# Yukon – Transmission Market Benefits Assessment

**Submitted By:** Midgard Consulting Incorporated

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# Executive Summary

The goal of this report is to analyze the net economic benefits that would accrue to the Yukon by developing an interconnection that would enable the Yukon to export and import electricity to and from neighboring jurisdictions. If the net benefits of electricity trade are greater than the net costs of required infrastructure necessary to facilitate trade, then developing an interconnection makes economic sense.

The net benefits of electricity trade is tied to the presumed quantity of electricity exported and the price at which the electricity is sold, as well as the potential revenues tied to an active buy low and sell high trading strategy. The net costs of infrastructure were based upon the construction and operating costs of an interconnection as well as the incremental generation facilities needed to support the export presumptions. Two potential interconnection options are evaluated: 1) Yukon to British Columbia and 2) Yukon to Fairbanks, Alaska.[1] The net benefit evaluation results for the two interconnection options studied in this report are shown in Table 0-1 below.

**Table 0-1 : Net Benefit Evaluation of Two Interconnection Scenarios**

| | (a) | (b1) | (b2) | (a) + (b1) + (b2) |
|---|---|---|---|---|
| **Interconnection Option** | **Export Revenue (Net of Import Costs) ($M)** | **New Transmission Costs ($M)** | **New Generation Costs ($M)** | **Net Benefits ($M)** |
| YK-BC | 214 | -1310 | -379 | -1470 |
| YK-Fairbanks | 202 | -1015 | -379 | -1190 |

**Both scenarios demonstrate significantly negative net economic benefits and are therefore uneconomic strategies.** The report also asked – "How large do exports have to be in order for the net benefits to equal the costs of building transmission infrastructure"? The answer is that it will require an average of:

- 227 MW for 60 years in order to defray the cost of a transmission interconnection to British Columbia; and 269 MW for 60 years in order to defray the cost of a transmission interconnection to Fairbanks, Alaska.

In both cases, the quantum of export volume exceeds the design capacity of the transmission line by 2x or more, and this would require additional transmission capacity (which would increase transmission costs, which would require even more exports, which would further increase the transmission costs, and so forth). Therefore, Midgard does not see a plausible scenario, given the assumptions employed in the analysis, where exporting electricity from the Yukon to either British Columbia or Fairbanks, Alaska makes economic sense.

[1] The proposed Whitehorse to Skagway interconnection will not be considered in this report because it was studied in the March 2015 Morrison Hershfield report, *Viability Analysis of Southeast Alaska and Yukon Economic Development Corridor*.

Importing electricity into the Yukon is similarly unattractive with required import volumes exceeding the forecast need for electricity in the Yukon beyond 2065 (i.e. 150MW and 109MW per winter peaking hour for 60 years for the BC interconnection and Alaska interconnection respectively). Midgard cannot see a plausible scenario, given the assumptions, where Yukon profitably imports electricity. Moreover, the import scenario requires that the Yukon be willing to accept that it will be dependent on an external jurisdiction for critical winter energy supply which raises reliability issues.

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# 1 Introduction

The Yukon Development Corporation ("YDC") commissioned Midgard Consulting Incorporated ("Midgard") and its team of sub-consultants to complete **Yukon *Next Generation Hydro and Transmission Viability Study***. The study, delivered through a series of technical papers, is intended to help inform the decisions necessary to identify and fill the territory's long-term future electrical energy gap in order to support Yukon's continued economic growth and prosperity.

The goal of the present report is to analyze the net economic benefits that would accrue to the Yukon by developing an interconnection that would enable the Yukon to access external transmission markets.

## 1.1 Economic Assessment of Developing Transmission Market Access

The primary potential economic benefit[2] to the Yukon of developing access to external transmission markets would consist of the revenues earned from trading electric energy with counterparties sited in external jurisdictions. Although the interconnection would also enable trading ancillary services and could provide some minor reliability benefits to the Yukon[3], the revenues associated with these items would be relatively minor, and the economic justification for developing market access will rely almost entirely on proceeds earned from energy trading.

Assessing the net economic benefits of developing market access involves subtracting the net costs incurred to facilitate energy trading from the revenues earned by trading. These facilitation costs include the costs of:

1. Developing and operating the interconnecting transmission lines and associated facilities
2. Building new generation dedicated to exports (including the expansion of facilities primarily intended for Yukon supply)
3. Electric energy that must be imported during low cost periods to enable exports during high cost periods[4]

As a result, the Yukon would consider trade with external jurisdictions only if the net benefits of electricity trade is greater than the net costs of required infrastructure, including operating costs, necessary to facilitate trade (see Figure 1-1 below).

[2] The dollar value of all costs and benefits referenced in this report are in real Canadian dollars (base year = 2015), unless otherwise noted.

[3] These potential ancillary services and reliability benefits are discussed in the Midgard report "**Jurisdictional Transmission Line Technical Logistics Analysis"**

[4] For example, BC Hydro is typically a net importer of electrical energy on an annual basis, so BC Hydro must import power during low market cost periods to enable power sales during high market cost periods.

**Figure 1-1: Economic Test for Developing Transmission Market Access**


To summarize, if the net benefits of electricity trade are greater than the net costs of required infrastructure necessary to facilitate trade then the net economic benefits of developing transmission market access are positive, and it makes economic sense to develop the infrastructure required to enable trading. If the net economic benefits are negative (i.e. costs are greater than benefits), then developing trading infrastructure does not make economic sense.

## 1.2 Required Transmission and Generation Infrastructure

### *1.2.1 Transmission Interconnection*

The single most important parameter needed to determine the net benefits of accessing external transmission markets is the cost of building the electrical interconnection. This report incorporates the capital costs and export capacities associated with two different transmission interconnection options described in the previously released Midgard report titled **Jurisdictional Transmission Line Technical Logistics Analysis**:

1. Yukon to British Columbia
2. Yukon to Fairbanks, Alaska[5]

Table 1-1 provides a summary of the capacity and costs for these transmission options.

**Table 1-1: Summary of Potential Interconnection Options**

| Route | Distance | Transmission Capacity (MW)[6] | Line Losses | Construction Cost |
|---|---|---|---|---|
| 287kV Yukon-BC | 745 km | 64 - 127 [7] | ≈5.7% | $1.710 B |
| 230kV Yukon-Fairbanks | 660 km | 70 - 80[8] | ≈6.6% | $1.325 B |

[5] Specifically, Yukon to Fairbanks refers to an interconnection between Yukon's transmission grid and Alaska's Railbelt grid. The Alaskan Railbelt stretches from the Fairbanks region in the North to the Anchorage region in the south, and encompasses 70% of Alaska's population.

[6] MW = megawatt

[7] Net Exports are dependent upon output of Forrest Kerr Hydro generation; Forrest Kerr output utilizes some portion of the available transmission capacity.

[8] Net Exports are dependent upon output of Delta Junction generation

### *1.2.2 Trade-Specific Generation Infrastructure*

To support electricity trade with external jurisdictions, new Yukon electrical generation facilities would be developed in part to support electricity trading during much of the year, with the exception of the summer snowmelt period when the existing Whitehorse facility normally spills surplus water. The timing of season changes in the Yukon, Alaska and British Columbia are similar enough that the peak energy demand periods of all three jurisdictions exhibit significant overlap. Specifically, energy is more valuable in the winter when electricity demand is highest and river flows the lowest, and less valuable in the spring/summer when electricity demand is lower and river flows the highest. Therefore, the seasonal value of electricity for the Yukon's neighbors mirrors the seasonal value of electricity domestically within the Yukon's borders.

An optimal hydro generation facility that could serve both internal Yukon demand and also support exports would need to store sufficient water (i.e. fuel to make energy) during the low demand (lower value/high water) summer season for use during the high demand (higher value/low water) winter season. A hydroelectric facility with a large storage reservoir enabling production of electricity during the high demand winter months would be more attractive for both internal Yukon consumption and export purposes than a run-of-river facility that would produce most of its electricity during the lower demand spring and summer months.

However, this report does not prescribe either a particular generation configuration or electricity production patterns for the new generation relative to seasonal market price signals, as the required analysis would be unnecessarily complex for this stage of interconnection evaluation. Instead, this report calculates the cost of new generation necessary to support electricity trading with the simplifying assumptions set out in Section 6.

## 1.3 Electricity Trading Benefits Assessment

As discussed above, to justify development of market access infrastructure the net benefits of electricity sales (exports) minus the net costs of purchases (imports) must be greater than the cost of building and operating the required transmission interconnection and any required new or incremental generation. The simplest approach to conducting a net benefits assessment involves calculating the net present value[9] ("NPV") of the revenue and cost components associated with each interconnection option being evaluated.

The inputs required to conduct the analysis for each interconnection option include:

1. Electricity Volume - the amount of exportable electric energy based upon the size and capacity factor of the new generation facilities
2. Net Benefits of Exports – revenue earned per MWh[10] of energy exported

[9] All net present value calculations of benefits and costs are discounted back to the initial capital outlay year, which is 2026 in this report, to allow for a 9 year development timeline and in service date of 2035.

[10] MWh = megawatt hour

3. Net Costs of Imports – purchase cost per MWh of energy imported
4. Interconnection Costs – capital and operating costs for the new interconnection facilities
5. Generation Costs – capital and operating costs for dedicated export generation facilities

The net benefits of developing market access are calculated by determining the (net present value of) annual electricity trading (export sales revenues minus import purchases costs), and subtracting the (net present value of) capital costs and annual operating costs of the transmission and generation infrastructure.

If the Net Benefits are:

1. Greater than zero – Developing transmission market access is economically positive.
2. Less than zero – Developing transmission market access is economically negative.

## 1.4 Outline of the Report

The report is divided into seven sections including this introduction (Section 1). Section 2 discusses the background and requirements to enable electricity trading. Section 3 discusses the methodology employed in the report to evaluate the benefits and costs of the various transmission interconnection options. Sections 4 and 6 describe the cost calculations for transmission infrastructure and the generation infrastructure, respectively. Section 5 highlights the volumes of electricity that could be traded, and discusses the expected pricing for imports and exports of electricity in neighboring markets. Section 7 assembles the cost and benefit inputs, and calculates a net economic result for the two transmission line scenarios, and summarizes the findings of the report.

The report also includes three (3) appendices: Appendix A: describes the neighboring electricity markets, Appendix B: describes the ancillary markets of the neighboring jurisdictions and Appendix C: provides the calculations used to assess the cost of new generic generation facilities.

# 2 Overview of Inter-jurisdictional Electricity Trading

It is common for neighboring jurisdictions to trade electricity with one another, and this electricity trade is typically motivated by economics, resource husbandry and natural endowment diversity. This section discusses the general requirements necessary to enable electricity trading, deconstructs a typical electricity trade, and finally looks at the specific inter-jurisdictional electricity trading example of British Columbia.

## 2.1 Inter-Jurisdictional Electricity Trade Logistics

To enable electricity trade between jurisdictions, transmission interconnection is the single most important prerequisite. Since the Yukon does not have an existing transmission interconnection with any of its neighbors, a new transmission interconnection must be constructed to enable the exchange of electricity. Implementing a transmission interconnection will also require arranging mutually acceptable operating practices and procedures between the connecting jurisdictions, and new inter-jurisdictional regulatory compliance requirements will likely be imposed.[11]

Electricity trading also involves trading-specific elements such as establishing a trading desk, developing risk management and trade capture systems, managing compliance, training, etc. Although a detailed analysis of these elements is beyond the scope of this report, they represent real costs to the trading entity (i.e. the Yukon), and must be fully understood and budgeted prior to entering the electricity trading industry.

## 2.2 Anatomy of an Electricity Trade

Assuming that the physical transmission and generation facilities, inter-jurisdictional agreements and trading infrastructure needed to support electricity trading are in place, the actual process of trading electricity can be broken into three fundamental steps:

1. Step 1 – Pre-Negotiate the contractual framework
2. Step 2 – Negotiate individual transaction details
3. Step 3 – Execute the transaction and associated logistics.

A hypothetical electricity trade between the Yukon and either BC or Alaska is deconstructed in Table 2-1.

[11] In the event of an interconnection to the BC grid, Yukon will need to adhere to WECC's mandatory reliability standards, as discussed in the Midgard report **Jurisdictional Transmission Line Technical Logistics Analysis**.

**Table 2-1: Anatomy of Electricity Trade**

| No. | Step | Process |
|---|---|---|
| **1.** | *Negotiate Power Purchase Agreement ("PPA") Contract*[12] | The precondition of any electricity trade and exchange is the negotiation of a legal framework for the exchange; the agreement sets out the terms and conditions of the exchange. Critical terms include but are not limited to:<br>1. Price of the electricity,<br>2. Delivery schedule and delivery point,<br>3. Term,<br>4. Quality and characteristics of the delivered product,<br>5. Security requirements,<br>6. Conditions precedent to the initiation of the arrangement,<br>7. Default arrangements. |
| **2.** | *Negotiate Detailed Adjustments for the Sale/Purchase Price of MWh* | Price of electricity is linked to the exchange point:<br>✓ The exchange point for electricity may be either in Vancouver or Fairbanks, at the Yukon border, or at some other mutually agreed point or points.<br>Price of electricity is linked to the time of day for the delivery:<br>✓ Electricity prices are higher during high demand hours (e.g. dinner time), than during low demand hours (e.g. during sleeping hours).<br>Price of electricity is linked to the time of year:<br>✓ Electricity prices are higher during high demand months (e.g. winter), than during low demand months (e.g. summer).<br>✓ Demand may be higher for some industries, such as tourism, during summer rather than winter, but on an aggregate basis, winter demand exceeds summer demand. |
| **3.** | *3a. Purchase Transmission Services* | Transmission services must be purchased from the transmission line owner/operator. Transmission rights may be purchased for short or long periods of time, and on a firm or non-firm basis.[13] |

[12] A comprehensive discussion of power purchase agreements is beyond the scope of this report

[13] In Yukon's case, the likelihood is that the same entity would be owner, operator and controller all of the capacity of the transmission line and infrastructure built within the Yukon, while the neighboring utility would own and operate the infrastructure within its jurisdiction. For the purpose of this report, the cost of these services is presumed embedded in the power purchase and sale price for the electricity.

| No. | Step | Process |
|---|---|---|
| | *3b. Schedule the Delivery (including Losses)* | Scheduling the transaction comprises registering the exchange of the electricity with the proper authority / area controller.<br>As part of any electricity exchange, transmission losses must be accounted for:<br>1. Transmission losses, represented as a percentage of the total amount of electricity exchanged, will reduce the quantity of electricity that is ultimately exported from or imported to the Yukon;<br>2. For example, if system losses are 10%, then 11.1 MWh must be bought/sold in order to receive 10 MWh at the point of delivery. |

## 2.3 Inter-jurisdictional Trading – The British Columbia Example[14]

British Columbia and its Crown utilities, BC Hydro and PowerEx, are among the most successful and active electricity trading entities in North America. Should Yukon choose to enter the electricity trading industry by developing an interconnection with BC, it must be prepared to compete against BC Hydro with its substantial transmission and generation infrastructure, and strategic position on the transmission trade route between Yukon and the US and Alberta markets.

### *2.3.1 Real Time Electricity Trading*

Electricity differs from other tradable goods in several ways, the most important of which may be the difficulty of storing or warehousing the product (i.e. electricity). Operating an electric transmission grid requires that the instantaneous consumption of electricity must match the instantaneous production of electricity. When consumption levels are high – either seasonally or diurnally – electricity production must exactly match the demand at every instant to avoid system brown-out or black out.

In the event that a jurisdiction does not have enough local electric generation capacity to meet peak local demand during a particular period, importing additional electricity from neighbors is an option. In addition, interconnected jurisdictions can choose to import electricity whenever the price of the imported electricity is lower than the price, or opportunity cost, of generating the electricity locally. For example, British Columbia

[14] Jurisdictions such as British Columbia, Quebec and Norway obtain significant electricity market arbitrage benefits by exporting electricity when it is costly and importing electricity when it is inexpensive. These arbitrage benefits are available to these special jurisdictions because these jurisdictions naturally have significant surplus water storage and hydro generation capacity, along with very robust transmission interconnections to very large markets with volatile daily and/or seasonal electricity prices. The Yukon's situation is fundamentally different than British Columbia, Quebec and Norway because the Yukon does not naturally have significant surplus hydroelectric generation and storage capacity, and it lacks interconnection to a large external market with volatile market prices.

often imports electricity from Alberta during the night or during windy periods because the price of the Alberta generated electricity at those times is lower than the price of generating electricity within BC.

The British Columbia case is particularly interesting because the price of generating electricity within BC is not simply a function of the *marginal cost* of activating a hydroelectric turbine, but rather it is the function of the *opportunity cost* of using the water stored in BC Hydro's reservoirs. Storing electricity is practically impossible, but storing the fuel (e.g. water) used to make electricity is not. BC Hydro owns and operates vast hydroelectric reservoirs, which are essentially huge storage batteries. These "hydroelectricity batteries" afford BC Hydro the flexibility of importing power to serve local loads during low electricity market price periods, thereby holding water in the hydroelectric reservoirs until it is economically attractive to generate surplus electricity for export during high market price periods.

Two other characteristics of British Columbia's electricity system bolster the relative value of BC Hydro's assets – the scarcity value of BC's hydroelectric water storage reservoirs, and the countercyclical seasonal demand patterns in British Columbia versus those of California (the largest electricity consumer in western North America).

### *2.3.2 Scarcity Value of Large Hydro Reservoirs*

British Columbia is an electrically interconnected member of the Western Electricity Coordinating Council ("WECC"). Although there are many generating resources and facilities throughout the WECC, BC Hydro's Columbia River and Peace River hydro storage reservoirs are considerably larger and store significantly more energy than any other hydro reservoirs within the WECC. Consequently, BC Hydro has more flexibility to opportunistically store energy and generate energy than any other utility in the WECC.

The regional scarcity of large hydroelectric reservoirs enhances the value of BC Hydro's reservoirs by keeping the market price of electricity high during resource-constrained peak demand periods, and by driving the market price of electricity very low during low demand periods that also have high generation from non-dispatchable generating resources[15] such as wind, solar and run-of-river hydro. Simply put, no utility in the WECC has the same ability to take advantage of energy storage and energy generation opportunities as easily as BC Hydro does.

### *2.3.3 Countercyclical Seasonal Demand Patterns*

Further underpinning the value of BC Hydro's flexibility to generate electricity at various times of the year is the fact that the largest electricity market in the WECC, California, has high load times that are counter-cyclical to BC's high load times. California's highest demands are caused by summertime air conditioning loads and are large enough to influence the price of power across the WECC. In contrast, British Columbia's

[15] A non-dispatchable generating resource is one that cannot be turned on or off; and generates electricity as and when fuel is available (e.g. sun, wind or water).

summer temperatures are temperate and consequently summertime electric loads are low at the same time melting snowpack simultaneously fills BC's reservoirs and rivers, thereby freeing up significant generation capacity to serve export markets such as California.

During the winter, California's climate is temperate, consequently, California's winter electrical loads are low and its generation capacity outweighs its internal electricity demand. The resulting California generation surplus can be sold to the US Pacific Northwest and Western Canada during their winter peak demand.

Table 2-2 summarizes the key reasons why neighboring jurisdictions trade electricity with one another.

**Table 2-2: Justification of Inter-jurisdictions Trade**

| | Opportunity Description | Example |
|---|---|---|
| *#1. Economically Advantageous Exchange Opportunity* | Countercyclical demand patterns between two or more jurisdictions | BC selling electricity to California during summer, California selling electricity to BC during the winter |
| | Diurnal exchange: e.g. selling surplus base load generator output during low load hours | Alberta selling electricity to BC during the night time hours |
| | Purchase / sale of "economical" peaking power | BC selling additional electricity into neighbouring markets during periods of abnormally high prices<br><br>BC importing abnormally low priced electricity from Mid-Columbia market during spring freshet (i.e. importing during time of negative pricing, when the importer is *paid* to consume electricity) |
| *#2. Technically Advantageous Exchange Opportunity* | Efficiency of sharing ancillary services e.g. regulation control | NYISO / IESO / NEPOOL trading spinning reserves amongst each other |
| | Sharing of reserves between multiple neighbouring jurisdictions | Northwest Power Pool reserve sharing arrangements |

The complementarity between the Yukon's electrical system and those of its neighbors is analyzed in greater detail in Appendix A: Overview of Yukon's Neighboring Electricity Markets and Appendix B: Ancillary Markets.

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# 3 Benefits and Costs of Electricity Trading - Assessment Methodology

In order to create electricity-trading opportunities, the Yukon would first need to construct an electrical interconnection with an external market, as well as ensure sufficient generation capacity to facilitate the export and import of electricity.

To pass an economic test, the proceeds from exporting electricity less the cost of importing electricity must be greater than the cost of building the required new transmission and generation infrastructure (Figure 1-1). Since two different interconnection options are being evaluated, the economic test must be applied to each interconnection option separately.

## 3.1 Cost-Benefits Calculation

To determine the net present value of the benefits of each interconnection option, annual revenue and cost components are calculated per the following steps:

### Step A: Calculate Annual Net Revenues Earned from Electricity Trading

#### *Step A.1 – Assess Electricity Export Volume*

Begin by assessing the amount of future electricity production that is to be exported over the 30-year evaluation period from 2035 to 2065. The export volumes are adjusted to account for transmission losses, thus resulting in a net volume of exported electricity in MWh/yr.

The volume of exported electricity is verified against the transmission line capacity limit. The line capacity limitation for the transmission lines used in the exercise are a minimum of 64 MW for the Yukon – British Columbia scenario, and 70 MW minimum for the Yukon – Fairbanks scenario.

#### *Step A.2 – Calculate Electricity Export Revenue*

A price per MWh of exported electricity is selected (see Section 5.2), and after the annual volume of electricity is determined along with the price per MWh, the two figures are multiplied together to obtain a total annual benefit for the exported electricity.

#### *Step A.3 – Assess Arbitrage[16] Trade Volume*

To maximize revenues, it is assumed that trading will involve arbitrage of low price imports and high price exports. The arbitrage period could be seasonal (i.e.: summer to winter) if the Yukon's hydro storage reservoir capacity was extremely large, but daily arbitrage periods are more practical for moderate reservoir capacity.

[16] The term "arbitrage" is used to represent the action of buying electrical energy at a low price and reselling an equivalent product at a higher price at a different time.

To implement daily arbitrage, electricity would be imported during the low demand periods that occur in the late evening and early morning ("Off Peak"), and exported during the highest demand periods that occur in the late afternoon or early evening ("Peak" or "Super Peak", see Section 5 for further discussion).

Arbitrage opportunities are limited by both the amount of imported electricity that can be suitably used, and by the total domestic generation capacity during the daily high load periods. To simplify the arbitrage analysis, arbitrage volume is estimated as a percentage of the total annual export volumes and measured in MWh/yr.[17]

### *Step A.4 – Calculate Arbitrage Price Spread and Revenues*

The spread between the price per MWh of imported electricity and the price per MWh of exported electricity is determined using available market indicators (see Section 5.2).

The total annual arbitrage revenues are determined by multiplying the price spread by the annual arbitrage volume determined in Step A.3 above.

## Step B: Calculate New Infrastructure Costs and Annual Costs

### *Step B.1 – Assess Transmission Line Costs and Annual Costs*

Compile the costs for constructing new interconnection transmission lines and associated infrastructure for both of the transmission interconnection options. The capital cost expenditure needed to construct both interconnection lines is taken from the **Jurisdictional Transmission Line Technical Logistics Analysis** report. See Table 4-1 for a summary of the total transmission infrastructure costs. The following assumptions are utilized to calculate the transmission line's annual outlays and operating costs:

1) 9 year development period for the transmission line, initiating in 2026 and commissioning in 2035;
2) Annual operating costs are assumed to be 0.5% of capital expenditure;
3) A 60-year life of the transmission line is used[18].

### *Step B.2 – Assess Generation Facilities Costs and Annual Costs*

Compile the costs to construct new generation facilities and associated infrastructure to support electricity exports. The capital cost expenditures needed to construct a new generation facility is derived from the baseline assumption of $185/MWh for the levelized cost of energy ("LCOE").[19] The calculation of the capital

[17] Arbitrage volume accounts for transmission line losses and is checked to ensure it does not violate interconnection line capacity limits.

[18] The cost-benefit analysis time period is actually 30 years with a salvage value (positive benefit) included in year 30 to estimate the benefits from transmission line's operation for years 31 to 60.

[19] An LCOE of $185/MWh is used for consistency with the assumptions outlined in [Site Screening (Part 1 of 2) Report, appendix B, page 1 & 2], updated to 2015 dollars. See "Appendix C: Calculating the Cost of New Generation" for further details.

costs for a generic generation facility is detailed in Section 6. The following assumptions are utilized to calculate the new generation facilities' annual outlays and operating costs:

1) 9 year development period for the initial generation asset, with outlays beginning in 2026 and facility commissioning in 2035;
2) Annual operating costs are estimated using an annual 4% of capital expenditure metric;
3) A 65-year life of the generation facility is used[20].

## 3.2 Calculate Net Present Value for Each Interconnection Option

Once all the annual cash flows are derived and totaled for each of the aforementioned steps, they are valued using a net present value calculation. All costs and benefits are discounted using a 3.38%[21] real dollar discount rate per annum.[22]

For each interconnection option, if the net present value is:

I. Greater than zero – then the interconnection option is economic;
II. Less than zero – then the interconnection option is not economic.

See Section 7 for a summary net benefits assessment for the two interconnection options studied.

[20] The cost-benefit analysis time period is 30 years with a salvage value (positive benefit) included in year 30 to estimate the benefits from the generation facility's operation for years 31 to 65.

[21] Site Screening Inventory (Part 1 of 2), Appendix B, Page 2 of 2.

[22] The report does not include inflation assumptions; all valuations are in real dollars 2015. The real rate of return plus an inflation rate assumption is equal to the nominal rate of return. The actual borrowing rate would be a nominal rate, and therefore higher than the real rate of return assumption (but only because it is inflation adjusted).

# 4 Transmission Interconnection Overview

Midgard's separate **Jurisdictional Transmission Line Technical Logistics Analysis** report reviewed Yukon's neighbouring jurisdictions and identified a number of potential transmission interconnection opportunities. Given the considerable technical and economic hurdles that would be faced constructing and operating an interconnection longer than 1,000 km, the two interconnection options[23] that were assessed in detail are:

1) Iskut, British Columbia (Yukon-BC Interconnection Option)
    A. Same transmission route as 1), but with Next Generation Hydro sited near Watson Lake
2) Fairbanks, Alaska (Yukon-Fairbanks Interconnection Option)

Table 4-1 summarizes key parameters associated with the alternative transmission routes.

**Table 4-1: Interconnection Option Information Summary**

| Option | Description | Distance (km) | Estimated Capital Cost ($M) | Potential Net Yukon Exports (MW) | Line Losses (%) |
|---|---|---|---|---|---|
| 1 | 287 kV from Whitehorse (Takhini) to Iskut, BC | 763 | $1,710 | 64 - 127[24] | 5.7 |
| 1A | As option 1, with one or more Next Generation Hydro sites developed near Watson Lake | 763 | $1,710 | 94 - 139[25] | 5.2 |
| 2 | 230 kV from Aishihik to Delta Junction | 662 | $1,325 | 70 - 80[26] | 6.6 |

## 4.1 Yukon to British Columbia Interconnection Description

An interconnection with BC following Yukon Highway 1 and BC Highway 37 would pass near Watson Lake, YT. Several potential Next Generation Hydro sites are located just north of Watson Lake along the Robert Campbell Highway, namely Middle Canyon, False Canyon and Upper Canyon. Since developing any or all of these sites could materially impact the export capability of the interconnection with BC, a separate sub-option was modeled (see Table 4-1 options 1 and 1A) with this configuration to help quantify this impact. Note that although the sub-option exhibits the same capital costs; the sub-option displays improved line operation characteristics.

[23] Distances are based upon paralleling the shortest highway route between the Yukon system and the potential external terminus point. The proposed Whitehorse to Skagway interconnection was not considered in this report because it was evaluated in the March 2015 Morrison Hershfield report, *Viability Analysis of Southeast Alaska and Yukon Economic Development Corridor*.

[24] Net Exports are dependent upon output of Forrest Kerr Hydro; Forrest Kerr output utilizes some portion of the available transmission capacity.

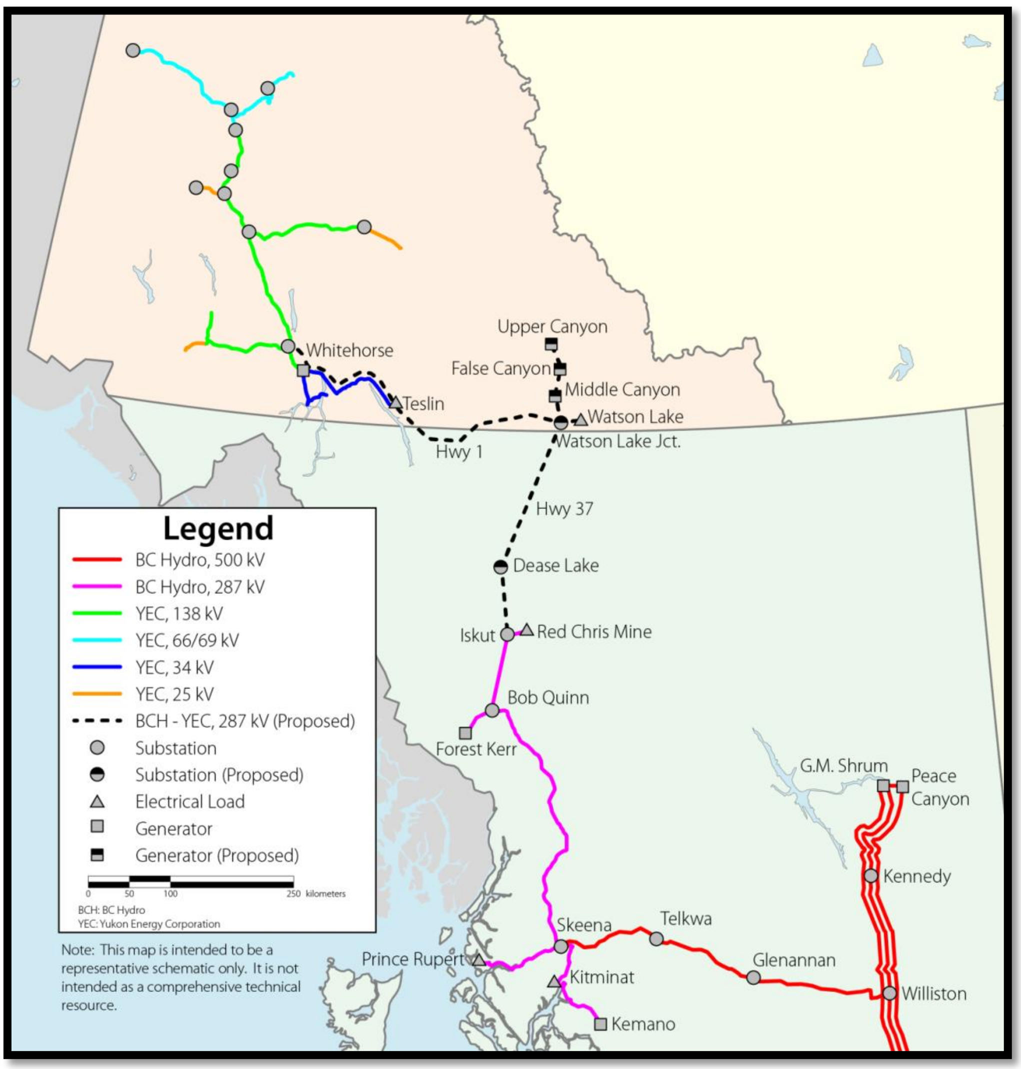
[25] Net Exports are dependent upon output of Forrest Kerr Hydro; Forrest Kerr output utilizes some portion of the available transmission capacity.

[26] Net Exports are dependent upon output of Delta Junction generation

Key features of the Whitehorse to Iskut interconnection path:

1) 745 km following Yukon Highway 1 (Alaska Highway) and BC Highway 37
2) 287 kV nominal voltage on recently completed line from Iskut to Skeena
3) 50 MW load at Red Chris Mine near Iskut
4) 200 MW Forrest Kerr hydro plant 40 km SW of Bob Quinn Lake
5) Intermediate load centers at Teslin, Watson Lake and Dease Lake
6) Sub-option considers Yukon generation at Middle, False and Upper Canyons
7) Substantial load and generation centers near Skeena substation (Prince Rupert, Terrace, Kitimat, Kemano)
8) Creates an interconnection with the 150,000 MW WECC system

**Figure 4-1: Yukon to BC Interconnection Option**



## 4.2 Yukon to Fairbanks Interconnection Description

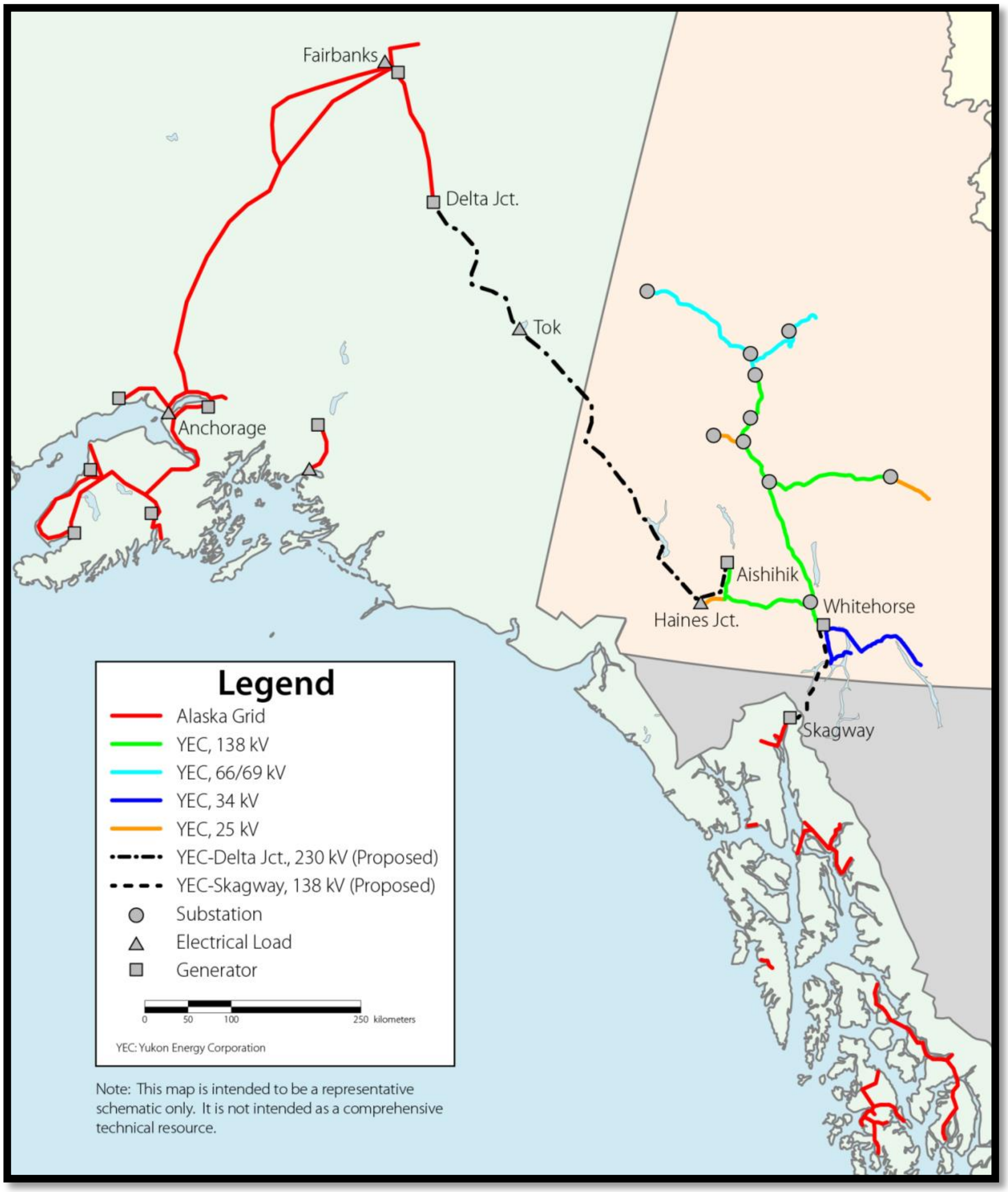
The Golden Valley Electric Association ("GVEA") provides electrical service to the city of Fairbanks and surrounding area. Total GVEA peak load is approximately 230 MW, and total local generation capacity is approximately 280 MW. The Fairbanks area is connected to the Anchorage area via a 115/138 kV system with a transfer capacity of approximately 75 MW.

The GVEA operates a 138 kV transmission line that extends southeast approximately 120 km along the Alaska Highway from Fairbanks to the Jarvis Creek substation near Delta Junction. The Jarvis Creek substation serves approximately 20 MW of local load and includes voltage control equipment. A 28 MW diesel generating plant is connected to the Jarvis Creek substation.

Key features of the Aishihik to Fairbanks interconnection path:

1) 780 km following the Alaska Highway
2) 660 km from Aishihik to Delta Junction (Jarvis Creek substation location)
3) Existing 120 km long 138 kV transmission line from Jarvis Creek substation to North Pole substation in Fairbanks
4) 230 MW Fairbanks region load and 280 MW generation (largely coal and diesel)
5) Existing 75 MW transfer capacity from Fairbanks to Anchorage area

**Figure 4-2: Yukon to Alaska Interconnection (To Fairbanks via Delta Junction)**



# 5 Volume & Price Determination

## 5.1 Volumes of Electricity

It is assumed that the Yukon energy gap, previously highlighted in the **Yukon Electrical Energy and Capacity Need Forecast (2035-2065)** report, will be filled by new internal resources dedicated to serving Yukon needs. In the event the new internal resources are constructed large enough, then potential electricity exports could offset some portion of the cost of developing an interconnection to a neighboring jurisdiction. For the purpose of this analysis, a new 30 MW[27] export-dedicated generation facility (with a 50% capacity factor) is assumed for both the Yukon-BC and the Yukon-Fairbanks interconnection options.

Financing new generation facilities dedicated to exports will require establishing a long-term Power Purchase Agreement with a credit-worthy counterparty in an external jurisdiction. The proxy PPA prices identified in Section 5.2 are based upon plausible marginal power purchase costs for buyers in the applicable jurisdictions. There is no guarantee that buyers will be willing to enter into long-term PPAs at these prices under terms that would be acceptable to Yukon.

### *5.1.1 Potential Export Volumes for Interconnection Options*

Table 5-1 shows the size specifications and trading volumes for the new generation assumed for this analysis. Note that the import and export quantities shown are net of transmission losses.

**Table 5-1: Parameters for New Generation to Enable Electricity Trading**

| Option | Size of New Generation (MW) | Capacity Factor (%) | Generation Available for Export (MWh) | Arbitrage Volume (MWh) |
|---|---|---|---|---|
| YK-BC | 30 | 50 | 123,914 | 58,214 |
| YK-Fairbanks | 30 | 50 | 122,777 | 57,077 |

## 5.2 Price of Electricity

Prices for electricity exports and imports must be established to assess the economic viability of developing an interconnection between the Yukon and a neighboring jurisdiction. It is assumed that no counterparty in either BC or Alaska will enter into a PPA with an electricity purchase price higher than an equivalent local generator because the counterparty would then be economically incented to build local generation.

Proxy PPA prices were developed for both interconnection options using publicly available information sources. The proxy used to evaluate the BC Interconnection Option is based upon BC Hydro's Standing Offer

[27] 30 MW is the approximate average size of the current three large hydroelectric facilities, maintaining a sensible balance for reliability planning.

Program pricing. The pricing proxy for the Fairbanks interconnection option is based on the avoided cost of power used by local independent power producers ("IPP").

Details of the prices used in evaluating both interconnection options are listed in Table 5-2, and further discussed in Sections 5.2.1 and 5.2.2. Additional discussion of the two jurisdictions and their characteristics is presented in Appendix A: Overview of Yukon's Neighboring Electricity Markets and Appendix B: Ancillary Markets.

**Table 5-2: Source of Information for Import/Export Market Price**

| Scenario | Source of Information | Import/Export Price ($/MWh) | Diurnal Spread ($/MWh) |
|---|---|---|---|
| YK-BC | Standard Offer Program – revised March 2015 | 106.8 | 28.3 |
| YK-Fairbanks | Avoided Cost of Power – Jan 2015 regulatory filing | 101.9 | 27.0 |

### *5.2.1 Price of Electricity in British Columbia*

BC Hydro's Standing Offer Program ("SOP")[28] is an ongoing power purchase arrangement available to qualified independent power producer projects in British Columbia. Qualifying projects may obtain a PPA with BC Hydro allowing the project proponent to sell electricity to BC Hydro for a period of up to 40 years. The price for energy delivered at Skeena substation for new projects qualifying under the SOP is $106.84/MWh.

For the purpose of evaluating the arbitrage opportunity (described in Section 3.1 Steps A.3 & A.4), the price spread is developed from the SOP Time of Delivery Factor ("TDF") matrix, as transcribed below in Table 5-3.

**Table 5-3: SOP Contract Price Matrix – Seasonal & Diurnal Prices**

| Month | Time of Delivery Factor | | |
|---|---|---|---|
| | Super Peak[29] | Peak[30] | Off-Peak[31] |
| Jan | 141% | 122% | 105% |
| Feb | 124% | 113% | 101% |
| Mar | 124% | 112% | 99% |

[28] https://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/standing_offer_program/who_can_apply.html

[29] "Super Peak" - hours commencing at 16:00 PPT and ending at 20:00 PPT Mon through Sat inclusive, but excluding BC statutory holidays

[30] "Peak" - hours commencing at 06:00 PPT and ending at 16:00 PPT, and commencing at 20:00 PPT and ending at 22:00 PPT, Mon through Sat inclusive, but excluding BC statutory holidays

[31] "Off Peak" refers to all hours not classified as "Super Peak" or "Peak"

| | | | |
|---|---|---|---|
| Apr | 104% | 95% | 85% |
| May | 90% | 82% | 70% |
| Jun | 87% | 81% | 69% |
| Jul | 105% | 96% | 79% |
| Aug | 110% | 101% | 86% |
| Sep | 116% | 107% | 91% |
| Oct | 127% | 112% | 93% |
| Nov | 129% | 112% | 99% |
| Dec | 142% | 120% | 104% |

Based upon an average annual price of $106.84/MWh, the maximum super-peak to off-peak daily exchange spread is $28.31/MWh. Given the 1:3 ratio between super peak hours (approximately 24 hours per week) and off-peak hours (approximately 72 hours per week) [32], the hourly quantity of exports would need to be three (3) times larger than the hourly quantity imports in order to exploit the arbitrage opportunity.

### *5.2.2 Price of Electrical Energy in Fairbanks / Alaska Railbelt*

The assumed price for a proxy PPA in Fairbanks is taken to be $101.8[33]/MWh, which is the avoided cost of power for Golden Valley Electric Association[34].

Fairbanks' market is a net importer of electricity, often being supplied from Chugach Electric and the Anchorage area. Fairbank's market size is approximately 2.5x the size of Yukon's market. Although the total volume of power that could be sunk into Alaska's market is limited, Alaska may be interested in a trading relationship. It is likely that the competition for the Yukon electricity would be from coal or other thermal-fired generation resources. The Alaska Railbelt is a regulated market and therefore does not have transparent market pricing mechanisms.

For the purpose of valuing the daily arbitrage opportunity, the spread between low load hour and high load hour prices is assumed to be similar to the British Columbia price spread. Using an average annual price of $101.875/MWh, the maximum super-peak to off-peak spread is $27.00/MWh.

[32] Standing Offer Program – Electricity Purchase Agreement, BC Hydro, Appendix 4, Page 71

[33] $81.5 USD/MWh, converted to a Canadian dollar equivalent using a $1CAD = $0.80USD exchange rate

[34] From GVEA Tariff application to Regulatory Commission of Alaska, Schedule No. QF-2 dated March 01, 2015

## *Are Very Large Exports of Electricity Profitable?*

| Profitability Criterion[35] | | |
|---|---|---|
| *Average Price of Surplus Electricity* | **<** | *Price Received for Exported Electricity* |

In this report, the generic cost of generation is linked to the levelized cost of electricity ("LCOE") hurdle rate of $185/MWh, which is also the average price of surplus electricity. For the purpose of this exercise, the LCOE cost assumption will be relaxed to a ½ of LCOE or $92.50/MWh.

| ***Yukon to British Columbia*** | Cost of transmission (refer Table 4-1) | : $ 1,710 Million |
|---|---|---|
| **92.5 $/MWh [LCOE]<br>Vs<br>106.8 $/MWh Export Price** | Electricity volume required | : 119,246,862 MWh |
| | Electricity volume per year (for 60 years) | : 1,987,448 MWh/yr. |
| | Electricity per hour (for 60 years) | : 227 MWh |

***Result:*** Exports of 227 MW for 60 years (approximately 450 MW of new generation) are required to defray the cost of a transmission interconnection to British Columbia

| ***Yukon to Fairbanks*** | Cost of transmission (refer Table 4-1) | : $ 1,325 Million |
|---|---|---|
| **92.5 $/MWh [LCOE]<br>Vs<br>101.9 $/MWh Export Price** | Electricity volume required | : 141,333,333 MWh |
| | Electricity volume per year (for 60 years) | : 2,355,556 MWh/yr. |
| | Electricity per hour (for 60 years) | : 269 MWh |

***Result:*** Exports of 269 MW for 60 years (approximately 540 MW of new generation) are required to defray the cost of a transmission interconnection to Fairbanks, Alaska.

In both cases, the quantum of export volume exceeds the design capacity of the transmission line by 2x or more, and would require additional transmission capacity (which would increase transmission costs, which would require even more exports, which would further increase the transmission costs, and so forth).

**Midgard cannot see a plausible scenario, given the assumptions, where Yukon profitably exports electricity, especially if the LCOE proves to be higher than the optimistic assumption of $92.50/MWh.**

[35] For the purpose of simplicity, transmission losses, real interest rate discount factors and other adjustments are ignored.

## *Are Very Large Imports of Electricity Profitable?*

| Profitability Criterion[36] | | |
|---|---|---|
| *Average price of new domestic electricity* | **>** | *Price paid for imported electricity* |

In this report, the generic cost of generation is linked to the levelized cost of electricity ("LCOE") hurdle rate of $185/MWh. In turn, this implies that the average price of new electricity is approximately $185/MWh.

| ***Yukon to British Columbia*** | | |
|---|---|---|
| **185 $/MWh [LCOE] Vs 106.8 $/MWh Import Price** | Cost of transmission (refer Table 5-1) | : $ 1,710 Million |
| | Electricity volume required | : 21,878,199 MWh |
| | Electricity volume per year (for 60 years) | : 364,637 MWh/yr. |
| | Electricity per hour (for 60 years) | : 42 MWh |
| | Electricity per winter peak hour | : 150 MWh |

***Result:*** Import volumes of 42 MW for every hour of the year or 150 MW per winter peaking hour for 60 years are required to defray the cost of a transmission interconnection to British Columbia.

| ***Yukon to Fairbanks*** | | |
|---|---|---|
| **185 $/MWh [LCOE] Vs 101.9 $/MWh Import Price** | Cost of transmission (refer Table 5-1) | : $ 1,325 Million |
| | Electricity volume required | : 15,939,850 MWh |
| | Electricity volume per year (for 60 years) | : 265,664 MWh |
| | Electricity per hour (for 60 years) | : 30 MWh |
| | Electricity per winter peak hour | : 109 MWh |

***Result:*** Import volumes of 30 MW for every hour of the year or 109 MW per winter peaking hour for 60 years are required to order to defray the cost of a transmission interconnection to Alaska

Although the import volumes do not immediately seem as large as the export volumes described in the previous box, it is important to note that Yukon's electric energy gap in 2035 is forecast to be 102,700 MWh, and in 2065 to be 265,200 MWh. Since the required import volumes are much larger than the forecast energy gaps, this means that the Yukon would be oversupplied with electricity from 2035 to 2065. Additionally, the peak delivery quantum also exceeds the YK-BC and YK-AK transmission line capacities in certain situations, thus further undermining the already unattractive economics of the import scenario.

**Midgard cannot see a plausible scenario, given the assumptions, where Yukon profitably imports electricity. Moreover, the import scenario requires that the Yukon be willing to accept that it will be dependent on an external jurisdiction for critical winter energy supply and reliability questions.**

[36] For the purpose of simplicity, transmission losses, real interest rate discount factors and other adjustments are ignored.

# 6 Calculating the Cost of New Generation

In addition to new transmission lines, electricity trading with external markets requires development of new generation infrastructure to produce surplus electricity for sale.

This report utilizes a generic construction cost estimate of $10 million per MW for new hydroelectric generation assets. The detailed cost calculation, presented in "Appendix C: Calculating the Cost of New Generation"), uses the following inputs:

1) **Levelized Cost of Energy** – LCOE of approximately $185/MWh based upon the hurdle rate used in the Site Screening Inventory (Part 1 of 2) report[37].
2) **Size of Asset** – A new 30 MW generation project is assumed[38] for both the Yukon-BC and Yukon-Fairbanks options.
3) **Capacity Factor of Asset** – A 50% capacity factor is assumed for the generic generation (equivalent to the average capacity factor of Yukon's three largest existing hydroelectric facilities).
4) **Life of Asset** – A 65 year asset life is assumed, as per the Site Screening Inventory (Part 1 of 2) report.[39] [40]

**Table 6-1: New Generation Resources by Interconnection Option**

| Option | Size of New Generation Facility (MW) | Capacity Factor (%) | Generation Available for Export (MWh) | Transmission Capacity Limitation (MW) | Undiscounted Cost of New Generation ($M) |
|---|---|---|---|---|---|
| YK-BC | 30 | 50% | 131,400 | 64 - 127 | 300 |
| YK-Fairbanks | 30 | 50% | 131,400 | 70 - 80 | 300 |

For both BC and Fairbanks, the interconnection capacity and the size of the electricity market is large enough to enable the import and export of more than 60 MW.

[37] Site Screening Inventory (Part 1 of 2), Section 5.1, Page 29.

[38] The asset size is somewhat discretionary within the bounds of the prospective Yukon sites evaluated in Site Screening Inventory (Part 1 of 2) and limited by the amount of export transmission capacity available under the different transmission interconnection options.

[39] Site Screening Inventory (Part 1 of 2), Appendix B, page 2 of 2,

[40] The Salvage Value of the generation portfolio in year 30 is based upon a straight-line depreciation, the salvage value of the generation portfolio is calculated as being equivalent to the remaining useful life of the assets

# 7 Assessing the Benefits of the Two Scenarios & the Economic Rationale for a Transmission Interconnection

As discussed in Section 1, assessing the net economic benefits to the Yukon of developing external transmission market access involves subtracting the costs incurred to facilitate energy trading from the revenues earned by trading, as shown in Figure 1-1.

The net benefit evaluation results for the two interconnection options studied in this report are shown in Table 7-1 below.

**Table 7-1: Net Benefit Evaluation of Two Interconnection Scenarios**

| | (a) | (b1) | (b2) | (a) + (b1) + (b2) |
|---|---|---|---|---|
| **Interconnection Option** | **Export Revenue (Net of Import Costs) ($M)** | **New Transmission Costs ($M)** | **New Generation Costs ($M)** | **Net Benefits ($M)** |
| YK-BC | 214 | -1310 | -379 | -1470 |
| YK-Fairbanks | 202 | -1015 | -379 | -1190 |

Development of market access via any of the studied interconnection options is economically rational only if the net benefit is positive (i.e. revenues are greater than the total costs of new transmission and new generation).

## 7.1 Conclusion

**Both scenarios demonstrate significantly negative net economic benefits and are therefore uneconomic strategies.**

It should be further noted that under both the YK-BC and the YK-Fairbanks interconnection options, the Export Revenue (Net of Import Costs) figures are lower than the Net Generation Costs ($M) (i.e. cost of building the new generation needed to support the exports). In other words, even if the transmission interconnection line were free, both the YK-BC and YK-Fairbanks interconnections would still be economically unattractive.

The report also asked – "How large do exports have to be in order for the net benefits to equal the costs of building transmission infrastructure"? The answer is that it will require an average of:

- 227 MW for 60 years in order to defray the cost of a transmission interconnection to British Columbia; and 269 MW for 60 years in order to defray the cost of a transmission interconnection to Fairbanks, Alaska.

In both cases, the quantum of export volume exceeds the design capacity of the transmission line by 2x or more and this would require additional transmission capacity (which would increase transmission costs, which would require even more exports, which would further increase the transmission costs, and so forth). Midgard cannot see a plausible scenario, given the assumptions employed in the analysis, where exporting electricity from the Yukon makes economic sense.

Importing electricity into the Yukon is similarly unattractive with required import volumes exceeding the forecast need for electricity in the Yukon beyond 2065 (i.e. 150MW and 109MW per winter peaking hour for 60 years for the BC interconnection and Alaska interconnection respectively). Midgard cannot see a plausible scenario, given the assumptions, where Yukon profitably imports electricity. Moreover, the import scenario requires that the Yukon be willing to accept that it will be dependent on an external jurisdiction for critical winter energy supply which raises reliability issues.

# Appendix A: Overview of Yukon's Neighboring Electricity Markets

## A.1 BC Market

British Columbia's electricity market is dominated by BC Hydro ("BCH") - Canada's third largest electric utility - which controls over 90% of the customers, transmission, and generation in the Province[41].

BC Hydro was created over 50 years ago to generate and deliver clean, reliable and competitively priced electricity to homes and businesses throughout British Columbia. The electricity generated by BCH dams and delivered by their transmission and distribution infrastructure has powered B.C.'s economy and quality of life for generations. With prudent reinvestment and careful planning, BC Hydro has positioned itself to safely deliver clean, reliable power for the long-term benefit of the growing province. Some of the key statistics[42] of BCH's assets are as follows

| | |
|---|---|
| **Total Generating Units** | 89 |
| **Hydroelectric facilities** | 31 hydroelectric facilities with 40 dam sites |
| **Number of thermal generating plants** | 3 |
| **Installed Generating Capacity** | 12,000 MW |
| **Annual average energy generation capability by BCH hydroelectric facilities** | 48,000,000 MWh per year |
| **Transmission Infrastructure** | 18,000 km of transmission lines and 133,000 transmission support structure |
| **Distribution Infrastructure** | 910,000 distribution poles and 300 substations |

[41] Although there are over 100 operating and contracted independent power producer projects in British Columbia, the buyer and distributor of the electricity is BC Hydro.

[42] BC Hydro 2014 Annual Report, Page 7

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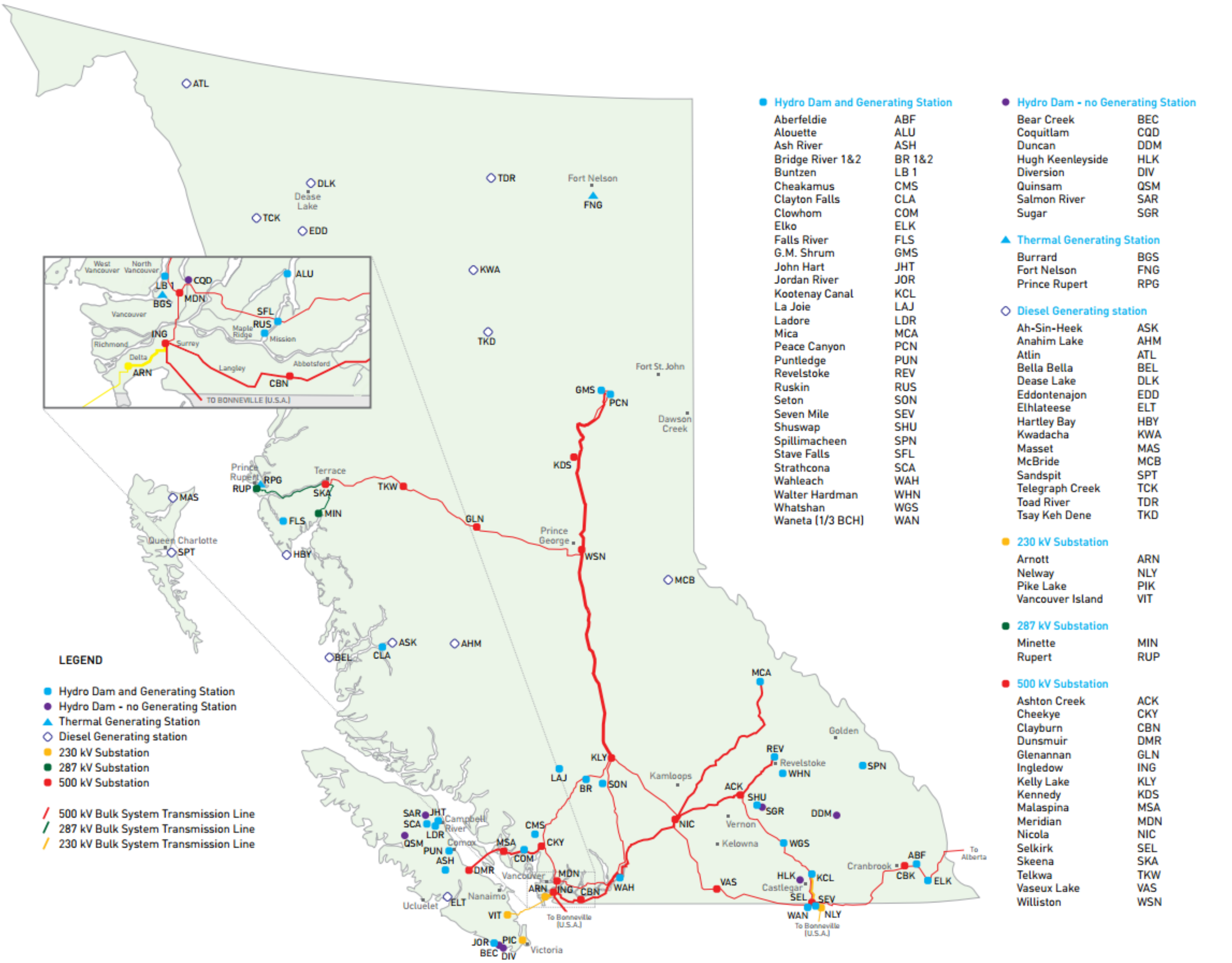
**Figure A-1: Map of BC Hydro Facilities and Infrastructure[43]**




BC Hydro's trading subsidiary is PowerEx. PowerEx works closely with BC Hydro to maximizing the potential value of BCH's hydro resources. PowerEx performs trade activities to help ensure low domestic electricity rates to BC Hydro customers.

[43] BC Hydro 2014 Annual Report, Page 6: Accessed on April 28, 2015.

PowerEx's marketplace extends across North America. PowerEx has licenses and permits from both Canadian and U.S. regulators to serve wholesale energy customers in Canada, across the U.S. and as far south as Mexico.

PowerEx dominates electricity trade within British Columbia, in part due to its substantial ownership position of rights to transmit electricity to and from British Columbia at times where there is value to trading electricity with neighboring jurisdictions.

Should Yukon interconnect with the BC Hydro grid, any trade between the Yukon utilities and BC likely will be in the form of a bilateral agreement with PowerEx, or a bilateral agreement with BC Hydro.

### *A.1.1 BC Market for Ancillary Services*

BC does not have a transparent market for ancillary services. Given BC Hydro's dominant position in the BC marketplace, and the very large hydroelectricity assets and reservoirs that BC Hydro controls, BC is not in short supply, of or in need of, any particular ancillary service (with the exception of certain regional issues, which require local solutions).

Any trading with BC Hydro or PowerEx, typically takes the form of the delivery of electricity at a point of delivery. The 'firmness' of the future deliveries, the time of day of the deliveries, and the time of year of the deliveries will all impact the price that BC Hydro (or PowerEx) is willing to pay for the electricity.

### *A.1.2 Current Supply Demand Situation*

BC Hydro's most recently Integrated Resource Plan dates from November 2013.[44] The plan shows that BC Hydro resources will exceed BC Hydro's customer demand until the end of this decade (~2020). Moreover, the Provincial Government has approved BC Hydro's proposal to construct Site C, an 1100 MW hydroelectric dam located in east central BC downstream of BC hydro's largest reservoir. Figure A-2 illustrates historic and future projected BC electrical energy supply and demand balance.

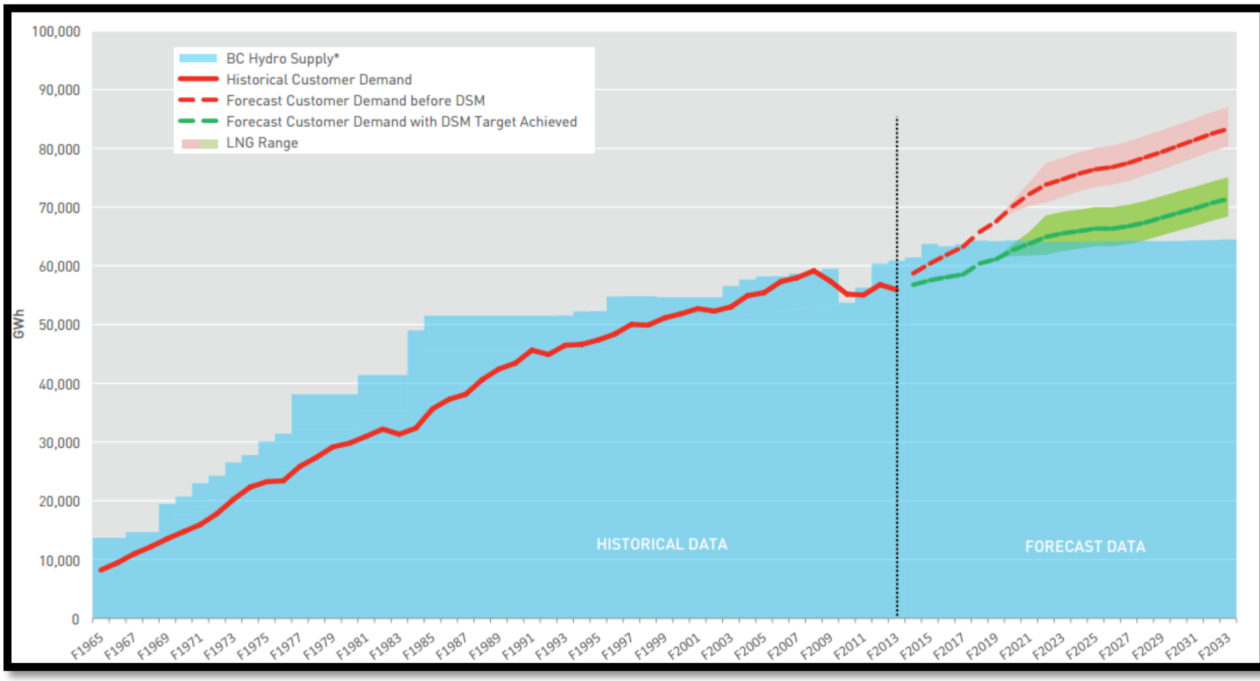
The unit energy cost ("UEC") (which represents the levelized cost of energy per MWh for the Site C dam over 70 years with a project capital cost of $ 7.9 Billion[45], and using a real discount rate of 5%, is 83 $/MWh[46] in 2013$.

[44] https://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/november-2013-irp.html#summary; accessed 18 March 2015

[45] The BC government revised the estimated cost to $ 8.8 Billion with a project life of 100 years in 2014.

[46] November 2013 Resource Options Report, BC Hydro, Chapter 5, Table 5-10, Page 5-61

**Figure A-2: BC Hydro Historical & Forecast Supply and Demand**[47]




### *A.1.3 Value of Electricity in BC*

As a proxy for the value of electricity in BC, Midgard makes reference to BC Hydro's Standing Offer Program.

BC Hydro's Standing Offer Program encourages the development of new small and clean or renewable energy projects throughout British Columbia. The SOP was developed to streamline the process for IPPs to sell electricity to BC Hydro. The SOP is also intended to decrease transaction costs for Developers while remaining cost-effective for ratepayers, and embodies the principles and policies set out in the BC Energy Plan and the Clean Energy Act.

Under the SOP, BC Hydro offers to pay projects 106.84 $/MWh[48]. Under the SOP contract, the price increases during the high demand winter months, but decreases during the low demand spring / summer / fall months. Additionally, the value of electricity is higher during the high load daytime hours than is the case for the low load nighttime hours. Following are two tables from BC Hydro's SOP, which shows the base price by region and how the prices are lowered or raised based on the time of delivery.

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[47] BC Hydro Integrated Resource Plan, November 2013 edition, Page 6: Accessed on April 28, 2015.

[48] Current Base Price (2015) for North Coast Region = 96.17 * $\frac{CPI\ in\ Feb\ 2015}{CPI\ in\ Feb\ 2010}$ = 96.17 * $\frac{146.1}{131.5}$ = $106.84 per MWh. The CPI data was taken from CANSIM Table 326-0020, British Columbia, CPI for Energy. Accessed on March 27, 2015.

**Table 7-2: Base Prices of Electricity in BC's Regions[49]**

| Region of POI | Base Price (2010$ / MWh) | Base Price (2015$ / MWh)[50] |
|---|---|---|
| Vancouver Island | $102.25 | $113.60 |
| Lower Mainland | $103.69 | $115.20 |
| Kelly/Nicola | $97.02 | $107.79 |
| Central Interior | $99.26 | $110.28 |
| Peace Region | $94.86 | $105.39 |
| North Coast | $96.17 | $106.84 |
| South Interior | $98.98 | $109.97 |
| East Kootenay | $102.18 | $113.52 |

*Note[51]:*

1) One hundred percent of the base price will be escalated at CPI annually up to the year in which a Project EPA is signed. Escalation will commence in 2011 and will be effective as of January 1st in each year.
2) The escalated base price is further adjusted based upon the time of day and month when the energy is delivered to establish the payment price for each MWh of energy delivered to the POI.
3) Interconnection: All projects must be interconnected to the BC transmission system or distribution system through a direct interconnection or an indirect interconnection. The developer must bear all costs of transmission and energy losses to that point of delivery.

**Table 7-3: Pricing matrix based on time of delivery**

| Time of Delivery Factor | | | |
|---|---|---|---|
| **Month** | **Super Peak** | **Peak** | **Off-Peak** |
| Jan | 141% | 122% | 105% |
| Feb | 124% | 113% | 101% |
| Mar | 124% | 112% | 99% |
| Apr | 104% | 95% | 85% |
| May | 90% | 82% | 70% |
| Jun | 87% | 81% | 69% |
| Jul | 105% | 96% | 79% |
| Aug | 110% | 101% | 86% |
| Sep | 116% | 107% | 91% |
| Oct | 127% | 112% | 93% |
| Nov | 129% | 112% | 99% |
| Dec | 142% | 120% | 104% |

[49] BC Hydro – Standing Offer Program Rules, Version 2.5, Nov 2014: Section 3, Page 8: Accessed on April 28, 2015.

[50] See Footnote 29 for calculation methodology.

[51] Standing Offer Program, Page 1, 10 and Appendix 4

4) "**Off-Peak Hours**" means all hours other than Super-Peak Hours and Peak Hours.
5) "**Peak Hours**" means the hours commencing at 06:00 PPT and ending at 16:00 PPT, and commencing at 20:00 PPT and ending at 22:00 PPT, Monday through Saturday inclusive, but excluding British Columbia statutory holidays.
6) "**Super-Peak Hours**" means the hours commencing at 16:00 PPT and ending at 20:00 PPT Monday through Saturday inclusive, but excluding British Columbia statutory holidays.

Based on the time of delivery factors and a base price of 106.85 $/MWh, the following table represents the price of electricity as per the time of delivery.

**Table 7-4: Base Prices based on time of delivery factor to North Coast in $2015**

| Time of Delivery Factor | | | |
|---|---|---|---|
| **Month** | **Super Peak** | **Peak** | **Off-Peak** |
| ***Jan*** | $ 150.65 | $ 130.35 | $ 112.19 |
| ***Feb*** | $ 132.49 | $ 120.74 | $ 107.92 |
| ***Mar*** | $ 132.49 | $ 119.67 | $ 105.78 |
| ***Apr*** | $ 111.12 | $ 101.51 | $ 90.82 |
| ***May*** | $ 96.16 | $ 87.61 | $ 74.79 |
| ***Jun*** | $ 92.96 | $ 86.55 | $ 73.72 |
| ***Jul*** | $ 112.19 | $ 102.57 | $ 84.41 |
| ***Aug*** | $ 117.53 | $ 107.92 | $ 91.89 |
| ***Sep*** | $ 123.94 | $ 114.33 | $ 97.23 |
| ***Oct*** | $ 135.70 | $ 119.67 | $ 99.37 |
| ***Nov*** | $ 137.83 | $ 119.67 | $ 105.78 |
| ***Dec*** | $ 151.72 | $ 128.22 | $ 111.12 |

## A.2 Alaska Market

Alaska does not have any transmission interties to the rest of the North American continent. Alaska's Railbelt region, the darker shaded area in Figure A-3, measures about 500 miles (800 km) north to south, and is broadly the area served by the railroad. Over 70% of Alaskans live in the Railbelt region where the 170-mile long, 345 kV Alaska intertie transmission line, operating at 138 kV, connects six of the largest utilities in Alaska[52]. Their service areas are marked as shown in Figure A-3.

[52] http://www.akenergyauthority.org/EnergyInfrastructure

**Figure A-3: Alaska Railbelt region and Utilities[53]**

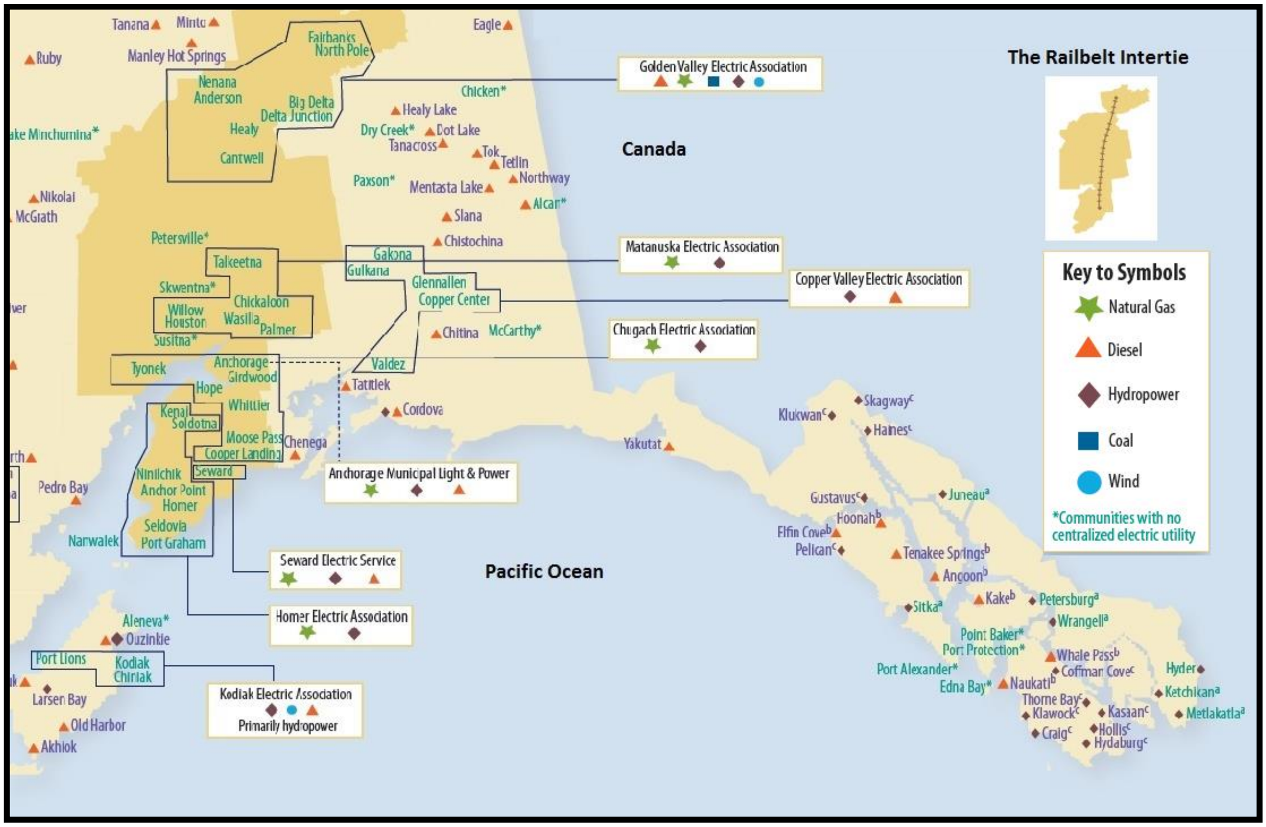


Table 7-5 shows the number of customers being served by these utilities and the amount of energy they generated, in the reference year 2013.

**Table 7-5: Customers, Sales and Average Price of Important Electric Utilities in Alaska[54]**

| Utility | No. of Customers | Sales (MWh) | Total Revenue (000's $) | Average Price (2013 U$/MWh)[55] |
|---|---|---|---|---|
| Chugach Electric Association Inc. | 78,989 | 1,162,364 | 155,208 | 133.5 |
| Matanuska Electric Association Inc. | 58,661 | 723,955 | 102,462 | 141.5 |
| Golden Valley Electric Association | 44,997 | 1,253,161 | 236,671 | 188.8 |
| Homer Electric Association | 30,149 | 481,573 | 80,444 | 167.0 |
| Anchorage Municipal Light & Power | 30,786 | 1,047,470 | 112,598 | 107.5 |
| Seward Electric Service | 2,706 | 57,950 | 10,908 | 188.2 |
| Alaska Electric Light and Power | 16,266 | 377,005 | 42,067 | 111.6 |
| Alaska Power and Telephone Company | 7,042 | 65,203 | 18,491 | 283.6 |

[53] Energizing Alaska: Electricity around the state by Alejandra Villalobos Melendez & Ginny Fay, Research Summary No. 73, July 2012.

[54] *Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files*, 2013 data released by EIA on Feb 19, 2015.

[55] The total revenue, sales and the number of customers served for the residential, commercial and Industrial sector. The average price was calculated based on the ratio of the total revenue in USD and the sales in MWh.

**Table 7-6: Alaska Net Electricity Generation by Source**[56]

| Alaska Net Electricity Generation by Source – January 2015 | |
|---|---|
| **Fuel** | **Electricity (MWh)** |
| Petroleum Fired | 80,000 |
| Natural Gas – Fired | 289,000 |
| Coal - Fired | 44,000 |
| Hydroelectric | 159,000 |
| Other Renewables | 19,000 |

Table 7-6 shows that 70% of the electricity is generated by thermal generation facilities and about 27% is being generated by hydroelectric facilities.

The following section gives a brief overview of the Fairbanks sub-region.

### *A.2.1 Fairbanks Market*

Golden Valley Electric Association serves Fairbanks and other Interior communities as far south as Cantwell. GVEA is the only Railbelt utility that generates a large share of its power from fuel oil, naphtha, and coal; it also has some wind power and a small solar project. It buys some electricity from Chugach Electric Association Inc. ("CEA") and all the energy generated by Aurora Energy LLC Chena, an independent power producer in the Fairbanks region.

GVEA operates and maintains approximately 5,100 km of transmission and distribution lines and 34 substations. The system is interconnected with Fort Wainwright, Eielson AFB, Fort Greely, the University of Alaska-Fairbanks and all electric utilities in the Alaska Railbelt, which extends from Homer, Alaska to Fairbanks.[57]

The 97-mile, 230-kilovolt Northern Intertie, energized in October 2003, helps GVEA maintain reliability. GVEA is the northern control point for the Fairbanks/Anchorage Intertie, which serves most Railbelt communities. Both interties allow GVEA to augment its 296 MW generation capacity with an additional 70 MW from the Anchorage area.[57] Table 7-7 lists the generation assets currently operating within GVEA's territory.

The world's most powerful battery energy storage system, in terms of megawatt output, belongs to GVEA. The BESS, Battery Energy Storage System, came online in November 2003. It can provide 27 megawatts of electricity for 15 minutes or up to 40 MW for less time.[57]

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[56] EIA Website Accessed on April 28, 2015: *http://www.eia.gov/state/?sid=AK#tabs-4*

[57] 2013 Year End Data – GVEA (*http://www.gvea.com/images/ataglance14.pdf*)

Figure A-4 shows the location of GVEA's generation assets numbered from 1-10 and the breakdown of the fuel source for the generation.[58] Table 7-7 lists the characteristics of GVEA's generation assets corresponding to the number shown in Figure A-4. Figure A-4 indicates that hydrocarbons are the major source of fuel amounting to 91%.

**Figure A-4: Power Generation location and Composition[58]**

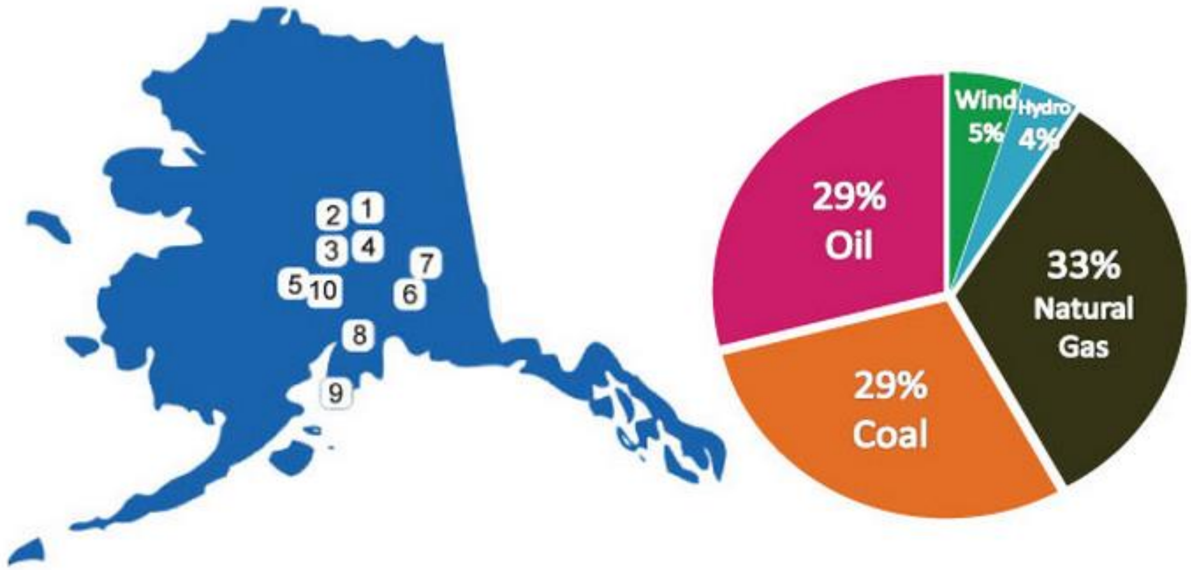


**Table 7-7: Power Generation in the Fairbanks Community[59]**

| # | Utility/IPP Name | Plant Name | Total Capacity (MW) | Type | Comments |
|---|---|---|---|---|---|
| 1 | Golden Valley Elec Assn Inc. | Zehnder Power Plant (Fairbanks) | 41 | Diesel | |
| 2 | Aurora Energy LLC Chena | Aurora Energy | 25 | Coal | IPP – sells all its power to GVEA |
| 3,4 | Golden Valley Elec Assn Inc. | North Pole | 180 | Diesel & Naptha | |
| 5 | Golden Valley Elec Assn Inc. | Healy | 28 | Coal | |
| 6 | Alaska Environmental LLC | Delta Wind | 1 | Wind | IPP – sells all its power to GVEA |
| 7 | Golden Valley Elec Assn Inc. | Delta Power | 27 | Diesel | |
| 8 | Purchases from Anchorage | Anchorage-Fairbanks intertie | 70 | Natural Gas | Capacity of Anchorage to Fairbanks Intertie |
| 9 | Homer Electric Assn Inc. | Bradley Lake | 20 | Hydro | Shared between GVEA and other major utilities in the Railbelt region. GVEA owns |

[58] Accessed on April 28, 2015: http://www.gvea.com/energy/power/powersupply

[59] Accessed on April 28, 2015: http://www.gvea.com/energy/power/powersupply

| | | | | | |
|---|---|---|---|---|---|
| | | | | | 17% share. |
| 10 | Golden Valley Elec Assn Inc. | Eva Creek | 25 | Wind | 33% annual capacity factor |
| **Total** | | | **417 MW** | | |

#### A.2.1.1 Value of Electricity in Fairbanks

As of January 31, 2015, the regulatory filing from GVEA indicate that the weighted average cost of power (energy only, no distribution or other charges) was 71.10 U$/MWh.[60]

For entities willing to sell power to GVEA, there are two options as per the "*Standard Power Purchase Agreement For Member Owned Small Scale Renewable Resources*" contract.[61] The entities may either fix the price for the term of the agreement, or they may receive a price equivalent to GVEA's avoided cost (as approved by the commission).

The two entities currently selling power to GVEA, Aurora Energy and Alaska Environmental Power LLC, both have chosen to receive a price tied to the avoided cost of energy. As per Schedule No. QF-2 of the RCA application, dated March 01, 2015, the avoided cost of energy for qualified facilities (greater than 100 kW) is 81.50 U$/MWh.[62] The equivalent in Canadian dollars, using a $0.80 exchange rate, is $101.875/MWh.

[60] RCA no. 13, Sheet no. 39, 332nd revision, Feb 01, 2015

[61] Standard Power Purchase Agreement For Member Owned Small Scale Renewable Resources, Page 8 of 16

[62] Tariff advice no. TA-228-13, dated April 26 2012

## Appendix B: Ancillary Markets

Besides the electric energy trading opportunities, there may also be an opportunity to provide ancillary services such as “resource firming” to jurisdictions with a high ratio of variable production resources such as wind and solar.  For example, establishing a robust market for firming services has become an important target for WECC member utilities, as the penetration of variable energy resources continues to increase dramatically across the western interconnection.

In the Yukon case, however, the distances between the Yukon grid and the neighboring grids diminishes the value of Yukon produced ancillary services.  Certain ancillary services [see Table 7-8 and Table 7-9 below] must be produced locally, while others, such as voltage support, simply cannot be transmitted over long distances.

Neither of the potential interconnected markets presents Yukon with an obvious or lucrative ancillary services export market.

- British Columbia is blessed with ample hydroelectric resources as well as hydroelectric reservoirs, which makes BC one of the foremost suppliers (and not a buyer) of tradable ancillary services in Western North America and the WECC.
- Alaska – as an islanded market – has provided its own ancillary services in the past, and is expected to do so in the future. Barring a substantive restructuring of the Alaskan Railbelt electricity market, there is no obvious ancillary market, which could be competitively supplied from Yukon transmitted electricity.

In practice, the value of the ancillary services will be embedded into any bilateral agreement, and reflected in the price (as well as the terms and conditions of the supply agreement, e.g., power quality requirements) of the electricity that is exchanged between the regions.

**Table 7-8: BC/Yukon Compatibility Test**[63]

| **BC Hydro Ancillary Services** | |
|---|---|
| ***Ancillary Service*** | ***Requirements*** |
| Scheduling, System Control and Dispatch | Must purchase from BC Hydro |
| Reactive Supply and Voltage Control | Must purchase from BC Hydro |
| Regulation and Frequency Response | Can self-supply, purchase from BC Hydro or purchase from a third party |
| Energy Imbalance | Can self-supply, purchase from BC Hydro or |

[63] *BC Hydro Open Access Transmission Tariff (OATT) – Business Practice: Ancillary Services*, last updated December 9, 2013.

| | |
|---|---|
| | purchase from a third party |
| Operating Reserve-Spinning | Can self-supply, purchase from BC Hydro or purchase from a third party |
| Operating Reserve Supplemental | Can self-supply, purchase from BC Hydro or purchase from a third party |
| Loss Compensation | Can self-supply, purchase from BC Hydro or purchase from a third party |

**Table 7-9: Yukon-Alaska Compatibility Test**[64]

| **Alaska Ancillary Services (from Chugach Electric Association, Anchorage)** | |
|---|---|
| ***Ancillary Service*** | ***Requirements*** |
| Scheduling : System control and dispatch service | Provided by the transmission system operator ("TSO") only. Transmission customers must acquire these from the transmission provider |
| Reactive supply and voltage control from generation sources service | Provided by the transmission system operator ("TSO") only. Transmission customers must acquire these from the transmission provider |
| Regulation and frequency response | Transmission customer must acquire either from the transmission provider or self-supply or can avail it from a 3rd party resource that will satisfy all the conditions of the transmission provider |
| Energy Imbalance | Transmission customer must acquire either from the transmission provider or self-supply or can avail it from a 3rd party resource that will satisfy all the conditions of the transmission provider |
| Operating reserve – Spinning reserve service | Transmission customer must acquire either from the transmission provider or self-supply or can avail it from a 3rd party resource that will satisfy all the conditions of the transmission provider |
| Operating reserve – Supplemental reserve service | Transmission customer must acquire either from the transmission provider or self-supply or can avail it from a 3rd party resource that will satisfy all the conditions of the transmission provider |

[64] Chugach Electric Association: Regulatory Commission of Alaska Tariff No. 8, Section 11.5, Effective June 1, 2014.

## B.1 Key Ancillary Market Products and Definitions

**Ancillary Services**: Services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services may include load regulation, **spinning** reserve, non-**spinning** reserve, replacement reserve, and voltage support.

**Black start resource:** A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.

**Energy Imbalance[65]:** Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy through the Transmission Provider's Transmission System over a single hour.

**Frequency Regulation:** The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.

**Load Following:** Regulation of the power output of electric generators within a prescribed area in response to changes in system frequency, tie line loading, or the relation of these to each other, so as to maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits.

**Loss Compensation:** Loss Compensation ancillary service is provided by the system operator or another supplier to compensate for the real power losses between the point of generation and point of delivery.

**Non-Spinning Reserves:** The generating capacity not currently running but capable of being connected to the bus and load within a specified time.

**Operating Reserves[66]** : Means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Non-spinning Reserve.

**Reactive power supply and voltage Regulation service[67]:** In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities use (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be

[65] Chugach Electric Association: Regulatory Commission of Alaska Tariff No. 8, Rate Schedule T-4, Effective June 1, 2014.

[66] NERC Glossary of terms – 2014 -10 - 01

[67] Chugach Electric Association: Regulatory Commission of Alaska Tariff No. 8, Rate Schedule T-2, Effective June 1, 2014.

provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

**Reserve generating capacity:** Amount of generating capacity available to meet peak or abnormally high demands for power and to generate power during scheduled or unscheduled outages.

**Reserve margin (operating):** The amount of unused available capability of an electric power system (at peak load for a utility system) as a percentage of total capability.

**Scheduling: System control and dispatch service[68]:** This service is required to schedule the movement of power through a Transmission Provider's Transmission System.

**Spinning Reserves[69]:** That reserve generating capacity running at a zero load and synchronized to the electric system.

[68] Chugach Electric Association: Regulatory Commission of Alaska Tariff No. 8, Rate Schedule T-3, Effective June 1, 2014.

[69] EIA Glossary

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## Appendix C: Calculating the Cost of New Generation

| | Year | CAPEX *($M)* | O&M *($M)* | Energy *(MWh/ yr)* | Df *(Rate = 3.38%)* | NPV *($M)* | NPV of Energy |
|---|---|---|---|---|---|---|---|
| | | | | | 3.38% | | |
| | 2026 | $ 0.10 | | | 100.00% | $ 0.10 | |
| | 2027 | $ 0.20 | | | 96.67% | $ 0.19 | |
| | 2028 | $ 0.20 | | | 93.46% | $ 0.19 | |
| | 2029 | $ 0.50 | | | 90.35% | $ 0.45 | |
| | 2030 | $ 1.00 | | | 87.35% | $ 0.87 | |
| | 2031 | $ 2.00 | | | 84.44% | $ 1.69 | |
| | 2032 | $ 2.00 | | | 81.63% | $ 1.63 | |
| | 2033 | $ 2.00 | | | 78.92% | $ 1.58 | |
| | 2034 | $ 2.00 | | | 76.29% | $ 1.53 | |
| 1 | **2035** | | $ 0.40 | 4380 | 73.76% | $ 0.30 | 3,231 |
| 2 | 2036 | | $ 0.40 | 4380 | 71.30% | $ 0.29 | 3,123 |
| 3 | 2037 | | $ 0.40 | 4380 | 68.93% | $ 0.28 | 3,019 |
| 4 | 2038 | | $ 0.40 | 4380 | 66.64% | $ 0.27 | 2,919 |
| 5 | 2039 | | $ 0.40 | 4380 | 64.42% | $ 0.26 | 2,822 |
| 6 | 2040 | | $ 0.40 | 4380 | 62.28% | $ 0.25 | 2,728 |
| 7 | 2041 | | $ 0.40 | 4380 | 60.21% | $ 0.24 | 2,637 |
| 8 | 2042 | | $ 0.40 | 4380 | 58.21% | $ 0.23 | 2,549 |
| 9 | 2043 | | $ 0.40 | 4380 | 56.27% | $ 0.23 | 2,465 |
| 10 | 2044 | | $ 0.40 | 4380 | 54.40% | $ 0.22 | 2,383 |
| 11 | 2045 | | $ 0.40 | 4380 | 52.59% | $ 0.21 | 2,303 |
| 62 | 2096 | | $ 0.40 | 4380 | 9.37% | $ 0.04 | 410 |
| 63 | 2097 | | $ 0.40 | 4380 | 9.06% | $ 0.04 | 397 |
| 64 | 2098 | | $ 0.40 | 4380 | 8.76% | $ 0.04 | 384 |
| 65 | 2099 | | $ 0.40 | 4380 | 8.47% | $ 0.03 | 371 |
| | | | | | | **$ 16.12** | **86,356** |

**ASSUMPTIONS**

| | | |
|---|---|---|
| CAPEX | $ 10.00 | |
| Capacity | 1 | MW |
| O&M | 4.0% | of CAPEX |
| CPI | 0% | |
| Real Discount (cost of real money) | 3.38% | |
| Assumed Cost per MW | $ 10.00 | $M |
| Assumed Capacity Factor | 50% | |

| | |
|---|---|
| COST PV | $ 16.12 |
| NGR PV | $ 86,356.11 |

| | |
|---|---|
| LCOE ($/MWh) | $ (186.64) |