench would then be in-filled with a mixture of cement, bentonite, aggregate, and water to create an impermeable wall. The slurry trench would be excavated by a backhoe or crane equipped with a clamshell or dragline.

Secant piles are circular steel pipes installed side by side through the earthfill cofferdam and riverbed alluvium down to bedrock, and connected by a series of interlocks welded onto the sides of the piles to form a continuous interlinked wall of piles. The secant piles would be installed by a crane equipped with a pile driving hammer. If necessary, a down-the-hole hammer could be used to break any large rocks encountered.

Once the cut-off walls have been installed, the water on the inside of the cofferdams would be pumped out to dewater or dry out the area where excavation and construction activities would take place.

Alternate methods of cut-off construction could be used, depending on contractor preferences.

Work would commence on the portion of the earthfill dam located within the north bank Stage 1 cofferdams as soon as the area is dewatered (see Section 4.4.3.3 for a description of the activities for construction of the earthfill dam and Figure 4.38, which shows the excavation for the earthfill dam within the cofferdams).

4.4.3.2.2 South Bank Stage 1 Cofferdams

The Stage 1 cofferdam on the south bank would be constructed along the river edge to isolate the south bank construction activities. All clearing, grubbing, gravel extraction, excavation, gravel fill placement, riprap placement, cut-off installation, and dewatering activities are identical to those described for the north bank Stage 1 cofferdams.
Work would commence on the portion of the earthfill dam located within the south bank
Stage 1 cofferdams and the south bank structures as soon as the area has been
dewatered (see Section 4.4.3.3 for a description of the activities for construction of the
earthfill dam and south bank structures and Figure 4.38, which shows the excavation for
the earthfill dam and south bank structures within the cofferdams).

4.4.3.2.3 Temporary Construction Access Bridge

A temporary construction bridge across the Peace River would be installed concurrently
with the Stage 1 cofferdams and remain operational until the downstream Stage 2
cofferdam has been completed (see Section 4.4.3.3), and could be used for access
across the river. The bridge would have two lanes and provide easy access between
both banks for safety and efficiency reasons. The bridge would not be used for hauling
of excavated materials, but would have sufficient capacity to allow unloaded large
equipment to cross.

The temporary construction bridge would comprise pipe pile piers installed into the
riverbed, with a timber deck supported on structural steel girders. The bridge would be
multi-span, with a length of about 330 m, and constructed across the Peace River near
the toe of the earthfill dam between the north and south bank Stage 1 cofferdams. The
north bridge abutment would be constructed as Part of the diversion tunnels outlet
cofferdam. A crane located on the cofferdam would install the piles for the first pier, and
then the support girders and deck for the first span. In this manner, the bridge would be
constructed span by span across the main river channel to the abutment in the south
bank Stage 1 cofferdam. Construction of this temporary bridge would take approximately
14 weeks. After the Stage 2 downstream cofferdam has been completed, the temporary
construction bridge would be redundant as access between the banks would be over the
downstream cofferdam, which would provide a wider access with greater load capacity.
Therefore, the bridge would be dismantled and removed.

4.4.3.2.4 Diversion Works

Construction of the diversion works would be on the critical path; therefore, work would
start as soon as access is available.

The diversion tunnels would be constructed through and under the north bank.
Construction of the diversion tunnel portals, structures, and tunnels would include the
following activities:

- Excavating overburden and rock at each end of the diversion tunnels (behind the
diversion tunnels inlet and outlet cofferdams) to form the portals for the two diversion
tunnels, which would include drilling and blasting, and rock support, including rock
bolts and shotcrete
- Excavating rock underground to form the two diversion tunnels, either by drilling and
blasting or by a road-header, which is a piece of heavy equipment with a mechanical
arm equipped with a rotating cutter bit at the end that excavates the rock
- Installing rock support, which would include steel ribs at each end of the tunnels,
rock bolts and shotcrete
- Relocating excavated material, loaded onto and transported via trucks, to Area L5
(upstream) and Area L6 (downstream)
Erecting formwork, fixing reinforcing steel, and placing and curing concrete for the construction of the diversion inlet and outlet structures.

Erecting formwork and placing and curing concrete to construct the concrete tunnel linings, including cement grouting to fill voids between the concrete and the tunnel roof.

Installing diversion tunnel gates and hydraulic hoists.

Excavating diversion tunnel inlet and outlet channels outside the extents of the diversion cofferdams (i.e., excavation of river alluvium and gravel from the existing riverbed using long-arm excavators; machinery working in water would use biodegradable hydraulic fluid).

Dewatering (partial drying) wet material from the wet excavations.

Excavating diversion tunnel inlet and outlet channels inside the cofferdams.

Installing erosion protection in the diversion tunnel inlet and outlet channels; options include riprap both inside and outside the confines of the cofferdams, or placement of a concrete slab within the confines of the diversion tunnel outlet cofferdam. Riprap installed outside of the cofferdams would be placed underwater in the riparian zone.

4.4.3.3 Stage 2 – River Diversion

After completion of the diversion works, the Peace River would be diverted through the diversion tunnels and the main river channel would be blocked off with upstream and downstream cofferdams (the Stage 2 cofferdams) in order to isolate the area where the earthfill dam would be constructed across the Peace River (see Figure 4.39).

River diversion would consist of the following activities:

Flooding the tunnels by pumping water from the river to provide balanced water levels across the inlet and outlet cofferdams.

Removing sections of the diversion inlet and outlet cofferdams at the upstream and downstream ends of the tunnels with heavy machinery working in water and in the riparian zone.

Placing riprap in water along the bottom of the river channel and along the exposed sides of the cofferdam where inlet and outlet cofferdam sections were removed.

Placing the upstream closure section across the Peace River downstream of the diversion tunnel inlet location by trucking rock from off-site locations, dumping it above water level, and then pushing it into the river with a bulldozer.

Placing the downstream closure section using identical procedures to the upstream closure section.

Dumping sand and gravel from trucks running on the rockfill onto the upstream face of the rockfill closure sections to reduce flow through the rockfill.

Transporting gravel from on-site locations, dumping it above water level, and then pushing it into the river with a bulldozer to form a platform just above water level between the closure sections (Figure 4.39) to form the base of the upstream and downstream Stage 2 cofferdams.
• For the upstream cofferdam only, transporting impervious material from the 85th Avenue Industrial Lands, dumping it above water level, and then pushing it into the river with a bulldozer between the rockfill closure section and the gravel platform to form the base of the upstream cofferdam

• Transporting, placing, and compacting gravel from on-site locations and impervious materials from 85th Avenue Industrial Lands to construct the closure sections of the upstream and downstream Stage 2 cofferdams

• Installing cut-off walls in both the upstream and downstream cofferdams using a slurry trench wall or a steel secant pile wall as described for the Stage 1 cofferdams

• Dewatering the area between the upstream and downstream Stage 2 cofferdams using pumps and pipes to pump water back to the river

• Transporting and placing riprap from off-site locations on the exterior faces of the Stage 2 cofferdams

4.4.3.3.1 Earthfill Dam and North Bank Excavation

Significant features of the Project include construction of the earthfill dam that would impound the reservoir, and excavation of overburden material from the north bank to improve the long-term stability of the slope. The construction activities associated with the earthfill dam and the north bank slope would be carried out in parallel over a number of years and would include:

• Excavating overburden material from the north bank slope with large excavators

• Excavating overburden, ripping, or drilling and blasting to excavate rock for the dam core trench (foundation)

• Relocating surplus excavated material via truck to Areas L3 (on the north bank terrace), L5 (upstream), and L6 (downstream)

• Cleaning the core trench with compressed air

• Applying shotcrete to the rock surfaces within the core trench to protect the surfaces from weathering

• Drilling holes into the core trench rock foundation and injecting grout, which is a cement water mixture, into the grout holes

• Drilling foundation drain holes

• Constructing an underground drainage system consisting of tunnels and drain holes into the north abutment

• Loading, transporting, placing, and compacting impervious glacial till from the 85th Avenue Industrial Lands for the core of the dam

• Loading, transporting, placing, and compacting sand and gravel (from the aggregate processing plants located downstream of the dam on the south bank terrace and on the north bank) for the filters of the dam

• Loading, transporting, placing, and compacting gravel from the south bank terrace gravel pits for the shells of the dam
• Loading, transporting, and placing riprap (from off-site locations) on the upper portion of the upstream face of the earthfill dam
• Removing the cut-off wall installed in the downstream cofferdam so as not to impede the flow of water from the drainage zones within the earthfill dam by excavating out the slurry trench cut-off wall or removing the secant piles and replacing them with granular material
• Placing asphalt paving on the powerhouse access road constructed on the downstream face of the dam to access the powerhouse (on the south bank) from the north bank

4.4.3.3.2 South Bank Structures
The construction activities for the south bank structures (RCC buttress, generating station, spillways, and approach channel) would include:
• Excavating overburden material, ripping, or drilling and blasting, and excavating rock
• Loading, transporting, and dumping the surplus excavated material, largely to relocation Area R5, using trucks, bulldozers, and graders
• Placing shotcrete on the rock foundation
• Drilling grout holes and injecting cement grout into the foundation to seal subsurface cracks and fissures within the foundations
• Excavating shear zones and filling with plastic concrete
• Loading, transporting, and placing impervious material from the 85th Avenue Industrial Lands in the approach channel as a liner
• Loading, transporting, and placing riprap and bedding material from the West Pine Quarry in the approach channel on top of the till lining
• Loading, transporting, and placing sand and gravel drainage layers
• Loading, hauling, placing, and curing the RCC buttress
• Erecting formwork, fixing reinforcing steel, loading, hauling, placing, and curing conventional concrete for the structures
• Erecting structural steel for the powerhouse superstructure using heavy equipment such as cranes
• Excavating river gravel in the wet in a riparian zone (i.e., beyond the limits of the south bank cofferdam) to excavate the tailrace channel
• Placing riprap in the wet
• Removing the cofferdam cut-off wall in the location of the tailrace
• Removing cofferdam gravel at the tailrace outlet
• Fabricating short sections of circular steel penstocks from plate, moving the penstock sections from the fabrication yard by truck, lifting the penstock sections into place with large cranes, and welding the sections together to erect the penstocks
• Transporting and placing gravel around the penstocks
• Placing asphalt paving at the permanent powerhouse parking areas
• Installing spillway gates and hoists
• Erecting structural steel and deck for the spillway access bridge
• Installing intake gates and hoists
• Installing generating equipment in the powerhouse
• Installing transformers and oil separators
• Installing ancillary mechanical and electrical equipment within the powerhouse
• Installing and energizing the transmission lines that connect the powerhouse transformers to the substation on the south bank

4.4.3.4 Reservoir Filling and Commissioning
Reservoir filling would take place near the end of construction and would be required for wet testing and commissioning of the units (see Volume 1 Appendix B Reservoir Filling Plan). The preference would be to fill the reservoir in the fall of the year when flows are normally low (after the flood season and before high flows from upstream generation); however, filling may occur at other times of year, depending on the final construction schedule.

The sequence of activities for reservoir filling and commissioning would include:
• Closing the gate in one of the diversion tunnel inlet structures to close off the tunnel; this would reduce the amount of flow diverted through the tunnels and the reservoir level would begin to rise
• Closing the gate(s) in the second tunnel once the reservoir was high enough to use the spillway underslides to control the discharge
• Using the underslides to control the rate of reservoir filling, including holding the reservoir at specified levels
• Testing and commissioning the spillway gates
• Testing and commissioning the intake gates and generating units
• Constructing an earthfill cofferdam across the diversion tunnel outlet channel (placing gravel in the riparian zone)
• Dewatering the diversion tunnels by pumping water to the river
• Placing and curing concrete plugs in the tunnel at the centreline of the earthfill dam to permanently seal the tunnels

During testing and commissioning of the generating units, a portion of the river flow would be diverted through the spillway.

4.4.3.5 Demobilization and Reclamation Activities
After completion of the permanent parts of the Project, all temporary structures and construction facilities, including temporary access roads and bridges, would be decommissioned and removed from the site. Grading, landscaping, contouring, and revegetating of the site would be the final activity.
4.4.4 Reservoir

4.4.4.1 Clearing and Debris Management

Clearing and debris management in the reservoir, including the access requirements, are described in Volume 1 Appendix A Vegetation, Clearing, and Debris Management Plan.

4.4.4.2 Boat Traffic Management

Volume 3 Section 26 Navigation describes the restrictions that would be in place on water access during dam construction and reservoir filling to ensure the safety of boaters, including the proposed public notifications of the restriction by signage and other means.

4.4.4.3 Hudson’s Hope Shoreline Protection

As described in Volume 2 Appendix B Geology, Terrain Stability, and Soil, Part 2 Preliminary Reservoir Impact Lines, the shoreline protection would be a combination of a granular berm and excavation to flatten the slope. The construction schedule for the Hudson’s Hope shoreline protection is shown in Figure 4.42.

D.A. Thomas Road in Hudson’s Hope, which provides access to the shoreline, would be upgraded to facilitate construction and future access to the proposed shoreline protection.

Approximately 9 ha along the berm would require clearing and grubbing of vegetation.

Materials required for the construction of the berm include:

- Clean gravel fill, cobbles or blast rock bedding material, to be placed in the river below the water level
- Cobbles or blast rock in areas where water emerges on the natural slope to allow free drainage behind the berm
- Granular materials that form the general fill for the bulk of the berm
- Riprap and bedding on the exposed surfaces for erosion protection

Approximately 270,000 m³ would be excavated to flatten the existing slope in the mid-portion of the shoreline protection (see Figure 13-2 in Volume 2 Appendix B Geology, Terrain Stability, and Soil, Part 2 Preliminary Reservoir Impact Lines). A horizontal bench would be left above reservoir level at the toe of the flattened slope. Riprap and bedding would be placed at the reservoir level below this bench to protect the shoreline from erosion by waves. The material in the slope at this location is granular and meets the specifications for granular fill, so it would be used for construction of the adjacent sections of the berm.

The berm would follow the existing shoreline to produce a more natural look and would be constructed by importing borrow materials from a local granular source, either from the inundated area near Lynx Creek or from an adjacent shoreline island downstream from the berm. Both locations would be submerged after reservoir filling.

Access to the berm would be required for hauling the construction materials. The proposed access points are the existing D.A. Thomas Road and from within the limits of...
the slope flattening. Should the island downstream be the source for the imported
granular material, then a foreshore tote road would be required between the end of the
berm and the island. Adjustment to the existing materials along the shore and capping
with some granular materials as a running surface would provide an adequate surface
for trucks hauling materials.

4.4.5 Substation and Transmission Line to Peace Canyon

The construction schedule for the substation and transmission line is shown in
Figure 4.41.

4.4.5.1 Transmission Line

Construction activities would include gaining access throughout the right-of-way, clearing
the right-of-way, constructing access roads for construction, erecting the transmission
towers, and stringing the conductors, as well as decommissioning of the existing 138 kV
transmission lines, construction areas, and access roads.

4.4.5.1.1 Right-of-Way Clearing

Clearing would be required for the transmission line right-of-way, access roads and
laydown areas (see Volume 1 Appendix A Vegetation, Clearing, and Debris
Management Plan).

Clearing would be required beyond the edge of the right-of-way to remove danger trees.
These are trees that either would pose a safety risk during construction or a reliability
risk for the lines after construction. The extent of this tree management area (see
Figure 4.26) would depend on the height of the trees and the slope of the terrain in
relation to the transmission line conductors and transmission line towers. Vegetation
would be allowed to regrow within the tree management area.

Clearing in the transmission corridor would involve felling, yarding, and disposing of
tall-growing vegetation within the clearing boundaries. Various methods, both manual
and mechanical, would be used for these activities. The choice of method would depend
on site conditions and the contractors’ work methods and equipment.

The access roads and associated laydown areas would be sited as close to the
transmission lines as possible.

Due to the proximity of trees to the existing 138 kV transmission lines, the clearing
adjacent to the lines couldn’t be started until the lines are de-energized, for safety
reasons. Therefore, clearing work would occur twice: prior to the construction of each of
the two 500 kV transmission lines.

4.4.5.1.2 Tower Foundations and Anchor Installation

Depending on terrain and soil conditions, a variety of foundation and anchor types would
be used for the project, including steel grillage footings and rock foundations.

Steel grillage footings would be pre-assembled and flown or trucked to each tower site.
A small excavation would be required for the grillage, with some larger excavations and
backfill required depending on soil conditions. Excavations would typically be conducted
by rubber-tire backhoe; blasting may also be necessary in situations where hard rock or
large boulders are encountered within the excavations.
Rock foundations would require drilling in the rock to install and grout anchor bolts. Then a small concrete foundation would be poured on top. In rock, after removing overburden with a light rubber-tired backhoe, light drilling equipment would be used to provide holes for grouted anchor rods for both the foundation and anchors. Approved corrosion protection would also be applied to metal parts of the foundation and anchors.

4.4.5.1.3 Concrete and Grout Production and Placement

The use of concrete along the transmission line corridor would be limited to tower rock footing pours, requiring concrete to be placed inside a wooden form. Concrete would be produced by a local supplier and, depending on the ease of access to specific sites, would either be transported by concrete truck or by helicopter.

Grouting of anchor dowels would be required at rock footing sites. Grout would be trucked in bags to the site and mixed on-site using a small mixer. In areas that would only be accessed by helicopter, the grout would be premixed at a staging location and transported to site via helicopter.

4.4.5.1.4 Assembly and Erection of Transmission Structures

Assembly of the structures would be done by either crane or helicopter, depending on access.

For assembly by crane, additional site preparation work would be carried out at each structure site to provide a level bench to assemble the mast and bridge components of the structures and locate the erection crane. The structure components would be delivered to the site and assembled at the structure location. The assembled tower would then be lifted by a crane to a vertical position over the foundation.

For assembly by helicopter, the structures would be assembled in a common staging area and lifted to the site by helicopter. The structure would be secured to the foundation, guy wires would be attached, and the structure would be plumbed.

4.4.5.1.5 Installation of Counterpoise

Counterpoise may be required for safety and to protect the circuit in the event of lightning strikes. Counterpoise installation would involve burying a single- or double-galvanized wire in a trench, approximately 0.5 m deep and 0.3 to 0.6 m wide, and excavated into mineral soils. Where practical, the counterpoise would be laid within trenches along access road routes for ease of installation. In rocky areas, the counterpoise wire would be attached to exposed rock between pockets of mineral soil.

The need and locations for counterpoise would be determined during detailed design of the transmission line.

4.4.5.1.6 Conductor Stringing

Conductor stringing would involve installing sheaves on structures, stringing pilot lines by helicopter, pulling the conductors, and sagging and clipping the conductors to the insulators.

The first activity would be establishing level puller or tensioner sites along the alignment from which the conductor would be installed. The geometry of the pull section would influence the spacing and location of the puller or tensioner sites. Puller sites would just be large enough to site the pulling machine and pilot line tensioner. The tensioner sites
would be larger to accommodate the tensioner, reels of conductor for the pull, crane for lifting the reels, and pilot line winder.

While establishing the work sites, crews would install insulators, hardware, and sheaves on the structures. This work would require pickup trucks or light-duty crane trucks, and the insulators or sheaves would be raised to the structure by winch. After the insulators had been installed, a helicopter would pull a pilot line from which the larger sock line is pulled through the sheaves, and then the conductor would be pulled through. When pulling the conductor, it would be necessary to have a complete line of sight over the length of the pull section in case of a mechanical problem or if an obstacle is encountered.

Sagging of the conductor would then be undertaken, which would require using a bulldozer to provide tension to pull the conductor into the sag position. Following sagging, each conductor would be marked and fastened to the insulator assemblies and the sheaves would be removed. Other activities would include dead-ending, which pins the conductor ends to dead-end structures, and splicing, joining lengths of conductor with a hydraulic press, and installing spacers to bundled conductors.

Where a ground wire or fibre optic cable would be required, this would be installed at the same time as the conductors.

### 4.4.5.1.7 Upgrades to Peace Canyon Substation

To connect the proposed new transmission lines and substation at Site C to the BC Hydro integrated electrical system, the following upgrades would be required at the Peace Canyon substation:

- Expand the existing 500 kV switchgear building to accommodate two new 500 kV gas-insulated line terminations
- Install two new 500 kV gas-insulated line terminations (designated 5L5 and 5L6) and associated gas insulated switchgear inside the switchgear building
- Construct steel structures for new transmission line terminations

The upgrades will be within the limits of the existing BC Hydro facilities. The site of the switchgear building extension was cleared during the construction of the Peace Canyon Project. The vegetation that has regrown since then would be cleared and grubbed.

### 4.4.5.1.8 Decommissioning of the 138 kV Transmission Lines

The existing 138 kV transmission lines between the Site C substation and G.M. Shrum would be decommissioned after completion of the Site C substation and energization of the first 500 kV line between the Site C and Peace Canyon substations.

Some of the line near G. M. Shrum may be retained to supply potential load customers in the area; otherwise, the line termination equipment at G.M. Shrum would be removed.

The existing 138 kV transmission lines are constructed of treated wood poles and steel-reinforced aluminum conductors. The wood poles are sufficiently old that they could not be reused, so would be sent to a pole recycling facility for disposal or recycling. Conductors and conductor hardware would be recycled at a local scrap metal recycling facility. Glass insulators would be kept as spares, provided they are in good condition, and porcelain insulators would be disposed of at a local landfill.
The equipment needed to remove the poles would include a crane for lifting the poles, log trucks for shipping poles to the pole recycler, dump trucks for removing hardware and conductor to the disposal facility, and a rubber-tired backhoe for excavating pole butts where required.

The poles would be cut off and the pole butts left in the ground where possible. Where the poles are located near an environmentally sensitive area, such as a watercourse or wetland, or where the poles are located where a new tower foundation is required, the butts would be removed, the soil excavated to remove contaminants, and the excavations backfilled with clean material.

4.4.5.1.9 Reclamation

The temporary access roads, laydown, and staging areas used for construction of the transmission lines would be reclaimed.

4.4.5.2 Site C Substation

4.4.5.2.1 Site Preparation and Grading

The substation site would be cleared and grubbed. The substation site would be graded and structural fills installed as required to support the equipment foundations. Grading would require the use of bulldozers, excavators, and dump trucks to excavate any unsuitable foundation material, which would then be replaced with structural fill obtained from the dam site area.

4.4.5.2.2 Ground Grid and Fencing

The ground grid for the substation would consist of copper ground rods installed using a small drill rig and copper conductors installed by excavating shallow 1 m deep trenches in a grid pattern over the entire substation site.

Chain-link fencing would be installed around the perimeter of the substation for safety and security.

4.4.5.2.3 Concrete Placement

Concrete would be required for all equipment and control building foundations, which would be obtained from the Site C batch plant and placed using concrete trucks and pumpers.

4.4.5.2.4 Installation and Testing of Electrical Equipment

Once the equipment foundations had been constructed, the electrical equipment would be installed. This would include the assembly of the substation control building, the assembly of the power transformers and filling them with oil, the installation of steel support structures, and the installation of other high-voltage electrical equipment.

Equipment installation would require the use of cranes and crane trucks to lift and position equipment and equipment supports.

The transformer installation would require the use of a large low-bed trailer to ship the transformer tanks to the site, and the use of either a large crane or a hydraulic jacking
system to move the transformer onto its foundation. Transformer oil would be shipped to the site in tanker trucks. The oil would be treated at site (removal of impurities and water) using a portable transformer oil treatment plant. During oil treatment, the oil would be stored in double-walled steel tanks; then the oil would be pumped into the transformer tanks. The transformers would be located within an oil containment system with a capacity greater than that of the transformers to completely contain a potential spill.

Circuit breakers installed on-site would be insulated with sulphur hexafluoride (SF$_6$) gas, and the installation contractor would be required to follow BC Hydro’s SF$_6$ gas management policies.

Testing and commissioning would require the use of high-voltage testing equipment to confirm that the electrical equipment is installed properly and is ready for energization.

4.4.6 Highway 29 Realignments

All road construction would be performed in accordance with the current version of the B.C. *Standard Specifications for Highway Construction*.

The Cache Creek segment would have to be completed prior to Stage 2 diversion, since after diversion water levels would be above the bridge level during large floods. The other five segments would have to be completed prior to reservoir filling. The construction schedule for the six segments is shown in Figure 4.42.

Construction activities for Highway 29 would include works within the existing and proposed highway rights-of-way, at gravel pits and borrow sites located within the inundated areas, and at the proposed riprap quarries.

Site preparation would be completed at each segment and at laydown, borrow, quarries and gravel pit locations. Clearing and grubbing would remove all commercial and non-commercial vegetation.

Activities for construction of the six realigned segments of Highway 29 would be as described in Sections 4.4.1 and 4.4.2, with typical site preparation, quarrying and excavating, and road construction, respectively.

Grading to construct the roadbed and causeways would be completed at each segment, including the connections to new and existing driveways, local roads, temporary construction roads, and temporary traffic detours. Unsuitable native material or surplus excavated material would be disposed of within the proposed highway right-of-way or in designated areas within the inundated zone.

The Highway 29 running surface would be asphalt pavement. Asphalt plants would be located in the gravel pits.

Most of the new highway segments and bridges would be located away from the existing highway, enabling construction to take place with minimal effect to the existing highway and traffic. Temporary detours would be necessary where portions of the new highway overlap the existing highway. At these locations, traffic flow would be managed, and could include sections of alternating single-lane traffic controlled by flag persons or short-term closures. Standard traffic control measures, such as signage, road markers, and flag persons, would be used for guiding traffic during construction.
The asphalt pavement and sub-base would be removed from abandoned sections of Highway 29 within the reservoir. Some reclaimed asphalt would be recycled for use in the new construction. Abandoned sections of the highway located outside of the reservoir would either be converted to local access roads or decommissioned and restored to natural conditions. The existing bridges at Farrell Creek and Halfway River may remain in place. Lynx Creek and Cache Creek bridges would be dismantled. The existing bridge at Cache Creek may be returned to BCMOTI for reuse.

All temporary construction roads and laydown areas would be deactivated and reclaimed.

### 4.4.7 Quarried and Excavated Construction Materials

The activities common to quarrying rock and excavating of earthen construction materials are described in this section.

#### 4.4.7.1 Riprap and Bedding Production

The quarries identified in Section 4.3.5 would be used for the production of riprap and bedding. Drilling and blasting would be used to break the rock. The blast hole pattern and explosive loading would depend on the rock characteristics and the size of riprap required.

After each blast, the rock would be sorted by equipment into stockpiles of the required riprap sizes. This could include loading rock into a quarry rock separator. Bedding would be selected from the finer rock or screened if required to produce the specified gradation.

The yield of a quarry (ratio of volume of usable materials to total excavated volume of material) depends on factors such as the joint spacing in the rock and the drilling and blasting techniques employed. The surplus materials listed by quarry in Table 4.8 and Table 4.9 would be unsuitable for use in the Project only because they do not meet the specified gradations for riprap and bedding. Such materials could be suitable for use by others in the future, e.g., crushed for rail ballast, road base, or asphalt aggregate.

#### 4.4.7.2 Excavating

Blasted rock and earth construction materials would require excavation and may require further processing prior to being transported to the site.

Excavation would typically be performed by excavator, loader, bulldozer, or scraper.

#### 4.4.7.3 Moisture Conditioning

The moisture content of impervious material may require adjustment in order to meet compaction requirements.

Water would be added to increase the moisture content using such methods as a tank and spray bar mounted on a vehicle or irrigation sprays. The material would be wetted and then mixed by a bulldozer or grader until a consistent moisture content is obtained. Moisture could also be added by spraying the material while on the conveyor and then mixed during stockpiling.
To reduce moisture content, the material would be disced to expose more surface area to promote drying of the material. Several turnings of the material could be necessary to achieve the correct moisture content. Another method would be to stockpile the material and allow the water to drain to the bottom.

### 4.4.7.4 Crushing and Screening

Crushing of granular materials involves mechanical breakage of particles into smaller sizes. A primary crusher and secondary crusher would be used in combination with screening. After crushing, the material would be passed through one or more screens of specified size. Screened materials would then be stockpiled.

### 4.4.7.5 Washing

Material may require washing to remove fine-grained particles in order to meet the specified gradation.

### 4.4.7.6 Stockpiling

Processed material would be stockpiled until required, or for blending with other materials, drying, or confirming of specification prior to using.

### 4.4.7.7 Surplus or Unsuitable Materials

Surplus or unsuitable materials at off-site sources would be disposed of at the source, as described in the applicable construction materials development plans (see Section 4.3.5). Unsuitable materials excavated from within the dam site area would be relocated as described in Section 4.4.3.

### 4.4.7.8 Reclamation

A reclamation plan would be developed for each quarry and excavated materials source.

### Table 4.11 Activities to Occur at Quarries and Materials Sources

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4.4.8 Access Roads and Rail

4.4.8.1 Construction Phase Activities

All access road construction works would be undertaken in accordance with the current version of the B.C. Standard Specifications for Highway Construction, the Forest Practice Code – Forest Road Engineering Guidebook, and any applicable standards for operational equipment, and in conformance with pipeline regulatory requirements.

Construction of rail works would be in conformance with CN Rail standards and guidelines.

Construction of access roads would be in accordance with typical site preparation, quarrying, and excavating, and with road construction activities described in Sections 4.4.1 and 4.4.2.

Construction of access roads would require small quantities of riprap and bedding for drainage works such as erosion protection at culverts and ditches as well as granular material. Some fill material would come from the excavations for the road grade and the remainder would be sourced off-site.

The granular materials for the north bank access roads to the dam site area would come from the dam site area or commercial pits. Riprap and bedding would come from the quarries at Wuthrich or Portage Mountain. Where riprap and bedding from Wuthrich are used early in the Project, it may be replaced with the more durable rock from Portage Mountain later in the Project.

The granular material for the Project access road on the south bank would come from the Del Rio Pit and the dam site area. Materials for upgrading the existing roads on the south bank would come from the Del Rio Pit or commercial pits. Riprap and bedding would come from the West Pine Quarry.

Road grading would be required for each access road. Unsuitable native material or surplus excavated material would be disposed of within the proposed right-of-way or in designated areas within the inundated zone. The grading, drainage, and finishing requirements would vary depending on access requirement and whether the facility would be temporary or permanent. Road use and maintenance agreements would be established with the forestry and oil and gas resource road licence holders. Crossing agreements may need to be established with pipeline owners and operators. Upgrades may include pipeline bridging, isolation, or protection.

Standard traffic control measures would be used for guiding traffic during upgrades to existing roads.

Access road construction depends on the component activity schedule. Based on current forecasting, the current access road construction schedule is presented in Error! Reference source not found.. As described in Section 4.3.7, the Project access road would remain in service after construction. All temporary construction service roads would be decommissioned, or reclaimed and restored to their pre-existing service level following construction, or would be inundated by the reservoir when filled. The abandoned section of Old Fort Road would be decommissioned and returned to natural conditions.
4.4.8.2 Transportation of Extraordinary Loads

Dam components would need to be transported from the port of entry to Site C dam utilizing highways within Alberta and British Columbia. Some of these components would require routing consideration based on weight and dimensions and possible highway infrastructure limitations.

BC Hydro engaged the service of a specialized industrial mover to evaluate possible rail and road transportation routes for the extraordinary loads. The evaluation concluded that for the larger dimension components the ports of Duluth, Minnesota and Houston, Texas would be suitable facilities for accepting these loads. Transportation would be via highway through the United States, into Canada at Coutts Alberta, then into British Columbia.

The proposed routing, along with the potential load parameters were provided to staff with the British Columbia Ministry of Transportation & Infrastructure Commercial Vehicle Safety and Enforcement Branch Provincial Permit Centre in Dawson Creek, B.C. The type of loading required for the Project is not unusual and there are numerous companies which specialize in transporting extraordinary dimension loads who are familiar with the permitting process required by state and provincial jurisdictions generally, and British Columbia specifically.

Based upon information from the British Columbia Ministry of Transportation & Infrastructure, Provincial Permit Centre, Commercial Vehicle and Safety Enforcement Branch, transportation of the components required by the Project would not require upgrades or new construction of roadways or structures along the proposed haul routes. However, the following would have to be taken into account by the industrial movers:

- On some bridges there may be clearance issues with railing heights and possible width restrictions that would not require structural improvements but would require possible temporary removal of railing to increase height clearance and width
- Any transport configurations must meet the 85 tonne route bridge restrictions and would be required to go through the extraordinary load application process
- Seasonal load restrictions would affect timing of transporting over weight loads
- There would be a requirement to cross bridge structures with traffic closed and travel down the centre lane for loads that are too wide to cross with oncoming traffic. Travel time restrictions such as Monday to Friday, travel time of day restrictions, pilot car requirements and a traffic management plan would be part of the approval process.

4.5 Operations

4.5.1 Dam, Generating Station, and Spillways

The Project would be operated, managed, and maintained in accordance with:

- The terms and conditions of all permits, licences, and approvals issued for the Project
- Canadian and international dam safety practices
- The Operations Environmental Management Program, described in Volume 5 Section 35 Summary of Environmental Management Plans
4.5.1.1 Dam Safety

British Columbia is one of four provinces in Canada with a formal dam safety program. There are approximately 1,900 dams in the province, including some of the largest structures in Canada. These dams are regulated under the British Columbia Dam Safety Regulation, with oversight by the Dam Safety Program, B.C. Ministry of Forests, Lands and Natural Resource Operations. The Dam Safety Section, under the Comptroller of Water Rights, is responsible for administration of the provincial dam safety program and regulation of major dams (9 m or higher) throughout the province. BC Hydro’s Dam Safety Program complies with the British Columbia Dam Safety Regulation. Dam safety management of the Project would be undertaken as Part of BC Hydro’s Dam Safety Program and would comply with the British Columbia Dam Safety Regulation.

Dam operation, maintenance, and surveillance encompass a number of activities and constraints so that the reservoir-retaining structures are managed safely. An Operation, Maintenance, and Surveillance Manual documents:

- Procedures and practices required to operate the dam safely under various conditions
- Prioritization of the maintenance activities that should be carried out for dam safety
- Surveillance, including visual inspections and instrument monitoring, as a means of checking whether the dam is performing satisfactorily and as intended by the design

Operation, Maintenance, and Surveillance Manuals would be prepared for the cofferdams and the permanent reservoir retaining structures and associated equipment. Operation, Maintenance, and Surveillance Manuals would follow the CDA Dam Safety Guidelines (CDA 2007) and comply with the B.C. Dam Safety Regulations. The Operation, Maintenance, and Surveillance Manuals would be submitted to the B.C. Comptroller of Water Rights with the Operation, Maintenance, and Surveillance Manual for the cofferdams submitted prior to diversion of the river through the diversion tunnels and the Operation, Maintenance, and Surveillance Manual for the dam submitted prior to reservoir filling. In both cases the Operation, Maintenance, and Surveillance Manuals would be submitted in sufficient time to make any changes that the Comptroller of Water Rights may require prior to impounding water.

The goal of surveillance is to identify deviations in performance so that corrective action or risk mitigation measures can be implemented before adverse consequences result. Instrumentation would be installed to measure the performance relative to the expected performance based on the design analyses. Instrumentation would include devices that measure water pressures in the foundation or body of the dam and buttress (piezometers) and devices that measure deformations. During and after reservoir filling, the readings from the instrumentation would be checked against expected values. If the readings indicated unsatisfactory performance, remedial work would be undertaken. For example, as described in Section 4.3.1, a drainage system would be installed as Part of the seepage control measures to limit seepage pressures acting on the buttress. The effectiveness of this drainage system would be monitored by piezometers. If measured seepage pressures are higher than expected from the design, additional drain holes would be drilled until the pressures were within expected values. As described in Volume 5 Section 37 Requirements for the Federal Environmental Assessment, the buttresses would be designed to be stable even if the seepage control measures are
completely ineffective. Therefore, there would be sufficient time to undertake any remedial measures required.

In accordance with the CDA Guidelines, Emergency Preparedness Plans describe the notifications to be issued and, in general terms, the actions expected from downstream responders in the event of a dam failure or passage of a major flood. Emergency Preparedness Plans are not response documents but contain essential information such as inundation maps and flood arrival details, so that local authorities can develop their own response plans. In the event of an emergency at the dam, the local authorities and other downstream stakeholders would be contacted. The CDA recommends that distribution of Emergency Preparedness Plans should generally be limited to those who have a legal and defined emergency response role. BC Hydro limits the distribution of Emergency Preparedness Plans for security reasons.

Emergency Preparedness Plans would be prepared for the cofferdams and the permanent reservoir-retaining structures. Emergency Preparedness Plans would follow the CDA Dam Safety Guidelines and comply with the B.C. Dam Safety Regulations. The Emergency Preparedness Plans would be submitted to the B.C. Comptroller of Water Rights, with the Emergency Preparedness Plans for the cofferdams submitted prior to diversion of the river through the diversion tunnels and the Emergency Preparedness Plans for the dam submitted prior to reservoir filling. In both cases, the Emergency Preparedness Plans would be submitted in sufficient time to make any changes that the Comptroller of Water Rights may require prior to impounding water.

4.5.1.2 Generation Operations

Similar to BC Hydro’s other generating facilities on the Peace River, the Project would be operated to respond to provincial electricity demand. The generation and flow of electricity would be controlled by BC Hydro’s System Control Centre.

Reservoir water levels and downstream flows during operation of the Project are characterized in Volume 2 Section 11.4 Surface Water Regime.

4.5.1.3 Spillway Operation

The gated spillway would discharge water (spill) whenever the inflow to the reservoir exceeded the available capacity of the generating units. The gates would be operated to maintain the maximum normal reservoir level, which would only be exceeded when all of the operating spillway gates are open. Spill from the Project is described in Volume 2 Section 11.4 Surface Water Regime.

As described in Section 4.3.1.5, the spillway would have a capacity of 10,100 m³/s at the maximum normal reservoir level. Extrapolation of flood frequency relationships beyond 1,000 years is generally discouraged (CDA 2007); however, extrapolation suggests that the annual probability of exceeding the maximum normal reservoir level with all spillway gates open is less than 1 in 10,000.

The spillway gates and undersluices would be capable of drawing the reservoir down to elevation 442 m, at which level the undersluices could pass upstream flows of 1,600 m³/s. The facility discharge to accomplish this drawdown would likely be limited to 5,000 m³/s to limit downstream flooding and scour. With a mean daily inflow of 1,250 m³/s (equal to the mean annual flow at the site) and a maximum discharge of 5,000 m³/s, it would take approximately 15 days to lower the reservoir from the
maximum normal reservoir level to elevation 442 m. A drawdown to elevation 442 m for inspection, maintenance, and repairs in the approach channel would likely be scheduled for the summer between the flood hazard season and high winter flows for generation. The approach channel lining would be designed and constructed to have a life of over 100 years; therefore, a drawdown for repairs is unlikely.

4.5.1.4 Maintenance

Maintenance policies and procedures would be implemented to ensure that structures and equipment are maintained in a safe operating condition. Regular maintenance work, including periodic servicing, such as greasing and overhauling equipment, clearing drains, and removing debris, would be done in conjunction with scheduled inspections.

Non-regular maintenance work such as painting, repairs, or equipment replacement would be undertaken as deemed necessary by either inspection or by equipment aging. Debris accumulated on the trashracks on the power intakes and at the spillway headworks would be removed. Wood debris would be disposed of through a combination of burning, composting, or landfilling, in accordance with provincial regulations in place at the time of disposal. Other debris would be disposed of in landfill, in accordance with provincial regulations in place at the time of disposal.

Regular inspection and maintenance would be undertaken on spillway equipment, including spillway gates, electrical hoist equipment, gantry travel equipment, controls and limit switches. Regular maintenance would include draining and refilling hoist gearboxes, lubricating moving parts, and replenishing the grease supply for the hoist screw lubricators.

Maintenance of structural steel elements, such as the gates, gate guides, hoists, hoist structures, and conduits, would also be undertaken on a regular basis.

Periodic maintenance would be expected to include the following tasks:

- Preventative maintenance inspections and tasks such as:
  - Annual servicing of cranes, gantry hoists, compressors, pumps, fans, and cooling water intakes
  - Semi-annual servicing of filters and intake gate hoists
  - Quarterly elevator inspection and servicing
  - As-required brush and slip ring maintenance

- Annual unit(s) inspection requiring unit(s) outage, during which the following is typically performed:
  - Generator winding dielectric and corona testing
  - Transformer oil testing and winding insulation testing
  - Medium voltage bus, and auxiliary systems contacts and connections cleaning, adjustment, and setting
  - Mechanical systems – speed switch, governors, shaft packing, vacuum valve – inspection and general maintenance
  - Turbine runner and fixed-Part inspection
Trash rack inspection and cleaning

Bearing oil system inspection

4.5.2 Reservoir

4.5.2.1 Reservoir Operation

The reservoir would have one of the narrowest normal operating ranges of reservoirs in BC Hydro’s system, with relatively little fluctuation in water levels throughout most of the year (see Volume 2 Section 11.4 Surface Water Regime for reservoir level fluctuations). Key reservoir levels are shown in Table 4.2.

In exceptional circumstances such as extreme floods, the proposed reservoir could rise above the maximum normal level for short periods. As described in Section 4.5.1, this would be a very rare occurrence.

The reservoir could be drawn down below the minimum normal reservoir level for unusual system requirements or system emergencies. The current expectation is the lowest reservoir level at which the generating station could operate during a system emergency would be elevation 455 m.

The spillway undersluices have been designed so that the reservoir could be lowered to an elevation of 440 m for inspection and repairs of the dam, generating station, or spillways, but this would be a rare occurrence.

4.5.2.2 Debris Management

Maintenance of the debris boom logs, cable, and anchoring points in the reservoir would be undertaken as necessary, based on inspections.

Reservoir debris management is described in Volume 1 Appendix A Vegetation, Clearing, and Debris Management Plan.

4.5.2.3 Maintenance of Hudson’s Hope Shoreline Protection

Maintenance of the shoreline protection features would require access for vegetation and earthwork maintenance. The berm may require minor repairs caused by severe weather events, or features may require repair. The slopes above the berm may require removal of mud and vegetation that has accumulated on the berm from the slopes above. The riprap may require repair periodically.

4.5.3 Substation and Transmission Line to Peace Canyon

Operation of the transmission system would involve transmitting electricity through the conductors between the Site C and the Peace Canyon substations. The flow of electricity on the transmission lines would be controlled by BC Hydro’s System Control Centre.

Vegetation maintenance would be carried out to ensure public and worker safety and system reliability. Tall-growing vegetation that is capable of encroaching on the transmission line and hazard trees adjacent to the right-of-way that are capable of falling onto the lines would be removed or pruned as necessary to meet BC Hydro clearance standards.
Maintenance activities would include manual, mechanical, and chemical methods for maintaining vegetation at a low height to protect electrical facilities; each of these general methodologies has many options.

Overview inspections of overhead structures would be performed regularly and detailed inspections would occur approximately every five years. Overhead structure maintenance could be undertaken from the ground, or by helicopter in sensitive areas or where ground access is difficult or impossible.

Refer to Section 4.5.6 for operation and maintenance of transmission line access roads.

**4.5.4 Highway 29**

Upon completion of the new segment of Highway 29, the new facility would be operated and maintained as a provincial public highway by the BCMOTI.

**4.5.5 Quarries and Excavated Construction Materials Sources**

When aggregates are required for maintenance of the dam and associated private access roads, permits would be obtained as required by the regulations in place at the time or commercial pits would be used to source materials.

**4.5.6 Access Roads**

Provincial public roads would be operated and maintained by BCMOTI. Permanent dam and generating station and transmission line corridor access roads would be operated and maintained by BC Hydro. These activities would include overview inspections, occasional culvert and bridge replacements, brushing, and repairing eroded areas on the road surface. The frequency of overview inspections would be determined based on road risk ratings and could range from six months to five years. The condition assessments made on these inspections would be used to prioritize the maintenance program in relation to safety and environmental considerations, business needs, and maintenance constraints.

**4.5.7 Sustaining Capital Expenditure**

The typical lifespan of major electrical and mechanical components in a hydroelectric facility ranges from 30 to 40 years for the generating equipment, and from 80 to 90 years for major mechanical components such as the spillway gates. The Project would be designed so that all electrical and mechanical components could be refurbished or replaced cost-effectively as they approach the end of their service life.

In addition, inspection, testing, and maintenance programs would be established to maximize the expected lifespan of these components between major refurbishment or equipment replacement cycles.

The components of the ancillary mechanical and electrical systems, such as water supply and lighting, typically have shorter lives. These systems would be maintained and components would be replaced as necessary during the course of normal maintenance of the Project.
The civil structures comprising the dam, generating station, and spillway would be
designed to last indefinitely, with regular inspection, maintenance, and periodic repairs
or replacements such as:

- Replacement of weathered or damaged riprap on the upstream face of the earthfill
dam, and in the tailrace or discharge channel
- Repair of freeze and thaw damage to concrete
- Replacement of roof membranes
- Repair of approach channel lining

The frequency of such repairs and replacement would be expected to range from
25 years for roof membranes to 50 years, or more for freeze and thaw damage.

Recent examples of BC Hydro investing in its facilities on the Peace River to prolong
their operational capacity include:

- The generator stator replacement and turbine overhaul project at the Peace Canyon
generating station, which came into operation in 1980
- The spillway chute and flip bucket refurbishment at the W.A.C. Bennett Dam, which
came into operation in 1968
- Units 1 to 5 turbine replacements at the G.M. Shrum generating station at the
  Bennett Dam

4.6 Project Decommissioning

BC Hydro expects that the Project would be operated for over 100 years, and that
decommissioning of permanent structures is not currently contemplated.

In addition to the dam, generating station, and spillway, the following permanent facilities
would be retained and maintained:

- Substation
- Transmission lines
- Project access road
- Realigned Highway 29
- Hudson’s Hope shoreline protection
- North bank access roads

Should a proposal be made to decommission the Site C dam and generating facilities in
the future, BC Hydro would address a plan for decommissioning and restoration in
accordance with the applicable regulations at that time.

An Environmental Protection and Monitoring Plan would be developed for
decommissioning to implement applicable measures for environmental protection, and to
restore the area to conditions deemed acceptable at the time of decommissioning.
Further details on decommissioning would depend on regulations and practice at the
time of a decision to decommission.
References

Literature Cited


Internet Sites


5 NEED FOR, PURPOSE OF, AND ALTERNATIVES TO THE PROJECT

5.1 Introduction

This section describes the need for, purpose of, and alternatives to the Project. The “need for” establishes the fundamental justification or rationale for the Project. The “purpose of” is defined as what is to be achieved by carrying out the Project. The “alternatives to” are the functionally different ways to meet the Project need. The alternative means of carrying out the Project are considered in Volume 1 Section 6 Alternative Means of Carrying Out the Project.

The definitions of “need for”, “purpose of” and “alternatives to”, and the following discussions, are consistent with the Agency’s “Policy Statement – Addressing the Need for, Purpose of, Alternatives to and Alternative Means under the Canadian Environmental Assessment Act” (Agency Need/Alternatives Operational Policy Statement). In particular, the need for and the purpose of the Project are established from the perspective of BC Hydro and provide the context for consideration of alternatives.

This section reviews both demand side management (DSM) and supply-side resources in the context of both need for and alternatives to the Project:

- The need for the Project is established using two reliability requirements – firm energy and dependable capacity:
  - Energy is the amount of electricity required over a period of time, measured in gigawatt hours per year (GWh/year)
  - Peak demand, which is the maximum hourly demand on BC Hydro’s system, is measured in megawatts (MW) and is met with dependable capacity. Securing dependable capacity resources to address future dependable capacity needs described in this section is becoming more of a challenge.
  - Over the last seven years, BC Hydro purchased large quantities of intermittent clean or renewable energy resources such as run-of-river and wind that have minimal dependable capacity. Intermittent resources are not dispatchable – that is, their electricity output cannot be controlled to respond to variations in customer demand. Intermittent clean or renewable resources require dependable capacity backup resources.
  - To address growth in the demand for dependable capacity in recent years, BC Hydro has benefited from being able to install additional generating units at each of its two Heritage hydroelectric facilities (Mica and Revelstoke Generating Stations). With one of these generating units now in operation (Revelstoke Unit 5), two more under construction (Mica Units 5 and 6) and the fourth (Revelstoke Unit 6) included in this EIS with an earliest in-service date of F2019, these additional capacity resources will be exhausted. (All year marks in this section are stated in fiscal years (F20XX) ending March 31, except where otherwise noted.) There are limited dependable capacity resource options available to BC Hydro after implementation of Revelstoke Unit 6, and this is
compounded by increased system reliance on non-dispatchable intermittent clean or renewable energy resources.

There are two broad categories of potential alternatives to the Project. Demand-side management consists of measures – such as conserving energy, promoting energy efficiency, and shifting the use of energy to periods of lower demand – that BC Hydro can take to reduce the customer demand that BC Hydro must serve. Supply-side resources are electricity generating facility resources that are consistent with the objectives of the B.C. Government, including those specified in the B.C. Clean Energy Act (S.B.C., 2010, c.22).

The remainder of this section is structured as follows:

- Section 5.2 sets out the need for the Project. The Project addresses BC Hydro’s need for firm energy and dependable capacity within the context of meeting the self-sufficiency requirement set out in Subsection 6(2)(a) of the Clean Energy Act. To determine the need for the Project, BC Hydro’s energy and capacity load-resource balances (LRBs) are analyzed for the BC Hydro integrated system, taking into account the current level of DSM targeted by BC Hydro. The result is a gap that must be filled with supply-side resources.

- Section 5.3 outlines the purpose of the Project. In addition to meeting BC Hydro’s need for firm energy and dependable capacity, the Project advances and aligns with the B.C. Government’s objectives set out in the Clean Energy Act and in its 2007 Energy Plan (provided in Volume 1 Appendix D Need for and Alternatives to the Project Supporting Documentation, Part 1).

- Sections 5.4 and 5.5 examine the potential alternatives to the Project:
  - Section 5.4 describes the process for identifying and reviewing potential alternatives to the Project. Section 5.4 also surveys the potential alternatives that were screened out on the basis that they are not viable (defined as meaning not practicable or not capable of being implemented) because 1) in the case of certain supply-side resources, they are not permitted by or are inconsistent with B.C. Government legal requirements, or are not technically or economically feasible, and 2) in the case of increased DSM levels, cannot reasonably be relied on because of delivery risk.
  - Section 5.5 characterizes the remaining available supply-side resources which, when combined into portfolios, are viable alternatives to the Project. Section 5.5.1 describes the major financial, technical, environmental, and economic development attributes applied to the available supply-side resources. Section 5.5.2 presents a qualitative assessment of the available supply-side resources. Section 5.5.3 sets out the portfolio analysis parameters, while Section 5.5.4 compares the available supply-side resources through portfolio and other analysis. In Section 5.5.5, BC Hydro concludes that the Project is the preferred alternative to meet the need identified in Section 5.2, based on the review of the financial, technical, environmental, and economic development attributes, and taking into account B.C. Government legal and policy requirements.
5.2 Need for the Project

The Environmental Impact Statement (EIS) Guidelines provide that the EIS will set out the fundamental rationale for proceeding with the development of the Project at this time within the relevant legal and policy context. The need for the Project is to address future customer demand (sometimes referred to as load in this EIS; load and demand are used interchangeably) for firm energy and dependable capacity in BC Hydro’s service area. The Project would provide long-term generation services for more than 100 years.

This section of the EIS contains a description of methodologies, assumptions, and conclusions used in the need for the Project analysis through an evaluation of the following:

- Current and forecasted BC Hydro customer demand
- Existing and committed supply-side resources
- The BC Hydro demand-side management target

To begin this discussion, it is important to underscore BC Hydro’s obligation to serve its customers in accordance with standards established by the British Columbia Utilities Commission (BCUC) pursuant to a number of sections in the B.C. Utilities Commission Act (R.S.B.C., 1996, c.473), including Sections 25, 28, 29, and 30. This service obligation drives BC Hydro’s long-term resource planning process. The long-term view is required, as most new resources require significant lead times to obtain approvals and build. All electric utilities like BC Hydro must plan ahead to be sure that the required resources will be in place when needed by customers. As a business planning tool, BC Hydro’s long-term resource planning process supports informed decision-making on resource acquisition by providing an analytical framework for assessing resource investment trade-offs:

- The first step in the analytical framework is for BC Hydro to forecast its future electricity demand requirements. As with any potential resource available to BC Hydro, energy and capacity LRBs are analyzed for the BC Hydro integrated system to determine the need for the Project’s generating capability. A load-resource balance is the difference between BC Hydro’s Load Forecast – which projects BC Hydro customer load over a 20-year period – and the supply from existing and committed resources. There is a gap if forecasted customer load exceeds the supply available to serve such load.
- The analytical framework is then used to evaluate different solutions for filling the load-resource gap. BC Hydro employs this analytical framework in this section to assess the Project and potential alternatives.

BC Hydro continues to face considerable uncertainty in its long-term resource planning environment, including:

- Load growth and the risk that load growth exceeds or falls below expectations
- DSM delivery risk – the risk that the response to DSM is less than planned or required
- Supply-side development uncertainty, including the type and location of resources supplied to BC Hydro, and the risk that the type and location of resources require
significant dependable capacity (for example, for intermittent clean or renewable resources such as wind) and transmission support

These uncertainties and the +20-year planning time frame underscore the need to de-emphasize single point estimates for forecasting load and the load-resource balance; rather, uncertainties with load forecasting and the capabilities of existing supply-side resources and DSM can be translated into a range of future resource requirements. The key uncertainties in load growth and resource delivery are discussed in Section 5.2.3.

The remainder of this section is organized as follows:

- Section 5.2.1 reviews the assumptions underlying the two inputs to the energy and capacity LRBs: 1) BC Hydro’s most recent (2012) Load Forecast, and 2) BC Hydro’s existing and committed resources. In addition, the legal requirement for BC Hydro to achieve electricity self-sufficiency by 2016 and each year after, pursuant to Subsection 6(2)(a) of the Clean Energy Act is explained.

- In Section 5.2.2, the resulting energy and capacity LRBs are provided. First, the LRBs are shown without the current BC Hydro DSM target. Second, the LRBs are depicted with the DSM target and Revelstoke Unit 6, as this is a project that BC Hydro proposes to undertake in advance of the Project, due to the need for dependable capacity. It is this second set of LRBs that provides the basis for demonstrating the need for the Project and sets the context for potential alternatives to the Project. BC Hydro summarizes some loads and LRBs with respect to the following years: F2017, F2022, F2026, and F2031. All values shown include electricity losses from the transmission and distribution systems, unless otherwise stated.

- Section 5.2.3 summarizes the risks and uncertainties with respect to the LRBs, focusing on the Load Forecast and delivery of anticipated DSM savings. Some of these – such as potential large and uncertain loads from liquefied natural gas (LNG) and mining, or lower than anticipated levels of DSM savings – would result in a larger LRB gap, while others, such as lower commodity prices, would result in a smaller LRB gap. Section 5.2.3 also describes BC Hydro’s Contingency Resource Plan to address dependable capacity shortfall risks.

- Section 5.2.4 contains BC Hydro’s conclusions with respect to the need for the Project

5.2.1 Load-Resource Balance Assumptions

This section explores the energy and capacity LRBs by first reviewing the 2012 Load Forecast in Section 5.2.1.1, and then examining existing and committed resources in Section 5.2.1.2. The resulting energy and capacity LRBs are presented in Section 5.2.2. Throughout Section 5.2 and Section 5.3, capacity MW values have been rounded to the nearest 50 MW and energy GWh values have been rounded to the nearest 100 GWh.

5.2.1.1 BC Hydro’s 2012 Load Forecast

Load is the amount of electricity required by a BC Hydro customer or group of customers. This section presents BC Hydro’s 2012 Load Forecast of energy and peak (capacity) load requirements for the BC Hydro integrated system. Some of BC Hydro’s customers live in areas too remote to be served by the integrated system. Local
generation serves these non-integrated communities. Unless otherwise indicated, this EIS does not address the non-integrated areas.

On an annual basis, BC Hydro prepares 20-year load forecasts for both energy and peak demand. The energy forecast represents the forecasted total annual electricity demand for the integrated system and the peak forecast represents the one-hour maximum demand on the integrated system.

The 2012 Load Forecast has been prepared in accordance with the BCUC’s Resource Planning Guidelines (copy in Volume 1 Appendix D Need for and Alternatives to the Project Supporting Documentation, Part 2), using the same methodological approach for the mid-forecast accepted by the BCUC in long-term resource plan proceedings, including a sector-by-sector analysis of load. The 2012 Load Forecast incorporates the most current third-party economic indicators available to be incorporated, including gross domestic product (GDP) forecasts from the B.C. Ministry of Finance, external economic consultants and customer-by-customer information included in the industrial customer forecast.

**Use of Mid-Load Forecast**

The values discussed in this EIS reflect BC Hydro’s mid-load forecast for both energy and peak demand. The mid-load forecast represents the expected future load, in which actual realized loads will be higher than forecast 50% of the time, and lower than forecast 50% of the time. The EIS is based on BC Hydro’s mid-load forecast because:

- The B.C. *Electricity Self-Sufficiency Regulation* (B.C. Reg. 315/2010) enacted under the *Clean Energy Act* prescribes the mid-load forecast as the forecast to be used for the purpose of determining the self-sufficiency requirement
- The mid-load forecast is the forecast that BC Hydro uses to determine the need for capital projects, both internally and in applications to the BCUC. The BCUC endorsed the use of the mid-load forecast for purposes of determining need in its 2008 Long-Term Acquisition Plan Decision (BCUC Order G-91-09, Reasons for Decision, page 54 and Directive 6).
- Use of the mid-load forecast is consistent with other public electric utilities

**Liquefied Natural Gas Load**

The 2012 mid-load forecast presented in this section does not include potential LNG load, which is discussed in Section 5.2.3.

**Energy and Peak (Capacity) Load Forecasts**

The 2012 Load Forecast reflects the impact of savings from DSM (i.e., energy efficiency and conservation) initiatives achieved through F2012, but does not include future targeted savings in F2013 and beyond. DSM targeted savings for F2013 and beyond are described in Section 5.2.2.2. Table 5.1 and Table 5.2 present the 2012 Load Forecast energy and peak demand requirements before anticipated DSM savings (resulting from DSM initiatives after F2012) without potential LNG load.
Table 5.1 Mid-Energy Load Forecast Before DSM

<table>
<thead>
<tr>
<th>(GWh)</th>
<th>F2017</th>
<th>F2022</th>
<th>F2026</th>
<th>F2031</th>
<th>Average Annual Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid-energy Load Forecast (No LNG)</td>
<td>63,200</td>
<td>70,800</td>
<td>73,800</td>
<td>78,400</td>
<td>2.2% 1.7%</td>
</tr>
</tbody>
</table>

Table 5.2 Mid-Peak Demand Load Forecast Before DSM

<table>
<thead>
<tr>
<th>(MW)</th>
<th>F2017</th>
<th>F2022</th>
<th>F2026</th>
<th>F2031</th>
<th>Average Annual Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mid-peak Load Forecast (No LNG)</td>
<td>11,700</td>
<td>12,750</td>
<td>13,450</td>
<td>14,500</td>
<td>2.1% 1.8%</td>
</tr>
</tbody>
</table>

Energy Load Forecast Components and Drivers

The three main components of the energy load forecast, each of which has its own primary drivers, are as follows. (Note that other small categories of load not included in residential, commercial, or industrial – such as sales to other electric utilities such as FortisBC Inc. – provide the balance of the total load forecast.)

Residential: BC Hydro’s residential sector currently consumes about 35% of BC Hydro’s total sales. Sales to the residential sector are weather sensitive, primarily to winter heating demand, and can fluctuate significantly year to year. The drivers of the residential forecast are the average annual use of electricity per account and the number of accounts, which is driven by population growth and housing starts. The average use per account is developed using an end use model that includes economic drivers such as disposable income, people per account, and efficiency trends for the primary residential end uses of electricity.

BC Hydro’s long-term forecast of housing starts is expected to be on average about 26,000 units per year, a reduction over pre-recession levels. In addition, trends in residential electricity use per account have been slowing. This is due to several factors that include recent slower economic growth, the effects of conservation, BC Hydro’s electricity rate changes, and an increasingly efficient appliance fleet. The average use per account is expected to grow slowly at less than 1% per year. This reflects a number of factors, including housing sizes and types, the demand for electronic, entertainment, and telecommunication devices in the home, and general improvements in the energy efficiency of major electrical appliances. With the current forecasts of housing starts and residential end use rate, the overall sales to the residential sector before DSM are expected to grow by about 1.8%, 2.0%, and 1.9% over the next five, 10, and 20 years, respectively.

Commercial: BC Hydro’s commercial sector currently consumes about 31% of its total sales. The electricity consumption of the commercial sector can vary considerably from year to year, reflecting the level of activity in B.C.’s service sector. The commercial sector is made up of two categories: commercial distribution (94% of the total commercial sales) and commercial transmission (6% of total commercial sales).
The forecast of commercial distribution sales is developed with an end use model. The drivers of the forecast include average commercial end use efficiencies trends and projections of retail sales, employment, and commercial output. Sales to the commercial distribution sector before DSM are expected to grow by about 2.0%, 1.9%, and 1.8% over the next five, 10, and 20 years, respectively. This growth reflects relatively stable provincial economic growth and no significant changes in average commercial end use efficiency. The overall commercial distribution load has been revised downwards since the onset of the recent recession, consistent with the lower projections of economic drivers. Slower economic growth projections for the U.S. and global economies impact tourism and retail spending in B.C. Sales to larger commercial customers such as ports and pipelines are projected to grow over the first five years of the forecast; after these expansions are completed, commercial sales are expected to remain relatively stable.

**Industrial:** BC Hydro’s industrial sector currently represents about 32% of its total sales. The industrial sector is made up of customers served at distribution voltages (20% of total industrial sales) and those served at transmission voltages (80% of total industrial sales, at voltage of over 69 kilovolts). BC Hydro prepares its industrial transmission load forecast on a customer-by-customer basis, considering the sector-specific issues that customers in each sector face. A projection for industrial distribution sales is developed for key sectors, including forestry (including pulp and paper), mining (coal), and oil and gas. The remaining industrial distribution sales are developed using an econometric model and provincial GDP growth as a load driver.

Industrial demand has been the most variable historically, and it is the most challenging to forecast due to sensitivity to factors such as global commodity markets and economic conditions in the U.S. and Asia. Excluding LNG, the industrial sub-sectors include the following:

1. Forestry (pulp and paper, and wood products): Historically, this has been the largest industrial sector in terms of electricity sales, accounting for about 60% on average of total industrial sales. With external experts, BC Hydro prepares a market analysis and a production outlook for each of BC Hydro’s pulp and paper and wood products customers. This includes production forecasts for the key commodities that the facilities produce such as pulp, various paper grades, and various wood products. A market analysis of Asian and U.S. demand and the status of the mountain pine beetle effects on wood supply are also reflected in the forecast. Sales to the forestry sector before DSM are expected to shrink by about 2.4%, 1.2%, and 0.6% over the next five, 10, and 20 years, respectively. This reflects lower mechanical pulp and related paper production forecast, attrition in some sawmills due to the wood supply situation, and the continuing trend to digital media substitution away from print media.

2. Oil and Gas: Currently, oil and gas sales are less than 10% of total industrial sales, but this is expected to increase. BC Hydro prepares natural gas production forecasts for the key B.C. production basins based on a variety of expert forecasts. BC Hydro also uses the B.C. Oil and Gas Commission’s production and drilling information to monitor natural gas historical production and possible future trends. Deferred drilling and natural gas processing due to current low natural gas prices have reduced expected growth in sales in the near term. Preferential drilling for higher value oil and liquids, and potential growth in B.C.’s supply of LNG to Asian markets are the key drivers of future load growth. The province is seen to have substantial gas development potential, particularly in the Montney (Dawson Creek to Chetwynd).
region. Sales to the oil and gas sector before DSM are expected to grow by about 19.0%, 14.3%, and 7.5% over the next five, 10, and 20 years, respectively.

3. Mining: The mining forecast is developed on an account-by-account basis using external expert advice and development plans obtained from current and prospective customers. BC Hydro also considers price forecasts for the key sector products (copper, gold, molybdenum, and coal) and the current status of environmental permitting. The forecast considers the likelihood that new mines will be completed and that existing mines will proceed with expansion plans. The 2012 mining sector forecast is lower relative to recent vintages of forecasts, due to lower price expectations for metals and coal, recent environmental decisions, and generally tighter capital markets. The outlook for mine completions in BC Hydro’s forecast have been reduced and expected start dates for several new mines have been deferred. Despite a lower forecast compared to previous years, mining is expected to be one of the strongest load growth areas. This is due to announced expansions at existing mines, along with new projects that have already begun construction. Sales to the mining sector before DSM are expected to grow by about 11.8%, 7.1%, and 2.8% over the next five, 10, and 20 years, respectively.

The breakdown of BC Hydro’s mid-energy load forecast by sector and for the total BC Hydro integrated system is set out in Table 5.3.

Table 5.3 Sector Breakdown of Mid-Energy Load Forecast Before DSM (Without Losses)

<table>
<thead>
<tr>
<th>Energy Load (GWh/year)</th>
<th>F2017</th>
<th>F2022</th>
<th>F2026</th>
<th>F2031</th>
<th>Average Annual Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>F2012–22</td>
</tr>
<tr>
<td>Residential</td>
<td>19,800</td>
<td>21,900</td>
<td>23,600</td>
<td>25,700</td>
<td>2.0%</td>
</tr>
<tr>
<td>Commercial</td>
<td>17,800</td>
<td>20,100</td>
<td>21,300</td>
<td>23,000</td>
<td>2.5%</td>
</tr>
<tr>
<td>Industrial (without LNG)</td>
<td>19,000</td>
<td>21,200</td>
<td>20,800</td>
<td>21,100</td>
<td>2.6%</td>
</tr>
<tr>
<td>Total domestic sales including sales to other utilities (No LNG)</td>
<td>57,600</td>
<td>64,500</td>
<td>67,200</td>
<td>71,400</td>
<td>2.4%</td>
</tr>
</tbody>
</table>

NOTE: * FortisBC Inc. and City of New Westminster

Peak Load Forecast Components and Drivers

BC Hydro creates a 20-year peak load forecast. BC Hydro’s peak demand typically occurs on a cold day in December or January, driven by electric heating demand. The primary drivers of the distribution component include housing starts and economic drivers such as retail sales, employment, and GDP. The transmission component of the peak load forecast is built up on an account-by-account basis at the same time that the industrial transmission customer forecast is created for the energy forecast described previously. Additional considerations in generating the peak forecast include planned facility expansions, and industry trends and growth in demand for B.C. exports of commodities.

The peak demand forecast generally follows the trends in the energy forecast. In the near term, the growth in distribution peak loads in the 2012 Load Forecast is slower relative to recent projections, due to a lower residential customer accounts projection.
and somewhat lower expectations of economic growth. The growth in the transmission
peak demand forecast is slower, due to mining deferrals and reduced demand for pulp
and paper customers.

5.2.1.2 Existing and Committed Supply-Side Resources

The other major input to the energy and capacity LRBs is the existing and committed
supply-side resources that serve the BC Hydro integrated system:

- Existing supply-side resources include BC Hydro’s Heritage hydroelectric and
  thermal (natural gas-fired) generating resources, as well as independent power
  producer (IPP) facilities delivering electricity to BC Hydro.

- Committed supply-side resources are:
  - Resources for which material regulatory approvals have been secured (BCUC,
    either secured or through exemption, and environmental assessment related), if
    required, and for which the BC Hydro Board of Directors has authorized
    implementation. Examples are Mica Units 5 and 6.
  - Resources that BC Hydro is currently pursuing, e.g., resources for which the
    BC Hydro Board of Directors implementation approval has been secured, but for
    which BC Hydro has not yet authorized individual contracts, called electricity
    purchase agreements (EPAs). An example is BC Hydro’s Standing Offer
    Program.

The existing and committed supply-side resources are grouped into three categories:
BC Hydro heritage hydroelectric resources, BC Hydro heritage thermal resources, and
EPAs with IPPs and other third-party suppliers. The following sections provide further
information on the supply resource-related assumptions. The energy capability and
dependable capacity of the resources are summarized in Tables 5.4 and 5.5.

Heritage Hydroelectric Resources

BC Hydro’s most significant existing supply-side resource is its heritage hydroelectric
system. BC Hydro’s 30 existing hydroelectric facilities are located throughout the Peace,
Columbia, and Coastal regions of B.C. BC Hydro’s heritage assets are identified in
Schedule 1 of the Clean Energy Act. Resource Smart is a BC Hydro program that
promotes the identification, study, and implementation of projects that provide
cost-effective energy and capacity gains at existing BC Hydro facilities. Committed
Resource Smart projects such as Mica Units 5 and 6, and the Ruskin Dam and
Powerhouse Upgrade Project are included in the heritage hydroelectric energy capability
and dependable capacity values set out in Tables 5.4 and 5.5.

The Electricity Self-Sufficiency Regulation provides that the water conditions prescribed
for purposes of the Heritage hydroelectric capability are ‘average water conditions’.
‘Water conditions’ refers to how much water BC Hydro has in its reservoirs, and ‘average
water conditions’ refers to the mean output of the BC Hydro Heritage hydroelectric
resources over the 60-year recorded period of stream flows between October 1940 and
September 2000. The energy LRBs in this EIS are based on firm energy capability – for
the heritage hydroelectric resources, this capability is defined under average water
conditions; for all non-heritage hydroelectric resources, like run-of-river hydro, BC Hydro
uses critical water conditions (the most adverse sequence of stream flows occurring
within the same 60-year period).
Heritage Thermal Resources

BC Hydro’s Burrard Thermal (Burrard) and Prince Rupert Generating Stations are the only two BC Hydro-owned thermal generating stations that serve the integrated system. Burrard is a natural gas-fired generating facility located in the Lower Mainland of B.C. For purposes of the LRBs:

- Pursuant to Subsections 3(5), 6(2)(d) and 13 of the Clean Energy Act, Burrard’s firm energy contribution is zero GWh/year
- Pursuant to Section 2 of the Burrard Thermal Electricity Regulation (B.C. Reg. 319/2010), Burrard’s dependable capacity of 900 MW will be phased out as Mica Units 5 and 6, the Interior to Lower Mainland Transmission Reinforcement Project, and the third transformer at the Meridian Substation are introduced into service

Existing and Committed IPP Supply

BC Hydro is forecast to have the rights to approximately 14,200 GWh/year and 1,400 MW of energy and capacity in F2022 through about 120 currently active EPAs with IPPs, after taking into account forecast attrition (attrition relates to the possibility that some of the IPP projects for which EPAs have been awarded will not proceed). IPP attrition is discussed in Section 5.2.3 below.

BC Hydro used Effective Load Carrying Capability (ELCC) to represent the capacity contribution from intermittent clean or renewable IPP resources such as wind and run-of-river resources in Table 5.5 below, and the capacity LRBs in Tables 5.7 and 5.9. The ELCC method for evaluating wind and run-of-river capability uses a probabilistic approach that is sensitive to wind and run-of-river availability, rather than relying on a deterministic value for available dependable capacity. The ELCC contribution to the system is largely drawn from BC Hydro’s large and reliable hydroelectric system. The ELCC method may overstate the capacity contribution of these intermittent clean or renewable resources. The incremental ELCC contributions of intermittent clean or renewable resources will decrease as more of these intermittent resources come into service.

Summary

A summary of the energy and dependable capacity of existing and committed supply-side resources is set out in Table 5.4 and Table 5.5 respectively.

Table 5.4 Energy Capability in F2022

<table>
<thead>
<tr>
<th>Gigawatt Hours (GWh) – Existing and Committed Supply</th>
<th>F2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heritage hydroelectric</td>
<td>(a)</td>
</tr>
<tr>
<td>Heritage thermal (Prince Rupert)</td>
<td>(b)</td>
</tr>
<tr>
<td>Existing and committed IPP supply</td>
<td>(c)</td>
</tr>
<tr>
<td><strong>Total supply</strong></td>
<td>(d)</td>
</tr>
</tbody>
</table>
Table 5.5  Dependable Capacity in F2022

<table>
<thead>
<tr>
<th>Megawatts (MW)</th>
<th>F2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heritage hydroelectric (a)</td>
<td>11,400</td>
</tr>
<tr>
<td>Heritage thermal (Prince Rupert) (b)</td>
<td>50</td>
</tr>
<tr>
<td>Existing and committed IPP supply (c)</td>
<td>1,200</td>
</tr>
</tbody>
</table>

**Reserves a**

| Supply requiring reserves              | (d) = a + b + c | 12,700 |
| 14% of supply requiring reserves       | (e) = d * 0.14 | 1,800  |

**Supply not requiring reserves**

| Alcan 2007 EPA (f)                     | 150    |
| Total supply (g) = d – e + f          | 11,100 |

**NOTE:**

a System generating capacity beyond that required to meet peak demand, ensuring sufficient generation is available if some generating units are not available; necessary to meet reliability criteria for planning and operation

5.2.2  Load-Resource Balances

The purpose of the LRBs is to define the future need for resources by comparing the annual mid-load forecast with the annual capability of BC Hydro’s existing and committed supply-side resources. This is done with respect to two views of the system – the energy balance and the capacity balance. There are two steps to analyzing the LRBs:

- First, in Section 5.2.2.1, the LRBs are depicted without future DSM or Revelstoke Unit 6. Bracketed numbers indicate a surplus, while unbracketed numbers indicate a gap. Thus, there is a need for energy in F2017 (Table 5.6) and a need for dependable capacity in F2016 (Table 5.7).

- Second, in Section 5.2.2.2 BC Hydro’s current DSM target is described, and the LRBs are presented with the DSM target and Revelstoke Unit 6 in Tables 5.8 and 5.9

5.2.2.1 Load-Resource Balances Without Demand-Side Management Target and Revelstoke Unit 6

Table 5.6  Energy Deficit/Surplus (GWh) (No LNG)

<table>
<thead>
<tr>
<th>Year</th>
<th>LRB without DSM</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2012</td>
<td>(1,100)</td>
</tr>
<tr>
<td>F2013</td>
<td>(4,000)</td>
</tr>
<tr>
<td>F2014</td>
<td>(2,000)</td>
</tr>
<tr>
<td>F2015</td>
<td>(2,400)</td>
</tr>
<tr>
<td>F2016</td>
<td>(800)</td>
</tr>
<tr>
<td>F2017</td>
<td>100</td>
</tr>
<tr>
<td>F2018</td>
<td>2,300</td>
</tr>
<tr>
<td>F2019</td>
<td>4,300</td>
</tr>
<tr>
<td>F2020</td>
<td>5,400</td>
</tr>
</tbody>
</table>
5.2.2.2 Load-Resource Balances with Demand-Side Management Target and Revelstoke Unit 6

Demand-Side Management Target

DSM is a major element in BC Hydro’s long-term resource plan to fill the load-resource gap.

Section 1 of the Clean Energy Act defines DSM (referred to as ‘demand-side measures’ in the Clean Energy Act) to mean:

“a rate, measure, action or program undertaken (a) to conserve energy or promote energy efficiency; (b) to reduce the energy
demand a public utility must serve; or (c) to shift the use of energy
to periods of lower demand...but does not include (d) a rate,
measure, action or program the main purpose of which is to
courage a switch from the use of one kind of energy to another
such that the switch would increase greenhouse gas emissions in
British Columbia, or (e) any rate, measure, action or program
prescribed”.

Demand-Side Management Tools

The DSM target consists of expected savings from the following three main tools:

- **Codes and standards** are public policy instruments enacted by governments – such
as building codes, energy efficiency regulations, tax measures, and local government
zoning and building permitting processes – to influence energy efficiency. The DSM
target relies on both Federal and Provincial Government implementation of a suite of
changes to existing codes and standards.

- **Rate structures** are aimed at conserving energy, promoting energy efficiency, or
reducing the energy demand that BC Hydro must serve, such as inclining block
(stepped) rate structures. BC Hydro has conservation rates in place (or with planned
implementation) for over 90% of its domestic load. Over the past five years,
BC Hydro implemented four conservation rate structures for residential, commercial,
and industrial customers. Estimates of energy savings from rate structures is
uncertain, particularly in a low electricity rate jurisdiction such as BC Hydro’s service
area.

- **Programs** are designed to address remaining barriers to energy efficiency and
conservation after codes and standards, and rate structures, and thereby capture
additional conservation potential. Programs include load displacement projects,
which reduce the energy demand that BC Hydro must serve as a result of existing
customers self-supplying through conservation or through customer self-generation.
While BC Hydro has extensive experience working with customer groups to
encourage energy conservation and efficiency, the fact that DSM programs are
targeting more aggressive levels of savings and that they depend on voluntary
participation makes forecasting DSM savings uncertain. Two key drivers of DSM
program savings are 1) participation rate of customers for that program, and
2) energy savings per participant.

In addition to these tools, there are six supporting initiatives – public awareness and
education, community engagement, technology innovation, codes and standards
support, information technology, and indirect and portfolio enabling – that provide a
critical foundation for awareness, engagement, and other conditions to support the
success of BC Hydro’s DSM initiatives.

**DSM Target**

BC Hydro’s current DSM target is 7,800 GWh/year of energy savings, with associated
capacity savings of 1,400 MW, in F2021. The DSM target is aggressive and
comprehensive, as it includes a broad range of codes and standards, rate structures,
and programs that provide BC Hydro customers in virtually all market segments an
opportunity to participate. BC Hydro is continually reviewing the DSM target to determine
if it is achievable and cost-effective.
There is regulatory risk with respect to implementing the DSM target. Implementing the current BC Hydro DSM target requires a filing with the BCUC pursuant to Subsection 44.2(1)(a) of the *Utilities Commission Act* for a determination that the expenditures associated with the BC Hydro DSM target are in the public interest. Please refer to the discussion of DSM delivery risk in Section 5.2.3.

Revelstoke Unit 6

Revelstoke Unit 6 is a capacity Resource Smart project consisting of installing a sixth unit into the existing powerhouse at Revelstoke Generating Station. Revelstoke Unit 6 would provide 488 MW of dependable capacity but limited energy gains (about 30 GWh/year). For purposes of this EIS, BC Hydro includes Revelstoke Unit 6 in its LRBs; therefore, Revelstoke Unit 6 is not an alternative to the Project. Implementing Revelstoke 6 requires an application for an EAC pursuant to BCEAA and amendment of the Columbia River Water Use Plan.

Results

The energy LRB in Table 5.8 shows that, after the DSM target and Revelstoke Unit 6, there is a need for energy beginning in F2024.

### Table 5.8 Energy Deficit/Surplus (GWh) with DSM Target and Revelstoke Unit 6 (No LNG)

<table>
<thead>
<tr>
<th>Year</th>
<th>LRB without DSM and Rev 6</th>
<th>DSM</th>
<th>Revelstoke Unit 6</th>
<th>LRB with DSM and Rev 6</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2012</td>
<td>(1,100)</td>
<td>900</td>
<td>0</td>
<td>(2,100)</td>
</tr>
<tr>
<td>F2013</td>
<td>(4,000)</td>
<td>1,200</td>
<td>0</td>
<td>(5,200)</td>
</tr>
<tr>
<td>F2014</td>
<td>(2,000)</td>
<td>2,000</td>
<td>0</td>
<td>(4,000)</td>
</tr>
<tr>
<td>F2015</td>
<td>(2,400)</td>
<td>3,000</td>
<td>0</td>
<td>(5,500)</td>
</tr>
<tr>
<td>F2016</td>
<td>(800)</td>
<td>3,900</td>
<td>0</td>
<td>(4,700)</td>
</tr>
<tr>
<td>F2017</td>
<td>100</td>
<td>4,800</td>
<td>0</td>
<td>(4,700)</td>
</tr>
<tr>
<td>F2018</td>
<td>2,300</td>
<td>5,700</td>
<td>0</td>
<td>(3,400)</td>
</tr>
<tr>
<td>F2019</td>
<td>4,300</td>
<td>6,500</td>
<td>0</td>
<td>(2,200)</td>
</tr>
<tr>
<td>F2020</td>
<td>5,400</td>
<td>7,200</td>
<td>0</td>
<td>(1,900)</td>
</tr>
<tr>
<td>F2021</td>
<td>6,400</td>
<td>7,800</td>
<td>0</td>
<td>(1,400)</td>
</tr>
<tr>
<td>F2022</td>
<td>7,200</td>
<td>8,200</td>
<td>0</td>
<td>(1,000)</td>
</tr>
<tr>
<td>F2023</td>
<td>8,200</td>
<td>8,400</td>
<td>0</td>
<td>(200)</td>
</tr>
<tr>
<td>F2024</td>
<td>9,100</td>
<td>8,900</td>
<td>0</td>
<td>200</td>
</tr>
<tr>
<td>F2025</td>
<td>9,900</td>
<td>9,200</td>
<td>0</td>
<td>700</td>
</tr>
<tr>
<td>F2026</td>
<td>10,400</td>
<td>9,600</td>
<td>0</td>
<td>800</td>
</tr>
<tr>
<td>F2027</td>
<td>11,000</td>
<td>9,800</td>
<td>0</td>
<td>1,200</td>
</tr>
<tr>
<td>F2028</td>
<td>12,100</td>
<td>10,200</td>
<td>0</td>
<td>1,800</td>
</tr>
<tr>
<td>F2029</td>
<td>13,000</td>
<td>10,600</td>
<td>0</td>
<td>2,400</td>
</tr>
<tr>
<td>F2030</td>
<td>14,000</td>
<td>10,900</td>
<td>0</td>
<td>3,100</td>
</tr>
<tr>
<td>F2031</td>
<td>15,000</td>
<td>11,200</td>
<td>0</td>
<td>3,800</td>
</tr>
</tbody>
</table>

The capacity LRB shown in Table 5.9 identifies a need for new dependable capacity supply in F2025.
Table 5.9  Capacity Deficit/Surplus (MW) with DSM Target and Revelstoke Unit 6 (No LNG)

<table>
<thead>
<tr>
<th>Year</th>
<th>LRB without DSM and Rev 6</th>
<th>DSM</th>
<th>Revelstoke Unit 6 (after Reserves)</th>
<th>LRB with DSM and Rev 6</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2012</td>
<td>(800)</td>
<td>150</td>
<td>0</td>
<td>(950)</td>
</tr>
<tr>
<td>F2013</td>
<td>(850)</td>
<td>150</td>
<td>0</td>
<td>(1,000)</td>
</tr>
<tr>
<td>F2014</td>
<td>(550)</td>
<td>350</td>
<td>0</td>
<td>(900)</td>
</tr>
<tr>
<td>F2015</td>
<td>(250)</td>
<td>500</td>
<td>0</td>
<td>(700)</td>
</tr>
<tr>
<td>F2016</td>
<td>400</td>
<td>650</td>
<td>0</td>
<td>(250)</td>
</tr>
<tr>
<td>F2017</td>
<td>600</td>
<td>800</td>
<td>0</td>
<td>(200)</td>
</tr>
<tr>
<td>F2018</td>
<td>850</td>
<td>950</td>
<td>0</td>
<td>(100)</td>
</tr>
<tr>
<td>F2019</td>
<td>1,150</td>
<td>1,100</td>
<td>400</td>
<td>(400)</td>
</tr>
<tr>
<td>F2020</td>
<td>1,300</td>
<td>1,250</td>
<td>400</td>
<td>(350)</td>
</tr>
<tr>
<td>F2021</td>
<td>1,500</td>
<td>1,350</td>
<td>400</td>
<td>(250)</td>
</tr>
<tr>
<td>F2022</td>
<td>1,650</td>
<td>1,450</td>
<td>400</td>
<td>(250)</td>
</tr>
<tr>
<td>F2023</td>
<td>1,850</td>
<td>1,500</td>
<td>400</td>
<td>(100)</td>
</tr>
<tr>
<td>F2024</td>
<td>2,000</td>
<td>1,600</td>
<td>400</td>
<td>–</td>
</tr>
<tr>
<td>F2025</td>
<td>2,200</td>
<td>1,650</td>
<td>400</td>
<td>100</td>
</tr>
<tr>
<td>F2026</td>
<td>2,350</td>
<td>1,750</td>
<td>400</td>
<td>200</td>
</tr>
<tr>
<td>F2027</td>
<td>2,500</td>
<td>1,800</td>
<td>400</td>
<td>300</td>
</tr>
<tr>
<td>F2028</td>
<td>2,700</td>
<td>1,850</td>
<td>400</td>
<td>450</td>
</tr>
<tr>
<td>F2029</td>
<td>2,950</td>
<td>1,900</td>
<td>400</td>
<td>600</td>
</tr>
<tr>
<td>F2030</td>
<td>3,200</td>
<td>2,000</td>
<td>400</td>
<td>800</td>
</tr>
<tr>
<td>F2031</td>
<td>3,400</td>
<td>2,050</td>
<td>400</td>
<td>950</td>
</tr>
</tbody>
</table>

5.2.3  Load/Resource Balance Uncertainty

There are a number of uncertainties that result in risks that would have significant consequences in terms of BC Hydro being able to reliably meet its service obligation.

Load Forecast Uncertainty

BC Hydro’s Load Forecast is sensitive to a number of variables, including economic conditions:

- Factors that can lead to lower load than forecast include:
  - An increase in the value of the Canadian dollar, which would slow commodity exports from B.C.
  - Reduction in growth in China and elsewhere, leading to a slowing of commodity demand and lower prices

- Factors that could lead to higher than forecast electrical sales include:
  - Strengthening world demand for commodities and strengthening business confidence, leading to increased investment in B.C. and thus increased growth and electrification. There is unprecedented load growth potential in the north of B.C., driven by mining and shale natural gas (e.g., there is up to 500 MW of mining load in the north of B.C.).
Electrification, which is the process of switching specific end uses in the residential, commercial, transportation, and industrial sectors from utilization of fossil-based fuels to using clean or renewable electricity. BC Hydro analyzed potential electrification load such as electric plug-in vehicles and fuel choice in residential space and water heating applications, but has only included a small portion of potential electrification load in the 2012 Load Forecast. For example, the 2012 Load Forecast includes about 150 GWh/year of electric vehicle load by F2022.

BC Hydro addresses load forecast uncertainty by developing high and low forecast bands. The intention of this analysis is the creation of high and low forecast bands with approximately 10% and 90% exceedance probabilities, respectively. As stated above, for planning purposes, BC Hydro uses its mid-load forecast. The high and low forecast bands are used to provide an indication of the magnitude of load uncertainty. Figure 5.1 and Figure 5.2 at the end of this section depict the 2012 mid-energy and capacity load forecasts, respectively, and the high and low uncertainty band forecasts before DSM.

The uncertainty bands generated as part of the Load Forecast do include the effects of variable economic drivers such as GDP (as provided from third-party economic forecasts), but the mid-load forecast inherently assumes smoothed projections of future growth. In long-term resource planning proceedings, the BCUC agreed with BC Hydro that it is not credible to forecast the precise timing of economic boom and bust cycles. While BC Hydro has incorporated reasonably foreseeable short-term conditions in creating its forecasts, the purpose of the mid-load forecast is to predict average long-term trends in load growth, which will invariably include periods of higher and lower economic growth than the average.

**LNG Load**

British Columbia’s *Natural Gas Strategy and Liquefied Natural Gas Strategy* (B.C. Ministry of Energy, Mines and Natural Gas 2012a, 2012b) details the B.C. Government’s commitment to LNG exports and outlines the priorities that are to guide development of this new industry. To date, several LNG proponents have approached BC Hydro and/or the B.C. Government with respect to LNG projects for the B.C. north coast.

For the purposes of this EIS, potential non-compression LNG demand could be between about 800 GWh/year to about 6,600 GWh/year of additional energy demand, corresponding to about 100 MW to 800 MW of additional peak demand.

The energy LRB shown in Table 5.10 identifies that the upper range of this LNG load would advance the need for new energy resources from F2024 to F2019.
### Table 5.10  Energy Deficit/Surplus (GWh) with DSM Target, Revelstoke Unit 6 and LNG

<table>
<thead>
<tr>
<th>Year</th>
<th>LRB with DSM and Rev 6 and no LNG</th>
<th>LRB with DSM, Rev 6 and Low LNG</th>
<th>LRB with DSM, Rev 6 and High LNG</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2012</td>
<td>(2,100)</td>
<td>(2,100)</td>
<td>(2,100)</td>
</tr>
<tr>
<td>F2013</td>
<td>(5,200)</td>
<td>(5,200)</td>
<td>(5,200)</td>
</tr>
<tr>
<td>F2014</td>
<td>(4,000)</td>
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<tr>
<td>F2015</td>
<td>(5,500)</td>
<td>(5,500)</td>
<td>(5,500)</td>
</tr>
<tr>
<td>F2016</td>
<td>(4,700)</td>
<td>(4,700)</td>
<td>(4,700)</td>
</tr>
<tr>
<td>F2017</td>
<td>(4,700)</td>
<td>(4,700)</td>
<td>(4,700)</td>
</tr>
<tr>
<td>F2018</td>
<td>(3,400)</td>
<td>(3,400)</td>
<td>(3,400)</td>
</tr>
<tr>
<td>F2019</td>
<td>(2,200)</td>
<td>(1,400)</td>
<td>300</td>
</tr>
<tr>
<td>F2020</td>
<td>(1,900)</td>
<td>(1,000)</td>
<td>4,700</td>
</tr>
<tr>
<td>F2021</td>
<td>(1,400)</td>
<td>(600)</td>
<td>5,200</td>
</tr>
<tr>
<td>F2022</td>
<td>(1,000)</td>
<td>(100)</td>
<td>5,600</td>
</tr>
<tr>
<td>F2023</td>
<td>(200)</td>
<td>600</td>
<td>6,400</td>
</tr>
<tr>
<td>F2024</td>
<td>200</td>
<td>1,000</td>
<td>6,800</td>
</tr>
<tr>
<td>F2025</td>
<td>700</td>
<td>1,600</td>
<td>7,300</td>
</tr>
<tr>
<td>F2026</td>
<td>800</td>
<td>1,600</td>
<td>7,300</td>
</tr>
<tr>
<td>F2027</td>
<td>1,200</td>
<td>2,700</td>
<td>8,400</td>
</tr>
<tr>
<td>F2028</td>
<td>1,800</td>
<td>2,700</td>
<td>8,400</td>
</tr>
<tr>
<td>F2029</td>
<td>2,400</td>
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</tr>
<tr>
<td>F2030</td>
<td>3,100</td>
<td>4,000</td>
<td>9,700</td>
</tr>
<tr>
<td>F2031</td>
<td>3,800</td>
<td>4,600</td>
<td>10,400</td>
</tr>
</tbody>
</table>

The capacity LRB shown in Table 5.11 identifies that the upper range of the LNG load would advance the need for new capacity resources from F2025 to F2020.
Table 5.11 Capacity Deficit/Surplus (MW) with DSM Target, Revelstoke Unit 6 and LNG

<table>
<thead>
<tr>
<th>Year</th>
<th>LRB with DSM and Rev 6 and No LNG</th>
<th>LRB with DSM, Rev 6 and Low LNG</th>
<th>LRB with DSM, Rev 6 and High LNG</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2012</td>
<td>(950)</td>
<td>(900)</td>
<td>(900)</td>
</tr>
<tr>
<td>F2013</td>
<td>(1,000)</td>
<td>(1,000)</td>
<td>(1,000)</td>
</tr>
<tr>
<td>F2014</td>
<td>(900)</td>
<td>(900)</td>
<td>(900)</td>
</tr>
<tr>
<td>F2015</td>
<td>(700)</td>
<td>(700)</td>
<td>(700)</td>
</tr>
<tr>
<td>F2016</td>
<td>(250)</td>
<td>(200)</td>
<td>(200)</td>
</tr>
<tr>
<td>F2017</td>
<td>(200)</td>
<td>(200)</td>
<td>(200)</td>
</tr>
<tr>
<td>F2018</td>
<td>(100)</td>
<td>(100)</td>
<td>(100)</td>
</tr>
<tr>
<td>F2019</td>
<td>(400)</td>
<td>(300)</td>
<td>(100)</td>
</tr>
<tr>
<td>F2020</td>
<td>(350)</td>
<td>(200)</td>
<td>500</td>
</tr>
<tr>
<td>F2021</td>
<td>(250)</td>
<td>(200)</td>
<td>500</td>
</tr>
<tr>
<td>F2022</td>
<td>(250)</td>
<td>(200)</td>
<td>500</td>
</tr>
<tr>
<td>F2023</td>
<td>(100)</td>
<td>0</td>
<td>700</td>
</tr>
<tr>
<td>F2024</td>
<td>0</td>
<td>100</td>
<td>800</td>
</tr>
<tr>
<td>F2025</td>
<td>100</td>
<td>200</td>
<td>900</td>
</tr>
<tr>
<td>F2026</td>
<td>200</td>
<td>300</td>
<td>1,000</td>
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<td>F2027</td>
<td>300</td>
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<td>1,100</td>
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<tr>
<td>F2028</td>
<td>450</td>
<td>500</td>
<td>1,200</td>
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<tr>
<td>F2029</td>
<td>600</td>
<td>700</td>
<td>1,400</td>
</tr>
<tr>
<td>F2030</td>
<td>800</td>
<td>900</td>
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</tr>
<tr>
<td>F2031</td>
<td>950</td>
<td>1,000</td>
<td>1,700</td>
</tr>
</tbody>
</table>

DSM Reliance and Delivery Risk

BC Hydro is relying on the DSM target to meet a large percentage of both the energy and capacity gaps:

- The DSM target amounts to about 107% of the energy LRB gap in F2021, meaning the current DSM target creates an energy surplus.
- The 1,400 MW of capacity savings in F2021 associated with the DSM target is being relied on to contribute a large portion of the capacity needs. The DSM target represents about 85% of the capacity LRB gap in F2021. At this level, the DSM target peak demand savings are more than the dependable capacity the Project would provide, or the three largest Resource Smart projects combined – Mica Units 5 and 6, and Revelstoke Unit 6 (after reflecting the associated reserve requirements that would be required for supply-side resources).

Precise forecasting of DSM savings for long-term planning purposes is challenging for several reasons, including:

- Limited BC Hydro experience with respect to targeting and achieving savings at and above the current DSM target level.
- Model uncertainty, in particular, linking customer response to DSM actions, and forecasting the timing and efficacy of regulatory (codes and standards) changes.

The BC Hydro DSM target is aggressive and entails delivery risks – that is, the risk that the current DSM target will not deliver the projected energy and particularly capacity.
savings within the specified time frame. Ensuring an adequate capacity supply is the
primary concern for BC Hydro, since capacity is required at specific times to meet peak
load requirements and to maintain system security and reliability. Capacity resources
also support intermittent clean or renewable generation resources that primarily supply
energy so that generation is available when the loads require it. On the capacity side, a
shortfall caused by missed DSM targets could undermine BC Hydro’s fundamental
obligation to serve its customers:

- The Utilities Commission Act service obligation means that BC Hydro must make
  sure its customers’ demand is met at the peak load every day
- The risk that DSM will not deliver the anticipated 1,400 MW of dependable capacity
  savings by F2021 is greater than the risk that DSM does not deliver the anticipated
  7,800 GWh of energy savings by F2021. There are two sources of uncertainties
  regarding DSM-related capacity savings:
  - The underlying uncertainty around the energy savings themselves
  - The capacity factors used to translate energy savings into the associated level of
    capacity savings. These factors have additional uncertainty, due to the lack of
    precise knowledge about how energy savings from multiple sources would
    reduce peak demand.
- The consequence of DSM not delivering the anticipated 1,400 MW of dependable
  capacity savings by F2021 is greater as compared to failure to deliver the anticipated
  energy. Generally, external markets can be counted on for supply of energy across
  the year (albeit with costs), but during winter peaks there are issues with:
  - The illiquid (thinly traded) nature of the market for capacity
  - Insufficient transmission capacity
  - The U.S. market not having surplus to sell

This is one of the reasons why BC Hydro develops contingency resource plans that can
provide dependable capacity to meet its customers’ requirements.

There are delivery risks associated with each major strategic element of the DSM target:

- Codes and standards are subject to Federal and/or B.C. Government approval and
  implementation, and may be deferred in implementation, may not apply to all
  equipment and buildings governments have planned, may have varying levels of
  minimum efficiency standards, or may depend on compliance by consumers,
  retailers, builders, etc.
- Conservation rate structures are subject to BCUC approval, and customer response
  to price signals is uncertain in a relatively low electricity rate jurisdiction such as
  BC Hydro’s service area
- Programs rely on voluntary customer participation and the rate of savings per
  participant is uncertain

BC Hydro developed the following ranges around the current DSM target (DSM
Option 2), referred to as DSM Option 1 and DSM Option 3:

- In Option 1, the DSM program component is reduced to achieve about 75% of the
  BC Hydro DSM target. All other tactics are similar to those employed in the
BC Hydro DSM target. Option 1 is expected to deliver about 7,500 GWh/year of energy savings and 1,200 MW of dependable capacity savings by F2021.

- DSM Option 3 targets more electricity savings than the current BC Hydro DSM target by expanding program efforts while keeping the level of activity and savings for codes and standards, and conservation rate structures, consistent with the DSM target. Program activities are expanded with increased incentives, advertising, or technical support to address customer barriers as means of potentially increasing customer participation. As a result, program costs increase to deliver the higher volume of projects and resulting applications. DSM Option 3 is expected to deliver 9,200 GWh/year of energy and 1,400 MW of capacity in F2021. BC Hydro notes that DSM Option 3 on its own is not an alternative to the Project because, on its own, Option 3 defers the energy LRB gap by five years and does not defer the capacity LRB gap.

**IPP Delivery Uncertainty – IPP Attrition and Price Risk and EPA Renewals**

IPP projects are subject to attrition, with EPAs being terminated for various reasons such as unexpected cost increases, financing obstacles, and permitting difficulties. For the most recent broadly-based BC Hydro power acquisition process, the Clean Power Call, a 30% attrition factor was assumed. The attrition rate for the F2006 Call is about 55% (excluding two coal-fired projects). There is also risk that IPP bid prices are not ‘all in’ prices. IPPs periodically request EPA amendments after power acquisition processes have been completed, including uplifts to EPA prices and delays in the commercial operation date. Both the attrition rate and the request for EPA amendments show that IPPs have been hampered by unanticipated development cost increases and project delays.

EPAs with IPPs and other third parties have varying durations, ranging from 15 to 40 years. BC Hydro assumes for purposes of the LRBs presented in this EIS that, with the exception of EPAs with bioenergy generation facilities, a portion of the EPAs with IPPs (about 75% of clean or renewable IPPs) will be renewed upon expiry, and that those IPP facilities will continue to provide the same amount of electricity to BC Hydro. BC Hydro assumes that about 50% of bioenergy EPAs will be renewed. In BC Hydro’s view, it is not prudent to plan on the renewal of all existing and committed EPAs with biomass generation facilities, due to fuel pricing and supply risk. In the last 10 years of the planning horizon, bioenergy EPAs totalling approximately 600 GWh/year and 60 MW of firm energy and dependable capacity are set to expire. Overall, there is no assurance that 1) IPP projects will continue operations past the expiry of the EPAs, 2) that IPPs will contract with BC Hydro if they do continue to operate, or 3) that IPPs will contract at a price comparable to their current real dollar prices. All of these factors represent significant supply and price risk to BC Hydro.

As noted above in Section 5.2.1.2, the ELCC method may overstate the capacity contribution of intermittent clean or renewable resources.

**Contingency Planning**

Contingency planning is done as a reliability management tool to manage the risk (consequences) of not being able to meet load. The contingency plan seeks to prepare to meet greater demand than forecast, and seeks reduce the lead time for contingency resources to be in service, if the need arises. Contingency planning is part of good utility
practice; it is also a component of long-term resource planning that is recognized as important in the BCUC’s Resource Planning Guidelines.

In developing its contingency plan, BC Hydro uses both capacity and energy shortfall risks summarized above. BC Hydro considers load forecast uncertainty (including LNG), DSM delivery risk and IPP delivery risk:

- Capacity requirements are the primary concern for BC Hydro, since capacity is required to meet peak load requirements and to maintain system security and reliability. After implementation of Revelstoke Unit 6, the capacity resources available to BC Hydro are limited to natural gas-fired generation Simple Cycle Gas Turbines (SCGTs) and/or pumped storage. The DSM target in particular creates significant uncertainty regarding the volumes of capacity that will ultimately be delivered. As described above, BC Hydro is relying on the current DSM target to deliver 1,400 MW of peak reduction (capacity savings) by F2021.

- BC Hydro considers additional uncertainty with respect to the reliance on ELCC for intermittent clean or renewable resources and the potential for increased IPP attrition. Uncertainty analysis indicates that the shortfalls shown in Table 5.12 below are adequate for planning purposes; however, using ELCC for intermittent clean or renewable resources and IPP attrition are risks that BC Hydro will need to continue to monitor.

Refer to Table 5.12 for a description of the shortfall risks addressed by BC Hydro’s Contingency Resource Plan, and to Figure 5.3 for a graphic depiction of the Contingency Resource Plan LRB.

### Table 5.12 BC Hydro Contingency Resource Plan Shortfall Risks

<table>
<thead>
<tr>
<th>Risk</th>
<th>Rationale</th>
<th>Capacity Reduction for Contingency Planning Purposes (MW)</th>
<th>Energy Shortfall Risk (GWh/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>F2022</td>
<td>F2031</td>
</tr>
<tr>
<td>General Load Forecast Uncertainty a</td>
<td>Peak load and energy requirements can increase as a result of either sustained growth or low temperatures at winter peak</td>
<td>1,100</td>
<td>1,450</td>
</tr>
<tr>
<td>DSM Delivery Risk</td>
<td>The BC Hydro DSM target has a significant range of delivery risk where the variability is driven by implementation of codes and standards, customer response to programs and rates</td>
<td>450</td>
<td>550</td>
</tr>
</tbody>
</table>

**NOTE:**

| a LNG load could add approximately 6,600 GWh/year and 800 MW to the amounts shown

As discussed in Section 5.5.2.8 below, if BC Hydro were to choose natural gas-fired generation such as SCGTs in lieu of the Project, it would deprive itself of being able to rely on SCGTs as a contingency resource if, for example, DSM does not deliver the anticipated capacity savings.
Project Range of In-Service Dates

Given the uncertainty described in this section and to provide a basis for Project alternatives evaluation, BC Hydro evaluated a range of Project in-service dates from F2022 to F2024. However, given the uncertainties around the amount and timing of potential LNG load and DSM and IPP delivery, BC Hydro considers it prudent to proceed with the Project for its earliest in-service date of F2022.

5.2.4 Conclusion

Based on the LRBs in Table 5.8 and Table 5.9, there are energy and capacity gaps within the 20-year planning period that must be filled with supply-side options. As described in Section 5.4, targeting more DSM is not a viable alternative to the Project. Section 5.5 contains the available supply-side resources analysis, including the trade-offs between different supply-side resources to address the energy and capacity deficits set out in Table 5.8 and Table 5.9, which forms the basis of the need for the Project.

5.3 Purpose of the Project

The EIS Guidelines confirm that the EIS will present the ‘purpose of’ the Project, and goes on to state that the purpose of the Project “will be established from the perspective of the Proponent, and will provide context for consideration of alternatives to the Project” in Sections 5.4 and 5.5. The EIS Guidelines also require that the EIS describe the objectives the Project is designed to achieve.

The purpose of the Project is to:

- Cost-effectively meet BC Hydro’s forecasted need for energy and capacity identified in Section 5.2.2. Refer to Section 5.3.1.
- Align with the relevant objectives of Section 2 of the Clean Energy Act and relevant B.C. Government policy statements, which in turn were used to develop Project-specific objectives, including the objective to maximize the development of the hydroelectric potential of the Site C Flood Reserve. Refer to Section 5.3.2.

5.3.1 Meeting Identified Need

The Project would provide about 5,100 GWh/year of average energy and up to 1,100 MW of dependable capacity. As demonstrated in Table 5.8 and Table 5.9, even with the additional actions of implementing the current BC Hydro DSM target and Revelstoke Unit 6, BC Hydro will have a projected energy shortfall beyond F2023, and a projected capacity shortfall beyond F2024.

Table 5.13 and Table 5.14 indicate that, by constructing the Project at its earliest in-service date of F2022, BC Hydro will have sufficient energy and capacity to meet its mid-load forecast energy and peak demand without LNG throughout the 20-year planning horizon.
### Table 5.13  Energy Surplus/Deficit (GWh) with DSM Target, Revelstoke Unit 6 and the Project (No LNG)

<table>
<thead>
<tr>
<th>Year</th>
<th>LRB with DSM, Rev 6 &amp; Site C Clean Energy Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2012</td>
<td>(2,100)</td>
</tr>
<tr>
<td>F2013</td>
<td>(5,200)</td>
</tr>
<tr>
<td>F2014</td>
<td>(4,000)</td>
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<tr>
<td>F2015</td>
<td>(5,500)</td>
</tr>
<tr>
<td>F2016</td>
<td>(4,700)</td>
</tr>
<tr>
<td>F2017</td>
<td>(4,700)</td>
</tr>
<tr>
<td>F2018</td>
<td>(3,400)</td>
</tr>
<tr>
<td>F2019</td>
<td>(2,200)</td>
</tr>
<tr>
<td>F2020</td>
<td>(1,900)</td>
</tr>
<tr>
<td>F2021</td>
<td>(1,400)</td>
</tr>
<tr>
<td>F2022</td>
<td>(1,400)</td>
</tr>
<tr>
<td>F2023</td>
<td>(4,600)</td>
</tr>
<tr>
<td>F2024</td>
<td>(4,900)</td>
</tr>
<tr>
<td>F2025</td>
<td>(4,400)</td>
</tr>
<tr>
<td>F2026</td>
<td>(4,300)</td>
</tr>
<tr>
<td>F2027</td>
<td>(3,900)</td>
</tr>
<tr>
<td>F2028</td>
<td>(3,300)</td>
</tr>
<tr>
<td>F2029</td>
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<td>F2030</td>
<td>(2,000)</td>
</tr>
<tr>
<td>F2031</td>
<td>(1,300)</td>
</tr>
</tbody>
</table>

### Table 5.14  Capacity Surplus/Deficit (MW) with DSM Target, Revelstoke Unit 6 and the Project (No LNG)

<table>
<thead>
<tr>
<th>Year</th>
<th>LRB with DSM, Rev 6 &amp; Site C Clean Energy Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>F2012</td>
<td>(950)</td>
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<td>F2013</td>
<td>(1,000)</td>
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<td>F2016</td>
<td>(250)</td>
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<td>F2017</td>
<td>(200)</td>
</tr>
<tr>
<td>F2018</td>
<td>(100)</td>
</tr>
<tr>
<td>F2019</td>
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<td>(250)</td>
</tr>
<tr>
<td>F2022</td>
<td>(250)</td>
</tr>
<tr>
<td>F2023</td>
<td>(1,050)</td>
</tr>
<tr>
<td>F2024</td>
<td>(950)</td>
</tr>
<tr>
<td>F2025</td>
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<tr>
<td>F2026</td>
<td>(750)</td>
</tr>
<tr>
<td>F2027</td>
<td>(650)</td>
</tr>
</tbody>
</table>
Section 5.3.2 Aligning with the *Clean Energy Act* and B.C. Government Policy

Section 2 of the *Clean Energy Act* sets out B.C. Government objectives, referred to as "British Columbia’s energy objectives", that BC Hydro must respond to and that the BCUC must consider and be guided by in various applications. The alignment of the Project with the relevant *Clean Energy Act* energy objectives is described in Table 5.15.

Table 5.15 Project Alignment with *Clean Energy Act* Objectives

<table>
<thead>
<tr>
<th>Clean Energy Act Objective</th>
<th>How the Project Supports the Objective</th>
</tr>
</thead>
<tbody>
<tr>
<td>At least 93% generation from clean or renewable resources</td>
<td>The Project is a clean or renewable resource as defined by Section 1 of the <em>Clean Energy Act</em>. The Project provides clean or renewable energy and dependable capacity, and also has the ability to shape, firm, and help integrate intermittent clean or renewable resources such as wind and run-of-river. Refer to Section 7.4.3 in Volume 1 Section 7 Project Benefits.</td>
</tr>
<tr>
<td>To ensure that BC Hydro’s rates remain among the most competitive of rates charged by public utilities in North America</td>
<td>The Project is a cost-effective resource for energy and capacity compared to alternative supply options; refer to Section 5.5</td>
</tr>
<tr>
<td>To reduce greenhouse gas (GHG) emissions</td>
<td>As a hydroelectric resource, the Project emits virtually no GHG emissions when compared to natural gas-fired electricity resources, and on a per GWh basis, emits a similar amount of GHGs as other clean or renewable resources such as wind. Refer to Section 7.4.2 in Volume 1 Section 7 Project Benefits and to Volume 2 Section 15 Greenhouse Gases.</td>
</tr>
<tr>
<td>To encourage economic development and the creation and retention of jobs</td>
<td>The Project is a job-intensive capital project that will create employment in B.C. during the construction period. Refer to Section 7.3 in Volume 1 Section 7 Project Benefits.</td>
</tr>
<tr>
<td>To maximize the value of B.C.’s generation and transmission assets</td>
<td>The Project provides additional benefits (e.g., shaping and firming benefits) to optimize the value of B.C.’s generation and transmission assets. In addition, as the third project on one river system, the Project would generate 35% of the energy produced at the W.A.C. Bennett Dam, with 5% of the reservoir area. Refer to Section 7.4.1 in Volume 1 Section 7 Project Benefits.</td>
</tr>
</tbody>
</table>

NOTE:

*"Clean or renewable resources" are defined in Section 1 of the *Clean Energy Act* as follows: “clean or renewable resource means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource”. To date, biogenic waste, waste heat and waste hydrogen have been added to this definition pursuant to the B.C. Clean or Renewable Resource Regulation, B.C. Reg. 291/2010.*

In addition to Section 2 of the *Clean Energy Act*, the 2007 Energy Plan sets the policy framework in which BC Hydro develops resources. The 2007 Energy Plan stresses the development of clean or renewable resources. While a number of 2007 Energy Plan...
Policy Actions have been overtaken by Section 2 of the *Clean Energy Act*, there are 2007 Energy Plan Policy Actions relevant to the review of natural gas-fired generation and other potential alternatives to the Project, as set out in Table 5.16.

Table 5.16  Relevant 2007 Energy Plan Policy Actions

<table>
<thead>
<tr>
<th>Policy Action</th>
<th>Section in Environmental Impact Statement</th>
</tr>
</thead>
<tbody>
<tr>
<td>18 – All new electricity generation projects will have zero net GHG emissions</td>
<td>The B.C. <em>Environmental Management Act</em> (S.B.C., 2003, c.53) is described in further detail in Section 5.5.2.8. All new natural gas-fired generation analyzed in the alternatives to Project analysis factors in the zero net GHG emissions requirement.</td>
</tr>
<tr>
<td>20 – Require zero GHG emissions from any coal thermal electricity facilities</td>
<td>See above in respect of Policy Action No. 18; the current status of coal-fired generation with carbon capture and storage is examined in Section 5.4.2.2</td>
</tr>
<tr>
<td>23 – No nuclear power</td>
<td>Nuclear technology is not an alternative to the Project; refer to Section 5.4.2.1</td>
</tr>
</tbody>
</table>

BC Hydro developed the Project objectives listed in Table 3.1 in Volume 1 Section 3 Project Overview, from the *Clean Energy Act* and the 2007 Energy Plan. BC Hydro’s objective to ensure a long-term source of energy and capacity and to optimize existing assets on the Peace River system is supported by the B.C. Government’s reservation of Crown land in the Peace River watershed for the purposes of hydroelectric development through an Order-in-Council in 1957 (further described in Section 6.2 in Volume 1 Section 6 Alternative Means of Carrying Out the Project). This Order-in-Council was subsequently amended and the Site C Flood Reserve described in Section 6.2 of this EIS defines the bounds within which the Project can be developed. As a result, to fulfill the Project objectives, the specific purpose of the Project design is to cost-effectively maximize the development of the hydroelectric potential of the Site C Flood Reserve to meet the need and maximize the benefits to British Columbia.

5.4 Identification of Potential Alternatives to the Project and Screened Resources

The EIS Guidelines call for the EIS to describe the functionally different ways to meet the need for the Project, that is, the technically and economically feasible alternatives to the Project. The EIS is to identify the alternatives to the Project that were considered. The EIS is to describe the criteria used to compare the Project to other alternatives, with consideration of the major financial, technical, environmental, and economic development attributes, per the Agency Need/Alternatives Operational Policy Statement. This analysis must be done to a level of detail that is sufficient to compare the Project to the alternatives.

BC Hydro’s analysis of the potential alternatives to the Project is contained in two parts:

- This section provides an overview of the identification and review process for potential alternatives to the Project, and concludes with the resources that were screened out on the basis that they are not viable. This first category of potential alternatives is referred to as the Screened Resources. The Screened Resources consist of:
  - Supply-side resources that are not permitted by or are inconsistent with B.C. Government legal requirements, namely: Burrard, Large hydroelectric projects
prohibited by the Clean Energy Act, nuclear, and external market purchases/imports including the Canadian Entitlement (Section 5.4.2.1)

- Supply-side resources that are not technically or economically feasible alternatives to the Project. These resources are: Coal-fired generation with carbon capture and storage, wave, tidal and solar (Section 5.4.2.2).
- Increased levels of DSM beyond the current BC Hydro DSM target (i.e., DSM Options 4 and 5) described in Section 5.4.2.3
- DSM options designed to deliver capacity savings during BC Hydro’s peak load periods (Section 5.4.2.4)

- Section 5.5 describes the second category of potential alternatives – the available resources and their attributes. The available resources are supply-side resources that, when used in various combinations, can meet the need identified in Section 5.2. The available resources encompass:
  - Clean or renewable IPPs, including wind, run-of-river hydro, biomass, geothermal, and pumped storage
  - BC Hydro Resource Smart potential
  - Clean or renewable IPPs and/or Resource Smart combined with some natural gas-fired generation. Natural gas-fired generation is constrained by the Subsection 2(c) Clean Energy Act target “to generate at least 93% of the electricity in British Columbia from clean or renewable resources...”. This target and its effect on natural gas-fired generation are addressed in Section 5.5.2.8.

5.4.1 Alternatives Identification

5.4.1.1 2010 Resource Options Report

The information for potential alternatives to the Project derives in large part from the 2010 Resource Options Report, which is a database of various resource options considered for meeting BC Hydro’s future energy and capacity needs. In line with long-term resource planning best practices and the BCUC’s Resource Planning Guidelines, BC Hydro included and assessed a wide variety of DSM, generation supply-side resource, and transmission options in its 2010 Resource Options Report. BC Hydro developed resource option attributes and costs reflecting information from BC Hydro project experience, consultant studies, and First Nations and public stakeholder input, including from members of the IPP community. A number of studies were conducted by BC Hydro and its consultants, including:

- Powertech Labs Inc., Coal with Carbon Capture & Sequestration for Long-Term Transmission Inquiry (September 15, 2009)
- Garrad Hassan Canada Inc., Updated Capital and O&M Cost Assumptions for Wind Power Development in British Columbia (November 26, 2010)
- Industrial Forest Service Ltd., Wood-Based Biomass Energy Potential of British Columbia (January 2011)
The 2010 Resource Options Report-related engagement process consisted of working with people and organizations with technical expertise to gather and review information on DSM and supply-side options in B.C. Focused workshops and meetings were held on specific energy sources, including:

1. DSM: BC Hydro engaged with its Electricity Conservation and Efficiency Committee.
2. Run-of-river hydro: A series of workshop meetings were held in September 2010. A draft of the Kerr Wood Leidal resource assessment report was posted on BC Hydro’s website for comment prior to finalization.
3. Wind resources (onshore and offshore): A working group was established in September 2010 to review drafts of the Garrad Hassan report on onshore/offshore wind cost assumptions, results of onshore wind potential, methodology, and assumptions for determining offshore wind potential. An individual meeting with IPPs was held in October 2010.
4. Biomass – Biogas, Municipal Solid Waste and Wood-Based: A series of workshop meetings were held between August 2010 and November 2010. A biomass working group, including representatives from the B.C. Ministry of Energy, Mines and Natural Gas, the B.C. Ministry of Forests, Lands and Natural Resource Operations, and consultants Industrial Forest Services Ltd., M.D.T. Ltd. and Murray Hall Consulting Ltd., participated in the studies to determine long-term availability potential and cost. A draft copy of the Forest Service report was circulated for comment in November 2010.
5. Geothermal: A series of workshop meetings were held in September 2010. It was agreed that data compiled by GeothermEX for the Western Renewable Energy Zone initiative would be the basis for conventional geothermal potential. It was recognized that this represents a conservative estimate of the potential, as it does not include resources from enhanced geothermal or co-produced fluids that are likely to be found in B.C.
6. Natural Gas-Fired Generation: Representatives from IPPs, consumer organizations, and consultants met in September 2010 and decided there was no need to establish a working group.
7. Pumped Storage: Two consultants – Knight Piésold and Hatch – participated with representatives from IPPs, individual developers, and consulting firms in a working group that met between July and October 2010. Among other things, this group reviewed the Knight Piésold study methodology and preliminary results, and shared information on potential sites, technical work that had been done to date, etc.
BC Hydro also received submissions from workshop participants, which informed the Resource Options Report, including Ocean Renewable Energy Group’s August 14, 2009 submission entitled “Resource Options Workshop – Wave and Tidal”. BC Hydro met with the B.C. Ministry of Environment and environmental organizations (Nature Trust of Canada, Ducks Unlimited, BC Sustainable Energy Association, David Suzuki Foundation, West Coast Environmental Law Association, Westcoast Wilderness Committee, Watershed Watch Salmon Society, Sierra Club, and Pembina Institute) to review the methodology for the environmental attributes. BC Hydro reported out on the draft 2010 Resource Options Report results on December 8, 2010. BC Hydro circulated a draft of the 2010 Resource Options Report and established a written comment period of between December 8 and 31, 2010.

Resource Technologies

The result is the 2010 Resource Options Report, which looks out 20 years for DSM and supply-side options. Table 5.17 shows the B.C.-based resources that are identified in the Resource Options Report and discussed in Sections 5.4.2 and 5.5.2.

Table 5.17 Resource Technologies Identified

<table>
<thead>
<tr>
<th>Technology</th>
<th>Screened/Available Resource</th>
<th>Section Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Demand Side Management Options</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DSM Options 4 and 5</td>
<td>Screened Resource</td>
<td>Section 5.4.2.3</td>
</tr>
<tr>
<td>DSM capacity-only initiatives</td>
<td>Screened Resource</td>
<td>Section 5.4.2.4</td>
</tr>
<tr>
<td><strong>Clean or Renewable Resources</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wave and tidal</td>
<td>Screened Resource</td>
<td>Section 5.4.2.2</td>
</tr>
<tr>
<td>Solar</td>
<td>Screened Resource</td>
<td>Section 5.4.2.2</td>
</tr>
<tr>
<td>Wind (on-shore and off-shore)</td>
<td>Available Resource</td>
<td>Section 5.5.2.2 and Section 5.5.2.3</td>
</tr>
<tr>
<td>Run-of-river hydro</td>
<td>Available Resource</td>
<td>Section 5.5.2.1</td>
</tr>
<tr>
<td>Geothermal</td>
<td>Available Resource</td>
<td>Section 5.5.2.7</td>
</tr>
<tr>
<td>Biomass</td>
<td>Available Resource</td>
<td>Section 5.5.2.4, Section 5.5.2.5, and Section 5.5.2.6</td>
</tr>
<tr>
<td>Large hydroelectric (other than the Project)</td>
<td>Screened Resource</td>
<td>Section 5.4.2.1</td>
</tr>
<tr>
<td>Pumped storage (dependable capacity only)</td>
<td>Available Resource</td>
<td>Section 5.5.2.10</td>
</tr>
<tr>
<td>BC Hydro Resource Smart</td>
<td>Available Resource</td>
<td>Section 5.5.2.9</td>
</tr>
<tr>
<td><strong>Fossil Fuel Resources</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal-fired generation with carbon capture and storage</td>
<td>Screened Resource</td>
<td>Section 5.4.2.2</td>
</tr>
<tr>
<td>Natural gas-fired generation SCGTSs (dependable capacity) CCGTs (firm energy)</td>
<td>Available Resource within the 93% Clean Energy Act clean or renewable target</td>
<td>Section 5.5.2.8</td>
</tr>
</tbody>
</table>

2010 Resource Options Report Attributes

A set of technical, financial, environmental, and economic development attributes were developed in the 2010 Resource Options Report for each technology to compare and evaluate the resource options and for IRP portfolio analysis. Section 5.5.1 describes these attributes.
Limitations

The 2010 Resource Options Report database of resources contains sufficient information on physical, financial, environmental, and economic development characteristics to allow for both economic and environmental analysis at a planning level. However, because the 2010 Resource Options Report values present a high level planning assessment of resource type costs, the values:

- Do not reflect site-specific information, permitting constraints, and other development risks. For example, the UECs estimated for the geothermal resource options do not reflect the exploration risks associated with drilling and proving site-specific resource potential.

- May not predict accurately future prices set through BC Hydro’s power acquisition processes. Historically, the resource options with the lowest unadjusted Unit Energy Cost (UEC) values are not always bid into BC Hydro’s power acquisition processes. A case in point is the geothermal resource option, which appears to be low cost, based on an unadjusted UEC value of $88/MWh ($F2013) and upward, but has never been bid into a BC Hydro power acquisition process by IPPs. Refer to Section 5.5.2.

5.4.1.2 Wind Cost Update

The wind UECs in the 2010 Resource Options Report were based on wind generation modelling studies completed by GEC-KEMA (formally known as DNV-GEC) in May 2009 and September 2009, and cost assumptions provided by Garrad Hassan Canada Inc. in November 2010. These studies were conducted and completed as changes in wind turbine efficiencies and apparent changes in wind turbine pricing were taking place.

The 2010 Resource Options Report wind UECs have been revised to reflect observed changes in turbine efficiencies and wind turbine prices that have occurred over the past three years:

- Wind turbine efficiencies: BC Hydro commissioned DNV-KEMA in May 2012 to provide a wind turbine power curve for International Electrotechnical Commission (IEC) Class III wind sites (corresponding to low average wind speeds) and to update the power curves for IEC Class I and II wind sites (corresponding to high and medium average wind speeds, respectively). The three wind power curves were developed by blending wind turbine power curves for a number of recent and current turbine models for each of the three IEC classes. The new power curves were then applied to the modelled wind speeds from the original 2010 Resource Options Report Wind Data Study to create new hourly generation profiles for each wind project. In this analysis, no changes were assumed for turbine hub heights, installed wind capacity of the individual wind projects, or wind farm losses. With the application of the revised power curves, the annual net energy production increased on average by 13% for IEC Class I wind projects, 6% for IEC Class II wind projects, and 18% for IEC Class III wind projects.

- Wind turbine prices: Over the past decade, wind turbine prices have undergone considerable changes. Turbine prices steadily increased from 2002 to 2009. Turbine prices peaked in the first half of 2009, but have dropped since then by approximately 20% to 30%. The trends in turbine prices have been subject to a number of reports (Bolinger and Wiser 2011; National Renewable Energy Laboratory 2012; U.S.
The increase in turbine prices has been attributed to increased material and labour costs, upscaling of turbine size, decline in the U.S. dollar relative to the euro, increased costs in turbine warranty provisions, and a general increase in turbine manufacturer profitability, due in part to strong demand growth, and turbine and component supply shortages. The decline in wind turbine prices since 2009 has coincided with the downturn in the global economic situation. The reduced turbine demand has increased competition among manufacturers, and shifted the turbine market from a seller’s market to a buyer’s market.

- The current wind turbine prices are forecasted to persist through 2015, but it is uncertain if the low sale margins can be maintained by the manufacturers in the long term. Improved efficiencies in the manufacturing process, continued technical advancements, and potential competition from Chinese turbine manufacturers may help keep turbine prices low in the future. At the same time, resurgence in wind turbine demand, resulting in supply chain pressures similar to those observed between 2004 and 2009, could counter the cost reductions and increase wind turbine prices. In light of these uncertainties, BC Hydro decreased the wind turbine price by 15% from the original assumption used in the 2010 Resource Options Report.

Refer to Figure 5.4 at the end of this section, which shows the updated onshore wind supply curve, which takes into account the new turbine efficiencies and lower turbine costs in comparison to the onshore wind supply curve based on the 2010 Resource Options Report. The costs are based on a cost of capital of 8%; refer to Section 5.5.3.4 for a discussion of cost of capital. The updated (lower) wind UECs are used in the available resources analysis in Section 5.5.

### 5.4.2 Screened Resources

Potential alternatives were screened to determine if they are viable. There are four categories of Screened Resources determined to be not viable, with the specific reasons set out in this part in respect of each resource.

#### 5.4.2.1 Category 1: Barred Resources

The Agency Need/Alternatives Policy Statement provides that “alternatives to the project should be established in relation to the project need and purpose and from the perspective of the proponent” (CEA Agency 2007). Accordingly, those resources that are legislatively barred (Burrard, the large hydroelectric projects prohibited by the Clean Energy Act, and external markets) or policy barred (nuclear) are not available to BC Hydro and thus are not alternatives to the Project.

**Burrard**

Burrard is not an alternative to the Project, as it is an existing resource that is already being relied on to the extent permitted under Sections 3(5), 6(2)(d) and 12 of the Clean Energy Act, which provides that the Burrard firm energy contribution is 0 GWh/year, and the Burrard Thermal Electricity Regulation, which requires that Burrard’s dependable capacity of 900 MW be phased out as Mica Units 5 and 6, the Interior to Lower Mainland Transmission Reinforcement Project, and the third transformer at the Meridian Substation are introduced into service by about F2016, well before the Project’s earliest
in-service date. After this, BC Hydro will only be able to operate Burrard in case of
emergency or for voltage support.

Other Large Hydro Barred by *Clean Energy Act*

Sections 10 and 11, and Schedule 2, of the *Clean Energy Act* prohibit the development
of the following large hydroelectric projects: Murphy Creek, Border, High Site E, Low
Site E, Elaho, McGregor Lower Canyon, Homathko River, Liard River, Iskut River, Cutoff
Mountain, and McGregor Diversion. Cutoff Mountain on the Skeena River and McGregor
Diversion are also legislatively barred by respectively 1) the B.C. *Fish Protection Act*
(S.B.C., 1997, c.21), which designates the Skeena River as a “protected river” and
prohibits the construction of bank-to-bank dams on the Skeena River, and 2) the B.C.
*Water Protection Act* (R.S.B.C., 1996, c.484), which prohibits the construction of
“large-scale projects” such as McGregor Diversion capable of transferring a peak
instantaneous flow of 10 or more cubic metres of water per second between major
watersheds. McGregor Diversion would divert most of the McGregor River flows across
the divide between the Pacific and Arctic watersheds into the Peace River basin.

Aside from pumped storage, which is examined in Section 5.5.2.10, BC Hydro is not
aware of any other B.C.-based potential large hydroelectric projects that could be an
alternative to the Project. The alternative means of delivering the Project are discussed
in Volume 1 Section 6 Alternative Means of Carrying Out the Project.

Nuclear

Policy Action No. 23 of the 2007 Energy Plan provides that “nuclear power is not part of
the Province of B.C.’s future” and that the B.C. “government rejects nuclear power as a
strategy to meet British Columbia’s future energy needs”. While the Federal Government
has siting authority over nuclear electricity-generating facilities (*Society of Ontario Hydro
Professional and Administrative Employees v. Ontario Hydro*. 1993. 3 S.C.R. 327
(S.C.C.)), the B.C. Government can prevent BC Hydro from purchasing electricity from
nuclear electricity-generating facilities through its ability to issue directions to BC Hydro
and the BCUC. Therefore, nuclear power is not an alternative to the Project.

External Market/Imports

Pursuant to Section 6 of the *Clean Energy Act*, BC Hydro is required to achieve
electricity self-sufficiency by the year 2016 (i.e., F2017) by holding the rights to an
amount of electricity that meets its electricity supply obligations, taking into account DSM
and electricity “solely from electricity generating facilities within the Province”. As a result
of the self-sufficiency legal requirement, the following external market/import energy and
capacity resources are not alternatives to the Project because they do not result “solely
from electricity generating facilities within the Province”:

- The spot market and imports from the U.S., Alberta, or other markets external to B.C.
  under long-term contract
- The Canadian Entitlement, which is the Canadian portion of the additional electricity
  produced in the Columbia River in the western U.S. as a result of provisions of the
  Columbia River Treaty of 1961, because the Canadian Entitlement is produced from
  electricity generating facilities in the U.S. and is delivered to the U.S.-B.C. border
5.4.2.2 Category 2: Supply-Side Resources Not Technically or Economically Feasible Alternatives

Coal-Fired Generation with Carbon Capture and Storage

Policy Action No. 20 of the 2007 Energy Plan stipulates that coal-fired generation in B.C. must meet a zero GHG emission standard “through a combination of ‘clean coal’ fired generation technology, carbon sequestration and offset for any residual GHG emission”. While clean coal technology in the form of Integrated Gasification Combined Cycle is now becoming available, technology that allows plant-generated carbon dioxide (CO2) to be captured and stored through sequestration is still evolving and is not presently viable on a commercial scale.

BC Hydro concludes that coal-fired generation with carbon capture and storage is not a technically feasible alternative to the Project. According to the Electric Power Research Institute (Electric Power Research Institute 2007), coal-fired generation plants with 90% CO2 emission capture and storage could not be commercially available in B.C. until about 2028; this was also the conclusion of Powertech Lab Inc. (Powertech Labs Inc. 2009). There is uncertainty with respect to the cost of carbon capture and storage, and with respect to what impact carbon capture and storage will have on a large coal-fired generating station’s efficiency. Although there are some geological sites in B.C. that may prove suitable for CO2 storage, there is limited information available to assess the suitability for geological storage at this time. There are also a number of legal/regulatory and public acceptance issues that likely need to be addressed before carbon capture and storage technology can be considered on a commercial scale in B.C. For example, there is currently no liability regime in place to govern responsibility for CO2 leakage once stored.

Wave

Wave energy is generated by winds blowing over the surface of the ocean. Currently, there are five generic approaches to capturing the wave energy resource, all of which are at the early stages of commercial development, with potential application in B.C. There are no wave energy projects in B.C. waters, although two demonstration projects received support from B.C. and Federal Government innovative clean energy funding agencies.

BC Hydro relied on information in the Geographic Information System map of the B.C. Integrated Land Management Bureau tenure database, and the incoming wave power from the Canadian Hydraulic Centre report (Canada Hydraulic Centre 2006) to develop the total theoretical wave energy potential. The costs associated with these wave energy projects have been estimated based on the cost projections from the U.K.-based Carbon Trust report (Carbon Trust 2006). A summary of the technical and financial results for wave resource is contained in Table 5.18.
Table 5.18  Summary of Wave Potential

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Potential Sites</th>
<th>Installed Capacity (MW)</th>
<th>Total Energy (GWh/year)</th>
<th>Firm Energy (GWh/year)</th>
<th>UEC at POI ($F2013/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Coast</td>
<td>1</td>
<td>143</td>
<td>418</td>
<td>418</td>
<td>819</td>
</tr>
<tr>
<td>Vancouver Island</td>
<td>15</td>
<td>936</td>
<td>2,088</td>
<td>2,088</td>
<td>479 – 844</td>
</tr>
<tr>
<td>Total</td>
<td>16</td>
<td>1,078</td>
<td>2,506</td>
<td>2,506</td>
<td>479 – 844</td>
</tr>
</tbody>
</table>

BC Hydro concludes that wave energy is not an economically feasible alternative to Project. In comparison, the Project UEC excluding sunk costs is $94/MWh at the point of interconnection (POI) with the BC Hydro integrated system ($F2013; refer to Volume 1 Appendix F Project Benefits Supporting Documentation, Part 1 Project Cost Estimate for details as to how the Project UEC is derived), and the Available Resource UECs are also well below the wave UEC range of $479/MWh to $844/MWh.

Tidal

Tidal energy refers to the energy available in the flow of water driven by the rotation of the earth in the gravitational fields of the sun and the moon. Tidal energy is variable from one hour to the next, but can be accurately predicted several years into the future. Tidal energy can be captured in two different ways – tidal barrages and tidal current systems.

Tidal barrage is not considered a realistic prospect in B.C. due to its need for dam construction and its negative estuary ecosystem impact. This assessment focuses on tidal current systems. There are no commercial tidal current projects in B.C., although there are two demonstration projects underway.

Owing to the early state of commercial development, there is little real-world experience with the costs associated with tidal power on a commercial scale. BC Hydro relied on the Carbon Trust report described above in relation to wave resources to assess the costs of tidal development. A summary of the technical and financial results for tidal resource is contained in Table 5.19.

Table 5.19  Summary of Tidal Potential

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Potential Sites</th>
<th>Installed Capacity (MW)</th>
<th>Total Energy (GWh/year)</th>
<th>Firm Energy (GWh/year)</th>
<th>UEC at POI ($F2013/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vancouver Island</td>
<td>12</td>
<td>617</td>
<td>1,426</td>
<td>1,426</td>
<td>275 – 605</td>
</tr>
<tr>
<td>Total</td>
<td>12</td>
<td>617</td>
<td>1,426</td>
<td>1,426</td>
<td>275 – 605</td>
</tr>
</tbody>
</table>

BC Hydro concludes that tidal is not an economically feasible alternative to Project. The Project UEC excluding sunk costs is $94/MWh at POI, and the Available Resource UECs are also well below the tidal UEC range of $275/MWh to $605/MWh.

Solar

Solar power is generated from sunlight and can be achieved directly using photovoltaic cells (crystalline silicon or thin film) or indirectly by using concentrating solar power technologies. Both technologies are commercially proven. Globally, the costs have achieved dramatic decline and are projected to continue to decline, but are not expected to become cost-competitive in Canadian jurisdictions over the next 10 years in the absence of price support. There are no known commercial solar power installations in...
B.C. However, there are several distributed generation installations on the customer side of the meter.

The solar resource option assessment focuses on utility-scale photovoltaic systems given the ability to modularly increase the size of the solar power installation size over time and thereby managing capital investment risk. Concentrating solar power technologies are not included due to the large upfront capital investment as utility-scale concentrating solar powerplants typically require a large-scale implementation. The solar resource assessment examined commercial installations on the utility side of the meter with commercial scale solar installations sized at 5 MW. A summary of the technical and financial results for the solar resource is contained in Table 5.20.

Table 5.20 Summary of Solar Potential

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Potential Sites</th>
<th>Installed Capacity (MW)</th>
<th>Total Energy (GWh/year)</th>
<th>Firm Energy (GWh/year)</th>
<th>UEC at POI ($F2013/MWh)</th>
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<tbody>
<tr>
<td>Peace River</td>
<td>1</td>
<td>5</td>
<td>6</td>
<td>6</td>
<td>409</td>
</tr>
<tr>
<td>North Coast</td>
<td>1</td>
<td>5</td>
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<tr>
<td>Central Interior</td>
<td>1</td>
<td>5</td>
<td>6</td>
<td>6</td>
<td>463</td>
</tr>
<tr>
<td>Kelly/Nicola</td>
<td>1</td>
<td>5</td>
<td>6</td>
<td>6</td>
<td>412</td>
</tr>
<tr>
<td>Mica</td>
<td>1</td>
<td>5</td>
<td>6</td>
<td>6</td>
<td>432</td>
</tr>
<tr>
<td>Revelstoke</td>
<td>1</td>
<td>5</td>
<td>6</td>
<td>6</td>
<td>434</td>
</tr>
<tr>
<td>Vancouver Island</td>
<td>1</td>
<td>5</td>
<td>6</td>
<td>6</td>
<td>473</td>
</tr>
<tr>
<td>Lower Mainland</td>
<td>1</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>450</td>
</tr>
<tr>
<td>Selkirk</td>
<td>1</td>
<td>5</td>
<td>6</td>
<td>6</td>
<td>879</td>
</tr>
<tr>
<td>East Kootenay</td>
<td>1</td>
<td>5</td>
<td>6</td>
<td>6</td>
<td>382</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>10</strong></td>
<td><strong>50</strong></td>
<td><strong>57</strong></td>
<td><strong>57</strong></td>
<td><strong>382 – 879</strong></td>
</tr>
</tbody>
</table>

BC Hydro concludes that commercial solar is not an economically feasible alternative to Project, although solar generation will continue to be used on the customer side of the meter. In comparison, the Project UEC excluding sunk costs is $94/MWh at POI, and the Available Resource UECs are also well below the solar UEC range of $382/MWh to $879/MWh.

5.4.2.3 Category 3: DSM Options

Section 5.2.2.2 describes the BC Hydro DSM target, and Section 5.2.3 outlines BC Hydro’s reliance on the current DSM target to fill the energy and capacity resource gaps and the delivery risk associated with the DSM target.

BC Hydro has developed a number of DSM options. BC Hydro’s traditional DSM initiatives (the DSM target, and DSM Options 1 and 3) are expected to deliver both energy and capacity savings. The following section discusses the two additional, more aggressive DSM options that could deliver both energy and capacity, known as DSM Option 4 and DSM Option 5. BC Hydro also examined DSM options specifically designed to deliver capacity savings during BC Hydro’s peak load periods on the electrical system through management and control of customers’ electricity demand; refer to part 5.4.2.4.
DSM Options 4 and 5

BC Hydro concludes that DSM Options 4 and 5 are not viable alternatives to the Project because:

- DSM Options 4 and 5 present government and customer acceptance issues arising from BC Hydro’s reliance on an aggressive and untested combination of rate structures, and codes and standards.
- DSM Options 4 and 5 entail significant delivery risk, especially with respect to capacity savings, and could jeopardize BC Hydro’s ability to serve its customers.

DSM Option 4 targets about 9,500 GWh/year of energy savings and 1,500 MW of dependable capacity savings by F2021, and DSM Option 5 targets 9,600 GWh/year of energy savings and 1,600 MW of dependable capacity savings by F2021.

Acceptance

DSM Option 4 is founded on new or more aggressive conservation rate structures, and significant government intervention and regulation in the form of codes and standards, to generate additional savings. For example, all BC Hydro customers would be exposed to a much larger degree to marginal cost price signals, and rate structures may also need to be tied to a house or building’s rated energy performance. Each industrial customer would need to meet a government mandated certified plant minimum efficiency level to take advantage of BC Hydro’s Heritage hydroelectric lower priced electricity; otherwise, electricity would be supplied at marginal (market-based) rates. These tactics go well beyond the current DSM target, and would be new and untested. It is uncertain whether they would be accepted by government, customers, and the BCUC. DSM Option 4 also represents a bridge to DSM Option 5 by including activities and pilot initiatives that would facilitate the market and social transformations targeted by Option 5. As noted under DSM Option 5, these additional activities and initiatives would be new and untested, and it is uncertain to what extent they would succeed in generating additional electricity savings.

DSM Option 5 is the most aggressive DSM option that BC Hydro considered within the range of DSM resource options. DSM Option 5 aims to create a future scenario where buildings are net-zero consumers of electricity, with some buildings being net contributors of electricity back to the grid. Energy efficiency and conservation activities would be pervasive throughout society and ingrained in a business decision-making culture. This shift would be reflected through widespread district energy systems and micro-distributed generation, smaller and more efficient housing and building footprints, community densification, distributed workforce and “hotelling” (shared workspace), best practices in construction and renovation, efficient technology choices and behaviour, and an integrated community perspective (land use, zoning, multi-use areas). A carbon neutral public sector would contribute to the culture shift. For the industrial sector, a market transformation to certified plants would occur, supported with expanded regulation.

Option 5 includes a fundamental shift in BC Hydro’s approach to saving electricity, one that places much greater emphasis on government regulation and rate structures to change market parameters and societal norms and patterns that influence electricity consumption and conservation. As a new and untested approach to saving electricity, Option 5 is subject to considerable uncertainty regarding government, customer, and...
BCUC acceptance and, ultimately, its effectiveness at generating additional cost-effective electricity savings.

Delivery Risk

Delivery risk increases as the amount of reliance on DSM increases in a portfolio of DSM and supply-side resources. It is useful to contemplate delivery risk in terms of energy and capacity separately. A shortfall in energy could lead to the acquiring of more costly supply-side resources, such as IPP clean or renewable resources, in a compressed time frame, or could lead to an energy shortfall that could not be met through purchasing from the B.C. market, which could result in relying on imports to a greater extent than contemplated by the legal self-sufficiency requirements. While these are serious shortcomings, delivery risk is more of a critical problem on the capacity side, where a shortfall in electricity at key times would undermine BC Hydro’s fundamental obligation to serve its customers’ demand.

An unexpected departure from the mid-load forecast is of concern, particularly with respect to capacity planning. BC Hydro is relying on the current DSM target to deliver 1,400 MW of dependable capacity by F2021. The corresponding figures for DSM Options 4 and 5 are 1,500 MW and 1,600 MW, respectively, by F2021. There is significant uncertainty with respect to DSM capacity savings across all options, including the DSM target (refer to Section 5.2.3); moving to higher levels of DSM increases uncertainty around capacity savings.

BC Hydro has limited contingency resource options available on a relatively short timeline if DSM does not deliver the anticipated capacity savings. Natural gas-fired SCGTs (peaking units) of about 100 MW in size would be the principal potential B.C.-based capacity contingency resource. It is anticipated that SCGTs sited outside the Lower Mainland would take about five years for approval and construction. SCGTs above 50 MW trigger BCEAA and the requirement that the B.C. Minister of Energy, Mines and Natural Gas, and the B.C. Ministry of the Environment, authorize an EAC prior to construction. Constructing and operating SCGTs also requires Air Emissions Permits under the B.C. Environmental Management Act. There are social licensing issues associated with natural gas-fired generation, which are discussed in Section 5.5.2.8.

5.4.2.4 Category 4: DSM Capacity Initiatives

While DSM Options 4 and 5 discussed in Section 5.4.2.3 have associated capacity savings, additional capacity savings may be possible through DSM capacity activities (also referred to as peak reduction or peak shaving). Capacity-focused DSM savings were grouped into two broad categories:

- Industrial load curtailment: This DSM option targets large customers who agree to curtail load on short notice to provide BC Hydro with capacity relief during peak periods. BC Hydro has implemented a load curtailment program targeted at shorter term (one to three years) capacity needs in recent years, and customers have delivered as requested. However, it is not clear how easily these can be translated into long-term agreements that can reliably reduce peak demand over the long-term when needed.

- Capacity programs: This DSM option contains programs that leverage equipment and load management systems to enable peak load reductions to occur
automatically or with intervention. Programs may involve payment for customer equipment and a financial payment for participation in the program. Examples of capacity programs include load control of water heaters, heating, lighting, and air conditioning. Thus capacity-focused programs are a collection of several activities; both demand response and load control, spread across different customer classes. The participation rates and savings per participant are key aspects of the uncertainty of capacity savings.

An attempt to assess the range of outcomes with respect to industrial load curtailment and DSM capacity programs for a selected year is shown in Table 5.21.

### Table 5.21  Savings From Capacity DSM and Uncertainty

<table>
<thead>
<tr>
<th>(MW in F2021)</th>
<th>Industrial Load Curtailment</th>
<th>Capacity-Focused Programs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low (P10 cut-off)</td>
<td>316</td>
<td>135</td>
</tr>
<tr>
<td>Mid (mean or expected)</td>
<td>382</td>
<td>193</td>
</tr>
<tr>
<td>High (P90 cut-off)</td>
<td>443</td>
<td>256</td>
</tr>
</tbody>
</table>

There are a number of uncertainties regarding DSM capacity initiatives that are not well understood. Since BC Hydro is just starting to develop long-term DSM capacity savings options, implementation success is an important issue. In particular, precise program initiation dates and customer participation rates are unknown; BC Hydro would want to test both of these drivers through pilot initiatives. Once these approaches are established, operational experience will still be required to understand how participation and savings per participant translate into peak shaving. Similarly, experience will be needed to see how savings for each initiative translates into peak reduction for the entire system – whether these peaks are coincident with peak load and whether peak shaving leads to other system peaks.

BC Hydro concludes that DSM capacity options are not viable alternatives to the Project, given the number of significant uncertainties underlying such DSM initiatives described above.

### 5.5  Available Resources

This section describes and compares the available resources using financial, technical, environmental, and economic development decision attributes. As set out in Section 5.4.1.1, the available resources are:

- Clean or renewable energy resources from third parties: wind – both on-shore and off-shore, run-of-river hydro, geothermal, and biomass
- BC Hydro Resource Smart energy and capacity resources
- A clean or renewable capacity resource: pumped storage
- Natural gas-fired generation and cogeneration, including energy resource CCGTs and capacity resource SCGTs, within the 93% Clean Energy Act clean or renewable target described in Section 5.5.2.8

The comparison consists of 1) an overview of the attributes of each individual available resource, provided in Section 5.5.2, and 2) portfolio analysis, the results of which are set out in Section 5.5.4. Portfolios are combinations of different mixes of available resources to meet the Project’s 5,100 GWh/year of firm energy and 1,100 MW of dependable
capacity. Thus these portfolios constitute the economically and technically feasible alternatives to the Project.

The remainder of this section is organized as follows:

- Section 5.5.1 describes the financial, technical, environmental, and economic development decision attributes
- Section 5.5.2 provides descriptions of the available resources, including the UECs and Unit Capacity Costs (UCCs) as applicable, and a summary of the key uncertainties and risks of each available resource. Section 5.5.2.8 sets out the Clean Energy Act’s 93% clean or renewable target, and the resulting permissible natural gas-fired generation in both GWh and MW for selected years. The result is that, on its own, natural gas-fired generation is not an alternative to the Project because there is not enough space, given the 93% clean or renewable target for natural gas-fired generation, to provide 5,100 GWh/year of firm energy and 1,100 MW of dependable capacity; rather, natural gas-fired generation must be combined with clean or renewable resources. This is done in the portfolio analysis in Section 5.5.4.
- Section 5.5.3 sets out the modelling and portfolio process
- Section 5.5.4 presents the expected costs and risk performance of the different portfolios with and without the Project across different future scenarios
- Section 5.5.5 summarizes the available resources assessment

### 5.5.1 Measurement Criteria: Attributes

Attributes are the measurement criteria by which impacts of resource alternatives are measured. There are several reasons why BC Hydro considered a broad set of attributes for purposes of the EIS:

- The Agency Need/Alternatives Policy Statement (CEA Agency 2007) states that “the major environmental, economic and technical costs and benefits” should be identified and described
- The EIS Guidelines provide that BC Hydro will describe the major financial, technical, environmental, and economic development attributes of the supply-side alternatives to the Project
- The Clean Energy Act stipulates that BC Hydro must carry out resource development consistent with good utility practice; this includes understanding the broader implications of BC Hydro’s planning actions
- As part of the IRP and Project-related First Nations and public engagement processes, BC Hydro found that First Nations and the public are interested in a broad set of effects beyond financial impacts
- As described in Section 5.3, the B.C. Government explicitly laid out a number of objectives in the Clean Energy Act. These objectives include a mix of financial and non-financial considerations, including a focus on clean or renewable electricity and GHG emissions. Refer to Table 5.22.
Table 5.22  \textit{Clean Energy Act} and Other Objectives and Attributes

<table>
<thead>
<tr>
<th>Decision Objective and Attribute</th>
<th>Reason for Inclusion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimize Financial Impacts:</td>
<td></td>
</tr>
<tr>
<td>- Cost</td>
<td>Good utility practice; First Nations, public and stakeholder interests; congruent with \textit{Clean Energy Act} objectives</td>
</tr>
<tr>
<td>- Cost risk</td>
<td></td>
</tr>
<tr>
<td>Minimize Environmental Footprint, Including:</td>
<td>Good utility practice; First Nations, public and stakeholder interests; congruent with \textit{Clean Energy Act} objectives</td>
</tr>
<tr>
<td>- Land footprint</td>
<td></td>
</tr>
<tr>
<td>- Water footprint</td>
<td></td>
</tr>
<tr>
<td>- Criteria air contaminants</td>
<td></td>
</tr>
<tr>
<td>- GHG emissions</td>
<td></td>
</tr>
<tr>
<td>Maximize Economic Development</td>
<td>First Nations, public and stakeholder interests; congruent with \textit{Clean Energy Act} objectives</td>
</tr>
</tbody>
</table>

These attributes are considered at a provincial level, as data do not exist at a regional or local level for all projects (in many cases, generation resources are represented as a “typical” project or block of projects). In addition, the resources selected through portfolio modelling are not necessarily the ones that would be selected through an actual acquisition process.

5.5.1.1  Financial Attributes

Financial attributes describe the cost of resource options. The \textit{Clean Energy Act} and good utility practice underscore the importance of tracking costs when comparing resource options. The financial implications of the supply-side resource options or strategies to fill the load-resource gap are tracked at a portfolio level as set out in Section 5.5.4, which provides the portfolio results, both for the cost of acquiring new resources and for how these resources interact with the existing system and the external electricity market.

Financial attributes considered include:

- UEC: reflects the real levelized cost (as described in Volume 1 Appendix F Project Benefits Supporting Documentation, Part 1 Project Cost Estimate) of a unit of energy from a resource option or portfolio (typically in $F2013/MWh). The values serve as an initial ranking of energy resources in scheduling resources to fill a load/resource gap.

- UCC: reflects the real levelized cost of a unit of capacity from a resource option (typically in $F2013/kW-year). UCCs are calculated by taking the levelized annual cost of a capacity resource divided by the resource’s dependable capacity.

Some key assumptions or methods of determination used to develop the financial attributes include:

- Point of Interconnection (POI): Unless otherwise stated, resource options costs are presented as UECs and UCCs at POI. The costs at POI represent the estimated overall cost of both non-firm and firm energy, and are based on the sum of three component costs: costs within plant gate, road costs (linking plant gate area to existing road infrastructure), and transmission interconnection costs. The costs at POI do not reflect the additional costs of delivering resources to the Lower Mainland (BC Hydro’s major load centre) and of firming and integrating intermittent clean or renewable resources. While these are important cost considerations, they are...
factored in at the portfolio analysis stage described in Section 5.5.3. GHG offset-related and fuel costs are included in the UECs/UCCs for natural gas-fired generation.

- Escalation: The UECs and UCCs are presented in constant dollars as of January 1, 2013 ($F2013). A 2% inflation factor is used in instances where it was necessary to inflate dollar values to $F2013.

- Weighted average cost of capital: An 8% real cost of capital rate is used in determining UECs and UCCs for available resources. Pursuant to Policy Action #13 of the 2002 Energy Plan, IPPs are to develop all resources other than DSM, Resource Smart and the Project, and IPPs have a higher cost of capital than BC Hydro. BC Hydro’s weighted average cost of capital is 5.5%; a rounded 6% cost of capital is used for the Project UECs. Refer to Section 5.5.3 for further detail.

All of the available resources have more cost uncertainty than the Project because they are feasibility- or conceptual-level estimates only. The cost estimates for available resources are generally a Class 4 (feasibility, fairly wide accuracy range, typically used for alternative evaluation) or a Class 5 (concept screening, wide accuracy range) degree of accuracy. In addition, the available resource cost estimates do not reflect site-specific information; on-the-ground assessments tend to increase cost estimates. In contrast, the Project cost estimate of $7.9 billion has a Class 3 (budget authorization or control) degree of accuracy, as defined by the Association for the Advancement of Cost Engineering (AACE 2012). Refer to Volume 1 Appendix F Project Benefits Supporting Documentation, Part 1 Project Cost Estimate for additional detail. A Class 3 degree of accuracy is consistent with the BCUC’s requirements for project cost estimates set out in the BCUC 2010 Certificate of Public Convenience and Necessity Application Guidelines.

The Project cost estimate of $7.9 billion (nominal dollars) contains cost allowances for mitigation, regulatory review, First Nation consultation, and public engagement. Implementation of the available resources would also entail mitigation, regulatory review, First Nation consultation, and public engagement costs (referred to as ‘soft costs’), but it is not possible to precisely quantify such soft costs, as it is difficult to predict the outcome of consultation/engagement or to identify the costs of such processes or the costs of mitigation requirements that may be imposed following these processes, not least because different First Nations and stakeholders may have conflicting goals and requirements. Accordingly, while the available resource costs set out in Section 5.5.2 do not include such costs, BC Hydro has put a cost adder of 5% on available resource portfolios to reflect the fact that implementing any of the available resource options would trigger soft costs. Refer to Section 5.5.3 for greater detail.

5.5.1.2 Technical Attributes

Technical attributes describe the energy and capacity that each available resource provides and are used to assemble portfolios that meet BC Hydro’s energy and capacity reliability planning criteria. The technical attributes considered for resource options are:

- Dependable generating capacity (DGC), which is used for non-intermittent resources, is the amount of MW that a plant can reliably produce when required, assuming all units are in service

- ELCC, which is used for intermittent or variable generation resources, is the maximum peak load (MW) that a generating unit or a system of units can reliably
Supply, such that the loss of load expectation will be no greater than one day in 10 years. Refer to Section 5.2.1.2 for a description of ELCC shortcomings.

- Installed (nameplate) capacity (MW)
- Firm energy load-carrying capability (FELCC) is the maximum amount of annual energy that a hydroelectric resource can produce under critical water conditions and is measured in GWh/year
- Average annual energy (GWh/year)
- Hourly/daily/monthly variability

A summary of the generation reliability assumptions and methods of development is presented in Table 5.23.

**Table 5.23  Generation Reliability Assumptions and Methods**

<table>
<thead>
<tr>
<th>Potential Generation Resources</th>
<th>DGC and ELCC Assumptions and Methods of Determination (MW)</th>
<th>FELCC Assumptions and Methods of Determination (GWh/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Run-of-river</td>
<td>ELCC: Weighted average of approximately 60% of the forecasted average MW of potential in the December/January period</td>
<td>Region-specific factors applied to the average annual energy; monthly variability</td>
</tr>
<tr>
<td>Biomass</td>
<td>DGC: 100% of installed capacity for wood-based biomass; 97% of installed capacity for municipal solid waste; and 95% of installed capacity for biogas</td>
<td>100% of average annual energy</td>
</tr>
<tr>
<td>Wind – onshore</td>
<td>ELCC: 24% of installed capacity</td>
<td>100% of average annual energy; hourly and daily variability</td>
</tr>
<tr>
<td>Wind – offshore</td>
<td>ELCC: 24% of installed capacity</td>
<td>100% of average annual energy; hourly and daily variability</td>
</tr>
<tr>
<td>Geothermal</td>
<td>DGC: 100% of installed capacity</td>
<td>100% of average annual energy</td>
</tr>
<tr>
<td>Natural gas-fired generation &amp; cogeneration</td>
<td>DGC: Varies from 88% to 100% of installed capacity</td>
<td>Based on 18% capacity factor for SCGTs and 90% for CCGTs</td>
</tr>
<tr>
<td>Project</td>
<td>DGC: 1,100 MW</td>
<td>4,700 GWh/year (average energy is 5,100 GWh/year)</td>
</tr>
<tr>
<td>Pumped storage</td>
<td>DGC: 100% of installed capacity</td>
<td>N/A (consumes energy)</td>
</tr>
</tbody>
</table>

**NOTE:**
* Capacity factor of an electricity generating facility is the ratio of the actual output of the electricity generating facility over a period of time and its potential output if it had operated at full installed capacity over the entire period; natural gas-fired generation is relied upon to run a minimum of 18% of the time for its energy contribution.

BC Hydro uses reliability planning criteria for planning purposes to evaluate when generation resources are required to maintain an adequate supply of electricity resources to reliably meet customer demand. BC Hydro considers both the peak load (generation capacity reliability planning criterion) and annual energy demand (generation energy reliability criterion) on its electrical system. With respect to energy, from a BC Hydro planning perspective:

- Heritage hydroelectricity facilities, including the Project, are relied on for their average energy contribution, as shown in Table 5.23, as a result of the Electricity...
Self-Sufficiency Regulation, which mandates that BC Hydro use the average water capability of its heritage hydroelectric resources.

- Available resources developed by IPPs or other third parties are relied on for their firm energy contribution. The Electricity Self-Sufficiency Regulation is silent on IPP energy output and, accordingly, BC Hydro uses its energy reliability criterion. Non-firm energy from IPPs does not contribute to BC Hydro’s energy reliability criterion.

As described below in Section 5.5.2, run-of-river and wind resources provide very little dependable capacity. For example, run-of-river and wind resources made up virtually all of the 25 EPAs awarded pursuant to BC Hydro’s most recent power acquisition process, the Clean Power Call. While these resources are to provide over 3,000 GWh/year of firm energy, they only provide 9 MW of dependable capacity.

5.5.1.3 Environmental Attributes

Environmental attributes provide high level information on the footprint of the available resources. BC Hydro retained Kerr Wood Leidal Associates Ltd., Hemmera Envirochem Inc. and HB Lanarc to develop the environmental attributes. The environmental attributes were selected based upon the following criteria:

- Appropriate for provincial-scale portfolio comparisons
- Science-based and defendable
- Measurable in a “quantity”-based approach that facilitates comparison between portfolios of available resources
- Representative of relevant biophysical resources
- Based on existing data or easily acquired data
- Easy to understand for long-term planning and stakeholder engagement purposes

The environmental attributes are grouped into four environmental categories: land, atmosphere, freshwater, and marine, and are further broken down into indicators, as described in Table 5.24.
### Table 5.24 Environmental Attributes

<table>
<thead>
<tr>
<th>Environmental Category</th>
<th>Indicator</th>
<th>Unit of Measure</th>
<th>Classifications</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Land</strong></td>
<td>Net primary productivity (gC/m²/year) (^a)</td>
<td>hectares (ha) per class</td>
<td>Low (0 to &lt; 69)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Medium (69 to &lt; 369)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>High (&gt; 369)</td>
</tr>
<tr>
<td>Remoteness – linear disturbance density (km/km²)</td>
<td>ha per class</td>
<td>Wilderness (&lt; 0.2)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Remote (0.2 to &lt; 0.66)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Rural (0.66 to 2.2)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Urban (&gt; 2.2)</td>
<td></td>
</tr>
<tr>
<td>High priority species count (percentile)</td>
<td>ha per class</td>
<td>0 to &lt; 20</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>20 to &lt; 40</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>40 to &lt; 60</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>60 to 80</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt; 80</td>
<td></td>
</tr>
<tr>
<td><strong>Atmosphere</strong></td>
<td>GHG emissions</td>
<td>tonnes/GWh</td>
<td>Carbon dioxide equivalent (CO₂e)</td>
</tr>
<tr>
<td></td>
<td>Air contaminant emissions</td>
<td>tonnes/GWh</td>
<td>Sulphur dioxide</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Oxides of nitrogen (NOₓ)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Carbon monoxide</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Volatile organic compounds</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Fine particulates (PM): PM₂.₅ (reported when data are available)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Fine particulates: PM₁₀ (reported when data are available)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Fine particulates: PM total</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Mercury</td>
<td></td>
</tr>
<tr>
<td><strong>Freshwater</strong> (^b)</td>
<td>Reservoir aquatic area</td>
<td>ha</td>
<td>Site C Clean Energy Project only (while pumped storage and resource smart may create reservoir aquatic areas, these have only been described qualitatively in Section 5.5.2, as the calculations were not done for the 2010 Resource Options Report)</td>
</tr>
<tr>
<td></td>
<td>Affected stream length</td>
<td>kilometres (km)</td>
<td>Run-of-river and the Site C Clean Energy Project (pumped storage and Resource Smart if applicable/available)</td>
</tr>
<tr>
<td>Priority fish species (number of priority fish (^c) species per watershed)</td>
<td>ha per class</td>
<td>No priority species (0)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Low species diversity (1 to 12)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Moderate species diversity (13 to 23)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>High species diversity (24 to 38)</td>
<td></td>
</tr>
</tbody>
</table>
### Environmental Category

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Unit of Measure</th>
<th>Classifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marine d</td>
<td>ha per class</td>
<td>None (0)</td>
</tr>
<tr>
<td>Valued ecological features</td>
<td></td>
<td>Low (1 to 2)</td>
</tr>
<tr>
<td>(number of valued ecological features)</td>
<td></td>
<td>Medium (3 to 5)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>High (&gt; 5)</td>
</tr>
<tr>
<td>Key commercial bottom fishing areas</td>
<td>ha per class</td>
<td>No bottom fisheries</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1 bottom fishery</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2 to 3 bottom fisheries</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt; 3 bottom fisheries</td>
</tr>
</tbody>
</table>

**NOTES:**

- a gC/m²/year = grams of carbon per square metre per year; this indicator is a proxy for how much annual vegetation growth occurs in an area per year.
- b The 2010 Resource Options Report developed a fourth freshwater attribute to address the riparian footprint. This attribute was subsequently dropped due to lack of data for potential run-of-river sites and pumped storage, which would have made the comparisons ineffectual.
- c Priority fish are those that have been identified for conservation in the province of B.C. through the B.C. Conservation Framework, and then filtered to ensure native species and provincial range data.
- d The 2010 Resource Options Report developed a third marine attribute of bathymetry, which is a descriptor of water depth. This attribute was subsequently not reported, given that it added negligible value compared with the other two marine attributes.

Refer to Section 5.5.2 for a description of the environmental attributes of individual Viable Alternatives.

#### 5.5.1.4 Economic Development Attributes

Economic development attributes describe the contributions that the available resources make to the provincial economy. The economic development attributes selected are categorized into three groups: provincial GDP, employment, and Provincial Government revenue, and are further broken down into sub-categories described in Table 5.25. The British Columbia Input-Output Model was used to determine the economic development attributes, using a methodology and definitions similar to that in Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impact: BC Stats.

### Table 5.25 Economic Development Attributes

<table>
<thead>
<tr>
<th>Economic Development Category</th>
<th>Sub-Category</th>
<th>Unit of Measure</th>
<th>Classifications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Provincial GDP</td>
<td>Construction/Operation</td>
<td>Dollars ($) and $/year</td>
<td>Direct</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Indirect</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Induced</td>
</tr>
<tr>
<td>Employment</td>
<td>Construction/Operation</td>
<td>Jobs</td>
<td>Direct</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Indirect</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Induced</td>
</tr>
<tr>
<td>Provincial Government revenue</td>
<td>Construction/Operation</td>
<td>$ and $/year</td>
<td>Direct</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Indirect</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Induced</td>
</tr>
</tbody>
</table>

#### 5.5.2 Description of Available Resources

This section presents an overview of the available resources. The available resource potential is screened only to remove sites from consideration if they were located in an...
area where there would be legal or regulatory prohibitions; therefore, this results in a
large volume of potential energy and dependable capacity with a wide range of costs,
which may or may not be developed in the future. At a high level, this section is
organized according to energy-rich available resources, followed by capacity-rich
available resources. Technical and financial results are presented for each resource
option where UECs and UCCs are shown at the POI. The summarized attributes of
portfolios are examined in the portfolio analysis in Section 5.5.4. Resource option data
are reported by BC Hydro transmission region where the interconnection to the
BC Hydro integrated system occurs.

For comparison purposes, the UEC of the Project excluding sunk costs is about
$94/MWh at POI ($F2013). See Volume 1 Appendix F Project Benefits Supporting
Documentation, Part 1 Project Cost Estimate with respect to the calculation of the
Project’s UEC.

5.5.2.1 Run-of-River Hydroelectricity

A run-of-river hydroelectric generation facility diverts a portion of natural stream flows
and uses the natural drop in elevation of a river to generate electricity. Run-of-river
projects divert some of a river’s flow for power generation and leave the remaining flow
in the original stream. A weir (i.e., a structure smaller than a dam used for storage hydro)
is required to divert flows into the pipelines (referred to as penstocks) that lead to the
power generation facility turbines. A run-of-river project either has no storage at all, or a
limited amount of storage, in which case the storage reservoir is referred to as pondage.

Some of the run-of-river generation facilities proposed and/or canvassed in the
2010 Resource Options Report rival traditional large hydroelectric facilities in scale and
installed capacity. The expected life of run-of-river projects is about 50 years, with the
maximum water licence term being 40 years. To date, BC Hydro run-of-river EPAs have
typically had terms of between 30 to 40 years.

Environmental Attribute Overview: Hydroelectricity is a clean or renewable resource
as defined by Section 1 of the Clean Energy Act. Run-of-river projects have a number of
environmental impacts, the most important of which is the impact to fish and aquatic
ecosystems. Diverting river water can reduce river flows, affecting water velocity and
depth, and potentially affecting habitat quality for fish and aquatic organisms. New
access roads and transmission lines can cause habitat fragmentation for many species,
introduce invasive species, and increase human activities such as illegal hunting. There
may also be recreational impacts.

Technical and Financial Attribute Overview: Run-of-river electricity is an intermittent
source of energy with low amounts of dependable capacity because such facilities have
little or no storage, and hence output is subject to seasonal river flows and cannot be
co-ordinated to match customer demand. Run-of-river hydroelectric facilities generate
more energy during times when seasonal river flows are high, such as the spring freshet,
which coincides with reduced demand and low electricity prices in external markets.
Generation drops during low flow periods. Figure 5.5 shows the power output of a typical
run-of-river project in BC Hydro’s Lower Mainland/South Coast region.

Typically, the output from run-of-river projects is not predictable outside the spring
freshet and cannot be regulated to match demand. Refer to Section 7.4.3 in Volume 1
Section 7 Project Benefits for a discussion of how integrating variable available
resources such as run-of-river and wind generation into the BC Hydro system requires
backup dispatchable capacity such as large hydroelectricity (the Project) or natural
gas-fired generation.

The 2010 Resource Options Report for run-of-river resources was undertaken in
collaboration with Kerr Wood Leidal. The study used a Geographical Information System
tool to assess the energy, capacity, and cost of selected potential run-of-river generating
sites. A summary of the technical and financial results for run-of-river is contained in
Table 5.26.

### Table 5.26 Summary of Run-of-River Potential

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Potential Sites</th>
<th>Installed Capacity (MW)</th>
<th>ELCC (MW)</th>
<th>Total Energy (GWh/year)</th>
<th>Firm Energy (GWh/year)</th>
<th>Unit Energy Cost at POI ($F2013/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peace River</td>
<td>14</td>
<td>83</td>
<td>1</td>
<td>250</td>
<td>215</td>
<td>436 – 600</td>
</tr>
<tr>
<td>North Coast</td>
<td>315</td>
<td>2,330</td>
<td>117</td>
<td>8,527</td>
<td>6,965</td>
<td>97 – 600</td>
</tr>
<tr>
<td>Central Interior</td>
<td>50</td>
<td>566</td>
<td>32</td>
<td>2,100</td>
<td>1,660</td>
<td>157 – 595</td>
</tr>
<tr>
<td>Kelly/Nicola</td>
<td>145</td>
<td>931</td>
<td>50</td>
<td>3,429</td>
<td>2,701</td>
<td>98 – 599</td>
</tr>
<tr>
<td>Mica</td>
<td>116</td>
<td>769</td>
<td>21</td>
<td>2,675</td>
<td>2,359</td>
<td>136 – 595</td>
</tr>
<tr>
<td>Revelstoke</td>
<td>139</td>
<td>786</td>
<td>30</td>
<td>2,796</td>
<td>2,431</td>
<td>110 – 596</td>
</tr>
<tr>
<td>Vancouver Island</td>
<td>395</td>
<td>2,709</td>
<td>502</td>
<td>10,778</td>
<td>8,237</td>
<td>105 – 599</td>
</tr>
<tr>
<td>Lower Mainland</td>
<td>187</td>
<td>1,599</td>
<td>245</td>
<td>6,829</td>
<td>5,177</td>
<td>82 – 599</td>
</tr>
<tr>
<td>Selkirk</td>
<td>80</td>
<td>568</td>
<td>10</td>
<td>1,886</td>
<td>1,641</td>
<td>128 – 599</td>
</tr>
<tr>
<td>East Kootenay</td>
<td>150</td>
<td>790</td>
<td>11</td>
<td>2,593</td>
<td>2,232</td>
<td>109 – 599</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,591</strong></td>
<td><strong>11,130</strong></td>
<td><strong>1,018</strong></td>
<td><strong>41,866</strong></td>
<td><strong>33,619</strong></td>
<td><strong>82 – 600</strong></td>
</tr>
</tbody>
</table>

**NOTE:**
The table presents results for run-of-river resources under $600/MWh

Historically, some of the run-of-river resource options with the lowest unadjusted UEC
values have not always bid into BC Hydro’s power acquisition processes. BC Hydro
examined the results of its two most recent broadly-based power acquisition processes,
the 2009 Clean Power Call and the F2006 Call. The Clean Power Call is considered to
be the best comparator derived from BC Hydro’s power acquisition processes, given that
it reflects the most recent BC Hydro power acquisition process pricing, and a large
volume and broad array of clean, renewable technologies, including both hydro-based
and wind-based projects. The Clean Power Call was open to any form of clean or
renewable energy (excluding wood-based biomass, which was subject to a separate call
for power), with 25 EPAs awarded in the spring/summer of 2010 for a total of
3,266 GWh/year of firm energy. Run-of-river projects made up about 50% of EPAs
awarded pursuant to the 2009 Clean Power Call (by firm energy) and dominated the
F2006 Call, the second most recent BC Hydro broadly based power acquisition process:

- The Clean Power Call weighted average levelized price is $109/MWh at plant gate
  ($F2013)
- The F2006 Call was undertaken over six years ago, resulting in a weighted average
  levelized adjusted plant gate price for large projects of about $86/MWh ($F2013)

### 5.5.2.2 Onshore Wind

Wind power refers to the conversion of energy from moving air into electricity. Modern
utility-scale wind turbines are horizontal axis machines with three rotor blades. The
blades convert the linear motion of the wind into rotational energy that is then used to
drive a generator. Onshore wind is considered a mature technology; see, for example,
Energy + Environmental Economics report (Energy + Environmental Economics 2012). The expected life of wind projects is about 20 to 25 years, although a recent British study concluded that the economic life of onshore wind turbines is between 10 and 15 years (Renewable Energy Foundation 2012). A shorter wind resource economic life would raise the per unit cost of energy produced (MWh). To date, BC Hydro wind EPAs have typically had terms of between 20 to 25 years.

Environmental Attribute Overview: Wind is a clean or renewable resource, as defined by Section 1 of the Clean Energy Act. Wind resources do not use combustion to generate electricity and hence do not produce air emissions. Concerns have been raised over the noise produced by the rotor blades (in recent years, engineers have made design changes to reduce the noise from wind turbines), visual impacts (because wind energy resources are generally sited in exposed places, wind turbines are often visible), and deaths of birds and bats that fly into the rotors. Footprint impacts can also include new access roads and transmission lines.

Technical and Financial Attribute Overview: Wind generation resources can have highly variable output over a time frame of minutes, hours, and days. Figures 5.6 and 5.7 show a sample wind resource generation profile over a sample eight-day period in June 2011 and January 2012, respectively. Due to this variability and the difficulty of accurately forecasting wind energy output, wind resources that are acquired by BC Hydro will result in new operating requirements and procedures. While BC Hydro has a large, flexible hydroelectric-based generation system that can manage this variability, the total system flexibility is limited. As a result, there are costs associated with managing wind variability that need to be recognized. Adding wind resources will require the carrying of appropriate additional reserves to compensate for sudden fluctuations in wind power in three different planning horizons: 1) regulation (minute to minute), 2) load following (minutes to hours), and (3) unit commitments/scheduling (hours to days). BC Hydro estimates that the wind integration cost is about $10/MWh generated. This total wind integration cost estimate is slightly higher than that used by Manitoba Hydro, but is comparable to the total wind integration cost estimates proposed by Hydro Quebec, the U.S. Pacific Northwest electric utility PacifiCorp, and the Bonneville Power Administration. The $10/MWh wind integration cost is not reflected in the UEC values set out in Table 5.27 below, but is included in the portfolio analysis in Section 5.5.4.

For the 2010 Resource Options Report, BC Hydro engaged DNV Global Energy Concepts Inc. to complete the Wind Data Study and Wind Data Study Update to obtain detailed information on the wind resource potential in B.C., and engaged Garrad Hassan to update the onshore wind costs. As noted above in Section 5.4.1.2, the 2010 Resource Options Report wind UECs have been revised (lowered) to take into account the changes in turbine efficiencies and wind turbine prices that have occurred over the past three years. A summary of the technical and financial results for onshore wind is contained in Table 5.27 using the revised wind costs. For comparison purposes, the average levelized plant gate cost of the approximately 50% of EPAs awarded for wind projects (by firm energy) through the Clean Power Call is $108/MWh ($F2013).
Table 5.27 Summary of Onshore Wind Potential

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Potential Sites</th>
<th>Installed Capacity (MW)</th>
<th>ELCC (MW)</th>
<th>Total Energy (GWh/year)</th>
<th>Firm Energy (GWh/year)</th>
<th>Unit Energy Cost at POI a ($F2013/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peace River</td>
<td>45</td>
<td>5723</td>
<td>1374</td>
<td>17778</td>
<td>17778</td>
<td>96 – 315</td>
</tr>
<tr>
<td>North Coast</td>
<td>23</td>
<td>4016</td>
<td>964</td>
<td>11025</td>
<td>11025</td>
<td>120 – 332</td>
</tr>
<tr>
<td>Central Interior</td>
<td>9</td>
<td>1132</td>
<td>272</td>
<td>2892</td>
<td>2892</td>
<td>130 – 234</td>
</tr>
<tr>
<td>Kelly/Nicola</td>
<td>22</td>
<td>3489</td>
<td>837</td>
<td>8886</td>
<td>8886</td>
<td>130 – 176</td>
</tr>
<tr>
<td>Revelstoke</td>
<td>4</td>
<td>644</td>
<td>155</td>
<td>1674</td>
<td>1674</td>
<td>126 – 154</td>
</tr>
<tr>
<td>Vancouver Island</td>
<td>13</td>
<td>1111</td>
<td>267</td>
<td>3143</td>
<td>3143</td>
<td>120 – 216</td>
</tr>
<tr>
<td>Lower Mainland</td>
<td>1</td>
<td>90</td>
<td>22</td>
<td>249</td>
<td>249</td>
<td>146</td>
</tr>
<tr>
<td>Selkirk</td>
<td>2</td>
<td>83</td>
<td>20</td>
<td>194</td>
<td>194</td>
<td>144 – 236</td>
</tr>
<tr>
<td>East Kootenay</td>
<td>2</td>
<td>138</td>
<td>33</td>
<td>324</td>
<td>324</td>
<td>147 – 157</td>
</tr>
<tr>
<td>Total</td>
<td>121</td>
<td>16,425</td>
<td>3,942</td>
<td>46,165</td>
<td>46,165</td>
<td>96 – 332</td>
</tr>
</tbody>
</table>

NOTE: a The UECs shown do not include a wind integration cost adder of about $10/MWh

5.5.2.3 Offshore Wind

In addition to onshore wind potential, BC Hydro examined the potential of offshore wind turbines located in ocean substrate depths of up to 40 m. Onshore and offshore wind assessments are undertaken separately because of the differences in methodologies used to assess the resource potential, as well as differences in the financial cost assumptions.

Technical and Financial Attribute Overview: The analysis is based on averaged wind speeds at 80 m hub height from the Canadian Wind Atlas, and gridded bathymetric data provided by the Canadian Hydrological Services. Modelled wind speeds from the Canadian Wind Atlas were compared to long-term wind speed estimates based on actual offshore observations. Garrad Hassan provided representative costs for offshore wind projects as a function of water depth. A summary of the technical and financial results for offshore wind are contained in Table 5.28.

Table 5.28 Summary of Offshore Wind Potential

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Potential Sites</th>
<th>Installed Capacity (MW)</th>
<th>ELCC (MW)</th>
<th>Total Energy (GWh/year)</th>
<th>Firm Energy (GWh/year)</th>
<th>Unit Energy Cost at POI a ($F2013/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Coast</td>
<td>36</td>
<td>12,873</td>
<td>3,090</td>
<td>41,991</td>
<td>41,991</td>
<td>208 – 734</td>
</tr>
<tr>
<td>Vancouver Island</td>
<td>7</td>
<td>2,466</td>
<td>592</td>
<td>8,270</td>
<td>8,270</td>
<td>190 – 279</td>
</tr>
<tr>
<td>Total</td>
<td>43</td>
<td>15,339</td>
<td>3,681</td>
<td>50,261</td>
<td>50,261</td>
<td>190 – 734</td>
</tr>
</tbody>
</table>

5.5.2.4 Wood-Based Biomass

Wood-based biomass electricity is generated from the combustion or gasification of organic materials as fuels. In developing the potential of wood-based biomass, the following categories of fuels were considered:

- Standing timber (including wood killed by mountain pine beetles)
• Roadside wood waste (wood already harvested, but left in the forest or on the roadside; some is wood killed by mountain pine beetles)

• Sawmill wood waste

To date, BC Hydro bioenergy EPAs have typically had terms of between 10 to 15 years.

**Environmental Attribute Overview:** Biomass is a clean or renewable resource, as defined by Section 1 of the *Clean Energy Act*. Combustion of biomass produces local air contaminants such as particulate matter and oxides of nitrogen. The amount of carbon dioxide released when biomass is burned is nearly the same as the amount required to replenish the plants grown to produce the biomass. Thus, in a sustainable fuel cycle, there would be no net emissions of carbon dioxide, although some fossil-fuel inputs may be required for planting, harvesting, transporting, and processing biomass. Footprint impacts can also include new access roads and transmission lines. The environmental attributes used in the portfolio analysis only include the footprint for the facility site – the footprint for fuel harvesting is not included.

**Technical and Financial Attribute Overview:** BC Hydro engaged consultants from Industrial Forest Services Ltd., together with industry experts, to conduct a modelling study to estimate the long-term energy potential, costs, and possible locations for wood-based biomass projects. Overall, the study found that the amount of standing timber available for fuel was forecast to decline significantly over the next 15 years, but then stabilize after that. In addition, the study identified the availability of significant volumes of roadside and sawmill wood waste, but indicated that there was uncertainty regarding the actual potential that could be realized.

Generally, when a secure fuel supply contract is in place, the installed capacity of wood-based biomass projects is considered dependable, and the annual energy production is considered firm. Biomass is generally not dispatchable.

A summary of the technical and financial results for wood-based biomass is presented in Table 5.29. BC Hydro has undertaken two wood-based biomass power acquisition processes, resulting in the following pricing:

• Bioenergy Phase I Call Request for Proposals (RFP) (2008/2009) with a levelized plant gate firm energy price of $111/MWh ($F2013). The Bioenergy Phase I Call RFP resulted in four EPAs for a total of 579 GWh/year of firm energy.

• Bioenergy Phase II Call RFP (2010/2011) with a levelized plant gate firm energy price of $123/MWh ($F2013). The Bioenergy Phase II Call RFP resulted in a total of 754 GWh/year of firm energy.
Table 5.29  Summary of Wood-Based Biomass Potential

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Potential Sites*</th>
<th>Installed Capacity (MW)</th>
<th>DGC (MW)</th>
<th>Total Energy (GWh/year)</th>
<th>Firm Energy (GWh/year)</th>
<th>Unit Energy Cost at POI ($F2013/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standing Timber</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peace River</td>
<td>2</td>
<td>112</td>
<td>112</td>
<td>892</td>
<td>892</td>
<td>175 – 232</td>
</tr>
<tr>
<td>North Coast</td>
<td>4</td>
<td>201</td>
<td>201</td>
<td>1,602</td>
<td>1,602</td>
<td>165 – 985</td>
</tr>
<tr>
<td>Kelly/Nicola</td>
<td>1</td>
<td>25</td>
<td>25</td>
<td>201</td>
<td>201</td>
<td>172</td>
</tr>
<tr>
<td>Vancouver Island</td>
<td>1</td>
<td>358</td>
<td>358</td>
<td>2,850</td>
<td>2,850</td>
<td>185</td>
</tr>
<tr>
<td>Lower Mainland</td>
<td>1</td>
<td>358</td>
<td>358</td>
<td>2,850</td>
<td>2,850</td>
<td>185</td>
</tr>
<tr>
<td>Selkirk</td>
<td>1</td>
<td>4</td>
<td>4</td>
<td>29</td>
<td>29</td>
<td>180</td>
</tr>
<tr>
<td>East Kootenay</td>
<td>1</td>
<td>3</td>
<td>3</td>
<td>23</td>
<td>23</td>
<td>167</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td><strong>11</strong></td>
<td><strong>1,060</strong></td>
<td><strong>1,060</strong></td>
<td><strong>8,447</strong></td>
<td><strong>8,447</strong></td>
<td><strong>165 – 985</strong></td>
</tr>
<tr>
<td>Roadside Debris &amp; Wood Waste</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peace River</td>
<td>1</td>
<td>31</td>
<td>31</td>
<td>248</td>
<td>248</td>
<td>141</td>
</tr>
<tr>
<td>North Coast</td>
<td>3</td>
<td>89</td>
<td>89</td>
<td>707</td>
<td>707</td>
<td>130 – 143</td>
</tr>
<tr>
<td>Central Interior</td>
<td>1</td>
<td>31</td>
<td>31</td>
<td>244</td>
<td>244</td>
<td>139</td>
</tr>
<tr>
<td>Kelly/Nicola</td>
<td>1</td>
<td>51</td>
<td>51</td>
<td>408</td>
<td>408</td>
<td>144</td>
</tr>
<tr>
<td>Vancouver Island</td>
<td>1</td>
<td>80</td>
<td>80</td>
<td>641</td>
<td>641</td>
<td>125</td>
</tr>
<tr>
<td>Lower Mainland</td>
<td>1</td>
<td>80</td>
<td>80</td>
<td>641</td>
<td>641</td>
<td>129</td>
</tr>
<tr>
<td>Selkirk</td>
<td>1</td>
<td>39</td>
<td>39</td>
<td>312</td>
<td>312</td>
<td>137</td>
</tr>
<tr>
<td>East Kootenay</td>
<td>1</td>
<td>37</td>
<td>37</td>
<td>298</td>
<td>298</td>
<td>141</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td><strong>10</strong></td>
<td><strong>439</strong></td>
<td><strong>439</strong></td>
<td><strong>3,499</strong></td>
<td><strong>3,499</strong></td>
<td><strong>125 – 144</strong></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>21</strong></td>
<td><strong>1,499</strong></td>
<td><strong>1,499</strong></td>
<td><strong>11,946</strong></td>
<td><strong>11,946</strong></td>
<td><strong>125 – 985</strong></td>
</tr>
</tbody>
</table>

**NOTE:**
For wood-based biomass, this reflects the number of fibre delivery locations considered in the study. The capacity figures shown reflect the total potential power generation (using multiple plants) based on the estimated fuel supply. In general, there is one fibre delivery location assumed for each forestry sub-region unless the potential is small.

Wood-based biomass is considered further in the portfolio analysis. The only exception is the standing timber portion of wood-based biomass, which has been excluded due to cost and other uncertainty.

5.5.2.5  Biomass – Municipal Solid Waste

Municipal solid waste biomass refers to the conversion of municipal solid waste into a usable form of energy, such as electricity. Conventional combustion and gasification are the most commonly used municipal solid waste technologies. The municipal solid waste resource option potential is estimated based on fuel source availability, where an attempt was made to incorporate the zero waste philosophy that endeavours to minimize the amount of waste going to landfills by employing waste avoidance and diversion strategies. A summary of the technical and financial results for municipal solid waste is contained in Table 5.30.
Table 5.30  Summary of Municipal Solid Waste Biomass Potential

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Potential Sites</th>
<th>Installed Capacity (MW)</th>
<th>DGC (MW)</th>
<th>Total Energy (GWh/year)</th>
<th>Firm Energy (GWh/year)</th>
<th>Unit Energy Cost at POI ($F2013/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vancouver Island</td>
<td>1</td>
<td>12</td>
<td>12</td>
<td>101</td>
<td>101</td>
<td>194</td>
</tr>
<tr>
<td>Lower Mainland</td>
<td>1</td>
<td>34</td>
<td>33</td>
<td>285</td>
<td>285</td>
<td>117</td>
</tr>
<tr>
<td>Selkirk</td>
<td>1</td>
<td>14</td>
<td>13</td>
<td>112</td>
<td>112</td>
<td>259</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>3</strong></td>
<td><strong>60</strong></td>
<td><strong>58</strong></td>
<td><strong>499</strong></td>
<td><strong>499</strong></td>
<td><strong>117 – 259</strong></td>
</tr>
</tbody>
</table>

5.5.2.6  Biomass – Biogas or Landfill Gas

Landfill gas is created when organic waste in a municipal solid waste landfill decomposes under anaerobic conditions. Landfill gas can be captured, converted, and used as an energy source to help prevent methane from migrating into the atmosphere and contributing to global climate change. Technologies for producing electricity from landfill gas include internal combustion engines, gas turbines, and micro turbines.

In developing the landfill gas resource potential, BC Hydro reviewed a report by Golder (Golder 2008). A summary of the technical and financial results for biogas is presented in Table 5.31.

Table 5.31  Summary of Biogas Potential

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Potential Sites</th>
<th>Installed Capacity (MW)</th>
<th>DGC (MW)</th>
<th>Total Energy (GWh/year)</th>
<th>Firm Energy (GWh/year)</th>
<th>Unit Energy Cost at POI ($F2013/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Interior</td>
<td>1</td>
<td>2</td>
<td>2</td>
<td>17</td>
<td>17</td>
<td>71</td>
</tr>
<tr>
<td>Kelly/Nicola</td>
<td>2</td>
<td>4</td>
<td>4</td>
<td>33</td>
<td>33</td>
<td>73 – 106</td>
</tr>
<tr>
<td>Vancouver Island</td>
<td>3</td>
<td>2</td>
<td>2</td>
<td>19</td>
<td>19</td>
<td>70 – 159</td>
</tr>
<tr>
<td>Lower Mainland</td>
<td>3</td>
<td>4</td>
<td>4</td>
<td>32</td>
<td>32</td>
<td>60 – 96</td>
</tr>
<tr>
<td>Selkirk</td>
<td>3</td>
<td>4</td>
<td>4</td>
<td>33</td>
<td>33</td>
<td>73 – 96</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>12</strong></td>
<td><strong>17</strong></td>
<td><strong>16</strong></td>
<td><strong>134</strong></td>
<td><strong>134</strong></td>
<td><strong>60 – 159</strong></td>
</tr>
</tbody>
</table>

Biogas is not included in the portfolio analysis in Section 5.5.4 because there has been only one biogas project with a small volume of energy bid into a 2003 BC Hydro power acquisition process, resulting in two EPAs.

5.5.2.7  Geothermal

Geothermal energy systems draw on natural heat from within the earth’s crust to drive conventional power generation technologies. The primary source of geothermal energy is radioactive decay occurring deep within the earth, supplemented by residual heat from the earth’s formation and heat generated by earth’s gravitational forces pulling dense materials into the earth’s core.

Geothermal electricity can be produced based on conventional or unconventional resources. Conventional resources are in the form of high or medium temperature steam or hot water associated with geological structures that bring heat relatively close to the earth’s surface. Only conventional hydrothermal resources using flash or binary technologies are considered within BC Hydro’s resource option assessment. There may be potentially significant unconventional resources that could increase the potential...
geothermal resource base of B.C., including hot dry rock or low temperature
hydrothermal resources in the sedimentary basin.

**Environmental Attribute Overview:** Geothermal is a clean or renewable resource, as
defined by Section 1 of the *Clean Energy Act*. Geothermal resources can have an effect
on groundwater flow. Footprint impacts can include new access roads and transmission
lines.

**Technical and Financial Attribute Overview:** BC Hydro reviewed a number of external
studies to develop its assessment of geothermal potential. A summary of the technical
and financial results for the geothermal resource option is contained in Table 5.32. The
geothermal cost estimates are based on generic capital and operating/maintenance
costs using U.S. industry experience, with an adjustment for climate and topography in
B.C. These values do not account for a relatively higher exploration risk that is expected
for B.C. greenfield geothermal resources. Development of greenfield geothermal
resources is associated with a relatively higher rate of drilling program failure in the
exploration stage, which can add to the development costs and the UEC of a given
project, especially for smaller projects. Due to this expected higher exploration risk and
the higher costs associated with failed exploration wells of B.C. resources relative to the
generic U.S. industry average, the estimates shown are likely to be low.

**Table 5.32 Summary of Geothermal Potential**

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Potential Sites</th>
<th>Installed Capacity (MW)</th>
<th>DGC (MW)</th>
<th>Total Energy (GWh/year)</th>
<th>Firm Energy (GWh/year)</th>
<th>Unit Energy Cost at POI ($F2013/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peace River</td>
<td>1</td>
<td>20</td>
<td>20</td>
<td>140</td>
<td>140</td>
<td>119</td>
</tr>
<tr>
<td>North Coast</td>
<td>3</td>
<td>270</td>
<td>270</td>
<td>2,111</td>
<td>2,111</td>
<td>90 – 121</td>
</tr>
<tr>
<td>Kelly/Nicola</td>
<td>1</td>
<td>20</td>
<td>20</td>
<td>140</td>
<td>140</td>
<td>125</td>
</tr>
<tr>
<td>Revelstoke</td>
<td>1</td>
<td>20</td>
<td>20</td>
<td>140</td>
<td>140</td>
<td>127</td>
</tr>
<tr>
<td>Vancouver Island</td>
<td>2</td>
<td>70</td>
<td>70</td>
<td>534</td>
<td>534</td>
<td>132 – 581</td>
</tr>
<tr>
<td>Lower Mainland</td>
<td>5</td>
<td>320</td>
<td>320</td>
<td>2,505</td>
<td>2,505</td>
<td>88 – 124</td>
</tr>
<tr>
<td>Selkirk</td>
<td>3</td>
<td>60</td>
<td>60</td>
<td>420</td>
<td>420</td>
<td>118 – 166</td>
</tr>
<tr>
<td>Total</td>
<td>16</td>
<td>780</td>
<td>780</td>
<td>5,992</td>
<td>5,992</td>
<td>88 – 581</td>
</tr>
</tbody>
</table>

**NOTE:**
The summary table excludes two sites that are technically inaccessible (e.g., within a protected area or within an area that exceeds technical criteria established for road or transmission access)

B.C.’s geothermal resource is estimated to total more than 700 MW of potentially
cost-effective clean or renewable power. However, BC Hydro has not included the
geothermal resource option in the portfolio analysis in Section 5.5.4 for the following
reasons:

- As described above in Section 5.5.2.1, historically, resource options with the lowest
  unadjusted UECs values have not always bid into BC Hydro’s power acquisition
  processes. Despite its relatively low cost (an unadjusted UEC of $88/MWh in
  $F2013), geothermal resource developers have never bid into BC Hydro’s power
  acquisition processes. From the 2010 Resource Options Report, BC Hydro
  understands that there are some challenges with geothermal development in B.C.
  related to the risk/reward of making a significant upfront capital investment at the
  early exploration and initial production drilling stages.
There are no commercial geothermal electricity projects in B.C. at this time. Since 2002, the B.C. Ministry of Energy, Mines and Natural Gas has released geothermal permits to developers at 12 locations in the province, but these have not resulted in any significant investments in exploration. The only significant private sector investment in exploration was led by Sierra Geothermal (now Ram Power) in 2004 at South Meager Creek; however, the multi-million dollar drilling program failed to yield geothermal wells useful for geothermal power production.

5.5.2.8 Natural Gas-Fired Generation and Cogeneration

Natural gas-fired units generate electricity using the heat released by the combustion of natural gas:

- CCGTs are an energy and capacity resource. CCGTs use the combination of combustion and steam turbines to generate electricity. Exhaust gases from a combustion turbine flow to a heat recovery steam generator that produces steam to power a steam turbine, resulting in higher efficiencies than those achievable by operating the combustion or steam turbines individually. CCGTs have a relatively high efficiency in converting fuel to electricity in comparison to other thermal generation. Conversion efficiencies are typically about 55% to 60% for CCGTs.

- SCGTs are a capacity resource. SCGTs are stand-alone generating plants that use combustion gases to propel a turbine similar to a jet engine connected to an electrical generator. SCGTs are less efficient than CCGTs in converting fuel to electricity. Conversion efficiencies are typically about 35% to 40% for SCGTs.

- Cogeneration is the simultaneous production of electrical and thermal energy from a single fuel. Cogeneration involves thermal power generation and a steam/thermal "host" to use the excess heat produced from the generating process. Steam/thermal hosts may include industries and institutions that need heat such as pulp mills, greenhouses, or hospitals. The efficiency of cogeneration plants is typically about 80% or less, depending on the nature of the steam host.

Large hydroelectric resources such as the Project, with hydroelectric conversion efficiencies of up to 95%, are more efficient at power generation than thermal resources such as natural gas.

Natural gas-fired generation raises unique legal and policy issues in B.C.

Clean Energy Act Considerations

Section 2 of the Clean Energy Act sets out two of British Columbia’s energy objectives which are relevant to the role of natural gas-fired generation:

- The first, described in Part 1, is found in Subsection 2(c) and provides: “to generate at least 93% of the electricity in British Columbia from clean or renewable resources…” The definition of “clean or renewable resources” in Section 1 of the Clean Energy Act does not include natural gas-fired generation.

- The second, described in Part 2, is contained in Subsection 2(g) of the Clean Energy Act, setting out the B.C. Government’s legislated GHG emission reduction targets
**Part 1: Clean Energy Act Clean or Renewable Target**

BC Hydro currently has five natural gas-fired generating facilities in its system:

1) Burrard [However, as described above, no energy is assumed from Burrard for planning purposes as a result of Subsection 3(5) and 6(2)(b) of the Clean Energy Act. Burrard cannot be relied on for dependable capacity after Mica Unit 6 goes into service in about 2016 as a result of the Burrard Thermal Electricity Regulation.], 2) Fort Nelson Generating Station, 3) Prince Rupert Generating Station, 4) Island Generation Plant (IPP), and 5) McMahon Cogeneration Plant (IPP). These facilities contribute

9,520 GWh/year of firm energy to the system, and account for more than 5% of the space currently available for natural gas-fired generation under the 93% clean or renewable target. Thus, little space is left for developing new natural gas-fired generation.

Table 5.33 sets out the maximum GWh of new natural gas-fired generation that could be built in F2022, assuming the 2012 Load Forecast after DSM without LNG load. Table 5.33 also shows the number of MW of new natural gas-fired generation that could be built by F2022 (the Project’s earliest in-service date).

<table>
<thead>
<tr>
<th>Year</th>
<th>F2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Space available for natural gas-fired generation (7% of total generation energy requirements used as a proxy for generation)</td>
<td>4,356 GWh</td>
</tr>
<tr>
<td>Energy contribution from existing natural gas-fired generation (GWh)</td>
<td>3,520 GWh</td>
</tr>
<tr>
<td>Permissible volume of new natural gas-fired generation that could be built (GWh)</td>
<td>836 GWh</td>
</tr>
<tr>
<td>Associated MW of new natural gas-fired generation (CCGT) (90% capacity factor)</td>
<td>106 MW</td>
</tr>
<tr>
<td>Associated MW of new natural gas-fired generation (SCGT) (18% capacity factor)</td>
<td>530 MW</td>
</tr>
</tbody>
</table>

Therefore, neither CCGTs nor SCGTs are an alternative to the Project on their own; they must be combined with clean or renewable resources to compare against the Project’s 5,100 GWh/year of average energy and 1,100 MW of dependable capacity. Refer to the portfolio analysis in Section 5.5.4. BC Hydro is relying on the remaining GWh of natural gas-fired headroom to facilitate future SCGT capacity needs under contingency circumstances (refer to Section 5.2.3).

**Part 2: GHG Offset Requirement**

Subsection 2(g) of the Clean Energy Act sets out the B.C. Government’s legislated GHG emission reduction targets. In addition, Policy Action No. 18 of the 2007 Energy Plan provides that all new natural gas-fired generation must have zero net GHG emissions. This requirement is legislated pursuant to Part 6.1 of the B.C. Environmental Management Act. While, to date, regulations to bring Part 6.1 of the Environmental Management Act have not been enacted, it is likely that as part of the BCEAA process, which would be triggered by a proposal to construct a CCGT or SCGT with a nameplate capacity of 50 MW or greater, a 100% offset requirement would be imposed through EAC conditions. BC Hydro has factored in GHG offset costs into the UEC values.

**Environmental Attributes Overview:** Natural gas-fired generation can have land use impacts for the facility itself and extension to the transmission grid. The environmental attributes only include the footprint of the facility itself – the footprint for fuel extraction is not included.
The products of natural gas combustion include the following air contaminants: NO\textsubscript{x}, sulphur dioxide (SO\textsubscript{2}), carbon monoxide, and PM. These are known as primary emissions. In addition, NO\textsubscript{x} is a precursor to ground-level ozone and can lead to its formation in the ambient air. Along with SO\textsubscript{2}, NO\textsubscript{x} is also a precursor of secondary particulate matter. There are known health and environmental effects associated with all of the aforementioned contaminants.

Natural gas-fired generation also emits carbon dioxide, methane, and nitrous oxide, which are GHGs. The GHG emissions of a SCGT facility with a nameplate capacity of 500 MW (18% capacity factor) are about 376,000 tonnes of CO\textsubscript{2}e/year. (The SCGT GHG emission factor is about 477 tonnes of CO\textsubscript{2}e per GWh).

Metro Vancouver, the regulator in the Lower Mainland, has taken the position that it will not approve any new natural gas-fired generation in the Lower Mainland. Accordingly, for EIS alternative comparison purposes, BC Hydro assumed that a CCGT or SCGT will not be located in the Lower Mainland. The following provides a high level overview of the major permitting requirements for natural gas-fired generation outside the Lower Mainland.

**CCGT:** Siting a 100 MW CCGT triggers the following material regulatory approvals:

- An EAC under BCEAA from the B.C. Minister of Energy, Mines and Natural Gas, and the B.C. Minister of Environment, as the replacement CCGT will exceed the B.C. Reviewable Projects Regulation threshold of a new powerplant with a nameplate (rated) capacity of 50 MW or greater.
- Air emission permit from the B.C. Ministry of Environment under EMA. CCGTs emit NO\textsubscript{x}, coarse and fine PM, sulphur dioxide, and ammonia (the latter as part of the select catalytic converter process to reduce NO\textsubscript{x} emissions), all of which can impact human health, as well as livestock and agricultural crops. The impact would depend in part on ambient (background) air quality. The public would be involved pursuant to the Public Notification Regulation (B.C. Reg. 202/94).

Assuming permitting could be secured and no legal challenges to the issuance of permits, the 2010 Resource Options Report indicates that lead times for new CCGTs would be about five years.

**SCGT:** BC Hydro’s 2010 Resource Options Report indicates similar lead times for SCGTs as CCGTs. With one exception, SCGTs would trigger similar regulatory approvals for siting CCGTs, including the requirement for an air emission permit from the B.C. Ministry of Environment. As the associated MW of SCGTs is over 200 MW under the Clean Energy Act clean or renewable target (see Table 5.33), in the context of this alternative analysis, SCGTs would also trigger CEAA, because the alternative SCGT is a fossil fuel-fired electrical generating station with a production capacity of 200 MW or more (Regulations Designating Physical Activities SOR/2012-147, schedule, Section 2):

- It may be easier to site SCGTs, given that they do not run as often as CCGTs and therefore do not emit as many air contaminants.
- However, the newly released performance standard for coal-fired generation of 420 tonnes of CO\textsubscript{2}e per GWh contained in the Federal Government’s Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations (SOR/2012-167) may challenge new SCGTs. The 420 tonnes of CO\textsubscript{2}e per GWh performance standard is the GHG emission intensity level of a CCGT.
Technical and Financial Attribute Overview: Natural gas-fired generation is dispatchable, that is, natural gas-fired generation can adjust power output on demand. The time periods in which dispatchable natural gas-fired generation can be turned on or off may vary, but can be considered in time frames of minutes or hours. This may be contrasted with intermittent clean or renewable resources such as run-of-river and wind, which cannot be controlled by operators. Natural gas-fired generation provides firm energy and dependable capacity.

In contrast to the Project and other clean or renewable resources such as run-of-river, a material portion of the costs of natural gas-fired generation is incurred during operations, due mainly to the cost of fuel. For example, the Project construction and development costs are about 85% of the overall costs, with operating, sustaining capital, and fuel costs (mainly water rentals) comprising the other 15%. For SCGTs, construction and development costs are about 20% of the overall costs, with operating and fuel costs comprising the remaining 80% of the overall costs. Refer to Section 7.1.3 in Volume 1 Section 7 Project Benefits for additional detail.

As a result, natural gas-fired generation has greater variable cost uncertainty when compared to clean or renewable resources. The two material variable cost risks are:

- Fuel price risk: This is the risk that the price of natural gas used to generate electricity will exhibit variability over the course of the 25-year to 30-year expected life of a natural gas-fired generating station. Among the fuels most commonly used to generate electricity, natural gas is the most volatile in price. The most significant recent development to affect natural gas prices has been the emergence of shale gas; long-term natural gas prices have dropped due to advancements in gas extraction technologies and the increase in shale reserves. Because there is future natural gas price uncertainty, BC Hydro does not rely on a single natural gas price forecast. Rather, BC Hydro uses a scenario-based approach employing a range of future natural gas prices developed by Ventyx. The mid Ventyx forecast for natural gas at the Sumas, B.C., hub price is between about $3 per gigajoule (GJ) to $7/GJ ($F2013) over the next 30 years and is used in the portfolio analysis in Section 5.5.4.

- Regulatory risk: GHG costs. The requirement that all new B.C.-based natural gas-fired generation have zero net GHG emissions is discussed above. The financial risks associated with GHG regulatory actions – the market price for GHG offsets – turns on the flexibility of compliance mechanisms. For example, is there flexibility to offset GHG emissions outside the Province of British Columbia? While the B.C. Greenhouse Gas Reduction (Cap and Trade) Act (S.B.C. 2008, c.32) contemplates such flexibility through eventual linkage of a B.C.-based cap-and-trade system (the B.C. cap-and-trade system would come into force by issue of a government regulation, which is currently in the consultation stage) to other systems, to date there is no western regional or continent-wide GHG cap-and-trade system. A GHG market confined to B.C. is likely to be more costly than a larger market. BC Hydro adopted a scenario approach to the impact of GHG offset price variability based on Ventyx’s GHG price forecast. The GHG price forecasts provide a wide range of possible future GHG offset prices that capture a range of economic and policy scenarios. The low GHG price is the carbon tax at $30/metric tonne of CO₂e, and is used in the portfolio analysis in Section 5.5.4. The high GHG price is about $173/metric tonne of CO₂e ($F2013, levelized between 2022 and 2046) and is
reflected in the upper financial attribute values for CCGTs (UEC, Table 5.34) and SCGTs (UCC, Table 5.35).

**Combined Cycle Gas Turbines and Cogeneration**

BC Hydro undertook an in-house update of the cost and performance characteristics of gas-fired generation units potentially located in the Kelly Lake/Nicola area in the interior of B.C. BC Hydro also undertook an in-house update for potential cogeneration units in the Lower Mainland. A summary of the technical and financial results for these natural gas-fired generation resource options is contained in Table 5.34.

**Table 5.34 Summary of CCGT and Small Cogeneration Gas-Fired Generation Potential**

<table>
<thead>
<tr>
<th>Resource Option</th>
<th>Number of Potential Sites</th>
<th>Installed Capacity (MW)</th>
<th>DGC (MW)</th>
<th>Total Energy (GWh/year)</th>
<th>Firm Energy (GWh/year)</th>
<th>Unit Energy Cost at POI ($F2013/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>50 MW CCGT in Kelly/Nicola</td>
<td>1</td>
<td>56</td>
<td>49</td>
<td>300</td>
<td>386</td>
<td>111 – 166</td>
</tr>
<tr>
<td>250 MW CCGT in Kelly/Nicola</td>
<td>1</td>
<td>263</td>
<td>236</td>
<td>1,450</td>
<td>1,861</td>
<td>79 – 131</td>
</tr>
<tr>
<td>Small cogeneration in Lower Mainland</td>
<td>20</td>
<td>200</td>
<td>200</td>
<td>1,600</td>
<td>1,600</td>
<td>75 – 127</td>
</tr>
</tbody>
</table>

**Notes:**
- Representative project used to characterize the resource option. Energy is based on a 90% capacity factor and UECs include associated fuel and GHG costs.
- Natural gas-fired generation options are based on natural gas price estimates for the 2022–2046 period using the Ventyx spring 2012 medium levelized forecast of $5.37/GJ ($F2013), which is the most likely forecast.

**Simple Cycle Gas Turbines**

BC Hydro undertook an in-house update of the cost and performance characteristics of a representative 100 MW SCGT unit in Kelly/Nicola. The UCC range is shown in Table 5.35.

**Table 5.35 Summary of SCGT Potential**

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Potential Sites</th>
<th>Installed Capacity (MW)</th>
<th>DGC (MW)</th>
<th>Unit Capacity Costs at POI ($2013/kW-year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 MW SCGT in Kelly/Nicola</td>
<td>1</td>
<td>103</td>
<td>98</td>
<td>89 – 121</td>
</tr>
</tbody>
</table>

**Notes:**
- UCCs for SCGTs are based on an 18% capacity factor and include associated fuel and GHG costs.
- Natural gas-fired generation options are based on natural gas price estimates for the 2022–2046 period using the Ventyx 2012 spring medium levelized gas price forecast of $5.37/GJ ($F2013).

**5.5.2.9 Resource Smart**

BC Hydro’s Resource Smart program identifies potential efficiency gains at existing BC Hydro hydroelectric facilities. Resource Smart projects result in 1) increased turbine efficiencies, and/or 2) increased nameplate capacity of turbines.

Resource Smart opportunities are limited to BC Hydro’s 30 existing hydroelectric facilities. In recent years, BC Hydro has implemented or is implementing a number of
such opportunities. Examples already included in BC Hydro’s resource stack as committed resources (discussed above in Section 5.2.1.2) are:

- The addition of an approximately 500 MW fifth unit at Revelstoke Generating Station in the B.C. Interior (Revelstoke Unit 5, in-service in F2011)
- Two additional approximately 500 MW units at Mica Generation Station (increasing capacity by approximately 1,000 MW) in the B.C. Interior (Mica Units 5 and 6, expected to be in-service in F2015 and F2016, respectively)
- G.M. Shrum Units 6 to 8, providing capacity Increase of about 90 MW (in-service in F2012) on the Peace River
- Replacing the runners at Ruskin Generating Station in the Lower Mainland, with about a 9 MW dependable capacity increase and 28 GWh/year of additional energy

The largest remaining Resource Smart project identified in terms of additional dependable capacity is Revelstoke Unit 6. Revelstoke Unit 6 is not an alternative to the Project, as it is a resource that is already included in the LRBs for purposes of this EIS; refer to Section 5.2.2.2 above.

Environmental Attribute Overview: Resource Smart projects generally occur within the existing hydroelectric facility footprint. Resource Smart projects may change hydroelectric facility operations (i.e., reservoir fluctuations and/or downstream flows).

Technical and Financial Attribute Overview: Table 5.36 is a list of potential additional Resource Smart projects.

### Table 5.36  Summary of Resource Smart Potential

<table>
<thead>
<tr>
<th>Resource Smart Option</th>
<th>Energy (GWh)</th>
<th>UEC at POI ($/MWh, $F2013)</th>
<th>Capacity (MW)</th>
<th>UCC at POI ($/kW-year, $F2013)</th>
</tr>
</thead>
<tbody>
<tr>
<td>G.M. Shrum Units 1–5 capacity increase (Peace River)</td>
<td>0</td>
<td>N/A</td>
<td>220</td>
<td>28</td>
</tr>
<tr>
<td>Cheakamus generator upgrade (Whistler area, Lower Mainland)</td>
<td>45</td>
<td>36</td>
<td>22</td>
<td>74</td>
</tr>
<tr>
<td>Strathcona additional unit (Campbell River, Vancouver Island)</td>
<td>0</td>
<td>N/A</td>
<td>31</td>
<td>118</td>
</tr>
<tr>
<td>Ladoire additional unit (Campbell River, Vancouver Island)</td>
<td>8</td>
<td>336</td>
<td>9</td>
<td>299</td>
</tr>
<tr>
<td>Ash River additional unit (Ash River, Vancouver Island)</td>
<td>30</td>
<td>100</td>
<td>9</td>
<td>334</td>
</tr>
<tr>
<td>Puntledge additional unit (Puntledge River, Vancouver Island)</td>
<td>18</td>
<td>82</td>
<td>10</td>
<td>149</td>
</tr>
<tr>
<td>Duncan Dam new generation (Duncan River/Columbia River area)</td>
<td>103</td>
<td>115</td>
<td>30</td>
<td>396</td>
</tr>
<tr>
<td>Lajoie additional unit (Bridge River/Fraser River area)</td>
<td>80</td>
<td>125</td>
<td>30</td>
<td>333</td>
</tr>
<tr>
<td>Replace runners at Seven Mile Generating Station (Pend-d’Oreille River, Interior)</td>
<td>26</td>
<td>411</td>
<td>32</td>
<td>334</td>
</tr>
</tbody>
</table>

Resource Smart projects contained in the above table would typically be implemented at the time of other necessary safety and reliability-related upgrades at the named
BC Hydro hydroelectric facilities. Resource Smart projects typically require BCUC
approval prior to implementation; two recent examples are the Ruskin Dam and
Powerhouse Upgrade Project and the John Hart Generating Station Replacement
Project (BCUC decision pending).

BC Hydro is not currently anticipating undertaking the G.M. Shrum Units 1–5 Capacity
Increase project because over the next 10 years, BC Hydro will be upgrading most of the
10 G.M. Shrum Generating Station units through other projects, making the undertaking
of the GM Shrum Units 1–5 Capacity Increase project difficult during that time frame.
BC Hydro notes that the G.M. Shrum Units 1–5 Capacity Increase project is not an
alternative on its own to the Project, as it only defers the need for capacity by two years.

5.5.2.10 Pumped Storage

Pumped storage hydro units are capacity resource options and use electricity from the
grid, typically during light load hours, to pump water from a lower elevation reservoir to
an upper elevation reservoir. The water is then released during heavy load hours to
generate electricity. Reversible turbine/generator assemblies or separate pumps and
turbines are used in pumped storage facilities. Pumped storage units are a net
consumer of electricity due to inherent inefficiencies in the pumping-generating cycle,
which result in recovery of about only 70% of the energy used.

Environmental Attribute Overview: The construction of greenfield pumped storage
facilities usually creates reservoirs, thus leading to land loss and impacting vegetation
and wildlife. It may be possible to use natural bodies of water for reservoirs or using
pre-existing dams, thus minimizing this impact. BC Hydro looked at both potential
greenfield pumped storage facilities in the Lower Mainland and on Vancouver Island,
and at the possibility of pumped storage at BC Hydro’s existing Mica Generating Station
in the Interior. Operationally, pumped storage can lead to rapid and frequent changes in
water reservoir levels, which can impact fish and fish habitat through reduction in the
wetted littoral zone (close to shore to about a maximum of 10 m or so in depth, where a
large part of biological production occurs), changes to water velocity/directions and
temperature, and increased erosion. Pumped storage facilities can create changes in
land use through an extension to the transmission line grid.

There are no commercial pumped storage facilities in B.C., and only one pumped
storage facility operating in Canada, which was permitted in the 1950s. Siting a pumped
storage facility in B.C. triggers a number of regulatory/government agency approvals,
including:

- A Course of Action Decision under CEAA, because in the context of this EIS,
pumped storage is a hydroelectric generating station with a production capacity of
200 MW or more (Regulations Designating Physical Activities SOR/2012-147,
schedule, Section 2)

- An EAC under BCEAA, because pumped storage facilities will exceed the B.C.
Reviewable Projects Regulation threshold of a new powerplant with a nameplate
(rated) capacity of 50 MW or greater

Technical and Financial Attribute Overview: The ability to store water and release it
during times of system need makes pumped storage a useful capacity resource.
Pumped storage hydro units can respond quickly to variations in system demand and
can provide ancillary services such as voltage regulation. As described above, pumped storage consumes energy due to the inefficiencies in the pumping-generation cycle.

BC Hydro engaged Knight Piésold Ltd. to identify greenfield pumped storage potential in the Lower Mainland and Vancouver Island regions, and engaged Hatch Ltd. to assess the cost of installing a pump-turbine or a pump at Mica Generating Station. A summary of the technical and financial results for the pumped storage resource option is contained in Table 5.37. As pumped storage is considered a capacity option, only the unit capacity cost is shown.

### Table 5.37 Summary of Pumped Storage Potential

<table>
<thead>
<tr>
<th>Transmission Region</th>
<th>Number of Potential Sites</th>
<th>Installed Capacity (MW)</th>
<th>DGC (MW)</th>
<th>Unit Capacity Costs at POI ($F2013/kW-year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kelly/Nicola</td>
<td>4</td>
<td>4,000</td>
<td>4,000</td>
<td>235 – 279</td>
</tr>
<tr>
<td>Mica</td>
<td>1</td>
<td>500</td>
<td>465</td>
<td>216</td>
</tr>
<tr>
<td>Vancouver Island</td>
<td>84</td>
<td>79,000</td>
<td>79,000</td>
<td>242 – 440</td>
</tr>
<tr>
<td>Lower Mainland</td>
<td>105</td>
<td>105,000</td>
<td>105,000</td>
<td>232 – 407</td>
</tr>
<tr>
<td>Total</td>
<td>194</td>
<td>188,500</td>
<td>188,465</td>
<td>216 – 440</td>
</tr>
</tbody>
</table>

**NOTE:**
UCCs for pumped storage include fuel costs using an 18% capacity factor and 30% energy loss factor.

### 5.5.2.11 Summary of Available Resources

The UEC results are summarized in Table 5.38. The UEC for the Project are included for comparison purposes.

### Table 5.38 UECs of Available Energy Resource Supply Options

<table>
<thead>
<tr>
<th>Energy Resource</th>
<th>Total FELCC Energy (GWh/year)</th>
<th>Total DGC or ELCC Capacity (MW)</th>
<th>Unit Energy Costs at POI ($F2013/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass – wood based</td>
<td>11,946</td>
<td>1,499</td>
<td>125 – 985</td>
</tr>
<tr>
<td>Biomass – biogas</td>
<td>134</td>
<td>16</td>
<td>60 – 159</td>
</tr>
<tr>
<td>Biomass – municipal solid waste</td>
<td>499</td>
<td>58</td>
<td>117 – 259</td>
</tr>
<tr>
<td>Wind – onshore</td>
<td>38,885</td>
<td>3,942</td>
<td>96 – 332</td>
</tr>
<tr>
<td>Wind – offshore</td>
<td>50,261</td>
<td>3,681</td>
<td>190 – 734</td>
</tr>
<tr>
<td>Geothermal</td>
<td>5,992</td>
<td>780</td>
<td>88 – 581</td>
</tr>
<tr>
<td>Run-of-river</td>
<td>35,880</td>
<td>1,074</td>
<td>82 – 600</td>
</tr>
<tr>
<td>Site C Clean Energy Project</td>
<td>4,700</td>
<td>1,100</td>
<td>94</td>
</tr>
<tr>
<td>CCGT and cogeneration</td>
<td>7,623</td>
<td>964</td>
<td>75 – 166</td>
</tr>
</tbody>
</table>

The UCCs of the supply-side capacity resource options are summarized in Table 5.39.
Table 5.39  UCCs of Available Capacity Resource Supply Options

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Capacity Options</th>
<th>Dependable Capacity (MW)</th>
<th>Unit Capacity Costs at POI ($F2013/kW-year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCGT</td>
<td>Various Locations</td>
<td>98</td>
<td>89 – 121</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>Various Locations</td>
<td>1,000</td>
<td>216 – 440</td>
</tr>
<tr>
<td>Resource Smart</td>
<td>Various Locations</td>
<td>About 390</td>
<td>28 – 370</td>
</tr>
</tbody>
</table>

5.5.3  Portfolio Modelling Framework

In addition to assessing available resources as reflected in Section 5.5.2, BC Hydro analyzed the available resources through portfolio analysis to determine whether the Project is the preferred option to serve the need identified in Section 5.2:

- Section 5.5.3 provides details regarding the portfolio-related models, modelling constraints, and input parameters
- Section 5.5.4 discusses the portfolio results. The portfolio results indicate that the Project is a cost-effective resource option compared to the available resources.

5.5.3.1  Introduction to Portfolio Analysis

Portfolio analysis is a process of developing and evaluating resource portfolios, each consisting of a sequence of supply-side and demand-side resources to meet the energy and capacity needs of BC Hydro’s customers. In its 2006 IEP/LTAP Decision, the BCUC stated “that a portfolio analysis is consistent with the Commission’s Guidelines”, and “is a best practice for IEP or IRP analysis” (BCUC 2006).

In general, portfolios were created in this analysis for the planning period from F2015 to F2041. Each portfolio contains BC Hydro’s current DSM target. The portfolio analysis for the Project examined how the Project compares to combinations of available resources. This analysis was conducted by comparing portfolios including the Project against portfolios of resources that excluded the Project but combining available resources that provide approximately the same amount of energy and capacity. In general, these alternatives are composed of multiple available resource projects, as most alternatives to the Project are not capable of delivering comparable amounts of energy and dependable capacity on their own. BC Hydro compares portfolios based on portfolio technical, financial, environmental, and economic development attributes.

Figure 5.8 shows a schematic of the overall process for developing portfolios and analyzing the results. The following sections provide a more detailed discussion of the components of the process.

5.5.3.2  Portfolio Analysis Process and Models

BC Hydro’s portfolio analysis uses a suite of models:

- Hydrological system simulation model (HYSIM)
- System Optimizer
- Multi-Attributes Portfolio Analysis
HYSIM is a BC Hydro-developed model. It is a system production cost model, which runs through 60 years of water records in modelling the large hydro system. HYSIM provides insight on how water variability may impact portfolio performance. It develops the monthly generation profile for the large hydro system that is an input to System Optimizer. For additional details on HYSIM, please see Section 11.4 in Volume 2 Section 11 Environmental Background.

Resource portfolios were developed using System Optimizer, a product of Ventyx that has been adopted by several utilities in North America. System Optimizer is a deterministic linear optimization model that selects an optimal resource expansion sequence (referred to as a portfolio) of generation and transmission additions for a given set of input assumptions. System Optimizer minimizes the present value of net costs, including the incremental fixed capital and operating costs for new resources and total system production costs (inclusive of trade revenues), to meet a given load based on BC Hydro’s planning criteria. System Optimizer does not capture either resource delivery risk, or the value of ancillary benefits (such as the ability to integrate intermittent resources and firming capability), which could be significant for resources such as the Project. The benefits of the Project are described in Volume 1 Section 7 Project Benefits.

Multi-Attributes Portfolio Analysis is a BC Hydro-developed model. It takes the portfolio output from System Optimizer and tracks the various attributes (e.g., environmental and economic development attributes as described in Section 5.5.1) for the portfolios.

5.5.3.3 Modelling Constraints

The portfolios created satisfy good utility practice (e.g., they meet reliability criteria). Two Clean Energy Act objectives are treated as constraints: 1) achieve self-sufficiency, and 2) meet the 93% clean or renewable energy target described in respect of natural gas-fired generation in Section 5.5.2.8. In addition, the 2007 Energy Plan requirement that natural gas-fired generation GHG emissions be completely offset is treated as a modelling constraint.

5.5.3.4 Financial Parameters

Costs are expressed on a present value basis to capture the impact of the timing of costs and trade revenues over the planning horizon. The portfolio analysis results are expressed in $F2013 dollars. The present values of the portfolios reflect the costs (or levelized costs, where appropriate) for the planning period F2015 to F2041. It is expected that extending the planning period beyond F2041 would increase the additional value of a portfolio with Project relative to one without the Project, reflecting the Project’s long expected life.

The key financial parameters in the portfolio analysis are described below.

Inflation Rate

Where nominal and real dollar conversion was necessary, a rate of 2% was assumed as the average inflation rate outlook. This inflationary assumption is consistent with the B.C. Consumer Price Index, which is provided in the Province of B.C. 2012 Budget and Fiscal Plan. Aside from the annual inflationary assumption, the portfolio analysis assumes no other incremental cost escalation or inflationary allowance for capital costs.
Discount Rate

BC Hydro used a 6% real discount rate in the portfolio cost assessments.

Cost of Capital

Policy Action #13 of the Provincial Government’s 2002 Energy Plan (page 30) provides that the private sector (i.e., IPPs) will develop new electricity generation, with BC Hydro restricted to improvements at existing plants (such as Resource Smart projects) and the Project. The BCUC in its 2006 IEP/LTAP Decision, page 205, found:

“...the [BCUC] panel agrees with BC Hydro [and the customer intervenors] that project evaluation methodology must consider the actual costs, benefits, risks and other characteristics of individual projects that may be relevant to cost-effectiveness, and should not seek to artificially compensate for real differences in projects costs, including possible differences in the cost of capital between BC Hydro and other developers. With respect to the cost of capital, BC Hydro projects will clearly have an advantage as a result of...access to the Province’s high credit rating.” [Emphasis added].

BC Hydro is an agent of Her Majesty the Queen in the right of the Province of British Columbia. BC Hydro’s borrowing is guaranteed by the Province; BC Hydro can also borrow directly from the Province. BC Hydro’s weighted average cost of capital (the overall costs of combined debt and equity capital used to finance an acquisition) is 5.5% (real), which is rounded upwards to 6% (real) for purposes of this EIS and the portfolio alternatives evaluation.

It is widely acknowledged that the private sector, including IPPs, has higher borrowing costs than governments such as the B.C. Government. Consistent with the BCUC’s 2006 IEP/LTAP Decision, BC Hydro used a higher weighted average cost of capital for the available resource portfolios, as these would be developed by IPPs. Based on its experience with negotiating with IPPs and other third-party developers, BC Hydro used a weighted average cost of capital of 8% (real) for IPPs for purposes of this EIS. In a study for the Western Electric Coordinating Council, Energy + Environmental Economics used an after tax weighted average capital cost for IPPs of 8.25% (Energy + Environmental Economics 2012).

U.S./Canadian Exchange Rate

Assumptions about the U.S. to Canadian dollar are required for the conversion of market price forecasts. The conversion rate assumption is $0.97 U.S/Cdn.

GHG Offset Cost

BC Hydro has explicitly considered the cost to offset GHG emissions from natural gas-fired generation because this will become financial liabilities for BC Hydro customers as a result of the requirement to completely offset such GHG emissions. BC Hydro conservatively used the lowest GHG offset cost of $30/t of CO2e, based on the B.C. carbon tax for the portfolio analysis. Refer to Section 5.5.2.8 for a discussion of higher GHG offset price scenarios.
Soft Cost Adder

As described above in Section 5.5.1.1, the Project cost estimate includes costs for mitigation measures, regulatory review, First Nation consultation, and public engagement. The UECs and UCCs for available resources set out in Section 5.5.2 do not include such costs.

Implementation of the available resources would entail mitigation, regulatory review, First Nation consultation, and public engagement costs (called soft costs). For example:

- Replacing the Project’s dependable capacity contribution of 1,100 MW requires either 1) a large replacement pumped storage facility, which would trigger both CEAA and BCEAA, and would have environmental effects described in Section 5.5.2.10, or 2) a combination of SCGTs and pumped storage. A replacement SCGT would trigger BCEAA, CEAA, and air emission permitting requirements (refer to Section 5.5.2.8).

- Replacing the Project’s average energy contribution of 5,100 GWh/year would entail acquiring clean or renewable intermittent resources such as wind resources. All wind projects awarded EPAs triggered BCEAA because they have a nameplate capacity of 50 MW or greater; refer to Table 5.40 below. The table of mitigation-related commitments appended to EAC E06-03 issued in respect of Dokie Wind Project is several pages in length.

Table 5.40  BC Hydro EPA Wind Projects and BCEAA Trigger

<table>
<thead>
<tr>
<th>Project</th>
<th>Nameplate Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bear Mountain</td>
<td>102</td>
</tr>
<tr>
<td>Dokie Wind</td>
<td>144</td>
</tr>
<tr>
<td>Quality Wind</td>
<td>142</td>
</tr>
<tr>
<td>Cape Scott</td>
<td>99</td>
</tr>
<tr>
<td>Tumbler Ridge</td>
<td>45</td>
</tr>
<tr>
<td>Wildmare</td>
<td>77</td>
</tr>
<tr>
<td>Meikle</td>
<td>117</td>
</tr>
<tr>
<td>Bull Moose</td>
<td>60</td>
</tr>
</tbody>
</table>

BC Hydro has put a cost adder of 5% on available resource portfolios to reflect the fact that implementing the available resource options would entail soft cost expenditures. BC Hydro chose 5% on the basis of its experience; for example, the environmental assessment, First Nation, and stakeholder engagement costs of a sample of recent representative BC Hydro capital projects ranged from 0.02% to about 10%.

Sunk Costs

A key concept in understanding the portfolio analysis is the concept of incremental costs. The incremental cost approach focuses on examining how costs change based on potential alternatives. Sunk costs, which are costs that have been incurred prior to the current analysis, are not relevant for purposes of the incremental cost analysis. Accordingly, the Project-related sunk costs (about $5/MWh) have been removed for purposes of the portfolio analysis.
5.5.3.5 Load, Market and Transmission Parameters

Load/Resource Balance Assumptions
Portfolios were created and evaluated across the base LRB gap (Mid-level 2012 Load Forecast, existing and committed resources, the current BC Hydro DSM target, Revelstoke Unit 6; refer to Section 5.2.2.2).

Market Energy Price Assumptions
Using costs to compare portfolios requires estimating the costs and trade revenues of each portfolio operating over the planning time frame. These operating costs and revenues are affected by market price assumptions, including the market prices of natural gas, GHG, and electricity. BC Hydro used the Ventyx Spring 2012 market price forecast in the portfolio analysis. This Ventyx forecast assumes slower economic growth and is the basis for BC Hydro’s most likely market price forecast. The forecast of Mid-Columbia spot market electricity price is the hourly price for buying and selling surplus electricity at a trading hub near the Washington/Oregon border. In the portfolio analysis in Section 5.5.4 BC Hydro uses a forecast of Mid-Columbia spot market electricity prices ranging from about $25/MWh to $50/MWh (with a further adjustment for the costs of wheeling and losses to the B.C. border) over the next 30 years.

Transmission Assumptions
The analysis of the long-term transmission requirements is based on BC Hydro’s Integrated System Planning Criteria. These criteria define BC Hydro’s guidelines for planning a reliable transmission network that is adequate for dispatching designated generation resources to serve the forecasted demand. For system performance under normal and emergency conditions, BC Hydro’s planning criteria conform to the BCUC-approved North American Electric Reliability Corporation (NERC) Reliability Standards for transmission planning.

In accordance with the criteria, the System Optimizer identifies where and when incremental transmission capacity will be required for a particular portfolio. System Optimizer first selects a set of applicable wire or non-wire transmission options for removing congestion from an existing transmission path by adding incremental transfer capacity to the constrained path. The result is reviewed and, if needed, the reinforcement requirements are adjusted. The present values of the portfolios reflect these adjustments.

5.5.3.6 Characterization of Portfolio Attributes
Once the System Optimizer creates portfolios for each scenario, the Multi-Attributes Portfolio Analysis process is used to determine the financial, technical, environmental, and economic development characteristics of each portfolio. Please see Section 5.5.1 for a more detailed description of the attributes.

The portfolio attributes are summarized at a level appropriate for comparing the Project against other portfolios using consequence tables. A consequence table is a collection of the above information arranged in a matrix format so that the Available Resource options considered are displayed as column headers, the relevant decision objectives are displayed as row labels, and for each row, the specific units of measurement are provided. While some judgment is required to reduce the full analysis down to a
condensed level, this view allows a reader to easily see the relative impacts of Available
Resource options across alternatives and decision objectives.

5.5.3.7 Uncertainties and Risks Not Captured by Portfolio Modelling

Key uncertainties and risks include the following:

- Current DSM Target – The portfolio modelling assumes that the current DSM target
  will deliver the expected energy and dependable capacity savings

- Expected Life – The Project is expected to have a life of more than 100 years. In
  contrast, EPAs with IPPs for available resources have varying durations that are
  shorter, ranging from 15 to 40 years (refer to Section 5.5.2 for each available
  resource that has been the subject of prior BC Hydro power acquisition processes
  such as run-of-river, wind and bioenergy). As described in Section 5.2.3, at the end
  of EPA terms, there is significant supply and price risk to BC Hydro because there is
  no assurance that 1) IPP available resource-related projects will continue operations
  past the expiry of EPAs, 2) that IPPs will contract with BC Hydro if they do continue
  to operate, or 3) that IPPs will contract at a price comparable to their current
  real-dollar prices.

- IPP Attrition Risk – The portfolio modelling does not reflect the relatively high IPP
  attrition rate that BC Hydro has observed through its power acquisition processes. If
  BC Hydro were to pursue some combination of available resources instead of the
  Project, it would likely have to award EPAs representing more energy than the lost
  Project contribution of 5,100 GWh/year of average energy.

- Regulatory Risk – The portfolio model does not account for available resource
  development and regulatory risk. If BC Hydro were to pursue available resources,
  the EPAs with IPPs must be filed with the BCUC for acceptance pursuant to
  Section 71 of the Utilities Commission Act. BC Hydro qualitatively described
  available resource development and regulatory risks above in Section 5.5.2; see, for
  example, SCGTs (air emission permitting) and pumped storage (only one such
  facility permitted to date in Canada).

5.5.4 Portfolio Evaluation Results

This section compares the technical, financial, environmental, and economic
development attributes of portfolios with and without the Project.

5.5.4.1 Portfolio Development

To compare the Project to available resources, BC Hydro built a number of portfolios
including the Project and excluding the Project. Three categories of portfolios were
established, using different assumptions regarding available resources:

- Site C Portfolios that include the Project, with the remaining energy and capacity
  gap being filled using clean or renewable generation resources

- Clean Generation Portfolios that exclude the Project and fill the energy and
  capacity gap using clean or renewable generation resources. As referenced in
  Section 5.5.2, available clean or renewable resources for portfolio purposes are
  wind, run-of-river, and biomass to provide energy and capacity, with pumped storage
  providing backup capacity but representing an energy consumer.
• **Clean + Thermal Generation Portfolios** that exclude the Project and fill the energy gap using clean or renewable generation resources as in the Clean Generation Portfolio, while backup capacity is provided by thermal generation (in the form of SCGTs) up to the 93% clean or renewable target, as well as pumped storage. It should be noted that the partial replacement of the dependable capacity provided by the Project with SCGTs would use up all of the 7% non-clean headroom. As a result, BC Hydro’s ability to use natural gas-fired generation for contingency resource planning purposes is foregone. This value is not fully represented in the portfolio analysis undertaken.

A number of assumptions are consistent through all portfolios, including:

- LRB is based on 2012 Load Forecast with no LNG load
- Electricity and gas market scenario based on Ventyx’s spring 2012 price forecast
- The current BC Hydro DSM target is used in every portfolio
- The cost of most alternatives is based on 2010 Resource Options Report data using an 8% weighted average cost of capital (refer to Section 5.5.3.4)
- Wind costs are based on the 2012 wind cost update (see Section 5.4.1.2)

Refer to Figure 5.9 for a representation of the portfolios considered.

Once the portfolios were constructed, BC Hydro compared the technical, financial, environmental, and economic development attributes between these portfolios.

**5.5.4.2 Technical Attributes**

The portfolios used to compare alternatives to the Project are constructed to have similar overall technical attributes (i.e., each portfolio is built to fill the energy and capacity gaps identified in Section 5.2.2). However, there are some differences between these portfolios that are important to highlight.

**Energy:** BC Hydro’s portfolio building exercise identified wind as the primary energy technology to provide energy in both the Clean Generation portfolios and the Clean + Thermal Generation portfolios. The balance of energy requirements are mostly provided by biomass resources in the Clean Generation portfolio, while both biomass and SCGTs provide energy in the Clean + Thermal Generation portfolio. Run-of-river resources provide only a minor amount of energy. This result is not aligned with the results of previous BC Hydro power acquisition processes – in these calls, run-of-river was the primary resource bid in. This is generally due to the lower wind costs resulting from the wind cost update discussed in Section 5.4.1.2. If wind costs are left at the levels in the Resource Options Report, run-of-river hydro and/or biomass would provide higher proportions of energy for the portfolio.

The Clean Generation portfolio requires more energy resources in total due to the requirement to offset energy losses from pumped storage. That is, an additional 700 GWh/year of energy generation resources are required in the Clean Generation portfolio, due to the net energy consumption from the pumped storage capacity resource.
Figure 5.10 shows the comparison of the energy provided by the Project to a 5,100 GWh/year block of energy resources that are similar to those selected in the Clean Generation and Clean + Thermal Generation portfolios.

**Capacity:** In both the Clean Generation and Clean + Thermal Generation portfolios, capacity is partially provided by the DGC of biomass and the ELCC of wind resources. The balance of the capacity requirements are provided by DGC from pumped storage in the Clean Generation portfolio, while SCGTs and pumped storage provide DGC in the Clean + Thermal Generation Portfolio.

ELCC has a greater level of uncertainty than the DGC of a dependable capacity resource such as the Project, which is set as part of the project design. A portfolio that relies significantly on the contribution of intermittent clean or renewable generation to ELCC has the potential to overstate the available capacity due to an expected capacity contribution versus having dependable capacity that is known to be available when the system requires it.

Both the Clean Generation and Clean + Thermal Generation portfolios rely significantly on intermittent resources for the energy contribution. There may be additional firming and/or shaping capability required from the BC Hydro system that is not included in the portfolio analysis.

Figure 5.11 shows the comparison of the dependable capacity provided by the Project to an 1,100 MW block of energy resources that are similar to those selected in the Clean Generation and Clean + Thermal Generation portfolios.

### 5.5.4.3 Financial Attributes

The analysis evaluated the cost-effectiveness of the Project by comparing the present value of the costs between portfolios with and without the Project. This represents the financial benefits over the 30-year analysis period. This present value calculation was performed for a range of in-service dates for the Project to evaluate whether the Project was cost-effective both at F2022 and at F2024. Table 5.41 shows the results of this present value analysis. Note that the present value analysis is based on a no LNG load scenario and on the current DSM target. The present value analysis does not take DSM or other resource delivery risk into account.

<table>
<thead>
<tr>
<th>Portfolio Comparison</th>
<th>Project In-Service Date</th>
<th>Portfolio Present Value Differential ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site C portfolio compared to Clean Generation portfolio</td>
<td>F2022</td>
<td>450</td>
</tr>
<tr>
<td>Clean Generation portfolio</td>
<td>F2024</td>
<td>660</td>
</tr>
<tr>
<td>Site C portfolio compared to Clean + Thermal Generation portfolio</td>
<td>F2022</td>
<td>(150)</td>
</tr>
<tr>
<td>Clean + Thermal Generation portfolio</td>
<td>F2024</td>
<td>180</td>
</tr>
</tbody>
</table>

**NOTES:**
Positive values indicate that the Site C portfolio has lower costs than the alternative portfolio
Present value calculated at 6% discount rate
All values in F2013 dollars, rounded to nearest $10 million

This present value analysis shows that the Project is cost-effective at its earliest in-service date, saving about $450 million in present value, compared to a Clean
The Project is more expensive than a Clean + Thermal Generation portfolio at an F2022 in-service date; however, the Project becomes more cost-effective than a Clean + Thermal Generation portfolio with an F2024 in-service date. A change to BC Hydro’s load-resource balances that accelerated the capacity and/or energy gap would create a similar change to the Project present value benefits.

In addition to the present value analysis, BC Hydro evaluated the adjusted UEC of the Project against the adjusted UEC of a comparable block of 5,100 GWh/year of energy and 1,100 MW of capacity. This adjusted UEC represents the present value of the amount BC Hydro’s customers pay per unit energy delivered, and is a proxy for the financial benefits over project life. Table 5.42 provides the difference in portfolio UEC between portfolios with and without the Project in F$2013.

**Table 5.42 Adjusted Unit Energy Cost Comparison**

<table>
<thead>
<tr>
<th>Clean Generation</th>
<th>Clean + Thermal Generation</th>
<th>Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted UEC ($)</td>
<td>181</td>
<td>156</td>
</tr>
</tbody>
</table>

**NOTE:**
UEC values include transmission-related costs to the Lower Mainland, wind integration costs, soft costs, and costs of capacity backup, and exclude sunk costs.

5.5.4.4 Environmental Attributes

Portfolios with and without the Project were compared based on their environmental attributes. More details of the measures can be found in Section 5.5.1. Table 5.43 shows the differences in the environmental attributes between the Project and a 5,100 GWh/1,100 MW block of power from the Clean Generation and Clean + Thermal Generation portfolios.

Note that the environmental attributes for the Project are unique within the range of resource options under analysis, given the advanced level of project definition for the Project and accompanying accuracy in the project footprint. The portfolios without the Project are populated with forecast generic ‘typical’ projects with estimated footprints. The portfolio values include the impacts of associated transmission requirements to the POI.

**Table 5.43 Environmental Attribute Comparison**

<table>
<thead>
<tr>
<th>Environmental Attribute</th>
<th>Clean Generation</th>
<th>Clean + Thermal Generation</th>
<th>Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land footprint (ha)</td>
<td>2,230</td>
<td>2,430</td>
<td>5,660</td>
</tr>
<tr>
<td>Affected stream length (km)</td>
<td>15</td>
<td>15</td>
<td>125</td>
</tr>
<tr>
<td>Reservoir created (ha)</td>
<td>0</td>
<td>0</td>
<td>9,300</td>
</tr>
<tr>
<td>Operational GHG Emissions (t/year, 000s)</td>
<td>200</td>
<td>650</td>
<td>0</td>
</tr>
<tr>
<td>Local Air Emissions (t/year, 000s)</td>
<td>NOx</td>
<td>0.5</td>
<td>0.6</td>
</tr>
<tr>
<td></td>
<td>Carbon Monoxide</td>
<td>0.4</td>
<td>1.3</td>
</tr>
</tbody>
</table>

**NOTE:**
All values are rounded.
Land and freshwater footprint: The environmental attributes for the Project are unique compared to the alternatives shown as a result of the advanced level of project definition for the Project, which allows a higher level of accuracy in determining the Project footprint. The portfolios without the Project are populated with forecast “typical” projects with estimated footprints. As a result, the differences in environmental attributes between portfolios shown in this section compare a defined attribute for the Project to a representative estimate for IPPs. The actual difference in attributes between portfolios cannot be known with certainty.

Both the Clean and the Clean + Thermal Generation portfolios identified wind resources as the primary alternative source of energy. Based on these portfolio compositions, the comparison of environmental attributes shows that the Project could have a larger land footprint than portfolios without the project. However, the difference between the portfolios is less than the full 5,660 ha Project land footprint, as a portfolio without the Project must employ different supply-side resources to meet energy and capacity needs, which also have environmental footprints.

As with the land footprint, based on the wind-heavy portfolio composition of the Clean and the Clean + Thermal Generation portfolios, the Project could have a larger freshwater footprint than the portfolios that do not include the Project.

The land and freshwater footprint of the Project reservoir represents a conversion of habitat from terrestrial and river environments to a reservoir environment, and not a loss of productive environment. This may not be the case with other portfolios of alternative resources. As a result, portfolios with the Project include the creation of a 9,330 ha reservoir, while portfolios without the Project do not. It should be noted, however, that pumped storage, an alternative capacity-rich option and net energy consumer, is assumed to occur on existing water bodies with no reservoir footprints for this modelling analysis. Since, to date, no pumped storage project has ever been permitted in B.C., this is a conservative assumption.

The differences in land and freshwater footprint are highly dependent on the mix of energy resources. The portfolios of available resources generally include a majority of wind energy. If these portfolios had a higher proportion of run-of-river resources (as was the result of BC Hydro’s recent calls for power), it is likely that the portfolios of alternatives would have a comparable or larger footprint than the Project. This is because wind and biomass resources generally have smaller footprints per unit energy delivered than either the Project or run-of-river hydro.

It is also important to note that the land footprints in Table 5.43 only include the footprint of the primary generation site. For hydroelectric projects such as the Project and run-of-river resources, this footprint therefore includes the structures to capture the fuel (i.e., the water) for generation purposes. For other available resource options such as natural gas-fired generation and biomass, the fuel collection footprint is not included in the land footprint.

GHG Emissions: The portfolio analysis compared the operating phase GHG emissions due to fuel combustion between the portfolios. The operating phase GHGs are sufficient for planning-level analysis. A full assessment of the life-cycle GHGs of the Project may be found in Volume 2 Section 15 Greenhouse Gases.

The portfolio including the Project has lower operational GHG emissions than both portfolios not including the Project. The Clean Generation portfolio selects a municipal...
solid waste resource option, which includes GHG emissions from fuel combustion. The Clean + Thermal Generation portfolio has the highest level of GHG emissions, due to the combustion of natural gas.

**Local Air Emissions:** The portfolio including the Project has lower local air emissions than both portfolios not including the Project. The Clean Generation portfolio selects both wood-based biomass and municipal solid waste resource options, which create local air emissions from fuel combustion. The Clean + Thermal Generation portfolio includes biomass resources as well as natural gas-fired generation and, as a result, has the highest level of local air emissions.

**Marine Attributes:** Due to the location and characteristics of the Project, there are no significant differences in the marine attributes between portfolios with and without the Project.

**Location of Portfolio Footprint:** The locations of the environmental attributes used in the analysis of alternatives were compared between portfolios. The Project is located solely in the Northeast Development Region (NEDR), while the available resources are located in a range of locations across the province. However, the portfolio analysis identified wind as the primary source of energy to the system, and more than 90% of wind resources identified were located in the NEDR. As a result, more than 50% of the land footprint in both the Clean and the Clean + Thermal Generation portfolios would be located in the NEDR, with the balance in the Lower Mainland and on Vancouver Island.

### 5.5.4.5 Economic Development Attributes

Portfolios with and without the Project were compared based on their economic development attributes, including jobs and GDP. Table 5.44 shows the differences in the economic development attributes between the Project and a 5,100 GWh/1,100 MW block of power from the Clean Generation and the Clean + Thermal Generation portfolios. The portfolio values include the impacts of associated transmission requirements to the POI.

<table>
<thead>
<tr>
<th>Economic Development Attribute</th>
<th>Clean Generation</th>
<th>Clean + Thermal Generation</th>
<th>Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction jobs (total jobs)</td>
<td>33,200</td>
<td>28,500</td>
<td>44,200</td>
</tr>
<tr>
<td>Construction GDP ($ million)</td>
<td>2,600</td>
<td>2,200</td>
<td>3,500</td>
</tr>
<tr>
<td>Operations jobs (jobs per year)</td>
<td>1,175</td>
<td>1,025</td>
<td>75</td>
</tr>
</tbody>
</table>

**NOTE:**
All values rounded

The portfolio with the Project generally increased measures of economic development during construction as compared to portfolios without the Project. Jobs and GDP related to construction are higher for the portfolio including the Project, due to the high job intensity of the construction period. Jobs and GDP during operations are lower for the portfolio including the Project, as a result of the low operating costs for the Project.

These estimates are high level for use in comparing the resource options at a portfolio level, and as with the environmental attributes, the exact difference between the economic development attributes is uncertain.
5.5.5 Summary and Rationale for Project Selection

There is a need for new energy and capacity resources within the next 10 to 15 years of BC Hydro's planning horizon in order to meet forecast customer demand, as demonstrated in Section 5.2.2. New energy and capacity resources may be required at the Project’s earliest in-service date in scenarios where BC Hydro is required to meet LNG facility non-compression load, if BC Hydro’s current DSM target does not deliver anticipated energy and/or capacity volumes, or if higher than mid-load forecasts are experienced. BC Hydro has an obligation to meet this customer demand, and has evaluated a range of different options to do so.

The Project is the most cost-effective manner in which BC Hydro can meet this need, as shown by the portfolio analysis in Section 5.5.4. The Project would also provide the additional benefits of economic development and employment, and would generate electricity with comparatively low GHG emissions per unit energy.

- Portfolios including the Project generally have a lower present value of costs to ratepayers, as compared to portfolios including only clean or renewable resources, and portfolios including both clean and thermal resources.

- The environmental footprint analysis shows that the Project may have a larger land and freshwater footprint than portfolios of alternative resource options; however, this is dependent on the mix of resources that would replace the Project.

- The Project would have a lower amount of greenhouse gas emissions and local air emissions than portfolios of alternative resource options, which would involve the combustion of fuel at municipal solid waste and/or natural gas facilities.

- The economic development attributes of the portfolio analysis show that portfolios including the Project provide higher amounts of provincial GDP and employment during construction.

Based on this portfolio analysis, BC Hydro believes that the Project provides the best combination of financial, technical, environmental, and economic development attributes and is therefore a preferred option to meet the need for energy and capacity within BC Hydro’s planning horizon.
References

Literature Cited

Internet Sites

6 ALTERNATIVE MEANS OF CARRYING OUT THE PROJECT

6.1 Introduction

The need for and purpose of the Project are discussed in Volume 1 Section 5 Need for, Purpose of, and Alternatives to the Project, and the benefits of the Project are described in Volume 1 Section 7 Project Benefits. As discussed in Volume 1 Section 5 Need for, Purpose of, and Alternatives to the Project, the specific purpose of the Project is to cost-effectively maximize the development of the hydroelectric potential of the Site C Flood Reserve.

This section describes the:

- Flood reserves that were put in place by the government of British Columbia to reserve Crown land in the Peace River watershed for hydroelectric development
- History of the selection of the dam site
- Study that was undertaken to evaluate alternate means of developing the hydroelectric potential of the Peace River within the Site C Flood Reserve

The Peace Site C Project Application for an Energy Project Certificate submitted to the British Columbia Utilities Commission in 1980 described the dam located downstream of the Moberly River, with a maximum normal reservoir level of elevation 461.8 m.

Whenever BC Hydro considered the Site C project since 1980, it was for the location and reservoir level described in the 1980 British Columbia Utilities Commission application. Furthermore, BC Hydro considers that when the government of British Columbia instructed BC Hydro to consider the Site C project under the BC Energy Plan, it was implicitly the location and reservoir level described in the 1980 application.

6.2 Flood Reserve

The first steps to develop the hydroelectric potential of the Peace River in British Columbia were undertaken in the 1950s. The government of British Columbia reserved Crown land in the Peace River watershed for the purposes of hydroelectric development through Orders-in-Council issued by the Executive Council as described below.

Order-in-Council 2452 dated October 11, 1957 reserved an area of Crown land from alienation, pursuant to Section 94 of the Land Act, R.S.B.C., 1948, c. 175. The Order-in-Council included the following portions of the watershed and tributaries of the Peace River:

- All the portion downstream from the 121°55’ meridian of West longitude to the British Columbia-Alberta border and situated below the 1,700 ft. (518.2 m) contour of elevation
- All the portion upstream from the 121°55’ meridian of West longitude and situated below the 2,450 ft. (746.8 m) contour of elevation
Order-in-Council 369 dated February 15, 1963 amended Order-in-Council 2452 by changing the contour elevations to 1,525 ft. (464.8 m) in the downstream portion and 2,250 ft. (685.8 m) in the upstream portion.

Order-in-Council 1995 dated August 5, 1963 amended Order-in-Council 369 by changing the contour elevation to 2,225 ft. (678.2 m) in the upstream portion.

Order-in-Council 1079 dated May 30, 1985 amended Order-in-Council 369 by cancelling the portion from the easterly border of Township 83, Range 19, West of the 6th Meridian, Peace River District, downstream to the British Columbia-Alberta boundary, and situated below the 1,525 ft. (464.8 m) contour of elevation (G.S.C. datum).

The current reserve is shown on Figure 4.7 in Volume 1 Section 4 Project Description. The portion of the reserve between Peace Canyon Dam and the easterly border of Township 83, Range 19, West of the 6th Meridian, Peace River District is referred to herein as the Site C Flood Reserve.

### 6.3 Historic Selection of the Location of the Site C Dam

The selection of the proposed dam site, summarized below, is based on the Review of Alternate Sites on the Peace River (Klohn Crippen Berger, SNC-Lavalin, Hatch 2011), which is contained in Volume 1 Appendix E Review of Alternate Sites on the Peace River.

Studies to develop the hydroelectric potential of the Peace River between Peace Canyon and the British Columbia-Alberta border commenced in 1958. Five sites (designated A through E) were identified based on consideration of preliminary engineering, environmental, and social issues.

A feasibility study of power development on the Peace River between the site of the Peace Canyon Dam and the Alberta border by International Power and Engineering Consultants Limited in 1972 concluded that the best options to develop the 79.2 m of head on the Peace River were either:

- A single dam located at Site E near the Alberta border, or
- Two low dams, one at Site E and the other at Site C

Although the single high Site E option was more economic than the two-dam option, neither of the two options studied appeared to have any major advantage over the other, and it was recommended that the possibility of selecting better axes at Site E and at Site C should be investigated further.

The first location considered for Site C was upstream of the confluence of the Peace and Moberly rivers (referred to as Axis C1); however, based on the results of subsurface investigations completed in 1976, a second location further downstream but still upstream of the Moberly River (referred to as Axis C2) was investigated.

Studies culminated in 1978 with the selection of a third location downstream of the Moberly River (referred to as Axis C3) as preferred because at this location:

- The overburden on the abutments was substantially less than on Axis C1 and Axis C2, and less material to be excavated means less cost and less time for construction
- The abutments appeared to be more stable
Both abutments are protected by terraces from potential slides originating above the crest of the proposed dam.

The Site C project described in the 1980 British Columbia Utilities Commission application (BC Hydro 1980) consisted of a dam located downstream of the Moberly River at Axis C3 with a maximum normal reservoir level of elevation 461.8 m. References to Site C since the British Columbia Utilities Commission hearings have been to a project at this location and with this reservoir level.

In 2006, an assessment was undertaken of the cost and schedule effects of relocating the Site C Project back to Axis C1 or Axis C2 (Klohn Crippen Berger & SNC-Lavalin 2006). The assessment considered the history of selecting the Site C axis, the stability of the valley slopes, and the general topography of the sites. Simplified geological sections were developed for Axis C1 and Axis C2 in order to estimate the order of magnitude of changes to the major quantities that would result by moving the dam location to one of the upstream axes.

As shown in Figures 10-8 and 10-10 in Volume 1 Appendix E Review of Alternate Sites on the Peace River, at Axis C1 and Axis C2, the valley walls rise steeply to the plateau at about elevation 640 m on the north bank and 625 m on the south bank, and there are considerable depths of landslide debris on the slopes.

In comparison, at Axis C3:
- The slopes above the dam are lower than at Axis C1 and Axis C2: the north bank slope rises steeply to about elevation 570 m and then relatively gently to elevation 610 m, while on south bank the slope rises steeply to elevation 450 m, where a broad terrace is located that rises gently to elevation 480 m followed by a relatively flat slope to elevation 630 m
- Bedrock is exposed in the north bank to above dam crest level, and on the south bank bedrock is close to the surface

The key findings were that moving the Site C axis to Axis C1 or Axis C2 would:
- Require 95 million m$^3$ to 100 million m$^3$ more excavation for the dam to remove the landslide debris because of the higher slopes
- Require 8 million m$^3$ to 10 million m$^3$ more earthfill for construction of the earthfill dam
- Reduce average annual energy generation by approximately 5% to 8%
- Double the direct cost of the project
- Increase the schedule by approximately 5 years

As a result, it was concluded that Axis C3 was topographically and geologically superior to the two upstream axes and, due to the adverse topography and geology, it would not be possible to develop a project layout and design at either of the upstream axes that would have a similar cost to the proposed Site C project.

6.4 Location and Number of Dams

During the period 2001 to 2006 when BC Hydro was reconsidering development of a hydroelectric project at Site C, four reviews of alternative means of developing the hydroelectric potential in the Site C Flood Reserve were undertaken. These reviews
ranged in level from a three-day workshop to prefeasibility studies. Three reviews were based on using a cascade of lower dams and included a cascade of low dams similar to that being considered at the Dunvegan site on the Peace River in Alberta. One of the reviews was based on a single dam constructed upstream of the Moberly River.

Between 2009 and 2011, Klohn Crippen Berger Ltd., SNC-Lavalin Inc., and Hatch Ltd. undertook a comprehensive study (the Alternates Study) to evaluate alternate means of developing the hydroelectric potential of the Site C Flood Reserve (Volume 1 Appendix E Review of Alternate Sites on the Peace River). The intent was to undertake a comprehensive review of all previously identified alternates and any new alternates and compare them to the Project using a consistent evaluation process.

### 6.4.1 Alternates Considered

The following alternates were considered that would reduce the total reservoir area and, accordingly, the potential reservoir effects:

- A single dam located upstream of the Moberly River to avoid effects on that river, but that would not develop all of the available head between Peace Canyon Dam and Axis C3. Single-dam alternates considered were:
  1. A dam located at Axis C1, 5.5 km upstream of Axis C3
  2. A dam located at Axis C2, 3 km upstream of Axis C3
  3. A dam located just downstream of Wilder Creek, 11.5 km upstream of Axis C3

- Cascades of two or more dams lower in height than the proposed Site C dam that would reduce the area of flooded land while maximizing development of all of the head between Peace Canyon Dam and Axis C3. Cascades of multiple dams considered were:
  1. A two-dam cascade with a dam at Axis C3 and an additional dam located approximately 66 km upstream
  2. A three-dam cascade with a dam at Axis C3 and two other low dams located approximately 22 km and 59 km upstream
  3. A four-dam cascade with a low dam at Axis C3 and three other low dams located approximately 18 km, 39 km, and 61 km upstream
  4. A seven-dam cascade with a dam at Axis C3 and six other dams located approximately 10 km, 23 km, 37 km, 53 km, 65 km, and 79 km upstream

The eastern boundary of the Site C Flood Reserve is approximately 3.7 km downstream of Axis C3. Moving the dam further downstream was not considered since downstream of Axis C3 the geological conditions are less favourable, as the elevation of the bedrock outcrop on the north bank of the river drops and the slopes above bedrock comprise debris from slides and slumping of the overburden.

### 6.4.2 Technical Assessment

#### 6.4.2.1 Layouts

Layouts were developed for the Project and the alternates as described below to prepare relative cost estimates and the facility characteristics (see Section 6.4.2.2).
The layout for the Project was adjusted with the allowances for the increased maximum
design earthquake and rebound mitigation identified in Stage 2 (Klohn Crippen Berger &
SNC-Lavalin 2009). Rebound refers to long-term swelling of the shale bedrock, which
occurs when the weight of a structure is less than the weight of the soil and rock
excavated to reach the foundation of the structure.

A dam at Wilder Creek and the two-dam cascade were new alternates that had not been
previously studied. Layouts for these alternates were therefore developed and the
dimensions of the various components determined in sufficient detail to allow the major
quantities to be estimated so that the facility characteristics could be determined.

Dams at Axis C1 and Axis C2 had been previously studied and the facility characteristics
were based on the previous work. Since the previous study, the maximum design
earthquake had been increased, and allowances for the measures required to mitigate
rebound of the rock due to unloading had been made for the Project. These design
changes would also affect the design at Axis C1 and C2, which would increase the
scope, cost, and schedule of dams at these locations. The intent was to update the
previous study to include allowances for the increased maximum design earthquake and
the measures required to mitigate rebound at Axis C1 and Axis C2, only if the initial
screening (Section 6.4.5.3) indicated that development of a dam at one of those axes
could be competitive with the Project.

A cursory evaluation had previously been done of three- and four-dam cascade
alternates, which had developed layouts based on the topography at Axis C3 and
assumed that suitable topographically similar sites could be found upstream. In the
Alternates Study, it was assumed that the dam locations and layouts would be as
identified in the previous evaluation; however, the dimensions of the various components
were updated so that the facility characteristics could be determined on a consistent
basis with the other alternates. The intent was to undertake detailed topographic studies,
detailed layouts, and cost estimates for the dams located upstream of Site C only if the
initial screening (Section 6.4.5.3) indicated that the three-dam or the four-dam cascade
could be competitive with the Project.

The seven-dam cascade had been previously studied and was updated so that the
facility characteristics would be determined on a consistent basis with the other
alternates. In particular, allowances were made for increasing the spillway capacity so
that the dams could pass the probable maximum flood, and increasing the number of
anchors to withstand the new maximum design earthquake. The intent was to undertake
a more detailed analysis (increasing the maximum normal reservoir level at the
upstream dam and replacing the post-tensioned anchors with mass concrete), only if the
initial screening (Section 6.4.5.3) indicated that the seven-dam cascade could be
competitive with the Project.

Figures and more detailed descriptions of the layout for the Project and each alternate
are provided in Volume 1 Appendix E Review of Alternate Sites on the Peace River.

6.4.2.2 Facility Characteristics

The facility characteristics required to assess the technical feasibility, economic
feasibility, environmental effects, and functionality of each alternate relative to the
Project are related to the location and number of dams, site topography and geology,
site layout, number of construction sites, sequence of construction, construction
schedule, Highway 29 realignments, and transmission lines and substation(s).
The layouts enabled definition of the following key facility characteristics of the Project and each alternate:

- Location of dam(s)

- Geological characteristics:
  - Physical and topography
  - Surficial geology
  - Bedrock geology
  - Slope stability
  - Seismicity
  - Geological investigations

- Hydrological and reservoir characteristics:
  - Mean annual flow
  - Inflow design flood
  - Maximum normal reservoir level
  - Tailwater elevation at mean annual flow
  - Gross head at mean annual flow
  - Total net head at maximum capacity
  - Reservoir area
  - Reservoir shoreline length
  - Reservoir volume
  - Reservoir filling time
  - Reservoir flushing time
  - Length and area of the Peace River and tributaries inundated (the Moberly River, Tea Creek, Wilder Creek, Cache Creek, the Halfway River, Farrell Creek, Lynx Creek, and Maurice Creek)
  - Length of shoreline created along the Peace River and tributaries inundated (the Moberly River, Tea Creek, Wilder Creek, Cache Creek, the Halfway River, Farrell Creek, Lynx Creek, and Maurice Creek)

- Infrastructure characteristics:
  - Lengths of Highway 29 realignments and bridges at Cache Creek, the Halfway River, Farrell Creek, and Lynx Creek
  - Lengths of new permanent access roads required
  - Number of new bridges required

- River diversion characteristics, including location, type, and length of diversion works, and duration of diversion

- Excavation and relocation of surplus excavated materials including:
Section 6: Alternative Means of Carrying out the Project

- Total volume of excavation
- Volume of dam materials required
- Location of materials sources
- Location of relocated surplus excavated materials
- Dam characteristics, including number of dams, dam types, dam height, and crest elevation
- Approach channel location and configuration
- Intake/water conduits/powerhouse characteristics, including type and size of conduits, service bay, and powerhouse size
- Spillway characteristics, including location, layout, and capacity
- Tailrace location and layout
- Mechanical and electrical characteristics, including:
  - Number and type of turbines
  - Installed capacity
  - Number and size of intake gates
  - Number and size of spillway gates
- Switchyard characteristics, including location and area
- Transmission line characteristics, including:
  - Number of transmission corridors
  - Characteristics of transmission lines and corridors
  - Length and cleared area
- Navigation facilities
- Fish passage facilities
- Availability of construction material, including:
  - Dam fill (or roller compacted concrete aggregate)
  - Dam core material
  - Concrete aggregate
  - Slope erosion protection
- Locations of areas for temporary works, camps, and laydown
- Accessibility, including road and rail access
- Schedule estimates, including site investigations, applications, design, and construction
- Energy estimates:
  - Total gross head at weighted average flow
Energy cost ratio

For details, refer to the Facility Characteristics Matrix in Appendix A1 in Volume 1.

Appendix E Review of Alternate Sites on the Peace River.

For each alternate, the physical footprint areas in the Facilities Characteristics Matrix were overlaid on terrestrial ecosystem mapping data and physical environment themed data. These data were used to determine the effect of each footprint area on the physical, biological, and socio-economic environments.

The themed data consisted of the following areas affected by each alternate subdivided by reservoir, transmission line(s), dam, and each segment of highway realignment:

- Proposed protected areas
- Visual landscape inventory
- Petroleum titles
- Oil and gas fields
- Property: BC Hydro leased
- Property: BC Hydro owned
- Property: Crown
- Property: Private
- Land Act tenures
- Hunting zones
- Trapline areas
- Cut blocks
- Old Growth Management areas
- Timber Harvesting Land Base Class "C"
- Timber Harvesting Land Base Class "N"
- Timber Harvesting Land Base Class "P"
- Timber Harvesting Land Base Class "X"
- Recreational reserves and sites
- Grazing leases
The terrestrial ecosystem mapping data consisted of the following parameters affected by each alternate subdivided by reservoir, transmission line(s), dam, and each section of highway realignment:

- TEM – AM:ap – Creamy peavine (seral association) (01) both majority and minority
- TEM – CB – Cutbank (00) both majority and minority
- TEM – CF – Cultivated field (00) both majority and minority
- TEM – FM02 – Cottonwood-spruce-red-osier dogwood (09) both majority and minority
- TEM – GB – Gravel bar (00) both majority and minority
- TEM – SE – Sedge wetland (09) both majority and minority
- TEM – SH:ac – Cow parsnip (seral association) (07) both majority and minority
- TEM – WS – Willow sedge (00) both majority and minority
- TEM – SH:sw – Currant-horsetail (07) both majority and minority

For details of the terrestrial ecosystem mapping data categories and environmental themes, as well as the areas of the data affected by each footprint category, refer to the Environmental Areas Matrix in Appendix A2 in Volume 1 Appendix E Review of Alternate Sites on the Peace River.

6.4.2.3 Functionality Assessment

An assessment was made of the functional differences between the Project and each alternate. The engineering parameters considered in this assessment were:

- Dam safety factors:
  - Capability to draw down the reservoir
  - Time to draw down the reservoir(s)
  - Hydrological – the relative reliability to pass high inflows
  - Landslide risks – the relative vulnerability to landslides
  - Seismic – the relative vulnerability of each alternate to large earthquakes
  - Geological conditions:
    - Effects of rebound, which is exacerbated by excavation depth
    - Effects of creep, which is likely less with lower dams
    - Piping potential, which is less with lower dams
  - Consequence of failure
  - Resilience and robustness

- Life cycle factors:
  - Operation and maintenance
  - Operating flexibility
6.4.2.4 Comparative Assessment of Engineering Parameters

A comparative assessment of the engineering parameters of the Project and the alternates was undertaken. The parameters assessed included:

- Geological risks, including:
  - Certainty
  - Slope stability
  - Shoreline impacts (i.e., potential effects of reservoir shoreline slides on the dams)
  - Foundation conditions
  - Rebound conditions

- Design risks including:
  - Level of design development
  - Dam
  - Discharge facilities
  - Generating facilities
  - Other aspects, such as diversion logistics

- Construction factors, including:
  - Construction materials
  - Excavation and relocation of surplus excavated materials
  - Accessibility (road and rail)
  - Areas for temporary works, camps, and laydown
  - Project sequencing

- Schedule and cost certainty, including pre-construction and construction

The assessment is presented in Section B through D of the Engineering Comparative Matrix contained in Appendix E in Volume 1 Appendix E Review of Alternate Sites on the Peace River.

Technical issues affecting the feasibility of a dam at Axis C1 or Axis C2 are:

- The stability of the very high slopes
- Substantially greater rebound than at the Project, due to deeper excavations
Volume of surplus excavated material requiring relocation several times that of the Project

6.4.3 Economic Feasibility

The criterion developed to assess the economic feasibility was the energy cost ratio, which takes into account the energy cost of an alternate relative to the Project and how efficiently the alternative developed the hydroelectric potential in the Site C Flood Reserve. An energy cost ratio greater than 1.00 indicates that compared to the Project, an alternate produces higher cost energy, or produces less energy, or produces less energy at a higher cost. Examples are given below.

The energy cost ratios for the six alternates relative to the Project are shown in Table 6.1.

Table 6.1 Energy Cost Ratios

<table>
<thead>
<tr>
<th>Single Dam</th>
<th>Cascading Dams</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Two Dams</td>
</tr>
<tr>
<td>C1 or C2</td>
<td>Wilder Creek</td>
</tr>
<tr>
<td>Wilder Creek</td>
<td>2.14</td>
</tr>
</tbody>
</table>

The energy cost ratios show that all six alternates would have a greater energy cost ratio than the Project.

A single dam at Wilder Creek would have an energy cost ratio of 1.38 because the unit energy cost would be 20% higher and it would produce 87% of the energy produced by the Project (energy cost ratio = $\frac{1.20}{0.87} = 1.38$).

The two-dam cascade would have an energy cost ratio of 1.55 because the unit energy cost would be 49% higher and it would produce 96% of the energy of the Project (energy cost ratio = $\frac{1.49}{0.96} = 1.55$).

As described in Section 6.3, the site geology and topography at Axis C1 and Axis C2 are adverse, resulting in a construction cost that is double the cost of construction of the Project.

The Project is better economically, compared to the two single-dam alternates, as those alternates would produce less energy at higher unit energy costs.

Compared to single dams, alternates consisting of two or more dams have two important disadvantages: multiple dams are less energy-efficient and they cost more to build.

6.4.4 Environmental Effects

6.4.4.1 Physical Environment

The information contained in the Facilities Characteristics Matrix was used to assess the relative differences between the potential effects on the physical environment of each alternate and the Project as follows:

- Construction effects on the geological environment, including:
  - Reservoir filling, resulting in loss or alteration of Peace River physiographic features
Site C Clean Energy Project Environmental Impact Statement
Volume 1: Introduction, Project Planning, and Description
Section 6: Alternative Means of Carrying out the Project

6-12

- Dam facility and associated infrastructure construction footprint, resulting in alteration of the local topography (i.e., landforms) at dam site
- Reservoir filling and facility construction (e.g., roads, dam, etc.), resulting in loss of existing soils that support productive uses (e.g., agriculture)
- Reservoir clearing and filling, resulting in terrain instability and shoreline erosion
- Reservoir filling and dam construction, resulting in decreased ability to either extract resources or depletion of existing resources or both
- Reservoir filling, resulting in decreased ability to extract oil and gas resources

- Construction effects on the hydrological environment including:
  - Flow diversions (e.g., cofferdams and tunnels), resulting in changes to Peace River flows and water levels
  - Reservoir filling, resulting in decreased flows in the Peace River

- Construction effects on water quality due to suspended sediment and turbidity resulting from:
  - Vegetation removal and potential soil erosion
  - Cofferdam installation and removal, and in-stream construction

- Construction effects on the atmospheric environment and air quality due to:
  - Vehicle and equipment exhaust
  - Fugitive dust (equipment, road traffic, blasting, wind-generated dust from either exposed or disturbed soils)
  - Vegetation burning

- Operation effects on the geologic environment, including shoreline instability and erosion

- Operational effects on the hydrologic environment, including:
  - Timing and magnitude of reservoir level fluctuations and downstream river flows
  - Slowing of river velocities resulting in increased residence time
  - Ice conditions in the reservoir and in the downstream Peace River
  - Changes to sediment transport and deposition within the reservoir, tributaries, and Peace River downstream
  - Effects on local groundwater conditions

- Operational effects on water quality, including:
  - Changes to water chemistry (e.g., suspended sediment, total metals, nutrients)
  - Changes to water temperature
  - Increases in methyl mercury levels due to decaying vegetation
  - Supersaturation of dissolved gases in spillway discharges harmful to fish

- Operational effects on the atmospheric environment, including:
6.4.4.2 Biological Environment

The information contained in the Facilities Characteristics Matrix was used to assess the relative differences between the potential effects on the biological environment of each alternate and the Project as follows:

- Construction effects on the aquatic environment, including:
  - Fish communities in the Peace River, the Moberly River, Wilder Creek, Cache Creek (including Red Creek), the Halfway River, Farrell Creek, Lynx Creek, and Maurice Creek
  - Upstream and downstream fish movements and migrations
  - Lower trophic level communities (plankton, benthos, and macrophytes)
  - Rare and listed species

- Construction effects on aquatic habitat, including:
  - Spawning and rearing habitat in the Peace River, the Moberly River, Wilder Creek, Cache Creek (including Red Creek), the Halfway River, Farrell Creek, Lynx Creek, and Maurice Creek
  - Foraging and or refuge habitat in the Peace River, the Moberly River, Wilder Creek, Cache Creek, the Halfway River, Farrell Creek, Lynx Creek, and Maurice Creek
  - In-stream flows

- Construction effects on riparian habitat and species, including:
  - Wetlands
  - Shoreline vegetation community
  - Islands or in-stream structures
  - Rare and listed riparian species or communities

- Construction effects on terrestrial habitat and wildlife, including songbirds, raptors, owls, bats, butterflies, waterfowl, shorebirds, beavers, amphibians, ungulates, and rare and listed wildlife species or communities

- Operation effects on aquatic habitat and fauna, including:
  - Reservoir habitat characteristics (shoreline erosion, sedimentation, nutrients, and temperature regime)
  - Reservoir fish community (composition, abundance, growth, and health)
6.4.4.3 Socio-Economic Environment

The information contained in the Facilities Characteristics Matrix was used to assess the relative differences between the potential effects on the socio-economic environment of each alternate and the Project as follows:

- Construction effects on land use and land tenure
- Construction effects on resource use, including:
  - Agricultural lands
  - Forestry lands
  - Oil and gas
  - Mining and aggregates
  - Irrigation
- Construction effects on roads and traffic
- Construction effects on transmission line interconnections
- Construction effects on public health and safety, including:
  - Fugitive dust emissions
  - Noise
  - Worker and public safety, including recreation users
- Construction effects on culture and heritage, including:
  - Archaeological sites
  - Cultural resources
- Construction effects on recreation and tourism, including:
Site C Clean Energy Project Environmental Impact Statement
Volume 1: Introduction, Project Planning, and Description
Section 6: Alternative Means of Carrying out the Project

1. Fishing
2. Hunting
3. Trapping and guiding
4. Recreational boating and navigation
5. Recreational sites
6. Proposed protected areas
7. Viewscapes and area aesthetics
8. Tourism
9. Construction effects on employment and economic opportunities, including:
   a. Labour requirements and effects
   b. Construction services and infrastructure
10. Construction effects on:
    a. Community services and infrastructure
    b. Economic development and finances
11. Construction effects on First Nations, including:
    a. Traditional lands and uses
    b. Economic opportunities
    c. Public interest and quality of life
12. Operations effects on land use
13. Operations effects on groundwater and water wells
14. Operations effects on recreation and tourism, including
    a. Recreational fishing
    b. Hunting, trapping, and guiding
    c. Recreational boating and navigation
    d. Scenic viewscapes and tourism potential
15. Operations effects on employment and economic opportunities, including:
    a. Employment
    b. Local and regional economic development
    c. Public interest and quality of life
For details, refer to the Socio-Economic Environmental Matrix in Appendix D in Volume 1 Appendix E Review of Alternate Sites on the Peace River.
6.4.5 Multi-Attribute Decision-Making Process

The multi-attribute decision-making process used to confirm whether the Project is the preferred means of developing the hydroelectric potential in the Site C Flood Reserve is described in the Alternates Study and summarized below.

6.4.5.1 Overview

As described in the Alternates Study and summarized below, a multi-attribute decision making process was used to assess the six alternates relative to the Project.

The evaluation process consisted of:

- Identifying environment effects and engineering functionality of each alternate relative to the Project and one another
- Ranking and weighting the environmental effects and functionality of each alternate, and comparing these relative to the Project and each other
- Comparing the relative footprint ratio and energy cost ratio of each alternate to the Project

The relative footprint ratio was determined for each alternate relative to the Project by weighting and combining the ratings for each of the four attributes, namely:

- Functionality (Section 6.4.2.3)
- Effects on the physical environment (Section 6.4.4.1)
- Effects on the biological environment (Section 6.4.4.2)
- Effects on the socio-economic environment (Section 6.4.4.3)

A preliminary analysis screened out four alternates as a result of a higher energy cost ratio due to higher project cost and lower energy production without providing a decrease in the relative footprint ratio. A series of sensitivity analyses were performed on the three remaining alternatives to determine whether changing the various weightings would materially change their ranking.

6.4.5.2 Evaluation Process

The attributes of the Project and each alternate that was evaluated were contained in the following four “accounts” as described in Volume 1 Appendix E Review of Alternate Sites on the Peace River:

- Physical Environment Matrix (Appendix B of the Alternates Study)
- Biological Environment Matrix (Appendix C of the Alternates Study)
- Socio-Economic Environmental Matrix (Appendix D of the Alternates Study)
- Functionality Matrix (Section A of the Engineering Comparative Matrix in Appendix E of the Alternates Study)

Using a bottom-up approach, ratings were assigned representing the potential change (positive, neutral, or negative) resulting from a particular action or activity for each account relative to that same attribute for the Project. Once all the individual attributes had been rated, weightings were assigned to provide an overall weighted rating for each
of the four accounts for each alternate relative to the Project. For the most part, the
ratings were based on a quantitative comparison of such things as inundation areas,
number of terrestrial ecosystem units, and length of road or transmission line between
alternates. However, where quantitative data were not available, ratings and weightings
were assigned by the discipline experts and then reviewed, confirmed, and challenged in
two separate decision-making Delphi workshops. These qualitative ratings were based
on changes that could potentially result from various construction and operations
activities associated with a hydro development project of the scope and scale of the
Project. The principles applied were those generally accepted in conducting multiple-
criteria analyses.

The first Delphi workshop focused on the three environmental accounts, with participants
representing the three discipline areas (physical environment, biological environment,
and socio-economic environment). BC Hydro also participated in this process. Its role
was to ensure that recent and historical data from BC Hydro’s records were made
available for the analysis, to provide input on operating regimes for existing BC Hydro
facilities located on the Peace River, and to respond to questions of clarification
regarding BC Hydro practices. The outcome of this first workshop was a refinement of
the ratings and weightings within and between the three environmental accounts.

The second workshop focused on all of the discipline areas (engineering and
environment) and was attended by BC Hydro engineering and environmental discipline
leads teams. The outcome of this second workshop was:

- Further refinement of the environmental ratings and weightings
- Refinement of the engineering rankings and weightings
- Weighting between the four accounts

BC Hydro enlisted the services of Mr. Mike Saxton from Manitoba Hydro International to
act as an external peer reviewer at critical steps throughout the evaluation of alternates.
Mr. Saxton attended the second Delphi workshop. Mr. Saxton is Department Manager,
Project Sustainability Review & Coordination, Manitoba Hydro International.

To assist in sorting data, ranking, and weighting the outcomes of given actions or
activities on the various attributes, and to provide a visual representation of the
comparison of the alternates relative to the Project, Hatch’s proprietary Four Quadrants
of Analysis (4QA) decision support tool was used.

The relative differences in physical risks, construction factors, schedule, and cost
certainty between each alternate and the Project (Sections B through D of the
Engineering Comparative Matrix, contained in Appendix E in Volume 1 Appendix E
Review of Alternate Sites on the Peace River) were included in the range of energy cost
ratios used in the assessments.

Sensitivity analyses were conducted at various levels, first by adjusting the relative
ranking and weighting of sub-accounts within individual accounts, and then by adjusting
the relative weighting between each of the four accounts.

6.4.5.3 Initial Screening

The following Base Case weightings were used to undertake an initial screening of the
alternates to the Project:
The ratings for each account (rating category) for the six alternates relative to the Project are shown in Figure 6.1. The total rating for each alternate shown on Figure 6.1 is the relative footprint ratio.

In summary, for the potential effects on the physical environment:

- Dams at Axis C1, Axis C2, the three-dam and seven-dam alternates were all rated better than the Project, largely due to less:
  - Effect on physiography
  - Inundated soils and lands
  - Effect on oil and gas resources
  - Effect on shoreline stability or erosion, and associated effect on water quality
  - Effect on local climate

- The four-dam alternate was rated worse than the Project overall due to the following factors, which offset the advantages listed in the preceding bullet points:
  - Larger disturbance (four large dams at four sites, with associated access roads and infrastructure)
  - Larger predicted effects on water and air quality during construction
  - Higher greenhouse gas production, due to greater volumes of excavation and construction materials, including concrete

In summary, for the potential effects on the biological environment:

- The three-, four- and seven-dam alternates were all rated worse than the Project, largely due to:
  - Greater effects on the Peace River fish communities, including their spawning, rearing, foraging, and refuge habitat
  - Greater effects on fish movements during both construction and operations, due to multiple dams and multiple work sites
  - The smaller reservoirs provide less opportunity for development of reservoir fish communities and would have higher operational effects, due to entrainment and turbine mortality at multiple work sites

- The aquatic effects were partially offset by less effect on terrestrial habitats and species, as the smaller reservoirs would inundate less terrestrial and riparian habitats

In summary, for the potential effects on the socio-economic environment:

- The two-, three-, four- and seven-dam alternates were all rated better than the single dam alternates, due to:
Less effect on land and resource use

Fewer archaeological sites and cultural resources affected

Less effect on trapping and hunting

Greater employment and economic opportunities for local communities, associated with the longer construction period needed for the multiple dam alternates

Greater employment during operation

Greater economic benefit to local companies and industries associated with the maintenance of the facilities

The foregoing advantages were partially offset by greater effects on:

Transportation

Infrastructure

Health

Safety

Recreational boating during both construction and operation

In summary, for functionality, the three-, four- and seven-dam alternates were rated worse due to:

Dam safety factors:

Increased potential for spillway gate malfunctions, due to the large number of gates

Landslide risk, due to dams located in close proximity to previous slides

Resilience and robustness – multiple gates and turbines increase the potential for malfunction

Life cycle factors which rated lower (i.e., worse), due to the large number of smaller units at multiple sites adversely affecting:

Operation and maintenance

System integration

Personnel safety

The overall results are shown on the 4QA plot for the Base Case in Figure 6.2 where the relative footprint ratios versus the energy cost ratio is plotted for each alternate and the Project. This plot demonstrates that four of the alternates, namely a dam at Axis C1 or Axis C2, and the three-, four- and seven-dam alternates were dominated by the Project and the other two alternates. This means that changing to a dominated alternate would increase the energy cost ratio and not decrease the relative footprint ratio, whereas changing to a non-dominated alternate would increase the energy cost ratio and decrease the relative footprint ratio.

For example, a change from the Project to the Wilder Creek alternate increases the energy cost ratio and decreases the relative footprint ratio, and changing from the Wilder Creek alternate to the two-dam alternate increases the energy cost ratio and decreases...
the relative footprint ratio; however, changing from the two-dam alternate to the seven-
dam alternate increases the energy cost ratio and increases the relative footprint ratio.

It would not be logical to get less energy at a higher cost with greater environmental
effects; therefore, Axis C1 or Axis C2 and the three-, four-, and seven-dam alternatives
were screened out from further analysis.

6.4.5.4 **Comparison of Non-Dominated Alternates**

Figure 6.3 shows the comparison between the physical environment ratings by
subcategory of the Project, and the Wilder Creek and two-dam alternates with the Base
Case weightings.

For the physical environment:

- Wilder Creek rated highly for all subcategories during construction, as it would affect
  a shorter length of the Peace River than the Project and the two-dam alternate, and
  would avoid any effects to the Moberly River valley

- During operation, Wilder Creek and the two-dam alternate were rated similarly for
  most subcategories, with the exception of the geological environment, where the
  shorter shoreline around the Wilder Creek reservoir would result in less potential for
  shoreline erosion and stability issues

- Summing all physical environment subcategories for both construction and
  operation, the difference between Wilder Creek and the two-dam alternate was
  minimal

Figure 6.4 shows the comparison between the biological environment ratings by
subcategory of the Project, and the Wilder Creek and two-dam alternates with the Base
Case weightings.

For the biological environment:

- Wilder Creek rated highly within most subcategories during construction, as it would
  affect a shorter length of the Peace River than the Project and the two-dam alternate,
  and would avoid any effects to the Moberly River valley. The one exception was in
  the riparian habitat subcategory, where construction of the two-dam alternate would
  have less effect on wetlands

- The two-dam alternate was rated worse than the Project and Wilder Creek for
  aquatic fauna and habitat, due to the presence of two work sites within the river
  valley and associated effects on fish community and habitat, including:
    - More disturbance to movement patterns including migrations
    - Larger footprint area associated with the two dam sites
    - Greater potential for sediment releases, resulting in water quality impairment
      from work at two sites, compared to one

- During operation, Wilder Creek and the two-dam alternate were rated similarly for
  most subcategories, with the exception of riparian habitat, where Wilder Creek would
  have the shorter length of shoreline
• Overall, the aquatic effects/benefits of one alternate would be generally offset by the riparian/terrestrial effects/benefits of the other alternate, such that only very small differences were present between alternates.

Figure 6.5 shows the comparison between the socio-economic environment ratings by sub-category of the Project, and the Wilder Creek and two-dam alternates with the Base Case weightings.

For the socio-economic environment, as with the physical environment and biological environment, each alternate has its own positive and negative aspects:

• During construction, the two-dam alternate was rated higher than the Project and the Wilder Creek alternate in the land and resource use; culture, heritage and first nations; and employment and economic opportunities subcategories because the two sites would:
  o Result in less inundation of valley lands and terraces
  o Provide a longer construction period with more employment and economic opportunities

• During construction, the positive aspects of two-dam alternate in the foregoing would be partially offset by greater effects on the transportation, infrastructure, and health and safety subcategories because for the two sites, there would be:
  o Longer travel distances, with construction traffic affecting a larger area
  o Greater need for services and infrastructure

• During construction, the recreation and tourism subcategory effects would be less for the Wilder Creek alternate, due to less effect on:
  o Recreational boating and navigation, as the Moberly River would not be affected
  o Proposed protected area, including the Peace River Boudreau Lake

• During operation:
  o Wilder Creek and the two-dam alternate were both rated higher than the Project in the land and resource use, and public interest subcategories, due to the smaller inundation area and less effect on future land use
  o Wilder Creek was rated higher in the recreation and tourism subcategory due to the retention of the Moberly River valley and positive effects on downstream recreational fisheries
  o The two-dam alternate was rated higher, as the two facilities would provide additional employment opportunities and greater economic benefits to the local communities

• Overall, the Wilder Creek and the two-dam alternates were rated better than the Project, with the two-dam alternate rated better than the Wilder Creek alternate

Figure 6.6 shows the comparison between the functionality ratings by subcategory of the Project, and the Wilder Creek and two-dam alternates with the Base Case weightings.

For functionality:

• The two-dam alternate:
Rated higher than the other two alternates on all dam safety factors because the smaller dams and reservoirs present less risk.

Rated lower than the other two alternates for most life cycle factors because the larger number facilities and components:

- Require more operation and maintenance
- Are harder to integrate into the electrical system
- Have greater potential for worker accidents and environmental incidents

Would have higher generation reliability because with the greater number of units in the two facilities, a single unit outage for maintenance or repairs would have less effect on the system.

Overall, the potential dam safety advantages of a two-dam alternate were offset by the lower rating of the life cycle factors, resulting in all three alternates having similar ratings.

6.4.5.5 Sensitivity Analysis

Sensitivity analyses were performed to determine whether changing the weightings would materially change the relative footprint ratio of the Wilder Creek and the two-dam cascade alternates so that the higher energy cost ratios of either of these alternates could be justified. For the Wilder Creek alternate, the main difference is that this alternate would not flood the lower part of the Moberly River, although there would be some terrestrial effects in the Moberly catchment, mainly due to transmission. Therefore, the question would be how much more one would have to value the Moberly River to make a difference in the outcome.

For the two-dam alternate, the main difference is that this alternate would flood less land, particularly agricultural land and Watson Slough. Therefore, the question would be how much more one would have to value the land and the socio-economic factors to make a difference in the outcome.

These two questions were addressed by the following sensitivity analyses:

1. Changing the overall environment weighting to 60% and functionality to 40%, which was considered to be the lowest weighting reasonable for functionality, given the nature of the project, the size of the investment, and the consequences of a dam failure or operational problems. The ranking of the alternates did not change and the differences between the alternates remained the same.

2. Increasing the weighting of the Moberly River to 50% relative to the other fish bearing watercourses (i.e., the Moberly River was valued the same as the Peace River and all other tributary rivers and creeks combined). The ranking of the alternates did not change, but the Wilder Creek alternate was rated better.

3. Increasing the weighting of the Moberly River to 100% relative to the other fish bearing watercourses (i.e., all other tributary rivers and creeks combined were assumed to have no value), and increasing the weighting of the aquatics environment to 100% relative to terrestrial (i.e., terrestrial effects were assumed to
The ranking of the alternates did not change, but the Wilder Creek alternate was rated better than in sensitivity analysis #2, above.

4. Increasing the weighting of Watson Slough and valley bottom agriculture. Riparian habitat, islands, and shoreline vegetation community value were given higher weightings for the biological environment, and agricultural land was weighted 50% of overall land value for the socio-economic environment. The ranking of the alternates did not change and the differences between the alternates remained the same.

The results of the sensitivity analyses are shown in Figure 6.7. Sensitivity #2 assigned an equivalent weight to the Moberly River aquatic resources as the Peace River and all other tributaries and Sensitivity #3 gave no weight to aquatic resources other than the Moberly River (including the total exclusion of terrestrial values in Sensitivity #3). These two sensitivities are unreasonable, given the size and importance of the Peace River and other tributaries, including the Halfway River, which provides habitat for the blue-listed bull trout, as well as other species. While other tributary streams (i.e., Wilder Creek, Cache Creek, Farrell Creek, Lynx Creek, and Maurice Creek) are less important, it is unreasonable to give them no value. However, the results of these three sensitivities demonstrated that the relative footprint ratios are not sensitive to the weighting applied to the aquatic resources of the Moberly River.

Sensitivity #4 demonstrated that the relative footprint ratios are not sensitive to the weighting applied to the terrestrial and agricultural resources.

6.4.5.6 Preferred Alternate

As discussed in Volume 1 Section 5 Need for, Purpose of, and Alternatives to the Project, the specific purpose of the Project is to cost-effectively maximize the development of the hydroelectric potential of the Site C Flood Reserve. Volume 1 Section 7 Project Benefits describes the ratepayer, taxpayer, economic, and sustainability benefits of the Project.

The potential environmental effects of the Project and the alternates were not monetized, i.e., dollar values were not assigned to the various environmental and functional attributes that were combined to give the relative footprint ratio. In contrast, the energy cost ratio is a measure of the cost-effectiveness of each alternate for developing the hydroelectric potential of the Site C Flood Reserve relative to the Project. Figure 6.2 shows the energy cost ratio and the footprint ratio for each alternate relative to the Project. The scales of the two axes are different:

- Suboptimal energy cost ratios, i.e., greater than 1.0, indicate less energy production at a higher unit energy cost. As shown in Table 6.1, the energy cost ratios for the Wilder Creek alternate and the two-dam alternate are 1.38 and 1.55, respectively. A 38% to 55% increase of energy cost ratio indicates a commensurate loss in economic efficiency.
- Optimal relative footprint ratios indicate less environmental effects; however, as shown in Figure 6.7, the differences between the Wilder Creek alternate and the two dam alternate are modest

The Alternates Study concluded that:

- There are no environmental factors that would eliminate an alternate
• The relative differences in environmental effects and functionality between alternates are small

• The small relative differences in benefits between the alternates do not justify the greater costs

The Alternates Study demonstrates that the Project is the preferred means of cost-effectively maximizing the development of the hydroelectric potential of the Site C Flood Reserve.

References

Literature Cited

7 PROJECT BENEFITS

This section of the EIS describes the expected benefits of the Project on a local, provincial, and federal level. These benefits enable BC Hydro, through the Project, to build relationships with Aboriginal groups, the public and local governments while ensuring that the Project remains cost-effective for BC Hydro ratepayers. The discussion of these benefits has been organized in this chapter as follows:

• Section 7.1 describes the financial benefits to ratepayers resulting from the cost-effective energy generated by the Project

• Section 7.2 describes the financial benefits to various levels of government, in the form of government revenues at the local, provincial, and federal level, generated by the Project

• Section 7.3 describes the economic benefits of the Project resulting from increased economic activity and job creation

• Section 7.4 describes the environmental, social, and sustainable development benefits of the Project. This includes the low greenhouse gas emission intensity of the energy produced, the role of the Project in integrating intermittent clean or renewable resources and in optimizing the hydroelectric potential of the Peace River, the role of the Project in increasing fish habitat and aquatic productivity in certain areas, in providing increased fishing opportunities and water-based recreational use and in providing improvements to public roads and to the reliability of the transmission system

7.1 Ratepayer Benefits

The EIS Guidelines state that the EIS is to include a description of the extent, distribution, and duration of the benefits of the Project, including the value of electricity generated.

This section provides a description of the benefit of cost-effective energy and dependable capacity to BC Hydro customers, and is structured as follows:

• Section 7.1.1 provides background information concerning BC Hydro’s competitive electricity rates resulting from its Heritage hydroelectric system

• Section 7.1.2 provides a description of the energy and dependable capacity generation benefits from the Project

• Section 7.1.3 provides a description of the net ratepayer benefits arising from the Project

The EIS Guidelines also state that the EIS is to include a description of the initial capital construction cost and operating cost estimates for the Project, including a description of the methodology for developing cost estimates. This information is contained in Volume 1 Appendix F Project Benefits Supporting Documentation, Part 1 Project Cost Estimate.
7.1.1 Competitive BC Hydro Rates

Due to its Heritage hydro system, BC Hydro electricity is currently among the most competitively priced in North America, which helps reduce the utility component of the cost of living and provides a competitive advantage for businesses operating in B.C. Each year, BC Hydro participates in a Hydro-Québec comparison survey of average electricity prices for 12 Canadian utilities and 10 American utilities. The Hydro-Québec report provides the monthly bills, excluding taxes and non-utility levies, calculated for specific consumption points for four different customer segments: residential, small power, medium power, and large power. The average price is also calculated, for each customer segment and specific consumption point, by dividing the monthly bill by the amount of monthly energy consumption. For example, if an electric bill for 1,000 kWh was calculated to be a monthly amount of $50, the average price would be $50 divided by 1,000 kWh, or 5 cents/kWh.

The most recent completed rate comparison was undertaken in 2012 (BC Hydro 2012). Figure 7.1 shows a comparison of the rates in multiple North American cities. As shown, BC Hydro’s rates for fiscal 2012 were identified as among the lowest in North America.

BC Hydro’s competitive electricity rates result from its Heritage hydroelectric system. As described below in Section 7.1.3, while large hydroelectric generating facilities have relatively high initial capital costs, operating and maintenance costs are minimal when compared to other sources of electricity such as natural gas-fired generation:

- Comparing the cost of electricity with the initial investment of a hydropower generating station, the pay-back period is short relative to the economic life of the hydroelectric facility. As described in Volume 1 Section 5.5.2, natural gas-fired and wind generating facilities have shorter economic lives than large hydroelectric facilities.

- A hydroelectric generating station can produce electricity with minimal cost increases over the life of the facility. This contrasts with natural gas-fired plants where the price of natural gas fluctuates depending on what the market is doing.

For hydroelectric projects like the Project, a longer lifespan means not only are costs spread across a longer timeframe but also power generating equipment used at the hydroelectric facilities can often operate for long periods of time without needing major replacements or repairs.

7.1.2 Capacity and Energy Provided by the Project

The Project will provide needed, long-term, cost-effective dependable capacity and energy for as long as the project operates. Volume 1 Section 5.2 demonstrates that there is a need for the Project’s energy and dependable capacity, while Volume 1 Section 5.5 shows that the Project is the most cost-effective way to meet the identified need.

7.1.2.1 Capacity

Capacity represents the instantaneous power output of a generating facility at any given time. As described in Volume 1 Section 5.2, BC Hydro plans its system to ensure that there is sufficient dependable capacity to meet customer needs, which represents the maximum generation output that can be reliably supplied coincident with system peak
load, taking into account the physical state and availability of the equipment and water or fuel constraints. The Utilities Commission Act service obligation discussed in Volume 1 Section 5.2 means that BC Hydro must make sure customer demand is met at the peak load every day.

The dependable capacity of the Project is established as part of the project design. The dependable capacity of the Project is 1,100 MW, as discussed in Section 4.3.1.4 in Volume 1 Section 4 Project Description. As described in Volume 1 Section 5.2, after BC Hydro implements Revelstoke Unit 6, there are limited dependable capacity resource options available to BC Hydro. Proceeding with the Project avoids dependable capacity resources such as natural gas-fired SCGTs and/or pumped storage facilities. Therefore the long-term value of the Project’s dependable capacity is the avoided cost of a SCGT (within the 97% Clean Energy Act clean or renewable target) and/or pumped storage, which have unit capacity costs of between $89/kW-year up to $440/kW-year (refer to Table 5.38, Volume 1 Section 5). These capacity costs are reflected in the value of the avoided costs of energy presented in Section 7.1.2.3 below.

7.1.2.2 Energy

Energy represents the cumulative amount of electricity produced or consumed over a specific period of time. For the Project, the amount of energy that can be produced is driven by the water inflows into the proposed Project reservoir from the Peace Canyon generating station and from local tributaries.

To determine the average annual energy produced by the Project, BC Hydro modeled the BC Hydro generation and transmission system in HYSIM for 60 different water inflow scenarios, for portfolios (as defined in Volume 1 Section 5 Need for, Purpose of, and Alternatives to the Project) with the Project and without the Project. (Please see Volume 2 Section 11.4 Surface Water Regime for a more detailed discussion of the HYSIM model.) The difference between the annual energy in these two portfolios represents the energy contributed to the system by the Project.

Variability in weather conditions (most importantly, variability in precipitation amounts) will result in variability in the energy contributed by the Project from year to year. To quantify this variability in annual generation, the HYSIM analysis (Volume 2 Section 11.4 Surface Water Regime) calculated the energy contribution across the range of 60 water inflow scenarios. Table 7.1 shows the average annual energy contributed by the Project, as well as the firm energy, which represents the average energy contributed in the worst three-year sequence of inflows out of the 60 water inflow scenarios.

### Table 7.1 Annual Energy Contribution of the Project

<table>
<thead>
<tr>
<th>Annual Energy Contribution</th>
<th>GWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average annual energy:</td>
<td></td>
</tr>
<tr>
<td>Average annual energy contribution across all modelled inflow scenarios</td>
<td>5,100</td>
</tr>
<tr>
<td>Firm energy:</td>
<td></td>
</tr>
<tr>
<td>Average annual energy contribution in worst three-year sequence of inflows</td>
<td>4,700</td>
</tr>
</tbody>
</table>

The timing of this energy generation throughout the year is also a key benefit to BC Hydro ratepayers, as generation can be timed to match customer demand. See Section 7.4.1 for further discussion.
Proceeding with the Project avoids higher cost clean or renewable intermittent resources (referred to as Available Resources in Volume 1 Section 5). The long-term value of the Project's 5,100 GWh/year of average energy is based on the avoided cost of alternative resources, and falls into the following range ($F2013):

- $135/MWh ($F2013), which is the adjusted weighted average price resulting from the most recent, broadly-based BC Hydro energy acquisition process, the Clean Power Call (about 3,000 GWh/year of firm energy)
- $131/MWh ($F2013), which is the adjusted weighted average price of the clean energy resources that make up the portfolios shown in Table 5.42, Volume 1 Section 5, based on pricing from the 2010 Resource Options Report

7.1.2.3 Combined Value of Site C Energy and Capacity

The long-term value of the Project's 5,100 GWh/year of average energy and 1,100 MW of dependable capacity can be valued through the avoided cost of a replacement portfolio of both energy and capacity resource options. The range of UECs for the replacement portfolios are:

- $163/MWh to $189/MWh, which is the unit energy cost for a portfolio with energy priced at the $135/MWh Clean Power Call adjusted weighted average price, plus capacity resources priced at the range provided in Section 7.1.2.1
- $156/MWh to $181/MWh, which is the adjusted unit energy cost range for the Clean Generation and the Clean + Thermal Generation portfolios (refer to Table 5.42, Volume 1 Section 5). This values energy at $125/MWh based on information in the 2010 Resource Options Report (as per Section 7.1.2.2) and values capacity based on the range in Section 7.1.2.1.

7.1.3 Effect on Ratepayer Costs

Costs associated with generation projects are recovered from ratepayers based on the revenue requirements collected by BC Hydro, as regulated by the British Columbia Utilities Commission (BCUC). The addition to the total customer revenue requirement resulting from a hydroelectric project is generally composed of:

- Operations costs
- Financing costs (i.e., interest on debt associated with the project)
- Amortization of the project capital cost (depreciated over a period as determined by accounting principles and accepted by the BCUC)
- A regulated return on equity on the capital invested in the project

One of the benefits of the Project to BC Hydro ratepayers arises from the difference in ratepayer costs between different portfolios including the Project and portfolios where the Project is replaced by alternatives, as described in Volume 1 Section 5.5 Need for, Purpose of, and Alternatives to the Project. Based on the analysis in Volume 1 Section 5.5, the Project is expected to result in lower long-term costs to ratepayers than alternative resource options.
Figure 7.2 provides a directional depiction of the expected annual costs to ratepayers of the Project and a comparable block of either clean or clean plus thermal alternative resources.

- The Project’s annual costs are calculated based on assumptions regarding the expected cost recovery from ratepayers. The manner of cost recovery is determined by the BCUC, and may therefore differ from these assumptions. Increases in the cost of service after Year 40 are due to significant sustaining capital requirements in these years.

- The cost of the portfolios of alternatives assume an annual payment schedule similar to the electricity purchase agreements (EPAs) signed under the Clean Power Call, which is the most recent BC Hydro power acquisition process, where costs increase at half of an agreed-upon inflation index (this results in a year-by-year decrease in the real dollar annual cost). The terms of future EPAs would be subject to commercial negotiations, and may therefore differ from these assumptions.

As shown by Figure 7.2, the Project consistently has a lower cost of service than the portfolios of alternative energy resources. This cost differential is smaller at the start of the operations period, as the financing costs for the Project are at their highest. As the project debt is repaid, financing costs decrease and the cost differential between portfolios increases. It should be noted that the average EPA term under the Clean Power Call was approximately 30 years (with the maximum being 40 years), and the price and volume of the replacement or renewal of EPAs after that point would be uncertain. Refer to Section 5.2.3 in Volume 1 Section 5 Need for, Purpose of, and Alternatives to the Project for additional detail.

An additional benefit of the Project is the lower uncertainty in the cost of energy paid by BC Hydro customers. The majority of the levelized cost of the Project is from construction and development costs, and thus would be fixed once construction of the Project is complete. Conversely, for a thermal resource such as a natural gas generating facility, a material portion of the costs are incurred during operations, and therefore energy costs are subject to market fluctuations in fuel prices. Table 7.2 demonstrates this difference by comparing the makeup in levelized unit energy cost (see Volume 1 Appendix F Project Benefits Supporting Documentation, Part 1 Project Cost Estimate for a description of the Project’s unit energy cost) between the Project and a natural gas generating facility.

<table>
<thead>
<tr>
<th>Component of Unit Energy Cost</th>
<th>Site C Clean Energy Project (%)</th>
<th>Sample Combined-Cycle Gas Turbine (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction and Development Costs</td>
<td>85</td>
<td>20</td>
</tr>
<tr>
<td>Operations Costs, Sustaining Capital, and Taxes</td>
<td>5</td>
<td>10</td>
</tr>
<tr>
<td>Fuel Costs (water rentals, natural gas)</td>
<td>10</td>
<td>70</td>
</tr>
</tbody>
</table>

NOTES:

- All numbers rounded to nearest 5%
- Capital cost information from Appendix 3 of BC Hydro’s Resource Options Report (BC Hydro 2010)
Compared to natural gas generating facilities, the Project provides relative price certainty for ratepayers, and protects ratepayers from volatility in ongoing operating costs due to fluctuating fuel prices.

**7.2 Taxpayer Benefits**

This section describes the annual taxpayer benefits of the Project, including the following:

- Annual federal, B.C. provincial, municipal, and regional government revenues that will accrue during the construction and operation phases of the Project
- Annual federal and provincial gross domestic product (GDP) that will accrue during the construction and operations phases of the Project

This section is structured as follows:

- Section 7.2.1 provides a summary of the benefits to government revenues in the Northeast Development Region for the construction and operations periods
- Section 7.2.2 provides a summary of the benefits to provincial and federal government revenues for the construction and operations periods
- Section 7.2.3 summarizes these taxpayer benefits

**7.2.1 Local Government Revenues**

The Project will provide additional revenues to local governments during both the construction and operations periods. The major sources of this local government revenue are general taxation revenues, grants-in-lieu, and school taxes. Further details on the local government revenues effects assessment are provided in Volume 3 Section 16 Local Government Revenue.

**7.2.1.1 Taxation Revenues**

The key source of additional taxation revenues to local governments will be from incremental property taxes collected from new residents and businesses in local communities who are attracted by the opportunities presented by the construction of the Project. Based on the British Columbia Input-Output Model analysis, there would be a total of $40 million in direct, indirect, and induced incremental tax revenues resulting from the construction phase of the Project (Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats).
Table 7.3  Estimated Local Tax Revenues Derived from Project Expenditures During Construction

<table>
<thead>
<tr>
<th>Year of Construction Phase</th>
<th>Year 0</th>
<th>Year 1</th>
<th>Year 2</th>
<th>Year 3</th>
<th>Year 4</th>
<th>Year 5</th>
<th>Year 6</th>
<th>Year 7</th>
<th>Year 8</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tax revenue from direct Project expenditures</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>5</td>
</tr>
<tr>
<td>Tax revenue from indirect and induced activity</td>
<td>1</td>
<td>3</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td>6</td>
<td>5</td>
<td>3</td>
<td>1</td>
<td>35</td>
</tr>
<tr>
<td>Total</td>
<td>2</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td>7</td>
<td>6</td>
<td>6</td>
<td>3</td>
<td>1</td>
<td>40</td>
</tr>
</tbody>
</table>

NOTES:

1. All values in $ million
2. Source: Modified from Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats
3. There would be additional taxation revenues accruing to local governments during the operations phase of the project. However, grants-in-lieu (see below) replace the majority of traditional taxation revenues, and any remaining incremental revenues are expected to be non-material, given the low project operations costs. As a result, taxation revenues during the operations phase have not been included in the estimate of the Project’s financial benefits.

7.2.1.2 Grants-in-Lieu of Taxes

BC Hydro’s generating facilities are generally exempt from assessment and taxation, per B.C. Order-in-Council 2091/82. However, for most existing projects the Province has authorized BC Hydro to pay an annual grant-in-lieu of taxes to local communities during project operations. Whether this amount is paid is at the Province’s sole discretion.

If the Province authorizes BC Hydro to pay grants-in-lieu for the Project, the estimated payment would be approximately $1,300,000 per year (in 2012 dollars) based on current rates. These rates are indexed to annual inflation in municipal tax revenues.

7.2.1.3 School Taxes

While BC Hydro generating facilities are generally exempt from assessment and taxation, this exemption does not extend to transmission assets. As a result, Project transmission assets such as transformers, circuit breakers, and the buildings that house them would be subject to school taxes.

The estimated school taxes on the Project transmission assets is approximately $800,000 per year (in 2012 dollars), but would depend on the actual assessed value of the assets once constructed. The school tax rate varies annually, but typically increases at the rate of inflation.
7.2.2 Provincial and Federal Government Revenues

The provincial and federal governments are expected to receive incremental revenues as a result of the Project during both construction and operations. The major sources of provincial government revenue are general taxation revenues, water rentals, and the Government return on equity. Federal government revenues are primarily from taxation revenues.

7.2.2.1 Taxation Revenues

During construction, these incremental revenues will come from taxes on a range of sources that would be associated with the Project, including provincial and federal income tax, net child benefits, net property tax, sales tax, fuel tax, health care premiums, payroll taxes, federal taxes, and net GST for B.C. families of various sizes and various incomes.

The British Columbia Input-Output Model (Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats) estimates that the provincial government would receive approximately $176 million in revenues from direct, indirect, and induced activities during the construction phase of the Project. Meanwhile, the federal government will collect an estimated $270 million over same period from direct, indirect, and induced activities.

Table 7.4 Estimated Provincial and Federal Tax Revenues Derived from Project Expenditures During Construction

<table>
<thead>
<tr>
<th>Year of Construction Phase</th>
<th>Year 0</th>
<th>Year 1</th>
<th>Year 2</th>
<th>Year 3</th>
<th>Year 4</th>
<th>Year 5</th>
<th>Year 6</th>
<th>Year 7</th>
<th>Year 8</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Provincial Revenue ($ million)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tax revenue from direct project expenditures</td>
<td>3</td>
<td>12</td>
<td>14</td>
<td>15</td>
<td>18</td>
<td>20</td>
<td>17</td>
<td>10</td>
<td>2</td>
<td>111</td>
</tr>
<tr>
<td>Tax revenue from indirect and induced activity</td>
<td>2</td>
<td>6</td>
<td>8</td>
<td>9</td>
<td>11</td>
<td>10</td>
<td>10</td>
<td>6</td>
<td>2</td>
<td>65</td>
</tr>
<tr>
<td>Total provincial tax revenue</td>
<td>6</td>
<td>18</td>
<td>22</td>
<td>24</td>
<td>29</td>
<td>30</td>
<td>27</td>
<td>16</td>
<td>4</td>
<td>176</td>
</tr>
<tr>
<td><strong>Federal Revenue ($ million)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tax revenue from direct project expenditures</td>
<td>5</td>
<td>17</td>
<td>21</td>
<td>22</td>
<td>26</td>
<td>38</td>
<td>33</td>
<td>18</td>
<td>4</td>
<td>185</td>
</tr>
<tr>
<td>Tax revenue from indirect and induced activity</td>
<td>3</td>
<td>9</td>
<td>11</td>
<td>13</td>
<td>15</td>
<td>12</td>
<td>12</td>
<td>7</td>
<td>2</td>
<td>84</td>
</tr>
<tr>
<td>Total</td>
<td>9</td>
<td>26</td>
<td>32</td>
<td>35</td>
<td>41</td>
<td>51</td>
<td>45</td>
<td>26</td>
<td>6</td>
<td>270</td>
</tr>
</tbody>
</table>

**NOTE:**

**Source:** Modified from Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats
During project operations, revenues would continue to accrue to the provincial government through water rentals and BC Hydro’s regulated return on equity. These items are also included in the Project’s unit energy cost (discussed in Volume 1 Appendix F Project Benefits Supporting Documentation, Part 1 Project Cost Estimate), either as direct costs (e.g., water rentals) or implicit in the discount rate (e.g., government dividend, via the return on equity).

### 7.2.2.2 Water Rentals

Water rentals are fees paid by BC Hydro and collected by the Water Stewardship division of the B.C. Ministry of Environment, as established by the Water Act and the Financial Administration Act (B.C. Reg. 204/88, O.C. 889/88). There are separate water rental charges based on energy output, authorized capacity, and water impounded for storage. In total, for all facilities, BC Hydro paid $346 million in water rentals to the Province for the fiscal year ending March 31, 2012.

Based on current water rates, the annual water rental revenues to the Provincial government associated with the Project are expected to be $41.2 million dollars in 2012 real dollars (BCMOE 2012). Water rentals are currently indexed to escalate at the rate of Canadian Price Index inflation and are therefore expected to stay constant on a real dollar basis.

### 7.2.2.3 Government Return on Equity and Dividend

The Project will provide incremental returns to the provincial government during operations through its contribution to BC Hydro’s regulated return on equity and government dividend. Through Heritage Special Direction HC1, the province requires BC Hydro to make annual dividend payments to the province of 85% of BC Hydro’s net income, as long as BC Hydro’s debt-equity ratio, after deducting the payment, is not greater than 80:20.

BC Hydro’s return on equity and dividend is based on all BC Hydro activities, and is not calculated on an individual basis for a project such as the Project. However, an approximation of the Project’s contribution to the return on equity and dividend can be made to estimate the potential increase to government revenues.

The Project will represent a $7.9 billion capital investment held by BC Hydro at its in-service date. This initial capital investment will depreciate over time, although sustaining capital investment associated with asset rehabilitation or replacement will partially offset this depreciation.

BC Hydro collects a return on deemed equity, as established by Heritage Special Direction HC2 as 30% of its average asset/rate base. The return that BC Hydro collects on deemed equity is established by the BCUC on the basis of a comparison with the pre-tax rate of return earned by private utilities in B.C., and was 11.78% as of March 31, 2012.

For the Project, the incremental return on equity was estimated by taking 30% of the project’s depreciated capital asset and calculating an 11.78% return on this amount. This analysis assumes that the sole effect on BC Hydro’s return on equity is due to the increase in BC Hydro’s capital asset base. Table 7.5 shows the approximate incremental return on equity and dividend for a selection of years throughout the life of the Project.
### Table 7.5 Estimated Contribution of the Project to the Province of B.C.’s Return on Equity and Dividend (Selected Years)

<table>
<thead>
<tr>
<th>Years from Project In-Service Date</th>
<th>Contribution to Return on Equity</th>
<th>Contribution to Dividend</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>220</td>
<td>185</td>
</tr>
<tr>
<td>5</td>
<td>190</td>
<td>160</td>
</tr>
<tr>
<td>10</td>
<td>160</td>
<td>135</td>
</tr>
<tr>
<td>25</td>
<td>95</td>
<td>80</td>
</tr>
<tr>
<td>50</td>
<td>35</td>
<td>30</td>
</tr>
</tbody>
</table>

**NOTE:**
All values in $ million, 2012 real dollars

#### 7.2.2.4 Other Revenues

In addition to the above, the provincial and federal governments would also expect to receive incremental personal and corporate income tax revenues resulting from economic activity associated with project operations. However, these additional revenues are not expected to be material, given the low project operations costs, and have not been included in the estimate of the Project’s financial benefits.

#### 7.2.3 Summary of Taxpayer Benefits

A summary of the local, provincial and federal taxpayer benefits for the construction and operations phases of the Project are provided in Table 7.6.

### Table 7.6 Estimated Government Revenues – Construction Period and Operations Period (Selected Years)

<table>
<thead>
<tr>
<th></th>
<th>Construction Period Total</th>
<th>Operations Period</th>
<th>Year 1</th>
<th>Year 5</th>
<th>Year 10</th>
<th>Year 25</th>
<th>Year 50</th>
</tr>
</thead>
<tbody>
<tr>
<td>Local revenues</td>
<td>40</td>
<td></td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Provincial revenues</td>
<td>176</td>
<td></td>
<td>260</td>
<td>230</td>
<td>200</td>
<td>135</td>
<td>75</td>
</tr>
<tr>
<td>Federal revenues</td>
<td>270</td>
<td></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

**NOTE:**
All values in $ million, 2012 real dollars, rounded

#### 7.3 Economic Benefits

This section describes the projected economic benefits of the Project, including:

- Estimated direct employment stated in number of person-years, to be created by major job category (e.g., labour, management, business services) during construction and operations
- Estimated indirect employment (i.e., employment in industries that supply goods and services used to produce an industry’s output or to be consumed by individuals) and
induced employment (i.e., employment due to the spending and re-spending of
directly and indirectly generated incomes in the broader economy) during
construction and operation predicted by the British Columbia Input-Output Model
developed and maintained by BC Stats (Volume 3 Appendix A Economic
Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats)

- Predicted locality of direct and indirect hires
- Contractor supply services estimates, including the value of supply of service
  contracts expected for the Project’s construction and operations phases

For definitions of direct, indirect, and induced effects, please see Volume 3 Appendix A

This section also describes the economic benefits for Aboriginal groups, including:
- Employment
- Contracting and business development, including small and medium-sized
  enterprises
- Capacity-building initiatives

This section is structured as follows:
- Section 7.3.1 provides a description of spending on contractors and consultants for
  the construction period of the project
- Section 7.3.2 presents the employment benefits of the project through both the
  construction and operations phases
- Section 7.3.3 provides a description of the economic benefits that BC Hydro expects
  to provide to Aboriginal groups
- Section 7.3.4 provides a description of the economic benefits that BC Hydro expects
  to provide to communities local to the Project
- Section 7.3.5 provides a description of the economic benefits that BC Hydro expects
  to provide to B.C. Ministry of Transportation and Infrastructure (BC MoTI) through
  quarry expansion

7.3.1 Economic Development Benefits

7.3.1.1 Construction Phase

Construction of the Project will provide economic benefits at the local, provincial, and
federal level, due to the purchase of goods and services for construction and the
resulting increase in output from supplier industries, GDP, and household income.
The Project will provide benefits to a range of contractors and consultants supplying
direct and indirect goods and services to the Project. The effects on economic
development indicators for the construction period were estimated by providing cost
estimates and supporting information to BC Stats for use in the British Columbia
Input-Output Model (Volume 3 Appendix A Economic Assessment Supporting
Documentation, Part 2 Project Economic Impacts: BC Stats). For the Northeast
Development Region (NEDR), the increased output would be through the expansion of
existing businesses or the establishment of new ones, including branch and subsidiary operations of major suppliers who do not already have offices in the NEDR. In addition to the potential effects to direct suppliers, the Project is expected to increase GDP and household income in both the construction and operations phases.

The estimated magnitude of the effect on output, GDP, and household income at the regional and provincial level during construction is presented in Table 7.7. The majority of the effect on federal GDP will be due to the increase in B.C. provincial GDP; however, estimated imports from other provinces are provided in order to estimate the GDP increase in other provinces.

**Table 7.7 Economic Development Benefits During Construction Period ($ million)**

<table>
<thead>
<tr>
<th></th>
<th>Direct Suppliers</th>
<th>Other (Indirect) Suppliers</th>
<th>Induced Increase</th>
<th>Total Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Northeast Development Region</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GDP</td>
<td>35</td>
<td>52</td>
<td>45</td>
<td>132</td>
</tr>
<tr>
<td>Output</td>
<td>99</td>
<td>127</td>
<td>99</td>
<td>324</td>
</tr>
<tr>
<td>Household income</td>
<td>25</td>
<td>26</td>
<td>31</td>
<td>81</td>
</tr>
<tr>
<td><strong>Provincial</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GDP</td>
<td>1,725</td>
<td>976</td>
<td>507</td>
<td>3,228</td>
</tr>
<tr>
<td>Output</td>
<td>1,429</td>
<td>774</td>
<td>814</td>
<td>3,016</td>
</tr>
<tr>
<td>Household income</td>
<td>1,294</td>
<td>648</td>
<td>291</td>
<td>2,232</td>
</tr>
<tr>
<td><strong>Federal</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Imports from other provinces</td>
<td></td>
<td></td>
<td></td>
<td>580</td>
</tr>
</tbody>
</table>

**NOTE:**

**Source:** Modified from Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats

It is expected that the Project would create opportunities for supplier industries and diversify the economic base of the NEDR during the construction period. Table 7.8 shows the change in dollars to the top five supplier industries of contracts associated with the Project during the construction phase. A more detailed table can be found in the BC Stats report in Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats.
Table 7.8

Estimated Increases in Output in Top Five Supplier Industries During Construction Phase

<table>
<thead>
<tr>
<th>Supplier Industry</th>
<th>$ million</th>
</tr>
</thead>
<tbody>
<tr>
<td>Finance, insurance, real estate, and renting and leasing</td>
<td>635</td>
</tr>
<tr>
<td>Manufacturing</td>
<td>190</td>
</tr>
<tr>
<td>Professional, scientific, and technical services</td>
<td>315</td>
</tr>
<tr>
<td>Wholesale trade</td>
<td>210</td>
</tr>
<tr>
<td>Operating, office, cafeteria, and laboratory supplies</td>
<td>205</td>
</tr>
</tbody>
</table>

NOTES:
The top five supplier industries represent approximately 52% of the total increase in supplier output.

Source: Modified from Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats

7.3.1.2 Operations Phase

Operations of the Project will provide economic benefits at the local, provincial, and federal level, due to the purchase of goods and services for operations and sustaining capital investment. These purchases will increase supplier industry output, GDP, and income.

The effects on output, GDP, and income for the operations period were estimated by providing cost estimates and supporting information to BC Stats for use in the British Columbia Input-Output Model, as was done for the construction phase. The estimated magnitude of the change to output, GDP, and household income at the regional and provincial level during construction is presented in Table 7.9. As discussed for the construction phase, the majority of the effect on federal GDP will be due to the increase in B.C. provincial GDP; however, estimated imports from other provinces are provided in order to estimate the GDP increase in other provinces.

Table 7.9

Average Annual Economic Development Benefits During Operations Phase ($ million Per Year)

<table>
<thead>
<tr>
<th></th>
<th>Direct Suppliers</th>
<th>Other Suppliers</th>
<th>Induced Increase</th>
<th>Total Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Northeast Development Region</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GDP</td>
<td>0.0</td>
<td>0.2</td>
<td>0.3</td>
<td>0.4</td>
</tr>
<tr>
<td>Output</td>
<td>0.2</td>
<td>0.4</td>
<td>0.5</td>
<td>1.1</td>
</tr>
<tr>
<td>Household income</td>
<td>0.0</td>
<td>0.0</td>
<td>0.2</td>
<td>0.3</td>
</tr>
<tr>
<td><strong>Provincial (including Regional)</strong></td>
<td>2.9</td>
<td>1.5</td>
<td>2.6</td>
<td>7.0</td>
</tr>
<tr>
<td>GDP</td>
<td>6.0</td>
<td>3.0</td>
<td>3.4</td>
<td>13.5</td>
</tr>
<tr>
<td>Household income</td>
<td>2.7</td>
<td>1.3</td>
<td>1.9</td>
<td>4.9</td>
</tr>
<tr>
<td><strong>Federal</strong></td>
<td></td>
<td></td>
<td></td>
<td>1.8</td>
</tr>
<tr>
<td>Imports from other provinces</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

NOTES:
Values include both average annual increases from operations and maintenance, and levelized sustaining capital.

Source: Modified from Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats
Table 7.10 shows the dollar changes to the top five supplier industries of contracts associated with the Project during the operations phase. These increases are split between operations and maintenance and sustaining capital, due to the difference in the types of industries affected by these different operating period activities.

### Table 7.10 Estimated Increases in Output in Top Five Supplier Industries During Operations Phase ($ million Per Year, Average)

<table>
<thead>
<tr>
<th>Increase in Supplier Industry Output</th>
<th>Increase in Supplier Industry Output</th>
</tr>
</thead>
<tbody>
<tr>
<td>Professional, scientific, and technical services</td>
<td>4.3</td>
</tr>
<tr>
<td>Finance, insurance, real estate, and renting and leasing</td>
<td>1.4</td>
</tr>
<tr>
<td>Finance, insurance, real estate, and renting and leasing</td>
<td>0.2</td>
</tr>
<tr>
<td>Transportation and warehousing</td>
<td>0.4</td>
</tr>
<tr>
<td>Operating, office, cafeteria, and laboratory supplies</td>
<td>0.9</td>
</tr>
<tr>
<td>Manufacturing</td>
<td>0.6</td>
</tr>
<tr>
<td>Retail trade</td>
<td>0.3</td>
</tr>
<tr>
<td>Wholesale trade</td>
<td>0.5</td>
</tr>
<tr>
<td>Travel and entertainment, advertising, and promotion</td>
<td>0.2</td>
</tr>
<tr>
<td>Professional, scientific, and technical services</td>
<td>0.4</td>
</tr>
</tbody>
</table>

**NOTE:**
Source: Modified from Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats

A more detailed table can be found in the BC Stats report in Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats.

**Business Engagement**

BC Hydro has been engaging with businesses in order to enable participation both prior to and during the construction of the Project. Please see Section 9.1.3.5 in Volume 1 Section 9 Information Distribution and Consultation for a description of these activities, which would continue through the construction period. In addition to these engagement activities, BC Hydro proposes to staff a procurement or economic development office in the NEDR.

BC Hydro has worked to engage local businesses with development work on the Project. To date, more than two dozen companies with local or regional offices are engaged with the Project, with a large number of additional vendors supplying goods and services to the Project.

Further information on ways in which BC Hydro is engaging local businesses can be found in Volume 1 Section 4 Appendix F Project Benefits Supporting Documentation, Part 2– Local Participation Strategies.

#### 7.3.2 Employment Benefits

The Project is expected to provide employment benefits both prior to and during the construction and operations phases. This section describes the direct, indirect, and induced employment (as defined in Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats) resulting from
the Project for the period prior to and during the construction phase, as well as employment during the operations phase.

7.3.2.1 Prior to and During the Construction Phase

The Project would provide employment during the eight-year construction phase, and has been providing employment prior to and during the Environmental Assessment as well. Approximately 70% of the construction employment would involve trade occupations, 18% would involve contractor supervisors, and 11% would involve BC Hydro personnel. Of the trades occupations employment, 60% would be equipment operators, labourers, and truck drivers.

Table 7.11 Estimated Employment Provided by the Project Prior to Project In-Service Date

<table>
<thead>
<tr>
<th>Direct Jobs</th>
<th>Indirect and Induced Jobs</th>
<th>Total Employment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prior to and during the Environmental Assessment</td>
<td>2,200</td>
<td>1,500</td>
</tr>
<tr>
<td>Construction Phase</td>
<td>10,200</td>
<td>19,100</td>
</tr>
<tr>
<td>Total Jobs to Project ISD</td>
<td>12,400</td>
<td>20,600</td>
</tr>
</tbody>
</table>

NOTES:
All values in person-years of employment

Source: Modified from Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats

The locality of the construction employment can be estimated using the British Columbia Input-Output Model. Table 7.12 shows the component of the project employment expected to be provided in the NEDR.

Table 7.12 Estimated Employment During Construction in the Northeast Development Region

<table>
<thead>
<tr>
<th>Direct Jobs</th>
<th>Indirect and Induced Jobs</th>
<th>Total Employment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction Phase</td>
<td>1,600</td>
<td>2,300</td>
</tr>
</tbody>
</table>

NOTES:
All values in person-years of employment

Source: Modified from Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats

In order to achieve this expected employment in the NEDR, BC Hydro has undertaken and will continue to undertake activities to engage labour not currently in the workforce. Details of these activities can be found in Section 7.3.4 as well as in Volume 1 Appendix F Project Benefits Supporting Documentation, Part 2 Local Participation Strategies.

7.3.2.2 Operating Period

The Project’s operating labour requirements were estimated based on a comparison of existing BC Hydro facilities of a similar size. For plant operations and maintenance, BC Hydro estimates that the Project would require approximately 25 persons for
long-term employment, approximately 13 of whom would be located in the NEDR. These jobs are primarily composed of skilled trades, engineering, and management functions, with some supporting administrative and janitorial positions. Employment in supplier industries will result from positions related to environmental monitoring and mitigation activities, as well as other jobs related to equipment supply and other supporting activities.

Additional employment will result from major sustaining capital expenditures over the life of the Project. Sustaining capital investment occurs as project components require refurbishment or replacement, and is not expected to occur during the first 25 years of operations. When the sustaining capital investment does occur, the workforce required will depend on the magnitude and complexity of the work undertaken. For simplicity, employment associated with sustaining capital is presented as an average employment over the 100-year evaluation period in the BC Stats report in Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats. Actual employment will vary from year to year.

### Table 7.13 Estimated Employment Provided by the Project After Project In-Service Date

<table>
<thead>
<tr>
<th></th>
<th>Direct Jobs</th>
<th>Indirect Jobs</th>
<th>Induced</th>
<th>Total Employment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations and Maintenance</td>
<td>25</td>
<td>51</td>
<td>12</td>
<td>88</td>
</tr>
<tr>
<td>Sustaining Capital (levelized)</td>
<td>33</td>
<td>20</td>
<td>20</td>
<td>73</td>
</tr>
<tr>
<td>Total employment after Project in-service date</td>
<td>58</td>
<td>71</td>
<td>33</td>
<td>161</td>
</tr>
</tbody>
</table>

**NOTES:**
All values in person-years per year

**Source:** Modified from Volume 3 Appendix A Economic Assessment Supporting Documentation, Part 2 Project Economic Impacts: BC Stats

It is expected that approximately 50% of the direct operations jobs on the Project will be located in the NEDR. Indirect and induced employment are expected to be similarly split evenly. Direct jobs associated with sustaining capital are expected to be more concentrated, with approximately 75% located in the NEDR. Indirect and induced jobs from sustaining capital investment would be expected to be more evenly split (i.e., 50% in the NEDR).

### 7.3.2.3 Tools for Engaging Local Labour

BC Hydro has, and would continue to, implement measures to increase the availability of local labour in recognition of the existing high local employment rate.

- BC Hydro donated $1 million to the Northern Lights College Foundation for skills and trades training for Aboriginal and non-Aboriginal students
- BC Hydro would build a daycare in the Fort St. John area early in the construction phase to support families wanting to participate in the local workforce
- BC Hydro’s Project labour strategy is to seek to promote and maximize opportunities for local and regional hiring
BC Hydro is planning for approximately 15% of workers to live in local communities and commute daily to the work site. If additional workers are available, both locally and regionally, BC Hydro would be able accommodate this increase.

7.3.3 Economic Benefits to Aboriginal Groups

BC Hydro is committed to the advancement of economic opportunities for Aboriginal groups, both to build their capacity and to develop more sustainable long-term relationships. BC Hydro has an existing Aboriginal Contract and Procurement Policy that is intended to increase the involvement of First Nations in economic opportunities associated with BC Hydro’s business activities by allowing certain procurement practices, including:

- Capacity-building initiatives, where BC Hydro provides funding or resources in order to provide training, improve skills, or increase business capacity in Aboriginal businesses
- Directed Aboriginal procurement, such as set-asides, restricted tendering, and single source negotiations
- The use of Aboriginal evaluation criteria in procurement packages. This provides an incentive for primary contractors to establish working relationships with First Nations groups, and increases the likelihood of Aboriginal participation in the construction contracts while maintaining a competitive environment that provides maximum benefits to ratepayers.
- The use of an Aboriginal business directory. BC Hydro’s Aboriginal Business Directory is accessible by BC Hydro to suppliers and contractors, and enables BC Hydro to promote partnerships between non-Aboriginal, First Nations, and Aboriginal businesses in contract work for BC Hydro.

BC Hydro has sought to provide economic benefits and to support capacity-building opportunities for Aboriginal people during activities prior to and during the construction phase of the Project. Some highlights of these activities include:

- BC Hydro has been building Aboriginal business capacity through the use of directed procurement activities, both prior to and during the Environmental Assessment process on the Project. This directed procurement has been used on engineering investigations contractor work as well as environmental baseline and effects assessment studies.
- BC Hydro will contribute $1 million in funding to support trades and skills training bursaries at Northern Lights College, with 50% of the funding for bursaries to be dedicated to Aboriginal students
- In July 2011, BC Hydro entered into a three-year funding agreement with Northern Opportunities, a partnership of the school districts of Fort Nelson (SD #81), Peace River North (SD #60), and Peace River South (SD #59) along with Northern Lights College, local First Nations, and industry, as well as local communities, with the objective of providing young people with a seamless learning pathway from secondary school to post-secondary training, leading to career success. The program covers academic, trades, apprenticeship, and vocational programs, and is open to both Aboriginal and non-Aboriginal students.
• In December 2012, BC Hydro announced that it would contribute $100,000 to the North East Native Advancing Society in support of advancing North East Aboriginal Trades Training participants into trades training not currently offered by Northern Lights College for those trades that are of interest to BC Hydro for the Project, such as heavy duty equipment operators. The funding would be used to defray tuition and related costs for those students who are pursuing trades training.

For more details on the activities undertaken by BC Hydro to provide economic benefits to Aboriginal groups, see Volume 1 Appendix F Project Benefits Supporting Documentation, Part 2 Local Participation Strategies.

7.3.4 Economic Benefits to Local Communities

Local communities will receive benefits from:

• Employment opportunities (as discussed in Section 7.3.2)
• Economic development opportunities (as discussed in Section 7.3.1)
• Revenues to their local governments (as discussed in Section 7.2.1)

Specific business, skills, and employment initiatives that BC Hydro is undertaking to support the opportunities above include:

• Establishing a Business Liaison Program to keep the business community updated on the status of the project and to advise on future business opportunities (see Volume 1 Section 9.1.3.5)
• As noted in Section 7.3.3, BC Hydro will contribute $1 million in funding to support trades and skills training bursaries at Northern Lights College
• As noted in Section 7.3.3, BC Hydro entered into a three-year funding agreement in July 2011 with Northern Opportunities, a partnership of the school districts of Fort Nelson (SD #81), Peace River North (SD #60), and Peace River South (SD #59), along with Northern Lights College, local First Nations, and industry as well as local communities, with the objective of providing young people with a seamless learning pathway from secondary school to post-secondary training, leading to career success.

Communities will also benefit from project construction plans and proposed mitigation plans such as:

• **Improved Infrastructure:** As described in Section 4.3 in Volume 1 Section 4 Project Description, some of the roads upgraded and enhanced during the construction phase will be accessible to the public, in addition to the realigned segments of Highway 29. These enhanced and upgraded roads and highways would support the economic development of the communities in the NEDR in the long term, both during Project construction and after construction is complete. As a further example, the proposed Hudson’s Hope shoreline protection, designed to protect the shoreline from the effects of erosion from the reservoir, will improve the stability of the slopes compared to their current condition, and will include a new walking trail.

• **Improved Tourism:** As part of its proposed mitigation plans, BC Hydro is also proposing funding for tourism improvements, including building a viewing site for
construction of the dam, providing enhancements to the W.A.C. Bennett Visitor Centre, and providing funding for other regional and local museums.

- **Affordable Housing:** To encourage workers to live locally, BC Hydro has committed to build approximately 50 new housing units in the City of Fort St. John, in cooperation with B.C. Housing; 40 of these units would be for use by BC Hydro’s workforce and their families during construction and 10 would be for use by the community. After construction of the Project, all 50 housing units would be available as affordable housing in the community.

In addition to these benefits, BC Hydro is undergoing discussions with local and regional governments to pursue legacy initiatives that will provide additional economic and social benefits for local communities. Discussions are continuing with local and regional governments with a view to achieving benefits agreements.

Activities related to business and labour engagement are outlined in Sections 7.3.1 and 7.3.2, respectively. Additional initiatives to promote economic opportunities for northern communities are outlined below.

7.3.5 **Economic Benefits from Quarry Expansion**

West Pine and Wuthrich quarries would be expanded and the Portage Mountain quarry specifically developed for the Project, and available for production after the Project is constructed. A surplus of 2.9 million m³ will be available for use by the B.C. Ministry of Transportation and Infrastructure and other potential users.

7.4 **Environmental, Social and Sustainability Benefits**

This section describes the environmental and sustainability benefits of the Project, including the ability of the Project to:

- Integrate clean or renewable generation resources such as wind and run-of-river hydro
- Generate electricity with a low amount of greenhouse gas emissions per unit of energy delivered
- Increase fish habitat and aquatic productivity in certain areas
- Provide increased fishing opportunities and water based access for a variety of boats
- Improve the safety of public roads and the reliability of the local transmission system

This section is structured as follows:

- Section 7.4.1 describes the manner in which the Project improves on the value of existing BC Hydro assets on the Peace River
- Section 7.4.2 describes the low greenhouse gas intensity of the electricity produced by the Project
- Section 7.4.3 describes the Project’s potential increase in BC Hydro’s ability to integrate additional intermittent clean resources such as wind and run-of-river hydro
- Section 7.4.4 describes the potential benefits to downstream infrastructure resulting from the improved control of flows provided by the Project
Section 7.4.5 describes the potential benefits to fish habitat and aquatic productivity in certain areas.

Section 7.4.6 describes the potential benefits to outdoor recreation.

Section 7.4.7 describes the potential benefits to public roads and safety.

Section 7.4.8 describes the potential benefits to the local transmission system.

### 7.4.1 Optimizing the Value of Existing BC Hydro Assets on the Peace River

A key benefit and competitive advantage of the Project is its location on the Peace River in British Columbia, downstream of the W.A.C. Bennett Dam and Peace Canyon Dam and their associated reservoirs, Williston and Dinosaur reservoirs, respectively. Williston Reservoir has a multi-year storage capacity; consequently, it has the capability to store water in wet years for use in dry years.

Electricity demand in British Columbia varies, with the highest seasonal demand in the winter, the highest weekly demand during the work week, and the highest daily demand during the daytime. As shown in Figure 7.3, water inflows to the BC Hydro reservoirs also vary, peaking in the spring with annual snowmelt and reaching a minimum in late winter. As part of normal operation of Williston Reservoir, water is stored during the high runoff and relatively low electricity price period from late April/May to early July, making water available to supplement the low runoff during the high demand and/or high price electricity period in summer and winter.

The Williston Reservoir can store three years of water inflow and enables BC Hydro to use water for generation when required for domestic demand. Flow from Williston Reservoir is regulated by the G.M. Shrum generating station. The regulated flow from G.M. Shrum and the natural flow enter Peace Canyon Dam’s Dinosaur Reservoir. Outflow from Peace Canyon Dam is regulated by the Peace Canyon generating station. The flow into the Project’s proposed reservoir would thus be regulated by the G.M. Shrum generating station and, to a lesser extent, the Peace Canyon generating station, to provide year-to-year shaping as well as seasonal and weekly shaping. In effect, this optimizes the value of the water stored behind W.A.C. Bennett Dam, as that water would be used for generation a third time after being run through turbines at the G.M. Shrum generating station and the Peace Canyon generating station.

This upstream regulation allows the Project to generate electricity to match the timing of BC Hydro customer demand without the need to establish another large multi-year storage reservoir similar to Williston Reservoir. As a result, the Project is able to produce approximately 35% of the energy produced by the G.M. Shrum generating station with 5% of the reservoir area.

### 7.4.2 Low Greenhouse Gas Emission Energy

All generation resources emit some greenhouse gas (GHG) emissions during their lifetime. All facilities will have GHGs emissions associated with construction and operations. In addition, thermal resources such as natural gas and coal have additional GHG emissions associated with the operational combustion of hydrocarbons. One of the benefits of the energy that would be provided by the Project is its low GHG intensity, with GHG emissions per unit energy produced at levels comparable to other renewable
resources such as wind and run-of-river hydro, and substantially less than thermal
generation resources.

BC Hydro has developed an estimate of GHG emissions associated with the Project, as
discussed in Volume 2 Section 15 Greenhouse Gases. GHG emissions were modeled
using the Intergovernmental Panel on Climate Change guidelines. The modeled
emissions for the Project were then compared to those of other alternative generation
options to determine if there are GHG reduction benefits to the selection of the Project
over other alternatives.

In order to perform this comparison, BC Hydro used the GHG emissions per unit energy
generated by the Project and by alternative generation options. This provides a relative
comparison of the GHG emissions that would result in replacing the 5,100 GWh
produced by the Project with 5,100 GWh of energy produced by other sources.

As shown in Table 7.14, results from GHG modeling found that, when compared to other
forms of electricity generation, the Project would produce among the lowest GHG
emissions per unit of energy produced. Over the next 100 years, the Project would
produce the same or lower GHG emissions than all other options available in B.C. for
the 5,100 GWh of annual energy generation from the Project.

### Table 7.14  Emissions Intensity – Site C Clean Energy Project and Other
Generation Options

<table>
<thead>
<tr>
<th>Generating Facility Type</th>
<th>Range (g CO₂e/kWh)</th>
<th>Average (g CO₂e/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site C Clean Energy Project ¹</td>
<td>N/A</td>
<td>7.8</td>
</tr>
<tr>
<td>Canada Boreal Hydroelectric</td>
<td>8 – 60</td>
<td>36</td>
</tr>
<tr>
<td>Tropical Hydroelectric</td>
<td>1,750 – 2,700</td>
<td>2,150</td>
</tr>
<tr>
<td>Model Coal</td>
<td>959 – 1,042</td>
<td>1,000</td>
</tr>
<tr>
<td>Integrated Gasification Combined Cycle</td>
<td>763 – 833</td>
<td>798</td>
</tr>
<tr>
<td>Diesel</td>
<td>555 – 880</td>
<td>717</td>
</tr>
<tr>
<td>Natural Gas Combined Cycle</td>
<td>469 – 622</td>
<td>545</td>
</tr>
<tr>
<td>Solar Photovoltaic</td>
<td>13 – 104</td>
<td>58</td>
</tr>
<tr>
<td>Wind Turbines</td>
<td>7 – 22</td>
<td>14</td>
</tr>
</tbody>
</table>

¹ Reported Project emissions intensity is based on IPCC – Tier 3 Likely values from Volume 2 Appendix S Greenhouse Gases Technical Report

N/A – Not applicable


As would be expected, the Project would produce less GHGs per gigawatt hour than
fossil fuel sources such as natural gas, diesel, or coal. Emissions intensity from the
Project is more than an order of magnitude lower than the lower emissions intensity from
a thermal generation resource (i.e., natural gas combined cycle generation).
The estimates also suggest that the GHG emissions intensity from the Project would fall within the ranges expected for other renewable sources, such as wind, while outperforming solar photovoltaics.

The Project is in the lower range of GHG emissions intensity for hydroelectric facilities, as a result of the Project being located in a northern environment. Facilities constructed in northern (i.e., temperate and boreal) environments generally emit lower quantities of GHG emissions than tropical reservoirs (Volume 2 Appendix S Greenhouse Gases Technical Report). In addition, cold, deep, well-oxygenated systems emit a higher proportion of CO₂, which has a lower global warming potential than CH₄.

The Project also benefits from requiring a smaller reservoir and footprint than what would normally be required for a hydroelectric project to generate 5,100 GWh. This is a result of the benefit provided by the upstream storage in Williston and Dinosaur reservoirs.

As shown by the analysis of GHG emissions in Volume 2 Appendix S Greenhouse Gases Technical Report, the GHG emissions intensity from the Project will be as low as, or lower, than other generation alternatives. This will benefit the provincial and federal governments by contributing to meeting provincial and federal GHG reduction targets.

### 7.4.3 Integration of Clean or Renewable Resources

Many clean or renewable energy resources — such as wind or run-of-river hydro — are intermittent, as their generation varies with natural factors. In order to integrate these clean or renewable resources into the BC Hydro system and meet electricity demand, this variability must be backed up by dispatchable capacity. The Project provides additional clean and renewable dispatchable capacity to the BC Hydro system and increases the system’s capability to integrate renewable resources such as run-of-river hydro and wind.

As described in Section Volume 1 Section 5.2, run-of-river hydroelectric projects do not have any material amounts of storage, meaning that their output varies with the natural flow in the river. Typically, run-of-river projects generate at full output during the spring and early summer when river flows are high as well as during periods of heavy rain. Generation drops during low flow periods. Refer to Figure 5.5 in Volume 1 Section 5.5.2.1, which shows the annual power output of a typical run-of-river project in the coastal region of B.C. The coastal region of B.C. includes projects in the Lower Mainland and Vancouver Island. Typically, projects in this region have a profile that has slightly more generation in the winter peak than those in the interior of B.C. This is a conservative view of the seasonal variability of run-of-river hydro resources and means that run-of-river projects in the interior of the Province may benefit even more from additional dispatchable capacity and reservoir storage. The output from run-of-river projects is less predictable outside of the spring freshet, which makes it difficult to operate to match demand.

As described in Volume 1 Section 5.2, due to natural variations in wind speed, wind power generation is highly variable in the short-term timescales of seconds to minutes, resulting in the need for additional highly responsive generation capacity reserves on the electric system to maintain system reliability and security. The natural variability in wind power generation also makes it difficult to forecast wind in the hour- to day-ahead time frame, resulting in the need to set aside system flexibility to address the potential for
wind generation to either under- or over-generate in this time frame. Figures 5.6 and Figure 5.7 in Volume 1 Section 5 of this EIS show sample BC Hydro load and wind generation variability from a sample eight-day period in June 2011 and January 2012, respectively.

7.4.3.1 Wind Integration Studies

BC Hydro has identified the integration of wind resources as having a potential effect on the BC Hydro system, and has therefore conducted additional analysis on potential limits to wind generation for the BC Hydro system. The cost associated with reserving system flexibility to integrate wind resources is reflected in the evaluation of alternatives to the Project in Volume 1 Section 5 Need for, Purpose of, and Alternatives to the Project.

Currently, there are three operational wind farms in the Peace Region of B.C. with a combined installed or nameplate capacity of about 380MW supplying BC Hydro’s integrated system. Additional wind generation is expected to be added through existing electric purchase agreements with independent power producers. The effect of wind power generation on electric systems is an area of interest in the electric utility industry. Many wind integration studies have been undertaken, and the knowledge base of the effect of wind integration continues to grow. BC Hydro has reviewed many wind integration studies, utility practices, and regulatory agency proposals in the area of wind integration to inform the analysis of the effect of wind integration on the BC Hydro system. BC Hydro expects that the understanding of the issues surrounding the integration of wind resources will continue to evolve as BC Hydro gains more experience with the operation of wind resources in B.C.

A preliminary analysis has been completed to determine the amount that the Project would increase the maximum amount of wind power that can be integrated into the BC Hydro system without affecting the reliability and security of the system. The results of the analysis show that the wind integration limit could increase by up to 900 MW with the addition of the Project.

7.4.4 Improved Operational Control of Peace River Flows

Improved operational controls will result in two benefits downstream of the Project.

- Improved access to Taylor wells:

  The District of Taylor’s water supply wells are located on a small island close to the left bank of the Peace River, just upstream of the confluence with the Pine River. In the past, District officials have requested low releases of water from Peace Canyon Dam so that they could access their wells for maintenance. However, there is currently no control over flows from the tributaries (primarily coming from the Halfway and Moberly rivers) between Peace Canyon and Taylor.

  With the Project, there would be a larger degree of control over the flows at the Taylor wells since the volume of flows originating from the tributaries between the Project and the wells would be regulated.

- Improved ability to manage risk of ice breakup flooding at the Town of Peace River:

  Flooding has occurred in the past at the Town of Peace River when the Smoky River ice cover breaks up dynamically before the ice cover on the Peace River has regressed downstream of the confluence of the two rivers. BC Hydro controls flow
releases from the W.A.C. Bennett and Peace Canyon dams in order to help manage ice breakup and minimize the risk of flooding. This is discussed in Section 11.7 Thermal and Ice Regime in Volume 2 Section 11 Environmental Background.

The Project would move the point of flow control between 10 and 12 hours closer to the Town of Peace River, providing a faster response time if a particular flow was required in the Peace River at this location to reduce the flooding risk.

7.4.5 Aquatic Productivity Benefits

The Project would result in the creation of a 9,300 hectare reservoir, which would result in an increase in fish habitat area compared to the current river environment. As discussed in Volume 2 Section 12.4.3 Effects Assessment – Operations – Change in Fish Habitat, the increase in fish habitat area is expected to be 3.3 fold.

This increase in fish habitat area and change from a river to a reservoir environment would be accompanied by an increase in certain areas of aquatic productivity.

- Increase in algal biomass both upstream (100-600% increase) and downstream (250% increase) of the dam
- Increase in secondary production in reservoir
- Increase in fish biomass both in the reservoir (200% increase) and downstream of the dam (20-40% increase). This increase will be net across all species – there will be different effects on different species, as discussed in Volume 2 Section 12.4.3 Effects Assessment – Operations – Change in Fish Habitat

7.4.6 Recreation and Tourism Benefits

Fishing opportunities during operations would be expected to increase over baseline conditions as the Site C reservoir would support increased boating and angling use, and would continue to support sport fish.

A positive effect on outdoor recreation is expected during operations after debris clearing and slope stability monitoring. Water-based recreation is expected to increase in the reservoir compared to the baseline conditions as a result of greater potential access by a variety of boats.

7.4.7 Improvements to Public Roads

The design for new construction and upgrades to public roads would be in accordance with applicable British Columbia and Canadian guidelines, codes, supplements, and technical circulars. Upgrades to the provincial and municipal public roads would improve upon existing conditions, and the benefits from road and highway infrastructure improvements completed as part of the Project would be realised into the future. As described in Volume 1 Sections 4.3.4 and 4.3.7, permanent road upgrades are planned on the following existing routes:

- **Realignment of Highway 29**: Realignment of nearly 30 km of existing highway at Lynx Creek, Dry Creek, Farrell Creek, Halfway River and Cache Creek, resulting in geometric and cross-section improvements. Existing issues along Highway 29, particularly at steep and curvilinear sections where the smaller tributaries to the Peace River are crossed by the highway, will be eliminated. At these crossings the
new bridges and highway approach realignments proposed would be constructed to a higher standard than the existing highway, reducing grades and 'flattening' the horizontal curves. As a result, drivers will benefit from travel time savings and road safety will be improved. In addition, the Province benefits from new road and bridge infrastructure.

- **Improvements to the North Bank Roads:**
  - Hard-surface 240 Road and the portion of 269 Road south of the intersection with 240 Road
  - Realign a portion of Old Fort Road south of 240 Road
  - Widen shoulders or add a path on 271 Road between Wuthrich Quarry and Highway 97
  - Potentially widen shoulders or add a path on Old Fort Road between Highway 97 and the realigned segment, and between the end of the realigned segment and the gravel pit entrance at km 5.5
  - Conduct intersection lighting calculations to determine if illumination is warranted and then, in collaboration with BCMoTI, consider installing intersection lighting

  As a result, drivers will benefit from improved driving conditions, road safety will be improved, and cyclists would benefit from wide shoulders or paths.

- **Upgrades to Jackfish Lake Road:**
  - The current network of unpaved resource roads would be upgraded to provide access to the dam site area during the first year of construction, including isolated widening and localized grading, and road base repairs along the 53 km of unpaved resource roads
  - Upgrade about 31 km of the unpaved portion of Jackfish Lake Road, including road base strengthening and hard surfacing, which may require the widening of some sections
  - Examine the feasibility of widening the shoulders along the first 30 km of Jackfish Lake Road to meet current BCMoTI rural collector standards, potentially including two 1.5 m wide paved shoulder

  As a result, drivers will benefit from improved driving conditions, road safety will be improved, and cyclists would benefit from wide shoulders.

- **Construct the Project access road**, a new permanent 33 km road alongside the existing transmission line corridor, extending northeast from the Jackfish Lake Road. While this would be a private road, others would be able to use it, potentially with safety-based restrictions. This may enable decommissioning of other resource roads in the vicinity and consolidate the road with the existing transmission corridor in this area. Benefits of the Project Access Road during construction including improved travel times for workers and deliveries to the dam site, and improved reliability and road safety relative to travelling to and from the dam site during construction on the existing PDR roads.
• **Improvements to Roads in the Hudson’s Hope area:**
  
  o D.A. Thomas Road, which would provide improved vehicle access to the shoreline, berm and proposed day use recreation area and small craft boat launch
  
  o Construct a paved brake check before the grade on Canyon Drive, west of Hudson’s Hope. Also explore opportunities for constructing, and install if feasible, either arrestor beds or runaway lanes, or both, on Canyon Drive above Hudson’s Hope. Construction of the brake check and arrestor bed/runaway lane will improve road safety.

7.4.8 **Transmission System Benefits**

The Site C substation would include 500 kV to 138 kV step-down transformers to provide service to Fort St. John and Taylor, and allow for the removal of the 138 kV lines. The advantages of connecting Fort St. John and Taylor to the new Site C substation would be:

• Improvements in system reliability, as they would be connected to the transmission system at a much closer point

• Reduction in transmission system energy losses for the supply to Fort St. John and Taylor

**References**

**Literature Cited**


**Internet Sites**

8 ASSESSMENT PROCESS

In this section, the environmental assessment process is described as required by Section 6 of the EIS Guidelines.

8.1 Provincial Agencies, Departments, and Organizations

8.1.1 Provincial Agencies

The following provincial agencies, departments, and organizations in British Columbia are involved in the environmental assessment process for the Project:

- Minister of Environment
- Minister of Forests, Lands and Natural Resource Operations
- The Executive Director of the Environmental Assessment Office
- Environmental Assessment Office
- Ministry of Environment
- Ministry of Energy, Mines and Natural Gas
- Ministry of Agriculture (including Agricultural Land Commission)
- Ministry of Justice
- Ministry of Public Safety and Solicitor General
- Ministry of Transportation and Infrastructure
- Ministry of Jobs, Tourism and Skills Training
- British Columbia Utilities Commission
- BC Oil and Gas Commission

8.1.2 Summary of Issues and Concerns Identified by Provincial Agencies

The issues and concerns identified by provincial agencies with respect to the Project are summarized in Volume 1 Section 9.3 Government Agency Information and Distribution.

8.1.3 Issues Tracking Table – Provincial Agencies

A table listing the detailed comments provided by provincial agencies and BC Hydro’s responses to those comments is presented in Volume 1 Appendix I Government Agency Information Distribution and Consultation Supporting Documentation.

8.1.4 Summary of Issues and Concerns Identified by Local and Regional Government Agencies

Issues and concerns identified by local and regional government agencies are summarized in Volume 1 Section 9.1 Public Information Distribution and Consultation.
8.1.5 Issues Tracking Table – Local and Regional Government Agencies
A table listing detailed comments provided by local and regional government agencies and BC Hydro’s responses to those comments is presented in Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation.

8.2 Federal Authorities
The following federal authorities have been involved in the environmental assessment process:

- Minister of Environment
- Canadian Environmental Assessment Agency
- Natural Resources Canada (Major Projects Management Office)
- Natural Resources Canada (Environmental Assessment)
- Natural Resources Canada (Explosives Safety and Security Branch)
- Fisheries and Oceans Canada (Environmental Assessment and Major Projects Unit)
- Fisheries and Oceans Canada (Marine Programs Division)
- Fisheries and Oceans Canada (Cooperative Resource Management Institute)
- Fisheries and Oceans Canada (Environmental Assessment and Major Projects Unit)
- Fisheries and Oceans Canada (Alberta District, Peace River Office)
- Transport Canada (Navigable Waters Protection)
- Transport Canada (Environmental Office)
- Transport Canada (Major Projects Management Office Technical and Environmental Services)
- Environment Canada (Environmental Assessment Unit)
- Environment Canada (Water Science and Technology)
- Environment Canada (Water Resources)
- Environment Canada (Marine Programs Division)
- Environment Canada (Canadian Wildlife Service)
- Environment Canada (Water Quality Branch)
- Environment Canada (Hydrological Process and Modelling Research)
- Health Canada
- Parks Canada (Resource Conservation)

8.2.1 Summary of Issues and Concerns Identified by Federal Authorities
Issues and concerns identified by federal authorities are summarized in Volume 1 Section 9.3 Government Agency Information and Distribution.
8.2.2 Issues Tracking Table – Federal Authorities

A table listing detailed comments provided by federal authorities and BC Hydro’s responses to those comments is presented in Volume 1 Appendix I Government Agency Information Distribution and Consultation Supporting Documentation.

8.3 Cooperative Review Process

8.3.1 Cooperative Review Process Under the B.C./Canada Agreement

As discussed in Volume 1 Section 1 Introduction, in February 2012, the Minister of Environment of British Columbia and the Minister of Environment of Canada entered into the B.C./Canada Agreement. That agreement was amended in September 2012, after the enactment of CEAA 2012.

The preamble of the B.C./Canada Agreement includes the following:

“WHEREAS the federal Minister of the Environment and the provincial Minister of Environment have determined that a cooperative environmental assessment including a joint review panel for the Site C Clean Energy Project will avoid unnecessary duplication and delays that could arise from individual reviews by each government; and agree to establish a joint review panel for the Site C Clean Energy Project…”

8.3.2 Stages of Assessment under the B.C./Canada Agreement

The B.C./Canada Agreement provides for three stages of assessment, the Pre-Panel Stage, the Joint Panel Review Stage, and the Post-Panel Stage (B.C./Canada Agreement, Section 2.1).

8.3.2.1 Pre-Panel Stage

8.3.2.1.1 Duration of the Pre-Panel Stage

The federal and provincial Ministers of Environment, the parties to the B.C./Canada Agreement, do not expect the Pre-Panel Stage to exceed 24 calendar months from August 2, 2011, the date that the Notice of Consideration for the Project was posted on the Agency’s website (B.C./Canada Agreement, Section 3.15.). The 24-month period will end on August 1, 2013.

8.3.2.1.2 Establishment of the Working Group

During the Pre-Panel Stage, the Working Group (also referred to as the Advisory Working Group) was established (B.C./Canada Agreement, Section 3.1).

The following Aboriginal groups and government agencies are members of the Working Group:

Federal Agencies

- Canadian Environmental Assessment Agency
- Environment Canada
Site C Clean Energy Project Environmental Impact Statement
Volume 1: Introduction, Project Planning, and Description
Section 8: Assessment Process

- Fisheries and Oceans Canada
- Health Canada
- Major Project Management Office
- Natural Resources Canada
- Parks Canada
- Transport Canada

B.C. Agencies and Local Governments
- Agricultural Land Commission
- BC Oil and Gas Commission
- British Columbia Utilities Commission
- City of Dawson Creek
- District of Chetwynd
- District of Hudson’s Hope
- District of Mackenzie
- District of Taylor
- District of Tumbler Ridge
- Environmental Assessment Office
- Intergovernmental Relations Secretariat
- Ministry of Transportation and Infrastructure
- Ministry of Aboriginal Relations and Reconciliation
- Ministry of Agriculture
- Ministry of Community, Sport and Cultural Development
- Ministry of Energy, Mines and Natural Gas
- Ministry of Forests, Lands and Natural Resource Operations
- Ministry of Jobs, Tourism and Skills Training
- Northern Health
- Northern Rockies Regional Municipality
- Peace River Regional District
- Village of Pouce Coupe

B.C. Aboriginal Groups
- Blueberry River First Nation
- Doig River First Nation
• Fort Nelson First Nation
• Halfway River First Nation
• Kwadacha First Nation
• McLeod Lake Indian Band
• Métis Nation of British Columbia (invited by Canada)
• Prophet River First Nation
• Saulteau First Nations
• West Moberly First Nations
• Treaty 8 Tribal Association
• Tsay Keh Dene First Nation

**Alberta Agencies and Local Governments**
• Alberta Environment and Sustainable Resource Development
• Birch Hills County
• Clear Hills County
• County of Northern Lights
• Mackenzie County
• Municipal District of Fairview
• Municipal District of Peace
• Municipal District of Spirit River
• Northern Sunrise County
• Saddle Hills County
• Town of Fairview
• Town of Peace River

**Alberta Aboriginal Groups**
• Athabasca Chipewyan First Nation
• Beaver First Nation
• Bigstone Cree Nation
• Chipewyan Prairie First Nation
• Dene Tha’ First Nation
• Driftpile First Nation
• Duncan’s First Nation
• Fort Chipewyan Métis Local 125
• Fort McKay First Nation
• Fort McMurray #468 First Nation
• Horse Lake First Nation
• Kapawe’no First Nation
• Kelly Lake Métis Settlement Society (invited by Canada)
• Little Red River Cree First Nation
• Loon River Cree First Nation
• Lubicon Lake First Nation
• Métis Nation of Alberta Region 6
• Mikisew Cree First Nation
• Paddle Prairie Métis Settlement
• Peerless Trout First Nation
• Sawridge First Nation
• Smith’s Landing First Nation
• Sturgeon Lake Cree First Nation
• Sucker Creek First Nation
• Swan River First Nation
• Tallcree First Nation
• Whitefish Lake First Nation
• Woodland Cree First Nation

Northwest Territories
• Government of the Northwest Territories

Northwest Territories Aboriginal groups
• Akaitcho Territory Government
• Deninu K’ue First Nation
• K’atlodeeche First Nation
• Lutsel K’ee Dene First Nation
• Northwest Territory Métis Nation
• Salt River First Nation #195
• Yellowknives Dene First Nation – Dettah Hayorila
• Yellowknives Dene First Nation – Ndilo Hayorila
Saskatchewan Aboriginal Groups

- Black Lake First Nation
- Clearwater River Dene First Nation
- Fond du Lac First Nation

8.3.2.1.3 Preparation and Review of the Draft EIS Guidelines

During the Pre-Panel Stage, the draft EIS Guidelines were:

- Prepared by BC Hydro (B.C./Canada Agreement, Section 3.4)
- Reviewed by members of the Working Group (B.C./Canada Agreement, Section 3.5)
- Reviewed by members of the public and, again, by some members of the Working Group, during the public comment period (B.C./Canada Agreement, Section 3.6)
- Reviewed by the Agency and the BCEAO

During the preparation of the EIS Guidelines, members of the Working Group, including Aboriginal groups, government agencies, and members of the public, provided comments and information requests, to which BC Hydro provided detailed responses. The issues raised by Aboriginal groups, government agencies, and members of the public are discussed in Sections 9.1, 9.2, and 9.3 in Volume 1 of this EIS. All comments and information requests, and BC Hydro’s detailed responses, are available on the BCEAO and CEA Agency project websites.

8.3.2.1.4 Finalization and Issuance of the EIS Guidelines

During the Pre-Panel Stage, the federal Minister of Environment and the Executive Director of the EAO determined that the EIS Guidelines were adequate. They then finalized the EIS Guidelines. The final EIS Guidelines dated September 5, 2012 were issued by the federal Minister of Environment and the Executive Director of the EAO to BC Hydro on September 7, 2012 (B.C./Canada Agreement, Section 3.8).

8.3.2.1.5 Review of EIS During the Pre-Panel Stage

During the Pre-Panel Stage:

- The Working Group will review the EIS and provide comments and information requests (B.C./Canada Agreement, Section 3.11)
- The EAO and the Agency will make the EIS available for a public comment period of 60 days (B.C./Canada Agreement, Section 3.12)
- BC Hydro will provide detailed responses to the comments and requests from the Working Group (B.C./Canada Agreement, Section 3.11) and to public comments on the EIS received by the EAO and the Agency during the public comment period (B.C./Canada Agreement, Section 3.13)
- The Working Group will consider the public comments and BC Hydro’s responses, and provide advice to the EAO and the Agency (B.C./Canada Agreement, Section 3.13)
After considering the public comments, the comments of the Working Group, and BC Hydro’s responses, the EAO and the Agency will, if required, direct BC Hydro to supplement the EIS (B.C./Canada Agreement, Sections 3.11 and 3.13).

8.3.2.1.6 Determination that the EIS is Satisfactory, Submission to the Joint Review Panel, Completion of the Pre-Panel Stage

During the Pre-Panel Stage, the EAO and Agency will determine when the EIS is satisfactory to them, and direct BC Hydro to submit the EIS to the Panel (B.C./Canada Agreement, Section 3.14.).

At that point, the Pre-Panel Stage will be complete (B.C./Canada Agreement, Section 3.14).

8.3.2.2 Joint Panel Review Stage

8.3.2.2.1 Establishment of a Joint Review Panel

A Joint Review Panel will be established pursuant to CEAA 2012 and BCEAA (B.C./Canada Agreement, Section 4.1).

The Panel must be established within 260 days of the coming into force of CEAA 2012. Since CEAA 2012 came into force on July 6, 2012, pursuant to Order-in-Council (SI/2012-0056), the federal and provincial Ministers of Environment must establish a Joint Review Panel by about March 25, 2013 as the 260th day falls on Saturday, March 23, 2013. Consequently, it is anticipated that the Panel will be appointed during the Project’s Pre-Panel Stage.

8.3.2.2.2 Commencement and Duration of the Joint Review Panel Stage

The Joint Panel Review Stage will commence when BC Hydro submits the EIS to the Panel (B.C./Canada Agreement, Section 3.14).

The Joint Review Panel must satisfy its Terms of Reference and submit its final report to the federal Minister of Environment and to the Executive Director of the EAO within 225 days following the submission of the EIS. This time period does not include any time required by BC Hydro to prepare any additional information required by the Panel (B.C./Canada Agreement, Section 4.5).

The federal Minister of Environment and the provincial Minister of Environment do not expect the Joint Review Panel Stage of the assessment, including preparation and submission of the Joint Review Panel Report, to exceed eight calendar months from the date the EIS is submitted to the Joint Review Panel (B.C./Canada Agreement, Section 4.6).

8.3.2.2.3 Conduct of the Joint Review

The Joint Review Panel will conduct its review in accordance with the requirements of the CEAA 2012 and associated Regulations, and the requirements in the Terms of Reference set out in Appendix 1 of the B.C./Canada Agreement (B.C./Canada Agreement, Section 4.16).

The Panel will conduct its review in a manner that will facilitate the meaningful participation of Aboriginal groups (B.C./Canada Agreement, Section 4.17).
8.3.2.4 **Pre-hearing Review of the EIS**

Before commencing public hearings, the Panel will determine whether the EIS is sufficient for the purpose of giving notice of, and holding, public hearings. It must make this determination in accordance with its Terms of Reference (B.C./Canada Agreement, Section 4.20).

8.3.2.5 **Public Hearings**

The Joint Review Panel will undertake a public hearing. In accordance with Section 4.21 of the B.C./Canada Agreement, the review must provide opportunities for timely and meaningful participation by:

- Aboriginal groups
- The public
- Governments
- Other interested groups
- BC Hydro

8.3.2.6 **Joint Review Panel Report**

The Joint Review Panel must deliver its Joint Review Panel Report within 90 days of the close of the public hearings (B.C./Canada Agreement, Section 4.23).

In the assessment set out in its report, the Panel must include consideration of the factors set out in paragraph 2.2 of its Terms of Reference, the scope of which is set out in the EIS Guidelines.

In respect of the manner in which the Project may adversely affect asserted or established Aboriginal rights and treaty rights, the Panel will receive information and, in its report, make recommendations and describe asserted or established Aboriginal rights and treaty rights, in accordance with paragraphs 2.3, 2.4, and 2.6 of its Terms of Reference. However, under paragraph 2.5 of its Terms of Reference, the Panel will not make any conclusions or recommendations as to:

- The nature and scope of asserted Aboriginal rights or the strength of those asserted rights
- The scope of the Crown’s duty to consult Aboriginal Groups
- Whether the Crown has met its duty to consult Aboriginal Groups and, where appropriate, accommodate their interests in respect of the potential adverse effects of the Project on asserted or established Aboriginal rights or treaty rights
- Whether the Project is an infringement of Treaty 8
- Any matter of treaty interpretation
8.3.2.3 Post-Panel Stage

8.3.2.3.1 Draft Referral Package for the Provincial Ministers

In the Post-Panel Stage, for the purposes of environmental assessment of the Project under BCEAA, the Executive Director of the BCEAO will prepare a referral package for the provincial Ministers of Environment and Forests, Lands and Natural Resource Operations. The referral package will be provided to the Ministers within 45 days of the issuance of the Joint Review Panel Report (B.C./Canada Agreement, Section 8.1).

8.3.2.3.2 Publication of the Joint Review Panel Report

Following the 45-day period, the Joint Review Panel Report will be provided to Aboriginal groups and posted on the websites operated by the Agency and the BCEAO (B.C./Canada Agreement, Section 8.5).

8.3.2.3.3 Preparation and Finalization of Key Provincial and Federal Documents

A steering committee consisting of senior representatives of the BCEAO and the Agency will be established (B.C./Canada Agreement, Section 9.1). Under Section 9.2 of the Agreement, that steering committee will:

“...discuss elements of the proposed provincial response to and the federal Minister’s potential decision on the Joint Review Panel Report, the recommendations and conclusions contained in the Joint Review Panel Report, and key issues and responsibilities respecting these recommendations and conclusions in order for EAO and federal government to prepare and finalize their respective key documents.”

The Ministers of Environment of Canada and British Columbia do not expect the finalization of key provincial and federal documents to exceed 84 days from the day the Joint Review Panel Report is made public (B.C./Canada Agreement, Section 9.3). Section 9.3 also provides that, during the 84-day period:

“...Aboriginal Groups will be consulted on the Joint Review Panel Report and the draft provincial and federal consultation and accommodation reports. Comments will be considered by the federal government and EAO and revisions will be made to the draft reports on consultation and accommodation where appropriate.”

Aboriginal groups will be entitled to provide separate submissions for inclusion in the Referral Package that will be provided to the provincial Ministers (B.C./Canada Agreement, Section 9.4):

“If Aboriginal Groups do not agree with the conclusions of the Joint Review Panel Report or the sections of the provincial report on consultation and accommodation that relate to their interests, they may provide a separate submission to be included in the Referral Package for the provincial Minister of Environment and the other responsible provincial Minister.”

The Executive Director of the BCEAO will finalize the Referral Package for the provincial Ministers of Environment and Forests, Lands and Natural Resource Operations (B.C./Canada Agreement, Section 9.5).

8.3.2.4 Provincial and Federal Environmental Assessment Decision-Making

Within 45 days of receipt of the Referral Package, the provincial Ministers of Environment and Forests, Lands and Natural Resource Operations will make a determination under Section 17(3) of BCEAA. This period of time may be extended by the provincial Minister of Environment (B.C./Canada Agreement, Section 10.3; BCEAA, Section 24).

Within 174 calendar days of receipt of the Joint Panel Review Report, the federal Minister of Environment will issue an environmental assessment decision statement with respect to the Project under Section 54 of CEAA 2012. If the federal Minister of the Environment requires BC Hydro to undertake additional studies or collect additional information in accordance with Section 47(2) of the CEAA 2012, the time required by the proponent to prepare and submit this information will not be included in this 174 calendar-day period (B.C./Canada Agreement, Section 10.4).

8.3.2.4 Record of the Joint Review

The record upon which the joint review is to be conducted must be maintained in a public registry:

- By the Agency, in compliance with Sections 45(4), 45(5), and 78 to 81 of CEAA 2012 (B.C./Canada Agreement, Sections 5.1, 5.3)
- By the BCEAO, in compliance with Section 25 of BCEAA (B.C./Canada Agreement, Section 5.2)

8.3.3 Preparation of the EIS Guidelines

The EIS Guidelines were drafted, reviewed, finalized, and issued in accordance with the procedure set out in Sections 3.4 through 3.8 of the B.C./Canada Agreement.

8.3.3.1 BC Hydro’s Preparation of the Draft EIS Guidelines

BC Hydro prepared and submitted draft EIS Guidelines as required by Section 3.4 of the B.C./Canada Agreement. The draft EIS Guidelines were submitted to the BCEAO and the Agency on January 26, 2012.

8.3.3.2 Review by the EAO, the Agency and the Working Group, and the Public

Separate sets of comments were received from members of the Working Group. In total, the members of the Working Group provided 1,007 comments.

BC Hydro prepared detailed responses to each comment. BC Hydro also prepared separate written summaries, each referred to as a “Topic Summary”, with respect to a number of key issues that arose from the comments.

On March 30, 2012, BC Hydro submitted:

- A tracking table with BC Hydro’s detailed response to each comment
The BCEAO and the CEA Agency revised the draft EIS Guidelines and, on April 10, 2012, posted the draft for public comment. In the public comment period, members of the public provided comments. In addition, several members of the Working Group also provided further comments. The issues of concern to various Aboriginal groups, various government agencies, and members of the public are discussed in Volume 1 Sections 9.1, 9.2, and 9.3 of this EIS.

On June 1, 2012, BC Hydro submitted its own comments on the version of the draft EIS Guidelines posted by the BCEAO and the Agency on April 10, 2012.

On June 27, 2012, BC Hydro submitted:

- A tracking table with BC Hydro’s detailed response to each comment received during the public comment period
- A set of revised and additional Topic Summaries

**8.3.3.3 Finalization and Issuance of the EIS Guidelines by the Federal Minister of the Environment and the Executive Director of the BCEAO**

On September 7, 2012, after completion of the process prescribed in the B.C./Canada Agreement, the Executive Director of the BCEAO and the Minister of Environment for Canada issued the EIS Guidelines dated September 5, 2012.

**8.4 Permitting**

In addition to the requirements under CEAA 2012 and BCEAA to conduct an environmental assessment, a number of federal and provincial permits would be required for construction and operation of the Project. Under Section 32 of the *Hydro and Power Authority Act*, R.S.B.C., 1996, c. 212, except as otherwise provided under that Act, BC Hydro is not bound by any statute or statutory provision of British Columbia. A list of potential key federal and provincial permits that would be required by BC Hydro for construction or operation is shown in Table 8.1.
### Table 8.1 Potential Key Federal and Provincial Permits that would be Required for the Project

<table>
<thead>
<tr>
<th>Act</th>
<th>Section(s)</th>
<th>Name of Permit</th>
<th>Ministry/Agency</th>
<th>Permit Description or Purpose</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Federal</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Canada Transportation Act; Railway Safety Act</td>
<td></td>
<td>Crossing Agreement</td>
<td>CN Rail</td>
<td>Negotiated agreement with the railway covering all construction and maintenance issues</td>
</tr>
<tr>
<td>Explosives Act</td>
<td>7(1)(a)</td>
<td>Licence</td>
<td>Natural Resources Canada</td>
<td>Authorization for an explosives factory or magazine explosives licence</td>
</tr>
<tr>
<td>Explosives Act</td>
<td>7(1)(b)</td>
<td>Permit to Transport Explosives</td>
<td>Natural Resources Canada</td>
<td>For vehicles used for the transportation of explosives</td>
</tr>
<tr>
<td>Fisheries Act</td>
<td>26</td>
<td>Authorization</td>
<td>Fisheries and Oceans Canada</td>
<td>For works or undertakings affecting fish habitat</td>
</tr>
<tr>
<td>Fisheries Act</td>
<td>29</td>
<td>Authorization</td>
<td>Fisheries and Oceans Canada</td>
<td>For obstruction of the passage of fish</td>
</tr>
<tr>
<td>Fisheries Act</td>
<td>35(2)</td>
<td>Authorization</td>
<td>Fisheries and Oceans Canada</td>
<td>For “harmful alteration, disruption or destruction” (HADD) of aquatic habitat</td>
</tr>
<tr>
<td>Fisheries Act</td>
<td>32</td>
<td>Authorization</td>
<td>Fisheries and Oceans Canada</td>
<td>For killing of fish</td>
</tr>
<tr>
<td>Migratory Birds Convention Act and Migratory Birds Regulations</td>
<td>4</td>
<td>Special Permit</td>
<td>Environment Canada</td>
<td>Impacts or alterations to migratory bird nests or individuals or deposition of deleterious substances that may impact migratory birds</td>
</tr>
<tr>
<td>Navigable Waters Protection Act</td>
<td>5</td>
<td>Approval</td>
<td>Transport Canada</td>
<td>For any works built or placed in, on, over, under, through, or across a navigable water</td>
</tr>
<tr>
<td>Radio Communication Act</td>
<td>5</td>
<td>Licences</td>
<td>Industry Canada</td>
<td>Authorization for use of radios on-site</td>
</tr>
</tbody>
</table>
### Site C Clean Energy Project Environmental Impact Statement

**Volume 1: Introduction, Project Planning, and Description**

**Section 8: Assessment Process**

<table>
<thead>
<tr>
<th>Act</th>
<th>Section(s)</th>
<th>Name of Permit</th>
<th>Ministry/Agency</th>
<th>Permit Description or Purpose</th>
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<tbody>
<tr>
<td><strong>Transportation of Dangerous Goods Act</strong></td>
<td>14</td>
<td>Safety Compliance or Permit</td>
<td>Transport Canada</td>
<td></td>
</tr>
<tr>
<td><strong>and Transportation of Dangerous Goods Regulations</strong></td>
<td></td>
<td></td>
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</tbody>
</table>

**British Columbia**

<table>
<thead>
<tr>
<th>Act</th>
<th>Section(s)</th>
<th>Name of Permit</th>
<th>Ministry/Agency</th>
<th>Permit Description or Purpose</th>
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<tbody>
<tr>
<td>Agricultural Land Commission Act</td>
<td>16</td>
<td>Approval</td>
<td>Agricultural Land Commission</td>
<td>To remove land from the Agricultural Land Reserve</td>
</tr>
<tr>
<td>Agricultural Land Commission Act</td>
<td>20</td>
<td>Non-farm Use Permit</td>
<td>Agricultural Land Commission</td>
<td>To use land in the Agricultural Land Reserve for a non-farm purpose</td>
</tr>
<tr>
<td>Agricultural Land Commission Act</td>
<td>20(4)</td>
<td>Soil Removal Notification</td>
<td>Agricultural Land Commission</td>
<td>For removal of soil, which is considered a non-farm use under Section 20(2)</td>
</tr>
<tr>
<td>Commercial Transport Act</td>
<td>8</td>
<td>Crossing Permit</td>
<td>Ministry of Transportation and Infrastructure</td>
<td>For operation of a commercial vehicle along a highway</td>
</tr>
<tr>
<td>Commercial Transport Act</td>
<td>8</td>
<td>Approval for oversize loads or bulk haul</td>
<td>Ministry of Transportation and Infrastructure</td>
<td>Approval of oversize, over-height, overweight loads, or bulk hauls on highways</td>
</tr>
<tr>
<td>Cremation, Interment and Funeral Services Act</td>
<td>19(2)</td>
<td>Authorization to disinter or remove human remains</td>
<td>Business Practices and Consumer Protection BC</td>
<td>Refers to human remains not located in a registered cemetery or regulated under the Heritage Conservation Act or Coroners Act</td>
</tr>
<tr>
<td>Drinking Water Protection Act</td>
<td>7 and 8</td>
<td>Construction and Operating Permits</td>
<td>Ministry of Health (Northern Health Authority)</td>
<td>For provision of drinking water related to worker accommodations</td>
</tr>
<tr>
<td>Electrical Safety Act – Safety Standards Act</td>
<td></td>
<td>Permits</td>
<td>BC Safety Authority</td>
<td>For electrical services or gas-fired equipment for worker accommodations facilities</td>
</tr>
<tr>
<td>Act</td>
<td>Section(s)</td>
<td>Name of Permit</td>
<td>Ministry/Agency</td>
<td>Permit Description or Purpose</td>
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</tr>
<tr>
<td>Environmental Management Act</td>
<td>14</td>
<td>Permits</td>
<td>Ministry of Environment</td>
<td>For disposal of waste products (effluents, sewage, refuse)</td>
</tr>
<tr>
<td>Environmental Management Act –</td>
<td>43</td>
<td>Hazardous Waste Registration</td>
<td>Ministry of Environment</td>
<td>Required to produce, store, treat, recycle, or discharge more than a prescribed quantity of hazardous waste within 30 days</td>
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<tr>
<td>Hazardous Waste Regulation</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Environmental Management Act –</td>
<td>45</td>
<td>Hazardous Waste Transport Licence</td>
<td>Ministry of Environment</td>
<td>To transport hazardous waste within the province of British Columbia under the conditions as specified on the licence</td>
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<td>Hazardous Waste Regulation</td>
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<tr>
<td>Environmental Management Act –</td>
<td>55</td>
<td>Contaminated Soil Relocation Agreement</td>
<td>Ministry of Environment</td>
<td>Necessary if soil or sediment is being moved and exceeds a defined &quot;trigger value&quot; in the Contaminated Soil Regulation</td>
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<td>Contaminated Soil Regulation</td>
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<tr>
<td>Forest Act</td>
<td>113</td>
<td>Cruise Plan Approval</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>For Crown timber disposed of under the Forest Act</td>
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<tr>
<td>Forest Act</td>
<td>47.4</td>
<td>Occupant Licence to Cut</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>Authorizes the cutting, or cutting and removal, of Crown timber from Crown land or private land</td>
</tr>
<tr>
<td>Forest Act</td>
<td>52</td>
<td>Authorization</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>Authorizes the cutting, or cutting and removal, of Crown timber from Crown land or private land</td>
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<tr>
<td>Forest Act</td>
<td>117–119</td>
<td>Road Use Permit</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>For industrial use of Forest Service Roads</td>
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<tr>
<td>Forest Act</td>
<td>115</td>
<td>Special Use Permit and Works Permit</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>For construction and maintenance of a road, including construction and maintenance of bridges and other drainage structures</td>
</tr>
<tr>
<td>Forest Act – Timber Marking and</td>
<td>84</td>
<td>Timber Transport Permit</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>To transport timber from its harvest location</td>
</tr>
<tr>
<td>Transportation Regulation</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Act | Section(s) | Name of Permit | Ministry/Agency | Permit Description or Purpose
--- | --- | --- | --- | ---
*Forest Act – Timber Marking and Transportation Regulation* | 85 | Timber Mark Certificate | Ministry of Forests, Lands and Natural Resource Operations | For cut timber before it may be removed from the land where the timber was cut
*Forest and Range Practices Act* | | Variances and Exemptions | Ministry of Forests, Lands and Natural Resource Operations | Variances and exemptions for various aspects of the *Forest and Range Practices Act*
*Heritage Conservation Act* | 12 | Site Alteration Permit | Ministry of Forests, Lands and Natural Resource Operations | Authorizes the removal of residual archaeological deposits once inspection and investigation are completed to the satisfaction of the Archaeology Branch
*Heritage Conservation Act* | 14 | Inspection Permit | Ministry of Forests, Lands and Natural Resource Operations | Authority to assess the archaeological significance of land or other property
*Heritage Conservation Act* | 14 | Investigation Permit | Ministry of Forests, Lands and Natural Resource Operations | Authority to recover information that might otherwise be lost as a result of site alteration or destruction
*Industrial Roads Act* | 5 | Junction Permit | Ministry of Transportation and Infrastructure | To cross provincial highways with access roads
*Industrial Roads Act* | 16 | Approval | Ministry of Transportation and Infrastructure | To act as administrator of an industrial road
*Integrated Pest Management Act* | 6 | Permit to use Pesticide | Ministry of Environment | For the use of a prescribed pesticide or class of pesticides
*Land Act* | 48 or 51 | Issue of Crown Grant | Ministry of Forests, Lands and Natural Resource Operations | Fee simple with full property rights. Section 51 applies specifically to government corporations and bodies.
<table>
<thead>
<tr>
<th>Act</th>
<th>Section(s)</th>
<th>Name of Permit</th>
<th>Ministry/Agency</th>
<th>Permit Description or Purpose</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land Act</td>
<td>38</td>
<td>Licence of Occupation Quarries</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>Right to modify the land and/or construct improvements as specified in the tenure contract. The tenure holder has exclusive use.</td>
</tr>
<tr>
<td>Land Act</td>
<td>15 and 16</td>
<td>Reserves and Notifications</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td></td>
</tr>
<tr>
<td>Land Act</td>
<td>80</td>
<td>Public Road Dedication</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td></td>
</tr>
<tr>
<td>Land Act</td>
<td>14</td>
<td>Works Permit</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>For construction and use of roads</td>
</tr>
<tr>
<td>Land Act</td>
<td>107</td>
<td>Road Dedication</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td></td>
</tr>
<tr>
<td>Mines Act</td>
<td>10</td>
<td>Aggregate and Quarry Mine Permit</td>
<td>Ministry of Energy and Mines</td>
<td>For any work in, on, or about a mine. For ≥ 250,000 tonnes per year with blasting.</td>
</tr>
<tr>
<td>Mines Act</td>
<td>10</td>
<td>Aggregate and Quarry Mine Permit</td>
<td>Ministry of Energy and Mines</td>
<td>For any work in, on, or about a mine. For &lt; 250,000 tonnes per year, no blasting.</td>
</tr>
<tr>
<td>Mining Right of Way Act</td>
<td>3 and 4</td>
<td>Mining Right-of-Way Permit</td>
<td>Ministry of Energy and Mines</td>
<td>Authority to take or use Crown or private land for a right-of-way access to the mine</td>
</tr>
<tr>
<td>Act</td>
<td>Section(s)</td>
<td>Name of Permit</td>
<td>Ministry/Agency</td>
<td>Permit Description or Purpose</td>
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</tr>
<tr>
<td><em>Public Health Act and Food Premises Regulation</em></td>
<td>8</td>
<td>Food Premises Authorization</td>
<td>Ministry of Health (Northern Health Authority)</td>
<td>For food premises related to worker accommodations</td>
</tr>
<tr>
<td><em>Public Health Act - Sewerage System Regulation</em></td>
<td>9</td>
<td>Sewage Certification Letter</td>
<td>Ministry of Health (Northern Health Authority)</td>
<td>For disposal of sewage related to worker accommodations</td>
</tr>
<tr>
<td><em>Transport of Dangerous Goods Act</em></td>
<td>4</td>
<td>Transport of Dangerous Goods</td>
<td>Ministry of Transportation and Infrastructure</td>
<td></td>
</tr>
<tr>
<td><em>Transportation Act</em></td>
<td></td>
<td>Approval to Connect to Public Highway</td>
<td>Ministry of Transportation and Infrastructure</td>
<td></td>
</tr>
<tr>
<td><em>Transportation Act</em></td>
<td>48</td>
<td>Highway Access Permit</td>
<td>Ministry of Transportation and Infrastructure</td>
<td>For highways that have been designated as &quot;controlled access&quot;</td>
</tr>
<tr>
<td><em>Transportation Act</em></td>
<td></td>
<td>Infrastructure Upgrade Agreement</td>
<td>Ministry of Transportation and Infrastructure</td>
<td>For upgrades to shoulders, secondary roads, bridges, culverts, resource roads</td>
</tr>
<tr>
<td><em>Transportation Act</em></td>
<td>60(1)</td>
<td>Permission for Road Closures</td>
<td>Ministry of Transportation and Infrastructure</td>
<td>To close roads during construction</td>
</tr>
<tr>
<td><em>Transportation Act</em></td>
<td></td>
<td>Utility Permit</td>
<td>Ministry of Transportation and Infrastructure</td>
<td>To construct utilities within the provincial highway right-of-way</td>
</tr>
<tr>
<td><em>Transportation Act</em></td>
<td>62</td>
<td>Works Permit</td>
<td>Ministry of Transportation and Infrastructure</td>
<td>To construct works within a highway right-of-way</td>
</tr>
<tr>
<td><em>Water Act</em></td>
<td>12(2)</td>
<td>Water Licence</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>Authority to store, use, and/or divert surface water including installation of works</td>
</tr>
<tr>
<td>Act</td>
<td>Section(s)</td>
<td>Name of Permit</td>
<td>Ministry/Agency</td>
<td>Permit Description or Purpose</td>
</tr>
<tr>
<td>----------------------------</td>
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<td>------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Water Act</td>
<td>26</td>
<td>Permit</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>To authorize the flooding of Crown land, or the construction, maintenance, or operation on the land, of works authorized under a licence or approval</td>
</tr>
<tr>
<td>Water Act</td>
<td>44</td>
<td>Order in Council</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>Reservation of water</td>
</tr>
<tr>
<td>Water Act</td>
<td>8</td>
<td>Approval</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>For temporary use of water</td>
</tr>
<tr>
<td>Water Act</td>
<td>9</td>
<td>Approval</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>For work in and about a watercourse</td>
</tr>
<tr>
<td>Wildfire Act and Wildfire Regulation</td>
<td>24(1) and E21</td>
<td>Burn Registration Number</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>For disposal of non-merchantable materials or materials not removed from site</td>
</tr>
<tr>
<td>Wildlife Act</td>
<td>40</td>
<td>Notification for temporary closure</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>Notification if temporary closure to hunting, trapping, and guide outfitting is required during construction</td>
</tr>
<tr>
<td>Wildlife Act</td>
<td>19(1)</td>
<td>Wildlife Permit</td>
<td>Ministry of Forests, Lands and Natural Resource Operations</td>
<td>For capture, killing, removal, or relocation of fish and wildlife. Required for compliance with Sections 9 and 34.</td>
</tr>
</tbody>
</table>
9 INFORMATION DISTRIBUTION AND CONSULTATION

In accordance with Section 7 of the EIS Guidelines, Section 9 describes the Project’s information distribution and consultation program with the public (Section 9.1), Aboriginal groups (Section 9.2), and government agencies (Section 9.3). For the purpose of Section 9.1, the “public” is defined to consist of local and regional governments, communities, stakeholders, property owners, and the general public. Section 9.3 on government agency consultation includes federal, provincial, and territorial governments and agencies.

Sections 9.1, 9.2, and 9.3 below each describe the information distribution and consultation activities for the public, Aboriginal groups, and government agencies, respectively, that were conducted prior to and during the environmental assessment process. This includes the pre-Panel Review Stage and communication that would occur during construction.

Each section includes a summary of issues, concerns, and interests, based on input provided by the public, Aboriginal groups, and government agencies. These are presented in the form of tracking tables provided in the following appendices:

- Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation (Parts 1-3)
- Volume 1 Appendix H Aboriginal Information Distribution and Consultation Supporting Documentation
- Volume 1 Appendix I Government Agency Information Distribution and Consultation Supporting Documentation

Any outstanding issues and processes to resolve them are included in each section below, where applicable.

9.1 Public Information Distribution and Consultation

This section describes BC Hydro’s information distribution and consultation activities undertaken with the public, as defined above. This section is divided into four subsections.

Section 9.1.1 provides historical background to the public information distribution and consultation program for the Project.

Section 9.1.2 provides a description of the public information distribution and consultation program leading up to and including the pre-Panel Review Stage. Details include the purpose, methods, and activities BC Hydro used to inform and consult with the public. This section also describes the communication and public notification activities relating to the EIS Guidelines and the EIS, including how public input was received and responded to during the public comment period for the EIS Guidelines, and the expected information and distribution activities anticipated during the public comment period for the EIS.
Section 9.1.3 provides the sources of input for the issues and interests identified by the public during the Project's public information distribution and consultation activities during the pre-Panel Review Stage, how those issues were considered by BC Hydro, and how they are summarized in issues tracking tables. A similar summary is provided with respect to issues identified by local and regional governments, and with respect to issues identified by the public during the public comment period for the EIS Guidelines. Section 9.1.4 provides an outline of the communications and community relations that would be carried out during construction.

9.1.1 Background

In the late 1950s, the location known as “Site C” was identified as a potential third dam and hydroelectric generating station on the Peace River. In the late 1970s, “Site C” was examined further by BC Hydro and the provincial government as a potential source of hydroelectric power for British Columbia. In advance of an application to the British Columbia Utilities Commission (BCUC) to develop the site, BC Hydro began public meetings in 1977. Additional public meetings and open houses were held prior to the filing of an application for an Energy Project Certificate with the BCUC in 1981. In 1983, the BCUC concluded that construction of a dam at “Site C” was an acceptable project, but indicated that more information was required around the future demand for electricity and alternatives to the project. BC Hydro undertook no further public consultation until 1989. Between 1989 and 1991, there was further consultation when the development of a hydroelectric dam at “Site C” was again examined. In 1991, the provincial government suspended this option in favour of demand-side management.

In 2007, the provincial government’s BC Energy Plan directed BC Hydro to “enter into initial discussions with First Nations, the Province of Alberta, and communities to discuss Site C [the current Project, as defined by this EIS] to ensure that communications regarding the potential project and the processes being followed are well known.” Based on this direction, BC Hydro designed a multi-phased public information and consultation program that provided opportunities for public input early in project planning, as well as throughout project planning and design (2007–2012). BC Hydro initiated its multi-phased program by conducting pre-consultation with members of the public, seeking input regarding how they wanted to be consulted and on what topics.

9.1.2 Pre-Panel Review Stage

The following sections describe the Project’s public information distribution and consultation program leading up to and including the pre-Panel Review stage.

9.1.2.1 Purpose

The purpose of BC Hydro’s public information distribution and consultation program has been to:

• Consult on components of the Project and its potential effects and benefits
• Consider public input in the context of technical, environmental, economic, health, social, and heritage information

• Keep communities, stakeholders, property owners, and the general public informed about the proposed Project and the opportunities for public participation

9.1.2.2 Information Distribution: Methods and Activities

The following subsections describe the methods and activities used by BC Hydro to exchange and disseminate Project information. Consultation methods and activities are described below in Section 9.1.2.3.

The information distribution methods and activities include:

• Community relations
• Project website
• Field study notices and project information sheets
• Public inquiries
• Business liaison program
• Media relations

9.1.2.2.1 Community Relations

In 2007, BC Hydro initiated a community relations program that will continue through all stages of the Project. The program provides an avenue for the public to receive information about the Project, and to ask questions and provide comments regarding the Project outside of formal consultation periods. The program also provides a mechanism for notification of ongoing consultation opportunities.

The community relations program consists of the following:

• Community consultation offices in Fort St. John and Hudson’s Hope
• Regular and ongoing field study communications
• Regular and ongoing presentations and meetings with stakeholders and community groups
• Community outreach, defined as the sharing of Project updates and Project information as part of a larger BC Hydro- or community-sponsored event, such as a trade show

The objective of the Project’s community relations program has been, and will continue to be, to provide timely information to the public, and to address their inquiries in an effective and timely manner.

See Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 6 Public Information Materials and Part 7 Community Outreach Activities for two documents that provide information on the Project’s community relations activities:

• Part 6 Public Information Materials lists the field studies, Project information, Project updates, maps, and field study outlines that have been posted on the Project website
Part 7 Community Outreach Activities provides a list and description of the Project’s community outreach activities from 2007 to November 30, 2012. In total, BC Hydro conducted or participated in 161 activities (e.g., project updates at trade shows, etc.).

9.1.2.2 Project Website

The Project website (www.bchydro.com/sitec) was launched in December 2007 and provides comprehensive Project information, contact information, and current news about the Project, as well as notices about public consultation opportunities.

The website contains the following sections:

- **About Site C** – This section provides current news and background information about the Project, such as Project updates and bulletins, information sheets, brochures, and videos. At the request of the public, orthophotographical maps were also added to the website. The maps show the location of the Project and reservoir area, preliminary impact lines, and preferred Highway 29 realignments.

- **Where We Are Today** – This section provides information about BC Hydro’s multi-staged approach to evaluating the Project. Specific information about field studies taking place in the Project activity zone is also located in this section. BC Hydro has provided and published information notices about all studies taking place in the Project activity zone since 2008.

- **Consulting With You** – This section provides information about consultation opportunities for the public and Aboriginal groups.

- **Site C Reports** – This section includes more than 150 reports about the Project and is organized by subject. In addition to reports on environmental, engineering, and technical studies, the website also includes historical reports from the 1990s.

- **Business and Job Opportunities** – Information about employment and contractor opportunities with the Project is located in this section, as well as information about business information sessions and registration forms for the Site C Business Directory. (See Section 9.1.2.2.5 Business Liaison Program for more information.)

- **Contact Us** – This section contains contact information for the two community consultation offices and office hours, as well as a toll-free line, mailing address, fax number, and an option to receive email alerts about the Project.

- **Frequently Asked Questions** – This section contains a list of common questions and answers about the Project.

9.1.2.2.3 Field Study Notices and Project Information Sheets

BC Hydro provided regular and ongoing notification regarding technical and environmental field studies and activities taking place in the Project activity zone. These field study notices, as well as information sheets, have been posted to the Site C website and at the Site C community consultation offices in Fort St. John and Hudson’s Hope. See Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 6 Public Information Materials for a full listing.
9.1.2.2.4 Public Inquiries

In 2007, BC Hydro established a program to respond to public inquiries about the Project. Public inquiries have been made through the Project’s toll-free information line, by email, fax, mail, and in person at the community consultation offices. Between December 1, 2007 and November 15, 2012, a total of 2,902 public inquiries were recorded.

Inquiry topics included, but were not exclusive to (listed in order of most frequent to least frequent): general information about the Project; expressions of support for the Project; business and procurement opportunities; expressions of opposition to the Project; environment and wildlife; First Nations; flooding and water management; Highway 29; recreation; Project timeline; and transmission.

For a full list of the type and source of public inquiries, see Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 5 Public Inquiries.

9.1.2.2.5 Business Liaison Program

The Project established a Business Liaison Program to:

- Keep the business community updated on the status of the Project
- Inform and engage the B.C. business community on future Site C business opportunities

To meet the objectives of the program, the Project established a business directory and conducted business information sessions, as described below.

Business Directory

The Site C Business Directory provides information about possible business opportunities with the Project. Registered companies receive updates, via email, on potential business opportunities as they arise, including notifications about events such as Site C Business Information Sessions.

As of November 30, 2012, there were 512 companies registered with the Site C Business Directory.

Business Information Sessions

Business information sessions on the Project were held in the communities of Chetwynd, Dawson Creek, Fort St. John, Prince George, and Vancouver in fall 2011 and fall 2012. An additional session in the District of Hudson’s Hope was added in fall 2012. BC Hydro partnered with business organizations and the District of Hudson’s Hope to host and promote the business information sessions.

The sessions provided an early opportunity for businesses to hear directly from members of the Project team about Project design, as well as about potential future business opportunities. Attendees were asked to provide feedback on how they would like to be engaged about potential business opportunities in the future.

A total of 372 people attended the November 2011 business information sessions, and 52 individuals completed registration forms for the Site C Business Directory.
Information contained in the feedback forms from the November 2011 sessions indicated that 95% of respondents said they would be interested in attending a business information session in the future. Based on that feedback, a second round of business information sessions was held in November 2012 in the same five communities, with the addition of Hudson’s Hope.

A total of 313 people attended the November 2012 business information sessions, and 41 individuals completed registration forms for the Site C Business Directory. At that session, 99% of respondents indicated they would be interested in attending a business information session in the future.

See Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 8 Business Liaison Program for more information about the Business Directory and for copies of the December 2011 and December 2012 Site C Business Information Sessions Summary reports.

9.1.2.6 Media Relations

In 2007, a media spokesperson for the Project was assigned to respond to media inquiries. Media relations activities were designed to be responsive and inform the media and its audiences about the Project, as well as provide a forum for public notification of consultation opportunities. Media relations activities included:

- Responding to media inquiries and interview requests
- Submitting letters to the editor
- Providing technical media briefings as required
- Submitting Information Bulletins/News Releases
- Notifying media of opportunities for public consultation and other events

9.1.2.3 Public Consultation: Methods and Activities

In addition to sharing and distributing information as described in the previous section, BC Hydro conducted consultation with the public leading up to and including the pre-Panel Review stage. Public consultation included asking for public comment about the consultation process itself, Project design features, and potential Project effects, including draft mitigation plans.

This section describes consultation activities with the public, including:

- Consultation methods
- Public notification
- Consultation activities and topics
- Reporting
- Public opinion research

A summary of issues, concerns and interests – based on input provided by the public and stakeholders – and how BC Hydro has considered them in project planning and design, is outlined in Volume 1 Appendix G Public Information Distribution and
Consultation Supporting Documentation, Part 1 Public and Stakeholder Issues and Interests Tracking Table.

Additionally, a summary of issues, concerns and interests – based on input provided by regional and local governments – and how BC Hydro has considered them in project planning and design, is outlined in Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 2 Regional and Local Government Liaison Program Summary, and Issues and Interests Tracking Table.

9.1.2.3.1 Consultation Methods

Methods used for consultation included the following:

- **Community Consultation Offices**: BC Hydro opened a community consultation office in Fort St. John on January 7, 2008, and based on community feedback, opened another office in Hudson’s Hope on October 7, 2008. The offices are staffed by Project employees (the Hudson’s Hope office is staffed one day per week; the Fort St. John office is staffed five days per week) to provide a location where the public can get information about the Project, ask questions, and submit feedback forms or written submissions.

- **Consultation Discussion Guides and Feedback Forms**: A discussion guide was produced for each round of consultation. The discussion guides provided information such as an overview of the Project, the current stage of project planning, and how public input would be used and considered, as well as technical information (graphs or maps) specific to each topic of consultation.

- Each discussion guide also included feedback forms with specific questions related to consultation topics, as well as space for participants to provide additional feedback on any topic related to the Project. Online feedback forms were also available through the Project website.

- **Open Houses**: Open houses provided an opportunity for the public to read information about the Project provided in the discussion guides, view display boards and wall-sized maps, and to have one-on-one or small-group discussions with members of the Project team and subject matter experts. At many open houses, a question-and-answer session was also held, moderated by a professional facilitator. When a question-and-answer session was held, meeting notes were taken that were subsequently made available on the Project website.

- **Stakeholder Meetings**: Meetings were held with groups of stakeholders consisting of 10 to 40 people. At these meetings, participants were provided with a discussion guide and feedback form, and Project subject matter experts were available to present information and answer questions. Stakeholder meetings were moderated by a professional facilitator. Meeting notes were taken and subsequently made available on the Project website. See Section 9.1.2.3.2 Public Notification below for more information about stakeholders.
• **Property Owner Meetings**: Meetings were held with property owners potentially directly affected by the Project. Most meetings took place with individual property owners, but some were held as small-group meetings on specific issues of interest. BC Hydro also conducted specific meetings with property owners potentially affected by realignment of segments of Highway 29, reservoir creation and impact lines, transportation infrastructure, and sources of construction materials.

• **Submissions**: The Project received public submissions and input about the Project through email, mail, fax, and the Project’s toll-free line.

• **Website/Email**: All consultation materials were posted to the Project website (www.bchydro.com/sitec), including a feedback form that could be completed online.

• **Toll-free line**: Consultation input was received through phone calls to the Project’s toll-free line (1-877-217-0777).

• **Public Opinion Research**: BC Hydro conducted two province-wide public opinion polls regarding the Project, one in 2008 and one in 2012. For more information, see Section 9.1.2.3.5 Public Opinion Research.

• **Fact Sheets**: Fact sheets were produced for topics of high interest (such as agriculture, consultation opportunities, and impact lines) and were available on the Project website and at consultation events.

9.1.2.3.2 **Public Notification**

• **Stakeholder identification**: BC Hydro’s water use planning processes, long-term electricity planning processes and several stages of consultation about Site C helped the Project team identify and develop a preliminary list of potential stakeholders who might be interested in consultation opportunities regarding the Project. Local governments and regional districts were also added to this stakeholder list.

BC Hydro also undertook broad public notification to encourage participation in the consultation process. Members of the public and stakeholder organizations were added to the stakeholder list over time and include:

  o Those who signed up to receive updates through the Project website
  o Members of the public who participated in stakeholder meetings and open houses
  o Members of the public who submitted feedback during consultation or submitted an inquiry through the public inquiry program
  o Those who signed up to the Site C Business Directory or attended a business information session

• **Newspaper/radio ads**: Prior to each round of public consultation, notification of consultation opportunities (stakeholder meetings, open houses, and online consultation) were placed in newspapers in the northern B.C. (see listing below) and, when appropriate, in the *Vancouver Sun* and *Business in Vancouver*.

Northern and other provincial B.C. media included:

  Newspapers
  o *Alaska Highway News*
• **Emails to stakeholder list**: BC Hydro sent invitation emails to stakeholders inviting them to participate in stakeholder meetings, open houses, or to complete online feedback forms.

• **BC Hydro bill inserts**: Approximately 1.3 million residential BC Hydro customers received a bill insert regarding the Project and opportunities to participate in
consultation. These inserts were sent prior to Project Definition Consultation, fall 2008 and Project Definition Consultation, spring 2012.

- **Project updates**: BC Hydro produced Project updates with notification of opportunities to participate in consultation, which were emailed to those who signed up for Project updates.

- **Website**: The Project website was updated with opportunities to participate in consultation.

- **Householder notification**: BC Hydro sent household mailers to approximately 21,000 households in the Peace River region prior to periods of consultation. The mailers included information about opportunities to participate in consultation, the topics of consultation, and the schedule of open houses.

- **Phone call notification/reminders**: Prior to each round of consultation, reminder phone calls were made to those who were sent email invitations.

- **Media**: Media in the Peace River region were advised of the consultation opportunities in their communities. This usually led to stories regarding the consultation process, which included links to the Project website or consultation meeting dates and times.

### 9.1.2.3.3 Consultation Activities

The following section summarizes BC Hydro-led public consultation activities completed to date.

**Pre-Consultation, December 2007 – February 2008**

During pre-consultation (December 2007 to February 2008), BC Hydro asked the public across British Columbia how they wanted to be consulted and about what topics they wished to discuss during consultation for the Project.

In total, there were 992 participant interactions during pre-consultation, which included 400 participants attending 48 stakeholder meetings; 56 participants attending a public meeting and open house at Hudson’s Hope; 305 feedback forms returned; 31 additional submissions by mail, email and fax; and 200 visits to the Fort St. John community consultation office.

BC Hydro made changes to its consultation program based on public feedback from pre-consultation. For example:

- Open houses were added as a consultation method
- Feedback from pre-consultation informed the topics that were brought forward for Project Definition Consultation, such as recreation, transportation, energy alternatives, local effects, and community benefits
- A consultation office was opened in the District of Hudson’s Hope

The feedback received during pre-consultation is described in the Pre-Consultation Summary Report (2008) and how that input was considered is found in the Consideration of Input from Pre-Consultation document (2008). For both documents, see Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 4 BC Hydro-Led Public Consultation Activities and Materials.
Project Definition Consultation, May to June 2008
From May to June 2008, BC Hydro consulted on the following topics:

- Site C as an energy option
- Community and provincial benefits
- Project design elements
- Recreation (such as river-based opportunities versus reservoir-based opportunities)
- Infrastructure (such as relocation of segments of Highway 29 and worker housing)
- Environment (such as potential increase of fog and effects on fish)
- Land uses (such as heritage resources and impacts on archaeological sites)

During this round of consultation, there were 1,160 participant interactions, which included 284 participants attending 29 stakeholder meetings; 380 participants attending 10 open houses; 224 feedback forms returned; 22 submissions received by mail, email, fax, or phone; and 250 visits to the Fort St. John Community Consultation Office.


Project Definition Consultation, October - December 2008
From October–December 2008, BC Hydro consulted on the following topics:

- Site C as an energy option
- Powerhouse access bridge and associated access roads
- Provincial and community benefits – other potential infrastructure improvements
- Reservoir preparation considerations
- Sourcing dam construction materials, and relocation and reclamation of excavated soil and rock
- Potential environmental effects

During this round of consultation there were 1,254 participant interactions, which included 358 participants attending 26 stakeholder meetings; 326 participants attending seven open houses; 345 feedback forms returned; 72 submissions received by mail, email, fax, or phone; and 153 visits to the Fort St. John and Hudson’s Hope community consultation offices.


Project Definition Consultation, Spring 2012
The topics presented in spring 2012 consultation included:

- Highway 29 realignment options
- Outdoor recreation
- 85th Avenue Industrial Lands
Information was also provided about worker accommodation, transmission line and preliminary impact lines, and land use.

During the spring 2012 consultation period, there were 926 participant interactions, which included 302 participants attending 18 stakeholder meetings; 278 participants attending five open houses; 85 feedback forms returned; 39 submissions received by mail, email, and fax; and 150 visits to the Fort St. John and Hudson’s Hope community consultation offices.

Project Definition Consultation, Fall 2012

Consultation topics during fall 2012 included:

- Worker accommodation
- Transportation
- Clearing
- Agriculture

During the fall 2012 consultation period, there were 495 participant interactions, which included 231 participants attending 15 stakeholder meetings; 118 participants attending four open houses; 42 feedback forms returned; 12 submissions received by mail, email, and fax; and 92 visits to the Fort St. John and Hudson’s Hope community consultation offices.

The feedback received during the spring and fall rounds of Project Definition Consultation in 2012 is described in Project Definition Consultation Summary reports. How that input was considered is found in the Consideration of Consultation Input document. See Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 4 BC Hydro-Led Public Consultation Activities and Materials.

Regional and Local Government Liaison Program

BC Hydro established a Regional and Local Government Liaison Program in April 2010 to formalize engagement with local governments and provide a forum for discussion. Program components included:

- Regional and Local Government Liaison Committee (RLGC) The RLGC provided a forum for BC Hydro and elected officials to share information and discuss community interests, issues and potential benefits related to the Project. Terms for Reference for the RLGC were developed and approved by the Committee.
  - The Committee was chaired by the Project’s Executive Vice President and meets quarterly
  - Five RLGC meetings were held between June 2010 and September 2011 in Fort St. John, Hudson’s Hope, Taylor, Dawson Creek, and Chetwynd
  - Four RLGC Meetings were held between October 2011 and November 2012 in Fort St. John (2), Hudson’s Hope, and Taylor
  - A SharePoint website was developed to allow committee members to share meeting materials. Meeting materials were also made available to the public on the Project website.
• **Local Government Technical Engagement (LGTE)** The LGTE provided regular and working communications between the Project team and staff from each municipality.
  - Meetings were led by the Socio-Economic lead for the Project
  - Capacity funding was offered to regional and local governments to participate; some accepted this offer
  - A total of 64 LGTE meetings and conference calls were held with individual local governments between June 2010 and November 2012. There were also six joint LGTE meetings during the same period.

• **Council Presentations** Project team representatives also provided updates to local and regional government councils on major Project milestones, or as requested.
  - Regular meetings were held and inquiries answered, and workshops were held as appropriate on issues of community interest, including potential Project benefits.

For Regional and Local Government Liaison Summary reports (Winter 2011/2012 and January 2013), see the Project website and Volume 1 Appendix G, Part 2 Regional and Local Government Liaison Program Summary, and Issues and Interests Tracking Table.

**Property Owner Liaison and Consultation**

BC Hydro initiated a separate liaison and consultation program with property owners and established a properties team within the Project team to implement the program. The purpose of the program was to:

• Provide information and update property owners regarding Project planning and design
• Facilitate two-way information exchange between property owners and the Project team
• Engage with property owners prior to, and during, defined periods of consultation
• Negotiate and provide compensation for permissions to access private property for the purposes of technical and environmental field studies

In addition, BC Hydro held specific consultations with property owners as described below.

1. **Highway 29 realignment options (November 2008–February 2009):** The creation of the Site C reservoir would require the realignment of up to six segments of Highway 29 over a total distance of up to 30 km. In spring 2008, BC Hydro consulted with the public about the segments of the highway that, at that time, had been identified for potential realignment. BC Hydro undertook further property owner consultation from November 2008 to February 2009 on the specific highway realignment options.

   During this consultation, engineering and other representatives from the Project team met individually with potentially directly affected property owners to review property maps, and to seek feedback on the specific realignment options. A consultation summary report (Property Owner Consultation on Potential Highway 29 Realignment Options, November 2008–March 2009) is available on the Project website and is listed in Volume 1 Appendix G, Public Information Distribution and Consultation.
Supporting Documentation, Part 4 BC Hydro-led Public Consultation Activities and Materials.

2. **Site C Project and Field Study Update (April 2011):** On April 5, 2011, at Hudson’s Hope, and April 6, 2011, at Fort St. John, subject matter experts from the Project team provided property owners in the Peace River region with an information update on the Project and field studies planned for the 2011 field season. Topics included shoreline geotechnical investigations, heritage studies, clearing plan investigations, and wildlife studies. BC Hydro also sought permission from property owners to access properties to complete these studies.

3. **Preliminary Impact Lines and Highway 29 Realignment (2011–2012):** Prior to Project Definition Consultation, spring 2012, subject matter experts from the Project team met with property owners whose properties could be affected based on preliminary impact lines. Preliminary impact lines outline potential effects from flooding, erosion, slope instability, and landslide-generated waves that could affect safety and land use around the reservoir.

BC Hydro representatives also met with property owners whose properties could be potentially directly affected by Highway 29 realignment to discuss pre-construction work, including topographic surveys, geotechnical investigations, development of detailed bridge and drainage designs, confirmation of the highway alignment, and preparation of construction drawings and specifications.

BC Hydro representatives also met with property owners on the south bank of the proposed dam site whose properties could be potentially directly affected by upgrades to Jackfish Lake Road, construction of the Project access road and resource roads, and dam site area and transmission line construction.

**Local Area Consultations**

BC Hydro conducted area-specific consultation where Project-related plans and effects were of local interest. Consultation methods included stakeholder meetings, open houses, discussion papers and feedback forms.

Local area consultation included:

- **Hudson’s Hope Shoreline Protection Consultation (October 2011–November 2011):** BC Hydro consulted with the District of Hudson’s Hope, property owners and the community regarding the Hudson’s Hope shoreline protection, including options for a berm, potential public use options for berm areas, public access to berm areas, and potential landscaping and recreation opportunities in berm areas.

- A consultation summary report is listed in Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 4 BC Hydro-Led Public Consultation Activities and Materials and is available on the Project website.

In addition, BC Hydro provided information and conducted local meetings with area residents in the vicinity of the 85th Avenue Industrial Lands, a 96 ha parcel of land located in the Peace River Regional District, adjacent to the City of Fort St. John, about the proposed use of the site during construction, potential mitigation measures, and future use after construction.
9.1.2.3.4 Reporting

Consultation Summary Reports

Following each round of consultation, a Consultation Summary Report was written by a professional facilitator and a survey research firm that independently tabulated the results of consultation. The Consultation Summary Reports included:

- Participation numbers
- Public notification prior to consultation
- Quantifiable results from feedback forms
- Qualitative results from the stakeholder meetings and open houses, including the key themes from each meeting
- Detailed meeting notes from each stakeholder meeting and open house where a question-and-answer session took place
- A copy of all feedback forms submitted, emails, public inquiries, and written submissions during the consultation period

The reports were posted on the Project website and made available in the Community Consultation Offices. An email was also sent to consultation participants advising that the Consultation Summary Reports were available online. See Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 4 BC Hydro-Led Public Consultation Activities and Materials.

Consideration Memos

BC Hydro documented its consideration of public input in Consideration Memos. These memos demonstrated how BC Hydro considered the input along with technical and financial information in refining project designs or developing mitigation or compensation measures. See Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 4 BC Hydro-Led Public Consultation Activities and Materials.

9.1.2.3.5 Public Opinion Research

In July 2012, BC Hydro commissioned Harris/Decima to undertake a province-wide public opinion poll relating to the Project. The survey was conducted as part of BC Hydro’s public and stakeholder consultation program and is publicly available.

The Harris/Decima poll was a telephone survey with a sample of 807 people across the province of British Columbia. The margin of error for a sample of this size is +/- 3.5% 19 times out of 20. Field dates for the study were July 8, 2012 to July 12, 2012.

The Harris/Decima survey found the following key results:

- 80% of those polled either supported (40%), or could accept under certain circumstances (40%), building Site C to meet future electricity needs, while 15% were opposed
- 77% would be comfortable with Site C, provided it underwent an extensive and independent environmental assessment that is approved at the end of the process, while 16% disagreed
• 80% would be comfortable with Site C provided that people and communities affected were properly consulted and their views taken into account as much as possible, while 15% disagreed
• 74% agreed that Site C would provide economic opportunities for B.C., particularly in the north, while 17% disagreed

These results are similar to an August 2008 public opinion poll conducted as part of BC Hydro’s integrated energy planning. At that time, the poll found that 81% of those polled either supported (44%), or could accept under certain circumstances (37%), building Site C to meet future electricity needs, while 17% opposed the Project.

9.1.2.4 EIS Guidelines and EIS Communication

This section describes the communication and public notification activities relating to the EIS Guidelines and the EIS, including how public input was received and responded to during the public comment period for the EIS Guidelines, and the expected information and distribution activities anticipated during the planned public comment period for the EIS.

EIS Guidelines

During the pre-Panel Review Stage, the Canadian Environmental Assessment Agency (CEA Agency) and the B.C. Environmental Assessment Office (BCEAO) held a 45-day public comment period on the draft EIS Guidelines (April 17, 2012 to June 1, 2012). The Guidelines provided direction to BC Hydro and identified information required in the EIS.

As part of the public comment period, the CEA Agency and BCEAO hosted six public open houses in May 2012 in the communities of Fort St. John, Hudson’s Hope, Chetwynd, Peace River (AB), Dawson Creek, and Prince George. During these Agency/BCEAO-led open houses, BC Hydro provided Project team subject matter experts to answer questions and to provide specific technical information regarding the draft EIS Guidelines. This information complemented the environmental assessment process and other Agency/BCEAO-related information provided by the Agency/BCEAO staff in attendance.

The CEA Agency and BCEAO provided public notification of the public comment period and open houses to local and regional media and stakeholders prior to the commencement of these activities, which included:
• A joint CEA Agency-BCEAO News Release announcing that the draft EIS Guidelines were available for public comment and to announce the open house sessions
• A public notice advertisement placed in seven regional newspapers and aired on five regional radio stations
• Emails to stakeholders
• Posting of the public notice and news release to the CEA Agency and BCEAO websites

The CEA Agency and BCEAO also accepted written comments from the public, stakeholders, and Aboriginal groups. These comments were posted on the CEA Agency public registry and BCEAO website.
On June 26, 2012, BC Hydro provided responses to 1,388 comments from 912 individual submissions received during the public comment period on the draft EIS Guidelines. In accordance with Chapter 7 of the EIS Guidelines, a summary of the issues raised and BC Hydro’s responses to these information requests can be found in Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 3 EIS Guidelines Public Comment Summary Table.

For a listing of all the comments received and BC Hydro’s responses, including “Topic Summaries” that provided more detailed responses on key themes raised during the public comment period, please see www.ceaa-acee.gc.ca or www.eao.gov.bc.ca.

EIS

It is anticipated that BC Hydro will similarly participate in public open houses during an Agency/BCEAO-led public comment period for the EIS in 2013, including responding to information requests. BC Hydro will provide subject matter experts at open houses and Advisory Working Group meetings to provide information and gather feedback. More information on Agency/BCEAO-led public comment periods for the Project can be found at:

- Canadian Environmental Assessment Agency: www.ceaa-acee.gc.ca
- British Columbia Environmental Assessment Office: www.eao.gov.bc.ca

9.1.3 Issues, Concerns, and Interests

A summary of issues, concerns, and interests – based on input provided by the public – and how BC Hydro considered them in project planning and design, is outlined in Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 1 Public and Stakeholder Issues and Interests Tracking Table.

Additionally, a summary of issues, concerns, and interests – based on input provided by regional and local governments – and how BC Hydro considered them in project planning and design, is outlined in Volume 1 Appendix G Public Information Distribution and Consultation Supporting Documentation, Part 2 Regional and Local Government Liaison Program Summary, and Issues and Interests Tracking Table.

The summary of issues in the tracking tables are derived from the detailed consultation and information distribution activities and reports as described in this section. By nature, the tables provide a summary of the issues, not a detailed reporting of each issue, topic, or concern mentioned in the course of the five years of consultation on the Project. Detailed reporting includes:

- Consultation Summary Reports (Public and Stakeholder Consultation, and Property Owner Consultation)
  - The issues tracking tables reference the consolidated key themes from each round of consultation
  - Additional publicly available information
    - Meeting notes from each meeting where a question-and-answer session was held, including a summary of key themes of each of those individual meetings
    - Quantitative reporting from feedback forms
9.1.3.1 Process for Resolving Outstanding Issues

Throughout the Project’s environmental assessment – including the pre-Panel Review Stage, the Joint Review Panel Stage and the post-Panel Stage – BC Hydro has and will continue to work with the public to ensure that potential Project-related effects on identified interests and concerns continue to be heard and considered. Throughout these stages, BC Hydro commits to identifying and considering outstanding public issues, concerns, or interests that have not been addressed. BC Hydro will respond to information requests during the EIS public comment period, the Joint Review Panel Stage, and the post-Panel Stage, and during ongoing community relations, consultation, and communication with the public.

BC Hydro continues to engage in discussions with local and regional governments about the Project’s construction plans, draft mitigation plans as well as pursuing potential legacy initiatives that would provide additional economic and social benefits for the region.

As described in Section 9.1.2.2, BC Hydro will continue to use the following methods and activities to resolve outstanding public issues through the information distribution program (and, where appropriate, the consultation methods and activities described in Section 9.1.2.3):

- Public inquiry program
- Local government liaison, and continuing discussion with local governments
- Business Liaison Program
- Local area consultations
- Property owner liaison

9.1.4 Construction Phase Communications and Community Relations

This section describes BC Hydro’s proposed communication objectives and community relations with the public during construction, should the Project proceed.

9.1.4.1 Objectives

The construction phase communication objectives are to:

- Continue to facilitate regular community and stakeholder communications regarding the Project
• Maintain cooperative relationships with regional and local government and work with them to manage construction information and issues
• Maintain strong relationships with the business community through the Business Liaison Program

9.1.4.1.1 Community Relations
The purpose of community relations during the construction phase is to continue to maintain and build relationships with the public through ongoing and regular Project updates, including:
• Construction activities and schedules
• Traffic information
• Other relevant Project information and milestones
• Community consultation offices
Community relations also includes attending public and stakeholder meetings and dealing with inquiries from the public, providing Project updates, and problem solving on issues as they arise, often with the involvement of construction managers.
BC Hydro would continue to provide local and regional media with Project updates.
A Public Safety Management Plan will be developed and implemented during construction and operations of the Project (see Volume 5 Section 35 Summary of Environmental Management Plans).

9.2 Aboriginal Group Information Distribution and Consultation

9.2.1 Introduction
The Aboriginal Group Information Distribution and Consultation section describes the approach, methods, and activities that BC Hydro used to inform and consult with Aboriginal groups prior to and during the environmental assessment process. The environmental process is described in Volume 1 Section 8 Assessment Process. This section provides an overview of consultation activities, presents the processes in place to address outstanding issues raised by Aboriginal groups, and looks ahead to the approach and activities that are planned for Aboriginal consultation, should the Project proceed to construction.
Specific details of consultation activities undertaken with each of the 29 Aboriginal groups identified in Table 9.1 are provided in Volume 5 Appendix A Asserted or Established Aboriginal Rights and Treaty Rights, Aboriginal Interests and Information Requirements Supporting Documentation. The issues, interests, and concerns raised through the consultation process are presented in Volume 1 Appendix H Aboriginal Information Distribution and Consultation Supporting Documentation. Related material is also addressed in Volume 3 Section 19 Current Use of Lands and Resources for Traditional Purposes, Volume 5 Section 34 Asserted or Established Aboriginal Rights and Treaty Rights, Aboriginal Interests and Information Requirements, Volume 5 Section
BC Hydro is the Crown actor responsible for the development, construction, and operation of the Project and is, therefore, responsible for consultation with Aboriginal groups with respect to the Project generally. In addition, the BCEAO and CEA Agency have a role in consultation for the purposes of the environmental assessment being conducted under the EIS Guidelines. In the exercise of that role, they delegate to proponents certain procedural aspects of consultation. BC Hydro is a proponent in the environmental assessment process and has been delegated, through the provisions in the EIS Guidelines, certain procedural aspects of consultation to enable the BCEAO and the CEA Agency to fulfill their roles. While at times in this EIS BC Hydro will include consultation activities undertaken in connection with its Crown actor role, the EIS is directed to consultation with Aboriginal Groups through to the statutory decision-making stage of the environmental assessment and is not intended, except where noted, to reflect all of the consultation activities of BC Hydro that will be undertaken after the environmental assessment process is complete.

BC Hydro began consultation with Aboriginal groups in regard to the Project in late 2007 and prior to any decision to advance the Project to an environmental assessment. BC Hydro made initial contact with 41 Aboriginal groups in B.C., Alberta, and the Northwest Territories. BC Hydro provided project-related information and requested input from those Aboriginal groups in order to inform the Project from an early stage of development. In some cases, BC Hydro has entered into consultation agreements to provide interested Aboriginal groups with capacity funding and to set out a structured consultation process that reflects the interests of both parties.

As described in this section, BC Hydro has also entered into Traditional Land Use Agreements, and in addition to those agreements, some Aboriginal groups have provided traditional land use information relating to the Project. BC Hydro has conducted consultation with Aboriginal groups regarding Project components and activities, the potential effects of the Project, and the potential changes to the environment resulting from the Project. BC Hydro has also supported consultation with Aboriginal groups as part of the environmental assessment process, including the review of the draft EIS Guidelines. Through the course of the consultation process conducted to date, Aboriginal groups have raised issues, concerns, and interests. BC Hydro has responded to the Aboriginal groups as appropriate, and as information was available, and has developed a process for addressing outstanding issues, concerns, and interests. BC Hydro intends to utilize this approach, should the Project proceed to construction and operation.

9.2.1.1 Approach to Aboriginal Consultation on the Project

BC Hydro began consultation with Aboriginal groups in regard to the Project in late 2007 and prior to any decision to advance the Project to an environmental assessment. BC Hydro’s Aboriginal Relations and Negotiations department established the Site C First Nations Engagement Team, tasked with carrying out consultations with Aboriginal groups with respect to the Project. Aboriginal consultation for the Project is ongoing. BC Hydro and Aboriginal groups are engaged in a process that will continue through all stages of the environmental assessment process, as well as through the proposed construction and operations stages, as described in greater detail below.
Since 2007, BC Hydro has been proactive in establishing relationships and meeting with Aboriginal groups who may potentially be affected by or have an interest in the Project. The extent (or level) of consultation has been guided by the potential for impacts on the exercise of asserted treaty and Aboriginal rights, as well as the level of interest expressed. In keeping with this adaptive and flexible approach, BC Hydro has engaged in consultation that has ranged from notification of key Project milestones for those Aboriginal groups where BC Hydro anticipated little to no potential adverse change in the environment from the Project, to structured consultations aimed at identifying and assessing potential effects of the Project on those groups located in and around the Project activity zone that may experience those effects, and seeking to address them.

As described in Volume 1 Section 4.1 Project Location, the Project is located within the area covered by Treaty 8. BC Hydro’s understanding of Treaty 8 and the rights contained therein is set out in Volume 5 Section 34 Asserted or Established Aboriginal Rights and Treaty Rights, Aboriginal Interests and Information Requirements. BC Hydro has consulted in greater depth with Treaty 8 First Nations that are in close proximity to the Project and whose members may experience direct effects that may result from the Project. For the purposes of this EIS, Blueberry River First Nations, McLeod Lake Indian Band, Saulteau First Nations, and the Treaty 8 Tribal Association (representing Doig River, Halfway River, Prophet River, and West Moberly First Nations), are considered by BC Hydro to be “Project Area Aboriginal Groups”. With these groups, BC Hydro has engaged in more extensive consultations regarding project components and activities, and the potential effects of the Project. The scope of the topics covered through the consultation process is explored in greater detail in Section 9.2.3.3.

BC Hydro has also consulted with other Treaty 8 First Nations who are located in B.C. or downstream of the Project. This includes those Aboriginal groups located in Alberta and the Northwest Territories, in proximity to the Peace River watershed, and along the Slave River. Consultations with Aboriginal groups located away from the immediate Project activity zone have tended to focus on the potential downstream changes resulting from the Project.

BC Hydro has also consulted with the Tsay Keh Dene Band and Kwadacha First Nation to fulfill commitments in formal agreements with those First Nations to identify and attempt to address any potential effects and to identify project opportunities associated with any new BC Hydro projects within the area of the mainstem of the Peace River between Peace Canyon Dam and the Alberta border.

Métis groups have been engaged to varying degrees, dependent upon jurisdiction, level of interest expressed, and proximity to the Project or the Peace River watershed, consistent with the approach described above. The CEA Agency has also directed BC Hydro to consult with select Métis organizations in B.C., as outlined in Table 9.1.

In addition to the Aboriginal groups identified in Table 9.1, BC Hydro also engaged with additional Métis organizations and all remaining Treaty 8 First Nations in Alberta, the Northwest Territories, and Saskatchewan, including those located outside of the Peace River watershed. A list of these additional Aboriginal groups is presented in Section 9.2.2. BC Hydro has provided notification of Project milestones and, in many cases, has offered to meet and discuss the Project.
9.2.1.2 Project Consultation Objectives

BC Hydro’s specific consultation objectives have and will continue to evolve over time in response to the stage of the Project, as well as feedback received from Aboriginal groups. Additional details regarding BC Hydro’s specific consultation objectives at different stages of the Project can be found in Sections 9.2.3.3.1 and 9.2.3.3.2.

More generally, the objectives of BC Hydro’s consultations with Aboriginal groups are to:

- Provide access to and facilitate an understanding of Project-related information
- Create opportunities to receive input from Aboriginal groups into the planning, design, construction and operation of the Project
- Facilitate Aboriginal participation in the environmental assessment process through provision of capacity funding and access to technical expertise as it relates to the Project
- Identify and understand the issues, interests, and concerns brought forward by Aboriginal groups about the Project and as they relate to the potential effects of the Project on:
  - The exercise of asserted or established Aboriginal and treaty rights
  - The past, current, and reasonably anticipated future use of lands and resources for traditional purposes (as defined in Section 20.3 of the EIS Guidelines)
  - Identify potential training, employment, contracting, and broader economic opportunities related to the Project that may be of interest to Aboriginal groups or individuals

9.2.2 Aboriginal Groups

This section describes the process BC Hydro used to identify Aboriginal groups whose Aboriginal or treaty rights could be adversely affected by the Project, and presents a complete list of the Aboriginal groups consulted in regard to the Project.

9.2.2.1 Identification of Aboriginal Groups

Prior to initiating consultation in late 2007, preparatory work was undertaken to identify the Aboriginal groups whose Aboriginal or treaty rights could potentially be affected by the Project. BC Hydro examined the then-anticipated Project activity zones and formed a general understanding of the potential for the Project to cause changes to the ecological, physical, and social environments, to human health, and to heritage resources. BC Hydro then reviewed publicly available information to determine which Aboriginal groups might potentially be exercising Aboriginal or treaty rights in the area. This work recognized the reach of the Peace River and its tributaries; BC Hydro elected to be more, rather than less, inclusive in the scope of Aboriginal groups that it would consult. BC Hydro remained receptive to meeting with any Aboriginal group who expressed interest in the Project and has undertaken to review its assumptions as BC Hydro’s understanding of the Project and the interests of Aboriginal groups has evolved over time.

Table 9.1 presents the list of Aboriginal groups potentially affected by the Project as identified in Section 20.1 of the EIS Guidelines. A map showing the location of the Indian
Reserves and Métis Settlements associated with these Aboriginal Groups is presented in Figure 4.4 in Volume 1 Section 4.1 Project Location.

### Table 9.1 Aboriginal Groups Potentially Affected by the Project

<table>
<thead>
<tr>
<th>Treaty 8 First Nation Signatories</th>
<th>Alberta</th>
<th>Northwest Territories</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blueberry River First Nations</td>
<td>Athabasca Chipewyan First Nation</td>
<td>Deninu K’ue First Nation</td>
</tr>
<tr>
<td>Fort Nelson First Nation</td>
<td>Beaver First Nation</td>
<td>Salt River First Nation</td>
</tr>
<tr>
<td>McLeod Lake Indian Band</td>
<td>Dene Tha’ First Nation</td>
<td></td>
</tr>
<tr>
<td>Saulteau First Nations</td>
<td>Duncan’s First Nation</td>
<td></td>
</tr>
<tr>
<td>Treaty 8 Tribal Association (T8TA):</td>
<td>Horse Lake First Nation</td>
<td></td>
</tr>
<tr>
<td>Doig River First Nation</td>
<td>Little Red River Cree Nation</td>
<td></td>
</tr>
<tr>
<td>Halfway River First Nation</td>
<td>Mikisew Cree First Nation</td>
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</tr>
<tr>
<td>Prophet River First Nation</td>
<td>Smith’s Landing First Nation</td>
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</tr>
<tr>
<td>West Moberly First Nations</td>
<td>Sturgeon Lake Cree Nation</td>
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<td></td>
<td>Tallcree First Nation</td>
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<tr>
<td></td>
<td>Woodland Cree First Nation</td>
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<tr>
<td>British Columbia First Nations</td>
<td></td>
<td></td>
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<tr>
<td>Kwdacha First Nation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tsay Keh Dene Band</td>
<td></td>
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</tr>
</tbody>
</table>

### Métis

<table>
<thead>
<tr>
<th>British Columbia</th>
<th>Alberta</th>
<th>Northwest Territories</th>
</tr>
</thead>
<tbody>
<tr>
<td>Métis Nation British Columbia (as directed by the CEA Agency)</td>
<td>Métis Nation of Alberta – Region 6</td>
<td>Northwest Territory Métis Nation</td>
</tr>
<tr>
<td>Kelly Lake Métis Settlement Society (as directed by the CEA Agency)</td>
<td>Paddle Prairie Métis Settlement Society</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Fort Chipewyan Métis Local 125</td>
<td></td>
</tr>
</tbody>
</table>

Section 20.1 of the EIS Guidelines refers to the Fort Chipewyan Métis Local 125 as the Fort Chipewyan Métis Association, the McLeod Lake Indian Band as the McLeod Lake First Nation, the Tsay Keh Dene Band as the Tsay Keh Dene First Nation, and the Métis Nation of Alberta – Region 6 as the Métis Nation of Alberta – Zone 6.

Section 20.1 of the EIS Guidelines does not specifically include Tribal Associations, however, on March 24, 2008, the Saulteau, West Moberly, Halfway River, Fort Nelson, Doig River, and Prophet River First Nations indicated to BC Hydro that they wished to be consulted respecting the Project through a tribal council entity originally called the Council of Western Treaty 8 Chiefs and later referred to as the Council of B.C. Treaty 8 Chiefs. On January 25, 2010, Saulteau First Nations informed BC Hydro that it was no longer represented by the Tribal Council. Beginning in April 2010, Fort Nelson First Nation was no longer represented by the Tribal Council. After April 2010, the Tribal Council was referred to as the Treaty 8 Tribal Association (T8TA).

### 9.2.2.2 Additional Aboriginal Groups and Other Organizations

BC Hydro has indicated a willingness to meet with additional Aboriginal groups and other organizations to discuss the Project in more detail, or upon request to provide additional...
information or project updates. In addition to the Aboriginal groups identified in Table 9.1, BC Hydro also provided information about the Project to the following groups:

- Bigstone Cree Nation
- Black Lake
- Chipewyan Prairie First Nation
- Clearwater River Dene
- Driftpile First Nation
- Fond du Lac First Nation
- Fort McKay First Nation
- Fort McMurray #468 First Nation
- Fort Resolution Métis
- Fort Smith Métis
- Fort Vermilion Métis Local
- Hay River Métis
- Kapawe'no First Nation
- K'atlodeeche First Nation
- Kee Tas Kee Now
- Kelly Lake Cree Nation
- Lesser Slave Lake Indian Regional Council
- Loon River Cree
- Lubicon Lake
- Lutsel K’ee Dene First Nation
- Métis Nation of Alberta
- Métis Nation of Alberta Region 1
- North Peace Tribal Council
- Peace River Métis Local
- Peerless Trout First Nation
- Sawridge First Nation
- Sucker Creek First Nation
- Swan River First Nation
- Western Cree Tribal Council
- Whitefish Lake First Nation
- Yellowknives Dene First Nation
9.2.3 Pre-panel Review Stage

This section of the EIS provides a description of how project information was made available to Aboriginal groups and how this information was recorded. This section also presents a summary of BC Hydro’s approach to consulting with Aboriginal groups in the pre-Panel Review Stage of the environmental assessment process, including the preparation of the EIS Guidelines and the EIS. Finally, this section, in combination with Volume 1 Appendix H Aboriginal Information Distribution and Consultation Supporting Documentation, will present the key issues and concerns raised by Aboriginal groups and the process proposed by BC Hydro for addressing outstanding issues.

9.2.3.1 Information Distribution Methods

Information was distributed to Aboriginal groups using the methods outlined below.

- **Project website**: The Project website (www.bchydro.com/sitec), which was launched in December 2007, contains all publicly available documents, provides comprehensive Project information, contact information, public consultation opportunities and current news about the Project. The Project website is more fully described in Section 9.1.2.2.2.

- **Secured file transfer website for Aboriginal groups**: In the spring of 2012, 55 Aboriginal groups, including all of the Aboriginal groups identified in Table 9.1, were provided with usernames and passwords for a protected web-based environment. The secured file transfer website includes key environmental and engineering reports, fieldwork updates, and information regarding economic opportunities associated with the Project. Those Aboriginal groups with which BC Hydro had not concluded a consultation agreement were offered the opportunity to sign a confidentiality agreement that would increase their access to confidential materials, such as up-to-date mapping and a series of presentations on key components of the Project and potential effects of the Project. The purpose of the secured file transfer website was to ensure distribution of key documents to all Aboriginal groups in a systematic and accessible manner.

- **Direct communication**: BC Hydro directly engaged with Aboriginal groups in the following ways: meetings, telephone calls, conference calls, site visits, faxes, letters, and emails. Communication was often supplemented by the use of visual aids, including PowerPoint presentations and Project maps.

- **In-community consultation**: BC Hydro has sought opportunities to engage directly with members of the Aboriginal communities. BC Hydro has organized and/or attended community meetings, often having technical staff available to engage directly with community leaders or members of the communities. BC Hydro has also attended and/or sponsored in-community conferences, events, and celebrations.

- **Technical Working Groups**: By agreement of the parties, BC Hydro technical experts and/or consultants have worked directly with their counterparts on staff with or retained by Aboriginal groups to review technical reports, as part of a working group or technical committee.
BC Hydro has used the following approach to obtain input from Aboriginal groups:

- BC Hydro provides Aboriginal groups with access to information related to the Project and seeks input, and the identification of issues, concerns or interests from those Aboriginal groups.

- BC Hydro provides Aboriginal groups with resources, including the provision of capacity funding and access to subject matter specialists to evaluate and consider the information provided and, where appropriate, to formulate a response for BC Hydro’s consideration.

- BC Hydro considers all information provided by Aboriginal groups and allows for time and internal resources to take into account input received.

- BC Hydro also allows for time in the Project schedule for the above process to be iterative, where appropriate, and to address concerns brought forward by Aboriginal groups.

In order to facilitate the approach outlined above, BC Hydro has pursued consultation agreements with Aboriginal groups where more in-depth or structured consultation was required (lists of concluded consultation agreements are provided in Sections 9.2.3.3.1 and 9.2.3.3.2). Consultation agreements were negotiated between BC Hydro and the individual Aboriginal groups, or in some cases Tribal Associations designated by Aboriginal groups to represent them, and were designed to provide a framework for dialogue and a structured process for distributing and exchanging information about the Project.

In some cases, in lieu of a formal consultation agreement, BC Hydro and Aboriginal groups or organizations signed letters of understanding. These agreements also facilitated a structured process for distributing and exchanging information about the Project. In other cases, BC Hydro undertook consultation and distributed information about the Project without any formal consultation agreement.

### 9.2.3.2 Methods of Documenting Project Consultation

BC Hydro has documented communication with Aboriginal groups using a variety of methods. Beginning in 2007, all project communication has been recorded using a document storage database. Prior to April 2010, BC Hydro also utilized Excel software to track consultation related records. In April 2010, BC Hydro began using the newly created Consultation and Agreement Tracking Software (CATS) to track and record communications with Aboriginal groups.

### 9.2.3.3 Description of Consultation Activities

The following section provides a summary description of the activities undertaken to notify and consult with the Aboriginal groups identified in Table 9.1 in regard to the Project. The consultation activities described below are presented in accordance with the stages of the Project, which are defined in Volume 1 Section 3.1 Project Overview. During Stage 1, Review of Project Feasibility, existing studies and historical information related to engineering, costs, environment, consultation, and First Nations were reviewed. The description below includes BC Hydro’s approach to consultations with Aboriginal groups during Stages 2 and 3, including the environmental assessment process, activities related to the preparation and the review of the EIS Guidelines and
the EIS. While this section provides an overview of consultation activities, the specific
details of consultation activities undertaken with each of the 29 Aboriginal groups
identified in Table 9.1 are provided in Volume 5 Appendix A Aboriginal Summaries. The
issues, interests, and concerns raised through the consultation process are presented in
Volume 1 Appendix H Aboriginal Information Distribution and Consultation Supporting
Documentation.

9.2.3.3.1 Stage 2: Consultation (Fall 2007–Spring 2010)

Objectives

Further to the objectives of consultation outlined in Section 9.2.1.2, BC Hydro has
specific consultation objectives for each stage of the Project. During Stage 2, Project
Definition and Consultation, the primary purposes of early consultation were to develop
positive relationships with Aboriginal groups, to share information about the Project, give
Aboriginal groups opportunities to advise BC Hydro of their interests and concerns, and
to increase knowledge and mutual understandings about the potential effects of the
Project.

Early Contact Regarding the Project

In February 2007, the provincial government’s BC Energy Plan provided BC Hydro with
the first direction to “enter into initial discussions First Nations, the Province of Alberta,
and communities to discuss Site C to ensure that communications regarding the
potential project and the processes being followed are well known.”

In November of 2007, BC Hydro made initial telephone contact and sent an introductory
letter to Aboriginal groups regarding the Project. The letter introduced BC Hydro’s senior
advisor responsible for Aboriginal consultation, and expressed BC Hydro’s commitment
to effective consultation with Aboriginal groups, should the Project proceed further
through BC Hydro’s multi-stage decision-making process.

In December 2007, BC Hydro released the “Peace River Site C Hydro Project, An
Option to Help Close B.C.’s Growing Electricity Gap, Site C Feasibility Review: Stage 1
Completion Report”, noting that dialogue with Aboriginal groups was needed to fully
understand the issues, concerns, and potential effects of the Project on Aboriginal
groups.

BC Hydro initially initiated consultation with 41 Aboriginal groups consisting primarily of
Treaty 8 First Nations in B.C., as well as Aboriginal groups in Alberta and the Northwest
Territories. In Stage 2, BC Hydro initiated consultation with all of the Aboriginal groups
outlined in Table 9.1 with the exception of the Métis Nation of Alberta – Region 6 and
Métis Nation British Columbia.

Initial meetings with all Project Area Aboriginal Groups, as defined in Section 9.2.1.1,
occurred in March 2008. These meetings allowed BC Hydro to provide a high-level
introduction to the Project, and to describe the status of early exploratory work and the
proposed process to be used to inform Aboriginal groups, should the decision be made
to advance the Project to the regulatory and environmental review stage.

In the spring of 2008, copies of the Summary: Stage 1 Review of Project Feasibility
report (BC Hydro 2007b) were sent to Aboriginal groups. Introductory and follow-up
meetings were then completed with 21 Aboriginal groups who had expressed an interest
in meeting; in some cases, these entities represented more than one Aboriginal group.
Consultation Agreements

Based on these initial meetings, BC Hydro reached eight consultation agreements with groups representing 13 Aboriginal groups:

- Duncan’s First Nation (September 16, 2008)
- Blueberry River First Nations (October 2, 2008)
- Treaty 8 Tribal Association (referred to in the consultation agreement as the “Treaty 8 First Nations”, representing Doig River, Halfway River, Prophet River, Saulteau, West Moberly, and Fort Nelson First Nations) (December 1, 2008)
- Horse Lake First Nation (March 3, 2009)
- Dene Tha’ First Nation (April 21, 2009)
- Little Red River Cree First Nation (April 24, 2009)
- Tallcree First Nation (May 7, 2009)
- McLeod Lake Indian Band (June 25, 2009)

BC Hydro also tabled consultation agreements with an additional five Aboriginal groups on the dates below; however, agreements were not finalized in Stage 2:

- Mikisew Cree First Nation (tabled March 3, 2009)
- Athabasca Chipewyan First Nation (tabled March 4, 2009)
- Smith’s Landing First Nation (tabled March 4, 2009)
- Beaver First Nation (tabled April 21, 2009)
- Deninu K’ue First Nation (tabled May 20, 2009)

Consultation agreements were negotiated between BC Hydro and Aboriginal groups, or their respective Tribal Associations, and were designed to provide a structured framework for dialogue, dispute resolution processes, an agreed work plan, and funding to support these activities.

Consultation Topics

BC Hydro sought input from Aboriginal groups on a range of studies related to the environment, archaeology, socio-economic conditions, and land use.

As described in Section 9.3.1, in 2008–09, BC Hydro created Technical Advisory Committees (TACs) for Fish and Aquatics; Wildlife and Vegetation; Land and Resource Use (Agriculture, Oil & Gas, Mines, Forestry, Parks and Conservation Lands); Recreation and Tourism; Community Services and Infrastructure; Heritage; and Greenhouse Gas. While all B.C. Treaty 8 First Nations and the Horse Lake First Nation were invited to participate along with provincial, federal, and municipal government agencies, only the Blueberry River First Nations participated in the TAC process. In May 2009, BC Hydro provided Aboriginal groups with materials from the environmental and socio-economic TACs. BC Hydro advised that it was providing the materials for the purpose of early information sharing, and cautioned that the information should not be relied upon as a forecast of final study results.
A separate technical advisory review process, called the Technical Advisory Representative (TAR) process, was established with the Treaty 8 Tribal Association. The TAR process covered the same key program areas as the Technical Advisory Committees outlined above; however, it was conducted in accordance with a TAR work plan developed collaboratively between BC Hydro and the Treaty 8 Tribal Association. The purpose of the TAR process was to exchange technical information about the Project, seek input from the Treaty 8 Tribal Association on potential environmental and socio-economic issues, and to identify information that would assist in assessing the potential effects of the Project. Seven meetings, over 10 days in total, occurred between March and November 2009, and resulted in the completion of a 74-page joint report signed off by both parties. The TAR process resulted in the parties sharing over 75 documents, including completed studies, proposed study outlines, terms of reference, preliminary wildlife inventory results, mapping, literature summaries, information sheets, and technical presentations.

By June of 2009, consultation with Treaty 8 Tribal Association led to its submission of a document including 97 questions regarding the Project, which were answered by BC Hydro in October of 2009.

To conclude Stage 2, BC Hydro prepared a final report summarizing the outcomes of the Project Definition and Consultation Phase. Through the consultation process, the Treaty 8 Tribal Association requested an opportunity to provide input directly into the final report. The parties agreed that a submission from the Treaty 8 Tribal Association would be appended to BC Hydro’s final Stage 2 Report. The appendix drafted by the Treaty 8 Tribal Association outlined several concerns, primarily in regard to the timing of the Stage 2 Report and BC Hydro’s accompanying recommendation to the provincial government that the Project be moved into Stage 3, the Regulatory and Environmental Review stage. In the fall of 2009, BC Hydro released the report, which was entitled “Peace River Site C Hydro Project, A Potential Source of Clean, Renewable and Reliable Power for Generations. Stage 2 Report: Consultation and Technical Review, Fall 2009”. This document reported on the consultations, including a specific section regarding consultation with Aboriginal groups that had been undertaken between 2007 and 2009 and highlighted key findings.

In summary, BC Hydro began consultation with Aboriginal groups in regard to the Project in late 2007 and prior to any decision to advance the Project to an environmental assessment. During the course of Stage 2, which ended in the spring of 2010, BC Hydro engaged with 41 Aboriginal groups, with which BC Hydro conducted over 140 meetings, and exchanged over 2500 emails, 300 letters, 550 telephone calls, and other communications in regard to the Project.

**9.2.3.3.2 Stage 3: Consultation (Spring 2010 to present)**

In April of 2010, BC Hydro advised Aboriginal groups by email that the Government of B.C. had announced that the Project would move forward to Stage 3, the Regulatory and Environmental Assessment Stage. The email also provided a link to the Project website where the final “Stage 2 Project Report: Consultation and Technical Review” and appended studies and reports were available online. Printed copies of reports and other documents were provided to Aboriginal groups upon request.
Objectives

During Stage 3, the Regulatory and Environmental Assessment Stage, BC Hydro’s objectives evolved as consultations were advanced to a greater level of detail. To date, consultation has involved ongoing information sharing and input, but has generally involved a greater focus on effects assessment, and on identifying and considering strategies or measures to mitigate and/or otherwise accommodate any potential adverse effects of the Project. Since the beginning of the Regulatory and Environmental Assessment Stage in 2010, BC Hydro’s objectives have been to:

- Continue to consult and engage Aboriginal groups
- Provide information about the Project and identify interests, concerns, and issues
- Seek input regarding ongoing baseline studies
- Continue to consult regarding required authorizations and permit applications for exploratory work
- Negotiate consultation agreements where appropriate
- Acquire, consider, and incorporate traditional land use information
- Facilitate participation in the environmental assessment process
- Ensure that the requirements for consultation with Aboriginal groups set out in the EIS Guidelines, issued in September 2012, have been met
- Gain further understanding of asserted Section 35 (1) rights, and identify and consider strategies or measures to mitigate and/or otherwise accommodate potential adverse effects of the Project, as necessary
- Negotiate impact benefit agreements, where appropriate

Consultation Agreements

Early in the Regulatory and Environmental Assessment Stage, BC Hydro continued to build on the working relationships established during Stage 2 and reached 13 consultation agreements with groups representing 16 Aboriginal groups as follows:

- Duncan’s First Nation (July 12, 2010)
- Blueberry River First Nations (September 2, 2010)
- Saulteau First Nations (September 30, 2010)
- Kwadacha First Nation (November 26, 2010)
- Horse Lake First Nation (December 27, 2010)
- Tallicree First Nation (February 23, 2011)
- Mikisew Cree First Nation (March 31, 2011)
- Treaty 8 Tribal Association (representing Doig River, Halfway River, Prophet River, and West Moberly First Nations) (April 21, 2011)
- Deninu K’ue First Nation (November 16, 2011)
- McLeod Lake Indian Band (December 20, 2011)
Although each of the consultation agreements reflects the unique priorities of each Aboriginal group, all of the agreements provide a framework for consultation and the identification of any potential effects of the Project on Section 35(1) rights. Generally, the agreements call for joint community meetings, joint technical briefings and, in some cases, consultation regarding permit applications as well as input from Aboriginal groups on key regulatory submissions.

All consultation agreements provide funding to facilitate Aboriginal participation in the consultation process. As of the end of November 2012, and dating back to 2008, BC Hydro has provided approximately $8.5 million in capacity funding to Aboriginal groups, including $1.3 million to support traditional land use studies. All consultation agreement funding is subject to financial reporting submitted to BC Hydro on an ongoing basis. Typically, consultation agreements contain two types of funding: general and defined consultation funding.

General funding is intended to cover the costs associated with the implementation of the consultation agreements, including participation in consultation meetings and/or technical briefings with Chief and Council or staff representatives, legal, negotiation, or administrative support, and travel costs. Consultation agreements include a provision that allows for the amount to be reviewed on an annual basis to reflect any increase or decrease in the level of consultation activities anticipated by the parties.

Defined Consultation Funding is provided for specific deliverables or initiatives that fall outside the scope of activities covered under General Funding and that are agreed to by both parties. Examples of activities funded under Defined Consultation Funding may include review of investigative permit applications, thirdparty technical review of engineering or environmental studies, specific community engagement activities, etc.

In addition to the formal consultation agreements outlined above, BC Hydro also reached letters of understanding to support funding and joint work plans with respect to the Project with:

- Kelly Lake Métis Settlement Society (April 26, 2012)
- Métis Nation British Columbia (June 3, 2012 and a supplemental agreement signed November 20, 2012)
- Kelly Lake Cree Nation (July 30, 2012)

BC Hydro also tabled consultation agreements with an additional five Aboriginal groups on the dates below; however, agreements have not yet been finalized as of the submission of the EIS:

- Tsay Keh Dene Band (tabled June 18, 2010 and substantive agreement reached in the fall of 2010; however, to date, the Tsay Keh Dene Band has not ratified the agreement)
- Little Red River Cree Nation (tabled September 23, 2010)
- Smith’s Landing First Nation (tabled September 23, 2010)
Site C Clean Energy Project Environmental Impact Statement
Volume 1: Introduction, Project Planning, and Description
Section 9: Information Distribution and Consultation

- Salt River First Nation (tabled January 14, 2011)
- Beaver First Nation (tabled June 9, 2011)

Traditional Land Use Information

Another major focus of work during the Regulatory and Environmental Assessment Stage was gathering traditional land use information and, where possible, traditional knowledge. Since December 2009, BC Hydro has negotiated Traditional Land Use Study (TLUS) agreements with those Aboriginal groups located immediately downstream of the Project or who may exercise rights within the area that is now defined as the Project activity zone. Additional information regarding the traditional land use information made available to BC Hydro, as well as how this information has been considered and integrated in the EIS, is available in Volume 3 Section 19 Current Use of Lands and Resources for Traditional Purposes and in the Volume 5 Appendix A Asserted or Established Rights and Treaty Rights, Aboriginal Interests and Information Requirements Supporting Documentation.

Formal agreements to complete TLUS reports were concluded with:

- Treaty 8 Tribal Association (representing Doig River, Halfway River, Prophet River, and West Moberly First Nations) (signed an agreement to negotiate a TLUS Agreement on December 18, 2009; the final TLUS Agreement itself was finalized on December 16, 2010, and the parties later entered into a related TLUS Amending Agreement on October 4, 2011)
- Duncan’s First Nation (July 12, 2010)
- Saulteau First Nations (July 20, 2010)
- Blueberry River First Nations (September 2, 2010)
- Horse Lake First Nation (December 27, 2010)
- Dene Tha’ First Nation (August 16, 2012)

Each of the TLUS agreements is unique and reflects the interests of both parties. Generally, however, the agreements set out provisions dealing with TLUS methodology, reporting and deliverables, confidentiality provisions, and funding to support the required work. Each TLUS agreement includes a map outlining the TLUS study area in relation to the Project.

As of the filing of the EIS, all of the TLUS reports referenced above have been completed and shared with BC Hydro, including technical staff responsible for conducting the Wildlife Resources, Vegetation and Ecological Communities, Fish and Fish Habitat and Heritage Resources effects assessments. BC Hydro and McLeod Lake Indian Band have agreed that McLeod Lake Indian Band will carry out a TLUS that will be provided to BC Hydro in early 2013.

BC Hydro also reached agreements with the Kelly Lake Métis Settlement Society, Métis Nation British Columbia, Fort Nelson First Nation, Athabasca Chipewyan First Nation, Mikisew Cree First Nation, and the Deninu K’ue First Nation to provide funding to allow for existing traditional land use information that is applicable to the Project to be assembled and shared with BC Hydro. As of the filing of the EIS, BC Hydro has received traditional land use information from all of these groups with the exception of the Deninu...
K’ue First Nation which is expected to provide BC Hydro with this information in early 2013.

BC Hydro engaged Traditions Consulting Services to review the completed TLUS reports and related materials, and to consider where additional information would be beneficial. BC Hydro responded to the Aboriginal groups with specific questions, clarifications, or requests for additional information. Traditions Consulting Services prepared Aboriginal Land and Resource Use Summaries (see Volume 5 Appendix A01-A29, Part 4) for consideration as baseline information in the effects assessment carried out pursuant to Volume 3 Section 19 Current Use of Lands and Resources for Traditional Purposes, and the assessment of impacts to asserted or established Aboriginal or treaty rights in Volume 5 Section 34.

Consultation on Permits for Geotechnical Investigations

Throughout Stage 2 and 3 of the Project, Project Area Aboriginal Groups, as defined in Section 9.2.1.1, were consulted on the permits required from the Province for BC Hydro to complete geotechnical investigations for the Project. Such consultations were generally led by relevant provincial agencies, with support from BC Hydro technical staff and consultants.

As the investigative nature of the work often did not allow BC Hydro to include precise information on the scope, timing, or location of specific activities in the permit application, BC Hydro worked in cooperation with the Integrated Land Management Bureau and the Treaty 8 Tribal Association and developed a process that allowed for continued consultation following the issuance of the permits, ensuring that, as details about proposed work became available, Aboriginal groups input and concerns could be considered or incorporated throughout the investigative process.

Beginning in 2011, BC Hydro secured the services of Golder Associates (Golder) to provide environmental management and monitoring for the geotechnical investigations. Golder developed and provided Project Area Aboriginal Groups with Environmental and Archaeology Management Plans (EAMPs) and weekly environmental and archaeological monitoring reports containing information on the progress of investigative work, any environmental or archaeological issues encountered, and the protective measures recommended or implemented on site.

Consultation on Environmental Field Studies

Since 2009, BC Hydro has provided Project Area Aboriginal Groups with regular information on the Project’s environmental program. Information provided included proposed study outlines for planned work, status updates for ongoing work, and study summaries for completed work. In each case, Project Area Aboriginal groups were invited to review the information and provide input.

In addition to providing the above study summaries to Project Area Aboriginal groups, BC Hydro also sought input from Aboriginal groups located downstream of the Project specifically in regard to studies and reports related to the physical environment. These include the examination of water level and flows, water temperature and ice, sediment transport, microclimate, noise, air quality, and contaminated sites (Volume 2 Section 11 Environmental Background), and greenhouse gases (Volume 2 Section 15).
Commencement of the Environmental Assessment Process

On May 17, 2011, BC Hydro advised Aboriginal groups that a Project Description Report had been submitted to the BCEAO and the CEA Agency. Telephone and/or letter notifications, as well as an email containing an online link to access the full text document, were provided to Aboriginal groups.

On August 2, 2011, the CEA Agency and the BCEAO sent an introductory letter regarding the Environmental Assessment of the Project. The letter indicated that capacity funding would be made available to interested Aboriginal groups, and that the CEA Agency and the BCEAO would take a coordinated approach to consultation. A follow-up letter was sent again, on September 2, 2011, that included an invitation to attend an introductory meeting in Fort St. John on October 5, 2011. The introductory meeting attendees included federal, provincial, and territorial government agencies (including those of B.C., Alberta, and the Northwest Territories), Aboriginal groups, and local governments that had been identified as having an interest in the Project. Although open to all invited Aboriginal groups, the meeting was attended by representatives from the Dene Tha’, Driftpile, Kapawe’no, McLeod Lake, Prophet River, Saulteau, and West Moberly First Nations, as well as the Treaty 8 Tribal Association and the Métis Nation British Columbia.

On September 30, 2011, BC Hydro advised Aboriginal groups that the federal and provincial governments had announced a draft harmonization agreement that would refer the Project to a Joint Review Panel. BC Hydro noted that the regulators would be inviting written public comments on the draft agreement and provided website links to the CEA Agency and BCEAO websites. Following input from Aboriginal groups and the submission of approximately 85 comments, a Joint Agreement was finalized by the federal and provincial Ministers of Environment of the CEA Agency and the BCEAO and posted online in February 2012.

Consultation Regarding Project Components

In 2011 and 2012, a major focus of consultations with Project Area Aboriginal Groups and other interested Aboriginal groups involved specific components of the Project. BC Hydro asked each Project Area Aboriginal Group to provide BC Hydro with their topics of interest to ensure that the information provided by BC Hydro through the consultation process was relevant to each Aboriginal group’s unique areas of interest.

Presentation materials were discussed at a variety of venues (Chief and Council meetings, community meetings, and/or with technical representatives) and provided to multiple Aboriginal groups upon request. Presentation topics included:

- Transmission options
- Worker accommodation options
- Highway 29 realignment options
- Reservoir clearing options
- Proposed reservoir road access
- Reservoir impact lines
- Options for sourcing off-site construction materials
• Alternative dam site locations (alternative means of project delivery)
• Alternatives to the Project (BC Hydro Integrated Resource Planning process)
• Hudson’s Hope shoreline protection options
• Agriculture
• Archaeology and heritage program
• Reservoir recreation options

As information evolved, BC Hydro updated the presentations and offered to provide interested Aboriginal groups with updates as appropriate. BC Hydro has endeavoured to initiate discussions with Aboriginal groups on each of these topics at an early stage in the planning process. Where feasible, BC Hydro has presented options and sought input from Aboriginal groups to contribute to the analysis.

In each case, BC Hydro endeavoured to present these materials in a comprehensive way that was accessible to non-technical audiences. This was achieved using layperson terminology and through a variety of means including the use of videos, customized maps, diagrams, PowerPoint presentations, pictures, and interactive tools such as Google maps simulations. In some cases, BC Hydro provided Aboriginal groups with funding, available through consultation agreements, to provide for third-party technical support services, if required. BC Hydro requested that the Aboriginal groups provide input regarding the materials presented either verbally or through written follow-up. In instances where BC Hydro received feedback from Aboriginal groups on any of the project components, BC Hydro considered the input and responded in writing regarding how the input was considered and/or incorporated into the Project and/or BC Hydro’s assessment.

In addition to topics requiring input from Aboriginal groups, BC Hydro has followed up on suggestions from Aboriginal groups to provide basic information to increase the level of knowledge regarding a variety of topics. For example, BC Hydro developed a presentation, accessible to a non-technical audience, called “Dams 101, How to Build a Dam”, which outlined the construction sequence and basic structures of a typical dam. BC Hydro also prepared a similar presentation called “Highway 29 101”.

BC Hydro facilitated consultation meetings regarding project components and prepared the relevant technical experts responsible for each component to present the materials directly to the various Aboriginal groups. This approach ensured that issues and concerns brought forward by Aboriginal groups would be heard first-hand by the subject matter experts within the project team responsible for considering the issue.

Select presentations were also posted on the BC Hydro’s secured file transfer website for access by all Aboriginal groups.

Consultation Regarding the Need for, Purpose of, and Alternatives to the Project through the Integrated Resource Plan (IRP):

Volume 1 Section 5 outlines the need for, purpose of, and alternatives to the Project. The proposed Project is a resource addressed within the BC Hydro’s Integrated Resource Plan (IRP) to meet future electricity needs over the next 20 years and, as such, is a topic of consultation in the development of the IRP. The consultation undertaken as part of the IRP informs the discussion of the need for and alternatives to
the Project discussed in Volume 1 Section 5 Need for, Purpose of and Alternatives to the Project.

In developing the IRP, BC Hydro consulted with First Nations in the Province, including those located in proximity to the Project. A more detailed description of the First Nations consultation process on the IRP, including the issues brought forward by Aboriginal groups is documented in the BC Hydro Integrated Resource Plan First Nations Consultation Report (September 26, 2012), which is posted on BC Hydro's website at www.bchydro.com/irp.

BC Hydro notified all B.C. First Nations about the development of the IRP. There were opportunities to provide input into the development of a draft IRP, and to provide feedback on it, via two rounds of consultation in March 2011 to April 2011 and June 2012 to August 2012, as described below.

Beginning in January 2011, BC Hydro invited First Nations, Tribal Councils, and First Nations organizations to participate in the development of the draft IRP through a province-wide consultation process. The invitations included background information on the development of the IRP. In March 2011, BC Hydro hosted nine one-day workshops in regional locations around the province and invited Aboriginal groups to provide written comments by the end of April 2011. Blueberry River First Nations and the Treaty 8 Tribal Association participated in the workshop in Fort St. John. The McLeod Lake Indian Band, Tsay Keh Dene Band and the Kwadacha First Nation participated in the workshop in Prince George.

BC Hydro's presentation at the March 2011 regional workshops included a description of the IRP, an overview of how an IRP is developed, and information on six planning topics related to development of the IRP. To elicit input on electricity generation options, three example portfolios of resources were presented at the workshops: a renewable mix of run-of-river hydro and wind without the Project, a renewable mix of run-of-river hydro and wind with the Project, and a renewable mix of run-of-river hydro and wind with the Project and gas-fired generation (within the 7% non-clean Clean Energy Act target). The purpose was to explain what portfolios are and to explore the nature of portfolio trade-offs such as cost, greenhouse gas emissions, and the number of jobs created.

In May 2012, BC Hydro wrote to B.C. First Nations to provide the draft IRP and request feedback on the draft, including the IRP’s recommended actions. Between June 26 and July 13, 2012, BC Hydro hosted eight one-day workshops, and written comments were invited by August 13, 2012. West Moberly First Nations and the Treaty 8 Tribal Association participated in the workshop in Fort St. John.

During the second round of workshops, BC Hydro sought input from B.C. First Nations on the complete set of draft recommended actions, including a draft recommendation specific to the Project: “Build Site C to add 5,100 gigawatt hours of annual energy and 1,100 megawatts of dependable capacity to the system for the earliest in service date, subject to environmental certification and fulfilling the Crown’s duty to consult and, where appropriate, accommodate Aboriginal groups.”

On November 5, 2012, BC Hydro wrote to B.C. First Nations to inform them that the provincial government had extended the submission date for the IRP from December 3, 2012, to August 3, 2013. BC Hydro will continue to consider the input it has received to date on its draft IRP as it works to finalize the Plan.
In addition to the consultation process associated with the IRP described above, the Treaty 8 Tribal Association requested additional consultation regarding alternatives to the Project. A summary of these supplemental consultations is included in Volume 5 Appendix A Asserted or Established Rights and Treaty Rights, Aboriginal Interests and Information Requirements Supporting Documentation. The issues, interests, and concerns raised by the Aboriginal groups outlined in Table 9.1 through the IRP consultation process, as well as through supplemental consultations undertaken with the Treaty 8 Tribal Association regarding the need for, purpose of, and alternatives to the Project, are provided in Volume 1 Appendix H Aboriginal Information Distribution and Consultation Supporting Documentation.

Consultation Regarding Potential Effects of the Project

Following the submission of the EIS to the BCEAO and CEA Agency, BC Hydro will continue consultations with Aboriginal groups regarding BC Hydro’s effects assessment in key areas of interest. As of November 2012, BC Hydro had initiated consultation regarding potential effects of the Project on the following topics:

- Fish and fish habitat
- Vegetation and ecological communities
- Wildlife resources
- Heritage resources

Copies of presentations in regard to all of these topics were made available on the secured file transfer website for access by Aboriginal groups, and BC Hydro has made technical staff available to meet and review the presentations with Aboriginal groups upon request.

Consultations with Aboriginal groups on potential effects of the Project focused on the following:

- Reviewing the results of baseline studies
- Seeking to integrate traditional knowledge as made available to BC Hydro, including through the TLUS reports
- Reviewing and seeking input from Aboriginal groups into BC Hydro’s preliminary effects assessment
- Requesting input from Aboriginal groups regarding potential impacts to the exercise of Aboriginal and treaty rights
- Requesting input from Aboriginal groups on potential mitigation strategies

With respect to potential effects of the Project on fish and fish habitat, BC Hydro conducted meetings with Chief and Council, community meetings, and technical workshops with representatives of the Treaty 8 Tribal Association, Blueberry River First Nations, and Saulteau First Nations, beginning in the summer of 2012. BC Hydro has also made approximately 39 studies and reports related to Fish and Aquatics available through the secured file transfer website for Aboriginal groups, including reports regarding Peace River fish community indexing, Peace River and tributaries fish and habitat inventories, fish radio tracking studies, and reports related to mercury.
Beginning in the spring of 2012, BC Hydro conducted meetings with Chief and Council, community meetings, and technical workshops regarding the potential effects of the Project on wildlife resources, vegetation, and ecological communities with representatives from the Treaty 8 Tribal Association, Blueberry River First Nations, Saulteau First Nations, and Kwadacha First Nation. In October 2012, BC Hydro provided Project Area Aboriginal Groups, as well as Duncan’s First Nation, Fort Nelson First Nation, and Horse Lake First Nation, with a report entitled “Peace River Valley Ungulates Study Program, Final Report” for review. BC Hydro has also made approximately seven baseline inventory surveys and reports related to vegetation and wildlife available through the secured file transfer website for Aboriginal groups.

BC Hydro also met with representatives from the Saulteau First Nations and the Treaty 8 Tribal Association regarding the potential effects of the Project on heritage resources. Through the secured file transfer website for Aboriginal groups, BC Hydro provided reports regarding archaeological site reconciliation and heritage resources data gap analysis. Additional information on how Aboriginal groups were engaged as part of the Archaeological Field Program is available in Volume 4 Appendix C Heritage Resource Assessment Report.

In addition to the consultation led by BC Hydro and described above, in March and April of 2012, both the CEA Agency and the BCEAO wrote to Aboriginal groups outlining their preliminary understandings regarding potential effects of the Project and the potential impact on Aboriginal rights.

Consultation Regarding Potential Changes to the Downstream Conditions

With respect to the Project’s potential changes to downstream conditions, including the surface water regime, thermal and ice regime, fluvial geomorphology, and sediment transport, BC Hydro focused on consulting with interested Aboriginal groups primarily located downstream of the Project. Consultations were guided in large part by two reports. The first report, titled Stage 2 Review of Potential Downstream Changes from Site C Operations – Preliminary Findings was released in 2009 and was based on the results of studies completed up until that time, including studies on expected changes in flows and water levels, ice regime, and sediment movement in the Peace River. A subsequent Potential Downstream Changes Report was released in 2012. This report superseded the 2009 report and presented the results of updated studies completed on the same topics.

In 2008 and 2009, BC Hydro met with Aboriginal groups including the Athabasca Chipewyan, Beaver, Dene Tha’, Deninu K’ue, Duncan’s, Horse Lake, Little Red River Cree, Mikisew Cree, Salt River, Smith’s Landing, and Tallcree First Nations, as well as the Fort Chipewyan Métis Association, North Peace Tribal Council, Northwest Territory Métis Nation, and Paddle Prairie Métis Settlement, to seek early input regarding interests, issues, and concerns related to the Project, particularly as they related to BC Hydro’s preliminary understandings regarding the potential changes to downstream conditions.

In March of 2011, BC Hydro provided Aboriginal groups with a summary of the preliminary report (Stage 2 Review of Potential Downstream Changes from Site C Operations – Preliminary Findings) and offered to meet to discuss the contents. BC Hydro also provided Aboriginal groups with study outlines that provided a summary of work conducted to date as well as ongoing work in relation to the following studies:
Site C Clean Energy Project Environmental Impact Statement
Volume 1: Introduction, Project Planning, and Description
Section 9: Information Distribution and Consultation

- Water Levels and Flows Assessment
- Flood Forecasting Network Review
- Water Temperature and Ice
- Sediment Transport Studies and Monitoring
- Groundwater Studies

The purpose of the studies was to characterize existing baseline environmental conditions. BC Hydro explained that the baseline data would be used to inform the assessment of potential environmental effects associated with the Project. BC Hydro sought input from Aboriginal groups regarding the studies summarized, and indicated that they could be changed or revised in scope or timing on the basis of input from the Aboriginal groups.

On February 10, 2012, BC Hydro sent a letter to Aboriginal groups to provide an update on the progress towards completing an updated report regarding the potential downstream changes expected with the Project. The letter provided an overview of the work carried out to date, a description of the scope of the current analyses, and some preliminary study results. BC Hydro offered to meet with Aboriginal groups to review the interim results or upon completion of the updated report.

In May of 2012, BC Hydro provided Aboriginal groups with the updated report (titled “Potential Downstream Changes Report”) and requested input regarding the results. BC Hydro offered to arrange meetings between interested Aboriginal groups and the subject matter expert in hydrology to discuss the report’s findings. Consequently, beginning in the spring and summer of 2012, BC Hydro conducted meetings with the representatives of Athabasca Chipewyan, Beaver, Dene Tha’, Deninu K’ue, Duncan’s, Horse Lake, Mikisew Cree, and Smith’s Landing First Nations, as well as the Kelly Lake Métis Settlement Society, Métis Nation of Alberta – Region 6, and the Northwest Territory Métis Nation. A copy of a PowerPoint presentation regarding the potential downstream changes was also provided through the dedicated website specifically for Aboriginal groups.

Consultation Regarding the EIS Guidelines

BC Hydro Consultation Agreements included capacity funding to support consultations with Aboriginal groups throughout the environmental assessment process, including the review of both the EIS Guidelines and the EIS. In addition to funds made available to Aboriginal groups by BC Hydro, funding was also provided by the CEA Agency under the Aboriginal Funding Envelope for the Project. The CEA Agency funding review committee recommended that a condition of any funding allocation be that the applicants provide input to the environmental assessment through comments on the EIS Guidelines, the EIS, and a written submission or oral presentation at the Joint Review Panel hearings during the Joint Review Stage of the environmental assessment process (Volume 1 Section 8 Assessment Process).

In late fall 2011, BC Hydro prepared the first draft of the EIS Guidelines based in part on a consideration of issues, concerns, and interests raised by Aboriginal groups through the consultation process.

The Working Group (defined in Volume 1 Section 8 Assessment Process) provided Aboriginal groups with the opportunity to provide input into the EIS Guidelines prior to its
public release. The members of the Working Group were provided with copies of the
draft EIS Guidelines and asked to submit comments between January 31, 2012 and
March 15, 2012. Following the comment period, BC Hydro responded to over 500
comments, suggestions, and requests submitted by Aboriginal groups. BC Hydro either
incorporated the input into the draft EIS Guidelines, or where BC Hydro did not agree
with a proposed change suggested by an Aboriginal group, BC Hydro provided a
rationale and explanation as to why.

The first meeting of the Working Group was held on March 1, 2012 in Fort St, John and
included representatives from the following Aboriginal groups:

- Athabasca Chipewyan First Nation
- Dene Tha’ First Nation
- Deninu K’ue First Nation
- Duncan’s First Nation
- Kwadacha First Nation
- Fond du Lac First Nation
- Fort Chipewyan Métis Local 125
- Fort Nelson First Nation
- Little Red River Cree First Nation
- McLeod Lake Indian Band
- Métis Nation of Alberta – Region 6
- Mikisew Cree First Nation
- Prophet River First Nation
- Saulteau First Nations
- Sucker Creek First Nation
- Swan River First Nation
- Treaty 8 Tribal Association
- Woodland Cree First Nation

During this meeting, BC Hydro presented the first draft of the EIS Guidelines, including
an overview of the EIS’s proposed content as follows:

- The Project components and activities
- Need for, Alternatives to, Purpose of, and Alternative Means of Carrying out the
  Project
- Project Benefits
- Assessment Process
- Information Distribution and Consultation
• Environmental Assessment Methodology (including the scoping process, selection of valued components, spatial and temporal boundaries, effects assessment, and cumulative effects assessment)

• Technical Data, Environmental Background

• Environmental Valued Components and Effects Assessments

• Economic Valued Components and Effects Assessments

• Land Use Valued Components and Effects Assessment

• Social Valued Components and Effects Assessment

• Health Valued Component and Effects Assessment

• Heritage Valued Component and Effects Assessment

In addition to participation in the Working Group, Aboriginal groups were able to submit additional input into the draft EIS Guidelines during the public comment period, which ran from April 17, 2012 to June 1, 2012. On June 26, 2012, BC Hydro submitted responses to the public comments on the draft EIS Guidelines, including responses to over 300 additional comments, suggestions, and requests submitted by Aboriginal groups.

BC Hydro participated in agency-led consultation as part of the environmental assessment process, including six open houses during the public comment period for the draft EIS Guidelines in May 2012. Although the open houses were not specifically targeted at Aboriginal groups, approximately 60 Aboriginal people, including members from the West Moberly, Doig River, and Halfway River First Nations, attended the Open House in Dawson Creek, where they had the opportunity to express concerns directly to the CEA Agency, the BCEAO, and BC Hydro.

In May of 2012, BC Hydro sent a letter to Aboriginal groups regarding the identification of valued components and spatial boundaries for the environmental assessment and expressed its desire to consult further on these issues. The letter explained the process and rationale used to identify valued components in the draft EIS Guidelines, and attached a graphic representation of the valued components identification methodology. The letter also explained the process of defining spatial boundaries for each valued component. The letter expressed BC Hydro’s interest in receiving feedback from Aboriginal groups regarding the proposed valued components and related spatial boundaries.

On September 21, 2012, BC Hydro sent a letter to Aboriginal groups to inform them that the EIS Guidelines had been finalized by the CEA Agency and the BCEAO and provided a link to where the document was available online. In the letter, BC Hydro highlighted the areas of the EIS Guidelines that specifically addressed the incorporation of information from Aboriginal groups. BC Hydro requested any additional information such as mapping of traditional territories; traditional knowledge; concerns regarding potential for adverse effects on the various components of the environment, as identified by each Aboriginal group; current land use information, including reasonably anticipated future use of lands and resources; current use of lands and resources for hunting, fishing, and trapping; and current use of lands and resources for activities other than hunting, fishing, and trapping.

BC Hydro advised Aboriginal groups that it would like to continue to receive information with respect to any asserted or established Aboriginal rights and treaty rights of the...
community that may be adversely affected by the Project, and in particular, information concerning hunting, fishing, and trapping. BC Hydro expressed interest in understanding how the environment was valued by the community for the current use of lands and resources for traditional purposes, including activities conducted in the exercise of asserted or established Aboriginal rights and treaty rights, and how current use may be affected by the Project. BC Hydro invited Aboriginal groups to continue to identify any interests the community may have had with respect to potential social, economic, health and physical, and cultural heritage effects of the Project.

On October 25, 2012, BC Hydro sent a follow-up letter requesting that Aboriginal groups provide BC Hydro with any additional information required to support the preparation of the EIS, as outlined in the previous letter dated September 21, 2012.

Consultation Regarding the EIS

The Public and Working Group review period will provide Aboriginal groups with the opportunity to provide input respecting the EIS directly to the BCEAO and the CEA Agency. BC Hydro will support this Agency-led consultation process with working group members by providing technical support at working group meetings and by responding to information requests raised through the public and working group comment period.

Following the submission of the EIS and prior to it being finalized for submission to the Joint Review Panel, the EIS will be the focus of ongoing consultation between BC Hydro and Aboriginal groups. The baseline studies and assessments respecting key valued components, and BC Hydro’s assessment respecting impacts on the exercise of any asserted or established Aboriginal and treaty rights will form the basis of consultation. Prior to finalizing the EIS, BC Hydro will update the document with any additional issues, interests, and concerns raised by Aboriginal groups resulting from the consultation process regarding the potential effects of the Project.

Since entering into consultation with Aboriginal groups in 2007, BC Hydro has consulted in regard to the Project with all 29 Aboriginal groups identified in Table 9.1 and in Section 20.1 of the EIS Guidelines. During the course of this consultation, BC Hydro conducted over 350 meetings, and exchanged over 9000 emails, 1400 letters, 1800 telephone calls, and other communications in regard to the Project.

9.2.3.4 Key Issues and Concerns Raised by Aboriginal Groups

BC Hydro has tracked the issues, concerns, and interests identified by Aboriginal groups through the consultations described above. A summary of these issues, concerns, and interests, and BC Hydro’s corresponding consideration and response are provided in an issues tracking table in Volume 1 Appendix H Aboriginal Information Distribution and Consultation Supporting Documentation. The table provides (a) a Summary of the Issue, Concern or Interest, (b) the Source of Input, and (c) BC Hydro’s Consideration and/or Response.

Volume 3 Chapter 19 Current Use of Lands and Resources for Traditional Purposes and Volume 5 Chapter 34 Asserted or Established Aboriginal Rights and Treaty Rights, Aboriginal Interests and Information Requirements, Volume 5 Section 35 Summary of Environmental Management Plans, and Volume 5 Section 37 Requirements for the Federal Environmental Assessment also address many of the issues, concerns and interests raised by Aboriginal groups.
9.2.4 Process for Resolving Outstanding Issues Raised by Aboriginal Groups

Volume 5 Section 34 Asserted or Established Aboriginal Rights and Treaty Rights, Aboriginal Interests and Information Requirements includes a description of the potential adverse impacts on asserted or established Aboriginal and treaty rights that have not been mitigated and or otherwise accommodated as part of the environmental assessment and associated consultations with Aboriginal groups.

It is BC Hydro’s intent to continue to work with Aboriginal groups to identify both potential adverse effects of the Project on the current use of lands and resources for traditional purposes and any impacts of the Project on asserted Aboriginal or treaty rights. In some cases, Aboriginal groups have raised issues, concerns, or interests that, at time of filing of the EIS and in the view of BC Hydro, have not been fully addressed. After the filing of the EIS, BC Hydro will continue the consultation process described above. During the Panel Review Stage, particular attention will be given to resolving outstanding concerns, and this may result in further improvements to the Project as the environmental assessment process continues. BC Hydro will continue to engage in the consultation process with Aboriginal groups as a means of identifying and considering outstanding issues.

The nature of the consultation process will be in accordance with existing Consultation Agreements and/or other processes established between the parties. Generally, BC Hydro will seek to address outstanding issues by:

- Continuing consultation respecting the Project with the Aboriginal groups identified in Table 9.1
- Creating opportunities for traditional knowledge to inform project planning or operations as appropriate
- Continuing to answer questions from Aboriginal groups relating to the Project, and by making appropriate in-house expertise available to attend community meetings
- Continuing to seek input and engage in dialogue regarding the EIS and the Project, and to answer questions and address issues, interests, and concerns from Aboriginal groups by identifying appropriate mitigation measures and/or other appropriate means by which to address or resolve potential impacts
- Working closely with the CEA Agency and the BCEAO to carry out any reasonable requests of the Crown with respect to consultation
- Providing copies of the EIS and facilitating access to any relevant and reasonably available supporting documentation/studies that may be of interest to specific Aboriginal groups
- Continuing to keep Aboriginal groups informed in relation to the scope, potential effects, timing and progress of the Project
- Communicating any potential employment, contracting, or related opportunities associated with the Project, including ongoing engagement with the Aboriginal business community regarding economic opportunities

In addition to the consultation process, BC Hydro is prepared to engage with Project Area Aboriginal Groups who may have outstanding issues or concerns related to Section 35 (1) rights that may be adversely affected by the Project in ways that cannot
be fully mitigated or otherwise accommodated. In such cases, outstanding issues and concerns may be addressed as part of impact benefit agreement negotiations. Additional information regarding impact benefit agreements is available in Volume 5 Section 34 Asserted or Established Aboriginal Rights and Treaty Rights, Aboriginal Interests, and Information Requirements.

9.2.5 Construction Communication

BC Hydro is committed to ongoing dialogue with Aboriginal groups who have expressed interest in the Project. Aboriginal consultation will be guided by the information gathered during the consultation process to date and the evolving nature of the Project. This section describes BC Hydro’s proposed approach to continuing engagement with Aboriginal groups, should the Project proceed to construction, including any consultation required in relation to the issuance of permits and other required authorizations. This section will also describe BC Hydro’s proposed approach for tracking and reporting regulatory issues and concerns raised by Aboriginal groups during project construction and operations.

Following the submission of the EIS, BC Hydro is committed to seeking input from Aboriginal groups regarding the approach to construction stage communication.

9.2.5.1 Objectives

BC Hydro will continue to consult with Aboriginal groups on issues of interest, should the Project proceed to construction.

Construction stage consultation objectives include:

- Continue to facilitate a two-way exchange of information regarding the Project and activities occurring in the Project activity zone
- Negotiate and implement the terms of any impact benefit agreements reached with Aboriginal groups in regard to the Project
- Negotiate and implement the terms of any other agreements, such as communication protocol agreements that may apply
- Communicate economic opportunities to Aboriginal groups
- Continue to consult with Aboriginal groups on permits and other authorizations as required

9.2.5.2 Activities

In addition to activities proposed in Section 9.1.4, Construction Phase Communications and Community Relations, the following is an outline of expected activities to support the consultation with Aboriginal groups during the construction and operation of the Project.

Interested Aboriginal groups will continue to receive written notification of major project milestones throughout the construction stage. BC Hydro will remain receptive to meeting with any Aboriginal group to discuss the Project during the construction stage. Information shared may include construction schedules, traffic, pertinent access issues, safety, and economic or business opportunities associated with the Project.
Throughout the construction stage, Project Area Aboriginal Groups may need to be consulted regarding provincial permits and authorizations required to build the Project. Consistent with the process undertaken to date, such consultations would be led by the relevant provincial agencies with support from BC Hydro technical staff and consultants, as required.

In order to fulfill the objectives outlined above, BC Hydro may pursue communication protocol agreements with Project Area Aboriginal Groups where more in-depth or structured communication may be required. To date, BC Hydro has engaged in preliminary discussions with some Aboriginal groups regarding the establishment of one or more advisory committee(s), including representatives from interested Aboriginal groups, as a means of establishing a structured process for exchanging information and addressing issues, interests, and concerns during the construction and or operations stages. Further discussions with Aboriginal groups would be required prior to finalizing an approach.

9.2.5.3 Tracking and Reporting Regulatory Issues and Concerns

Should the project proceed to construction and operation, BC Hydro will continue to consult with Aboriginal groups in regard to the Project and liaise with government as appropriate. BC Hydro will continue to use the Consultation and Agreement Tracking Software (CATS) described in Section 9.2.3.2 to track and report regulatory issues and concerns raised by Aboriginal groups.

9.3 Agency Information Distribution and Consultation

This section describes BC Hydro’s information distribution and consultation activities undertaken with federal, provincial, and territorial governments prior to and during the environmental assessment process. Information distribution and consultation with local governments is described in Section 9.1. Information was distributed and consultation took place with agencies prior to commencement of the environmental assessment through the Technical Advisory Committees process. Once in the environmental assessment process, consultation and information distribution took place during the Pre-Panel Review stage during the preparation, review, and finalization of the EIS Guidelines. A description of these consultative processes, key discussions or issues raised, and how the input was considered by BC Hydro is described below.

9.3.1 Consultation Prior to Entering Environmental Assessment Process

In 2008 and 2009 BC Hydro consulted with provincial, federal, and municipal government agencies and First Nations to seek their input on potential environmental and socio-economic issues and on identifying information that would assist in assessing the potential effects of the Project on the biophysical and human environments. Technical Advisory Committees (TACs) were developed for Fish and Aquatics; Wildlife and Vegetation; Land and Resource Use (Agriculture, Oil & Gas, Mines, Forestry, Parks, and Conservation Lands); Recreation and Tourism; Community Services and Infrastructure; Heritage; and Greenhouse Gas.

The role of each TAC was to provide a forum for BC Hydro to present information and materials regarding environmental and social issues, studies, and options, and for participants to review, discuss, and comment on information that was provided. Participants were encouraged to seek input from others within their organization and to
share the input with BC Hydro and the other participants, subject to confidentiality considerations.

Through the TAC process, participants were invited to, and did, provide BC Hydro with any existing agency or regulatory requirements, management objectives, legislation, bylaws, or other guiding materials related to the topic.

The objectives of each of the TACs were to:

- Scope and identify potential issues (impacts and benefits) of the Project
- Review the assessment methodology for determining the potential effects of the Project
- Identify information requirements and review proposed study programs
- Consider and evaluate preliminary mitigation options (where sufficient information was available at the time) to minimize or avoid potential adverse effects or to enhance beneficial effects of the Project

Each TAC met between three and five times between September 2008 and March 2009 in a workshop format. Meetings were held primarily in Fort St. John, with some meetings taking place in Vancouver.

The exact approach taken by each TAC to address the objectives varied according to the nature of the topics, the status of available information, or participant preferences. In general, however, the structured dialogues of the meetings were consistent with the generic steps followed in an environmental assessment process, as summarized in Table 9.2.

**Table 9.2 TAC Discussions of Generic Environmental Assessment Steps**

<table>
<thead>
<tr>
<th>Typical Environmental Assessment Steps Discussed</th>
<th>TAC Focus Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>Identify Project Components – These are discrete physical components or activities of a project and/or stages of its implementation.</td>
<td>Project components and activities</td>
</tr>
<tr>
<td>Identify Endpoints – Also called valued (ecosystem or social) components (VCs), these represent key issues and considerations when assessing the effects of the project. For each endpoint, one or more “measures” were to be defined. Measures may be quantitative or qualitative, but were intended to represent a concise way of summarizing the effects of the project on the endpoint of concern.</td>
<td>Issues/VCs and rationale</td>
</tr>
<tr>
<td>Identify Potential Effects Mechanisms – Sometimes called “potential interactions” or “impact hypotheses”, mechanisms link project components and endpoints, and describe the pathways or mechanisms by which the endpoints could be affected, positively or negatively.</td>
<td>Potential interactions</td>
</tr>
<tr>
<td>Establish Scope of Assessment – Effects were to be generally characterized at multiple scales, including the local effects in the direct project area, and an assessment of the regional significance of these effects. An appropriate geographic scope of analysis was to be defined for each endpoint.</td>
<td>Scope questions</td>
</tr>
<tr>
<td>Assess Baseline Conditions – This was to involve establishing the baseline condition (pre-project) of the endpoints and measures that were to have been identified.</td>
<td>Current baseline studies/information</td>
</tr>
<tr>
<td>Assess Effects – This was to involve predicting the effect of the project on valued components (ecosystem or social) compared with either pre-project (baseline) conditions or a predicted future state without the project (base case). The analysis will generally characterize the direction, magnitude,</td>
<td>Methods for assessing potential effects</td>
</tr>
<tr>
<td>Typical Environmental Assessment Steps Discussed</td>
<td>TAC Focus Area</td>
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<tr>
<td>------------------------------------------------------------------------------------------------------------------</td>
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<tr>
<td>duration/frequency, and probability of effects.</td>
<td>Fish and aquatics, wildlife habitat/life stage limiting factors</td>
</tr>
<tr>
<td>Identify Limiting Factors – Where negative effects were to be projected to occur, an analysis was to be conducted</td>
<td>Preliminary mitigation areas</td>
</tr>
<tr>
<td>Identify Mitigation Options – Based on the assessment of effects and limiting factors, mitigation options to</td>
<td>Deferred to Stage 3</td>
</tr>
<tr>
<td>Assess Residual Effects – This was to involve estimating the net effects of the project including proposed mitigation</td>
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</table>

Input from these TACs informed the scope of baseline studies for these technical disciplines. These TACs facilitated the likelihood that early and multi-year environmental and social programs would meet anticipated regulatory principles, including consideration of Aboriginal and government agency interests, identification of the approach for determining and evaluating of potential project effects, and identification and evaluation of preliminary mitigation measures.

Invitations to participate in the TAC process were sent from BC Hydro to senior levels of potential participating agencies, and First Nations. While all B.C. Treaty 8 First Nations and the Horse Lake First Nation were invited to participate, only the Blueberry River First Nations participated in the TAC process. A separate technical advisory review process was established for the Council of Western Treaty 8 Chiefs, which is described in Section 9.2.3.3.1.

Membership in the TACs is shown in Table 9.3

**Table 9.3 Technical Advisory Committee Membership**

<table>
<thead>
<tr>
<th>Technical Advisory Committee</th>
<th>Members</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fish and Aquatics</td>
<td>• B.C. Ministry of Environment – Fisheries and Science Section</td>
</tr>
<tr>
<td></td>
<td>• B.C. Ministry of Environment – Section Head Fish and Wildlife</td>
</tr>
<tr>
<td></td>
<td>• Blueberry River First Nations</td>
</tr>
<tr>
<td></td>
<td>• Fisheries and Oceans Canada – Science Branch, Vancouver</td>
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<td></td>
<td>• Fisheries and Oceans Canada – Major Projects, Vancouver</td>
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<tr>
<td></td>
<td>• Fisheries and Oceans Canada – Fish Habitat Biologist</td>
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<tr>
<td></td>
<td>• District of Taylor</td>
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<tr>
<td></td>
<td>• Fisheries and Oceans Canada – Habitat Protection Engineer, Central Region</td>
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<tr>
<td></td>
<td>• Transport Canada – Senior Environmental Officer</td>
</tr>
<tr>
<td></td>
<td>• B.C. Ministry of Environment – Environmental Quality Regional Manager</td>
</tr>
<tr>
<td></td>
<td>• BC Hydro</td>
</tr>
<tr>
<td>Wildlife</td>
<td>• B.C. Ministry of Environment, Ecosystem Section Head (Fort St. John)</td>
</tr>
<tr>
<td></td>
<td>• B.C. Ministry of Forests – Stewardship and Range.</td>
</tr>
<tr>
<td></td>
<td>• District of Taylor</td>
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<tr>
<td></td>
<td>• Blueberry River First Nations</td>
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<tr>
<td></td>
<td>• Canadian Wildlife Service</td>
</tr>
<tr>
<td></td>
<td>• BC Hydro</td>
</tr>
<tr>
<td>Technical Advisory Committee</td>
<td>Members</td>
</tr>
<tr>
<td>-----------------------------------</td>
<td>-------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Greenhouse Gas Emissions</td>
<td>• B.C. Ministry of Environment – Climate Change Policy Analyst</td>
</tr>
<tr>
<td></td>
<td>• Environment Canada – Head, Air Quality Science Unit</td>
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<td></td>
<td>• District of Taylor – Director of Finance</td>
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<td></td>
<td>• Blueberry River First Nations</td>
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<td>• BC Hydro</td>
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<tr>
<td>Recreation and Tourism</td>
<td>• Transport Canada – Navigable Waters Protection Officer</td>
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<tr>
<td></td>
<td>• District of Taylor – Community Services Director</td>
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<tr>
<td></td>
<td>• City of Fort St. John – Director of Legal and Administrative Services</td>
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<td></td>
<td>• City of Fort St. John – Director of Community Services</td>
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<tr>
<td></td>
<td>• B.C. Ministry of Tourism, Culture and Art – District Recreation Officer</td>
</tr>
<tr>
<td></td>
<td>• B.C. Ministry of Environment – Planning Officer, Peace Regional Office</td>
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<td></td>
<td>• BC Hydro</td>
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<tr>
<td>Land and Resource Use</td>
<td>• B.C. Ministry of Forests – Stewardship Forester, Peace District</td>
</tr>
<tr>
<td></td>
<td>• District of Taylor – Fire Chief and Building Inspector</td>
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<td></td>
<td>• City of Fort St. John – Director of Planning and Engineering</td>
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<td></td>
<td>• City of Chetwynd – Chief Administrative Officer</td>
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<tr>
<td></td>
<td>• Peace River Regional District – General Manager of Development Services</td>
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<td></td>
<td>• District of Hudson’s Hope – Chief Administrative Officer</td>
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<td></td>
<td>• B.C. Ministry of Forests and Range – Range Land Officer</td>
</tr>
<tr>
<td></td>
<td>• B.C. Ministry of Environment – Planning Officer, Peace Region</td>
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<tr>
<td></td>
<td>• B.C. Ministry of Transportation and Infrastructure – District Manager</td>
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<td></td>
<td>• Blueberry River First Nations</td>
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<td>• BC Hydro</td>
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<tr>
<td>Community Services and Infrastructure</td>
<td>• Provincial Emergency Program – Regional Managers and Senior Regional Manager</td>
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<td></td>
<td>• District of Taylor – Public Works Superintendent</td>
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<tr>
<td></td>
<td>• City of Fort St. John – Chief Administrative Officer</td>
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<tr>
<td></td>
<td>• District of Chetwynd – Economic Development Officer</td>
</tr>
<tr>
<td></td>
<td>• District of Chetwynd – Chief Administrative Officer</td>
</tr>
<tr>
<td></td>
<td>• Peace River Regional District – General Manager of Development Services</td>
</tr>
<tr>
<td></td>
<td>• District Of Hudson’s Hope – Director of Works and Protective Services</td>
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<tr>
<td></td>
<td>• Blueberry River First Nations</td>
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<td></td>
<td>• BC Hydro</td>
</tr>
</tbody>
</table>

1 A summary of key discussions by the TACs is provided in Table 9.4 More detail can be found in the Site C Environmental and Socio-Economic Technical Advisory Committees Process Report, 2008 and 2009, Executive Summary in Volume 1 Appendix I Government Agency Information Distribution and Consultation Supporting Documentation.
### Table 9.4  Key TAC Discussions

<table>
<thead>
<tr>
<th>TAC</th>
<th>Key Discussions, Issues or Concerns</th>
<th>BC Hydro Consideration/Response</th>
</tr>
</thead>
</table>
| Fish and Aquatics    | 1. Identified 31 aquatic species to serve as endpoints (of concern) and suggested how they could be further categorized for study purposes. “Endpoints” include species and communities of interest that could be potentially affected by the project, and are analogous to key indicators of valued components.  
2. Developed and reviewed “effects mechanism” (cause - effect) diagrams to identify areas of potential interaction of Site C and the endpoints.  
3. Considered possible approaches to assessing effects that might be adopted in an EA process, with the goal of understanding the implications for information requirements. These included habitat-based and biodiversity/biomass-based approaches.  
4. Based on the effects diagrams, reviewed existing information and identified information gaps in consideration of likely future EA needs.  
5. Recognized the key role that an explicit set of fisheries management objectives could play in guiding a potential future EA, the TAC reviewed the draft objectives developed by the Ministry of Environment concurrent with (but separate from) the TAC process.  
6. Identified opportunities to mitigate or enhance fish outcomes with project design. The most important of these were fish passage and reservoir enhancement opportunities. For these, the TAC provided input on the process and criteria for evaluating these options, as well as associated information needs. | 1. Fish species categories were used in aquatic productivity modelling.  
2. Effects mechanisms were used to identify interactions with the projects and “key aspects” for the effects assessment.  
3. Key indicators and key aspects.  
4. Information gaps were addressed in baseline studies.  
5. During the meetings, BC Hydro indicated that the TAC needed management objectives and important key species to drive the assessment. The Ministry of Environment followed up with the draft management objectives.  
6. Opportunities identified informed the fish passage feasibility assessment, which identified all possible options along with the technically and economically feasible options. |
### TAC Key Discussions, Issues or Concerns

<table>
<thead>
<tr>
<th>TAC</th>
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<th>BC Hydro Consideration/Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wildlife</td>
<td>1. Recommended additional baseline data surveys for a number of additional species or species groups (referred to as ‘guilds’ by the TAC), including northern goshawk, northern harrier, yellow rail, Nelson’s sparrow, American bittern, Le Conte’s sparrow, fisher, grouse, woodpeckers, swallows, and dragonflies. Work on other species, such as that for Stone sheep based on input from Blueberry River First Nations, was integrated into ongoing work for the remainder of 2008/09 season.</td>
<td>1. In 2009, added species-specific studies and expanded technical study area based on TAC recommendations; EIS: 14 Wildlife Resources.</td>
</tr>
<tr>
<td></td>
<td>2. Reviewed and generally supported the definitions of proposed local and regional study areas.</td>
<td>2. EIS: 14 Wildlife Resources.</td>
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<tr>
<td></td>
<td>3. Agreed with the individual methodologies for the field studies already initiated and underway for establishing baseline data. In some cases, it was noted that main data gaps existed not with data collection in the local study area, but rather with the ability to understand that information in a regional context.</td>
<td>3. Baseline data collection was expanded to gain regional context.</td>
</tr>
<tr>
<td></td>
<td>4. Participants were unanimous in their strong preference for the full decommissioning of any new temporary access roads in the south bank of the river to avoid facilitating access by recreational users and associated degradation of wildlife values.</td>
<td>4. The number of new roads required for Project construction has been minimized through the use of existing roads or placing new roads within existing corridors. Construction of temporary access roads in ungulate winter range will be minimized. All temporary access roads will be deactivated when no longer required for project construction.</td>
</tr>
</tbody>
</table>
### Key Discussions, Issues or Concerns

<table>
<thead>
<tr>
<th>TAC</th>
<th>BC Hydro Consideration/Response</th>
</tr>
</thead>
</table>
| Recreation and Tourism (Hunting and Guide Outfitting; Fishing; Public Recreation; Tourism; Navigable Waters) | 1. Baseline data for Section 25 Outdoor Recreation and Tourism and Section 24 Harvest of Fish and Wildlife Resources includes recreation and angler survey data.  
2. Recreation use survey data used in Section 26 Navigation.  
3. Considered in Section 25 Outdoor Recreation and Tourism. Wildlife issues addressed (see Wildlife TAC discussions above). Section 22 Oil, Gas, and Energy considered the Peace River Boudreau Lake proposed protected area. Section 24 Harvest of Fish and Wildlife Resources does not consider the Peace River Boudreau Lakes proposed protected area, as the activities allowed in this new protected area would likely include hunting. |

1. Discussions related to the collection of baseline information, which included support for BC Hydro’s ongoing recreation and angler surveys.  
2. Transport Canada outlined to BC Hydro and participants the regulatory requirements related to the *Navigable Waters Protection Act*, including how the current recreation use survey should consider detail on water craft usage.  
3. Discussions about access issues and priorities between recreation and wildlife conservation interests on the south bank of the Peace River and the Peace River Boudreau Lake proposed protected area; this raised the need for the Ministry of Environment to clarify its potential management objectives for this area.
### TAC Key Discussions, Issues or Concerns

<table>
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<th>TAC</th>
<th>BC Hydro Consideration/Response</th>
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| Land and Resource Use (Forestry; Agriculture; Powerhouse Access Bridge; Transportation (highways); Minerals and Aggregate; Oil and Gas; Land Use Planning; Trapping; Traditional Use Activities) | 1. Land being altered or converted from its current use<br>   - Considered in Section 20 Agriculture<br>   - Considered in Section 21 Forestry  
2. Land and resource use effects assessments consider impediments to or alienation of access (agriculture, forestry, minerals and aggregates, oil, gas, and energy).  
3. Project design was updated and no longer includes a permanent powerhouse access bridge.  
4. Existing regulatory processes are in place to address this concern.  
5. The Peace River Boudreau Lake proposed protected area is included in the baseline conditions for the land and resource use effects assessment.  
6. Cumulative effects assessment is described in Section 10.5 Cumulative Effects Assessment. |

1. Land being altered or converted from its current use  
   - Loss of agricultural land, or the conversion of land away from agricultural purposes, including fragmentation of farm land.  
   - Loss of timber from the timber harvest land base and an associated potential change to the annual allowable cut, and possible pricing and market distortions to the regional forestry industry associated with project clearing activities (i.e., merchantable timber).  
2. Impeding access to or alienation of resources.  
3. Potential “public use” of the powerhouse access bridge – any future decision to allow “public use” of the powerhouse access bridge would increase the study area for assessing project effects on land and resource use, due to increased access to south bank land and resources, and a possible shift in regional travel and access patterns.  
4. Local government future development areas – understanding any direct or indirect project effects or constraints to local government planning boundaries (e.g., would it be more difficult for local governments to withdraw areas from the ALR).  
5. Regional land use planning clarifying the future base case against which project effects would be compared, including the Peace River Boudreau Lake proposed protected area.  
6. The importance of including a cumulative effects assessment associated with other land use activities and developments was raised.
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<th>TAC</th>
<th>Key Discussions, Issues or Concerns</th>
<th>BC Hydro Consideration/Response</th>
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| Community Services and Infrastructure (Labour Market; Housing; Community Infrastructure; Education; Health Services; Solid Waste Management; Government Finances – Economic Development; Lifestyle and Recreation; Public Safety) | 1. Local labour market effects associated with the potential project construction phase.  
2. Need to understand the potential implications of temporary and permanent construction worker housing requirements, and worker housing alternatives, including the location and size of any worker camps.  
3. Demographic and population changes in host communities, if people move to the area in response to employment opportunities.  
4. Any requirements by the project for community services (e.g., education, health, or recreation) or infrastructure (e.g., sewer, water or waste).  
5. The lead time necessary for local or provincial governments to plan for and implement any services or infrastructure programs after a decision has been made to proceed with the project.  
6. The limited capacity of current regional solid waste management facilities to accept project waste.  
7. The inter-community effects between northern communities associated with the potential project. | 1. Considered in Section 17 Labour Market  
2. Described in Section 4 Project Description and considered in Section 29 Housing  
3. Considered in Section 28 Population and Demographics, Section 17 Labour Market, and Section 18 Regional Economic Development  
4. Considered in Section 30 Community Infrastructure and Services  
5. Considered in Section 30 Community Infrastructure and Services  
6. Considered in Section 30 Community Infrastructure and Services  
7. Considered in Section 28 Population and Demographics and Section 18 Regional Economic Development. |
| Heritage | 1. Changes in the condition or integrity of an archaeological site,  
2. Changes in access to a site for future scientific investigation or research,  
3. Spiritual value or importance of a site,  
4. The ability to use the site for social and traditional use purposes,  
5. Appropriate approach for carrying out an archaeological inventory and a general framework for guiding a sampling program was agreed to. | 1. Considered in Section 32 Heritage Resources  
2. Considered in Section 19 Current Use of Lands and Resources for Traditional Purposes and Section 34 Asserted or Established Aboriginal and Treaty Rights, Aboriginal Interests, and Information Requirements  
3. Considered in Section 32 Heritage Resources  
4. Considered in Section 32 Heritage Resources  
5. Considered in Section 32 Heritage Resources |
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<th>TAC</th>
<th>Key Discussions, Issues or Concerns</th>
<th>BC Hydro Consideration/Response</th>
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| Greenhouse Gas Emissions | 1. To enable comparison of Site C to other generation technology options, consistent methodologies should be used if possible (e.g., life cycle emissions accounting).  
2. Project emissions should be cumulative over the project lifespan.  
3. Maintain an ongoing understanding of policy and modelling methods (e.g., Western Electricity Coordinating Council, Province of B.C., and international).  
4. Update the estimate to include greenhouse gases (GHG) aspects of project construction, including fuel consumption and materials such as cement.  
5. At a later date, consider including GHG aspects of road and highway use changes, pending final decisions regarding regional roads.  
6. Preliminary discussion of GHG mitigation strategies included:  
   - Use of a conveyor belt (as used at W.A.C. Bennett Dam) to move material  
   - A biomass energy plant (thermal only or cogeneration) to combust wood waste  
   - Use of “clean” equipment in the construction of the dam site  
   - Use of Best Available Proven Technology (BAPT)  
   - Purchase of carbon credits | 1. Considered in Section 5 Need for, Purpose of, and Alternatives to the Project  
2. Considered in Section 15 Greenhouse Gases.  
5. No changes in regional road utilization to include in model update.  
6. Preliminary discussion of GHG mitigation strategies  
   - Conveyor belt incorporated into updated Project design  
   - Wood waste will be available to local biomass consumers; discussed in Volume 1 Appendix A Vegetation, Clearing, and Debris Management Plan and Section 15 Greenhouse Gases  
   - Subject to procurement and contract terms  
   - Subject to procurement and contract terms  
   - Other mitigation alternatives favoured |
The information provided by the TACs has been incorporated into the environmental assessment in a number of ways:

- “Endpoints” identified by the Fish and Aquatics, Wildlife Resources, and Greenhouse Gas Emissions TACs have been taken into account in the identification and selection of valued components and/or their key indicators
- Values identified in the Community Services and Infrastructure, Recreation and Tourism, and Land and Resource Use TACs have been carried forward as valued components in the environmental assessment
- Baseline studies, field programs, and methods used have been directly informed by the TAC process
- Local and Regional Assessment Area boundaries for some valued components were informed in part using information gained from the TACs

Consultation with the Province of Alberta and the Northwest Territories

In addition to consulting with communities and Aboriginal groups, the BC Energy Plan also indicated that the Province and BC Hydro needed to consult with the Province of Alberta. Subsequently, the provincial government provided direction to include the Northwest Territories in interprovincial consultation. BC Hydro has played a supporting role to these initial discussions, as it is the provincial government that took the lead on any interprovincial consultation involving other governments.

9.3.2 Consultation During the Environmental Assessment Process

BC Hydro’s Project Description Report was submitted to the BCEAO and the CEA Agency on May 17, 2011. On September 30, 2011, the federal Minister of the Environment and the B.C. Minister of the Environment announced a cooperative environmental assessment of the Project, including the establishment of a Joint Review Panel. The cooperative review process is described in detail in Volume 1 Section 8.3 Cooperative Review Process.

Information distribution and consultation with federal, provincial, and territorial agencies during the Pre-Panel Review Stage of the environmental assessment has been and will continue to be through participation in the Working Group (Volume 1 Section 8.3 Cooperative Review Process). Following submission of the EIS, these consultation activities will continue through the Joint Review Panel Stage.

An introductory meeting of the Working Group was held in Fort St. John on October 5, 2011 as a means of introducing the environmental assessment process and providing an overview of the Project to future Working Group members.

Preparation and Review of the EIS Guidelines

BC Hydro prepared and submitted draft version 1 of the EIS Guidelines for Working Group review in January 2012. The first Working Group meeting took place on March 1, 2012 in Fort St. John, and provided the Working Group with an overview of the content of the EIS Guidelines and an opportunity to ask questions about the draft EIS Guidelines. During the meeting, two issues arose for which BC Hydro subsequently provided further information to the Working Group through the BCEAO and the CEA Agency: electricity power distribution, and spatial study area and assessment boundaries.
During the Working Group review period of January 31 to March 15, 2012, the Working Group provided 26 submissions totalling 1,007 comments, suggestions, and requests to the CEA Agency and BCEAO. BC Hydro received the submissions on March 15, 2012 and provided a response package to the CEA Agency and BCEAO on March 30, 2012. The documents in the package included a covering letter, Topic Summaries on 13 recurring themes, and a table containing the comments and responses (BC Hydro 2012a). The Topic Summaries discussed the following recurring themes:

- Acid rock drainage & metal leaching
- Alternatives to the Project and planning
- Caribou
- Cumulative effects assessment
- Current use of lands & resources
- Dam safety
- Decommissioning
- Impact lines
- Methylmercury
- Peace Athabasca Delta
- Project need and purpose
- Seismic considerations
- Valued component selection & boundaries

Included in the response package submitted to the CEA Agency and BCEAO was a revised draft version 2 of the EIS Guidelines, reflecting review comments provided by the Working Group and BC Hydro’s responses.

The CEA Agency and the BCEAO reviewed and considered the documents in the response package and issued draft version 3 of the EIS Guidelines (available for download at http://www.ceaa.gc.ca/050/documents/55590/55590E.pdf) for public review and comment effective April 17, 2012. During this period of public review, many provincial, regional, and local government agencies provided further comment; some agencies took the opportunity to provide comment during both review periods, with others providing comment in one of the two comment periods. The public review period came to a close on June 1, 2012 with 912 individual submissions, resulting in a total of 1,388 comments received by the CEA Agency and BCEAO.

On June 26, 2012 BC Hydro provided detailed responses (BC Hydro 2012b) to the review comments in tabular format along with a covering letter providing discussion on key topics; three separate tables were submitted in response to comments from Aboriginal groups, the public, and government agencies. In addition, 16 Topic Summaries providing more detailed information on the following recurring themes were issued, along with the three response tables:

- Agriculture (new)
- Acid rock drainage and metal leaching (no changes)
• Alternatives to the Project and planning (updated)
• Caribou (updated)
• Cumulative effects assessment (updated)
• Current use of lands & resources (updated)
• Dam safety (updated)
• Decommissioning (no changes)
• Downstream technical study area boundaries (new)
• Hydroelectric storage and dispatchable capacity (new)
• Impact lines (no changes)
• Mercury (title changed from Methylmercury; no other changes)
• Project need and purpose (updated)
• Public information distribution and consultation (new)
• Seismic considerations (no changes)
• Valued component selection and boundaries (updated)

Topics of interest or concern identified by federal and provincial government agencies during the development and review process of the EIS Guidelines are summarized below at a high level, by agency.

**Alberta Environment**
Alberta Environment submitted comments related to the following topics of concern during review of the EIS Guidelines:
• Spatial boundaries should be expanded farther downstream into Alberta and the Northwest Territories
• Baseline data collection and field survey programs: fish and fish habitat, wildlife resources
• Environmental assessment methods: fish and fish habitat; wildlife resources; vegetation and ecological communities
• Potential accidents and malfunctions
• Project components: project construction activities and water quality; reservoir operations water management
• Cumulative effects; sediment transport; surface water regime
• Consultation and engagement
• Environmental management plans: reservoir water management

**B.C. Ministry of Agriculture**
The B.C. Ministry of Agriculture submitted comments related to the following topics of concern during review of the EIS Guidelines:
• Project benefits

• Alternatives to the Project

• Baseline data collection and field survey programs: agriculture; climate change; micro-climate; ungulates

• Potential changes or effects due to the Project: geology, terrain and soils; groundwater regime; economics; labour market; surface water regime; wildlife resources

• Agricultural mitigation and compensation

• Cumulative effects; agriculture; land status, tenure, and Project requirement

**B.C. Ministry of Environment**

The B.C. Ministry of Environment submitted comments related to the following topics of concern during review of the EIS Guidelines;

• Potential changes or effects: groundwater; methylmercury; water quality; sediment transport; surface water regime; human health

• Cumulative effects; Project Inclusion List

• Quality of data presented in the EIS

**B.C. Ministry of Forests, Lands and Natural Resource Operations**

The B.C. Ministry of Forests, Lands and Natural Resource Operations submitted comments related to the following topics of concern during review of the EIS Guidelines:

• EA process: technical working groups; consultation and engagement

• Project benefits

• Project overview and description: project location, GIS shape files; mapping; project construction activities

• Project components; construction access roads; Highway 29 realignment; quarried and excavated materials; reservoir clearing and preparation; worker housing; project decommissioning

• Alternatives to the Project

• Spatial boundaries: fish and fish habitat; harvest of fish and wildlife resources; outdoor recreation and tourism; vegetation and ecological communities; wildlife resources

• Valued component selection: fish and fish habitat; forestry; heritage resources; vegetation and ecological communities; wildlife resources

• Environmental assessment methods: residual effects characterization; greenhouse gases; surface water regime

• Baseline data collection and field survey programs: agriculture; fish and fish habitat; vegetation and ecological communities; forestry; harvest of fish and wildlife resources; heritage resources; minerals and aggregates; visual resources; wildlife resources
- Predictive models: geology, terrain and soils; greenhouse gases; surface water; thermal and ice regime; sediment transport; vegetation and ecological communities; visual resources.
- Potential changes or effects: forestry; vegetation and ecological communities.
- Mitigation and compensation: vegetation.
- Cumulative effects: Project Inclusion List; agriculture.

**B.C. Ministry of Jobs, Tourism and Innovation**

The B.C. Ministry of Jobs, Tourism and Innovation submitted comments related to the following topics of concern during review of the EIS Guidelines:

- Project overview and description: project location and description.
- Project need and purpose.
- Project benefits; employment estimates; contractor supply services estimates.
- Project costs; capital construction costs; operating costs.
- Potential changes or effects: economic; local government revenue.

**British Columbia Utilities Commission**

The British Columbia Utilities Commission provided comments during the Working Group review period. The Commission raised regulatory and permitting considerations in relation to an Application for a Certificate of Public Convenience and Necessity, with respect to: project description; comparison of capital costs; project cost estimate; revenue requirements; cost/benefit analysis.

**Fisheries and Oceans Canada**

Fisheries and Oceans Canada submitted comments related to the following topics of concern during review of the EIS Guidelines:

- Technical data being available during review of the EIS.
- Alternative means of undertaking the Project.
- Spatial boundaries: fish and fish habitat; harvest of fish and wildlife resources; thermal and ice regime; water quality.
- Temporal boundaries: groundwater regime.
- Valued component selection or attributes: fish and fish habitat VC rationale and key aspects.
- Baseline data collection and field survey programs: fish and fish habitat.
- Potential changes or effects: fish and fish habitat effects due to changes in mercury, thermal and ice regime; fish passage and entrainment; fisheries related effects on Aboriginal groups.
- Mitigation and compensation: fish habitat mitigation and compensation planning.
- Cumulative effects; Regional Assessment Area.
- Follow-up and monitoring plans.
Environment Canada submitted comments related to the following topics of concern during review of the EIS Guidelines:

- EA process: technical working group on ecological flow; consultation and engagement
- EIS content: mapping requirements; technical data availability
- Alternative means of undertaking the Project
- Alternatives to the Project
- Project benefits
- Project need and purpose
- Project overview and description
- Project components; reservoir operations and maintenance activities; reservoir operations water management; worker housing; reservoir clearing and preparation.
- Spatial boundaries: Aboriginal rights (asserted or existing); fish and fish habitat; water quality; surface water regime; air quality; microclimate; current use of lands and resources for traditional purposes; sediment transport; thermal and ice regime; vegetation and ecological communities; wildlife resources.
- Temporal boundaries: microclimate
- Valued component selection: interactions; factors to be considered in VC selection; wildlife resources
- EA methods: interactions ratings; full description and justification of methods
- Baseline data collection and field survey programs: construction emissions and air quality; greenhouse gases; groundwater regime; methylmercury; microclimate; water quality
- Predictive models: methods used to develop and validate models
- Potential changes or effects: effects of the environment on the project (climate change); potential contaminated sites; potential greenhouse gas emissions; groundwater regime; surface water regime; water quality; thermal and ice regime; methylmercury; vegetation and ecological communities (including wetlands); acid rock drainage; sediment transport
- Mitigation and compensation: sediment and runoff control during project construction
- Cumulative effects; spatial boundaries; Project Inclusion List; pre-development baseline; climate change and project changes; surface water regime; wildlife resources; microclimate; sediment transport
- Follow-up and monitoring plans: requirements per the Canadian Environmental Assessment Act; incorporation of adaptive management; construction effects on aquatic environment
• Potential accidents and malfunctions; general prevention and mitigation
• Project decommissioning

**Government of the Northwest Territories**

The Government of the Northwest Territories submitted comments related to the following topics of concern during review of the EIS Guidelines:

• Project overview and description: reservoir; operations water management;
• Spatial boundaries: government expertise to establish boundaries; current use of lands and resources; methylmercury; sediment transport; surface water regime; thermal and ice regime; water quality
• Valued component selection: effects of past energy projects on the Peace River
• Environmental assessment methods: determination of significance
• Predictive models: water quality; surface water regime
• Potential changes or effects: project construction activities and water quality
• Cumulative effects; pre-development baseline; Project Inclusion List; past energy projects on the Peace River
• Follow-up and monitoring plans

**Health Canada**

Health Canada submitted comments related to the following topics of concern during review of the EIS Guidelines:

• EIS content: reference documents; mapping; data, analysis reports
• Spatial boundaries: noise and vibration
• Temporal boundaries: human health
• Environmental assessment methods: human health
• Baseline data collection and field survey programs: methylmercury
• Potential changes or effects: air quality and human health; electric and magnetic fields and human health; mercury in fish and human health; noise and vibration; thermal and ice regime and harvest of fish and wildlife resources
• Cumulative effects; human health
• Follow-up and monitoring plans; methylmercury; drinking water quality

**Natural Resources Canada**

Natural Resources Canada submitted comments related to the following topics of concern during review of the EIS Guidelines.

• EIS content: regulatory considerations
• Alternative means of undertaking the Project: geotechnical analysis of alternate sites
• Project overview and description: project design criteria
• Project components; reservoir debris clearing and disposal; dam site and generating station; reservoir clearing and preparation; quarried and excavated materials
• Spatial boundaries: sediment transport; vegetation and ecological communities
• Valued component selection: vegetation and ecological communities
• Baseline data collection and field survey programs: methylmercury
• Potential changes or effects: seismic considerations and the effects of the environment on the project; acid rock drainage; forestry; geology, terrain and soils; methylmercury; vegetation and ecological communities
• Mitigation and compensation: reservoir clearing and methylmercury
• Cumulative effects; methylmercury; induced seismic activity from hydraulic fracking
• Environmental management plans: seismic considerations; methylmercury; acid rock drainage; vegetation
• Follow-up and monitoring plans; seismic considerations; reservoir slope stability monitoring

Northern Health
Northern Health submitted comments related to the following topics of concern during review of the EIS Guidelines:
• EA process: consultation and engagement
• Project components: worker housing
• Potential changes or effects: human health; air quality; agriculture and food security; electric and magnetic fields; greenhouse gases; groundwater regime; community infrastructure and services; socio-economic (general); water quality; surface water regime
• Mitigation and compensation: air quality; human health

Parks Canada
Parks Canada submitted comments related to the following topics of concern during review of the EIS Guidelines:
• Spatial boundaries: regional assessment area should include Peace Athabasca Delta; fish and fish habitat; outdoor recreation and tourism; sediment transport; surface water regime; thermal and ice regime; vegetation and ecological communities
• Temporal boundaries: pre-development baseline within the Peace Athabasca Delta
• Valued component selection: special protected areas; cultural importance of PAD to Aboriginal Peoples
• Environmental assessment methods: residual effects characterization criteria
• Potential changes or effects: current use of lands and resources for traditional purposes; fish and fish habitat; harvest of fish and wildlife resources; outdoor recreation and tourism; vegetation and ecological communities; wildlife resources
Environmental management plans: ice and water management plans
Cumulative effects; pre-development baseline within the boundaries of Wood Buffalo National Park

Transport Canada
Transport Canada submitted comments related to the following topics of concern during review of the EIS Guidelines:
- EIS content: consultation and engagement issues; regulatory considerations (blasting, navigation)
- EA process: consultation and engagement
- Project components; Highway 29 realignment; reservoir clearing and preparation and debris management; reservoir filling and commissioning; reservoir operations water management; transmission lines; reservoir filling and commissioning
- Spatial boundaries: Navigation Regional Assessment Area should include Peace Athabasca Delta
- Temporal boundaries: all project phases to be considered in assessment
- Valued component selection: Aboriginal interests
- Environmental assessment methods: cumulative effects; consultation and engagement issues; valued component selection; mitigation and compensation; linkages between technical subject matter and VCs
- Baseline data collection and field survey programs: navigation
- Potential changes or effects: Aboriginal rights (asserted or existing); current use of lands and resources for traditional purposes; resource harvesting; navigation; sediment transport; indirect effects to navigation; thermal and ice regime
- Mitigation and compensation: navigation compensation plan; facilitate transit at dam site; debris management
- Cumulative effects; pre-development baseline; navigation

Following the comment period, a meeting was held on May 17, 2012 in Vancouver, B.C. The issues discussed during this meeting were: 1) downstream spatial boundaries, and 2) the approach to assessing cumulative effects. Participants in this meeting are listed in Table 9.5; the asterisk indicates participation via teleconference.
Table 9.5  May 17, 2012 Meeting Agency Participants

<table>
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<tr>
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<td><strong>CEA Agency</strong></td>
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<tr>
<td></td>
<td>Linda Jones  Panel Manager</td>
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<tr>
<td></td>
<td>Analise Saely  Crown Consultation Coordinator</td>
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<td></td>
<td>Phil Seeto *  Analyst</td>
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<td><strong>BCEAO</strong></td>
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<td>Brian Murphy  Project Director</td>
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<td><strong>Environment Canada</strong></td>
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<tr>
<td></td>
<td>Laura MacLean  Head, Environmental Assessment Unit</td>
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<td></td>
<td>Warren Fenton  Guidance and Strategies</td>
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<td></td>
<td>Al Colodey  Sr. Advisor, Water Science and Technology</td>
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<td></td>
<td>Lorna Hendrickson*  Head, Environmental Assessment South</td>
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<td></td>
<td>Leslie Yasul* (Edmonton)  Environmental Assessment Coordinator</td>
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<td></td>
<td>Kathryn Fraser* (Edmonton)  EA Coordinator</td>
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<td></td>
<td>Raimo Kallio* (Ottawa)  Water Resources</td>
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<td></td>
<td>Manon Lalonde* (Ottawa)  Water Resources</td>
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<td></td>
<td>Andrew Robinson  Environmental Assessment, Canadian Wildlife Service</td>
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<td></td>
<td>Liliana Gwizdkowska*  Environmental Assessment and Marine Programs Division</td>
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<td></td>
<td>Barrie Bonsal* (Saskatoon)  Hydrological Process and Modelling Research</td>
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<td>Daniel Peters  Hydrological Process and Modelling Research</td>
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<td>Raimo Kallio*  Integration and Analysis</td>
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<td><strong>Transport Canada</strong></td>
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<td>Suzanne L’Heureaux  Sr. Environmental Officer</td>
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<td>John Mackie  Navigable Waters Protection Officer</td>
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<td>Colin Parkinson  Navigable Waters Protection Officer</td>
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<td>Jo-Anne Foy* (Winnipeg)  Superintendent, Major Projects Management Office</td>
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<td>Technical and Environmental Services</td>
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<td>Shannon Vollema* (Edmonton)  Navigable Waters Protection Officer (Coordinator)</td>
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<td><strong>Fisheries and Oceans Canada</strong></td>
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<td>Brenda Andres  Environmental Analyst, Fisheries and Oceans Canada</td>
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<td>Mike Bradford  Research Scientist</td>
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<td>Wanda Watts*  Senior Habitat Biologist</td>
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<td>Alberta District - Peace River Office</td>
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<td><strong>Parks Canada Agency</strong></td>
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<td>John Olysagner  Resource Conservation</td>
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<td>Salman Rasheed*  Resource Conservation</td>
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<td>Steve Oates  Resource Conservation</td>
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<td><strong>Natural Resources Canada</strong></td>
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<td>Jess Coulson* (Ottawa)  Team Leader</td>
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<td>Tim Archer* (Ottawa)  Senior Operational Officer, Western Operations</td>
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Consideration of and Response to Issues Raised during Preparation and Review of the EIS Guidelines

Issues raised by government agencies during both the Working Group and public review of the EIS Guidelines, summarized above, are presented in greater detail in the EIS Guidelines Review Government Agency Issues Tracking Table found in Part 1 of Volume 1 Appendix I Government Agency Information Distribution and Consultation Supporting Documentation. This summary table also describes how the issues were considered or addressed by BC Hydro, either in the information provided in the EIS or in the response documents described above.
From the perspective of BC Hydro, all of the issues raised by agencies during both EIS Guidelines review periods have been addressed through the response packages submitted to the CEA Agency and BCEAO or through information provided in this EIS. The “consideration/response” column of the Government Agency Issues Tracking Table demonstrates how each issue raised was resolved in one of the following ways:

- **IR (&name):** Requests for information/clarification were addressed or responded to directly in the IR response table.
- **Topic Summary (&name):** Requests for information/clarification were addressed or responded to by information in the indicated Topic Summary, issued along with the IR response tables.
- **EIS (&section):** Requests for changes to the EIS Guidelines that were considered by BC Hydro to be material to the scope of the environmental assessment were either accepted or the change was recommended by BC Hydro to the BCEAO and CEA Agency. Consideration and discussion of the topic can be found in the respective section of the EIS.

Requests for changes to the EIS Guidelines that were editorial in nature were often accepted or a recommendation was made by BC Hydro to the BCEAO and the CEA Agency to make the change. These editorial comments are not included in the issues table.

After considering the 2,395 comments made by the members of the Working Group and the public, BC Hydro’s responses to the comments, and the discussion on spatial boundaries and cumulative effects, the Executive Director of the BCEAO and the Minister of Environment of Canada finalized and issued the EIS Guidelines on September 7, 2012.

### 9.3.3 Construction Communication

Should the Project proceed to construction, BC Hydro will communicate with agencies with respect to compliance with permits, authorizations, and regulatory requirements. An overview of the methods to be used to document and report the status of project compliance with respect to requirements and conditions to the CEA Agency, federal authorities, BCEAO, and provincial ministries are described in Volume 5 Section 36 Compliance Reporting.
References

Internet Sites
