MINISTRY OF ENERGY

REPORT ON ECONOMIC FEASIBILITY AND MEANS FOR FINANCING STUDY OF THE BECK 3 GENERATING STATION

FINAL

June 2004

Submitted by:

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KLOHN CRIPPEN

June 17, 2004

Ministry of Energy
Energy Policy Branch
880 Bay Street, 3rd Floor
Toronto, Ontario
M7A 2C1

Mr. Rick Jennings
Director

Dear Mr. Jennings:

Economic Feasibility and Means for Financing Study of the Beck 3 Generating Station Project Final Report

Please find attached five (5) hard copies and one (1) electronic copy of our Final Report on the Economic Feasibility and Means for Financing Study of the Beck 3 Generating Station Project.

Our responses to your request for additional information on analysis results, as per your email to Mr. Bill Harvey dated May 14, 2004, have been included as Appendix II of the report.

We thank you for the opportunity to assist you with this interesting project. Please call us if you have any questions with the Report.

Yours truly,

KLOHN CRIPPEN CONSULTANTS LTD.

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EXECUTIVE SUMMARY

The Ontario Ministry of Energy engaged Klohn Crippen Consultants Ltd. ("Klohn Crippen") in association with ICF Consulting Inc. ("ICF") to study the proposed Beck 3 hydroelectric development located in Niagara Falls, Ontario.

Existing Ontario Power Generation facilities at the project site comprise Beck 1, Beck 2 and Beck PGS hydroelectric developments and have been found to have insufficient flow diversion and installed capacity to fully use the Canadian share of the water along the Niagara River. Commencing in early 1990, detailed engineering work was carried out for the Beck 3 generating station to address capturing these available power flows for the Ontario grid. An Environmental Assessment (EA) document was prepared and submitted to the Ministry of Environment for approval. Approval of the EA was granted in October 1998.

The scope of this immediate study was to conduct an independent assessment of the economic feasibility and means of financing of the Beck 3 project. The project and related options were studied in accordance with the approved EA and did not exceed any design and construction limitations set out in the EA. A subsequent confirmed methodology and work plan for this study was developed by Klohn Crippen and submitted to the Ministry of Energy for approval.

The hydrology of the proposed Beck 3 project is that of the Niagara River above Niagara Falls. One of the basic premises used for the hydrological analysis in this study is that the past will repeat itself and historical flow records can be used as input to accurately model potential project developments. Flows and water levels in the Great Lakes are no exception but have varied considerably over the approximately 140 years for which records exist. Climatic change, consumptive and diversionary modifications to the Great Lakes and conduct of the Niagara River Diversion Treaty between Canada and the United

States are impacts which have been taken into account when analyzing the available Niagara River power flows for Beck 3.

The available flows for diversion through the Beck system model the actual flow rates through the tunnels, canals and turbines and will depend on the hydrodynamic conditions in the system at any instant. Power potential and subsequently energy production for a hydroelectric development are directly related to the net head experienced by each station. With respect to the Beck complex the net head at each station is the elevation difference between the intake canal forebay level and the tail water (lower Niagara River) level, less any water passage and exit head losses. Existing power tunnels and canals convey power flows to the complex from the Grass Island Pool (GIP) upstream of the International Control Structure (ICS) to the power canals feeding the forebay. The existing Beck complex was modeled to establish baseline data for the power and energy study for Beck 3.

The objective of the power and energy study was to determine the generation benefits associated with specific project layouts of the Beck 3 alternatives, specifically the net benefit of the project comprising a new Tunnel T4 and the Beck 3 generating station.

As detailed in the study work plan approved by the Ministry of Energy, the following case alternatives were evaluated and the incremental benefits associated with each assessed:

Case 1: Existing Diversion Canal and Tunnels T1 and T2
Existing Generating Capacity at Beck 1
Upgraded Generating Capacity at Beck 2

Case 2: Existing Diversion Canal and Tunnels T1 and T2
Construction of New Tunnel T3
Existing Generating Capacity at Beck 1
Upgraded Generating Capacity at Beck 2

Case 3: Existing Diversion Canal and Tunnels T1 and T2
Construction of New Tunnels T3 and T4
Existing Generating Capacity at Beck 1
Upgraded Generating Capacity at Beck 2

Case 4: Existing Diversion Canal and Tunnels T1 and T2
Construction of New Tunnels T3 and T4
Existing Generating Capacity at Beck 1
Upgraded Generating Capacity at Beck 2
Construction of New 300 MW, 600 MW and 900 MW Capacity (Beck 3)

The average annual energy estimates for the 75-year period (1926-2000) and for two sub-periods occurring within the overall 75-year record are calculated by Klohn Crippen's energy simulation model. The first sub-period is for the distinctly higher flow or wet period of record from 1969 to 1993, and second for a lower flow or dry period from 1926 to 1942. These generation benefits derived from these shorter periods of record provide an indication of the potential range in generation benefits associated with the long hydrologic cycles experienced on the Niagara system. While each of the project capacities indicated for Case 4 was analyzed, the 600 MW Queenston Forebay scheme for Beck 3 was highlighted as the latest update of the project development and, hence, serves as the focus of the initial power generation and energy study, the results of which were used as input to the study's generation planning simulation and economic screening exercises.

The generation planning model provided quantitative analysis focused on the expected revenue performance of the 600 MW Beck 3 project. Revenues are forecast utilizing ICF's proprietary Integrated Planning Model (IPM®). IPM® is an advanced fundamental economic and engineering principals driving dispatch and pricing model covering all of North America. In this analysis we have used a version of IPM® which includes all regions in the North American Eastern Interconnect, including the Ontario electricity market.

Of note, hydroelectric power is considered a "clean" energy source that is free of greenhouse gases (GHGs), NO_x and SO_2 emissions. Environmental benefits, such as avoided emissions, may be achieved through the displacement of other forms of energy production, generally the combustion of fossil fuels. We have considered this potential environmental emission benefits of adding Beck 3 to the Ontario marketplace.

In the base case generation analysis, the Beck facility is represented as Case 2 comprising the two upgraded Beck 1 & 2 generating stations totalling 1943 MW of installed capacity with the addition of Tunnel T3 in place. In the analytical Case 4 - Beck 3, a fourth Tunnel T4 with an underground powerhouse of 600 MW, similar to what was studied in the report by Acres-Bechtel in the Definition Phase 2 Optimization Study Report is represented.

The Beck 3 analytical case is used to forecast operating revenue under the most likely market conditions. A "High Market Price" analytical case has been designed to forecast operating revenue for Beck 3 under best foreseeable market conditions. These favourable market conditions were chosen based on possible electricity sector changes being considered by the Ontario government at the time of this study. These include the decision not to restart Pickering nuclear facility units 2, 3 and 4 as well as replacing coal generation in the province in 2007. In addition to these factors, two other variables that could have a large impact on electricity sector behaviour were considered: a carbon price due to Kyoto implementation and natural gas price fluctuations. The carbon price was set to $15 CDN/tonne of CO_2 to reflect the Government of Canada's published intentions.

Natural Gas prices were determined using ICF's NANGAS modeling system assuming tight supply and rapid demand growth.

On a Net Present Value basis, operating revenues are expected to be $355 million or $592/kW between 2007 and 2025. This compares with an estimated project capital cost of $1,633/kW for development of the facility.

Gross margins in the High Market Price Case are expected to be more than 35 percent higher than the Base Case on an NPV basis. Even this admittedly high revenue estimate yields a value of only $799/kW. Again, this compares unfavourably with the estimated capital cost of the facility at $1,633/kW.

Preliminary benefit forecasts for each of the Case 4 capacities of Beck 3 (300 MW, 600 MW and 900 MW) were determined together with the associated preliminary capital costs. The preliminary benefits are then compared to the capital cost estimates to evaluate whether a particular generation expansion option appears economic or not.

A phased approach was adopted for updating previous cost estimates and schedules developed for the diversion works and generation facilities associated with the proposed Beck 3 project. The methodology adopted in the first phase is consistent with the level of detail required for the screening level economic assessment. Any economic alternative cases identified in the screening assessment would then be taken to the next phase to analyze costs more rigorously.

As illustrated in the following table, the benefit/cost ratio of all the Beck 3 options clearly fall significantly below the break even point of 1.0, even for an optimistic energy price scenario and assuming the continuous high river flows available during a wet hydrologic period.

Hydrological Period	**Case 4: Addition of Tunnel 4 and Beck 3 (600 MW)**		
	$ million		
	Annual Benefits*	**Annual Charges**	**Benefit/Cost Ratio**
Average Flow	54/44	88	0.61/0.50
Wet Period	75/61	88	0.85/0.69
Dry Period	30/24	88	0.34/0.27

* optimistic price/conservative price scenario

The case upon which the EA was issued in 1998, for the Niagara River Hydroelectric Development, is the 600 MW Queenston Forebay alternative, Case 4.

The screening level assessment indicates that Case 4 is not economic and therefore more detailed capital cost estimates for the various development options set out under the current EA will not be developed.

In the current circumstance in Ontario, electric power is potentially in short supply and electric energy costs may rise dramatically as a consequence. All options for new supply, and in particular, renewable energy options such as Beck 3 should be reviewed with a view to reducing costs while retaining a reasonable balance of protection for the environment. Our study proposal suggested that the basic modifications to the 600 MW Queenston Forebay alternative for Beck 3 scheme as currently described be reviewed regardless of the context of project design and construction limitation as set out in the existing EA. Hence, a preliminary estimate of potential project cost savings was investigated for both the powerhouse setting and permanent site access alternatives (surface vs. underground) with the results warranting no significant benefit-cost ratio improvement to warrant further detailed study. Similarly, these same development alternatives as applied to the 300 MW and 900 MW Queenston Forebay powerhouse schemes would not yield significant benefit/cost ratio improvement to warrant further detailed study.

It was concluded from analyzing the range and sensitivities of available revenue and estimated capital costs, that the Beck 3 development is not economic at this time.

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APPENDICES

1. INTRODUCTION

1.1 Background

Responding to a Request for Proposal (RFP) issued March 31, 2003 by the Shared Services Bureau on behalf of the Ontario Ministry of Energy (the "Ministry"), Klohn Crippen Consultants Ltd. ("Klohn Crippen") in association with ICF Consulting Inc. ("ICF") was awarded a contract September 23, 2003 to study the proposed Beck 3 hydroelectric development. The study comprised an independent study of the economic feasibility of proceeding with the Beck 3 generating station project situated in Niagara Falls, Ontario. A brief background of the project summarized from both the RFP and the Niagara River Hydroelectric Development Environmental Assessment dated March 1991 follows.

The Niagara River has a long history of hydroelectric development. The relatively steady outflow from Lake Erie and the natural drop in water level between Lake Erie and Lake Ontario has been a valuable asset to both Canada and the United States. The use of the water has been governed by treaty since 1909. In 1950 the Treaty Between Canada and the United States of America Concerning the Diversion of the Niagara River was put into place. This Treaty defined scenic minimum flows over Niagara Falls and after allocations for navigation, domestic and sanitary purposes, etc., the balance of Lake Erie outflow is available to be divided on an equal basis between the two countries.

The existing development consists of Sir Adam Beck Generating Station No. 1 (Beck 1) completed in 1923, and Sir Adam Beck Generating Station No. 2 (Beck 2) completed in 1954 and extended in 1958, and the Sir Adam Beck Pumping/Generating Station (Beck PGS) and its reservoir placed in service in 1958.

Beck 1 consists of a 20.2 km open canal from the Grass Island Pool to the crest of the Niagara Gorge near Queenston. The generating station contains 10 units ranging in capacity from 45.2 MW to 52.8 MW with a maximum output of 488.2 MW at a nominal head of 88.9 m. Potential upgrading conversion (from 25 Hz to 60 Hz) of four of the units would increase output by 38 MW.

Beck 2 uses two 15.2 m diameter tunnels 8.7 km in length and a 3.5 km canal from Grass Island Pool to the crest of the Niagara Gorge near Queenston and adjacent and just upstream of Beck 1. The powerhouse contains 16 units rated at the time of the 1991 Environmental Assessments at 71.2 MW each.

The Beck PGS consist of a pumping/generating station and reservoir located near the forebay area at the downstream end of the Beck 1 canal and Beck 2 tunnel and canal. This station was constructed to supplement the reduced divertible flow during daylight hours in the tourist season with water stored in the reservoir during the overnight hours when divertible flows are higher.

The general arrangement of the existing and proposed facilities are shown on Figures 1-1 to 1-5.

The existing facilities comprising Beck 1, 2 and PGS developments have been found to have insufficient flow diversion and capability to fully use the Canadian share of the water.

In early 1990, detailed engineering work was carried out for the Niagara River Hydroelectric Development. An Environmental Assessment (EA) document was prepared and submitted to the Minister of Environment for approval. Approval of the EA was granted in October 1998.

The undertaking identified in the 1991 EA document is summarized as follows:

- Construction of two new tunnels each approximately 10.5 km in length. Intake facilities located at the International Niagara Control Works. The tunnels connect to the Sir Adam Beck diversion canal system.
- A 3 X 300 MW underground generating facility complete with penstocks, tunnels and underground cables for incorporation to the electrical transmission system. The underground generating facility to be located just downstream of the Beck 1 generating station.
- Construction and upgrading of identified transmission facilities.

Figure 1-5 shows the general arrangement of the proposed Beck 3 Queenston Forebay Scheme development as identified in the 1998 EA.

Ontario Power Generation Inc. is in the process of evaluating the development of the first of the two tunnels (T3) approved under the EA. As a result, this study is to review the economic feasibility of the second tunnel (T4), the proposed underground generating facility and associated incorporation into the electrical system.

1.2 Scope of Work

In general the scope of work was to conduct an independent study of the economic feasibility and means of financing of the Beck 3 generating station project in Niagara Falls, Ontario. The project and any options studied were in accordance with the approved EA and did not exceed the overall electrical capacity identified in that document.

1.2.1 Work Included

The detailed scope of work is as follows:

- Data collection and review of available information.
- In consultation with the Ministry Project Lead, confirm scope of work required to complete the feasibility review and financing options for the project.
- In consultation with the Ministry Project Lead, update and confirm the milestone schedule included with this proposal.
- In consultation with the Ministry Project Lead, confirm the proposed methodology, deliverables, assumptions and assessment criteria used for this study.
- Review environmental assessment, engineering studies, amendments and approvals.
- Review hydrology and hydraulics to confirm estimates of incremental flows available for generation.
- Identify options for facility configuration within constraints of environmental approval.
- Review and update construction estimates and schedules.
- Estimate Operation and Maintenance costs as part of life cycle cost estimate for economic analysis.
- Develop and quantify benefits to Province and Ontario Power Generation.
- Prepare economic assessment of project using generation estimates, revenue forecasts and life cycle costs.
- Assess and recommend financing options for the project, if deemed economically feasible.
- Prepare Feasibility Study Report.

1.2.2 Deliverables

The study deliverables are as follows:

- Detailed Terms of Reference, Confirmed Methodology and Work Plan including milestone schedule, assessment criteria, assumptions and deliverables.
- Draft Feasibility Study Report in five (5) hard copies, one (1) electronic copy.
- Final Feasibility Study Report after Ministry's acceptance of the draft submitted in five (5) hard copies and one (1) electronic copy.

1.2.3 Available Data

As part of the execution phase of this study Klohn Crippen expected to have complete access to all available data, information, engineering studies, costs estimates and analysis prepared by and on behalf of Ontario Power Generation (formerly Ontario Hydro) and Hydro One. Klohn Crippen entered into confidentiality agreements with both Ontario Power Generation and Hydro One for review and use of this data.

The available documents include those listed in the RFP and Addendum #1 as well as additional documentation identified during data collection (reference Appendix I, List of Project Data).

1.2.4 Assumptions

The following assumptions as defined in the RFP were used in this study.

- Tunnel T3 of the Niagara River Hydroelectric Development will be operational by December 2007.
- Project costs shall include costs of connecting the Beck 3 plant to the Ontario transmission system.

- Transmission upgrades as identified in the EA document is completed and not included as part of the costs for this project.
- Frequency conversion and associated upgrades of all remaining 25 cycle units at Beck 1 will be completed by December, 2009.

1.3 Project Initiation

The Ministry of Energy, Klohn Crippen and ICF held a project initiation meeting November 19, 2003 to review the Beck 3 Feasibility Study (Project) scope of work, work plan and schedule.

All project-related contractual and confidentiality agreements between the Ministry of Energy, Klohn Crippen, ICF, Ontario Power Generation (OPG) and Hydro One Inc. were been signed by each of the respective parties December 8, 2003.

A schedule of available appointments with a designated OPG contact was provided to Klohn Crippen by the Ministry of Energy to initiate the study data collection phase, after which Klohn Crippen obtained several project documents for the purpose of review and confirmation of the project methodology and work plan.

2. TERMS OF REFERENCE, METHODOLOGY & WORK PLAN

2.1 Terms of Reference

The Project is to confirm the magnitude, availability and timing of incremental flows, size the generation assets to suit, model the revenue stream this new generation will provide, review appropriate development options and associated life cycle costs, develop economic rates of return and benefits, and, if economic, identify financing models for project implementation.

2.2 Work Plan

The confirmed terms of reference and draft work plan to execute this approach were submitted under separate cover to the Ministry December 23, 2003 and provides for both the methodology of this study and outline for this report as detailed in the following sections:

Section 3.0	Hydrology & Power Studies
Section 4.0	Generation Planning Model
Section 5.0	Review and Screening of Beck 3 Development Options
Section 6.0	Beck 3 Development Alternatives
Section 7.0	Project Cost Estimates & Financial Analysis
Section 8.0	Conclusions

2.3 Data Collection & Review

The initial data reviewed included documents listed in the Project RFP and Addendum #1. Upon review of this data, additional information was identified for use in the study. It is Klohn Crippen's understanding that considerable investigation and detailed engineering studies have been carried out during the 1990's and access to this data was initially considered essential. Data requested for this study:

- detailed engineering studies;
- detailed capital cost estimates and schedules;
- geotechnical studies and reports;
- dynamic hydraulic model and data sets;
- subsequent environmental studies;
- labour agreements;
- performance details of Beck 1 and 2 units (flow and generation);
- planned upgrades to Beck 1 and 2 units and flow and generation details;
- summary of design-build bid pricing received from contractors in the 1998 Beck Tunnel (T3) project bid; and
- other data as identified.

The review and use of this data was ongoing throughout the Project. Klohn Crippen allocated time to the collection and initial review of this data to confirm the work plan.

In addition to data collected from OPG and Hydro One, Klohn Crippen and our project subconsultant ICF applied extensive project experience and databases for inputs to the study.

Of note, no design-build pricing of vendor cost estimates as requested were made available to Klohn Crippen for the purpose of this study. Subsequently, we have provided analysis and treatment of previous study cost estimates by Acres Bechtel

Canada and others, supported by in-house data developed for similar tunnel project work completed by Klohn Crippen.

3. HYDROLOGY AND POWER STUDIES

3.1 Introduction

The hydrology of the proposed Beck 3 project is the hydrology of the Niagara River above Niagara Falls.

One of the basic premises of hydrological analysis is that the past will repeat itself and historical flow records can be used as input to accurately model potential projects. Flows and water levels in the Great Lakes are no exception but, have varied considerably over the approximately 140 years for which records exist.

The flow in the Niagara River is controlled by the rise and fall of water levels in Lake Erie. Three principal phenomena influence Lake Erie levels:

- Long-term climatic variations over the areas draining to Lake Superior, Lake Michigan, Lake Huron and Lake Erie.
- Seasonal effects from snowmelt, rainfall and evaporation.
- Short-term surges from wind-tides across Lake Erie.

Of these three influences, the first will have the greatest impact on the feasibility of the Beck 3. The availability of flow records from 1860 to the present for the Niagara River at Queenston might suggest that the long-term water available to Beck 3 would be well defined. However, this is not the case, because of the little understood cycles of high and low flow sequences in the record. As Figure 3-1 shows, cycles of flow above and below the long-term average have persisted for decades, with little or no respite. During the 30-year high flow cycle from 1969 to 1998 only 1989 dropped below the long-term average, and even then only marginally. The reason for these years of high flow are attributed to higher summer and fall precipitation over the Great Lakes region, but the reason for the increased rainfall is uncertain.

The persistence of high flows through the 70's, 80's and 90's resulted in new high water level records in 1973 and 1986 and led some to believe that the higher flow levels should be considered representative of future flows for planning purposes.

However, the cycle of high water levels and flows ended in 1998. The years 1999 to 2000 saw the second largest drop in lake levels since the North American Dust Bowl drought of 1931. Today Lakes Superior, Michigan and Huron remain significantly below long-term average levels and, although Lake Erie levels briefly returned to the long-term average in the spring of 2002, they have subsequently dropped back below the long-term average.

Hydrological analysis usually looks to the past to assess the future potential of hydropower projects, assuming the past will repeat itself over the long-term. The end of the recent 30-year cycle of high flows and the current five-year cycle of low flows suggests that this assumption holds true for the Niagara River. In this study the feasibility of the Beck 3 will be based on the long-term flow statistics for the Niagara River. However, the sensitivity of the study results to persistence of the current low flow cycle will also be addressed. The sensitivity to climate change will also be discussed using the findings of the recent studies on *The Potential Impacts of Climate Change in the Great Lakes Region* published in The Journal of Great Lakes Research (Volume 28, Number 4, 2002).

Climatic variation is not the only variable that has had an impact on flows in the Niagara River; mankind has also made changes that have affected flows. The following diversions into and out of the Great Lakes above Niagara Falls are implicitly included in the flows measured at Queenston from the years shown:

- 1860 Consumptive use (out);
- 1900 Lake Michigan diversion out at Chicago;
- 1918 New York State Barge Canal diversion out above Niagara Falls;
- 1932 Welland Canal diversion out from Lake Erie;
- 1939 Long Lac diversion in to Lake Superior;
- 1943 Ogoki diversion in to Lake Superior.

These locations of these diversions are shown Figure 3-2.

The Niagara River flow series used to evaluate the feasibility of Beck 3 GS must be adjusted to incorporate these diversions so that every year is subject to the same adjustments.

Before water can be taken from the Niagara River for hydropower generation the scenic flow requirements over Niagara Falls must first be met. These flow requirements are based on the Articles of the 1950 *Niagara River Diversion Treaty* between Canada and the USA and are described in detail in following sections of this report.

3.2 Flow Data

3.2.1 Data Sources

Flow data used in the study were collected for the locations summarized in Table 3.1.

Table 3.1 Flow Data Sources

River	Station		Drainage Area (km^2)	Period of Record	Mean Annual Flow (m^3/s)
	No.	Name			
Ogoki	02AD009	Diversion to Lake Nipigon	-	1943-1994	111
Ogoki	04GB004	Above Whiteclay Lake	11,200	1971-2000	106
Long Lake	04JD003	Diversion to Lake Superior	-	1939-1994	39.1
Welland Canal	02HA019	Diversion from Lake Erie	-	1984-2000	210
Welland	02HA007	Below Caistors Corners	230	1957-2000	2.23
Niagara	04216000	At Buffalo, NY	683,000	1927-2002	5796
Niagara	9063007	At Ashland Ave, NY	-	1970-2000	2278
Niagara	02HA003	At Queenston	686,000	1860-2000	5877

Hydrological analysis usually looks to the past to assess the future potential of hydropower projects. The Water Survey of Canada streamflow station on the Niagara River at Queenston has been monitoring river flows continuously from 1860 to the present day. Although flow data are available from 1860 for the Niagara River at Queenston, mean daily flows are only available from 1926. The location of this station is fortunate in that it measures flows from the Falls plus outflows from all the hydropower projects on both sides of the river, i.e. the total flow available before deduction of Niagara Falls flows. Since 1926 is also the first year of record at Buffalo, the flow database was restricted to 1926 to 2003 as a measure to enhance data sample accuracy.

The NOAA/NOS station at Ashland Ave. is located between the Falls and the Robert Moses GS. As such it represents the flow at the International Control Structure (ICS) minus the flows diverted to the Sir Adam Beck and Robert Moses plants. Hourly water levels for 2002 and mean daily water levels from 1970 to 2002 were available for this station. Conversion of the mean daily water levels to flows was undertaken in three stages:

- Conversion of the hourly and mean daily water levels to flows using the NOAA/NOS rating equation.
- Relating the more accurate mean daily flow from the hourly levels to the flow from the mean daily water levels.
- Using this regression equation to adjust the rating equation to convert mean daily water levels to mean daily flows.

The adjusted discharge rating equation derived for Ashland Ave. gauge was:

$$Qd = 33.75\ (Hd - 91.42)^2 + 728.74$$

Where: Qd is mean daily flow in m^3/s

Hd is the mean daily water level at Ashland Ave. gauge in metres above IGLD 1985 datum.

3.2.2 Flow Verification

The three Niagara River flow records provide the information required to define the flows that have been historically available for hydropower generation and the flows that have actually been diverted to Sir Adam Beck and Robert Moses plants. However, it is important to verify that these flow series are consistent, among themselves and with indirect flow data from other sources.

Daily flows do not balance exactly because of variations in channel storage, travel time between gauges, diversions out of the river basin and the use of the pump storage plants, but these short-term transient effects should balance out over the long-term.

Between the Buffalo gauge at the outlet of Lake Erie and the Queenston gauge upstream of the effluence to Lake Ontario the drainage area of the Niagara River increases from 683,000 km^2 to 686,000 km^2, an increase of 3,000 km^2. In this reach flows will be incremented by natural runoff from the incremental drainage area and lost to the diversion out of the basin to the New York State Barge Canal. Flows diverted to Sir Adam Beck and Robert Moses plants have no net impact on the water balance because they are returned to the river above the Queenston gauge.

The long-term inflow to the Queenston-Chippawa Canal, estimated from flows for the Welland River below Caistors Corners, is 13.5 m^3/s, or 0.015 $m^3/s/ km^2$. If this runoff rate is applied to the 3,000 km^2 between Buffalo and Queenston, the expected long-term incremental inflow would be 45 m^3/s.

The diversion to the New York State Barge Canal varies seasonally, but has an annual average of 700 cfs or 20 m^3/s. Thus the expected increase in flows between Buffalo and Queenston is 45 – 20 = 25 m^3/s.

The 1926-2000 unadjusted long-term average flows at Buffalo and Queenston are 5,806 m^3/s and 5,831 m^3/s, respectively. The difference between these to average flows is 25 m^3/s, which agrees exactly to the expected difference estimated above. This agreement is considered a confirmation of the consistency and stationarity of the flow series at Buffalo and Queenston.

The Ashland Ave. gauge flows represent the flow over the Falls plus any flows used by the hydropower plants that straddle the Falls. By 2002 only Canadian Niagara Power's Rankine GS remained in operation, and Rankine did not generate at all in 2002 due to the paucity of water. This means that the hourly water levels and flows recorded at Ashland Ave. represent flows that were allowed to pass over the Falls to meet the prescribed scenic flow requirements. The 1950 *Niagara River Treaty* states that 2,832 m^3/s (100,000 cfs) must be allowed to flow over the Falls from 8:00 am to 10:00 pm April 1 to September 15 and from 8:00 am to 8:00 pm September 16 to October 31. At all other times 1,416 m^3/s (50,000 cfs) must be allowed to flow over the Falls. Any flow in excess of these amounts shall be divided equally between Canada and the USA for hydro production.

Figure 3-3 shows the hourly Ashland Avenue flows for the whole of 2002. The upper and lower daily limits to these flows match the minimum Falls flow requirements quite closely, suggesting that the Ashland Avenue flows are accurate. Another check on Ashland Avenue flows is a comparison between the monthly hydropower flows available to Beck 1&2, estimated as 50% of (Buffalo – Ashland Ave.) flows, and actual Beck outflows computed from monthly generation data published in the Independent Market Operator (IMO) monthly generator disclosure reports. Table 3.2 shows this comparison for May to September 2002. The regression equation fitted to the two sets of flows shows only a 0.4% difference, which is considered a second validation of Ashland Avenue flows.

3.3 Diversions

Diversions into and out of the Great Lakes above the ICS must be applied to the flow series for the years prior to their introduction to adjust all flow years to a common time base. In this analysis flows have been adjusted to 2007 level, conceptually for this study, the year Beck 3 would be commissioned.

Table 3.2 Sir Adam Beck Monthly Flow Comparison

MONTHLY GENERATOR DISCLOSURE REPORT								
Month	**Total Station MCR**	**Planned Capability Factor %**	**Actual Capability Factor %**	**Actual Energy Production (MWh)**	**Actual Production Factor %**	**Zone**	**Q Estimated from Generation**	**Q Divertable from Falls Flow**
2002								
Beck 1								
May	539	95	71	216,475	54	Niagara	393	
June	539	99	70	176,685	46	Niagara	335	
July	539	100	76	117,054	29	Niagara	212	
August	498	86	84	112,482	30	Niagara	202	
September	498	85	71	130,572	36	Niagara	245	
Beck 2								
May	1,577.4	95	89	755,737	64	Niagara	1282	
June	1,577.4	94	89	753,722	66	Niagara	1322	
July	1,577.4	92	92	814,192	69	Niagara	1390	
August	1,451.0	90	89	777,309	72	Niagara	1327	
September	1,451.0	87	81	701,590	67	Niagara	1238	
Beck 1 & 2								
May	2116	95	84	972,212	61	Niagara	1675	1702
June	2116	95	84	930,407	61	Niagara	1657	1665
July	2116	94	88	931,246	59	Niagara	1602	1586
August	1949	89	88	889,791	61	Niagara	1528	1525
September	1949	86	78	832,162	59	Niagara	1482	1498

The magnitude of each diversion varies seasonally and from year to year according to demand and hydrologic conditions. The nominal rates of the diversions also differ between publications. Where possible the diversion rates have been verified or adjusted using recorded flow data. Table 3.3 shows the diversion rates used. Although it has been noted that these diversions vary seasonally and annually, the storage and lag times in the Great Lakes will smooth out most of these variations and a single, constant diversion rate has been adopted in each case.

Consumptive use of the Great Lakes waters has been examined in *Great Lakes Trends: Into the New Millennium*, May 2000, Office of the Great Lakes and *Protection of the Waters of the Great Lakes – Interim Report to the Governments of Canada and the*

United States, 1999, International Joint Commission. They projected the following trends in consumptive use:

- Thermoelectric power use – modest increases with population growth.
- Industrial and Commercial use – a gradual decline through 2020.
- Domestic and Public use – a slight increase in USA, a slight decrease in Canada.
- Agricultural use – a significant increase is expected by 2020.

Table 3.3 Great Lakes Flow Diversions

Diversion Name	Start Year	In/Out	Diversion Rate (m^3/s)		
			Nominal	Flow Record	Used
Chicago Diversion	1900	Out	91	-	91
New York State Barge Canal	1918	Out	20	-	20
Welland Canal	1932	Out	260	210	210
Long Lac Diversion	1939	In	45	39.1	45
Ogoki Diversion	1943	In	113	111	113

Overall the estimated consumptive use in the Great Lakes (excluding Lake Ontario) was 67 m^3/s in 1985 and 99 m^3/s in 1993 and is expected to increase by 5% from 1995-96 to 2020-21, giving a rate of 105 m^3/s in 2020. An s-shaped polynomial curve was fitted to these values to give the consumptive use estimates for flow adjustment presented in Table 3.4.

Table 3.4 Great Lakes Consumptive Use Estimates

Year	Consumptive Use (m^3/s)
1920	43
1940	60
1960	78
1980	92
2000	102
2020	105

Figure 3-4 shows the net diversion and consumptive use adjustments for 1860 to 2000 for equivalent 2010 flows.

Without diversions and consumptive use the estimated 1860-2003 long-term natural flow at Queenston would be 6031 m^3/s. The diversions and consumptive use described above are expected to reduce the actual 1860-2003 long-term flow at Queenston to 5764 m3/s, with a net diversion out of the system of 267 m^3/s, or 4.4%.

Articles III and V of the 1950 Niagara River Diversion Treaty states that the total flow out of Lake Erie via the Welland Canal and Niagara River, less the amount of water used and necessary for domestic and sanitary purposes and for the service of canals for the purpose of navigation, minus scenic flow requirements specified in Article IV, may be diverted for hydropower purposes and shared equally between Canada and the USA (Article VI)1.

Thus the Chicago Diversion is not included in the Treaty but flows to the Welland Canal are. On average the Welland Canal requires 80 m^3/s for navigation purposes of which

[1] Long Lac and Ogoki diversions are not included in this Treaty and are available to Canada.

35 m^3/s comes from local inflows. This means that 45 m^3/s of the Welland Canal diversion of 210 m^3/s is used for navigation purposes, which is exempt under Article III. This leaves 165 m^3/s for diversion through the DeCew GS as part of Canada's share of the available flow. When this is offset by the Long Lac and Ogoki diversions of 45 m^3/s and 113 m^3/s (= 158 m^3/s) the net benefit to Canada is only 7 m^3/s. On the USA side there is the diversion to the New York State Barge Canal of 20 m^3/s. These flows are small relative to the total Niagara flow and no further adjustment was considered necessary to the net flows available to Canada and the USA. i.e. The Niagara River flows net of diversions and scenic flow requirements were shared equally between Canada and the USA.

3.4 Divertible Flows

3.4.1 General

The availability of flow for the Sir Adam Beck generating stations depends on the Articles of the 1950 *Niagara River Diversion Treaty* between Canada and the USA and the variation of flows out of Lake Erie. The 1950 Treaty is clear and unambiguous. After minor diversions upstream of Niagara Falls, an allocation to Canada for the Ogoki and Long Lake diversions, and a prescribed schedule of flows over the Niagara "Falls", the remaining flow is shared equally between Canada and the USA for hydropower generation.

The flows divertible to the Sir Adam Beck plant will be dependent on the flow in the Niagara River, the scenic flows over Niagara Falls and the hydraulic capacity of the Beck system. The derivation of a long-term series of Niagara River flows for the conditions expected to apply in 2007 has been described above.

The minimum scenic flow rates specified by the 1950 *Niagara River Treaty* are 2832 m^3/s (100,000 cfs) from 8:00 am to 10:00 pm April 1 to September 15 and from 8:00 am to 8:00 pm September 16 to October 31. At all other times 1416 m^3/s (50,000 cfs) must be allowed to flow over the Falls. In terms of mean daily flow these rates become 2242 m^3/s from April 1 to September 15, 2124 m^3/s September 16 to October 31, and 1416 m^3/s from November 1 to March 31.

In previous studies these regulated Falls flows have been subtracted from the available flows to give a series of hydropower flows. However, this literal interpretation of the regulations ignores the practical problems involved in operating the ICS gates to exactly meet the Falls flow requirements. Figure 3-3 shows hourly flows for 2002 and Figures 3-5 and 3-6 show the hourly (Falls) flows at Ashland Avenue for typical winter and summer months.

It is evident from these figures that the prescribed scenic flow requirements are adhered to religiously. In fact even in a lower than average year such as 2002 the flow over the Falls rarely drops to the minimum flow requirement of 1416 m^3/s (50,000 cfs). This is the case even in the winter months when no daily variation of the minimum Falls flow is required.

This inherent conservatism in meeting the terms of the 1950 Niagara River Treaty means that in practice there is less flow available for power generation than would be suggested by direct subtraction of the Falls flow requirements.

3.5 Hydraulics

3.5.1 General

The divertible flow database described in Section 3.4 provides the flows available for diversion through the Beck system. The actual flow rates through the tunnels, canals and turbines will depend on the hydrodynamic conditions in the system at any instant. Power potential and subsequently energy production for a hydroelectric development are directly related to the net head experienced by the turbine. With respect to the Niagara complex the net head on the turbine is the elevation difference between the canal forebay level and the tail water (lower Niagara River) level, less any water passage and exit head losses. Existing power tunnels and canals convey the complex power flow from the Grass Island Pool (GIP) upstream of the International Control Structure (ICS) to the power canals feeding the forebay. The headloss or energy grade line change between the water in GIP and the cross over depends on the discharge rate within these conveyance systems.

3.5.2 Headlosses

Headloss estimates therefore not only directly affect energy production at the station however they also affect the discharge or diversion capacity of the existing conveyance systems, i.e. their ability to bring water to the stations. A change in the conveyance system layout, i.e. the addition of the Tunnel T3 significantly affects the existing conveyance capacity head loss relationship resulting in an increase in energy production. Accurate head loss estimates are fundamental to the energy estimates and as such Klohn Crippen has incorporated the accurate head loss relationships previously developed by into the energy simulation model

The report *Hydrodynamic Model – Conveyance System Grass Island Pool to Queenston* has been made available to Klohn Crippen. This report provided polynomial expressions to relate the water levels and gross heads to flow in the existing Beck system. These polynomials provided the base on what was previous referred to as the Niagara Optimal Dispatch (NOD1) Model.

Ontario Power Generation (OPG) or previously Ontario Hydro used the NOD1 Model to evaluate and optimize operation of the Niagara complex. This dispatch model is confidential and was not available to Klohn Crippen, however the actual data and the model polynomials derived from the data were presented above-mentioned report and was made available to the project team. These relationships remain valid, even if the NOD1 model is no longer used by OPG, as they represent the hydraulic response of the system to water level changes. This report presents measurements of water level and flow data from the existing canal layout and uses this to calibrate a numeric model estimating the affect of different conveyance system changes. Separate polynomial relationships for the following different layouts are developed and presented in the report:

- Existing layout (tunnels T1 and T2 plus Beck power canal).
- Existing layout plus addition of the Tunnel T3.
- Existing layout plus addition of Tunnels T3 and T4.

Figure 3-7 graphs the polynomial relationships between head loss and diversion discharge for the three layouts listed above. These relationships have been included in the energy simulation model together with head losses for the stations. These graphs show the head loss reduction associated with the construction of either the T3 or T4 diversion tunnels. This reduction in diversion head loss translates directly to an increase in net head on all the turbines within the Beck complex, thereby increasing overall energy production. For example with diversion flows of 1800 m^3/s the existing layout has a head loss from the GIP to the cross over of approximately 5.8 m. This head loss is estimated to reduce to approximately 3.2 m and 2.2 m with the addition of Tunnels T3 and T4 respectively.

3.5.3 Description of Generating Facilities

3.5.3.1 General

OPG currently has 26 units at the combined Niagara complex consisting of Beck 1 and Beck 2 with a combined existing installed capacity of approximately 1920.5 MW. These units operate with an average net head of approximately 88 m derived from the difference elevation from the canal forebay to the Niagara River. In addition to these units the PGS consists of six units with a combined generating and pumping capacity of 174 MW and 246 MW respectively. The PGS is connected to the Beck canal system by a short canal in the vicinity of the cross over. Figure 3-8 provides a schematic of the system, identifying the key hydraulic and generating components.

3.5.3.2 Existing Generating Facilities (Beck 1 and Beck 2)

Table 3.5 summaries the existing unit information as calculated by Klohn Crippen. This information is based on the current Generation Scheduling Program data as provided by OPG. OPG have indicated that the current unit upgrade program at Beck 2 will continue and that the remaining two units will be upgraded. Klohn Crippen has therefore been assumed that the remaining 2 non-upgraded units at Beck 2 (units 13 & 14) will be upgraded in the same manner as the other Beck 2 units.

It as also been assumed that the Beck 1 units will maintained with the existing characteristics. As the 25 Hz demand disappears, it is assumed that upgrading will be done, however the unit flow and output will remain unchanged.

Therefore, the upgraded Beck 2 together with the existing Beck 1 represent the assumed future capacity of the existing generating facilities for the energy simulation model.

Table 3.5 Existing and Upgraded Beck 1 and Beck 2 Unit Information

Unit No.	Existing Condition			Upgraded Condition		
	Frequency	**Max Flow**	**Max Power**	**Frequency**	**Max Flow**	**Max Power**
	(Hz)	**(m^3/s)**	**(MW)**	**(Hz)**	**(m^3/s)**	**(MW)**
Beck 1						
1	25	54.9	40.0	25	54.9	40.0
2	25	54.9	40.0	25	54.9	40.0
3	60	57.5	44.8	60	57.5	44.8
4	60	68.4	51.5	60	68.4	51.5
5	60	68.4	51.5	60	68.4	51.5
6	60	68.4	51.5	60	68.4	51.5
7	25	60.6	44.8	25	60.6	44.8
8	60	68.4	51.5	60	68.4	51.5
9	60	60.6	44.8	60	60.6	44.8
10	60	57.5	44.8	60	57.5	44.8
		619.5	**465.5**		**619.5**	**465.5**
Beck 2						
11	60	118.0	92.4	60	118.0	92.4
12	60	118.0	92.4	60	118.0	92.4
13	60	106.0	80.7	60	**118.0**	**92.4**
14	60	106.0	80.7	60	**118.0**	**92.4**
15	60	118.0	92.4	60	118.0	92.4
16	60	118.0	92.4	60	118.0	92.4
17	60	118.0	92.4	60	118.0	92.4
18	60	118.0	92.4	60	118.0	92.4
19	60	118.0	92.4	60	118.0	92.4
20	60	118.0	92.4	60	118.0	92.4
21	60	118.0	92.4	60	118.0	92.4
22	60	118.0	92.4	60	118.0	92.4
23	60	118.0	92.4	60	118.0	92.4
24	60	118.0	92.4	60	118.0	92.4
25	60	118.0	92.4	60	118.0	92.4
26	60	118.0	92.4	60	118.0	92.4
		1864.0	**1455.0**		**1888.0**	**1478.4**

3.5.3.3 Existing Beck PGS

Table 3.6 presents the pertinent station characteristics for the existing Beck PGS.

Table 3.6 Beck PGS Unit Information

Description	Characteristic
Maximum Pumping Flow	1129 m^3/s
Maximum Turbine Flow	891 m^3/s
Number of Units	6
Design Net head	26 m
Maximum Station Output	122 MW

3.5.3.4 Beck 3 Generation Facilities

The latest layout of the Beck 3 project is referred to as the Queenston Forebay scheme. This scheme will serve as the initial focus of the power generation modeling generation planning simulation and preliminary economic screening. The Queenston Forebay scheme as presented in the Definition Engineering Phase 2 series of reports is a 600 MW station consisting of 2 units located in an underground powerhouse. The powerhouse is fed by a new canal and power tunnel linked to the existing canals in the vicinity of the canal cross over. Table 3.7 presents a summary of the pertinent station characteristics for the proposed Beck 3 as included in the energy generation model.

Table 3.7 Beck #3 GS Unit Information

Description	Characteristic
Maximum Unit Flow	360 m^3/s
Number of Units	2
Assumed Efficiency	93.5 %
Design Net head	91 m
Maximum Station Output	600 MW

3.5.4 Storage Discussion

Storage is a critical aspect of any hydroelectric development as provides a measure by which the natural river flow can be distorted thereby increasing the resulting benefit. Although the Beck system is essentially a run-of-river scheme, some storage capacity is available. The Beck complex at Niagara Falls has two reservoirs, namely Grass Island Pool and the Pump Generating Station (PGS) reservoir. These reservoirs provide OPG with the limited ability to shift energy generation from one period of time to another so as to maximize the value of the energy production. Grass Island Pool is the in-river reservoir that was created by the construction of the International Control Structure. This storage is shared equally with the United States generator resulting in an available storage of 5.7×10^6 m^3 for the Beck system. The Beck PGS is located downstream of the existing diversion tunnels and connected to the existing canal system. The PGS has an active storage volume of 19.0×10^6 $m^{3.}$ This storage capacity is freely dispatchable, within the constraints of the PGS pumping and turbine capacity or Beck 3 turbine capacity. The total available storage to the Beck complex under all existing and development case is therefore assumed to be 24.7×10^6 m^3 (6,880m^3/s hrs).

This available storage is small when compared with the average Niagara River flows, and as such it can only influence the run-of-river generation for short period of time, i.e. hours over a period of days. This storage is insufficient to provide meaningful change to the natural flow over a longer time frame either weekly or seasonally.

The PGS has the installed capacity to fill the reservoir in 5.1 hrs and empty it in 6.5 hrs.

Previous studies have examined the possibly of further increasing the storage at the PGS however, they have concluded that the 19.0×10^6 m^3 represents the upper bound of what is practical. For this feasibility assessment it has therefore been assumed that no additional storage is available and that the existing arrangement represents the maximum available for future operation.

3.6 Power and Energy Studies

3.6.1 Objective

The objective of power and energy studies is to determine the generation benefits associated with a specific project layouts. The primary objective of the energy studies within this feasibility study is to determine the net benefit of the project consisting of Tunnel T4 and the Beck 3 generating station.

3.6.2 Methodology

This section presents the methodology that was followed to determine the generation benefits attributable for this project.

The power and energy studies represent the stage where the hydrology, head loss relationships, storage and unit characteristics are combined and a net benefit developed. The net benefit attributable to a specific alternative or layout change is the difference in benefits from two simulation runs, one with and one without, the layout change being evaluated.

As detailed in the confirmed feasibility study work plan approved by the Ministry of Energy the following case alternatives will be evaluated and the incremental benefits associated with each assessed.

Case 1: Existing Diversion Canal and Tunnels T1 and T2
Existing Generating Capacity at Beck 1
Upgraded Generating Capacity at Beck 2

Case 2: Existing Diversion Canal and Tunnels T1 and T2
Construction of New Tunnel T3
Existing Generating Capacity at Beck 1
Upgraded Generating Capacity at Beck 2

Case 3: Existing Diversion Canal and Tunnels T1 and T2
Construction of New Tunnel T3 and T4
Existing Generating Capacity at Beck 1
Upgraded Generating Capacity at Beck 2

Case 4: Existing Diversion Canal and Tunnels T1 and T2
Construction of New Tunnels T3 and T4
Existing Generating Capacity at Beck 1
Upgraded Generating Capacity at Beck 2
Construction of New 600 MW Beck 3

The difference in benefits between Layout 1 and Layout 2 represents the incremental benefit associated with Tunnel T3 construction, whereas the difference between Layout 3 and Layout 2 represents the incremental benefit associated with tunnel T4 and the 600 MW Beck 3 generating station. Tunnel T4 and Beck 3 are collectively referred to as the Beck 3 development, the primary focus of this feasibility study.

Schematics showing Cases 1, 2 and 4 are included as Figures 3-8, 3-9 and Figure 3-10 respectively.

The energy simulation model uses the daily divertible flows from the hydrologic records for the period 1926 to 2000, as developed in Section 4.4. The annual energy production for the three different layouts is determined.

3.6.3 Energy Generation Results

The average annual energy estimates for the 75-year period (1926-2000) as calculated by the energy simulation model are presented in Table 3.8. Results are also presented for two sub-periods occurring within the overall 75-year record. The first sub-period is for the distinctly wet period of record from 1969 to 1993, and second for a dry period from 1926 to 1942. These generation benefits derived from these shorter periods of record provide an indication of the potential range in generation benefits associated with the long hydrologic cycles experienced on the Niagara system.

Figures 3-11 and Figures 3-12 provide additional information as to the extent of the wet and dry periods in the form of Mass and Flow Duration Curves.

The monthly distribution of the energy generation results have been inputted into the generation planning model discussed in detail in Section 4. The economically viability of the project is also discussed in Sections 4 and 5.

3.6.4 Study Result Comparison

The energy simulation model results determined by Klohn Crippen and presented in Table 3.9 have been compared to energy estimates previously documented. The intent of this comparison is to demonstrate that the actual generation results determined are in line with those previously determined, even though different simulation models have been used containing slightly different projects assumptions and using a different hydrologic period as input.

A summary of incremental energy gains from Case 1 through Case 4 are summarized in Table 3.10.

Table 3.8 Total Beck Complex Average Annual Energy Estimates

Hydrologic Period	**Case 1**	**Case 2**	**ΔE T3 (Case 2- Case 1)**	**Case 3**	**ΔE T4 (Case 3-Case 2)**	**Case 4**	**ΔE Beck 3 (Case 4 -Case 2)**
	(GWh)	(GWh)	(GWh)			(GWh)	(GWh)
Average 1926 - 2000	11,778	13,244	1,466	13,591	348	14,018	774
Wet Period 1965 – 1993	12,183	14,306	2,123	14,809	504	15,374	1,068
Dry Period 1926 - 1942	10,926	11,486	560	11,641	155	11,915	429

Note:
1) Case 1 - Existing Configuration
2) Case 2 - Following construction of Tunnel T3
3) Case 3 - Following construction of Tunnel T3 and T4
4) Case 4 - Following construction of Tunnel T3 and T4 and 600 MW Beck 3

Table 3.9 Comparison of Average Energy Estimates

	Klohn Crippen (5) (GWh)	Reference Item No. 130 Appendix I(6) (GWh)	Reference Item No. 150 Appendix I(6) (GWh)
Case 1 (Existing System)	11,778	11,723	12,191
Case 2 (Including Tunnel T3)	13,244 (2)	12,898 (1)	13,594
Case 3 (Including Tunnel T3 & T4)	13,591	13,256	13,932
Case 4 (Including Tunnel T3 & T4 and 600 MW Queenston Forebay scheme, ('Beck 3'))	14,018 (4)	13,805 (3)	14,088(4)

Note:
1) Diversion Capacity is 485 m^3/s
2) Diversion Capacity is 500 m^3/s
3) Diversion Capacity is 971 m^3/s and Queenston Forebay is 668 MW
4) Diversion Capacity is 1000 m^3/s and Queenston Forebay is 600 MW
5) Hydrologic Record 1926 – 2000
6) Hydrologic Record 1900 – 1989

Table 3.10 Summary of The Power Study Results

	Diversion Capacity (m^3/s)	LONG TERM PERIOD (1926 - 2000)				WET PERIOD (1965 - 1993)				DRY PERIOD (1926 - 1942)			
		SAB No. 1 & 2 (Upgraded)	SAB No. 1 & 2 (Upgraded) + 300 MW	SAB No. 1 & 2 (Upgraded) + 600 MW	SAB No. 1 & 2 (Upgraded) + 900 MW	SAB No. 1 & 2 (Upgraded)	SAB No. 1 & 2 (Upgraded) + 300 MW	SAB No. 1 & 2 (Upgraded) + 600 MW	SAB No. 1 & 2 (Upgraded) + 900 MW	SAB No. 1 & 2 (Upgraded)	SAB No. 1 & 2 (Upgraded) + 300 MW	SAB No. 1 & 2 (Upgraded) + 600 MW	SAB No. 1 & 2 (Upgraded) + 900 MW
		Installed Capacity (MW)				Installed Capacity (MW)				Installed Capacity (MW)			
		1,943	2,243	2,543	2,843	1,943	2,243	2,543	2,843	1,943	2,243	2,543	2,843
Tunnels 1 & 2 + Canal	1,825	11,778				12,183				10,926			
△ Energy		***1,466***				***2,123***				***560***			
Tunnels 1, 2 & 3 + Canal	2,325	13,244				14,306				11,486			
△ Energy		***348***				***504***				***155***			
Tunnels 1, 2, 3 & 4 + Canal	2,825	13,591	13,859	14,018	14,174	14,809	15,197	15,374	15,545	11,641	11,783	11,915	12,048
△ Energy			***268***	***159***	***156***		***387***	***177***	***171***		***141***	***133***	***132***

4. GENERATION PLANNING MODEL

4.1 Facility Overview

ICF's quantitative analysis is focused on the expected performance of the Beck 3 600 MW project. The project system characteristics are described in Table 4.1.

Table 4.1 Beck 3 System Assumptions

Parameter	Operating Section 1
Capacity Type	Hydro
Dispatch (%)	14.6
Summer Capacity (MW)	600
Winter Capacity (MW)	600
Reliability Contribution (%)	14.6
On-Line Date[1]	2007
Maximum Seasonal Capacity Factor (%)[2]	
Winter	18.2
Winter Shoulder	15.7
Summer	11.4
Other	11.8

[1] An online year of 2007 was chosen for modelling purposes representing the earliest year in which revenue would be incurred. The timeline for possible introduction of the Beck 3 unit presented in the terms of reference spans 2007 to post-2009.

[2] Winter: January, February, December; Summer: June, July, August; Winter Shoulder: March, April, October, November; Summer Shoulder: May, September.

4.2 Introduction

Facility revenues are forecast utilizing ICF's proprietary Integrated Planning Model (IPM®). IPM® is an advanced fundamental economic and engineering principals driving dispatch and pricing model covering all of North America. In this analysis we have used a version of IPM® which includes all regions in the North American Eastern Interconnect, including the Ontario electricity market (reference Figure 4-1). Each region detailed below is characterized as a single wholesale power pool with a unique market clearing price in each hour. Interregional power transfers are characterized via aggregate transmission paths linking neighbouring pools. This integrated approach is necessary to capture interregional, interprovincial, and international transactions and externalities that affect a fully integrated grid such as the Eastern Interconnect.

Like most Canadian provinces, Ontario has been historically dominated by a single, provincial electric utility that controlled generation, transmission and distribution. The market has undergone several major changes in the past several years, including the loss of several large nuclear stations, plans for asset divestiture and market opening under an independent market framework. Additional fundamental changes continue to occur; for example, environmental regulations could have a significant impact on both pricing and dispatch in the market place. The performance and impact of a new facility such as Beck 3 or improvements to existing facilities such as Beck 1 and 2 will be dependant on the continued evolution of the Ontario market structure as well as on key risk factors of the fundamental drivers of dispatch and pricing.

Other recent developments in the Ontario electricity market include those announced by Energy Minister Dwight Duncan. During his speech on April 15, 2004, the Minister said that "OPG's (Ontario Power Generation [sic]) nuclear and baseloaded hydroelectric assets would be regulated by the Ontario Energy Board, who would set regulated prices". While it is not clear how new hydroelectric assets will be treated, this regulation of existing baseloaded hydroelectric generation could drive down the revenue stream. Please note, that this development was outside the scope of the current assignment.

Ontario has been modelled using a competitive framework for unit dispatch and market pricing. Klohn Crippen utilized ICF's existing, fundamentals-based approach to power-market price and production forecasting. This approach begins with a building-block methodology – first through accurately representing the current power system, including the operational characteristics of individual generating facilities, transmission facilities, and through detailed representation of the regional demand levels. Further, forward projections of input parameters such as the costs of alternate construction or refurbishment options are considered directly. This approach has been used extensively for projects in North America, Latin America, Europe, and Asia. This includes analysis of many hydro-generation oriented systems.

The same principle of fundamentals-based economic analysis is also applied to asset valuation. The value power plants earn from sales in wholesale spot power markets can be assessed within a regional market by examining the applicable forecast revenues and costs associated with operating the plant. Whether in a structured market such as the IMO design or not, power plants provide two fundamental products: (i) electrical energy, and (ii) "pure" capacity (also known as price spike revenue, or volatility). "Pure" capacity increases the reliability of electrical energy through reducing the probability of outages. These two products must be considered individually and simultaneously within forecasting exercises in order to capture the volatility associated with power prices.

4.3 Modeling Assumptions

The supply mix in Ontario is largely dominated by inexpensive baseload nuclear, hydro and coal-fired steam facilities. These capacity types comprise 94% of regional generating capacity. Remaining capacity in the region is comprised of gas-fired turbine and combined cycle capacity, and limited amounts of cogeneration and oil/gas steam capacity. Generation in the region is similarly dominated by low cost nuclear, coal, and hydro generation. Figure 4-2 below outlines the expected capacity and generation mix for Ontario in 2007 in our Base Case.

The table below outlines ICF's assumptions for the Ontario marketplace.

Table 4.2 Summary of Key Ontario Market Assumptions

Parameter	Base Case
Ontario Delivered Natural Gas Price[2] (2000$/mmBtu) 2007	5.70
2010	5.57
2020	5.38
Ontario Delivered Natural Gas Price Seasonality[3] (2000$/mmBtu) Winter	+ 0.80
Winter Shoulder	-0.37
Summer	-0.10
Summer Shoulder	-0.42
Operable Nuclear Capacity (MW) 2005	11,767
2010	12,278
Hydro Capacity (MW) Average Annual Hydro Generation (TWh) Average Hydro Capacity Factor (%) Hydro Reserve Contribution (% of Total MW)	7,727 35 52.4 75
Firm Builds 2003-2005 (MW)	3,825
Annual Average Electricity Demand Growth – Peak (%)	2.8
Environmental Regulations	**Canada**: Ontario Regulation 397/01, Regulation for NO_x and SO_2 trading program. Ontario Ozone annex.[4] **US**: National Title IV program State programs for NO_x and SO_2 implemented on a regional basis. Limited $C0_2$ and Hg policies in the Northeast.
Retirement/Mothball Activity	Existing steam units are allowed to retire or temporarily mothball based on economics. Existing CC units may temporarily mothball based on economics. Firmly planned mothballs are included.
Internal Transmission	No limitations considered.
External Transmission	Based on NERC Summer Assessment averages.
Market Structure	Deregulated, Perfectly competitive

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[2] Prices vary annually and seasonally, annual average for select years shown.

[3] Winter: January, February, December; Summer: June, July, August; Winter Shoulder: March, April, October, November; Summer Shoulder: May, September.

[4] Due to the uncertainties surrounding details of the implementation of the Kyoto Accord in Canada, a carbon policy was not included in the Base Case. However, because of the potential effects on the electricity sector, a carbon policy representation was included in the High Market Case for sensitivity.

4.4 Modeling Approach

ICF has utilized it's proprietary Integrated Planning Model, IPM®, to identify and analyze the impacts of proceeding with the construction of the second of two new 10.5 km tunnels (Tunnel T4) that connects to the Beck diversion canal system and the proposed 600 MW underground generating facility downstream of the Beck 1 generating station (Beck 3).

IPM® is an economic linear-programming model with detailed representation at the unit level in power sector regions. From previous work for Environment Canada, Natural Resources Canada and various private clients, we currently have nine Canadian provinces built in the model. The model is used to determine the least-cost means of meeting electric generation energy and capacity requirements, while complying with specified air pollution regulations and system parameters.

IPM® can explicitly consider natural gas, and coal markets, power plant costs and performance characteristics, environmental constraints, regional transmission grids and other power market fundamentals simultaneously. Unlike purely econometrically-driven models, IPM® captures the interactions of real world constraints and simulates electric markets based on economic fundamentals rather than trends in historic data. It is important to note that IPM® is completely data driven – the core of the model is the "engine" – those algorithms that represent the complex system being modelled. Some of the key data issues that drive IPM®'s features are shown in Figure 4-3 "IPM® Modelling Structure". The boxes around the edge of the exhibit are inputs or parameters for the model and the key items are discussed below.

Key Modelling Inputs

a) New and Existing Power Plants.

- Can represent fossil, nuclear, renewables, etc.
- Represents the intermittent nature of some renewables like wind and hydro with generation profiles.
- Accommodates different vintages of technology over time.
- Will make new capacity projections by type and location.
- Investment options can include demand-side resources, bulk power purchases and cogeneration, increased dispatch, advanced technology as supplied by user.

b) Resource Supply

- Selection of fuel for a unit is based on prices, availability constraints, usage constraints, emission characteristics, etc.
- The model simulates coal production, transportation, and consumption.
- IPM includes supply curves for 40 coal producing regions and has over 10 coal types distinguished by rank and by sulphur content.
- Natural gas prices are determined within the model using a similar supply curve and transportation network representation.

c) Energy Efficiency

- Characterized by load-shape impacts; equipment or measure costs; program and administrative costs; and penetration curves.
- End-use energy-efficiency investments compete on a level playing field with traditional, electric supply options to meet future demands.

d) Environmental Scenarios

- Considers environmental regulations and all other parameters and constraints simultaneously.
- Can apply different levels of regulations, for example, Ontario's NOX/SO2 regulation with a federal GHG regulation.
- Allows for various applications of regulations such as targets or allowance prices, etc.

e) Environmental Compliance Choices

- Will make decisions about fuel conversion, retrofits, repowering, life extension, and economic retirements for compliance.
- Decisions based upon trade-offs between capital costs and fuel savings over the planning horizon in comparison with other alternatives.
- IPM can model the cost and performance of various control-technology equipment.
- Currently incorporates dynamic equations for several control options of NOX, SO2 and Hg.
- Cost and performance representation reflect utility-application factors such as unit size and heat rate.

f) IPM® simultaneously optimizes the following parameters:

- Plant dispatch.
- Capacity expansion, mothballing and retirement in all years.
- Environmental compliance.
- Transmission flows.

4.5 Scenario Structure and Sensitivity Analysis

To complete this screening analysis, we have examined three distinct cases using the IPM® model. The "business as usual case" (or "base case") represents a continuation of the status quo assuming continuation of current requirements and characteristics of the Ontario electricity sector. Key assumptions are listed in Table 4.3. Once the base case has been established, analytical cases are modeled and can be compared against the base case to judge impacts.

In the Base Case analysis, the Beck facility is represented as Case 2 as described in Section 3.6.2, comprising the two upgraded Beck 1 & 2 generating stations totalling 1,943 MW of installed capacity with the addition of Tunnel T3 in place. In the analytical Case 4 - Beck 3, an underground powerhouse of 600 MW and a fourth Tunnel T4 is added similar to what was studied in the report by Acres-Bechtel in the Definition Phase 2 Optimization Study Report.

The Beck 3 analytical case is used to forecast operating revenue for a new underground powerhouse under the most likely market conditions. The "High Market Price" analytical case is designed to forecast operating revenue for a new underground powerhouse under best foreseeable market conditions as detailed in Table 4.3. These favourable market conditions were chosen based on possible electricity sector changes being considered by the Ontario government at the time. These include the decision not to restart Pickering nuclear facility units 2, 3 and 4 as well as replacing coal generation in the province in 2007. In addition to these factors, two other variables that could have a large impact on electricity sector behaviour were considered: a carbon price due to Kyoto implementation and natural gas price fluctuations. The carbon price was set to \$15 CDN/tonne of CO_2 to reflect the Government of Canada's published intentions.

Natural Gas prices were determined using ICF's NANGAS modeling system assuming tight supply and rapid demand growth.

Table 4.3 Scenario Structure and Assumptions

<table>
<tr><th>Case</th><th>Notes</th><th>CO_2 Tax(5)</th><th>Pickering 2, 3, 4</th><th>Delivered Natural Gas Prices (2004-2025 average $/mmBtu)</th><th>Native Coal past 2007</th></tr>
<tr><td>Business as Usual</td><td>Without new unit</td><td rowspan="2">$0</td><td rowspan="2">Return to service by 2007</td><td rowspan="2">5.46</td><td rowspan="2">Current operation continues</td></tr>
<tr><td>Beck 3 Unit</td><td rowspan="2">Includes new Beck 3 generating station and fourth tunnel</td></tr>
<tr><td>High Market Price Case</td><td>$15 CDN/ tonne</td><td>No return</td><td>6.64</td><td>offline</td></tr>
</table>

[5] The Government of Canada has indicated that it will provide Large Final Emitters such as power generating stations access to carbon credits at $15/tonne of CO_2 should no credits remain available at less than $15/tonne.

4.6 Environmental Benefits

Hydroelectric power is considered a "clean" energy source that is free of greenhouse gases (GHGs), NOx and SO2 emissions. Environmental benefits, such as avoided emissions, may be achieved through the displacement of other forms of energy production, generally the combustion of fossil fuels.

We have considered the potential environmental emission benefits of adding Beck 3 to the Ontario marketplace. Under Base Case conditions, we forecast a decrease in CO_2 emissions of less than 1 tonne over the study horizon as fossil-fired generation is offset by clean energy from the facility. Because NO_x and SO_2 emissions are assumed to be capped under Ontario stationary source emissions policies, no change to system level emissions is expected under Base Case conditions.

In the High Market Price case, CO_2, NO_x and SO_2 emissions are severely cut from current levels as all native coal generation is forcibly retired, and a CO_2 tax of $15 CDN is assumed. The addition of the generating station introduces minimal further decreases in emissions of all three major pollutants in the High Price Case.

4.7 Revenue Analysis

Forecast revenues for the facility in the Beck 3 analysis are presented below in Table 4.4. Energy revenues presented are derived assuming merchant operation of the facility in the Ontario spot market, while capacity revenues are calculated assuming a 14.8% contribution to reserve markets. Total operating costs include estimated fixed costs for the facility assuming a $15/kW annual cost (reference Section 5). Gross margins at the facility are expected to be approximately $28.7 million in 2007 (real 2004 $CDN) when the facility becomes available for operation. Capacity revenues are expected to increase through 2012 as North American markets recover from the recent excess of capacity. In 2018, facility margins reach their peak of $32.7 million (real 2004 $CDN). On a Net Present Value basis, revenues are expected to be $355 million or $592/kW between 2007 and 2025. This compares with an overnight capital cost of $1,633/kW (reference Section 5) for development of the facility. Note that these margin forecasts do not include any financing costs.

This financial analysis is based on revenues from Beck 3 commencing in 2007. In the event the unit's actual online date is earlier or later than 2007, the revenue stream shown here is representative of what would be seen in a similar study. In general, the near term years (2005 to 2010) show lower revenues than later years. This is largely a result of the projected gas price curve and rising demand. While delaying the facility several years may improve cash flows somewhat, the net present value is unlikely to increase significantly.

Table 4.4 Beck 3 Forecast Revenues – Beck 3 Unit

Year	Energy Revenues CDN (000$)	Capacity Revenues CDN (000$)	Total Operating Costs[7] CDN (000$)	Gross Margin CDN (000$)
2007	32,370	5,819	9,467	28,722
2008	32,090	6,947	9,467	29,570
2012	35,384	7,633	9,467	33,550
2018	35,719	6,727	9,467	32,979
2025	35,664	6,544	9,467	32,741
Total (all years from 2007 to 2025)				610,280
NPV (000$) 2007-2025[8]				355,226
NPV ($/kW) 2007-2025[8]				592

[7] Includes fixed and variable operating costs; Excludes financing payments and tax implications.
[8] Calculated using a 7.0 percent real discount rate and first quarter 2004 total CPI; represents value at the beginning of 2007 in real 2004 dollars.
For modeling purposes, 2025 is the last year used for analysis in the model. However, revenues for subsequent years would be similar to that shown for 2025. Source: ICF Consulting power market modeling simulations.

As outlined above in Table 4.5, the High Market Price Case was designed to present an absolute maximum of revenues for the facility as currently specified. Very high natural gas prices have been combined with a significant CO2 tax, and severely limited baseload competition from existing coal and nuclear units within the province, yielding a significantly increased revenue forecast for the facility. It is important to note that this case was designed as a screening tool only, and ICF does not considered the confluence of revenue increasing events likely.

Gross margins in the High Market Price Case are expected to be more than 35 percent higher than the Base Case on an NPV basis. Even this admittedly high revenue estimate yields a value of only $799/kW. Again, this compares unfavourably with the overnight capital cost of the facility that is estimated to be $1,633/kW (excluding financing costs).

Table 4.5 Beck 3 Forecast Revenues – High Market Price Case

Year	**Energy Revenues** CDN (000$)	**Capacity Revenues** CDN (000$)	**Total Operating Costs**[7] CDN (000$)	**Gross Margin** CDN (000$)
2007	46,345	7,404	9,467	44,282
2008	43,828	7,964	9,467	42,325
2012	47,441	7,820	9,467	45,794
2018	43,338	7,185	9,467	41,056
2025	43,035	6,308	9,467	39,876
Total (all years from 2007 to 2025)				803,778
NPV (000$) 2007-2025[8]				479,522
NPV ($/kW) 2007-2025[8]				799

[7] Includes fixed and variable operating costs.
[8] Calculated using a 7.0 percent real discount rate and first quarter 2004 total CPI; represents value at the beginning of 2007 in real 2004 dollars.
For modeling purposes, 2025 is the last year used for analysis in the model. However, revenues for subsequent years would be similar to that shown for 2025.
Source: ICF Consulting power market modeling simulations.

Given the apparent disparity between the NPV of the Beck 3 600 MW base case revenue and capital cost, no further revenue forecasts modelling was performed pending the preliminary review and screening of all Beck 3 options in Section 5.

5. REVIEW AND SCREENING OF BECK 3 OPTIONS

5.1 Preliminary Benefit Forecast and Cost Estimates

5.1.1 Descriptions of Basic Options

The preliminary benefits forecasts of four different cases (reference Section 4.0) are determined together with the preliminary capital costs associated with any expansion of the existing facilities at the Beck complex. The preliminary benefits are then compared to the capital cost estimates to evaluate whether a particular generation expansion option is economic or not.

In this initial screening level stage, both the preliminary benefit forecast and the cost estimate updates are done less rigorously than that which would normally be done for a feasibility study. The objective of the screening level study is to determine if any of the generation expansion options previously identified in the 1993 studies, is unquestionably economic, unquestionably uneconomic or may be economic and therefore warrants a more rigorous derivation of the updated cost estimates.

Four basic options are reviewed. The first option is the existing situation (no significant expansion of the generating facility) and forms the basis against which the other three generation expansion options are compared. The three generation expansion options are various possible combinations of the two diversion tunnels and the 600 MW Beck 3 generating facility. Other generation expansion options considered are those for which environmental approval has been received.

The following cases are used in this screening level assessment:

Case 1: The existing power facilities, Beck 1 and Beck 2 with all units upgraded to maximum capacity.

Case 2: Beck 1 and Beck 2 with all units upgraded to maximum capacity and with Tunnel T3 completed and in operation.

Case 3: Beck 1 and Beck 2 with all units upgrades to maximum capacity and with both tunnels T3 and T4 completed and in operation.

Case 4: Beck 1 and Beck 2 with all units upgraded to maximum capacity, with both tunnels T3 and T4 completed and in operation and with the underground Queenston-Forebay generating station alternative completed and in operation with installed capacity of 600 MW (Beck 3).

Case 1 is the case against which the economics of the other three options is compared and this arrangement is common to all four cases. The cost of upgrading all the generating units in Beck 1 and Beck 2 are common to all the cases and will not affect the assessment of the feasibility of the diversion tunnel and the Beck 3 generating facility. Therefore the cost estimates for upgrading these existing units is not required for this feasibility study and it will be assumed that this work has been completed by the Ontario Power Generation prior to the start of any expansion at the Beck complex. It is assumed that the upgrading of the existing units may include the frequency conversion of the existing 25 Hz units to 60 Hz as the 25 Hz load reduces.

5.1.2 Methodology for Updating Cost Estimates

A phased approach is adopted for updating the cost estimates and schedules for the diversion works and generation facilities associated with the proposed Beck 3 generating station. The methodology adopted in the first phase is consistent with the level of detail required for the screening level economic assessment. Any economic alternative cases identified in the screening assessment would then be taken to the next phase to analyze costs more rigorously.

The proposed additional diversion works and generating facilities at the Beck generating complex on the Niagara River consists of three main elements:

- The third diversion Tunnel T3 in this report, including all associated intake and outlet works required to construct and operate the tunnel.
- The fourth diversion Tunnel T4 in this report, including all associated intake and outlet works required to construct and operate the tunnel; and
- The 600 MW Queenston-Forebay generating station alternative, Beck 3, including the intake, power tunnels and penstocks, underground powerhouse complex and tailrace on the Niagara River; the layout of this alternative is that which has received current environmental approval.

Separate screening level project cost estimates for each of these three main elements were developed for this study to implement into the economic assessment of the four base options cases given above.

5.1.2.1 Base Data

For the screening level assessment, the capital cost estimates for the Beck 3 project that were previously completed over the period 1991 to 1998, were used to provide the basic data for developing the estimates. Reports containing the following previously completed capital cost estimates were made available by the Ministry of Energy and Ontario Power Generation for this study:

- The 1993 estimate for the construction of both tunnels T3 and T4, assuming a single construction contract for the tunnels.
- The 1992 estimate (in 1991$) for the optimization of the Beck 3 Queenston-Forebay generating station alternative, including a range of installed capacities and number of units.

- The 1998 estimate for the construction of one of the diversion tunnels; this estimate being an update of the 1993 estimate and included different tunnel lining alternatives.

Note: For the purpose of providing an economic screening focused on each of the basic generation alternatives, both transmission interconnection costs and project financing charges have not been included at this time.

5.1.2.2 Diversion Facilities

The reports for diversion facilities 1993 estimate present the estimate in detail and are very comprehensive. The estimate is contained in 11 volumes. This estimate was reviewed and it was decided that the summary of construction costs for each component of the diversion facilities could be used unaltered and that it was only necessary to update the costs for escalation from 1993 to the present. The estimate was broken down into 25 different contracts and assumed that tunnels T3 and T4 would be constructed as part of one construction contract.

The estimate comprises two major component; direct costs and indirect costs. The direct costs are those costs associated with main construction contracts for the tunnels, intake, outlet and associated works, such as site clearing, access roads etc. These estimates are developed by determining the measuring estimated quantities of each element based on the preliminary design of the works and by developing estimates for the construction of these works based on the amount of labour, plant and material needed for construction of each element. The overall estimate for these direct cost components is thus the sum of estimated construction cost all the elements that make up the particular contract. The major components that make up the direct costs of the estimate can be summarized as follows:

- Construction contract for the two diversion tunnels and outlets.
- Construction contract for the two diversion tunnel intake structures and all associated works at the International Niagara Control Works (INCW).
- Construction Contract for the dewatering shafts.
- Various contracts for site clearing, access roads, etc.
- Various supply contracts for mechanical and electrical equipment/
- An allowance for travel and subsistence costs in accordance with the labour agreements.

The indirect cost are those costs which are normally associated with services provided during the construction and are not derived directly from the quantities and unit prices for each element. Typically these indirect costs are:

- Engineering, procurement, project management and construction management.
- Costs incurred by the Owner that are not directly associated with construction contracts, such as payments to municipalities and local governments for upgrading roads and other utilities.
- Owner's cost of administering the overall project.
- Project contingency.

The estimates for these indirect costs are not determined explicitly, but derived from historical percentages of the total construction cost estimates. Other indirect costs of the Owner associated with finance costs and interest during construction have not been included into the capital cost estimates for the screening level assessment.

The report for the updated diversion works 1998 estimate was developed for the Sir Adam Beck Additional Diversion Project which was put out to tender by Ontario Hydro in 1998. This estimate provided the capital cost for four different alternatives:

- Single tunnel with a cast-in-place concrete tunnel lining.
- Single tunnel with a precast concrete tunnel lining.
- Twin tunnels with cast-in-place concrete tunnel linings.
- Twin tunnels with precast concrete tunnel linings.

The basis of these estimates was the 1993 diversion facility estimate, but separated into the single tunnel and twin tunnel options and included the precast concrete lining option. The breakdown of these estimates was similar to that adopted in the 1993 diversion tunnel estimates. An escalation factor of 12% was applied to the 1993 estimates to bring them to 1998 values.

Ontario Hydro called for tenders the design and construction of the third tunnel at the Niagara River Hydroelectric Development in 1998. This project is the same as that designated as Tunnel T3 in this assessment. Tenders were received from a number of international consortia for the design and construction of the Additional Diversion works, but no contract for the construction was placed. The lump sum tender prices for the construction of this third tunnel were unavailable for reference in this study.

5.1.2.3 Generating Facility

The reports for the generating facility 1992 estimate (in 1991$) are in less detail than those for the diversion facility, but still contain sufficient information at a summary level, to use for the screening level estimate. The estimates were from quantities and unit prices taken from the preliminary designs of various layouts. The following different layouts were considered in the 1992 study:

- 1 x 276 MW;
- 2 x 217 MW;
- 2 x 276 MW; and
- 2 x 334 MW.

All these layouts are for the Queenston-Forebay underground generating station alternative. The 2 x 334 MW option was selected to represent the nominal 600 MW alternative studied in report.

The direct costs for the construction of the two-unit 600 MW underground alternative was broken down into the following main components:

- Access tunnel.
- Headworks structure, watering the headworks area and widening of the existing Beck 1 forebay channel leading the headworks of Beck 3.
- Penstock tunnels.
- Underground powerhouse complex.
- All mechanical and electrical equipment including the turbines and governors, hydraulic gates, powerhouse cranes, generators and exciters, transformers and auxiliary electrical equipment, balance of mechanical plant and HV cables to the switchyard.
- Tailrace tunnels.

- Tailrace outlet structure including stabilization of the side of the Niagara gorge above the tailrace outlet structure and the dewatering of the tailrace area including cofferdams in the Niagara River.

The indirect costs included are:

- Engineering, procurement, project management and construction management.
- Costs incurred by the Owner that are not directly associated with construction contracts, such as payments to municipalities and local governments for upgrading roads and other utilities.
- Owner's cost of administering the overall project.
- Project contingency.

The estimates for these indirect costs are not determined explicitly but derived from historical percentages of the total construction cost estimates. Other indirect costs of the Owner associated with finance costs and interest during construction have not been included into the capital cost estimates for the screening level assessment.

5.1.2.4 Derivation of Screening Level Cost Estimates

The objective if this phase of the assessment is to produce capital cost estimates for the following components:

- Tunnel T3.
- Tunnel T4.
- Beck 3 600 MW Queenston-Forebay generating facility complex alternative.

Tunnel T3

The terms of reference for this study assumes that Tunnel T3 would have been constructed and in operation prior to the start of the proposed generation expansion for Beck 3. However, Case 2 is for the construction of Tunnel T3 only and in order to study all the base generation expansion options, the screening level costs for the construction of Tunnel T3 are estimated in a similar manner to tunnel T4 below.

Tunnel T4

Cases 3 and 4 assume that Tunnel T3 has already been constructed. The construction of tunnel T4 can be undertaken in a number of ways:

- as an extension of the Tunnel T3 work such that these two tunnels are constructed under one main construction contract to obtain the benefit of the same contractor designing and construction both tunnels;
- as a separate contract from Tunnel T3, constructed some time after the completion of the third tunnel, but utilizing the refurbished tunnel boring machine (TBM) fabricated for Tunnel T3 and the conveyor system constructed for Tunnel T3 to dispose of the excavated material; and
- as a completely separate contract from Tunnel T3, stating construction after the completion of Tunnel T3 and not utilizing any equipment used on Tunnel T3.

Two sources of estimating data are available for use to estimate the construction cost of Tunnels T3 and T4. Neither of these sources could be used directly for each of the costing alternatives sought above. However, as the 1993 estimate was presented in more detail, this estimate was used to separate the incremental costs of construction Tunnel T4 as part of a twin tunnel construction project. The 1993 estimate was based in a cast-in-place tunnel lining option, and therefore the separated costs for the two tunnels derived from the 1993 estimate were adjusted accordingly by the ratio of the pre-cast tunnel lining option to the cast-in-place tunnel lining option from the 1998 estimate.

The direct cost estimate thus derived in 1993 costs was escalated to 2004 cost by the following:

- 12% from 1993 to 1998;
- 16% from 1998 to 2004;
- resulting in an overall increase of 30% from 1993 to 2004.

The value of 12% escalation over the period 1993 to 1998 was used in the 1998 cost estimates to escalate costs from the 1993 report. Statistic Canada does not have a price index specifically for hydropower construction and the nearest price index that could be used related more to industrial building construction than to hydropower construction, including the purchase of off-shore equipment in non-Canadian currency. However the price indexes available were reviewed and the increase of 12% over the period 1993 to 1998 appears to be reasonable.

The escalation value of 16% over the period 1998 to 2004, was obtained as an average value from relevant Statistic Canada price indexes and from construction price indexes in North America generally, as published by the Engineering News Record journal. The value of 16% represents an average escalation of 3% per annum over that period.

The resulting capital cost estimates for Tunnel T3 and for the various options for the construction of Tunnel T4 are presented in Table 5.1 together with the indirect costs. These total estimated costs are for screening level studies only and it is recognized that several factors have not been included into these estimates, such as:

- significantly lower interest rates in 2004 compared to the early 1990's;

- higher insurance costs resulting from the post-2001 insurance market situation in North America;
- varying heavy construction market environment which can significantly influence prices on a year-to-year basis; and
- significantly different currency exchange rates depending upon the country of origin of the various components.

Table 5.1 Capital Cost of Tunnel Construction

Description	$1,000,000 (2004$)			
	Tunnels T3 & T4	**Tunnel T3 Only**	**Incremental Tunnel T4 Contract**	**Separate Tunnel T4 Contract**
Direct Construction Cost	759	442	322	372
Project Management (8%)	61	35	26	30
Construction indirects (6%)	46	27	19	22
Owner's costs (3%)	23	13	10	11
Subtotal	889	517	377	435
Contingency (10%)	89	52	38	44
Total (rounded)	980	570	420	480

If tunnel T4 is constructed as part of a single construction project to construct both tunnels, the estimated screening level portion of the total cost for the fourth tunnel is $420 million. If T4 is constructed under a separate contract after the completion of the third tunnel but some of the assets from the construction of T3 are left in place and handed over to the T4 tunnel contractor, the estimated screen level cost for T4 is $480 million. If T4 is constructed entirely separate from T3, the estimated screening level cost would be similar to that for the third tunnel, namely $570 million.

5.1.2.5 600 MW Beck 3 Queenston-Forebay Generating Station Alternative

The 2 x 334 MW cost estimate from the 1992 reports were used to derive the screening level 2004 estimates. The escalation from 1991 to 2004 was assumed to be 36%, based on the following:

- 5% escalation for the period 1991 to 1993;
- 12% from 1993 to 1998; and
- 16% from 1999 to 2004.

The value of 5% escalation over the period 1991 to 1993 was used in the 1998 cost estimates to escalate costs from the 1991 report. As in the case of reviewing the diversion facilities cost estimates, Statistic Canada does not have a price index specifically for hydropower construction and the nearest price index that could be used related more to industrial building construction than to hydropower construction, including the purchase of off-shore equipment in non-Canadian currency. However the price indexes available were reviewed and the increase of 5% over the period 1991 to 1993 appears to be reasonable.

The rationale for using the values of 12% for the period 1993 to 1998 and 16% from 1998 to 2004 is the same as that presented for the diversion facilities estimate.

The resulting capital cost estimate for the construction of the 600 MW Beck 3 generating facility is given in Table 5.2:

Table 5.2 Capital Cost of Beck 3 Generating Station

Description	600 MW Beck 3 Generating Station ($1,000,000, 2004$)
Access Tunnel	51
Headworks complete	54
Penstock Tunnel	69
Civil Underground Complex	57
Mechanical and Electrical Equipment	158
Tailrace Tunnel	17
Tailrace Outlet Structure Complete	22
Total Construction Cost	428
Project Management (8%)	34
Construction Indirects (6%)	26
Owner's costs (3%)	13
Subtotal	501
Contingency (10%)	50
TOTAL (rounded)	560

The screening level capital cost estimate for the 600 MW underground Beck Queenston-Forebay alternative is estimated to be $560 million in 2004$.

5.1.2.6 276 MW Beck 3 Generating Station

A single unit 276 MW underground alternative (Queenston-Forebay layout) was included in the 1992 reports and this cost estimate has been used to derive the screening level 2004 estimates using the same methodology as described above for the 600 MW Beck 3 alternative.

The resulting capital cost estimate for the construction of the 276 MW (nominal 300 MW) generating facility is $310 million. This project cost figure and associated preliminary generation benefit (Section 3) will provide a ranking benefit/cost index to the 600 MW Beck 3 alternative.

5.1.2.7 900 MW Beck Generating Station

A three-unit 900 MW underground alternative (Queenston-Forebay layout) was also assessed at screening level for this feasibility study. The 1992 reports did not contain a 900 MW alternative. The preliminary capital cost estimate here was derived from adding the incremental costs of one 300 MW unit to the 600 MW underground powerhouse complex. The same methodology was used to escalate the 1992 components of this estimate to 2004 as described for the 600 MW alternative.

The resulting capital cost estimate of the nominal 900 MW generating facility is $750 million. As with the 300 MW Beck 3 comparison above, this project cost figure and associated preliminary generation benefit will provide a ranking comparison to the 600 MW project.

5.2 Preliminary Benefit Forecast

5.2.1 Methodology

The preliminary annual benefit for screening study purposes is estimated by multiplying the incremental energy production of each of Cases 3 and 4 relative to Case 2 by the IMO average price range over the period May 2002 through January 2004. To provide optimistic and conservative price scenarios, the January 2004 average was used to represent a high electricity average as compared to the more conservative May 2002 to January 2004 price average:

IMO Average:	January 2004	$70/MWh
	May 2002 to Jan 2004	$57/MWh

5.2.2 Preliminary Results

The annual average energy for the four cases are presented in Table 5.3.

Table 5.3 Comparison of Average Energy Estimates

Hydrologic Period	Energy E (GWh/a)						
	Case 1: Beck 1 & 2	Case 2: Addition of T3	ΔE Case 2: Addition of T3	Case 3: Addition of T3 & T4	ΔE Case 3: Addition of T3 & T4	Case 4: Addition of T3, T4 & Beck 3	ΔE Case 4: Addition of Beck 3 (600 MW)
Average	11,778	13,244	1,466	13,594	348	14,018	774
Wet	12,183	14,306	2,123	14,809	504	15,374	1,068
Dry	10,926	11,486	560	11,641	155	11,915	429

5.3 Project Screening Evaluation and Results

Assume that the annual charges for the generation expansion Cases 3 and 4 are comprised of the following:

- long term bond interest rate, assumed to be 6% of total capital cost; and
- capital cost, operation and maintenance cost recovery and risk margin, assumed to be 3% of total capital cost.

The annual charges for the generation expansion cases, Cases 3 and 4, for this study, can therefore be estimated by multiplying the capital cost estimate by 9%.

The approximate annual benefits for Cases 3 and 4 are derived for an upper (optimistic) energy price of $70/MWh and for a lower (conservative) energy price range of $57/MWh.

The approximate annual benefits are then compared to the approximate annual charges to determine the economic viability, at screening level stage, of Cases 3 and 4. Tables 5.4 and 5.5 summarize the benefit-cost ratios under the flow and energy price variations.

Table 5.4 Case 3: Addition of Tunnel T4 only

Hydrological Period	**Case 3: Addition of Tunnel T4 only**		
	$ million		
	Annual Benefits	**Annual Charges[1]**	**Benefit/Cost Ratio**
Average Flow	24/30	38	0.63/0.53
Wet Period	35/29	38	0.92/0.76
Dry Period	11/9	38	0.29/0.24

[1] Capital Cost: T4 = $420 million; Total project cost= $420 million
Annual Charge: $420 million x 9% = $38 million

Table 5.5 Case 4: Addition of Tunnel 4 and Beck 3 (600 MW)

Hydrological Period	**Case 4: Addition of Tunnel T4 and Beck 3 (600 MW)**		
	$ million		
	Annual Benefits	**Annual Charges[2]**	**Benefit/Cost Ratio**
Average Flow	54/44	88	0.61/0.50
Wet Period	75/61	88	0.85/0.69
Dry Period	30/24	88	0.34/0.27

[2] Capital Cost: T4 = $420 million; Beck 3 (600 MW) = $560 million; Total project cost= $980 million
Annual Charge: $980 million x 9% = $88 million

Using the same methodology as for the 600 MW alternative, Tables 5.6 and 5.7 present the screening level benefit-cost ratios for the 300 MW and 900 MW underground alternatives to demonstrate project benefit-cost sensitivity over the range of available site capacities.

Table 5.6 Addition of Tunnel 4 and Beck 3 (300 MW)

Hydrological Period	**Addition of Tunnel T4 and Beck 3 (300 MW)**		
	$ million		
	Annual Benefits	**Annual Charges**[3]	**Benefit/Cost Ratio**
Average Flow	43/35	66	0.65/0.53
Wet Period	62/51	66	0.94/0.77
Dry Period	21/17	66	0.30/0.26

[3] Capital Cost: T4 = $420 million; Beck 3 (300 MW) = $310 million; Total project cost= $730 million
Annual Charge: $730 million x 9% = $66 million

Table 5.7 Addition of Tunnel 4 and Beck 3 (900 MW)

Hydrological Period	**Addition of Tunnel T4 and Beck 3 (900 MW)**		
	$ million		
	Annual Benefits	**Annual Charges**[4]	**Benefit/Cost Ratio**
Average Flow	65/53	105	0.62/0.50
Wet Period	87/71	105	0.82/0.68
Dry Period	39/32	105	0.37/0.30

[4] Capital Cost: T4 = $420 million; Beck 3 (900 MW) = $750 million; Total project cost= $1,170 million
Annual Charge: $1,170 million x 9% = $105 million

The benefit/cost ratio of all the options clearly fall significantly below the break even point of 1.0, even for the optimistic energy price scenario assuming the continuous wet period.

These screening results reasonably correlate with the 600 MW case generation planning analysis results summarized in Section 4 where the given annual average generation forecasted benefits revealed an optimistic/conservative pricing benefit-to-cost range of 0.49 to 0.36.

This screening level assessment indicates that neither of Cases 3 or 4 are economic and therefore more detailed capital cost estimates for the various options will not be developed at this time.

6. BECK 3 DEVELOPMENT ALTERNATIVES

6.1 Base Case

The base case upon which the Environmental Approval was issued in 1998, for the Niagara River Hydroelectric Development, is the 600 MW Queenston Forebay alternative. This alternative comprises:

- two diversion tunnels which convey water from the Grassy Pond Inlet to the forebay canals of the Beck complex;
- two intakes which are integral with the International Niagara Control Works (INCW) including a new accelerating wall constructed upstream of the INCW;
- two outlets on the north side of the buried St. David's Gorge, discharging the power flow into two outlet canals which form part of the forebay complex of the Beck generating facilities;
- two dewatering stations located just north of the buried St. David's gorge at the lowest points of the diversion tunnels to enable the tunnels to be dewatered into the nearby power canal;
- a headworks canal from the existing forebay complex to a headworks structure located between the PGS reservoir and the floral clock on the Niagara parkway;
- two power tunnels conveying the power flow from the headworks structure to the underground powerhouse;
- an underground powerhouse complex containing the generating equipment and main transformers;
- two tailrace tunnels conveying the power flow from the underground powerhouse to the open cut tailrace outlet structure on the west bank of the Niagara River, just north of Smeaton Cove and the existing Beck 1 GS;
- a cable gallery containing the main power cables which carry the electrical output of the generating station from the underground transformer gallery to the existing switchyard at the Beck complex;

- and an access tunnel which provides construction access and access during operation to the underground works and to the tailrace outlet structure, with entrance portal located to the east of the PGS.

The original development option for Beck 3 referred to in the Environmental Assessment was comprised of an underground powerhouse of 900 MW. Power flows were pumped from the Beck forebay complex into the PGS reservoir using the existing PGS. The headworks structure for the Beck 3 underground complex was to be located within the PGS reservoir and power tunnels conveyed the power flow to the underground powerhouse complex in a similar location to the Queenston Forebay alternative. This alternative was called the Queenston-Reservoir alternative. The average head for this alternative is 110 m.

This original development option underwent subsequent refinements, and was optimized as a forebay scheme, drawing flows directly from the forebay complex under a head of 90m. This refined alternative did not required the power flow to be pumped up to the PGS reservoir to the Beck 3 headworks but drew the power flow directly from the forebay complex of canals. The installed capacity was reduced to 600 MW. This is the arrangement that has been taken as the base case for the current feasibility review.

6.2 Limits of Alternatives Within the Existing Environmental Assessment

The Environmental Assessment report for the Niagara River Hydroelectric Project was prepared by Ontario Hydro in March 1991. The proposed mitigation measures were as follows:

- underground powerhouse, transformer gallery and power cables to minimize disruption to the Niagara Gorge and the Niagara Parkway;

- underground access tunnel to the powerhouse and the Niagara Gorge to eliminate disturbance to the Village of Queenston, traffic on the Niagara Parkway and the hiking trail along the foot of the Gorge (between Queenston and the proposed station);

- use of a tunnel boring machine to virtually eliminate noise and vibration effects within the City of Niagara Falls during construction of the diversion tunnels;

- selection of the tunnel alignment and number of tunnel service shafts to minimize disturbance to residents, businesses, and institutions within the City of Niagara Falls;

- alignment of the tunnels to pass under the buried St. Davids Gorge to minimize the disturbance of topography, land use, and vegetative cover of an open channel (e.g. parallel with the Beck 1 and Beck 2 canals).

- design and location of submerged intakes at the International Niagara Control Works and location of the tunnel closure gates at the downstream end of the tunnels to virtually eliminate visual effects at the intake area;

- removal of excavated rock from the downstream end of the diversion tunnels to minimize construction activities and traffic within the City of Niagara Falls;

- restoration of areas affected by construction to pre-construction conditions;

- selection of the transmission ROW to minimize acquisition of new property and effects on local property owners;

- agreement to the establishment of community impact management programs with affected communities to analyze the actual effects of the undertaking, ensure proposed mitigation measures are carried out and to respond appropriately, should unanticipated effects develop; and

- establishment of environmental pre- and post-operational monitoring programs to identify actual effects, assess the effectiveness of mitigation measures and assess the need for additional actions to protect the natural environment.

In the current circumstance in Ontario, electric power is potentially in short supply and electric energy costs may rise dramatically as a consequence. All options for new supply, and in particular, renewable options such as Beck 3 should be reviewed with a view to reducing costs while retaining a reasonable balance of protection for the environment. Our proposal suggests that the basic modifications described in the following Section 6.3 be reviewed regardless of being considered outside the context of the existing Environmental Assessment.

6.3 Basic Modifications to the General Arrangement for Beck 3

6.3.1 Surface Powerhouse Option, 2 units, 600 MW total capacity

The 600 MW Queenston Forebay underground alternative for the Beck 3 GS, which is the layout that received Environmental Approval in 1998, requires a significant open cut excavation on the west bank of the Niagara River for the tailrace outlet structure. This open cut also requires a cofferdam arrangement in the Niagara River during construction to dewater the excavations and to construct the outlets.

As this open cut is required for the tailrace outlet structure, an alternative to the underground powerhouse complex would be to increase the size of this open cut excavation to accommodate the powerhouse and transformers and incorporate the tailrace into the powerhouse. This would eliminate the need for the underground powerhouse complex.

Although outside the environmental approval for the project, the degree to which this alternative falls outside the limits is based on the size of the open cut excavation on the west bank of the Niagara River. The layout of the current underground Queenston Forebay alternative, shows the open cut excavation extending approximately 20 m above the water level in the Niagara River, to just under the Whirlpool formation.

A preliminary layout of a 600 MW surface powerhouse at the tailrace outlet location, would result in the open cut excavation extending approximately 40 m above the water level in the Niagara River, to the underside of the Grimsby formation. This additional 20 m of open cut excavation will be partly hidden by the powerhouse superstructure and will not be significantly noticeable from the Canadian side of the Niagara Gorge.

To maintain the other major mitigating features of the project, the access tunnel would be maintained to provide access to the surface powerhouse by widening the lower portion of the access tunnel to the tailrace outlet structure and all construction access and access during operations would be achieved by using this tunnel.

The potential cost savings achieved with the surface powerhouse alternative are:

- reduced underground excavation of the powerhouse complex, including rock support in the caverns in the Queenston Shale rocks, which are known to have expansive properties, and replacing this with a larger volume of open cut excavation adjacent to the river;
- reducing the total length of construction adits underground;
- reducing underground complex ventilation requirements and fire protection requirements as the main transformers would now be on a open air platform adjacent to the surface powerhouse;
- reducing the tailrace tunnels to zero length as the powerhouse now discharges directly into the Niagara River;
- reduces the size of the tailrace outlet structure as this portion of the works is now incorporated within the overall surface powerhouse.

These potential cost savings are offset by increased costs of the following components:

- longer power tunnels and longer length of steel lined tunnels;
- longer cable gallery from the surface powerhouse to the Beck switchyard complex with increased length of high voltage cables;
- larger excavation volumes of rock from the surface powerhouse and more material to dispose of.

A preliminary "order of magnitude" estimate into the potential cost reduction that could be achieved by a surface powerhouse alternative was investigated. The potential cost reductions were found to total approximately 11% of the total direct construction costs. These potential reductions are offset by the increase in components of the alternative of approximately 6%, leaving a net possible cost reduction of approximately 5%.

A 5% cost reduction of the capital cost of the Beck 3 facility will have little impact on the economic viability of the project at screening study level and it can be tentatively concluded that the surface powerhouse alternative alone, will not result in achieving significant savings in capital cost to reduce the capital cost to the level where the economics of the project appears to be viable.

6.3.2 Permanent Surface Access via Niagara River Gorge

The access tunnel for the 600 MW underground Queenston Forebay alternative currently accounts for approximately 12% of the total direct construction cost. If alternative surface access routes to the surface powerhouse scheme could be achieved for use during construction and later during operation, significant savings could be achieved in the overall direct capital construction costs.

The following possible access routes could warrant further assessment, although outside of the environmental limits of the approved project:

- permanent access along the Niagara River gorge from Queenston, by upgrading the existing trail that was previously a road;
- permanent access via the south over the tailrace decks of Beck 2 and Beck 1 generating stations, with necessary modifications to these structures to facilitate construction and later, heavy load maintenance traffic.

Both alternatives have significant environmental impacts. The northern access route via Queenston would eliminate the trail along the west bank of the Niagara River, at least for the duration of construction. The current plan indicates that excavated materials may be placed in the Queenston Quarry. The only routes from the northern end of the possible road in the gorge to the Queenston Quarry are via York road or the Niagara Parkway. The environmental assessment has identified that neither of these roads can carry heavy construction traffic.

Alternative methods of disposing of the excavated material could be investigated if an access road north along the gorge to Queenston is viable. These could include removing the excavated material by barge from Queenston down the Niagara River.

The south access route would require a short portion of approximately 2 km of the Niagara Parkway to be used from the point where the existing access roads to the Beck 1 and 2 powerhouses joins the Parkway, to the access road on to OPG property at the south end of the Whirlpool golf course.

If a nominal allowance is included into the capital cost estimate for alternative access routes and the access tunnel is eliminated, the direct construction cost of the 600 MW surface powerhouse option is reduced by an estimated 14% relative to the 600 MW underground Queenston Forebay alternative.

If this capital cost reduction is applied to the screening study assessment, the total capital cost of a surface 600 MW powerhouse with alternative surface access routes plus Tunnel 4 would be of the order of $900 million. This would result in estimated annual charges of $81 million against a most optimistic annual benefit of approximately $75 million in a continuous wet period. The benefit/cost ratio of this alternative is still significantly below 1.0 and even with these potential cost saving measures outside the environmental approval limits, the proposed 600 MW options is not economic at screening level.

Similarly, these same development alternatives applied to the 300 MW and 900 MW Queenston Forebay powerhouse schemes would not yield significant benefit/cost ratio improvement to warrant further detailed study.

7. PROJECT ANALYSIS & DISCUSSION

Klohn Crippen completed a comprehensive review of the available study data and documents. Further, we developed power generation and project cost models of each project scheme as addressed in the current EA, providing a screening level analysis of all Beck 3 alternatives described in the project terms of reference and work plan. At this time, none of the project schemes as presented are considered economically feasible.

Critical power generation modeling results correlated within 5% of previous engineering study results. Our developed preliminary cost estimates also agree with the most recent updated cost data provided for this project.

Screening level benefit sensitivities were explored for each available project case scenario with due consideration to provide a liberal assessment of capital costs excluding certain project cost indeterminates. Even under most optimistic hydrological, market pricing and capital cost conditions, all variations of the Beck 3 project failed to meet a benefit-cost ratio of 1.0.

In consultation with the Ministry of Energy, certain items listed in the draft work plan related to further generation revenue simulations, project scheduling and more detailed financial analysis were deferred in order to bring this study to a provident conclusion.

In summary, development of the incremental hydrologic resource available to Ontario for the purpose of power generation is uneconomic under current energy market conditions. While certain generation benefits have been identified, conveyance of the available flows to the vicinity of the existing Beck complex after completion of Tunnel T3 is considered too costly to complete a corresponding power generation facility. That being said, other development options for this resource not addressed in the current EA and subsequently not identified in this study may exist in the form of an alternate site location.

8. CONCLUSIONS

Under the study terms of reference, the Beck 3 hydroelectric project in all forms of capacity options within the current environmental assessment, and under all optimistic project capital cost and revenue scenarios, is considered to be uneconomic at this time.

The benefit-to-cost ratios used to screen available project options ranged between 0.94 (300 MW) under the most optimistic hydrological conditions and energy price scenario, to 0.26 (300 MW) under the most conservative benefit modelling treatment.

In any case, the timing to select a preferred hydrological trend (i.e., high flow or wet period) to benefit any development alternative is highly speculative as the historical flow data indicates. Such analysis would not support significant long-term investment.

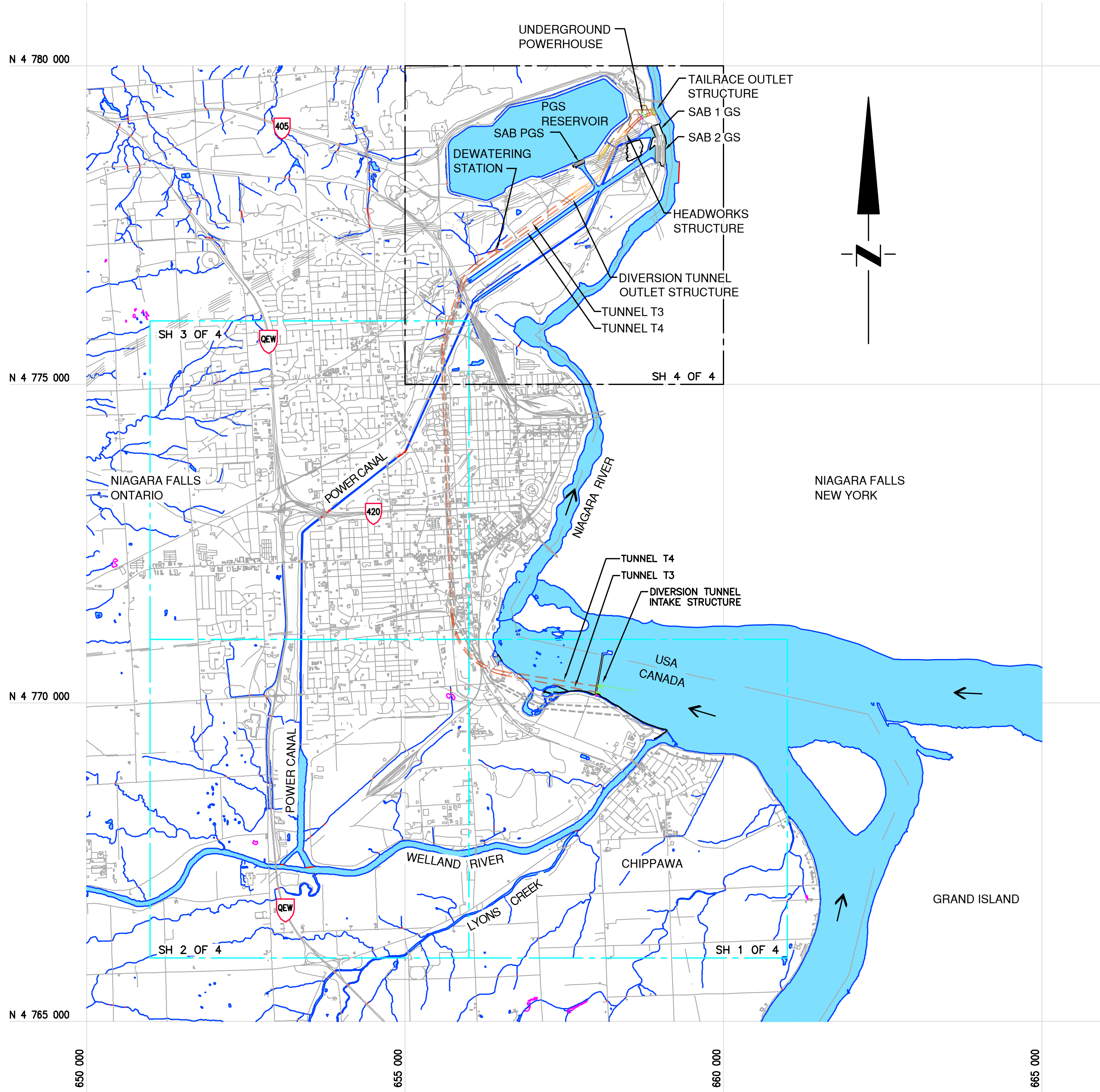
Yours truly,

KLOHN CRIPPEN CONSULTANTS LTD.

W.B. Harvey, P.Eng.
Project Manager

G.J. Law, P.Eng.
Senior Hydrotechnical Engineer

FIGURES



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TO BE READ WITH KLOHN CRIPPEN REPORT DATED JUNE 17 2004

SCALE 0 1 000 2 000 3 000 4 000 m

AS A MUTUAL PROTECTION TO OUR CLIENT, THE PUBLIC AND OURSELVES, ALL REPORTS AND DRAWINGS ARE SUBMITTED FOR THE CONFIDENTIAL INFORMATION OF OUR CLIENT FOR A SPECIFIC PROJECT AND AUTHORIZATION FOR USE AND/OR PUBLICATION OF DATA,STATEMENTS,CONCLUSIONS OR ABSTRACTS FROM OR REGARDING OUR REPORTS AND DRAWINGS IS RESERVED PENDING OUR WRITTEN APPROVAL.

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Ontario
Ministry of Energy

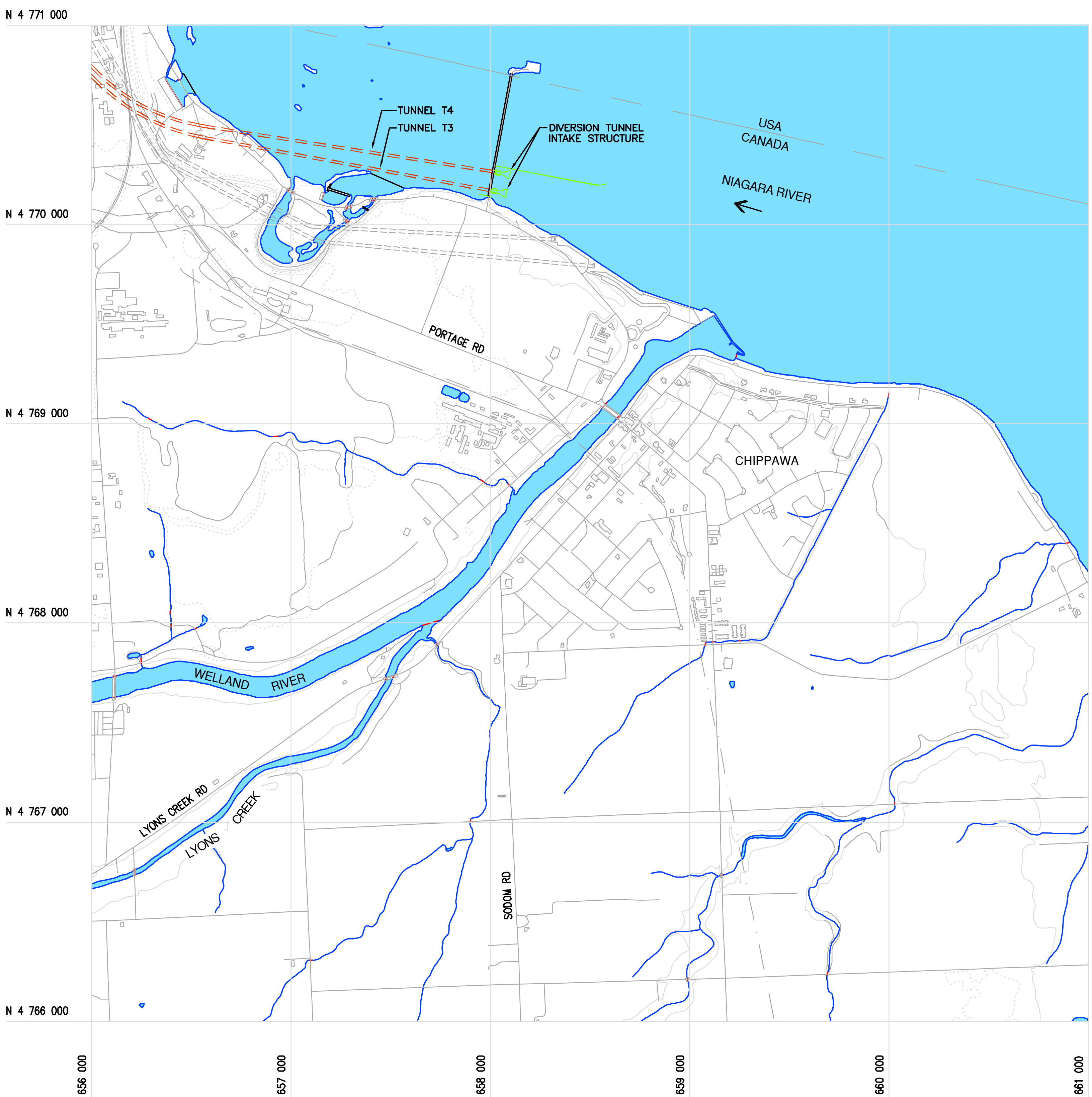
KLOHN CRIPPEN

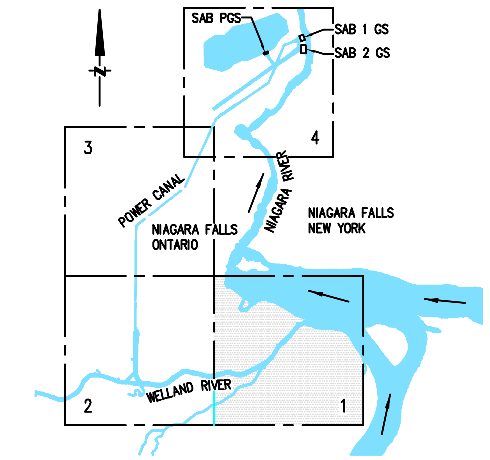
PROJECT
ECONOMIC FEASIBILTY STUDY OF BECK 3

TITLE
PROJECT AREA

PROJECT No.		FIG. No.
E00004	SSB–043121	1.1

KCR-BM





KEY PLAN
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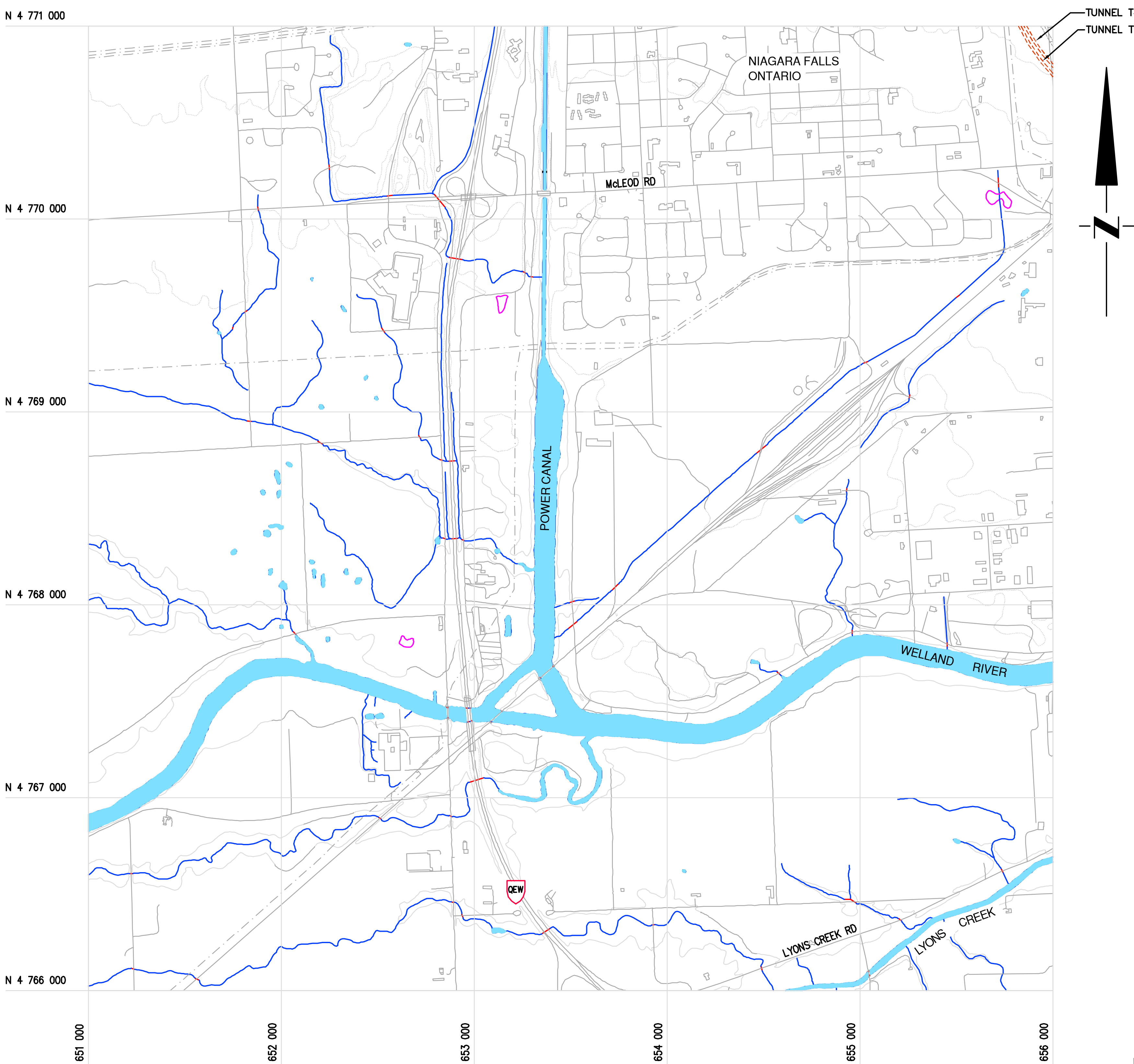
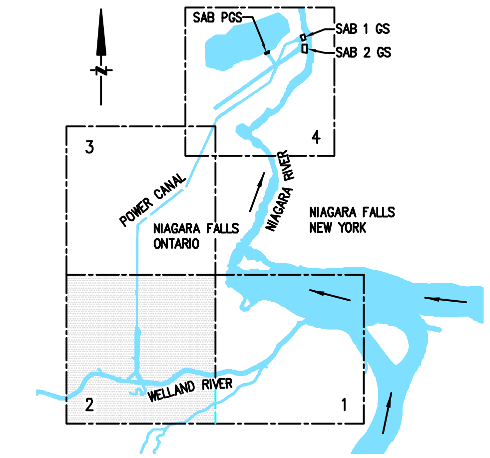
PROJECT
ECONOMIC FEASIBILITY STUDY OF BECK 3

TITLE
SITE PLAN
SHEET 1 OF 4

PROJECT No.	FIG. No.
E00004 SSB–043121	1.2

KCR-BM





KEY PLAN
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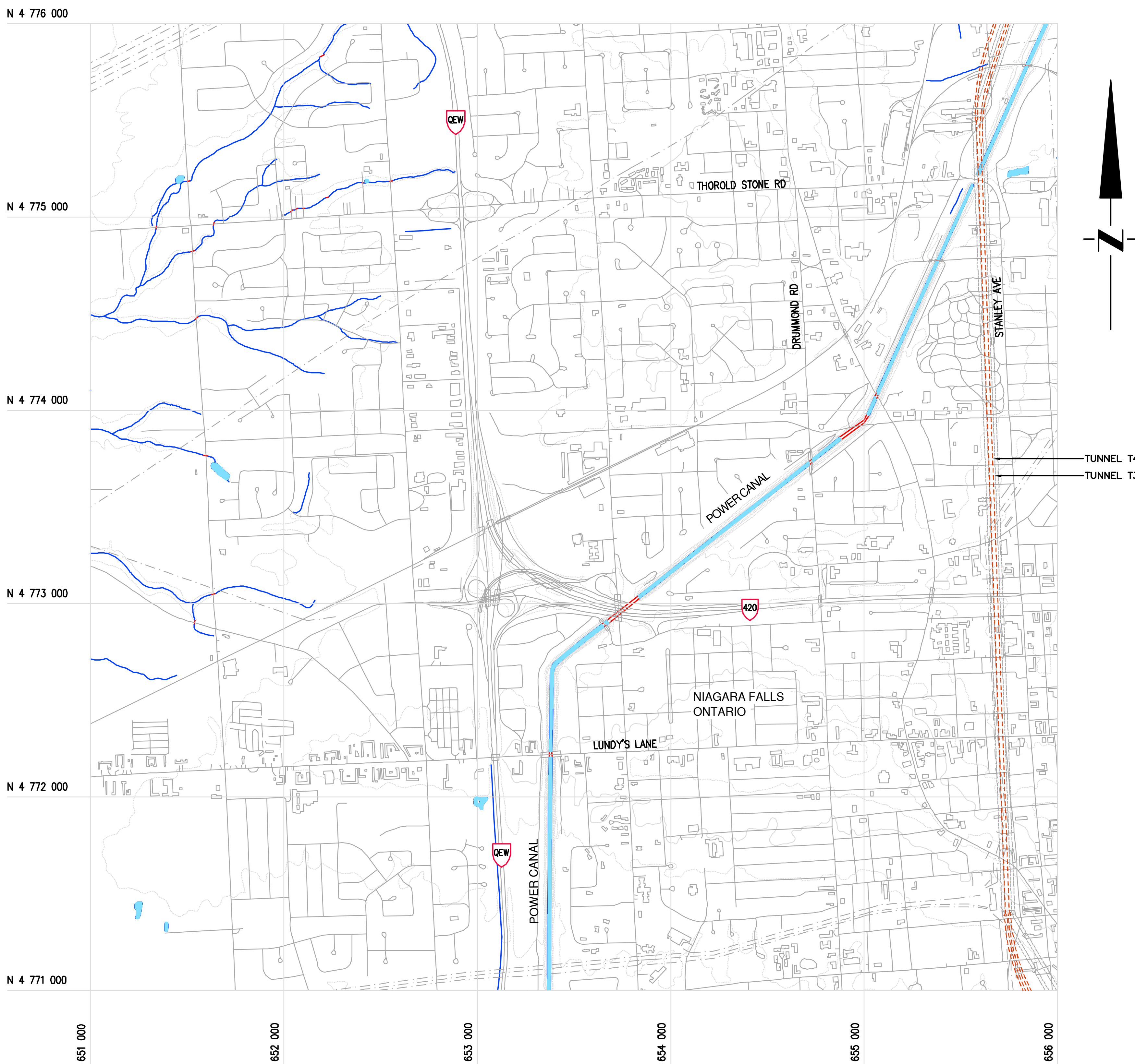
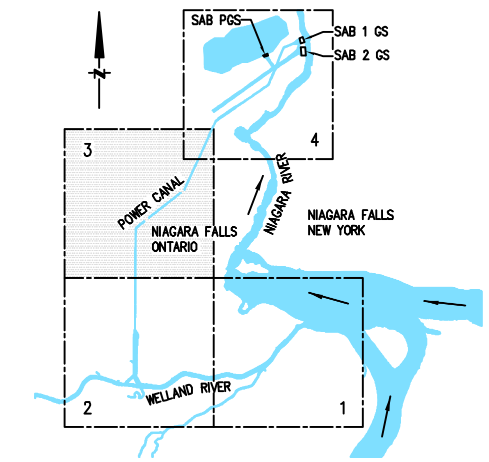
PROJECT
ECONOMIC FEASIBILITY STUDY OF BECK 3

TITLE
SITE PLAN
SHEET 2 OF 4

PROJECT No.	FIG. No.
E00004 SSB-043121	1.3

KCR-BM





KEY PLAN
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SCALE 0 500 1 000 m

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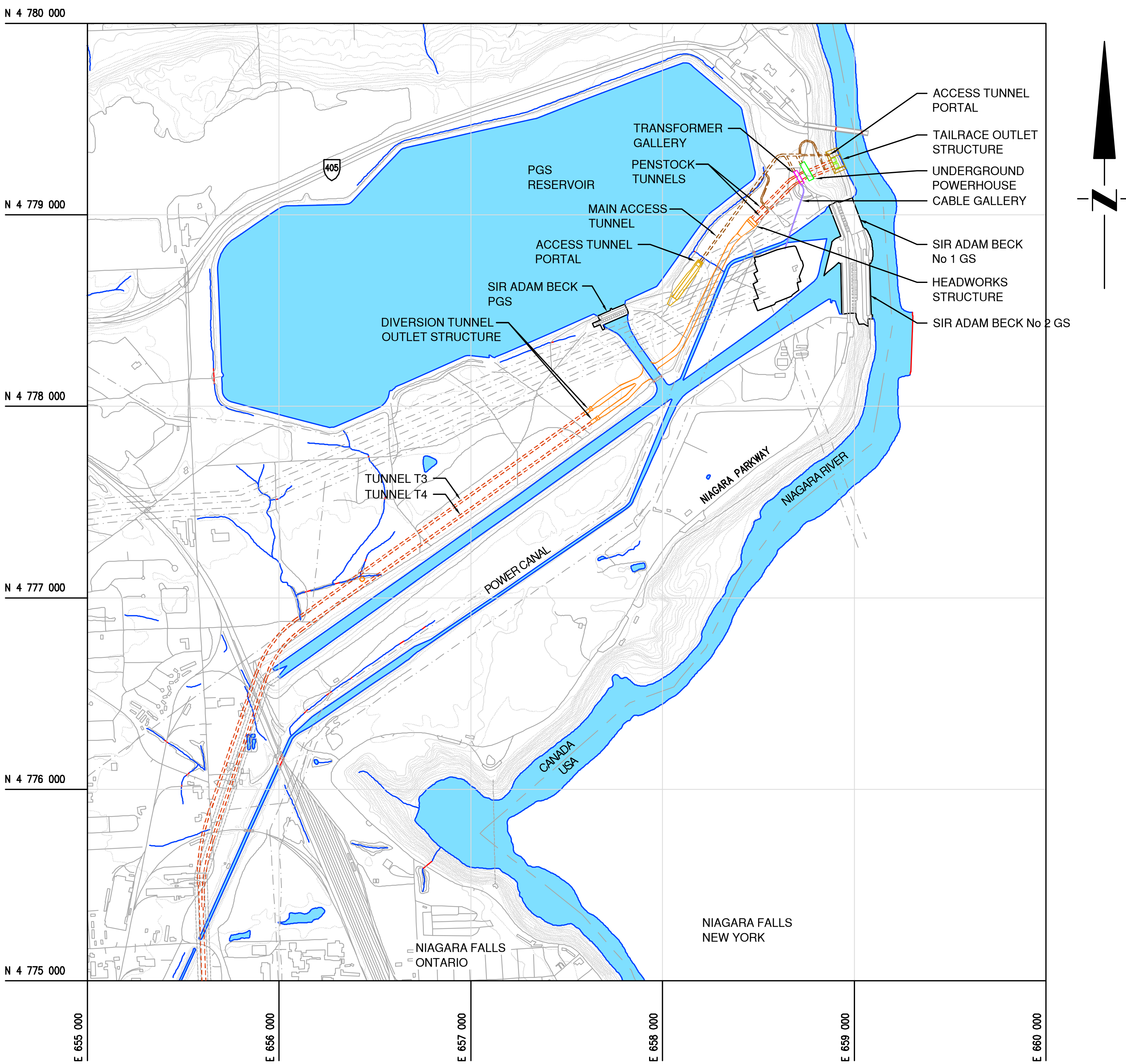
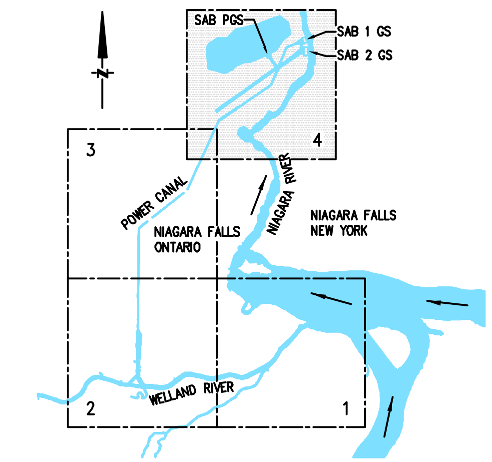
PROJECT
ECONOMIC FEASIBILITY STUDY OF BECK 3

TITLE
SITE PLAN
SHEET 3 OF 4

PROJECT No.	FIG. No.
E00004 SSB–043121	1.4

KCR-BM





KEY PLAN
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CLIENT	Ontario Ministry of Energy
	KLOHN CRIPPEN
PROJECT	ECONOMIC FEASIBILITY STUDY OF BECK 3
TITLE	SITE PLAN SHEET 4 OF 4
PROJECT No.	E00004 SSB–043121
FIG. No.	1.5

KCR-BM

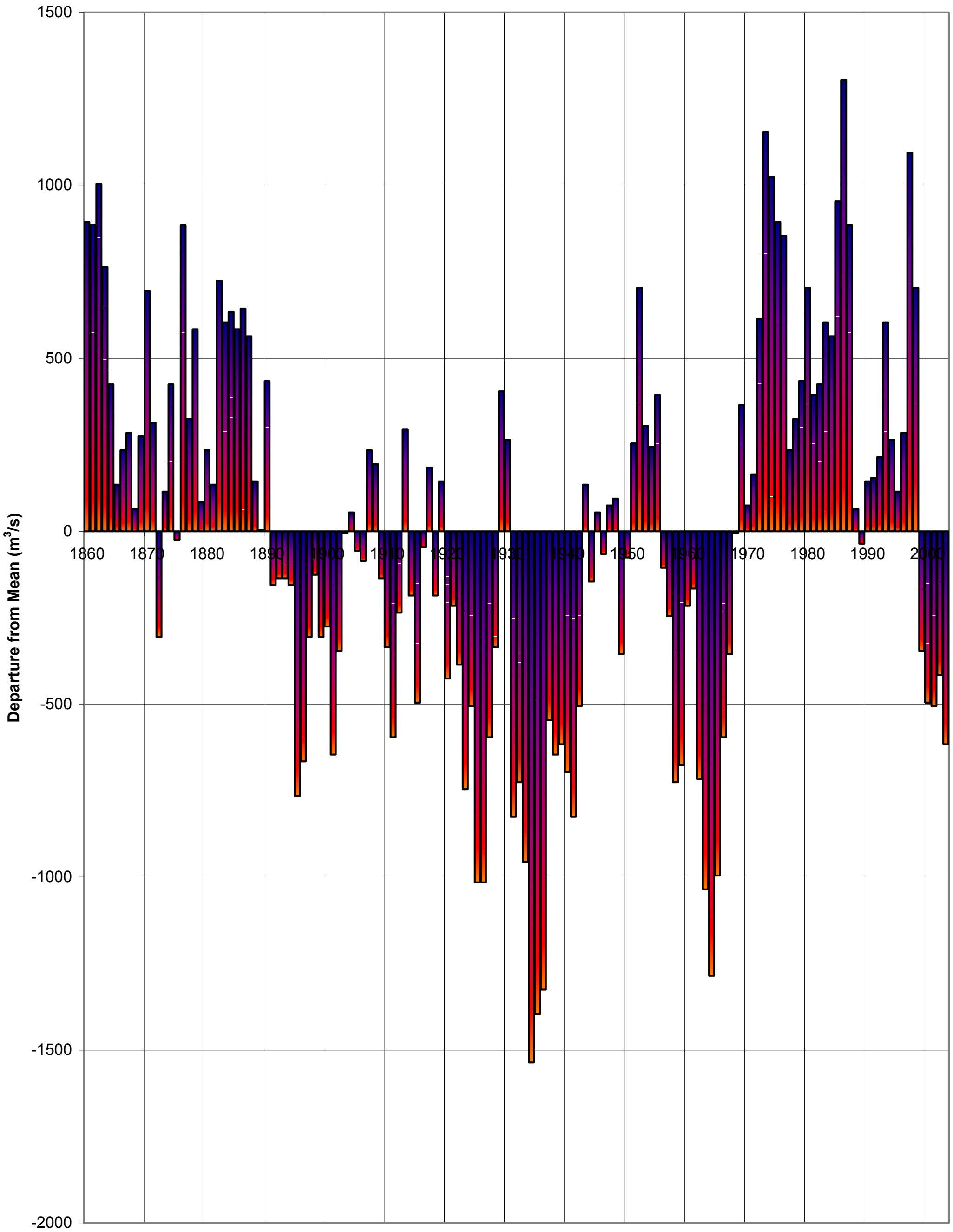


Figure 3-1 Niagara River at Queenston – Departures from Mean Annual Flow

Figure 3-2 Great Lakes Diversions

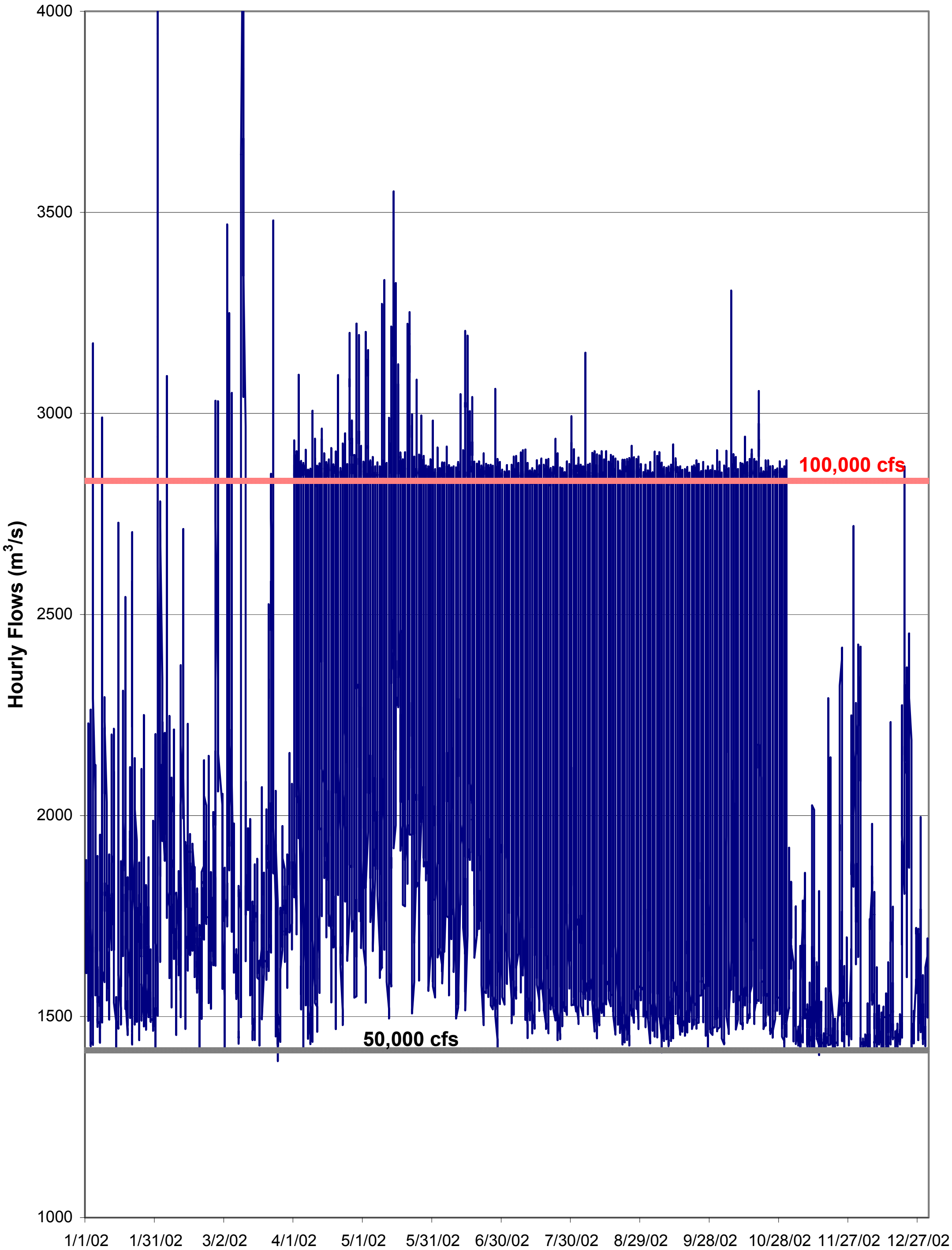


Figure 3-3 Hourly Ashland Ave. (Falls) Flows in 2002

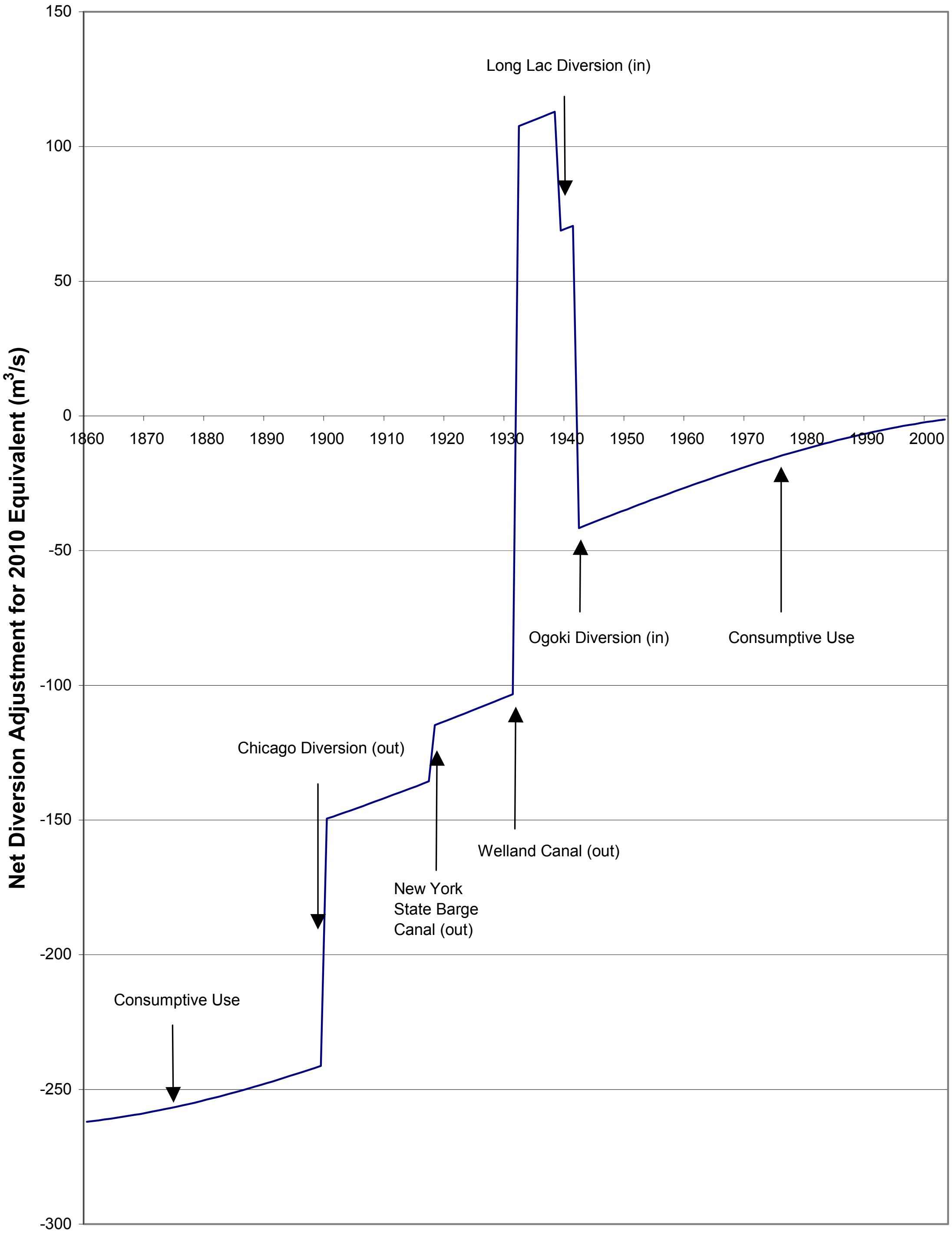


Figure 3-4 Net Adjustments for 2007 Flows

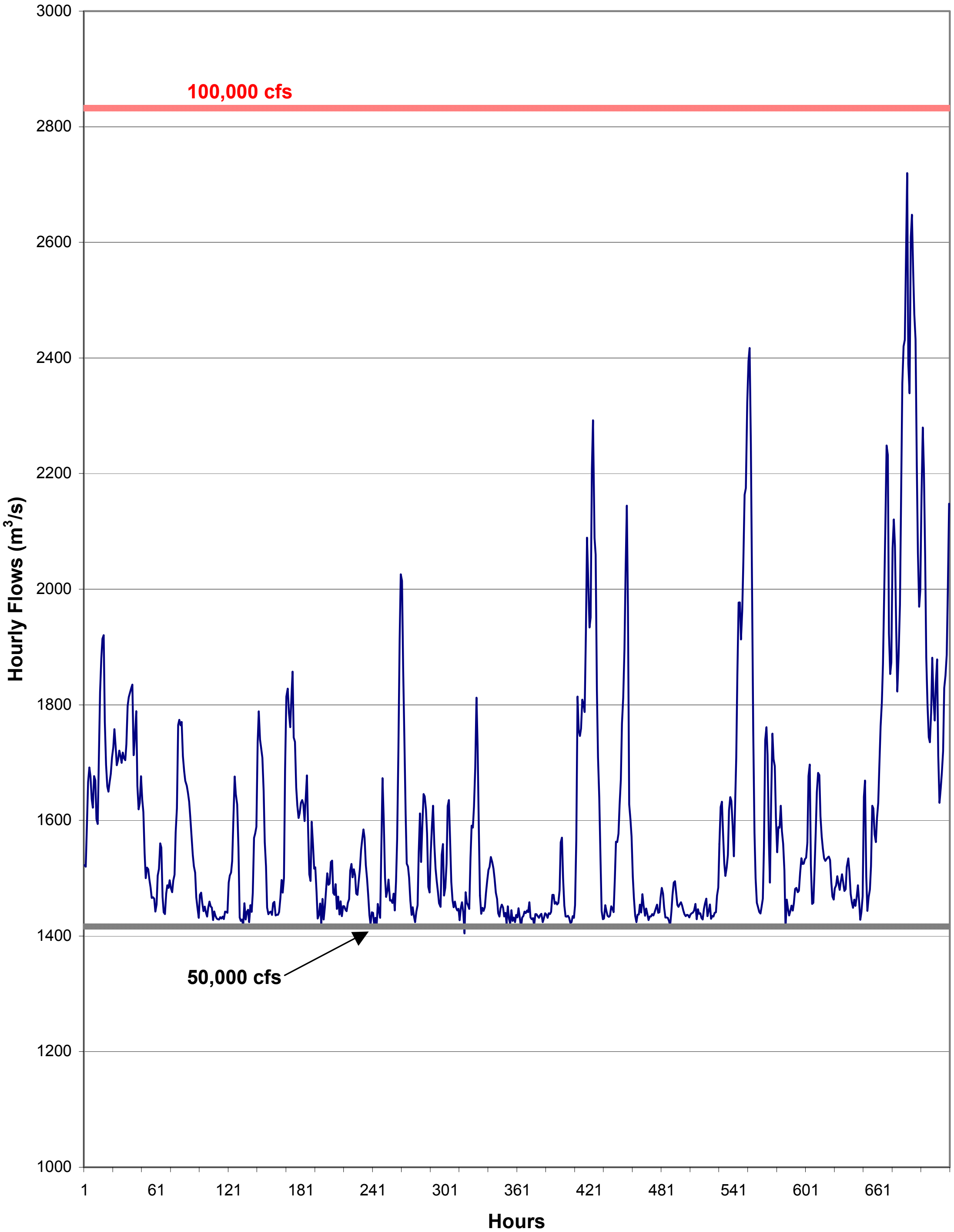


Figure 3-5 Hourly November (Winter) Ashland Ave. (Falls) Flows in 2002

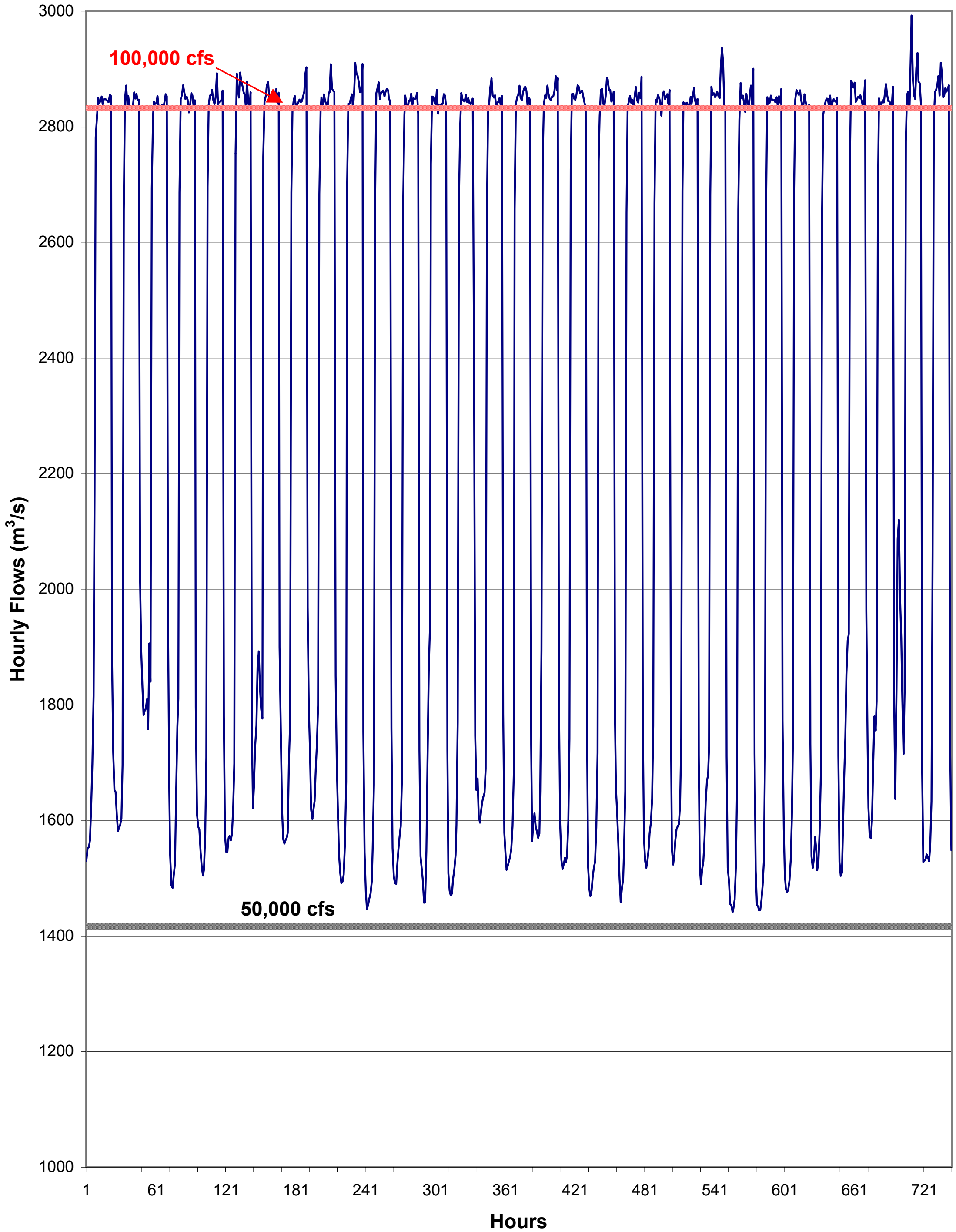


Figure 3-6 Hourly July (Summer) Ashland Ave. (Falls) Flows in 2002

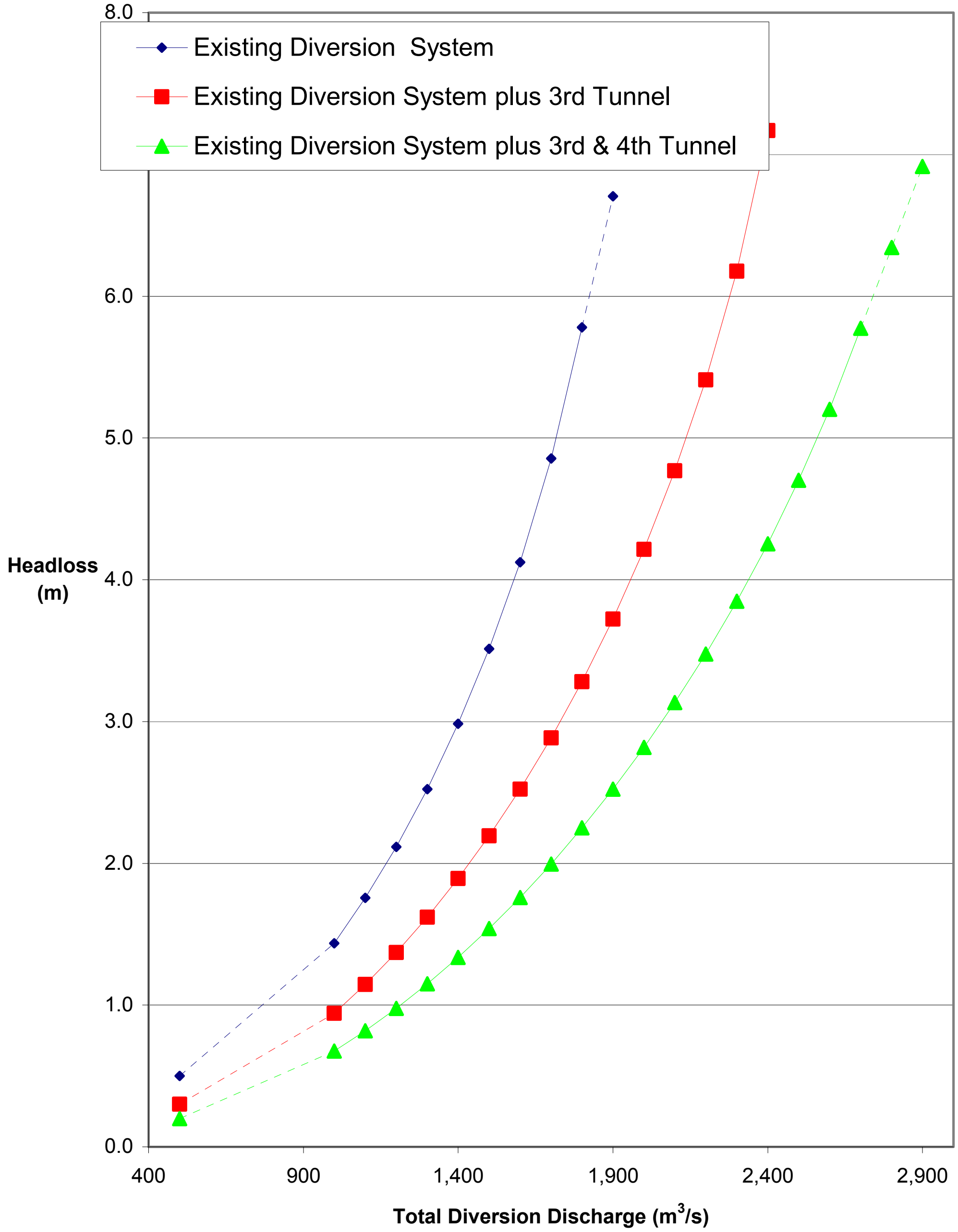


Figure 3-7 Diversion Flow Head Loss Relationship

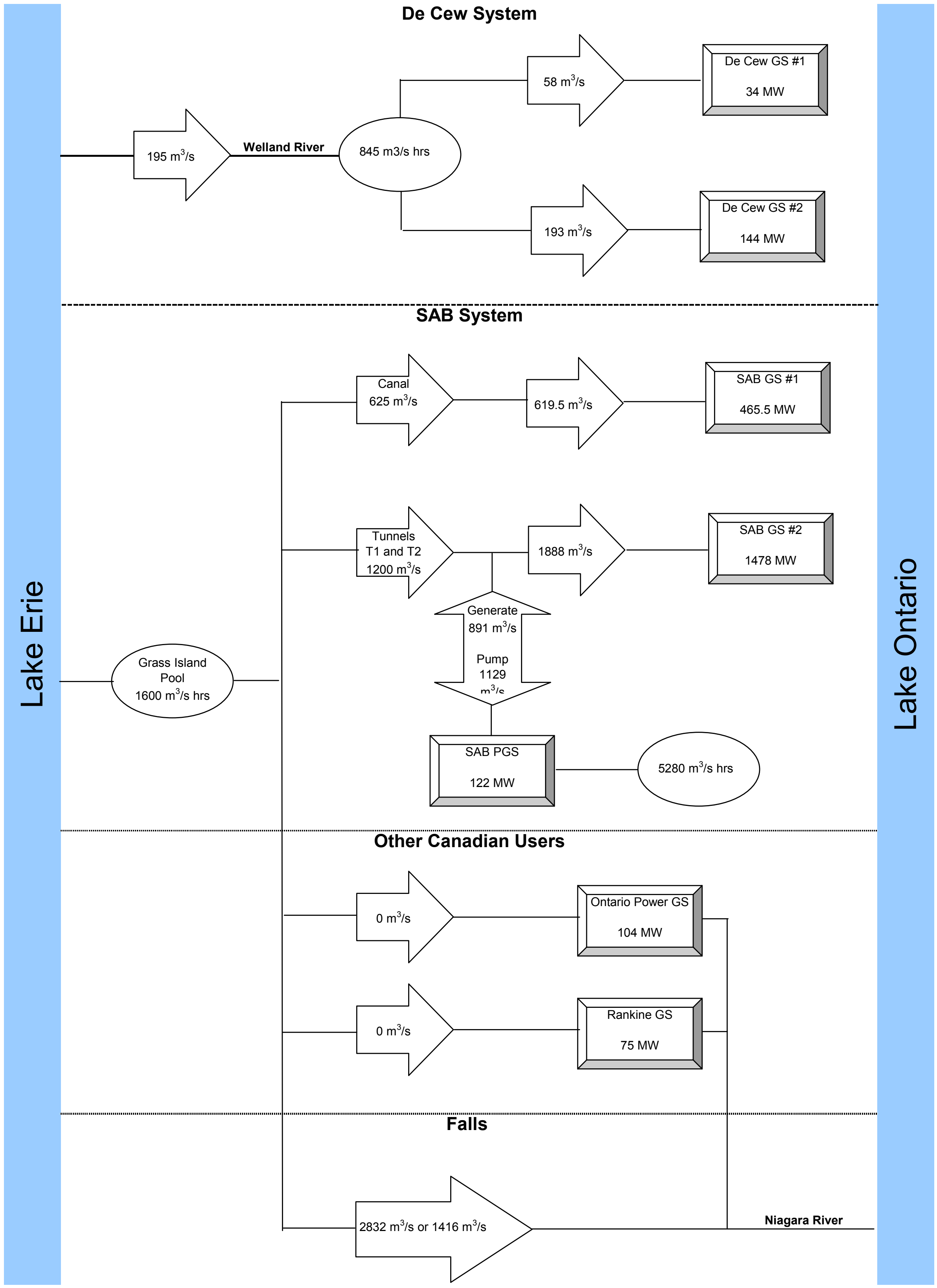


Figure 3-8 Schematic of Diversion, Storage and Generation Capacities, Case 1

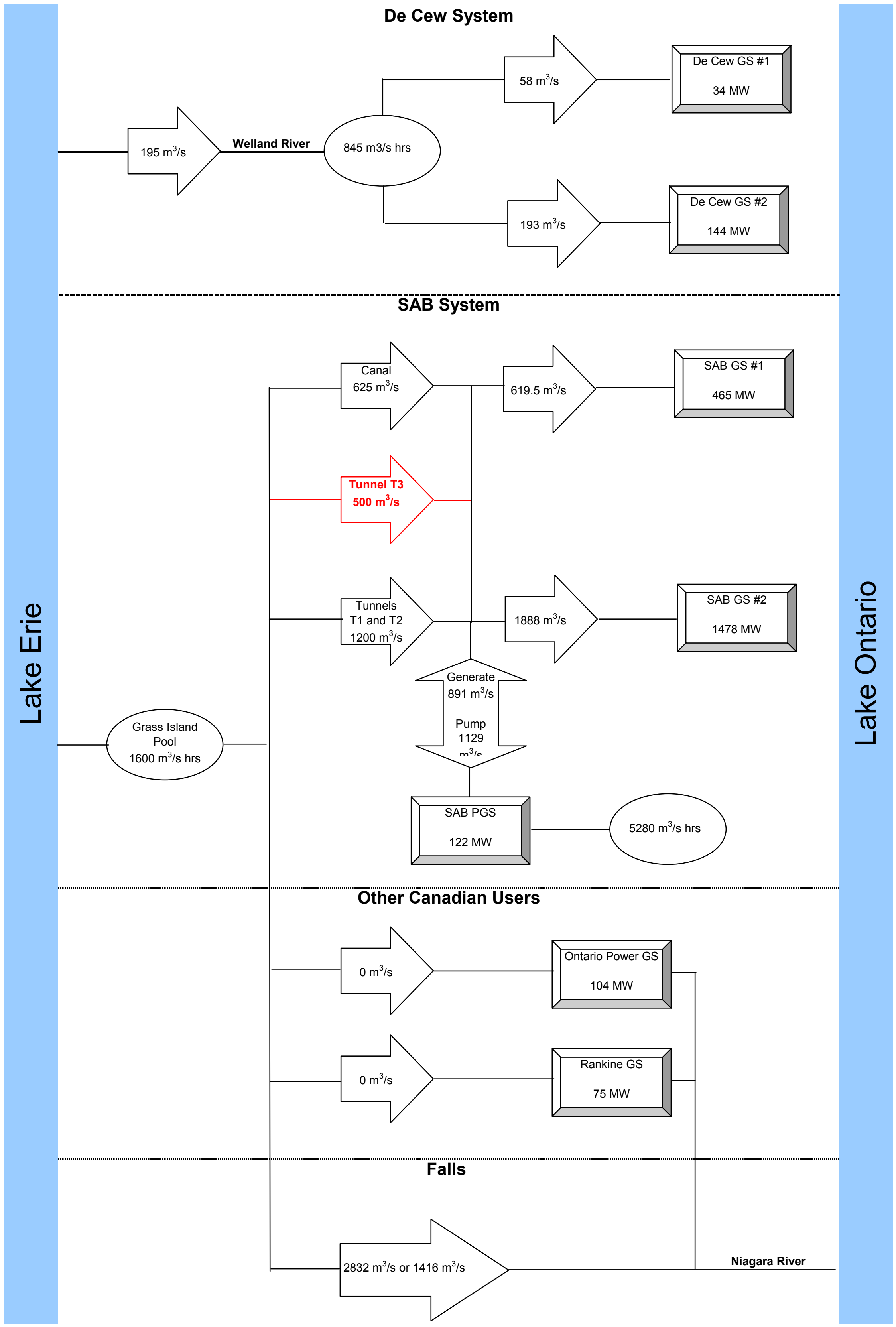


Figure 3-9 Schematic of Diversion, Storage and Generation Capacities, Case 2

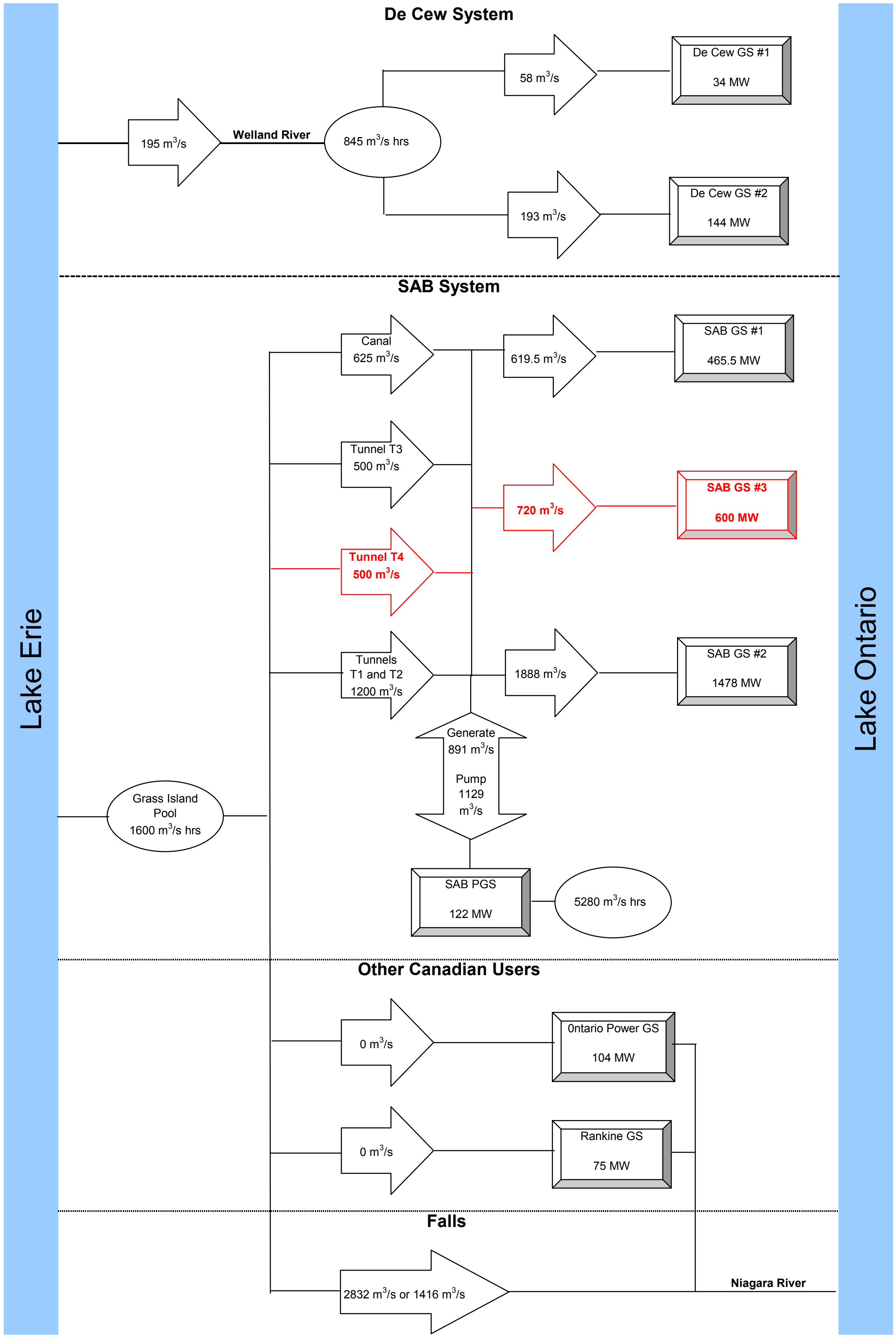


Figure 3-10 Schematic of Diversion, Storage and Generation Capacities, Case 4

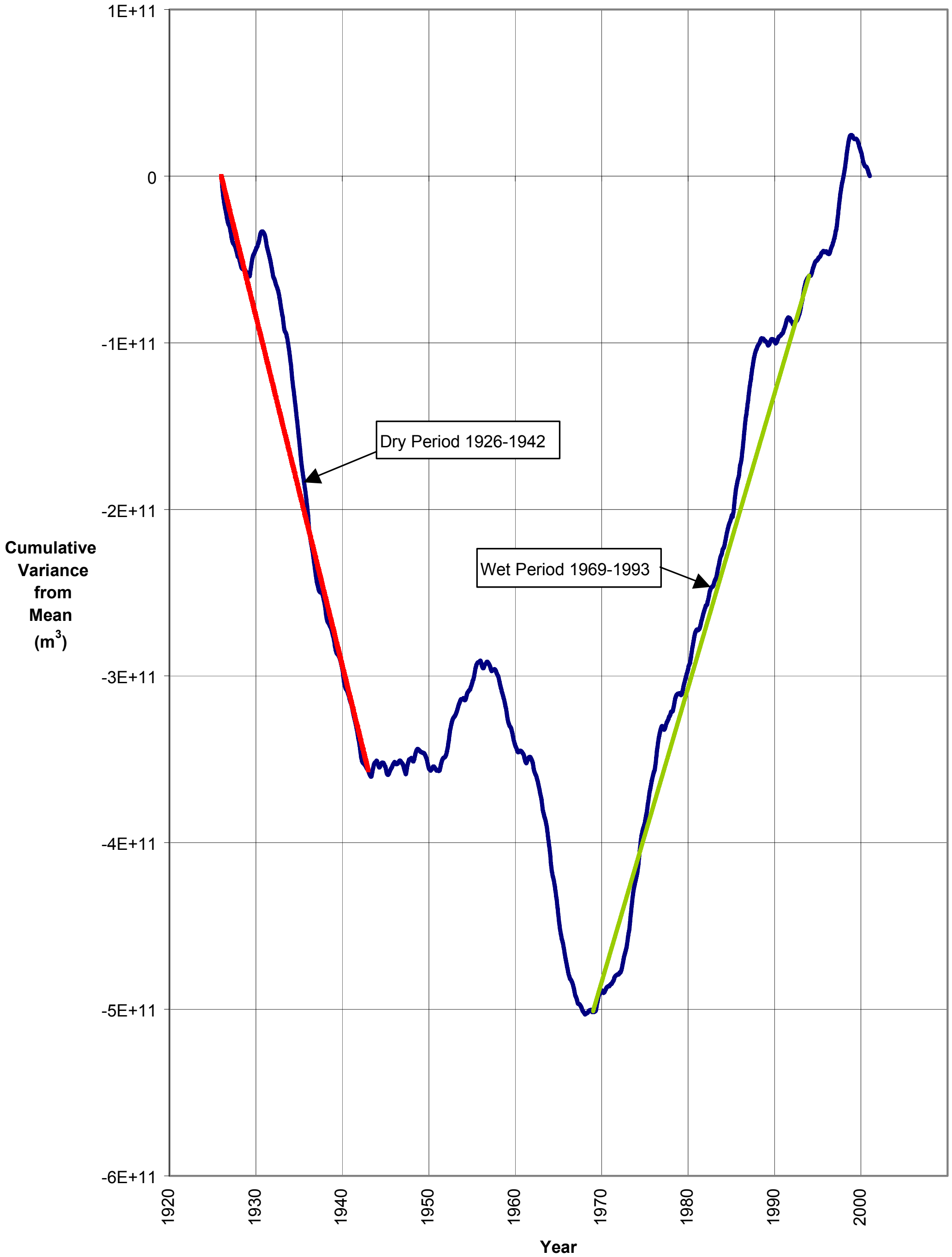


Figure 3-11 Mass Balance Curve, Adjusted Queenston Data

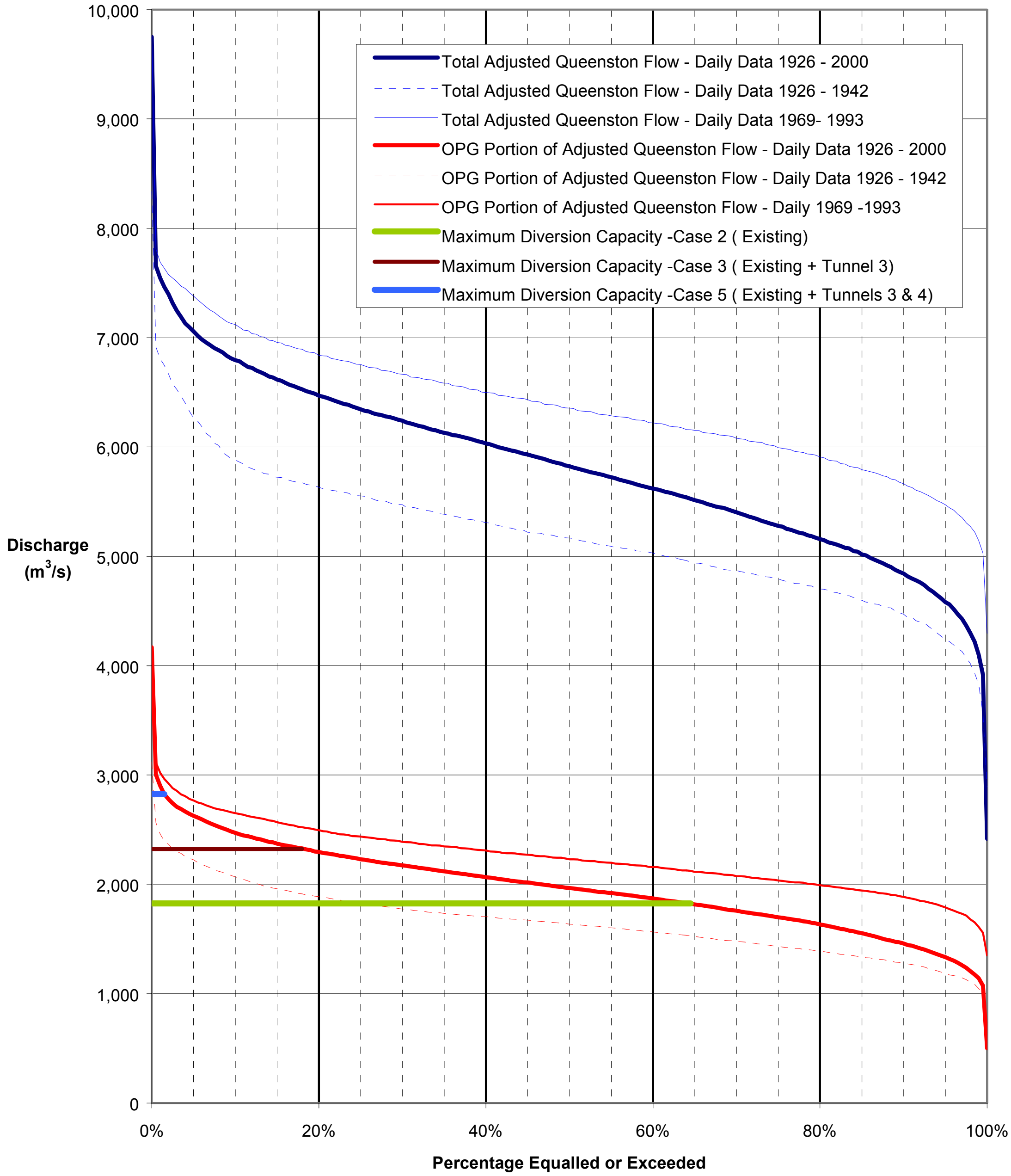


Figure 3-12 Flow Duration Curve

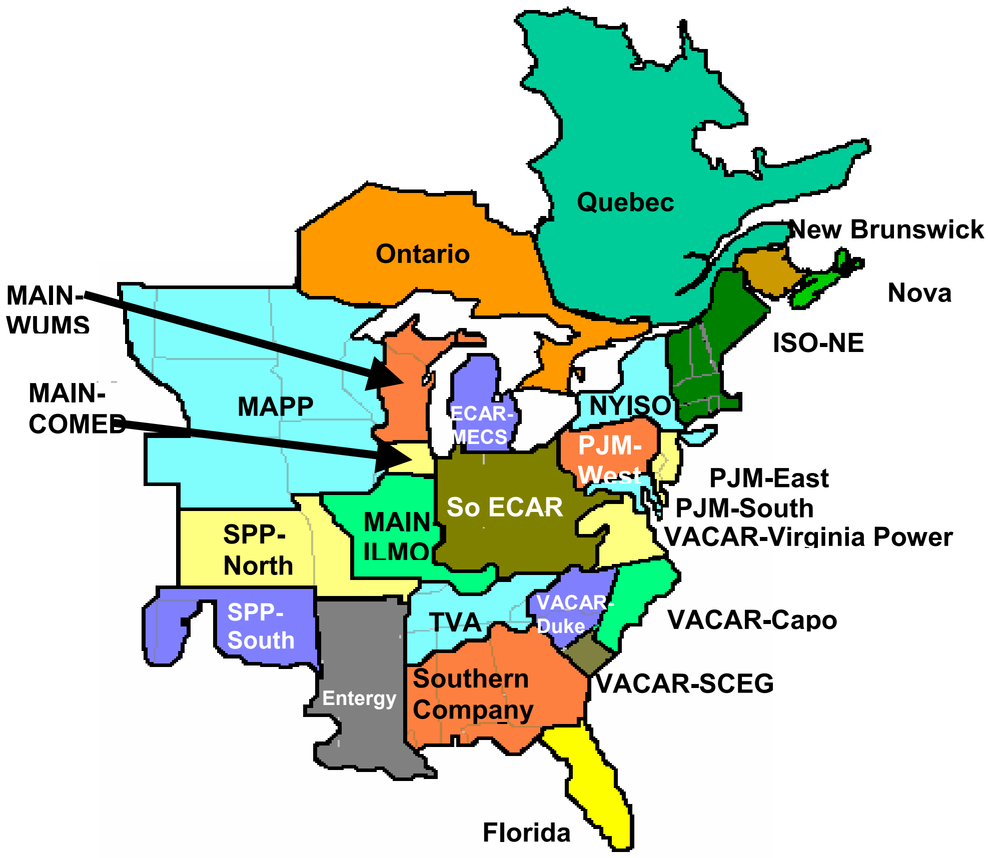
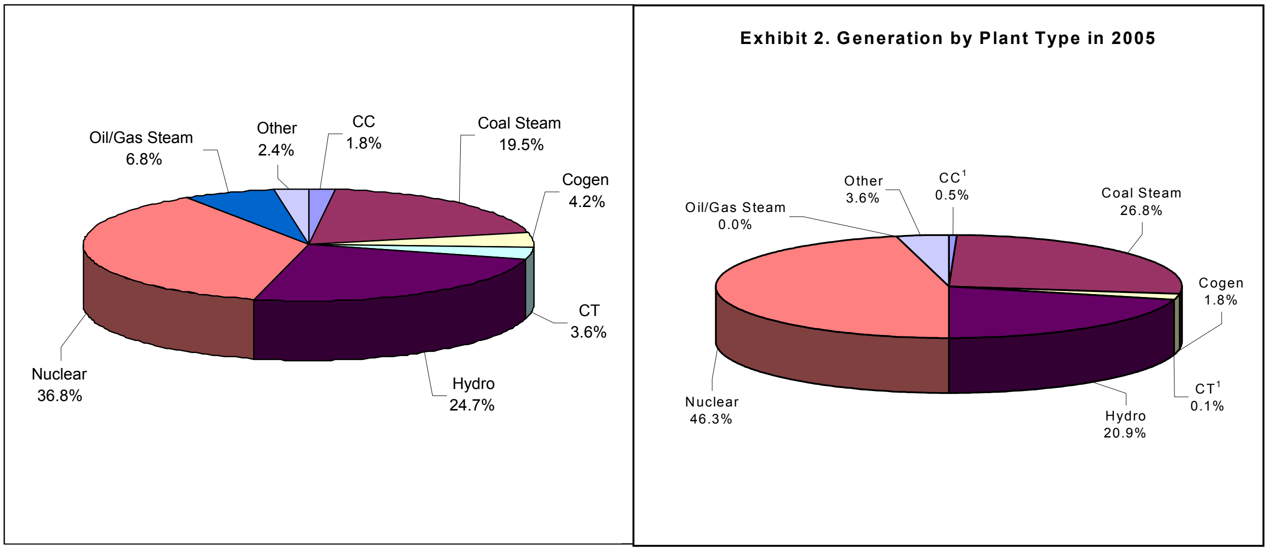


Figure 4-1 IPM® Power Market Characterization



Total Capacity: 32 GW **Total Generation: 170 TWh**

Figure 4-2 Ontario's Capacity and Generation Mix in 2007

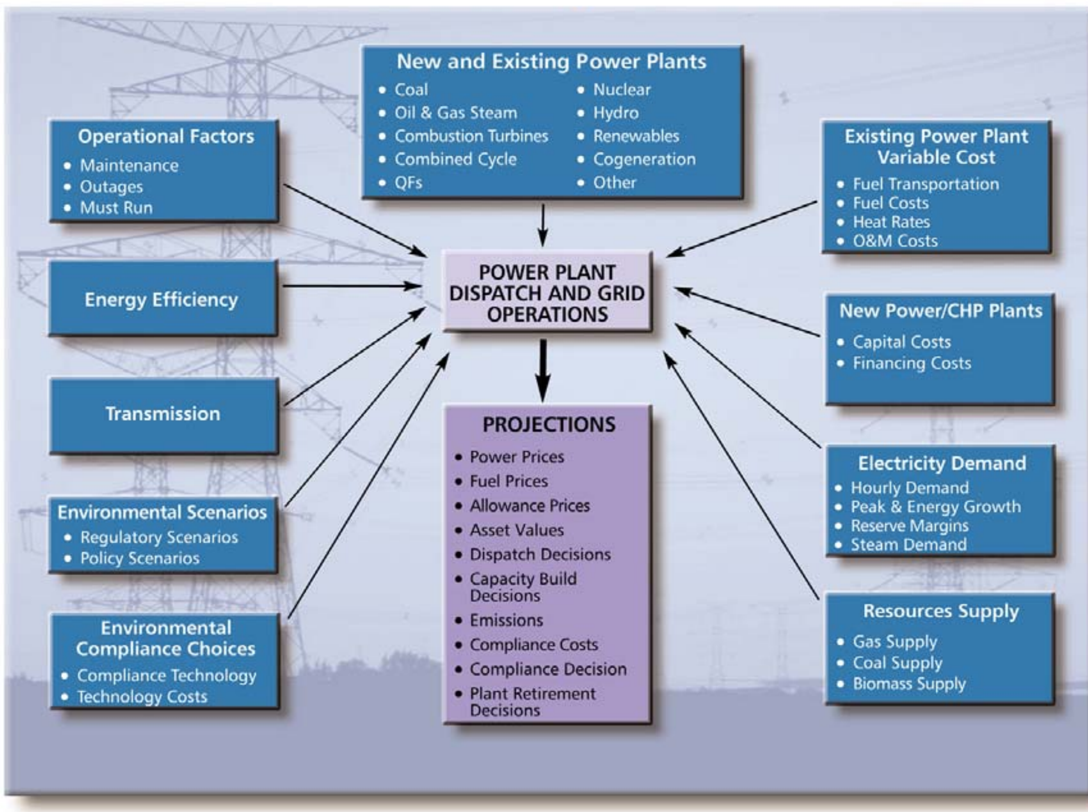


Figure 4-3 IPM® Modelling Structure

APPENDIX I

List of Project Data

Beck 3 Feasibility Study Project - List of Project Data

Item No.	File Reference No.	Description of Records
12	AW130-J4H-00005-0007	Niagara River Hydroelectric Development Project
19	R-NAW130-00005-0007	Niag. River Hydroelectric Develop. Preliminary Gen. Planning Specifications – Rev. 1
20	R-NAW130-00005-0007	Niag. River Hydroelectric Develop. Preliminary Gen. Planning Specifications – Rev. 2
26	R-NAW130-00032-0008	Niag. River Hydroelectric Develop. Def. Eng., Phase 2 Est. for EPCM Serv.
35	R-NAW130-00150-0001	NRHD Definition Engineering Phase 2 Contract Packaging
38	R-NAW130-00441-0004	NRHD Definition Engineering Phase 2 Diversion Facilities Capital Cost Estimate Vol. 1 Estimate Methodology & Provisos
44	R-NAW130-00441-0003	NRHD - Definition Engineering Phase 2 Diversion Facilities Capital Cost Est. Vol. 8 Estimate Details, DC01 Div. Tunnel Contr. Outlets, Outlet Canal and Construction Facilities
48	R-NAW130-00441-0012	NRHD - Definition Engineering Phase 2 Capital Cost
101	R-NAW130-10120-0013	NRHD Definition Phase Geotechnical Investigations and Evaluation – Evaluation of the PGS Reservoir Report No. 91151
109	R-NAW130-13000-0001	Report on the Impact of Proposed Ontario Hydro Beck 3 Generating Station and Associated Activities of the Regional Road System in the City of Niagara Falls
110	R-NAW130-19030-0001	NRHD – Definition Eng. Phase 2 Potential Effects of Higher Water Levels
113	R-NAW130-20102-0002	NRHD – Definition Eng. Phase 2 Generation Facilities – Power Complex Detailed Arrangement Report
115	R-NAW130-29230-0003	NRHD – Definition Engineering Phase 2 Hydroelectric Modelling of Grass Island Pool to Queenston Conveyance System
125	R-NAW130-80000-0001	NRHD – Definition Engineering Phase 2 Temporary Construction Facilities General Arrangement Report
130	R-NAW130-00430-0003	Niagara River Hydroelectric Development Definition Engineering Phase 2 Optimization Study Report
142	R-NAW130-07016-0001	Niagara River Hydroelectric Development Environmental Geology, Hydrogeology and Soils

Beck 3 Feasibility Study Project - List of Project Data

Item No.	File Reference No.	Description of Records
		Reference Document
150	R-NAW130-10120-0040	NRHD Definition Engineering Phase 2 Update of Cost Estimates Sched. & Energy Assessments – P12282.01.02
3452	R-H-08410.1-47--0119	Niagara River Hydroelectric Development Hydraulic Analysis of Lower Niagara River Report No. 89317
-	-	“Niagara River Feasibility Report on Increasing Hydroelectric Generating Capacity” Report No. 87269-Rev. 1
-	-	Ontario Hydro. Providing the Balance of Power. Demand/Supply Plan Report.
-	-	Ontario Hydro. Providing the Balance of Power. Demand/Supply Plans Environmental Analysis.
55	R-NAW130-01200-0001	Acres International Limited in association with Golder Associates Ltd. June 1990. Niagara River Hydroelectric Development Generation and Diversion Facilities. Final Report. Definition Engineering Phase 1.
64	R-NAW130-07000--0004	Acres International Limited. 1990. Niagara River Hydroelectric Development Environmental Assessment. Screening of Alternative Generation Methods Reference Document.
67	R-NAW130-07013--0001	Acres International Limited. 1990. Niagara River Hydroelectric Development Environmental Assessment. Surface Water and Sediment Quality Reference Document.
71	R-NAW130-07270-0001	Acres International Limited. 1990. Niagara River Hydroelectric Development Environmental Assessment. Hydraulics and Sediment Transport Reference Document.
80	R-NAW130-07400--0001	Acres International Limited, May 1990. Niagara River Hydroelectric Development Environmental Assessment. Transportation and Infrastructure Reference Document.

APPENDIX II

Responses to Questions on Analysis Results

Harvey, Bill

From: Jennings, Rick (ENERGY) [Rick.Jennings@energy.gov.on.ca]
Sent: Friday, May 14, 2004 2:20 PM
To: Harvey, Bill
Cc: Plagiannakos, Takis (ENERGY); Colaiacovo , Pelino (ENERGY)
Subject: FW: Comments on Beck 3 Report

Further to our meeting last week attached comments from Takis are the further information that we are looking for before finalizing the report. OPG staff are not requesting any additional infomation or changes. Let me know if you have any questions regarding these requests.

> -----Original Message-----
> From: Plagiannakos, Takis (ENERGY)
> Sent: Monday, May 10, 2004 1:35 PM
> To: Jennings, Rick (ENERGY)
> Cc: Plagiannakos, Takis (ENERGY)
> Subject: Comments on Beck 3 Report
>
> Hi Rick:
> As requested, I had a quick look at the Beck 3 Generating Station Draft
> Report and I thought the reader could benefit if the following information
> was included:
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> 1. Estimates of the Level Unit Energy Cost (cents/kWh) of generating
> electricity under each Case
> 2. Estimates of the electricity price for which the project would
> break-even under each Case
> 3. Sensitivity analysis using higher Ontario delivered gas prices i.e.
> Cnd$7.00 - Cnd$9.00 per MMBtu.
> 4. Discuss impact on results if lower/higher discount rates were used.
> 5. Discuss impacts on results if the evaluation period was extended
> over a sixty year period (i.e. life of investment?).
>
>
> Takis

Responses to Questions on Analysis Results of May 2004 Draft "Report on Economic Feasibility and Means for Financing Study of the Beck 3 Generating Station"

1. ***Estimates of the Unit-Level Energy Price (cents/kWh) of generating electricity under each Case:***

All-Hours Firm Power Price:

Base Case plus SAB3

	2005	2007	2008	2012	2018	2025	2030
(CDN/MWh)	**$35.99**	**$45.33**	**$46.34**	**$50.96**	**$50.43**	**$50.30**	**$50.98**

High Market Price Case

	2005	2007	2008	2012	2018	2025	2030
(CDN/MWh)	**$54.95**	**$64.24**	**$61.76**	**$65.64**	**$60.24**	**$58.97**	**$59.34**

2. ***Estimates of the electricity price for which the project would break-even under each Case:***

A preliminary calculation which included project financing charges (note that figures reported in the main text of this report did not include financing costs).

Overnight costs to build SAB 3 = $980 million CDN (year 2004)

NPV from 2007 to 2025 with a capital charge rate of 13% = $1,316 million CDN ($2004)

On a per kW basis = $2,194 CDN/kW ← This is the value the unit must meet

In order to realize $2,194 CDN/kW, the unit's realized energy price would have to be in the order of **<u>3-to-4 times higher</u>** than what this analysis shows. Similarly, a 3-to-4 times increase in dispatch could realize the NPV per kW necessary.

3. ***Sensitivity analysis using higher Ontario delivered gas prices i.e. CDN$7.00 - CDN$9.00 per mmBtu:***

We performed a sensitivity analysis whereby the delivered natural gas price throughout the Eastern Interconnect was significantly higher than current market levels. Specifically, delivered natural gas prices in Ontario were raised to a level of $8.00 CDN/mmBtu (real 2000$) average gas price over the study horizon. The higher gas prices raise the marginal energy price by approximately 19% over the model time horizon, resulting in a higher net present value of the Beck 3 unit. The resulting net present value is $720 CDN/kW in year 2004 dollars, up from $592 CDN/kW in year 2004 dollars, for an increase of approximately 22%. The overnight capital cost of the facility remains the same ($1,633/kW excluding financing costs).

However, it should be noted that ICF believes sustained natural gas prices of $8.00 CDN/mmBtu (real 2000$) are extremely unlikely over a 20 year forecast period. While fuel prices in the short term may significantly exceed marginal production costs, technological enhancements and competition (both domestic and through LNG imports) will conspire to bring prices back to equilibrium.

4. ***Discuss impact on results if lower/higher discount rates were used.***

We performed 2 sensitivity runs whereby the discount rate was lowered and raised by 2%: Low Discount Rate (5%); High Discount Rate (9%).

At the High Discount Rate of 9%, the net present value of Beck 3 decreases to $509 CDN/kW in year 2004 dollars from $592 CDN/kW, resulting in a 14% decrease. The High Discount Rate dropped the average capacity price from $78/kW-yr to $77/kW-yr resulting in a 1% reduction over the modelling time period.

At the Low Discount Rate of 5%, the net present value of Beck 3 increases to $698 CDN/kW in year 2004 dollars from $592 CDN/kW, resulting in an 18% increase. The Low Discount Rate had a negligible difference on the average capacity price over the modelling time period.

Both Net present values remain significantly lower than the overnight capital cost of the unit.

5. ***Discuss impacts on results if the evaluation period was extended over a sixty-year period (i.e. serviceable life of the investment).***

Due to the high uncertainty surrounding forecasts of system characteristics 60 years into the future, the model was not run over this time period. Instead, the final run year data was extended to the 60 year time period to perform a simple Net Present Value sensitivity analysis. All other data remained the same, e.g., discount rate, capacity factor.

Over a 60 year time period, the net present value of Beck 3 increases to $815 CDN/kW in year 2004 dollars from $592 CDN/kW. The overnight capital cost of the facility remains the same ($1,633/kW excluding financing costs) – higher than the increased net present value.

6. Other

Gas Prices (CDN$/mmBtu)

	2007	2010	2020
Base Case plus SAB3	$5.70	$5.57	$5.38
High Market Price Case	$6.87	$6.69	$6.47