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<td>2-35</td>
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2.0 PROJECT OVERVIEW

2.1 The Proponent

Glacier Power is a wholly owned subsidiary of Canadian Hydro Developers, Inc. (Canadian Hydro). Canadian Hydro is Canada’s largest independent developer of EcoLogo® certified low-impact renewable energy\(^1\). Publicly listed since 1990 (TSX symbol \(KHD\)), the company owns and operates 18 renewable power facilities spread across Canada in British Columbia, Alberta and Ontario. Run-of-river hydroelectric power accounts for 12 plants totalling 86.2 MW, wind-generated electricity accounts for five plants totalling 118.3 MW, and biomass one 25 MW plant. Glacier Power does not own or operate any existing facilities. The Dunvegan Hydroelectric Project (the Project) will be managed and operated by the Chief Operating Officer and Hydroelectric Division Manager of Canadian Hydro, Glacier Power’s parent company.

Canadian Hydro’s renewable power allows future generations to have reliable, efficient and affordable energy supplies. Additional information on the company and its projects is available at: http://www.canhydro.com.

The primary contacts for Glacier Power and Canadian Hydro are:

**Glacier Power Ltd.**

Company Address: 500, 1324–17 Avenue SW, Calgary, AB T2T 5S8

Incorporated: Northwest Territories, February 6, 1997
Continued to Province of Alberta, January 22, 2001
(Corporate Access # 209158286)

Registered: Province of Alberta, November 25, 1999

President and Chief Operating Officer: Ross Keating

Manager of Hydroelectric Division: Dave Keevill

**Canadian Hydro Developers, Inc.**

Company Address: 500, 1324–17 Avenue SW, Calgary, AB T2T 5S8

Amalgamated: Province of Alberta, December 1990 (Incorporation #207657784)

Primary Contact: Ross Keating, President
Phone: (403) 298-0250     Fax: (403) 244-7388

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\(^1\) Low-impact renewable energy includes wind, solar, earth energy, run-of-river hydroelectric and sustainable biomass fuels. These are non-fossil fuel energy sources that are replenished through the earth’s natural cycles and have a minimal impact on the environment and human health (Environment Canada 2005, Internet site).
2.2 Proposed Project Site

The project site is on the Peace River approximately 2 km west of the Dunvegan Bridge. Dunvegan is 80 km north of the City of Grande Prairie and 20 km south of the Town of Fairview. Access from Highway 2 to the project site is feasible along both sides of the river through a combination of private and Crown Land. Figure 2.2-1 illustrates the location of the Project.

At the proposed powerhouse location, the Peace River valley is deeply incised into glacial drift overlying mudstones. River valley bottom width is 420 m and valley wall slopes are typically in excess of 2:1. Channel width is approximately 400 m at 1500 m$^3$/s mean annual flow (MAF) and an average depth of approximately 4 m. The valley bottom is infilled with sand and gravel up to 30 m in depth. At the proposed project site, the riverbed is at elevation 338 m and the uplands adjoining the valley have an elevation of 520 m, giving a valley depth of about 180 m. The Peace River occupies an entrenched valley with high, irregular, and relatively steep slopes (approximately 45° on lower slopes, approximately 20° on upper slope) with varying degrees of stability and gully formations. The valley walls are generally bare or grassland on the northern (south-facing) wall and moderately forested on the south (north-facing) wall.

2.3 Project Components

The Project entails building a spillway and powerhouse across the Peace River about 2 km upstream from the Dunvegan Bridge. The Project is designed to increase the water level in the river at the headworks by 6.6 m on average to create adequate differential for the operation of a 100 MW low-head hydroelectric facility. The facility is a run-of-river hydroelectric plant that produces power from the flow of the river without storing water, and therefore does not regulate or change the flow regime downstream of the facility.

The powerhouse will consist of 30 turbine units arranged side by side extending from the south bank of the main channel and 10 turbine units arranged side by side extending from the north bank of the main channel for a total powerhouse length of 288 m. A crest gated spillway will extend between the north and south sets of powerhouse units across the remaining 110 m of channel width to maintain sufficient water level differential across the structure. Based on mapping of the local project area at 2-m contour intervals using orthographic air photos, the headpond created by the headworks structure will extend up to approximately 26 km upstream of the powerhouse and spillway. The increase in water level will result in a new water-bank interface zone that will inundate between 106 ha and 215 ha when comparing the pre-and post-project 5 percent and 95 percent exceedance conditions, respectively. The total extent of inundation is approximately equal to the current 1:100 year flood level.

The facility incorporates a boat lock for upstream and downstream passage of river traffic and a boat ramp upstream of the headworks to provide direct access to the headpond. The ramp fishways (fish ladders) will be placed on each bank to provide for upstream fish migration and 10 fish sluices will be placed between groups of five powerhouse units for downstream fish migration.
The project powerhouse, fish sluices and spillway are within the present wetted portion of the river channel, whereas the headworks abutments at each end of the headworks structure, the boat lock, boat ramp and the two ramp fishways are outside the present wetted channel on Crown Land.

Power will be transmitted along a new 144-kV transmission line for approximately 4.3 km to the southeast of the Project to interconnect at the existing ATCO 144-kV line (7L73-1).

Access to the project site will be available along both sides of the river through a combination of private and Crown Land.

A summary table of the project components and a detailed description of each component is presented in Section 3.0.

### 2.4 Land Tenure

The project headworks structure is in the river channel except at each end where the abutments will be on Crown Land. The headpond will be adjacent to Crown Land, much of which has been assigned grazing leases and traplines (referred to as registered fur management areas). Facilities on Crown and titled land at or adjacent to the Project include:

- the headworks abutments on Crown Land in SE-13-80-5-W6M on the north side of the river and in NE-12-80-5-W6M on the south side of the river
- the access road along the north bank of the river, which is partially on titled land, Crown Land, or municipal road allowances including SE-13-80-5-W6M, SW-18-80-4-W6M, NW-7-80-4-W6M and NE-7-80-4-W6M
- the access road along the south bank of the river, which is partially on Crown Land and titled land including NE-12-80-5-W6M, NW&SW-7-80-4-W6M
- the transmission line that interconnects at a new substation 4 km south of the Project, and be routed along the south access road through NE-18-80-5-W6M, NW&SW-7-80-4-W6M, and then follow Highway 2 to the interconnection with the new substation at NW-31-79-4-W6M

The Project works on Crown Land will require a License of Occupation, including the headpond inundation areas, weir abutments, control buildings, boat ramp, and boat ramp. Easements will also be required for the transmission line and access roads on Crown Land.

Where the access road and transmission line routes pass through titles land, agreements with the landowners and leaseholders have been signed.

Figure 2.4-1 illustrates the location of the Project in relation to Crown Land and deeded land.
2.5 Project Development Schedule

The environmental approvals and permitting timing was developed in consultation with both provincial and federal agencies responsible, particularly AENV, the EUB and the Canadian Environmental Assessment Agency. Glacier Power anticipates a one-year review period for the Environmental Impact Assessment (EIA) and EUB and Natural Resources Conservation Board (NRCB) Application and hopes to receive final approval for the Project granted as of September 2007. Table 2.5-1 presents the timing of project activities, based on a September 2007 approval. A detailed project construction schedule is provided in Section 3.0 (Project Description).

<table>
<thead>
<tr>
<th>Item</th>
<th>Start</th>
<th>Complete</th>
</tr>
</thead>
<tbody>
<tr>
<td>EIA and EUB and NRCB application review and approval</td>
<td>October 2006</td>
<td>October 2007</td>
</tr>
<tr>
<td>Detailed engineering</td>
<td>October 2007</td>
<td>December 2008</td>
</tr>
<tr>
<td>Tender, award and engineer turbine and major equipment</td>
<td>September 2007</td>
<td>April 2009</td>
</tr>
<tr>
<td>Manufacture turbine and major equipment</td>
<td>February 2008</td>
<td>January 2009</td>
</tr>
<tr>
<td>Pre-assembly of turbine</td>
<td>April 2009</td>
<td>August 2010</td>
</tr>
<tr>
<td>Site preparation, abutments, boat lock and fishways</td>
<td>April 2008</td>
<td>July 2009</td>
</tr>
<tr>
<td>construction</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construct powerhouse and spillway</td>
<td>April 2009</td>
<td>September 2011</td>
</tr>
<tr>
<td>Complete mechanical and electrical construction</td>
<td>September 2009</td>
<td>November 2010</td>
</tr>
<tr>
<td>Transmission line construction</td>
<td>May 2008</td>
<td>August 2008</td>
</tr>
<tr>
<td>Commission plant</td>
<td>August 2011</td>
<td>September 2011</td>
</tr>
<tr>
<td>Commercial operation</td>
<td>September 2011</td>
<td></td>
</tr>
</tbody>
</table>

Key factors that can adversely affect project development can include, environmental and municipal permitting delays, public and First Nations consultation, adverse weather during construction, equipment delivery delays, labour shortages, construction material shortages and obtaining a power sales contract to secure necessary financing. A detailed project construction schedule based on reasonable timelines to address the above items has been developed and reviewed. Defined timelines have been included for procurement of long lead items such as turbines, generators and transformers. Environmental permitting and consultation risks have been addressed to the extent possible by:

- timely submission of relevant approval applications, proactive correspondence with regulators, stakeholders and Aboriginal groups
- early completion of all necessary field programs
- organization of public open houses in the community to educate and collect feedback from stakeholders
- procurement of qualified professional consultants for engineering design and project management
The implications of a delay to the project schedule would include increased construction, materials and project management costs. A delay related to the factors described above is highly unlikely to jeopardize the feasibility or overall completion of the Project.

2.6 Capital Costs

A breakdown of the capital costs for the Project is provided in Table 2.6-1 below. The total expected capital cost, in 2004 dollars, is about $319 million.

Table 2.6-1: Capital Costs for the Project, by Major Component

<table>
<thead>
<tr>
<th>Description</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Civil and Structural Works</td>
<td></td>
</tr>
<tr>
<td>Site works and temporary works</td>
<td></td>
</tr>
<tr>
<td>Headpond and upstream work</td>
<td></td>
</tr>
<tr>
<td>Fishways</td>
<td></td>
</tr>
<tr>
<td>Boat lock, boat ramp and road</td>
<td></td>
</tr>
<tr>
<td>Powerhouse and spillway</td>
<td></td>
</tr>
<tr>
<td>Subtotal</td>
<td>$158,773,886</td>
</tr>
<tr>
<td>Turbine and Generator</td>
<td></td>
</tr>
<tr>
<td>Supply water to wire turbine and generator</td>
<td></td>
</tr>
<tr>
<td>Fabricate draft tube</td>
<td></td>
</tr>
<tr>
<td>Turbine, generator and electrical controls</td>
<td></td>
</tr>
<tr>
<td>installation</td>
<td></td>
</tr>
<tr>
<td>Subtotal</td>
<td>$61,809,000</td>
</tr>
<tr>
<td>Substation and Transmission Line and Controls</td>
<td></td>
</tr>
<tr>
<td>Subtotal</td>
<td>$6,151,000</td>
</tr>
<tr>
<td>Miscellaneous Items and Facilities</td>
<td></td>
</tr>
<tr>
<td>Office maintenance building</td>
<td></td>
</tr>
<tr>
<td>Communications system</td>
<td></td>
</tr>
<tr>
<td>Subtotal</td>
<td>$730,000</td>
</tr>
<tr>
<td>Construction Services</td>
<td></td>
</tr>
<tr>
<td>Project insurance</td>
<td></td>
</tr>
<tr>
<td>Temporary utilities, storage and construction</td>
<td></td>
</tr>
<tr>
<td>Road maintenance</td>
<td></td>
</tr>
<tr>
<td>Camp and travel time</td>
<td></td>
</tr>
<tr>
<td>Subtotal</td>
<td>$8,450,000</td>
</tr>
<tr>
<td>Construction Supervision and QC</td>
<td></td>
</tr>
<tr>
<td>Site investigation work</td>
<td></td>
</tr>
<tr>
<td>Construction management</td>
<td></td>
</tr>
<tr>
<td>Safety and first aid</td>
<td></td>
</tr>
<tr>
<td>Environmental monitoring and management</td>
<td></td>
</tr>
<tr>
<td>Subtotal</td>
<td>$5,930,000</td>
</tr>
<tr>
<td>Office Management and Engineering</td>
<td></td>
</tr>
<tr>
<td>Project management</td>
<td></td>
</tr>
<tr>
<td>Engineering design</td>
<td></td>
</tr>
<tr>
<td>Subtotal</td>
<td>$15,922,472</td>
</tr>
<tr>
<td>Owner Costs</td>
<td></td>
</tr>
<tr>
<td>Subtotal</td>
<td>$20,055,130</td>
</tr>
<tr>
<td>Subtotal Project</td>
<td>$277,821,488</td>
</tr>
<tr>
<td>Contingency at 15 %</td>
<td>$41,673,223</td>
</tr>
<tr>
<td>Total Project Cost</td>
<td>$319,494,711</td>
</tr>
</tbody>
</table>
No federal, provincial or municipal government departments are expected to incur any capital costs in order to provide support services, such as roads or sewer lines, to the Project. Improvements to access road intersections with Highway 2, access road clearing and maintenance, and the construction and maintenance of navigation infrastructure (including a boat ramp, boat lock, and safety booms) will be the responsibility of Glacier Power.

### 2.7 Regulatory and Planning Framework

#### 2.7.1 Background

The process of obtaining environmental approvals was first initiated early in 1999 at meetings with both AENV and the Canadian Environmental Assessment Agency (Agency). The Project subsequently went through a regulatory review process, including the submission and completion of an EIA, a full public and First Nations consultation process, and a joint EUB and NRCB public hearing, subsequent to which the 2000 application was denied.

Glacier Power submitted a new Disclosure Document to AENV and the Agency in February 2004. This document provided a description of the Project and a summary assessment of potential environmental and socioeconomic effects. In March 2004, Glacier Power submitted a Proposed Terms of Reference for an EIA for the Project. Meetings with provincial and federal regulators were held in March and April 2004.

The objectives of these meetings were to:

- examine the proposed Project in terms of thresholds and triggers to the Alberta *Environmental Protection and Enhancement Act* (*EPEA*) and the *Canadian Environmental Assessment Act* (*CEAA*) approval processes
- initiate communication with key individuals for purposes of collecting background information and developing study terms of reference

The Final Terms of Reference (ToR) were issued by AENV in July 2004, which took into consideration comments from federal agencies, the EUB, and the public and stakeholders in general. The Final ToR are presented in Appendix A.

#### 2.7.2 Provincial Regulations

##### 2.7.2.1 Alberta Environmental Protection and Enhancement Act

AENV is the provincial government ministry responsible for a range of environmental legislation including the *EPEA*. The *EPEA* takes an integrated approach to the protection of air, land, and water. It replaced and combined previous acts into one legal framework.

The *EPEA* establishes a legislated environmental assessment process to ensure that economic development occurs in an environmentally responsible manner with the opportunity for full public participation. There are four stages under the Environmental Assessment Process:
• Stage 1 - Initial Review
• Stage 2 - Screening
• Stage 3 - Preparation of an Environmental Assessment Report
• Stage 4 - Final Review

Projects such as pulp mills, oil refineries and large dams are subject to the environmental assessment process under the EPEA according to the Environmental Assessment (Mandatory and Exempted Activities) Regulation. Other projects, which do not meet any mandatory thresholds or that warrant further consideration, are referred to the Director responsible for environmental assessment for a decision regarding review and reporting requirements.

The proposed Project exceeds two of the provincial thresholds in the Environmental Assessment (Mandatory and Exempted Activities) Regulation requiring an EIA:

• a water reservoir with a capacity greater than 30 million cubic metres (the proposed headpond has a capacity of 60 million cubic metres)
• a hydroelectric power generating plant with a capacity of 100 megawatts (MW) or greater (100 MW capacity proposed)

The remaining applicable thresholds defined in the Environmental Assessment (Mandatory and Exempted Activities) Regulation are not exceeded by the proposed project design:

• a dam greater than 15 m in height when measured to the top of the dam (12 m headworks structure proposed)
• a transmission line with a voltage of 500 kilovolts or greater (144 kV transmission line proposed)

Glacier Power was formally notified on February 27, 2004 in a letter from the Director of Environmental Assessment that the Project is a mandatory activity, and as such the preparation of an environmental impact assessment (EIA) would be required, pursuant to section 44(1)(a) of the Environmental Protection and Enhancement Act.

2.7.2.2 Hydro and Electric Energy Act

The proposed Project is defined as a “hydro development” under the Hydro and Electric Energy Act (HEEA) administered by the EUB and is therefore subject to an approval under Section 9 of the HEEA. The HEEA was initially intended to ensure that new hydroelectric projects were given adequate review and consideration by the Alberta Legislature by requiring that a bill be passed in the legislature before a new hydroelectric project could proceed. There is a provision in 5(1)(b) of the HEEA for the EUB to pass a regulation which would exempt the Project from Section 9.
2.7.2.3 **Natural Resources Conservation Board Act**

The *Natural Resources Conservation Board Act* (*NRCBA*) defines a “water management project” as a project to build a dam, reservoir or barrier to store or conduct water that requires an environmental impact assessment. Because the Project requires an EIA under the *EPEA*, it meets the definition of a water management project under the *NRCBA* and is therefore considered a reviewable project. Glacier Power understands that the NRCB will review the Project jointly with the EUB.

2.7.2.4 **Water Act**

Under Alberta’s *Water Act*, the Minister of Environment must establish a framework for water management planning and a strategy for the protection of the aquatic environment. Part 6 of the *Water Ministerial Regulation* under the *Water Act*, which deals with dam and canal safety, will apply to the Project.

2.7.3 **Federal Regulations**

2.7.3.1 **Canadian Environmental Assessment Act**

The *CEAA* establishes a process to assess the environmental effects of projects requiring federal action or decisions. Under the *CEAA*, projects receive an appropriate degree of assessment depending on the scale and complexity of the likely effects of the project. Consequently, there are four types of environmental assessment:

- screening
- comprehensive study
- mediation
- panel review

A project is usually referred to a panel review only when it may cause significant adverse environmental effects or public concerns warrant it.

The Project is expected to trigger a screening-level review under the *CEAA* according to the discussions with the Agency in February 2004. The Project is subject to the requirements of the *CEAA*, since the Project will require a permit under the *Navigable Waters Protection Act* (*NWPA*) and an authorization under the *Fisheries Act*.

Pursuant to Section 2(1) of the *CEAA*, Aboriginal persons must be consulted for this Project because, according to the *CEAA*, an environmental effect is “any change the project may cause in the environment, including any effect of any such change on the current use of lands and resources for traditional purposes by Aboriginal persons.”

2.7.3.2 **Navigable Water Protection Act**

The Project will require permitting under Section 5(1) of the *Navigable Water Protection Act*. 

---

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2.7.3.3 Fisheries Act

The Project will require authorization under Sections 32 and 35 of the *Fisheries Act*.

2.7.3.4 Species at Risk Act

The federal *Species at Risk Act* (SARA) applies to all aquatic species and migratory birds and to all species listed by Committee on Status of Endangered Wildlife in Canada (COSEWIC) as endangered, threatened or extirpated on federal lands (which includes territorial lands). Also, SARA amends the definition of “environmental assessment” in the CEAA to include any change that the project may cause to a listed species, its critical habitat or the “residences of individuals” of that species. Provinces and territories are given the first opportunity to protect listed species through their laws. If the province or territory does not act, SARA has a "safety net". The Governor in Council, on the recommendation of the Minister of the Environment, may order that the prohibitions in Sections 32 and 33 apply for a given species in a province or territory.

The federal and provincial governments are empowered with species and habitat protection and recovery through the Canadian constitution. Cooperative efforts to jointly designate protected areas, implement international wildlife agreements, commit to conserving biodiversity, and protect species of special conservation concern and their habitats resulted in the October 1996 creation of the *Accord for the Protection of Species at Risk*. The federal, provincial and territorial ministers responsible for wildlife supported this Accord, which outlines the principles of species conservation, and commitments to protect species of special conservation concern. The provisions of the Accord were further strengthened in September 1998, with the ministers placing greater emphasis and recognition on stewardship. Under the Accord, coordination of federal, provincial and territorial ministerial activities occurs through the Canadian Endangered Species Conservation Council (CESCC). The purpose of the CESCC is twofold: to provide general direction on COSEWIC activities and to coordinate the SARA-related activities of various governments represented on the Council.

2.7.4 Joint Provincial and Federal Review

Fisheries and Oceans Canada (DFO) and Transport Canada are the federal government responsible authorities for the Project. However, the Province of Alberta is taking the lead role in the project review, which will proceed in the spirit of the 2005 *Canada–Alberta Agreement for Environmental Assessment Cooperation* (the Agreement). The Agreement is intended to streamline communications and information sharing between the two governments and provides a framework to coordinate the provincial EPEA and the federal CEAA processes. The Agreement thereby promotes effective, efficient, consistent and cooperative environmental assessment by the governments of Canada and Alberta, including the avoidance of uncertainty and duplication.

2.7.5 Kyoto Protocol

The Kyoto Protocol is discussed in Section 2.10 in relation to the way in which the Project will assist in reducing Greenhouse Gas (GHG) emissions, and in Section 2.13.7.1 with regards to the Protocol’s history, Alberta’s involvement, and federal initiatives and funding.
2.7.6 Northern River Basin Study

The Northern River Basin Study (NRBS) was a five-year scientific study initiated in 1991 to establish existing conditions in the Peace–Athabasca drainage basin and to assess the effects of development on the aquatic ecosystem. The NRBS was directed by a multi-stakeholder Study Board. At the conclusion of the program, the Study Board put forward a number of recommendations to guide the management of the natural resources in the basin. Some of the data generated by the NRBS research were used by the project team for this assessment.

2.7.7 Northern Rivers Ecosystem Initiative

The Northern Rivers Ecosystem Initiative (NREI) was initiated in 1998 with a five-year mandate to address the recommendations of the NRBS Study Board and commitments made by provincial and federal ministers to protect the northern rivers. The NREI was a science-based effort covering the Peace, Slave and Athabasca watershed implemented to obtain more information to help understand the impacts of human activities on aquatic ecosystems in this region. This program concluded in 2003 with a report outlining the key findings related to pollution prevention, endocrine disruption in fish, drinking water quality and monitoring environmental effects from human activity.

As a result of the NREI, many new policies and regulations were put in place between 1998 and 2003 to protect the aquatic ecosystems of Northern Canada (Environment Canada 2006c, Internet site).

2.7.8 Mackenzie River Basin Board

Many of the NRBS recommendations were conveyed to the Mackenzie River Basin Board (MRBB) under the Mackenzie River Basin Transboundary Waters Master Agreement, which was signed by Canada, Yukon, Northwest Territories, Saskatchewan, British Columbia and Alberta. The agreement commits jurisdictions to negotiating bilateral agreements. Ongoing studies are examining climate variability, flow regulation, and hydrology in connection with flooding of the Peace–Athabasca Delta. Membership on the MRBB includes government representatives plus a First Nations or Métis representative from each jurisdiction in the basin.

2.8 Permits, Licenses and Miscellaneous Agreements

Canadian Hydro, Glacier Power’s parent company, is presently operating several hydroelectric plants in Alberta. Permits, licenses and agreements were required to build and operate these plants. It is anticipated that similar permits, licenses and agreements will be required for the Project. Aside from those approvals explained in previous sections, the following list identifies additional approvals that may be required:

- EUB approval for a power generation plant under the HEEA
- EUB approval for development of a transmission line
- EUB approval for the interconnection of a transmission line
- land and lease holder agreements
• submission and approval of EIA under EPEA

• water license permit to withdraw or use water in a stream (Water Act)

• Crown Land tenure (Licence of Occupation) under the Public Land Act

• power purchase agreement (optional, otherwise Glacier Power will sell to the Power Pool through the Alberta Electrical System Operator (AESO)

• energization certificate from AESO

• Power Pool notification of a new plant

• agreement to tie into ATCO’s 144-kV line (7L73)

• development permits to build structures (buildings), roads and remove timber are required from Municipal District of Fairview (obtained April 16, 2002), Counties of Saddle Hills and Birch Hills. Municipal rezoning applications are not required.

Table 2.8-1 presents the estimated schedule for regulatory activities.

Table 2.8-1: Estimated Regulatory Schedule

<table>
<thead>
<tr>
<th>Regulatory Activity</th>
<th>Expected Start Date</th>
<th>Expected End Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Submission of EUB, NRCB, Water Act, and DFO Applications, along with Environmental</td>
<td>October 2006</td>
<td>-</td>
</tr>
<tr>
<td>Impact Assessment (EIA)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stakeholder and regulatory review of EIA</td>
<td>November 2006</td>
<td>December 2006</td>
</tr>
<tr>
<td>Supplementary Information Request (SIR) from AENV</td>
<td>January 2007</td>
<td>-</td>
</tr>
<tr>
<td>Glacier Power response to SIR</td>
<td>February 2007</td>
<td>-</td>
</tr>
<tr>
<td>Stakeholder and regulatory review of SIR</td>
<td>February 2007</td>
<td>March 2007</td>
</tr>
<tr>
<td>EIA deemed complete</td>
<td>March 2007</td>
<td></td>
</tr>
<tr>
<td>EUB and NRCB pre-hearing activities</td>
<td>April 2007</td>
<td>June 2006</td>
</tr>
<tr>
<td>EUB and NRCB public hearing</td>
<td>June 2007</td>
<td>-</td>
</tr>
<tr>
<td>EUB and NRCB deliberation and decision</td>
<td>July 2007</td>
<td>September 2007</td>
</tr>
<tr>
<td>Act passed in the Legislature under the Hydroelectric and Energy Act</td>
<td>September 2007</td>
<td>October 2007</td>
</tr>
<tr>
<td>Fisheries Act and Water Act Authorizations and Approvals</td>
<td>September 2007</td>
<td>December 2007</td>
</tr>
<tr>
<td>EUB Interconnection Application, review, and approval</td>
<td>January 2008</td>
<td>July 2008</td>
</tr>
<tr>
<td>Municipal development permits, road permits, Crown land tenure application,</td>
<td>September 2007</td>
<td>April 2008</td>
</tr>
<tr>
<td>transportation planning and permits, cutting permits, and other miscellaneous</td>
<td></td>
<td></td>
</tr>
<tr>
<td>permits and approvals as required prior to construction</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Start construction</td>
<td>April 2008</td>
<td></td>
</tr>
</tbody>
</table>
2.9 Canadian Electricity Industry

Electricity is a familiar and crucial form of energy and supplies about one fifth of all energy used by consumers in Canada. In 1998 this accounted for 480 terawatt hours of electricity in the end-use energy market. Due to increased demand from energy intensive industries such as resource extraction and refining, electricity demand grew at an annual rate of 1.3 percent during the 1990s (National Energy Board 2001).

Electricity is a secondary energy source created by converting primary energy (petroleum, natural gas, coal, hydroelectric, uranium, wind, biomass, solar) into useable electrical energy. In 2003, hydroelectric power was the largest source of net electricity production representing 58 percent of Canada’s electrical production. Fossil fuels (coal, natural gas and oil) represented 28 percent and nuclear represented 12 percent. Wind, bioenergy and other sources are now being considered as contributors to the overall portfolio, although combined they produce approximately 2 percent of the net electricity production in Canada (Canadian Electricity Association 2006).

The electricity supply industry falls mainly under provincial jurisdiction including both the procurement of a supply mix portfolio (supply) and distribution of adequate electricity volume (demand). Provincial electricity demand statistics from the National Energy Board and Statistics Canada indicate that Quebec and Ontario have the largest market totalling over 60 percent of the Canadian demand, while the Prairie Provinces account for approximately 20 percent. On the supply side, the generation base varies by region depending on the available natural resources such a hydroelectric, coal or natural gas. Thermal generation (coal and oil) are predominant on the east coast and the prairies; hydroelectric generation is dominant in Labrador, Quebec, Manitoba and British Columbia; with nuclear technology used mainly in Ontario with some facilities in Quebec and New Brunswick. All these dominant technologies that use the local resources for base-load electricity generation are supported by recent procurement of renewable technologies such as wind, biomass and small hydroelectric to meet increasing demand. Over the past five years Quebec, Ontario, Manitoba, New Brunswick, British Columbia and PEI have tendered independent power producers to develop, construct and operate renewable power facilities to increase overall generation while reducing environmental impacts from traditional technologies.

In the past, most provinces have tried to meet electricity demand from internal resources with limited reliance on neighbouring jurisdictions. This has led to a relatively low level of interprovincial electricity trade or exchange. Limited interconnection reflects both economics and historical self-sufficiency objectives of provincial utilities. As electricity demands increase with changes in population and energy use patterns, additional import and export exchange is being implemented between provinces and the United States. Interprovincial electricity flows account for approximately 10 percent of total Canadian electricity consumption, where over 80 percent of this flow occurs in Eastern Canada and the remaining 20 percent in Western Canada. Historically, Canada has been a net exporter of electricity to the United States; however, levels have been relatively stable in recent years. Canada exported about 38 billion kilowatt-hours (kWh) of electricity (gross) to the United States in 2001, mostly from Quebec, Ontario and New Brunswick to New England and New York. Smaller volumes are exported from British Columbia and Manitoba to Minnesota, California, Washington and Oregon. There is considerable reciprocity between the Canadian and U.S. power markets, as the U.S. also exports
smaller volumes of electricity to Canada (18 billion kWh in 2001) (Global Energy Network Institute 2003, Internet site).

In Alberta, implementation of the electricity supply mix has recently started to include less fossil fuel-intensive technologies and increased reliance on clean energy sources such as hydroelectric, wind and biomass that will result in future changes in GHG emissions from the electricity supply industry. The Canadian Electrical Association (1997) estimates conversion efficiencies for fossil fuels range between 40 percent to 60 percent compared to electrical energy from hydroelectric which has a conversion efficiency of up to 92 percent. The Canadian electricity industry can reduce their GHG emissions by procuring low-impact renewable energy in conjunction with promoting its use by Canadian customers. Renewable energy sources such as small hydroelectric offer a means to contribute significantly to Canada’s commitment in reducing greenhouse gas emissions and producing stable long-term energy with no risk associated with the cost of fuel supplies such as coal and natural gas.

2.10 Project Need

The question of project need relates to determination of the Project as being in the public interest. Need for the Project may be addressed from several perspectives including market fundamentals (supply-demand and price), electric system benefits and government policy regarding renewable energy. Both qualitative and quantitative statements may be used to show the need for low-impact renewable power projects such as the Project, particularly in Alberta’s northwest transmission quadrant.

In Alberta, replacing generating capacity that will reach retirement age in the next 15 to 25 years, plus the need to meet rising new demand, will be a formidable challenge. This will be complicated by potential opposing forces of competition to reduce cost and environmental pressures to reduce emissions associated with energy use and production, particularly GHGs.

In Alberta, the decision to develop a power project lies solely with the investor once all approvals and permits have been obtained. Even in a competitive environment the decision to develop one project over another requires a comprehensive cost-benefit analysis to assess the better investment. Any project that provides a substantial net-benefit should be considered in the public interest and is therefore needed. In addition to the direct project, economic, social and environmental cost-benefits, the need for any electric generating facility can also be supported by other or indirect benefits associated with any positive impact on:

- market fundamentals relating to electricity supply, demand and price
- electrical system benefits relating to technical interconnection and delivery
- other factors such as government policy relating to environmental objectives and standards

2.10.1 Supply and Demand

Planning for capacity, even in a competitive environment, is complicated by uncertainties associated with forecasting the demand for electricity. Alberta has enjoyed strong economic growth for some time, which has lead to increased demand for electricity across all consuming sectors. This trend is expected to continue with the development of Alberta’s vast oil sands and in situ bitumen resources. Correspondingly, Alberta’s electricity-generating sector has responded since the late 1990s by developing almost 4,000 MW of new incremental generating capacity that brought the provincial generating capacity reserve margin from below 10 percent in 1998 to over 35 percent in 2004. This new
investment, along with continued investment in existing units, has also made Alberta’s generating fleet much more fuel-efficient. Greater levels of supply and more efficient generation technology have to some extent protected Alberta’s electricity consumers from the high cost of energy, particularly natural gas. Correspondingly, electricity prices have traded at a discount relative to the historical all-in cost of converting natural gas to electricity. These lower electricity prices coupled with high reserve margins have served to slow generation development more recently, as part of the inevitable commodity cycle. Slower generation development coupled with several unit retirements over the next few years will now lead to a decline in capacity reserve margins. A lower capacity reserve margin with continued rising demand is now expected to result in rising electricity prices, particularly over the next five years.

The growth in the Alberta economy, and in almost every other developed economy (as measured by real gross domestic product (real GDP), is very much dependant on a reliable source of competitively-priced electricity. From 1960 to 1980, Alberta’s consumption of electric energy per dollar of real GDP doubled by growing an average of 7 percent per year. Currently, Alberta generates approximately $1.85 million in real GDP (1992 dollars) for every GWh of electric energy consumed—a relationship that has been relatively constant since the early 1980s. Canada and specifically, Alberta have two of the most electric-intensive economies in the world as measured by electric energy per capita.

A substantial portion of Alberta’s electric generating capacity will reach the end of its useful life in the foreseeable future. At the end of 2004, Alberta’s total gross installed generating capacity was approximately 13,000 MW (10,500 MW net-to-grid) of which almost 25 percent will reach retirement age in the next 15 years and just under 40 percent will reach retirement age in the next 25 years.

Alberta’s total electric energy sales, as measured by Alberta Internal Load (AIL), have grown by an annual compound growth rate (ACGR) of 3.4 percent per year from 1987 to 2003 and is anticipated to grow by 2.7 percent ACGR per year from 2004 to 2018. This level of demand growth coupled with retirements would necessitate the need to develop almost 4500 MW of new net-to-grid generating capacity plus an additional 1425 MW of on-site capacity bringing the total new generating capacity needed to just under 6,000 MW over the next 15 years or approximately 50 percent of today’s total capacity.

### 2.10.2 Electricity Market Price

The electricity market price in Alberta has been and will continue to be defined by the cost structure of the mix of supply technology that is added to meet rising demand and to replace older less efficient units. Historically the bulk of Alberta’s electric energy supply has been developed under a cost-of-service regulatory regime. The abundance of thermal coal in Alberta, coupled with a very high electrical system load factor (driven by a large share of industrial load on the Alberta grid), has favoured the development of high capital cost mine-mouth coal-fired facilities. Ironically, these large-scale high capital projects were developed during a time of relatively high cost of financing, notwithstanding the low cost of competing fuels such as natural gas. Also, high fuel cost and relatively low capital cost projects are now being built in an environment of much lower cost of capital and soaring marginal natural gas fuel prices. The continued rise in natural gas prices observed in recent years, as well as forward prices into the future, has already had a profound affect on Alberta’s electricity market in the short term, and is expected to have a lasting effect over the longer term as well. The short-term impact has been immediate and measurable, while the longer-term impact is expected to change the makeup of the generation supply portfolio.
The most immediate effect of higher natural gas prices has been on the electric energy spot price. In many hours the price of electricity in Alberta is determined by a marginal natural gas fired electricity generator, and has therefore resulted in much higher electricity prices. For example, a $4/GJ rise in spot market natural gas prices translated into a $25/MWh increase in power prices—all other things being equal—from January to September 2005.

The longer-term impact of higher forward natural gas prices is now expected to alter the decisions made by generation developers with respect to the technology of choice that is likely to proceed as the future supply options. The longer-term forward curve for natural gas has recently risen from an average of $5/GJ over the next 15 years to around $6.50/GJ. This fact has altered the relative economics of future generation supply options, particularly related to coal and other non-natural gas technologies relative to natural gas-fired technologies. More coal-fired generation is now expected to be developed in Alberta than previously anticipated.

It should be noted that the significant advances made in lower capital cost and higher fuel efficiency of natural gas-based technologies over the last couple of decades have fostered a greater level of natural gas-fired generation development. The other obvious change in Alberta’s electricity market which supports this new trend in generation development has been the implementation of a competitive market in place of the previous cost-of-service regulatory regime. The new market places the risk of capital investment squarely with the investor and passes the fuel cost to the consumer through the marginal price of the energy spot market. This new risk profile in the market clearly supports the development of smaller, more efficient, relatively lower capital-cost projects at the expense of high fuel costs. Finally, the uncertain future regarding environmental policy only serves to support the new trend, particularly in the absence of competitive low environmental impact options.

It is estimated that the market impact of the development of the Project could be a reduction in the all-hour average pool price by approximately $1 to $2/MWh in the first one or two years of service relative to the price that might be expected without the Project—all other things being equal. Assuming pool prices were reduced on average by $1 to $2/MWh, then the potential benefit to Alberta electricity consumers would be about $30.5 to $61 million dollars in 2009 and 2010 for a total market benefit of $91.5 million if 50 percent of all consumers were exposed to spot prices.

2.10.3 Electrical System Benefits

Generation development can provide benefit to the regional transmission system by reducing system losses and by providing voltage support as an interim measure prior to transmission development. In addition, some generation can provide benefit to the overall transmission system by providing various ancillary services that are required to facilitate a safe and reliable electric system. The Project has the potential to provide benefit to the Alberta electric system in all of the aforementioned ways.

In the Transmission Administrator’s (TA\(^2\)) most recent 10 year Transmission Development Plan (2002 to 2011), issued March 2002, a discussion of each broad area of the transmission network is presented. Each area discussion includes a brief description, a detailed load forecast, details of existing and new generation plants, a description of the main transmission reinforcements required for the next

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\(^2\) The TA was at the time ESBI Alberta Limited and now is the Alberta Electric System Operator (AESO).
10 years, along with the driving factor in each case. In the case of the northwest Alberta transmission grid, the TA provides the following discussion:\footnote{ESBI Alberta Limited, Transmission Development Plan (2002-2011), March 2002, page 36.}

*The electric system in northwest Alberta (specifically Rainbow Lake and High Level areas) is characterized by long 144 kV and 240 kV transmission lines connecting loads to generation. The system is generally radial with a low degree of redundancy of transmission paths. Some 144 kV transmission lines are heavily loaded and consequently have high transmission losses. The outage of a single transmission line or a local generator can result in voltage depressions outside of acceptable limits.*

*Because of the area's remoteness from any major source of generation and limited transmission capacity into the area, system security is maintained by ensuring certain local generation is running at all time, i.e., Transmission Must Run ("TMR"). The exact amount of generation required is generally determined by local load level at that time.*

Based on informal discussions with the Alberta Electric System Operator (AESO), the northwest transmission area typically imports approximately 500 to 600 MW of power in addition to requiring a significant amount of Transmission Must-Run (TMR) generation to maintain the system integrity. The AESO has noted that any additional generation in the northwest area of the province would help mitigate current TMR requirements. The AESO currently expends approximately $40 to 50 million per year on TMR payments, the majority of which are in northwest Alberta. The Project, because of the expected nature of its operations, could reduce northwest Alberta area transmission losses and TMR requirements by approximately $5 million dollars per year, which would result in a direct reduction in AESO transmission costs by 11 percent.

Another very important ancillary service provided by some generation is "black start" capability, to re-energize the system in the event of a system wide blackout. Once again the nature of the Project and its ability to self-generate its own electrical needs gives the Project the ability to provide black start capability to the northwest region. The AESO currently spends approximately $1 to 2 million per year in black start ancillary service payments to various generators in Alberta.

As noted above by AESO, the northwest Alberta transmission grid experiences heavy loading and as a result high thermal losses, particularly during peak demand periods. Additional generation in the area would reduce transmission load levels and, therefore, transmission line losses. On an AC system, line losses are a function of the square of the resistance on that transmission line, meaning that a doubling of the load results in transmission line losses that are four times; therefore, any reduction on a heavily loaded system will provide a significant marginal loss saving. Given that the regional heavy load periods would typically coincide with the system-wide heavy load periods, when electricity prices tend to be the highest, the monetary savings of lower losses would also represent a direct and potentially large benefit through the transmission tariff.

In addition, lower system wide losses tend to provide an overall lower level of system demand and therefore would also tend to lower the overall system pool price. This indirect effect, while somewhat difficult to assess with a high degree of accuracy given the small size of the change, would provide benefit, at least on a directional basis, to all consumers in Alberta through lower energy costs. The
AESO currently spends approximately $160 to 180 million per year to cover the cost of transmission losses.

Overall, the Project has the potential to provide significant benefit to all Alberta’s electricity consumers through an otherwise lower transmission tariff that would result from a combination of lower losses, reduced ancillary service costs and an overall lower cost-of-service due to possible delay in transmission development and the associated capital investment. While the foregoing assertion is somewhat subjective and reliant on assessments about the future (or forecasts), any project that can reasonably be expected to provide any of these benefits is clearly needed and in the best interest of Alberta’s consumers.

2.10.4 Economic Need

Capital costs to build the Project are estimated at $319 million (2004 dollars). The Project represents a significant contribution to economic activity in the region, accounting for almost one-quarter of the total major project expenditures of $1.4 billion (Alberta Economic Development, 2005). Viewed in the context of its contribution to economic activity beyond the geographic boundaries of the County of Grande Prairie, the Project appears even more significant, accounting as it does for three-quarters of $446 million in major project expenditures.

Construction of the Project would result in significant capital expenditures in the northwest Alberta region, and the engagement of both a construction workforce over a period of 4 years, and a full time operations workforce over the (100 year) life of the Project. The total direct, indirect, and induced long-term employment expected to result from the Project is 19 person years. Local contractors and skilled tradesmen have expressed the desire to work for Glacier Power on the Project close to home, instead of traveling to Fort McMurray or elsewhere within Alberta where the demand for labour has been extremely high in recent years. The Project will also result in infrastructure development such as road upgrades and a new boat ramp, and will generate significant local tax revenue as a result of the operations of the facility.

Further to the direct benefits to the local economy, Tables 2.10-1 and 2.10-2 estimate the monetary benefits of the Project over its financial life of 40 years. It is estimated that the economic benefit for the first year of operations would be 121.9 million dollars (in 2004 dollars). The GDP and labour income impact of the Project are estimated at $5.1 million and $2.1 million (2004 dollars), respectively.

Table 2.10-1: Estimated Monetary Benefits of the Project Electricity

<table>
<thead>
<tr>
<th>Estimated Monetary Benefits of the Project Millions of Dollars</th>
<th>2004 dollars assuming a 10% discount rate</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012 and thereafter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pool Price Effect</td>
<td>$55.1</td>
<td>$61.0</td>
<td>$30.5</td>
<td>$0.0</td>
<td>$0.0</td>
</tr>
<tr>
<td>Transmission Losses and TMR</td>
<td>$33.4</td>
<td>$5.0</td>
<td>$5.0</td>
<td>$5.0</td>
<td>$5.0</td>
</tr>
<tr>
<td>Green House Gas Emissions</td>
<td>$33.4</td>
<td>$5.0</td>
<td>$5.0</td>
<td>$5.0</td>
<td>$5.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$121.9</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: Present values were calculated assuming 40 years of project life.

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Footnote:

4 Financial life is used as a conservative proxy for operational plant life, while some technologies, particularly hydroelectric may have longer physical lives with some amount of capital investment.
Table 2.10-2: Estimated Operations-Related Income Impact

<table>
<thead>
<tr>
<th>Total Operations Related Income Impact</th>
<th>Millions of Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Direct Impact</td>
</tr>
<tr>
<td></td>
<td>GDP</td>
</tr>
<tr>
<td>Dunvegan Hydroelectric Project</td>
<td>$4,987</td>
</tr>
</tbody>
</table>

2.10.5 Environmental Factors

On a global scale, the Kyoto Accord has been the impetus for the adaptation and implementation of environmental stewardship principals in Canada and around the world. In Canada, governments at all levels have been working with industry and stakeholders to develop guiding principles that will define future policy with respect to GHG emissions. In keeping with the Clean Air Strategic Alliance 2003 recommendations, AENV is implementing new annual limits for nitrous oxide and sulphur dioxide emissions, which will create an emissions trading program for these two substances based from the electricity-generating sector.5 The assessment that the future generation fleet in Alberta may include more coal-fired generation than previously anticipated, combined with the fact that Alberta now has a moratorium on wind development activities, will make Alberta’s emissions targets from the electricity generating sector more difficult to meet. This situation once again underscores the value to electricity consumers and the “need” to diversify Alberta’s generation portfolio to include as much low-impact renewable generation sources, such as the Project, that will serve to lower Alberta’s emissions from the electricity-generating sector.

In addition, the Federal and most Provincial Governments have made commitments to increase supply from green energy sources which has led to an increased development of wind, run-of-river hydroelectric and biomass facilities across Canada and around the world. The Canadian Federal government has shown its commitment to development of renewable energy through programs such as the Wind Power Production Incentive (WPPI), and the additional funding allocation being contemplated for a broader Renewable Power Production Incentive (RPPI). Federal agencies and groups such as Clean Air Renewable Energy Coalition are actively working towards increased renewable energy development. Federal incentive programs as well as long-term commitment to greenhouse gas emissions reductions and energy conservation programs show the national commitment to a long-term, reliable, renewable energy supply. The Alberta government supports renewable energy research and energy conservation through Ministry of Environment programs as well as agencies such as Climate Change Central and Clean Air Strategic Alliance (CASA). The Alberta government has committed to purchasing 90 percent of the electricity used in government-owned facilities from green power sources. Alberta Infrastructure has entered into long-term agreements with both Enmax and Canadian Hydro Developers to procure approximately 210,000 MWh of renewable energy annually. This power is provided equally by the McBride Lake wind power project near Pincher Creek and Canadian Hydro Developers’ Grande Prairie EcoPower® Centre.

5 Currently the renewable generating technologies are excluded from participating in the NOx and SO2 trading system for a variety of reasons.
Given its expected operating characteristics, the Project would provide a significant reduction in greenhouse gas emissions in Alberta, in the order of 500,000 Tonnes annually (assuming 0.8 Tonnes per MWh) by displacing other thermal generation sources. This reduction is anticipated to save the electric industry approximately $5 million dollars per year in potential CO$_2$ offset costs assuming a cost of $10/Tonne.

The Pembina Institute for Appropriate Development (Pembina Institute) and the David Suzuki Foundation detail 17 measures leading to a significant reduction in GHG emissions (Hornung 1998). Within the electricity generation sector, Hornung suggests that electricity companies can reduce their GHG emissions by development of low-impact renewable energy in their systems, while encouraging its use by customers. Low-impact, renewable energy is defined as “non-fossil fuel energy sources that are replenished through the earth’s natural cycles and have a minimal impact on the environment and human health. They include wind, solar, earth energy, run-of-river hydro and sustainable biomass fuels.” (Environment Canada 2006, Internet site). Renewable energy sources such as small hydroelectric offer a means to contribute significantly to Canada’s commitment in reducing greenhouse gas emissions by the years 2008 to 2012.

2.10.6 Summary

As a result of the foregoing facts, reasonable capital cost projects—especially those with lower operating costs, such as the Project—are in the best interest of electricity consumers in Alberta. Further diversification of Alberta’s power sector’s fuel supply, particularly away from carbon-based fuels, can only provide additional value to the electricity consumer by mitigating long-term fuel supply risk. Direct and indirect technical benefits potentially arise from the interconnection of a facility in the northwest Alberta transmission grid that will benefit both regional and system-wide consumers. Finally, the environmental attributes of the Project will provide a long-lasting benefit with respect to global warming through reduced GHG emissions in Alberta, which is clearly in the public interest.

2.11 Alternatives to the Project

There are several alternative technologies available that can be applied to generate 100 MW of electrical energy. However, not all are as well suited to the Peace River region as hydroelectric generation and many alternatives use non-renewable resources, which generate higher greenhouse gas and other forms of emissions. The following section examines available alternative technologies and discusses the pros and cons of each technology in the context of providing electrical generation in the Peace River region. It begins with the no-development alternative followed by the small hydroelectric alternative to allow for a comparison of the Project with other technologies. Normally, large hydro-development electrical-generation capacity is much larger than that being proposed by Glacier Power at Dunvegan. However, large hydroelectric is included in this section on alternative technologies primarily because the same site has been examined for its large hydroelectric-development potential.
2.11.1 No Project Development

The alternative of no project development means that this area of Alberta would continue to be supplied with electrical energy from plants in the south and central area of the province. The Peace Region is deficient in local generation. The forecasted increased electricity demands would have to be made up by development of new generation elsewhere, possibly requiring additional transmission lines or upgrades. This scenario of long-distance power imports to the region could continue until local electrical generation using various technologies catches up to present and projected demands. The Peace River would remain in its present condition unless one of the various technologies implemented had either a direct, indirect or cumulative effect on the watershed.

2.11.2 Small Hydroelectric (the Project)

Small hydroelectric projects use a technology, implemented in thousands of plants around the world, that uses flowing water, a clean renewable resource. Small hydroelectric plants can be either run-of-river or storage types depending on whether the plant is being designed to provide power upon availability rather than on demand. In both run-of-river and storage types, the hydroelectric plant typically uses only a portion of the water available in the natural flow of a river.

Run-of-river hydroelectric means that there is no significant water storage, only minimal flooding associated with the headpond, and that power is generated in accordance with fluctuations in the available stream flow. Run-of-river hydroelectric facilities can take several configurations, depending on the amount of flow available and the head (difference in water levels between the intake headwater and powerhouse tailwater). Typically, a portion of flow is diverted away from the main river channel through an intake structure and conveyed through a penstock (pipeline) to a powerhouse containing one or two turbines.

Small hydroelectric can also take the form of storing a modest volume of water behind the intake structure to provide power on demand. This type differs from large hydroelectric primarily in the fact that large hydroelectric requires larger reservoirs for storage and flows downstream are regulated. Small hydroelectric is defined by Environment Canada’s Environmental Choice Program (ECP) as having less than 48 hours of storage, which limits the volume of water retained in the headpond and minimizes the extent of the area flooded. Therefore the power upon demand scenario for small hydroelectric usually would take the form of daily shaping rather than significant monthly shifts of power supply (i.e., river regulation).

The environmental effects associated with small hydroelectric developments can vary depending on the location and configuration of the project. Typically, small hydroelectric projects have a small footprint of disturbance and require minimal flooding. The Project is a run-of-river project whereby the flow in the Peace River is not diverted, and there is no significant storage of water, nor any regulation of downstream flows. Since there is no diversion of flow away from the main river channel, there are no concerns related to instream flow needs that are generally associated with run-of-river projects that do divert a portion of the flow through a penstock. Except for the small amount of vehicle exhaust during construction activities, the Project has no air emissions. The Project has also been designed to be integrated into the present river channel with minimal flooding or inundation of adjacent lands throughout the headpond. The Project has the operational benefit of re-using regulated flows coming from the Bennett Dam in British Columbia, while confining flooding associated with the headpond to...
pre-Bennett Dam floodplain levels. As such, short-term flooding of certain areas along the headpond that may not have been flooded since regulation by the Bennett Dam may be beneficial to trees such as cottonwoods that depend on periodic flooding for regeneration.

### 2.11.3 Large Hydroelectric

The Peace River has high electricity generation potential, particularly the Dunvegan site. Three alternative dam heights were studied by the Alberta Hydro Committee in the mid-1970s at the same location as the Project proposed by Glacier Power today. The site was determined to lack suitable bedrock to support a large hydroelectric dam structure and was dropped from further consideration (R. Both, pers. comm.). The environmental effects of large hydroelectric developments are substantial, particularly due to the formation and operation of large storage reservoirs and the regulation of flows downstream from dams. Large hydroelectric with water storage reservoirs, although having zero-emissions at the source, may produce GHG emissions during construction, the filling of the reservoir and throughout the life of the facility.

The following identifies the flooding area required to produce one effective megawatt hour of electrical energy (on an annual basis) at the Project compared to the areal effect of several large hydroelectric developments in the country.

<table>
<thead>
<tr>
<th>Location</th>
<th>Areal Effect (m²/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Churchill Falls, MB</td>
<td>143 m²/MWh</td>
</tr>
<tr>
<td>Bighorn Dam, AB</td>
<td>105 m²/MWh</td>
</tr>
<tr>
<td>James Bay, QC</td>
<td>104 m²/MWh</td>
</tr>
<tr>
<td>Brazeau Dam, AB</td>
<td>103 m²/MWh</td>
</tr>
<tr>
<td>WAC Bennett Dam, BC</td>
<td>88 m²/MWh</td>
</tr>
<tr>
<td>Dunvegan Project, AB</td>
<td>3.6 m²/MWh*</td>
</tr>
</tbody>
</table>

*Computed as 2,150,000 m² (106 to 215 ha flooded) ÷ 600,000 MWh

The areal effect per effective MWh of the Project is less than three percent of large hydroelectric facilities.

Large hydroelectric requires proportionally higher civil works during construction and operations compared to small hydroelectric developments. Therefore, significant effects on existing infrastructure can be anticipated for large hydroelectric.

### 2.11.4 Photovoltaic

Solar or photovoltaic (PV) electrical power technology has long been recognized as having potential for reliable power, primarily for stand-alone power systems in homes and cottages in remote areas. PV systems are being promoted in developing countries to help meet the basic electrical needs of the millions of people without access to conventional electricity grids. In addition, environmental and long-term fuel supply concerns are accelerating the market demand for PV systems.

In 2005, worldwide PV installations totalled approximately 1.5 gigawatts of capacity. The major sectors of end-use are grid-interactive power, remote power and communications. Grid connected PV applications include distributed or central power-plant generation. A distributed grid-connected application is usually a roof-mounted PV for individual residences (2 to 4 kW) or commercial buildings.
(up to 100 kW). The benefits of PV power generation are generally evaluated based on its potential to reduce costs for the supply (e.g., transmission lines) of electrical energy, as well as its environmental benefits. The advantages of distributed generation are that, since PV systems are at or near the site of electrical consumption, both energy (kWh) and capacity (kW) losses are reduced in the utility distribution network. Also, the utility can avoid or delay upgrades to the transmission and distribution network.

Over the last three decades, research and large-scale deployment initiatives have helped reduce the cost of PV modules by more than a factor of 10. However, the cost of PV still needs to be slashed three to five times to achieve competitiveness with other energy technologies. Central generation applications are not currently cost-competitive for PV. Development of a 100 MW PV plant would require an estimated land area of over 80 ha; however, since the capacity factor of PV is one third to one half that of small hydroelectric, a plant to produce 600,000 MWh per year of electricity would require 450 ha. Such an installation would be both more expensive and less efficient than the proposed Project.

2.11.5 Wind

The kinetic energy in wind offers a potential source of renewable energy but is highly dependent on the local average wind speed. The power potential in wind is proportional to the cube of the wind speed, and the duration of wind events. However, the power production performance of a practical wind turbine is typically more proportional to the square of the average wind speed. The difference is accounted for by the aerodynamic, mechanical, and electrical conversion characteristics and efficiencies of wind turbines.

For development of a wind energy project, site selection is critical to a project's overall feasibility and financial viability. According to Environment Canada’s Wind Energy Atlas (Environment Canada 2006a, Internet site), the wind resource in the uplands near Dunvegan is less than 300 W/m² and in the valley near the proposed hydroelectric site the wind resource is estimated between 0 and 100 W/m². The estimated resource is much less than the minimum wind energy necessary for development and operation of 100 MW of wind electricity. Compared to the rest of the province, the Dunvegan area has the lowest potential for development of wind-generated power, thus eliminating the feasibility of this alternative technology in this region. Also in spring 2006, the Alberta Electrical System Operator placed a moratorium on new wind development in Alberta, pending the resolution of the effects of the generation intermittency on the interconnected grid system.

2.11.6 Natural Gas Generation

After hydroelectric generation, gas generation is likely the next most feasible type of technology for the Peace River region given the local presence of the oil and gas industry and available supply of natural gas. However, gas generation is subject to fluctuating and uncertain gas prices and the technology of converting natural gas to electrical energy is evolving such that a new plant today may be outdated in 10 years and unable to meet future GHG emissions limits. This is why gas generation is commonly viewed as a medium-term solution for new electricity generation supply. Among the fossil fuel sources of electricity, including coal, oil and natural gas, natural gas generation offers the lowest rate of GHG emissions and other pollutants and represents the next most economical alternative to the Project.
Compared with the proposed Project, a gas generation plant with a capacity of 100 MW does not require as much civil works to build the actual plant, resulting in fewer local construction-related jobs. During operations, the proposed Project will require a similar number of operators and support staff, as would a 100 MW gas generation facility. In terms of supplies and services, the projects would be comparable.

Gas-generated electricity:

- will have a much shorter useful life than hydroelectric
- requires higher costs
- involves evolving new technology that uses a non-renewable resource
- generates a significant amount of GHG emissions

By comparison, the Project:

- makes use of a renewable resource
- generates zero emissions
- involves technology that has proven reliable as demonstrated by its use in thousands of hydroelectric plants all over the world
- will last as long as 100 years

2.11.7 Biomass and Wood Waste

Biomass-produced energy refers to those forms of energy derived from the combustion of plant or animal material, such as wood, straw, grass and manure. Wood waste is a common biomass fuel used in areas with sufficient wood supply. Automated biomass systems can efficiently burn wood waste that has no other potential use. This technology can also be combined with mini-district heating systems to heat individual or groups of buildings. These systems often require a back-up fuel source such as oil or natural gas. The environmental effects from wood waste technology relate to the clearing of forests to supply the wood and the greenhouse gas emissions from burning the wood and supplementary fuels. The benefits are realized by using wood waste that would otherwise become “hog fuel” thus reducing the toxic leachate and fire hazard (methane build-up) from hog fuel.

The Peace River region has active agriculture and forestry industries that could supply the raw materials needed for this technology. One such facility currently exists adjacent to the Canfor sawmill in Grande Prairie. The 25 MW Grande Prairie EcoPower® Centre was commissioned in 2005, and requires the use of 1.35 tonnes of wood waste (at 50 percent moisture) per MWh. Sixty-five percent of the wood waste fuel comes from the adjacent Canfor mill, while the rest is trucked in from sawmill and pulp mill operations in the region, including Chetwynd, Ainsworth and Taylor, British Columbia. It is unlikely that there is sufficient fuel to sustain another wood waste facility such as the EcoPower® Centre in this region. Also, the cost of this type of generation exceeds both the hydroelectric and natural gas options described above.
2.11.8 Coal-Fired Thermal

Coal-fired thermal generation of power is already well established in Alberta, and could potentially be developed in the Peace River region. As there are no known coal deposits in the region, raw materials (thermal coal) would have to be transported into the area from coal mines in the south and central parts of the province, which would likely make this type of generation relatively uneconomic. This type of generation would bring with it all of the environmental effects of coal mining, transporting coal and, most notably, the high emissions of GHG when burned. Coal-fired electricity plants have the highest rate of GHG emission per unit of electricity production of any form of generation. Coal also produces the most emissions of common pollutants such as carbon monoxide, nitrogen oxides, sulphur oxides and particulates. Finally, coal-fired plants are also large consumptive users of water, which is becoming an increasingly scarce resource in Alberta, and is the focus of many conservation initiatives.

Given the current electricity market and the relatively low cost of coal-fired generation, new coal-fired plants are expected to be built in Alberta; however, they are likely to be built close to coal deposits and mines in the central and southern Alberta to minimize the extra costs of transportation. New coal-fired generation is also likely to be required to seek out ways of reducing emissions of pollutants and GHGs, including the application of new technologies, and the purchase of offset credits from low- or zero-emission green power projects, such as wind or hydroelectric projects.

2.11.9 Summary of Alternatives and Conclusions

Every method of energy generation changes, impairs or endangers the environment. Relevant environmental variables for consideration in a comparison of alternative technologies include:

- efficiency
- energy payback time - the period of operations during which only as much power is supplied as is required for the manufacture and operation
- energy-harvesting factor - the quantity of energy that a plant generates during its life cycle divided by the quantity of power required for the manufacture, operation and demolition of the plant (the harvesting factor thus includes the grey energy as well, *i.e.*, the energy that is consumed in the life history, production and disposal of refuse)
- CO$_2$ and GHG emissions
- Criteria air pollutant emissions (nitrogen and sulphur oxides, and particulates)
- annual consumption of raw materials, including water
- space requirements
- annual period of use

Table 2.11.1 presents a comparison of environmental footprint of different sources of energy (Canadian Electricity Association 2006).
### Table 2.11-1: Environmental Footprint of Different Sources of Energy

<table>
<thead>
<tr>
<th>Technology</th>
<th>Criteria Air Pollutants</th>
<th>GHG</th>
<th>Water Use Impacts</th>
<th>Extraction</th>
<th>Waste</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand-side management</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>No</td>
<td>Disposal replaced equipment</td>
<td>Reduced demand = reduced emissions</td>
</tr>
<tr>
<td>Reservoir hydroelectric</td>
<td>None</td>
<td>Low</td>
<td>Pattern changed</td>
<td>No</td>
<td>No</td>
<td>Fish migration; flooding</td>
</tr>
<tr>
<td>Run-of-river hydroelectric</td>
<td>None</td>
<td>None</td>
<td>Minimal</td>
<td>No</td>
<td>No</td>
<td>Can interfere with recreational activity</td>
</tr>
<tr>
<td>Nuclear</td>
<td>None</td>
<td>None</td>
<td>Thermal discharge</td>
<td>Yes</td>
<td>Radioactive</td>
<td>High cooling water demand</td>
</tr>
<tr>
<td>Natural gas</td>
<td>Low</td>
<td>Medium</td>
<td>Thermal discharge</td>
<td>Yes</td>
<td>No</td>
<td>Moderate cooling water demand</td>
</tr>
<tr>
<td>Oil-fired generation</td>
<td>High</td>
<td>High</td>
<td>Thermal discharge</td>
<td>Yes</td>
<td>Yes³</td>
<td>Moderate cooling water demand</td>
</tr>
<tr>
<td>Conventional coal</td>
<td>High</td>
<td>High</td>
<td>Thermal discharge</td>
<td>Yes</td>
<td>Yes³</td>
<td>Mod/high cooling water demand</td>
</tr>
<tr>
<td>&quot;Clean coal&quot; with CO₂</td>
<td>Low</td>
<td>Medium</td>
<td>Thermal discharge</td>
<td>Yes</td>
<td>Yes³</td>
<td>Increased coal consumption per MWh</td>
</tr>
<tr>
<td>Energy recovery generation (ERG)</td>
<td>None</td>
<td>None</td>
<td>Low</td>
<td>No</td>
<td>No</td>
<td>Fertilizer for energy crops</td>
</tr>
<tr>
<td>Bioenergy</td>
<td>Low</td>
<td>None</td>
<td>Low</td>
<td>No</td>
<td>Yes³</td>
<td>Odour</td>
</tr>
<tr>
<td>Geothermal power</td>
<td>None</td>
<td>Low</td>
<td>Low</td>
<td>No</td>
<td>Yes</td>
<td>Odour</td>
</tr>
<tr>
<td>Wind power</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>No</td>
<td>No</td>
<td>Bird and bat kills</td>
</tr>
<tr>
<td>Solar PV</td>
<td>None</td>
<td>None</td>
<td>Low</td>
<td>For manufactur ing only</td>
<td>No</td>
<td>High energy consumption during manufacture</td>
</tr>
<tr>
<td>Tidal current power</td>
<td>None</td>
<td>None</td>
<td>Non-consumptive</td>
<td>No</td>
<td>No</td>
<td>Other impacts unknown</td>
</tr>
<tr>
<td>Wave power</td>
<td>None</td>
<td>None</td>
<td>Non-consumptive</td>
<td>No</td>
<td>No</td>
<td>Other impacts unknown</td>
</tr>
</tbody>
</table>

**Notes:**

1. Greenhouse gas emissions from energy conversion process only, not manufacture or construction.
2. Water use is difficult to compare for different technologies. In hydroelectric power stations, fossil and nuclear plants, water use is largely non-consumptive. Thermal power stations may cause some water losses through evaporation, as well as thermal discharges into watersheds, within regulated maximum limits. Hydroelectric dams do not cause thermal discharges but will affect flow patterns.
3. From ash management and or flue gas treatment.

Given all of the details regarding alternative technologies, Glacier Power believes that a 100 MW small run-of-river hydroelectric facility is the best means for generating 600,000 MWh/annum of clean, renewable energy to meet the growing demands of the Peace River region. The proposed Project will provide numerous benefits to the local economy, stabilize the electricity grid and provide long-term investment with little to no burden on local essential services and minimal impacts on the local, regional and global environment.
2.12 Site Alternatives Examined

Although the present site at Dunvegan has all the elements necessary for a hydroelectric facility, the Peace River offers other sites that have the potential to be developed as well. In contrast to the proposed Project, many of the potential sites have less favourable attributes or are missing some of the necessary conditions. It is the view of Glacier Power that the Dunvegan site is ideally suited for the development of hydroelectric energy, particularly at the scale of development currently proposed.

Table 2.12-1 provides a comparison of the key siting factors for the entire length of the Peace River. Figure 2.12-1 illustrates the location of all sites considered.

Within the regional area, three alternative sites were assessed briefly but rejected for several reasons. A possible site downstream from the proposed site, approximately 500 m upstream from the Dunvegan Bridge, was rejected because it is too close visually to the Dunvegan Historic Park, and it is too close structurally to the Dunvegan Bridge. As well, the historic Dunvegan Slide offers much less suitable abutment conditions for the headworks structure.

A second alternative site was examined about 3 km upstream from the present site. This alternative was considered during an effort to find alternative access along a tributary drainage on the north side of the river valley. The access conditions were considered unsuitable, and the upper end of the headpond would likely conflict with recreational activities and grazing leases at Pratt’s Landing, near the top end of the proposed headpond.

Glacier Power investigated a third potential area of development in 2003 approximately 80 km downstream from the Project near Shaftesbury. The driving force behind investigating hydroelectric development potential in this reach of the river included minimization of ice effects on the Town of Peace River. Numerous sites in the local Shaftesbury area were assessed based on geotechnical, hydraulic, environmental and social criteria. Due to geotechnical evaluation of slope stability, an assessment channel geometry, and proximity of the development to private landowners, this site is not as favourable as the proposed Dunvegan site. Glacier Power is not pursuing development of the Shaftesbury site.

2.12.1 Project Size Considerations

The size of the Project was determined through a best fit analysis involving a combination of factors such as:

- gross head (water differential from upstream to downstream of the headworks)
- capacity of the plant (based on gross head and river flow)
- turbine unit size (based on submergence requirements, gross head, and river flow)
- weir type, height and length (to control the gross head over the turbines)

A detailed discussion of the considerations that went into determining the size and layout of the Project can be found in Section 3.0.
<table>
<thead>
<tr>
<th>Peace River Segment</th>
<th>Segment Description</th>
<th>Physical Characteristics</th>
<th>Infrastructure</th>
<th>Labour and Services</th>
<th>Jurisdictional/Agreements</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>River Gradient</td>
<td>Geology</td>
<td>Ice Regime</td>
<td>Transportation and Access</td>
</tr>
<tr>
<td>S1</td>
<td>Bennett Dam to British Columbia border</td>
<td>Reasonable</td>
<td>Poor, very unstable valley walls</td>
<td>Good; ice pack is rare</td>
<td>Good; Hwy 97 nearby; valley access poor due to unstable slopes</td>
</tr>
<tr>
<td>S2</td>
<td>British Columbia border to Montagneuse River</td>
<td>Reasonable</td>
<td>Poor; very unstable valley walls</td>
<td>Good; ice pack is infrequent</td>
<td>Limited highway access and very limited valley access</td>
</tr>
<tr>
<td>S3</td>
<td>Montagneuse River to Shaftesbury Ferry</td>
<td>Reasonable</td>
<td>Good; more stable valley walls</td>
<td>Good; ice regime can be managed with minimal impacts</td>
<td>Good; Hwy 2 and Dunvegan Bridge; some valley access and boat ramps</td>
</tr>
<tr>
<td>S4</td>
<td>Shaftesbury Ferry to Carcajou</td>
<td>Shallow</td>
<td>Moderate; unstable valley walls</td>
<td>Good; ice management may benefit Town of Peace River</td>
<td>Limited, except near Peace River and Carcajou</td>
</tr>
<tr>
<td>S5</td>
<td>Carcajou to Wood Buffalo National Park</td>
<td>Shallow</td>
<td>Moderate; unstable valley walls</td>
<td>Poor due to Vermilion Rapids</td>
<td>Limited except near Ft. Vermilion</td>
</tr>
<tr>
<td>S6</td>
<td>Wood Buffalo National Park to Slave River</td>
<td>Shallow</td>
<td>Poor; fine sediment river bed</td>
<td>Poor due to Vermilion Rapids</td>
<td>Poor; limited roads</td>
</tr>
<tr>
<td>S7</td>
<td>Peace–Athabasca Delta</td>
<td>Significant seasonal backwater effects</td>
<td>Poor; fine sediment river bed</td>
<td>Poor due to significant level fluctuations and backwater effects</td>
<td>Poor; limited roads</td>
</tr>
</tbody>
</table>
2.12.2 Physical Site Characteristics

2.12.2.1 Hydraulic Gradient

Technically, the physical characteristics of the site provide an ideal location for the Project. The Project fits within the natural river channel banks and pre-Bennett Dam flood conditions such that inundation due to the headpond is minimized. The river channel cross-section is essentially rectangular with a flat, relatively level riverbed ideally suited to the design and construction of the Project. The hydraulic gradient (river slope) of the Peace River in the project headpond area is slightly greater than other potential locations downstream. This means a shorter headpond is required at Dunvegan than would be needed downstream from Manning or Carcajou, for example.

2.12.2.2 Geology

The foundation conditions of the river channel banks and bed are well suited to support the headworks structure. Although the valley walls show signs of active erosion and slumping, deep-seated failure of the bedrock is highly unlikely. The reason this site was examined in the mid-1970s for hydroelectric potential was due to the stable nature of the river channel and valley walls. However, the site foundation conditions were not considered suitable to support the size of dam structure proposed at the time. The suitability of the valley for hydroelectric facility development is less favourable upstream from the Montagneuse River confluence and downstream from the Little Burnt River confluence due to the presence of unconsolidated materials (post-glacial river channel) and the Shaftesbury Formation, a weak bedrock formation.

2.12.2.3 Ice

Ice affects many hydroelectric developments in the northern hemisphere. Ice formation and break-up through the Dunvegan area is not a deterrent to project development.

2.12.3 Transportation and Site Access

The Dunvegan site is ideally near Highway 2, a main transportation route with a well developed municipal road network to access local materials, such as gravel pits. The Dunvegan Bridge provides access to both sides of the river. The site is accessible along a combination of existing roads and trails with only short sections of new road required. The modular turbine units can be pre-built at fabrication shops and shipped by truck or rail to Grande Prairie, then trucked a short distance to the site.

Alternatively, transportation corridors that would provide suitable access to both sides of the river occur at or near the towns of Peace River and Fort Vermilion. The Town of Peace River has the added advantage of a rail line.

2.12.4 Proximity of Transmission Line Interconnection

An existing 144-kV transmission line is within 4.3 km of the site, providing a short distance between the site and the interconnection point. Placing the Project at alternative sites may require lengthy transmission lines at a higher cost. Between Dunvegan and downstream communities such as the Town of Peace River, Manning, High Level and Fort Vermilion, distances to transmission lines with
suitable capacity of 144 kV are reasonable. Further downstream through Wood Buffalo National Park and approaching Fort Chipewyan, the distances for interconnection become uneconomical. To the northwest of Dunvegan, 144-kV transmission lines again become too distant to make this scale of project viable.

2.12.5 Proximity of Labour Force

A trained labour force is available from the Grande Prairie and Fairview areas. The main local industries (such as oil and gas, forestry, pulp and paper, and agriculture) make available trained heavy-equipment operators and civil works contractors ideally suited to the construction and operations of the Project. Given that much of the oil and gas work occurs in the winter, and much of the Project's construction will occur in the summer, opportunities for local industries and labourers to participate in the Project are increased. In light of the current high demand for labour in Alberta, it is expected that some labour from outside the region will be required as well.

2.12.6 Proximity of Supplies and Services

The majority of supplies and services are available from main centres such as Grande Prairie, Fairview, Grimshaw and the Town of Peace River. The nearby community of Fairview has sufficient services in terms of temporary accommodations (e.g., hotels and motels), communications, and medical (hospital) to support the development phase of project development, although if sufficient local labour cannot be recruited, a camp may be required during the construction phase of the Project. Construction materials such as gravel and building materials are also available locally. During operations, it is Canadian Hydro's policy to hire local skilled workers to operate company facilities and to use local service providers for maintenance to the extent possible.

2.13 Market Setting

2.13.1 Impact of Electricity Industry Deregulation on Project Viability

The Project has become viable as a result of the deregulation of Alberta's electric power industry. The adoption of a competitive market for wholesale power through the Power Pool allows new generation to compete with existing utilities. Before 1996, non-utility generation projects were not allowed to compete directly or could only hope to receive the avoided utility variable cost of generation ($5 to $10/MWh). The Power Pool is an essential element in the deregulation of the electric energy generation sector as it allows independent power producers (IPPs) the opportunity to compete for incremental generation capacity and the opportunity for full cost recovery.

With the introduction of customer choice in 2001, customers are now able to choose their energy supplier; and franchised service areas for energy supply will eventually become a thing of the past. This development will enhance opportunities for IPPs, as customers will no longer be captive to the existing utilities. Individual choices regarding the type of generation, duration and price will be made directly by customers, e.g., choosing a green power source like hydroelectric.
2.13.2 Alberta Electricity Supply and Demand Outlook

Alberta has enjoyed strong economic growth for some time, which has lead to increased demand for electricity across all consuming sectors. This trend is expected to continue with the ongoing development of Alberta’s vast oil sands and in situ bitumen resources. Correspondingly, Alberta’s electricity-generating sector has responded since the late 1990s by developing almost 4,000 MW of new incremental generating capacity that brought the provincial generating capacity reserve margin from below 10 percent in 1998 to over 35 percent in 2004. This new investment along with continued investment in exiting units has also made Alberta’s generating fleet much more fuel efficient. Greater levels of supply and more efficient generation technology have to some extent protected Alberta’s electricity consumers from the high cost of energy, particularly natural gas. As a result, electricity prices have traded at a discount relative to the historical all-in cost of converting natural gas to electricity. These lower electricity prices coupled with high reserve margins have served to slow generation development more recently—as part of the inevitable commodity cycle. More specifically, high natural gas prices and long-term supply concerns, coupled with low electricity prices and localized transmission issues, have served to slow down the development of surplus generating capacity from Alberta’s oilsands cogeneration potential. In the Spring of 2006, the most active supply additions, coming from the wind power sector, were constrained by a moratorium on new development until the effects of the intermittency of the supply resource on the operations of the transmission system can be studied and more fully understood. Slower generation development coupled with several unit retirements over the next few years will now lead to a decline in capacity reserve margins. A lower capacity reserve margin with continued rising demand is now expected to result in rising electricity prices, particularly over the next five years.

2.13.3 Future Generation Costs

The continued rise in natural gas prices and forecasted future prices have already had a profound effect on Alberta’s electricity market in the short term and are expected to have a lasting effect in the longer term as well. The short-term impact has been immediate and measurable, while the longer-term impact is expected to change the makeup of the generation supply portfolio.

The most immediate effect of higher natural gas prices has been on the electric energy spot price. In many hours the price of electricity in Alberta is determined by a marginal natural gas-fired electricity generator, and has therefore resulted in much higher electricity prices. For example, a $4/GJ rise in spot market natural gas prices translated into a $25/MWh increase in power prices - all other things being equal - from January to September 2005.

The longer term impact of higher forward natural gas prices is now expected to alter the decisions made by generation developers with respect to their technology of choice when it comes to future supply options. The longer term forward curve for natural gas has recently risen from an average of $5/GJ over the next 15 years to around $6.50/GJ (July 2006). This fact has altered the relative economics of future generation supply options, particularly related to coal and other non-natural gas technologies relative to natural gas-fired technologies. More coal-fired generation is now expected to be developed in Alberta than previously anticipated.
2.13.4 Future Generation Supply Options

Alberta for the most part is blessed with several different future supply options for electrical energy. However, these supply options are dominated by thermal technologies that are reliant on depleting carbon based fuels—coal and natural gas. While coal and natural gas-based technologies are among the most mature, their future cost structure will be influenced by the cost of their respective fuels. This is of particular concern in light of the level of natural gas prices as noted above. Given an estimate of the current all-in levelized cost for each technology, it is apparent that base-load coal generation is the least costly generation option in Alberta at natural gas prices, as shown in Figure 2.13-1.

Figure 2.13-1 also shows that the Project is one of the least costly options relative to the other mainstream technology options, given the natural gas price environment.

**Figure 2.13-1: Comparative Electricity Supply Costs by Technology**

<table>
<thead>
<tr>
<th>Technology</th>
<th>30-Year Life</th>
<th>20-Year Life</th>
<th>30-Year Life</th>
<th>30-Year Life</th>
<th>40-Year Life</th>
<th>40-Year Life</th>
<th>40-Year Life</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simple Cycle</td>
<td>$50/ MWh</td>
<td>$60/ MWh</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>$40/ MWh</td>
<td>$50/ MWh</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cogeneration</td>
<td>$45/ MWh</td>
<td>$55/ MWh</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dunvegan Hydroelectric</td>
<td>$35/ MWh</td>
<td>$45/ MWh</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Greenfield Supercritical Coal</td>
<td>$30/ MWh</td>
<td>$40/ MWh</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Brownfield Supercritical Coal</td>
<td>$25/ MWh</td>
<td>$35/ MWh</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: EDC Associates Ltd. (2006)

As shown by the data above, certain large-scale base load generating options may produce power in the $50 to $60/MWh range, whereas some newer technologies with a relatively low utilization rate would be expected to produce power in excess of $80/MWh. The all-in cost structure for the median generation technology deployed in Alberta appears to be approximately $70 to $75/MWh—at expected natural gas prices. The following chart (Figure 2.13-2) illustrates the increased economic value to Alberta’s electricity consumers related to the development of non-natural gas-fired generating technologies. The chart shows that coal-fired generating technologies have a cost advantage, absent any significant CO₂ emissions costs, relative to even the most economic natural gas-fired cogeneration at a natural gas price above about $5/GJ. Also Figure 2.13-2 shows that the Project is more economic than cogeneration at natural gas prices in excess of $6/GJ—a level that reflects the forward curve.
Therefore, under current natural gas prices, more coal-fired generation is expected to be developed in Alberta than previously anticipated—particularly absent and significant environmental costs related to greenhouse gas emissions. This fact alone may have longer term implications for Alberta’s electric industry emissions management.

2.13.5 Northwest Alberta Outlook

The northwest regional total coincident peak load is approximately 1,142 MW (AESO 2005, Internet site). Over the next 9 years it is expected to grow to 1,310 MW, an incremental load of 168 MW by 2015. The anticipated growth is due to normal residential and industrial load growth.

The total installed capacity in the northwest is 695 MW and the region is a long distance from Alberta’s primary generation centres. Table 2.13-3 shows the existing generation in the northwest region. The northwest region is reliant on “transmission must run” (TMR) generation to provide voltage support and reliability, particularly in the Rainbow Lake area. In addition to the TMR units in the Rainbow Lake and Fort Nelson areas, there are also TMR units in Grande Prairie and Valleyview areas, primarily operated to provide voltage support but can be called upon to deliver real power if required.
### Table 2.13-3: Northwest Generation Summary

<table>
<thead>
<tr>
<th>#</th>
<th>Generating Plants</th>
<th>Fuel</th>
<th>Machine Continuous Rating (MW)</th>
<th>Type</th>
<th>Asset ID</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Bear Cree GT</td>
<td>Gas</td>
<td>50</td>
<td>GT</td>
<td>BRCK</td>
</tr>
<tr>
<td>2</td>
<td>Bear Creek ST</td>
<td>Gas and biomass</td>
<td>30</td>
<td>ST</td>
<td>BRCK</td>
</tr>
<tr>
<td>3</td>
<td>Diashowa</td>
<td>Biomass</td>
<td>35</td>
<td>Cogen</td>
<td>N/A</td>
</tr>
<tr>
<td>4</td>
<td>Fort Nelson</td>
<td>Gas</td>
<td>45</td>
<td>GT</td>
<td>FNG1</td>
</tr>
<tr>
<td>5</td>
<td>Elmworth</td>
<td>Gas</td>
<td>9</td>
<td>GT</td>
<td>NPC1</td>
</tr>
<tr>
<td>6</td>
<td>Gold Creek</td>
<td>Gas expansion</td>
<td>6</td>
<td>GT</td>
<td>GOC1</td>
</tr>
<tr>
<td>7</td>
<td>Grande Prairie EcoPower (CG and E)</td>
<td>Biomass</td>
<td>25</td>
<td>ST</td>
<td>CGE</td>
</tr>
<tr>
<td>8</td>
<td>HR Milner</td>
<td>Coal</td>
<td>144</td>
<td>ST</td>
<td>HRM</td>
</tr>
<tr>
<td>9</td>
<td>Poplar Hill</td>
<td>Gas</td>
<td>45</td>
<td>GT</td>
<td>PH1</td>
</tr>
<tr>
<td>10</td>
<td>Weyerhauser</td>
<td>Gas</td>
<td>30</td>
<td>Cogen</td>
<td>N/A</td>
</tr>
<tr>
<td>11</td>
<td>Rainbow 1</td>
<td>Gas</td>
<td>30</td>
<td>GT</td>
<td>RB1</td>
</tr>
<tr>
<td>12</td>
<td>Rainbow 2</td>
<td>Gas</td>
<td>40</td>
<td>GT</td>
<td>RB2</td>
</tr>
<tr>
<td>13</td>
<td>Rainbow 3</td>
<td>Gas</td>
<td>20</td>
<td>GT</td>
<td>RB3</td>
</tr>
<tr>
<td>14</td>
<td>Rainbow 5</td>
<td>Gas</td>
<td>45</td>
<td>GT</td>
<td>RB5</td>
</tr>
<tr>
<td>15</td>
<td>Rainbow Lake 1</td>
<td>Gas</td>
<td>45</td>
<td>Cogen</td>
<td>RL1</td>
</tr>
<tr>
<td>16</td>
<td>Sturgeon 1</td>
<td>Gas</td>
<td>10</td>
<td>GT</td>
<td>ST1</td>
</tr>
<tr>
<td>17</td>
<td>Sturgeon 2</td>
<td>Gas</td>
<td>8</td>
<td>GT</td>
<td>ST2</td>
</tr>
<tr>
<td>18</td>
<td>Valleyview</td>
<td>Gas</td>
<td>45</td>
<td>GT</td>
<td>VWW1</td>
</tr>
<tr>
<td>19</td>
<td>Whitecourt</td>
<td>Biomass</td>
<td>33</td>
<td>ST</td>
<td>EAGL</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td></td>
<td><strong>695</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: Refer to Table 3.3-2 (AESO 2005 Internet site)

Notes:
- GT gas turbine
- MCR machine continuous rating
- N/A not applicable
- ST steam turbine

The future electricity generation changes in the northwest quadrant have been outlined by the AESO in their Need Identification Results (AESO 2005, Internet site). Net reductions in load in the northwest quadrant of the transmission system will increase the need for regional, reliable, economic development of generation capacity. Electricity generation changes include:

- The power purchase agreements (PPA) for Rainbow Lake units 1, 2 and 3 expired at the end of 2005. The future of these units as a generation source is uncertain. Sturgeon units 1 and 2 have been forecast to be retired at the end of 2006.

- The HR Milner plant in the Grande Cache area has a significant impact on operations in the northwest quadrant. Milner Power Inc. has indicated that this plant will retire around 2020.

- It is also known that Weyerhauser is planning to expand its generation capacity on site. The new generation of 20 to 40 MW is expected to be online around 2008 to 2009.
• The Peace River Oil Sands area represents a potential future load or generation growth area due to oil and gas exploration activities. The net effect of the oil sand development on the northwest transmission system is uncertain as the impact may be a net load, net generation or net zero with the generation and load balancing each other. From preliminary discussions with stakeholders, the AESO has considered the possibility of up to 150 MW of net generation or about 30 MW of net load development in the area.

The Project was included in the sensitivity analysis of the AESO Need Identification Results which studied the transmission system in the northwest quadrant. For sensitivity analysis purposes, the output of the plant was assumed to be 40 MW during the peak load winter condition. Analysis for the project region revealed that with this hydroelectric plant, the voltage stability limit increases for a contingency of the Poplar Hill generator indicating this new generator would help to provide support to the transmission system.

2.13.6 Market for Green Power

The Canadian Government has shown its commitment to development of renewable energy through programs such as the WPPI, and the additional funding being contemplated for a broader Renewable Power Production Incentive (RPPI). Federal agencies and groups such as the Clean Air Renewable Energy Coalition are actively working towards increased renewable energy development. Federal incentive programs and commitments to GHG emissions reductions and energy conservation programs demonstrate a long-term commitment to the development of a reliable, renewable energy supply.

The federal and most provincial governments have made commitments to buy a large percentage of their power needs from green energy sources. This has lead to an increased development of wind, hydroelectric and biomass facilities across Canada. In parallel, the United States has adopted a renewable portfolio standard approach to support renewable energy project development directly.

2.13.6.1 Provincial Governments – Policy and Action

In the spring 2004 the Alberta government accepted recommendations from the CASA regarding an emissions management framework. One of these recommendations calls for 3.5 percent of all electricity traded through the AESO to be sourced from renewable or green energy sources by 2008. This target requires that approximately 800 MW of incremental green power capacity be developed in Alberta. The Project will play a critical role in the ability of the province to meet this target.

The Alberta government currently purchases 90 percent of the electricity used in government-owned facilities from green power sources (wind and biomass). Alberta Infrastructure (now Alberta Infrastructure and Transportation) has entered into a long-term agreement with Canadian Hydro (parent company of Glacier Power) to procure half of their annual requirements or approximately 110,000 MWh of renewable energy annually. This green power is provided primarily from Canadian Hydro’s Grande Prairie EcoPower® Centre.
The British Columbia government has committed to procuring 50 percent of new power generation from “clean” power, and 10 percent of new power generation from green sources. BC Hydro is currently purchasing power from projects built in 2003 and 2005, including Canadian Hydro’s Pingston Creek (45 MW) and Upper Mamquam (25 MW) hydroelectric projects, which generate approximately 300,000 MWh of renewable energy annually. In the summer of 2006, BC Hydro awarded several additional long-term power contracts to IPPs, including Canadian Hydro for four new green run-of river hydroelectric facilities totalling 44.5 MW.

The Ontario government, through the Ontario Power Authority, has contracted for the long-term supply of green power from 1300 MW of renewable energy facilities, which are expected to generate approximately 4,000,000 MWh of renewable energy annually. Canadian Hydro has recently commissioned the 67.5 MW Melancthon I Wind Plant, and is underway on the 132 MW Melancthon II Wind Plant, as well as the 198 MW Wolfe Island Wind Plant near Kingston.

The Alberta Urban Municipalities Association (AUMA) has an aggregate program for the purchase of green power for 2 percent of its total purchase, which amounts to approximately 60,000 MWh of renewable energy per year. Canadian Hydro supplies green credits to AUMA through a subcontract with Nexen Marketing.

2.13.6.2 Green Power Sales

Renewable energy credits (RECs), also known as green credits, can be sold with or without their associated electrical power. In the government-purchase examples above, the power has been sold along with its associated green credits. Those contracts are generally long-term contracts (i.e., for 20 or more years), which underlines another advantage of renewable energy, the low fuel price risk and the ability to forecast operating costs well into the future.

For some of Canadian Hydro’s wind and hydroelectric plants currently operating in Alberta, the power is sold on the spot market and the RECs are sold separately. Recently Canadian Hydro has found that the demand for RECs is greater than the company’s ability to supply them, even before the development of a formal regulated GHG emissions trading framework. The 800 MW cap placed on wind development in Alberta by the AESO in 2006 will limit the availability of new green credits from that technology. Development of new green power in Alberta will need to include other technologies, such as hydroelectric and biomass generation to meet demand.

The national and international market for green credits is becoming more structured. Significant progress has been made recently through the North American Association of Issuing Bodies (NAAIB), a voluntary organization formed to encourage the coordination and cooperation of systems issuing and tracking of RECs in North America. The NAAIB will continue its work in 2006 to create standards for Renewable Energy Credit certificates. An Albertan company recently completed a sale of green credits generated from a renewable energy project in Canada with a buyer in the Pacific Northwest. Green credits generated in Alberta are currently acceptable to buyers within the Western Electrical Coordinating Council (WECC), which includes Alberta, British Columbia and fourteen western states.

Canadian Hydro has had informal discussions with a number of potential buyers regarding the sale of electricity and or green credits from the Project. Alberta-based companies, such as TransAlta, Nexen,
EPCOR and Enmax, have expressed interest in the Project and are considered to be good prospects for long-term contracts.

2.13.7 Greenhouse Gas Emissions

2.13.7.1 Federal Government

The Kyoto Accord has been the impetus for the adaptation and implementation of environmental stewardship principals in Canada and around the world. In Canada, governments at all levels have been working with industry and stakeholders to develop guiding principles that will define future policy with respect to GHG emissions. The federal government has recently committed to the development and implementation of a “made-in-Canada” plan for reducing greenhouse gases that will be effective, realistic, and focus on “achieving sustained reductions in emissions in Canada while ensuring a strong economy” (Environment Canada 2006b, Internet site).

2.13.7.2 Provincial Government

In 2004, 99 large industrial facilities in Alberta reported a total of 110 Mt of greenhouse gas emissions, expressed as carbon dioxide equivalents. When compared with the figures in Canada’s National Greenhouse Gas Inventory 1990-2004 report (Environment Canada 2006) Alberta’s emissions were the largest of any province in Canada, accounting for 39 percent of the national total. This is the result of Alberta’s high number of large industrial facilities from the energy sector exceeding the reporting threshold (100 kt CO$_2$-e), and the predominant use of coal for electricity generation in the province. The highest percentages of total GHG emissions reported from large industrial emitters in Alberta were from power plants (46 percent), oilsands facilities (18 percent) and gas plants (8 percent). The majority of GHGs emitted were in the form of carbon dioxide (96 percent) from stationary combustion sources (85 percent).

Alberta is currently developing a new long-term management framework for air emissions from the electricity sector. A number of initiatives are related to developing this framework, including implementation of Alberta’s climate change action plan Taking Action, the CASA’s Electricity Project Team Report (2003), and negotiation of an agreement with the electricity sector on GHG emissions.

In 2001 Alberta established a policy that new coal-fired power generation must proactively reduce the GHG emission intensity to the same level as a natural gas combined cycle plant. This standard applied to the recently completed Genesee 3 coal-fired power facility, and will likely apply to the proposed 450 MW Keephills 3 project.

In addition to direct emissions reductions achieved through the deployment of technology, the policy states that any new coal-fired plants seeking to reduce GHG emissions to meet the target will have the option of investing in renewable energy, investing in emissions offsets, or initiating the early shutdown of existing facilities. The provincial government notes that emissions reduction equivalencies fulfilled under these principles may be eligible to be banked and carried forward to when greenhouse gas standards are set in the overall emissions framework (AENV 2004).

Given the rise in natural gas prices, base-load coal generation is likely the least costly generation option in Alberta in terms of future supply options. The confirmed assessment that the future generation fleet in Alberta will include more coal-fired generation, combined with Alberta’s moratorium on wind
power development, will make Alberta’s emissions targets from the electricity sector much more difficult to meet.

The Alberta government is supporting renewable energy research and energy conservation through AENV programs as well as agencies such as Climate Change Central and CASA. In keeping with the CASA 2003 recommendations, AENV is implementing new annual limits for nitrous oxide and sulphur dioxide emissions, which will create an emissions trading program for these two substances based from the electricity-generating sector. Given the assessment that the future generation fleet in Alberta may include more coal-fired generation than previously anticipated, it may make some of the overall emissions targets set by the provincial and federal governments more difficult to meet. This situation underscores the value to electricity consumers and the need to diversify Alberta’s generation portfolio to include as much low-impact renewable generation sources, such as the Project, that will serve to lower Alberta’s emissions from the electricity-generating sector.

2.13.7.3 The Project

Given its expected operating characteristics, the Project would provide a significant reduction in GHG emissions in Alberta, in the order of 500,000 tonnes annually (assuming 0.8 t per MWh) by displacing other thermal generation sources. This reduction is anticipated to save the electric industry approximately $5 million dollars per year in potential CO₂ offset costs assuming a cost of $10/t.

2.14 Project Sustainability

The Project is dependent on the flow of the Peace River. The Project benefits from the regulation of the Peace River by the Bennett Dam, approximately 300 km upstream from Dunvegan in British Columbia. The Peace Canyon Generating Station, a run-of-river style project 23 km downstream from the Bennett Dam, cycles its operations in step with operations at the dam and is therefore dependent on flows released from Bennett Dam. Informal discussions with BC Hydro indicated that there are no planned or potential changes to operations at the Bennett Dam.

The amount of water stored behind the Bennett Dam in the Williston Reservoir exceeds 1.5 years-worth of river flow, providing significant storage and resilience against the effects of annual climatic variations. Climate change trend forecasts indicate both warmer weather and increased precipitation in northeast British Columbia. These trends are not expected to necessitate changes in Bennett Dam operations, particularly given the large amount of storage available in the Williston Lake.

Historically, operational changes (reduced flow) have been required at the Bennett Dam to assist repair and maintenance activities. As in the past, any future changes to the operating regime to assist maintenance activities are expected to be short-term and will not affect the long-term viability of the Project.

The commonly used definition of sustainable development from the 1987 Brundtland Report, Our Common Future (WCED 1987) is “development that meets the needs of the present without compromising the ability of future generations to meet their own needs.” The following outlines the principles of sustainable development and methods by which the Project is striving to achieve these:

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6 Currently, the renewable generating technologies are excluded from participating in the NOₓ and SO₂ trading system for a variety of reasons.
Sustainable Development

- From the outset, the conceptual definition of the Project has balanced economic, environmental and social considerations. It is designed specifically to avoid the adverse environmental and social effects of large hydroelectric dam projects.

- The development of renewable, low-impact electrical energy coupled with sensitive environmental design is a top project priority.

- The sustainability of the Project, in terms of the three pillars of sustainable development (economic, environmental and social factors) has been assessed in the EIA, with due consideration of environmental integrity.

Stewardship

- The Project is essentially action today to provide benefit for many generations in the future.

- The Project would provide a significant reduction in GHG emissions in Alberta (in the order of 500,000 t annually, assuming 0.8 t per MWh) by displacing other thermal generation sources.

- The GHG reduction is anticipated to save the electric industry approximately $5 million per year in potential CO₂ offset costs (assuming $10/t). Reasonable capital cost projects, particularly those with lower operating costs, such as the Project, are in the best interest of future electricity consumers in Alberta.

- Further diversification of the power sector’s fuel supply in Alberta provides additional value to the consumer by mitigating long-term fuel supply risk. Direct and indirect technical benefits potentially arise from the interconnection of the Project in the northwest Alberta transmission grid that will benefit both future regional and system-wide consumers.

Shared Responsibility and Understanding

- Glacier Power is responsible and accountable to the public through public participation review and approval processes.

- A public consultation program has been undertaken to share information about the Project and to better understand and incorporate the views, values, traditions and aspirations of communities and people upstream and downstream from the project area, including First Nations. This information has contributed to the planning and design of the Project.

Prevention

- Potential significant adverse effects were avoided through the planning and design phases of the Project.

- Glacier Power has committed to ensuring adverse effects of the Project are prevented, mitigated or compensated for. Glacier Power has demonstrated this substantial commitment through its efforts
to advance technologies related to ice and fish passage, in order to understand, prevent, and mitigate potential adverse effects.

- Each project component has been planned with environmental management and contingencies built into the design, construction and operations.

- Environmental considerations played a key role in project siting, which resulted in a location where the Project fits within the natural river channel banks and pre-Bennett Dam flood conditions, such that inundation due to the headpond is minimized.

- Mitigation and adaptive management strategies and facilities for fish passage, habitat enhancement and compensation have been incorporated into the project design, construction and operations phases.

- The project headworks construction integrates sheet piles into the structure rather than cofferdams. Cofferdams can cause extensive disturbance to the channel bottom and tend to generate high sediment into the water column during installation and decommissioning.

- Project components will be pre-assembled and pre-cast as much as possible to minimize the amount of instream work required. The majority of construction access will be via each bank abutment, thereby minimizing instream equipment.

- Considerable study has been done on potential erosion effects of the Project and appropriate monitoring and mitigation steps have been outlined.

- The Project is the subject of extensive environmental impact studies that have determined that with the project design and mitigation plans, no significant residual adverse effects are anticipated. Monitoring programs will be conducted during the construction and operations phases to determine if the predicted effects are as anticipated. Should the monitoring programs identify unacceptable unanticipated effects, appropriate mitigation will be implemented.

Conservation and Enhancement

- The Project has been designed to avoid adverse effects and thereby reduce damage or degradation of the environment.

- The project scale does not pose a strain on surrounding infrastructure or the environment.

- Access to the facilities will utilize existing roads and trails as much as possible, and the power transmission line will follow the access roads and existing and former trails.

Rehabilitation and Reclamation

- Areas temporarily cleared during construction of the Project, e.g., the laydown areas, will be reclaimed upon completion of the construction phase.

- The Project is such that each of its components can be replaced as necessary over the life of the Project (minimum 100 years); however, during eventual decommissioning, machine components
will be removed and the protruding concrete structures will be demolished and hauled to an approved landfill site.

**Global Responsibility**

- The environmental attributes of the Project will provide a long-lasting benefit with respect to global climate change through reduced GHG emissions.

**Efficient Use of Resources**

- Run-of-river hydroelectric projects are positioned and sized to fit the environment where they are to operate. The overall objective of these projects is to fit into the landscape to provide low-impact, green energy from running water, a renewable resource.

- The Project does not divert water from the river, or change or regulate flows downstream. The run-of-river design is efficient in capturing the energy from the available water flow.

**Public Participation and Access to Information**

- The regulatory process provides the public with an opportunity for review, input and influence.

- The regulatory process, including the use of public registry and related documents, provides a formal process for the review of the EIA.

- An extensive participation program, ongoing since 1999, and making use of a variety of methods, has been undertaken to share information about the Project and to understand the interests and concerns of communities and people, including First Nations and communities, upstream and downstream from the Project. Methods include open house presentations, formal public notices, and presentation and information sessions with special interest groups. During these events new information was shared or discussed as it became available. This information has contributed to the planning and design of the Project.

**Integrated Decision Making and Planning**

- Through the several reviews of the Project, many perspectives were considered and integrated into a decision to improve the design of the weir and associated structures.

- The EIA process has involved a wide range of public interests in the ongoing planning of the Project.

- Glacier Power has been working with Alberta Sustainable Resource Development (SRD) and the DFO through the project approvals phase with the objective of obtaining provincial permits and Sections 32 and 35 Authorizations under the federal *Fisheries Act*.

- An Environmental Management Program will be developed for the Project, outlining the protection measures developed by Glacier Power in consultation with the regulatory agencies to address environmental considerations associated with the design, construction and operations of the Project. The plan will present standard, good environmental practices and the environmental
protection requirements of provincial and federal departments, and be used as an internal environmental management tool with applications for training and educating project personnel.

**Waste Minimization and Substitution**

- Solid and liquid wastes will be regulated, recycled and reused where possible, and the tender documents for construction will emphasize this aspect of the Project to the contractors.

**Research and Innovation**

- Information collected during environmental and physical studies has greatly increased knowledge of the local environment and may be valuable for future research and development in the Peace River area. Glacier Power has spent approximately $5 million on environmental studies and research, including the programs described below.

  o As a result of the project proposal, a joint ice data collection program was developed and implemented by Glacier Power, AENV and BC Hydro. The field program was initiated in 2002 and resulted in the collection of ice information not previously measured or available for the Peace River. Data from this research were applied to review the current joint task force flow control criteria, and to calibrate the Peace River ICE model (PRICE) for the project effects assessment.

  o Development of the PRICE model meant the adaptation and application of the worldwide state-of-the-art in-river ice modeling specifically to the Peace River. This powerful model may be of use in the future in understanding and managing Peace River ice processes.

  o Extensive aquatic studies were conducted to prepare a detailed risk assessment for the Project. Fish community baseline studies were conducted in 1999 and 2004, with an additional year of study planned prior to construction. In 2002 to 2003 and 2004 to 2005, fish movement studies were conducted from the Notekewin area in Alberta to Taylor, British Columbia. The movement studies filled a large gap in the understanding of fish life histories in this reach of the Peace River, and have provided critical information about movement timing for several of the species being targeted for upstream and downstream passage (including goldeye, walleye and burbot).

  o As fish passage for these freshwater species had not previously been attempted, Glacier Power spent three years working collaboratively and iteratively with DFO, ASRD, and fisheries biologists and hydraulic engineers from Calgary, Edmonton and Vancouver, to design and test fish passage facilities for the Project. This has resulted in the design of an innovative and leading-edge fish passage strategy that has already seen interest from the international scientific community.

  o Project design, construction techniques and schedules and operations have considered findings from extensive environmental studies (air, geotechnical, hydrology, ice, fish, vegetation, wildlife, historical resources, land and water use, health and safety and socioeconomics).

In summary, the Project is an excellent example of sustainable development—a project that balances social and environmental benefits while protecting the welfare of future generations of Albertans.