APPENDIX B:
Development Scenarios Workshop Report

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Memorandum

DATE:	**JUNE 30, 2014**	**PROJECT:**	P.777
TO:	File	**FILE:**	P:\P777\June workshop\Workshop Report\Summary of Scenarios.doc
CC:			
FROM:	Mona Pollitt-Smith		
SUBJECT:	**Southeast Alaska & Yukon Economic Development Corridor: Development Scenario Workshop Report**		

On June 18, 2014 a one-day workshop was held in Whitehorse that focused on identifying up to three transmission development scenarios for the Southeast Alaska and Yukon Economic Development Corridor Study (the "Study") that could potentially provide long term benefits to both Yukon and Alaska in terms of supply of seasonal renewable energy and other benefits, including improved telecommunication, reliability and capability. The workshop agenda and list of workshop participants and roles are provided in **Attachment A** and the Workshop Agenda is provided as **Attachment B**.

Materials were prepared to facilitate discussion at the workshop and were distributed to workshop participants; these materials are provided as **Attachment C** to this memo:

- Attachment C-1 – Workshop Background Papers
  - Background Paper #1 – Long Term Fossil Fuel Generation Requirement Scenarios
  - Background Paper #2 – Supply Options
  - Background Paper #3 – Initial Transmission Corridor Cost Estimate
  - Background Paper #4 – Alaska-Yukon Fibre Optic Corridor Link
- Attachment C-2 – Preliminary Development Scenarios [as reviewed at June 18 workshop]
  - Summary description
  - Detailed description
- Attachment C-3 – Other Workshop Materials
  - Assessment of Simulated West Creek Generation
  - Map of Southeast Alaska and Yukon Economic Development Corridor

This memo summarizes the outcomes of the Development Scenario workshop discussion, focused on the following:

1. Summary of Project elements that can be defined for purpose of viability assessment;
2. Summary of development scenarios for viability assessment;
3. Summary of key issues affecting the viability assessment; and
4. Summary of next steps.

1.0 SUMMARY OF PROJECT ELEMENTS THAT CAN BE DEFINED FOR PURPOSE OF VIABILITY ASSESSMENT

In order to assess the viability of a transmission intertie between Whitehorse and Skagway/SE Alaska, the Study must consider what specific conditions (loads, system reliability, other potential uses of the corridor such as telecommunications link) need to be present to make development of such a corridor work.

The workshop broadly discussed the concept for an economic development corridor between southeast Alaska and Whitehorse, and examined potential components beyond the fibre optic cable and transmission line options that are being actively considered at this time. It was noted that highway and rail elements of this corridor presently exist, (and at one time an oil pipeline also occupied the corridor). After discussion, it was concluded that at this time there is no quantifiable and specific market opportunity to be assessed for a new pipeline connection or any other elements beyond the fibre optic cable and transmission line. As noted below, the Study will consider potential synergies between development of the transmission line along the corridor and separate planned development of a fibre optic link between Carcross and Southeast Alaska along the corridor. It was noted that the Viability Assessment report should include a high-level discussion around the scope (and what was not included) of this "economic development corridor".

The fundamental features of the Project as discussed were as follows:

- **Cost estimates for Transmission line Project**
    - **Substation** – Substation costs will be lower than the $13 million to $18 million referenced in the Background Paper #3, based on recent YEC experience (assume approximately $8-10 million per substation).
        - It was confirmed that a requirement for a new Whitehorse substation can be avoided by utilizing the existing Riverside substation as the terminus for the 138 kV new line.
        - Possible locations for a substation at Skagway were considered, including the submarine landing (as proposed in AP&Ts West Creek FERC application), a location somewhere in Skagway, or at the Goat Lake powerhouse. It is assumed that the study would address only the cost of the substation and the 138 kV line. The study will identify feasible options but will not try to cost out each option. The location of the substation may influence the length of the transmission line (i.e., by approximately 12 km) and may consequently affect costs by a few million dollars.
    - **Line costs** – line costs are assumed in Background Paper #3 to average approximately $66 million (average of range of possible costs) assuming 138 kV line and wood poles. The group confirmed that the voltage would need to be 138 kV to support a load of 20-25 MW. Comments noted where costs were likely to exceed the average costs as assumed:
        - **Generic cost of line** - Background Paper #3 reviewed the generic costs of a transmission line and provided initial cost estimates for a 175 km transmission

line at between $55 million and $76 million [about $0.314 million/km to $0.434 million/km]. This estimate reflected a reasonable range based on recent experience and assuming road access and reasonably mild terrain on average for the Project.

        - **Provision for difficult terrain** - Based on an assessment of the actual terrain it was noted that there are areas of terrain in the White Pass (about 20 to 30 km) that will be more challenging due to poor access and will have higher costs of about $0.600 to $0.700 million/km ($US) [due to the requirement to use helicopters for construction]. In Canada, a portion of the line will similarly have higher costs due to avalanche risks. Overall, prior to developing more detailed estimated, it is suggested that the cost of the 175 km line is likely in the $70-$80 million range.

    - **Updated Estimate –** Overall, the updated average cost (from range of estimates) approximates about $84 million (reflects higher line cost at $70 to $80 million and lower substation cost at $8 to 10 million).

- **Timing for permitting and construction of line** – A high level assessment of the potential timelines required to plan, permit and construct the transmission corridor was discussed as follows:

    - **Feasibility Assessment** – It was noted that after decision to start feasibility study it would take approximately 12 to 18 months to complete the work (i.e., route selection and design for purpose of completing project description).

    - **Permitting and Licencing** – It was noted that the YESAB process would take at least 12 months; other federal processes for both Yukon and Alaska (including securing export permits through FERC and NEB) would take 18 to 24 months. Final design of the transmission line would occur concurrently with permitting and licencing.

    - **Procurement** – Approximately 12 months

    - **Construction** – Approximately 24 months

  In sum, the transmission project could take from 5.5 to 7.5 years while West Creek Hydro could take up to 10 years or more (after a decision to proceed with the next stage of work). Key considerations for staging the next steps for the transmission project would be:

    - Proceed with permitting, but not fund final commitment to build the transmission corridor until have commitments/ purchase power agreement with West Creek.

    - Consider whether cruise ship loads will be viable for shore power option if process delayed for five or more years from now.

- **Requirement for 138 kV Transmission line extending from South-east Alaska to Whitehorse –** The transmission corridor will be designed to be able to move approximately 25 MW of electricity from Alaska to Yukon (and vice versa) with a 138 kV voltage.

- Previous studies had considered feasibility of a 69 kV line; however, this lower voltage line is not likely to provide any material capital cost savings relative to 138 kV and would limit capability and ability to integrate with the Yukon grid which currently operates at Whitehorse at 138 kV voltage.
- Use of a 138 KV line would facilitate system stability [which is of critical importance when moving small loads over long distances between two relatively small electrical systems].
- Whether an AC or DC transmission connection should be considered was discussed. It was suggested that a DC line might enhance stability (it is effectively operated as an isolated section of the system) and avoid inter-jurisdictional regulatory requirements that otherwise must consider the effects of a system connection on system stability. However, a DC transmission connection would likely have greater costs compared to the AC option. A DC connection would also preclude connections to other projects (generation IPPs or loads) along the length of the DC line. It was noted that there is a need (separate from the Study) to clarify the regulatory implications of an AC connection in Yukon and Alaska. This may include gathering more information regarding regulatory implications, and legal or regulatory constraints.
- Use of ATCO Electric-Yukon's ("YECL's") existing 35 kV line – The existing 35 kV infrastructure extending from Carcross to Whitehorse was considered for possible use; however, preliminary assessments indicate as follows:
  - The existing 35 kV powerline between Carcross and Whitehorse cannot be used to move 25 MW of power [current line can move 17 MW and existing load in Carcross is about 4 MW].
  - Stepping down from 138 kV operation to 35 kV at Carcross would require an additional substation [which would range in cost around $8-10 million]
  - A 138 KV line can terminate within the existing Whitehorse substation without the requirement for new equipment and without requirement for transformation; this would in effect save $8-10 million in substation costs.

- **Transmission Pole Design**
  - It was noted that the preferred Yukon Energy pole configuration is an H-Pole Design; however, this design requires a wider right of way and will have increased clearing costs.
  - ATCO Electric-Yukon is amenable to having its line from Carcross north re-built as a single pole transmission line, which could accommodate both 138 kV transmission and 25 kV distribution.
  - All three utilities prefer wood poles; however, steel poles are more appropriate in areas prone to avalanches and inaccessible steep mountainous terrain (e.g., in mountain areas where helicopter access required). Steel poles cost slightly more than wood poles, but have a longer economic life (lower depreciation rate).
  - The tradeoffs regarding the economics of wood versus steel would need to be assessed, taking into consideration the difference in depreciation rates as well as in initial capital

cost. Steel poles are likely more cost effective in steep and heavy rock terrain due to lower foundation costs relative to two wood-pole designs.

- **Routing from Southeast Alaska To Whitehorse**
  - It was noted that potential routes for a line connecting Southeast Alaska and Yukon had previously been studied and had determined a preferred route along the Klondike Highway. The second route following the White Pass Rail Line was not considered viable due to its relative inaccessibility. Costs for construction access and maintenance would be higher than a route following the Klondike Highway. In addition, viewscapes along the scenic historic railway route would be a concern.
  - With regard to current assessments regarding routing; it was noted that two routing options should be discussed and considered for the section of line extending from Carcross north to Whitehorse:
    - Option 1 – re-building a line on the existing ATCO Electric-Yukon right-of-way; and,
    - Option 2 – A new right-of-way, potentially following portions of the White Pass and Yukon Railway alignment.
  - A third option was also discussed that would continue east from Carcross along the Tagish Road as far as Jake's Corner, and then north to Whitehorse adjacent to the Alaska Highway. It was confirmed that this option should be noted but not assessed at this time given the longer distances required. This latter option might have benefits to other possible projects, such as the Atlin Hydro Expansion (Pine Creek Hydro) project.

The Study will consider potential synergies between development of the transmission line and separate planned development of a fibre optic link between Carcross and Southeast Alaska along the corridor. The following was noted:

- If the timing of the two projects were coordinated there were potential material cost savings related to stringing the fibre optic line along the transmission line instead of burying it.
- If the timing of the two projects could not be coordinated (and the fibre optic link proceeded independently and ahead of the transmission line) there are still potential positive synergies related to securing concurrent easements and rights of way for both projects.

Other potential economic opportunities that may be facilitated by the transmission corridor are described under Section 2.3 below.

2.0 SUMMARY OF DEVELOPMENT SCENARIOS

Prior to the workshop the project team identified two development scenarios to be reviewed and confirmed at the workshop. These scenarios were summarized in two handouts provided for review and discussion at the workshop [Attachment C-2 of this memo] and are summarized as follows:

1. **Scenario 1 – Development with West Creek Hydro Generation** – this scenario presumes that West Creek Hydro project is developed in Skagway Alaska to provide hydro power to the Yukon grid and to the summer cruise ship load in Skagway and Haines. Under this scenario the construction of the transmission line would be timed such that it is available when the West Creek hydro project is commissioned, i.e., the scenario in effect assumes that the line is viable only with a West Creek hydro project.
2. **Scenario 2** – **Development with YEC Summer Hydro Surplus and Skagway Cruise Ship Loads –** this scenario would see a transmission line project advanced independent of any new hydro development in the Upper Lynn Canal area to export surplus hydro generation available on the Yukon grid in summer to Skagway in order to displace diesel otherwise used for the summer cruise ship load. The line in this scenario is not considered to be viable based on the assumed load; the scenario is examined to determine what type of subsidy would be required to make this work and what other benefits may arise from this (i.e., synergy with fibre optic line, ability to sell to cruise ship loads before West Creek or other local hydro development is advanced, and development of a transmission connection that may enhance prospects for future development of new hydro generation in SE Alaska for sale to the Yukon grid per Scenario 1 and thereby in future create load conditions where the line itself would be viable).

These two scenarios will have sensitivity analyses that will address some of the variations within each of the scenarios. Each of these scenarios is discussed in detail below, including issues raised during the workshop and additional assessments or sensitivities to be considered regarding each scenario in the viability assessment.

2.1 SCENARIO 1 – DEVELOPMENT WITH WEST CREEK HYDRO GENERATION

This development scenario is focused on development of the transmission corridor that would supply surplus power to Whitehorse from the proposed West Creek Hydro project near Skagway, Alaska in order to displace growing thermal generation requirements on the Yukon grid in the winter months.

Scenario 1 - Development with West Creek Hydro Generation

Whitehorse, Yukon	**Skagway, Alaska**
← About 54 GW.h/yr from Alaska to Yukon	
Need sufficient fossil fuel displacement opportunity New loads needed on grid of 25-50 GW.h/yr to proceed within next decade	Confirm West Creek Hydro volumes, timing and costs About 134 GWh/yr generation, less 80 GW.h/yr June to Nov (not needed in Yukon)
Financial & Economics viability issues (beyond timing): Expected cost savings from fossil fuel displacement Competitive renewable cost options (e.g., other hydro sites) Supply security & charges for delivered West Creek hydro	Financial & Economics viability issues (beyond timing): Net power charges to cruise ships & sustainability of loads Overall capital costs for new hydro & transmission Financing, ownership and cost recovery arrangements

In summary:

- Potential available generation from West Creek of 134 GW.h/year

  - It was concluded that a reasonable assumption of time needed to develop the West Creek hydro project (planning, permitting and construction) would be about 10 years.
  - Available information for a 25 MW West Creek Hydro project estimates average generation over 15 water years of record at 134 GW.h/yr (range of 110 to 160 GW.h/yr), with about 80 GW.h on average from June 1 to November 30 (when the Yukon grid does not typically have a fossil fuel generation requirement), and approximately 9 GW.h/month on average for the remaining six months (with lowest generation in April and May at about 7 GW.h/month). This represents a revised water management scheme for West Creek to maximize winter energy generation.
- Potential Summer Cruise Ship Load of 30 GW.h/Year
  - The potential cruise ship load to be supplied from the West Creek Hydro project is reviewed in section 1.1.2 of Background Paper #1 (Figures 6 and 7); this indicates that about one-third (11 GW.h for total season) of the cruise ship load involves ships that can currently connect to shore power (it is assumed that the balance could potentially be converted in 1-2 years under economic conditions).
  - A recent funding application estimated diesel generation cost per kW.h for cruise ships at about 33.4 cents/kW.h (2017), including about 32.1 cents/kW.h fuel costs and 1.3 cents/kW.h operating and maintenance expenses.
- Potential surplus power from West Creek Hydro project available to ship to Yukon to meet winter load requirements of 54 GW.h/Year
  - The most recent Yukon Energy ("YEC") updated near-term grid load scenario forecasts[1] indicate long-term average fossil fuel (diesel or LNG) generation requirement without any new industrial loads or new renewable generation ranging from 2018 to 2026 at 31.4 to 55.0 GW.h/yr (with growing requirements thereafter); these requirements would increase to the extent that DSM is less than assumed, and decrease to the extent that other renewable generation is developed for the Yukon grid.
  - YEC load forecast scenarios show that a potential new industrial load of 54 GW.h/yr in 2018 (Carmacks Copper) would increase fossil fuel generation requirements in the range of 37-40 GW.h/yr for about 7.5 years. It was noted that updated information indicates that this mine project is currently stalled.

2.2 SCENARIO 2 – DEVELOPMENT WITH YEC SUMMER HYDRO SURPLUS & SKAGWAY CRUISE SHIP LOADS

This development scenario is focused on development of the transmission corridor in advance of any new hydropower developments in the Upper Lynn Canal area (such as West Creek hydro generation project) being developed. The transmission corridor would be developed to ship surplus summer power from Whitehorse to Skagway to displace summer cruise ship diesel generation loads as soon as shore power is available in Skagway and Haines.

[1] Filed in December 2013 re: Application under Part 3 of PUA for Proposed Whitehorse Diesel-Natural Gas Conversion Project.

Scenario 2 - Development with YEC Summer Hydro Surplus & Skagway Cruise Ship Loads

Whitehorse, Yukon	**Skagway, Alaska**
About 30 GW.h/yr from Yukon to Alaska →	
Surplus Hydro (early June through September) Assume up to about 34-38 GW.h surplus summer hydro with current generation & loads - need LNG backup	Energy for Cruise Ships (early May through September) About from 30 GW.h per season with peak load 6.5 to 32.5 MW in different weeks over the period
Financial & Economics viability issues (beyond timing): Charges for hydro power supplies Charges for LNG back up generation Factors that reduce hydro surplus Upper limit on viable transmission charges	Financial & Economics viability issues (beyond timing): Diesel cost saved by ships Shore power connection costs Factors that limit cruise ship diesel displacement volumes Competitive cost option (LNG generation at Skagway)

In summary:

- Potential surplus generation of 34 to 38 GW.h/year is available in Yukon from early June to end of September.
  - Yukon Summer Surplus Hydro (Figure 2 in Background Paper #2) indicates that in 2018, summer surplus hydro without new mine connections ranges from 34 to 38 GW.h with average surplus per week ranging from 4 to 15 MW over the period; any new mine connections would reduce this surplus over the summer period.
  - Concerns were noted that capacity (MW) of surplus hydro range only from 4 to 15 MW to supply cruise ship capacity requirements of 25 MW or more, and that YEC LNG generation could be considered as backup subject to pricing arrangements.
  - It was noted that Scenario 2, with its lower transmission loads relative to Scenario 1, would not enable recovery of the full annual cost of the transmission line under normal financing arrangements, i.e., this scenario would require some level of government funding support (which will be assessed), and therefore the ultimate viability of the project would presume either a future Scenario 1 or some other future cost effective renewable supply would be developed to use the line to displace Yukon winter fossil fuel generation.

Sensitivities for Development Scenarios:

1. Sensitivity analysis that looks at whether the transmission corridor can be justified without any cruise ship load in Alaska.
   a. This will address issues with uncertainty regarding sustainability of cruise ship load and/or ability for cruise ships to connect to shore power (solve logistical and funding of material cost issues regarding AP&T distribution infrastructure requirements for shore power connection).
   b. Confirm that no other potential summer loads in Alaska could be served with surplus Yukon or Alaska hydro generation as assumed under Scenarios 1 and 2. This may include consideration of other operating or potential mines in the Lynn Canal area that

could connect to receive grid power. The possibility of connecting mines in the Lynn Canal area can be noted, but will not be examined further.

2. Sensitivity assessment related to development of other renewable projects

    a. Assess any expected impact on Project viability of development of smaller hydro enhancements on Yukon grid in near term (i.e., if Mayo Lake and Marsh Lake enhancements are assumed to proceed, then diesel generation requirements would be reduced by 4 and 6 GW.h/year respectively; Gladstone is not expected to proceed in near term, but were it to proceed it would materially reduce the diesel generation requirements on the Yukon grid).

    b. Assess if interconnection with Alaska would help to provide an economic justification for other hydro projects (in the Upper Lynn Canal area, Yukon or BC) in the absence of West Creek. Development of a greenfield hydro project in any of these jurisdictions would likely take up to 10 years to licence and develop.

2.3 OTHER ECONOMIC OPPORTUNITIES FACILITATED BY THE PROJECT

Discussion at the workshop indicated the need for the viability assessment to raise and review "other economic opportunities" that may arise due to the presence of the transmission corridor. It was noted that while these other economic opportunities need to be discussed, there is currently not sufficient information or clarity available regarding the definition of these other opportunities (i.e., proponent, cost, timing, etc) for a specific economic or business case assessment to be undertaken as part of the current viability assessment. As such, the discussion of other economic opportunities will be qualitative in nature and not treated as a separate "development scenario".

Other Economic Opportunities as discussed are summarized as follows:

- The presence of the transmission corridor in southern Yukon and Southeast Alaska may support and facilitate future development of a number of smaller hydro (or other renewable generation) projects. This may include the following:
    - **Southeast Alaska** – Other potential projects have been identified in southeast Alaska that may proceed in the future, such as Connelly Lake, Burro Creek, and Schubee Lake.
    - **Northwest BC** – Potential projects that have been identified in Northwest BC that may be positively affected by the presence of this transmission corridor include Moon, Tutshi and Pine Creek (Atlin). Discussion also indicated the need to identify as an opportunity the potential to facilitate the development of small IPP's in proximity to the Yukon grid. However, the extent of any IPP opportunity could be quantified until there was a specific proponent and Power Purchase Agreement arrangements were defined; any Power Purchase Agreement would need to address costs for the project to connect to the grid (including transmission and substation costs).
    - **Yukon Development Corporation (YDC) Large Hydro Study** - It was also noted that the viability assessment study needs to consider how it may relate to the separate large hydro study being undertaken by YDC.

- The presence of a transmission corridor in southern Yukon and Southeast Alaska may support and facilitate continued operation or future development of mines in the region.
  - **Southeast Alaska** – Consider potential for grid connection to mines half way between Skagway and Juneau. For example it was noted that the Kensington mine was a 5 MW mine currently operating using on site power (diesel). The mine has operated for five years and is expected to keep operating for at least the next ten years. The Greenstone Creek mine was also raised as a potential mine load.
  - **Yukon –** No substantive mine developments or opportunities have been identified along the transmission corridor; discussions regarding impacts on Yukon development related mostly to the availability of renewable supply from Alaska to meet growing Yukon grid load requirements.

3.0 SUMMARY OF KEY ISSUES AFFECTING VIABILITY ASSESSMENT

Key issues that may affect the viability assessment were discussed. The most fundamental issue raised at the workshop was the required assessment of the shore power infrastructure and costs required for cruise ships in Haines and Skagway to connect to shore power. Discussion at the workshop indicated the following material concerns:

1. It was noted that in order for each cruise ship to connect to shore power there is need to develop distribution infrastructure to accommodate cruise ship voltages and loads which are very different from current utility voltages.
2. The cost in Juneau to supply distribution infrastructure for one ship to connect to shore power was approximately $5 million. The cost at Skagway to accommodate the identified potential cruise ship loads would be at least three to four times higher (assuming that up to four connections were supplied at the existing berths). At this time, no plan is in place to undertake or fund these costs.
3. It was noted that the shore power infrastructure to connect cruise ships was outside the scope of the current corridor Study. However, the feasibility of connecting cruise ship loads is integral to the viability of the Project overall under Scenario 2 and likely also Scenario 1. If it is determined that the costs of developing shore power infrastructure to provide shore power are prohibitive, then the cruise ship loads cannot be relied upon or assumed in the development of the transmission corridor and the West Creek project.
4. The key issues to determine are:
   a. What are the expected capital costs needed for shore power infrastructure at Skagway (and perhaps Haines)?
   b. If this work occurs, would AP&T be the party to undertake the costs for shore power distribution infrastructure and when is the earliest that this could occur?
   c. What arrangements can be undertaken for parties other than AP&T to finance some of all of the costs for shore power distribution infrastructure? [It was noted that in Alaska there

is a commercial passenger vessel excise tax to provide funds to support local related activities; while the funds are retained by the state the communities might seek to invest these funds in cruise ship shore power distribution infrastructure.]

d. It was noted that Juneau had ability to connect one ship to shore power and was looking at electrifying other berths; it was noted that there is need to get further information regarding what Juneau is doing in this regard.

4.0 NEXT STEPS

1. Send out electronic versions of workshop materials [these are incorporated into this document as Attachment C].
2. Alaska participants to set up Task Force to address issues related to cruise ship distribution infrastructure requirements and costs to connect to shore power, as well as possible financing arrangements to enable this to proceed in a timely manner, and report back to project team by September 2014 in order that shore power cruise ship loads may continue to be considered in the current viability assessment Study.
3. Contact YG Telecommunications regarding potential cost savings associated with fibre optic cable above ground (using transmission line poles) vs. underground cable.
4. Obtain information regarding FERC regulatory implications of AC connection.

ATTACHMENTS

ATTACHMENT A
WORKSHOP PARTICIPANTS

ATTACHMENT A – WORKSHOP PARTICIPANTS

Project Team	Morrison Hershfield	Forest Pearson Kathleen Wood Greg McNeil
	InterGroup	Cam Osler Mona Pollitt-Smith
	Dryden Larue	Greg Huffman
Government Representatives	Yukon Government, Energy Branch	Shane Andre Ryan Hennessy
	Southeast Conference (Alaska)	Robert Venables
	Alaska Energy Authority	Gene Therriault [by phone]
Utility Representatives	Yukon Energy Corporation	Lawrence Joudry
	ATCO Electric Yukon	Yesh Sharma
	Alaska Power and Telephone	Jason Custer Darren Belisle

ATTACHMENT B
AGENDA

ATTACHMENT B – AGENDA

SOUTHEAST ALASKA & YUKON ECONOMIC DEVELOPMENT CORRIDOR: DEVELOPMENT SCENARIO WORKSHOP

Energy Solutions Centre Boardroom

206A Lowe St, Whitehorse, YT

June 18, 2014

8:30 a.m. to 4:00 p.m.

WORKSHOP OBJECTIVES

- Focus on question: what are the conditions (economic, system planning, etc.) that would result in a viable intertie of the electrical systems between Skagway and Whitehorse?
- Identification of up to 3 development scenarios that will form the basis of further analysis
- Identification of other economic development opportunities, for reference only (not part of current scope of analysis)

WORKSHOP AGENDA

1. Introductions – 8:30 a.m.

   a. Name, Organization, Interest/ Role in Project

2. Overview – 8:45 a.m. to 10:30 a.m.

   a. Review agenda for day
   b. What do we mean by development scenarios?
      i. Concept for Economic Development Corridor
      ii. Specific development scenarios (conditions for viability) for transmission corridor
      iii. Anything else agreed on today
   c. Concept for Economic Development Corridor
      i. Potential components: Fibre Optic cable; Transmission Line; Road; Pipeline; Other?
      ii. Implications and options for joint planning of more than one component
      iii. Focus for today (transmission development scenarios) and potential scenario for synergy with fibre optic cable

Morning Break at 10:30 am [15 minutes]

3. Transmission Line - Technical Feasibility – 10:45 a.m. to 12:00 p.m.

a. Overview – Need to match loads and opportunity.
    i. Purpose/ value of transmission corridor is to provide value by moving power between Alaska and Yukon. This requires supply on one side that can be cost effectively moved to the other side where there is suitable demand.
b. Electrical systems and existing infrastructure and its capability: Yukon and Alaska
    i. Review map of existing electrical transmission system, location of hydro sites in proximity to intertie, existing infrastructure and land ownership, voltage, substations.
    ii. Challenge of connecting two small systems over a distance of 175 km
c. Possible line routing and voltage, rights of way (options assumed for this study)
d. Potential Costs, Timing and Economic Life

Lunch Break at noon [45-60 minutes]

4. Economic Viability/ business case to make work – 1:00 p.m. to 2:30 p.m.

a. Overview of economic/financial feasibility requirements for transmission corridor
    a. Opportunity to move lower cost electricity supply over the line to displace higher cost electricity required at the other end – potential options to do this at different times in opposite directions
    b. Ownership and financing issues and potential implications to viability
b. Forecast Grid Electricity Demand and Fossil Fuel Generation Requirements in Alaska and Yukon without the Alaska-Yukon Transmission Corridor
    a. Alaska – near term and longer term grid load profile
        - Balanced system with potential to develop lumpy cruise ship market
        - Potential cruise ship loads
        - Near term and longer term supply options [identified in PRP – generation & transmission]
        - West Creek Hydro new supply options
        - Potential loads and/or supplies for Alaska-Yukon transmission
    b. Yukon - near term and longer term grid load profile
        - Scenarios without new mine connections
        - Scenarios with potential new mine connections
        - Near term and longer term supply options [identified in 2011 RP – generation & transmission]
        - Summer hydro generation surplus
        - Potential loads and/or supplies for Alaska-Yukon transmission
c. Potential development scenarios and feasibility issues
    a. Define potential development scenarios [earlier scenarios 1 and 2]
    b. Preliminary review of viability issues for each development scenario

Afternoon Break at 2:30 pm [15 minutes]

5. Review and confirm development scenarios - 2:45 p.m. to 3:30 p.m.

6. Next Steps – 3:30 p.m. to 4:00 p.m.

ATTACHMENT C

MATERIALS AS PROVIDED AT THE JUNE 18, 2014 WORKSHOP

ATTACHMENT C-1
WORKSHOP BACKGROUND PAPERS

BACKGROUND PAPER #1 – LONG TERM FOSSIL FUEL GENERATION REQUIREMENT SCENARIOS

Long term fossil fuel generation requirement scenarios are summarized below based on forecast grid power loads and current renewable generation capabilities, first for Alaska (Skagway and Haines integrated grid and environs, including cruise ship loads), and then for Yukon (integrated Yukon grid). These scenarios are based on available information and forecasts as noted.

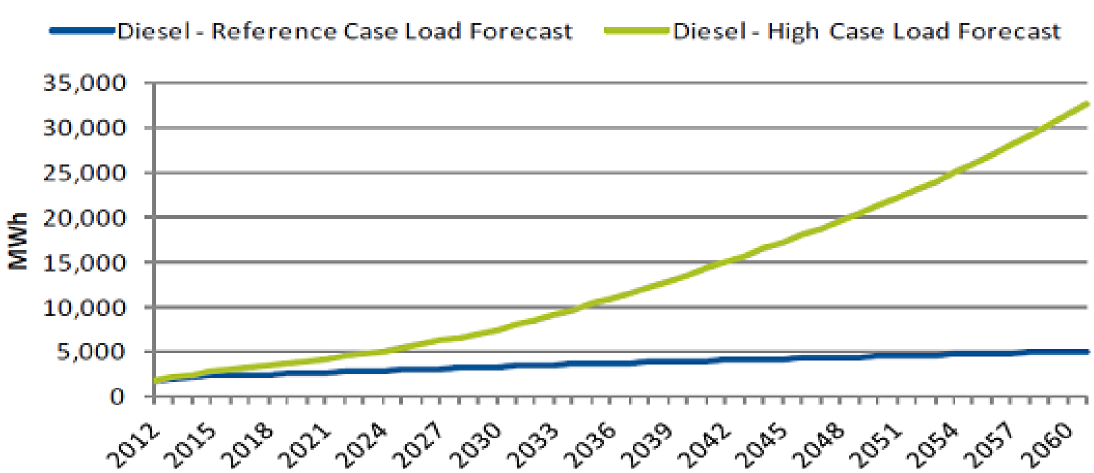
1.1 ALASKA

Two separate Alaska fossil fuel generation requirements are examined: the Skagway-Haines area integrated grid diesel requirements, and the diesel requirements of the cruise ships visiting these ports (i.e., these ship power loads are not currently connected to the grid).

1.1.1 Skagway-Haines Area Integrated Grid

The Southeast Alaska Integrated Resource Plan ("SEIRP") provides a long term forecast of loads and generation for the Upper Lynn Canal area (includes Skagway and Haines integrated grid) from 2011 to 2061.[1] The SEIRP forecast grid diesel generation requirement over the period from 2011-2061 is summarized in Figure 1 below (as excerpted from the SEIRP) for the reference case scenario and for the high load scenario. These scenarios are reviewed in more detail below.

Figure 1: Upper Lynn Canal Annual Diesel Generation Forecast



[1] The load forecast was prepared based on three timeframes: Short term (2011-2015), Intermediate Term (2016-2035) and Long Term (2036-2061). In addition to Skagway and Haines, the Upper Lynn Canal area also includes Klukwan [about 0.4 GW.h load] and Chilkat Valley [1.2-1.5 GW.h load]. Figure 4-2 of the SEIRP shows Chilkat Valley and Klukwan as a connected system served by Inside Passage Electric Cooperative (IPEC). SEIRP notes that the existing AP&T system connects Haines and Skagway and an intertie connects the AP&T system to the existing IPEC system that serves Klukwan and Chilkat Valley. Klukwan and Chilkat Valley are served by hydro generation from 10 Mile hydro plant (0.55 MW or about 1.05 GW.h/year) and power purchased from AP&T. Table 4-2 in the SEIRP notes that there are also two diesel units in Chilkat Valley with 0.5MW and 0.6MW.

Reference Case

The SEIRP indicates that over the planning period (from 2011 to 2061), the requirement on the Skagway-Haines area grid will not materially exceed the capacity and energy currently available on the grid.

- The reference case total energy requirement for the Skagway and Haines grid was forecast at 28.8 GW.h by 2011, increasing to 31.1 GW.h by 2015, to 31.8 GW.h by 2020 and to 32.7 GW.h by 2025. Under the reference case and assuming no new renewable generation development, the diesel generation requirement for the Upper Lynn Canal area was forecast to be below 5 GW.h in all years of the forecast period (see Figure 1).

- The existing system includes 8 MW of hydro generation and an additional 9.6 MW of thermal generation[2]. The total peak demand requirement for Skagway and Haines was forecast at 5.7 MW in 2011, increasing in line with load forecast at an average 58% load factor (i.e., 6.1 MW in 2015, 6.3 MW in 2020, and 6.5 MW in 2025). The peak demand by year 2061 is forecast to be 7.3 MW, which remains lower than the currently installed hydro capacity on the Skagway-Haines grid.

The annual energy and peak demand forecast for the Skagway-Haines area is provided in Figure 2 below. The load forecast was prepared by Black & Veatch based on historical trends in energy and peak demand, and population growth as projected by the Alaska Department of Labor (ADL) [3], and reflects the following assumptions:

- An annual growth rate of 2% from 2012 to 2014;
- An annual growth rate of 1.9% in 2015;
- An annual growth rate of 0.5% from 2016 to 2035; and
- An annual growth rate of 0.3% after 2035.

The SEIRP indicates that the economy in the region over the period from 2011-2015 will continue to improve modestly with a mining development expected to become operational over the next 5 years and the expansion of an ore terminal in Skagway. However, Black & Veatch indicates that the population over the period from 2011 to 2015 will either be steady or decrease slowly, and annual sales to all customers except the new mining facility will increase at 0.5% annually for 2015 to 2035.

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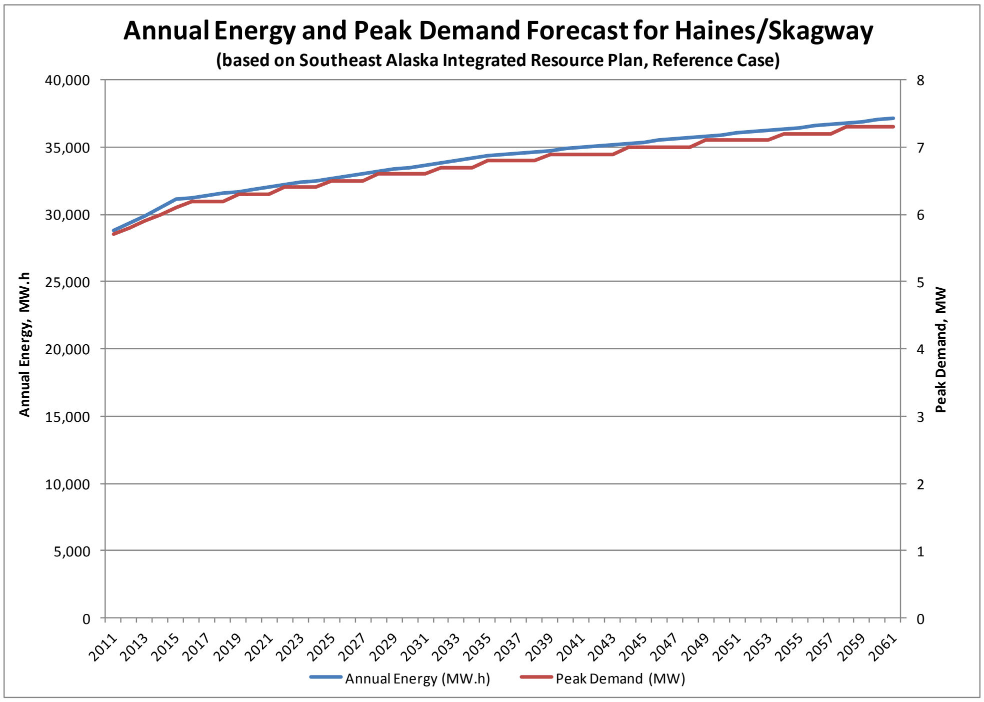
[2] There are three hydro-electric power plants in Skagway-Haines area with a total capacity of 8 MW: Goat Lake (4 MW), Kasidaya Creek Hydro (3 MW) and Dewey Lakes Hydro (1 MW). Thermal generation units are located in Skagway (3.4 MW) and Haines (6.2 MW).

[3] The SEIRP notes that according to the population count developed by ADL, the population of the Skagway Hoonah and Angoon areas together has declined by approximately 5 percent between 2006 and 2010 and forecast to decrease by approximately 7.0 percent of 2010 levels between 2010 and 2015, and that AP&T also indicated that the population in Skagway has been decreasing, and the population in Haines has been increasing in recent years.

Figure 2: Annual Energy and Peak Demand Forecast for Skagway-Haines area



Sensitivity Analysis

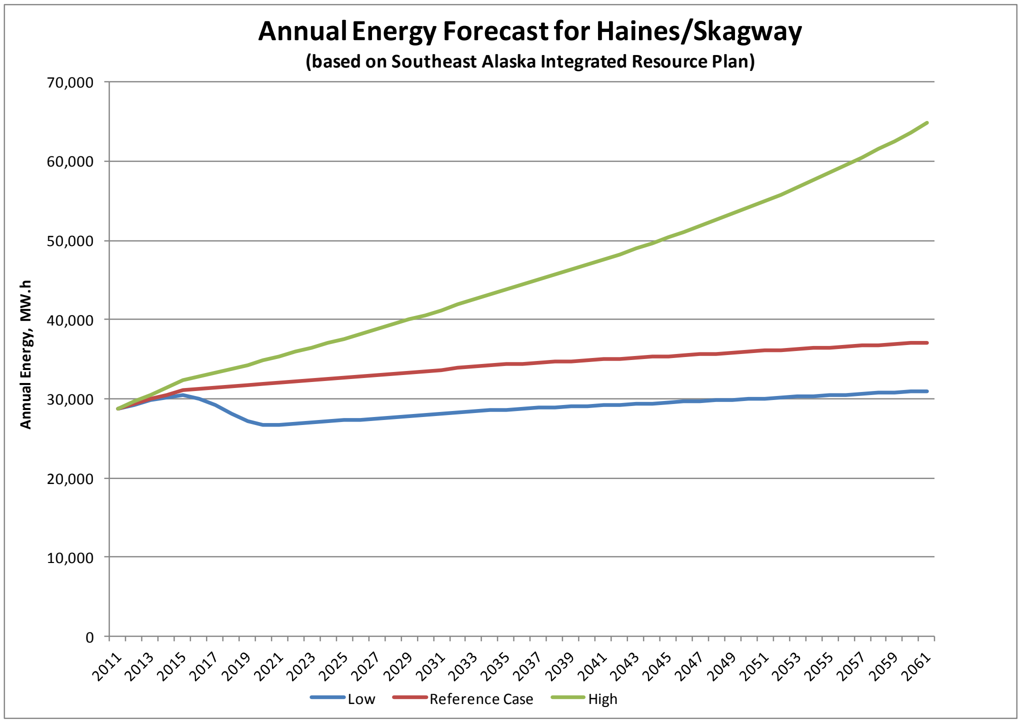
In additional to the Reference Case load forecast, high and low forecasts were also developed in the SEIRP.

- The high forecast scenario considered load growth due to market penetration of plug-in hybrid electric vehicles (PHEVs) as well as load growth related to high economic growth and development (an additional 1% growth in load over the Reference Case scenario to account for increased loads related to faster than expected economic growth and development). The SEIRP (Figure 10-18) indicated that assuming no new hydro generation resources are available prior to 2034, diesel generation will increase to approximately 10 GW.h/year under the high load scenario (see Figure 1).

- The low load forecast scenario considered implementation of a significant Demand Side Management/ Energy Efficiency ("DSM/EE") program. There was significant uncertainty regarding the low load forecast scenario due to limited available data relative to DSM/EE in the Southeast.

Figure 3 provides the SEIRP High and Low Forecast Scenarios compared to the Reference Case load forecast.

Figure 3: Comparison of Annual Energy Forecast for Skagway-Haines area



No potential mine loads were included in the load forecast. However, the SEIRP indicates a new mine is expected to start operation in 2016 (additional 2 MW of load, with total annual energy of 10.5 GW.h assuming a 60% load factor).[4] A second mine is expected to develop in 2020 (with a 10 MW load); however, this mine is not expected to connect to the grid.

1.1.2 Skagway & Haines Cruise Ship Loads

Cruise ships visiting Skagway and Haines in summer currently generate all power requirements on-board using petroleum fuels, with the resulting exhaust creating concerns regarding significant environmental degradation in each community.

However, the cruise ship industry plays an essential role in economy of the region. Economic Impact of Visitors to Southeast Alaska 2010-11, prepared by McDowell Group for Alaska Wilderness League, states that "[v]isitor industry-related spending in Southeast Alaska (described in detail below) generated an estimated 8,000 full- and part-time jobs in Southeast Alaska, and $253 million in annual payroll, during the 2010-11 study period"[5]. The document also notes that, "Skagway owes nearly its entire economy to the visitor industry" (page 23) and Skagway's most popular sightseeing tours in this category are a "streetcar" tour of the downtown area and a longer bus tour to the Yukon (page 10).

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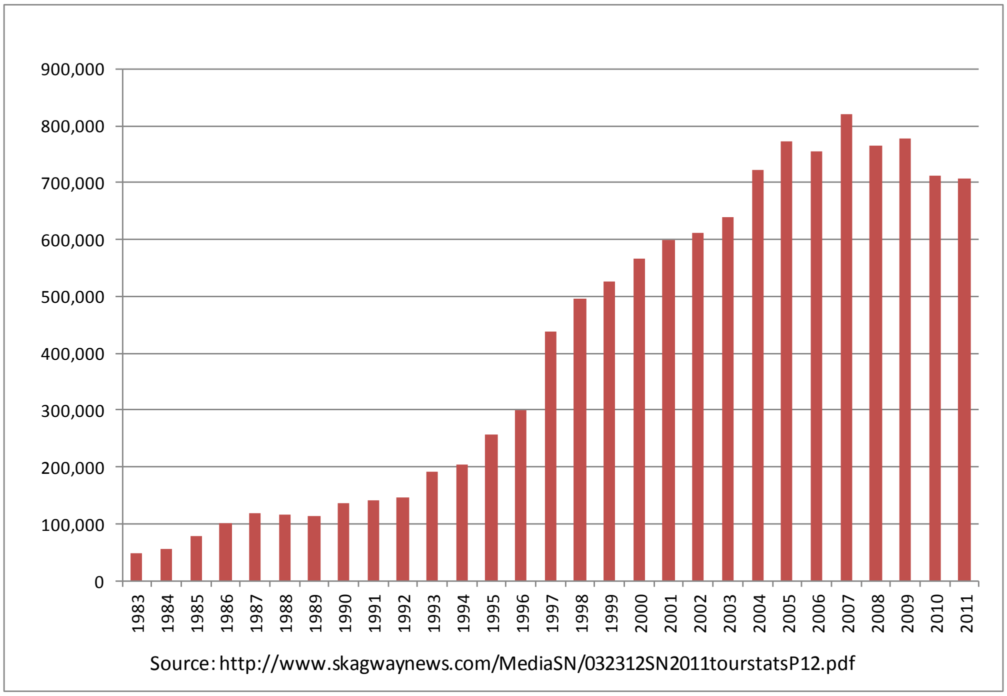
[4] This mine was not included in the forecast due to uncertainty regarding its development and due to the fact that many mines are served by dedicated facilities.
[5] http://www.alaskawild.org/wp-content/uploads/mcdowell_report_final.pdf, page 1.

Figure 4 below provides number of cruise visitors to Skagway for 1983-2011 years, which was above 600,000 for the last 10 years.

Figure 4: Cruise Visitors to Skagway 1983-2011 years[6]



The SEIRP indicates that the total load for all cruise ships docked in Skagway could be as high as 45 GW.h/year[7]. By comparison, the total reference case load forecast for the Skagway-Haines area grid for the 2011-15 period ranges from 28-31 GW.h.

The cruise ship load is seasonal in nature – available information indicates that for 2014 about 30 ships[8] with approximately 796,522 cruisers will dock in Skagway over the period starting in early May and ending in late September. Table 1 below provides the Skagway cruise ship 2014 schedule (with hotel mode power information, where available from earlier sources). The total number of calls in 2014 is estimated to be 423 with an average 14 calls per ship (with an average of 16 calls for larger ships). The time for larger ships in port ranges from 12 to about 14 hours. Each cruise ship can require as much as 11 MW, with potential for 3 or 4 ships in port at any one time.

Figure 5 summarizes the hotel power for cruise ships in Skagway based on 2008 inventory and indicates at least three ships with a load in excess of 10 MW, seven ships with a load between 6 and 10 MW, nine ships with a load between 4 and 6 MW and five ships with a load lower than 2 MW.

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[6] Source: http://www.skagwaynews.com/MediaSN/032312SN2011tourstatsP12.pdf.
[7] Page 8-10 of SEIRP.
[8] All information in this paragraph is based on 2014 Skagway Cruise Schedule, Skagway Convention & Visitors Bureau, http://skagway.com/wp-content/uploads/2012/01/2014-Skagway.pdf.

In order to reduce emissions from cruise ships, the first program to connect cruise ships to shore power, also known as "cold ironing", started in Juneau by Princess Cruisers in 2001. This technology has now grown to include systems in Seattle (2005), Vancouver (2009), San Diego (2010), San Francisco (2010) and Los Angeles (2011), and is planned to roll out in other ports that have made commitments to shore power programs, including New York[9]. The Alaska Cruise Association notes that in Juneau, shore power is available at one dock, allowing the vessel moored there to reduce emissions by plugging into the city's hydroelectric power[10]. The annual power consumption in that dock is about 11-12 GW.h[11].

Availability of cold ironing in Skagway would provide an opportunity for the cruise ship industry and local ports to use the infrastructure to maximize fuel and emissions savings. This could potentially result in increased moorage times in Skagway (and consequently increased port revenues and local expenditures due to longer port calls). It is noted that Juneau experiences longer port calls than other Alaskan ports, in part, due to availability of shore power.[12]

In contrast to the above, it is noted that the Greater Victoria Harbour Authority has opted against pursuit of shore power for cruise ships, indicating that shore power is cost prohibitive investment with limited benefits for ports-of-call such as Victoria[13] and citing recent advancements and investments in new on-board technology, and the implementation of regulations to improve air quality[14]. Over the past year, the main cruise lines calling in Victoria have announced commitments to install scrubber technology[15] on many of their ships. Specifically, Carnival Corporation, which owns Princess Cruise lines, Holland America line and Carnival Cruise Lines, announced that it is installing scrubbers on 38 of its vessels.

The economic analysis for the West Creek Hydro project provided as part of Renewable Energy Fund Round 6 Grant Application of Municipality of Skagway before Alaska Energy Authority[16] assumed an average load for each ship at 7 MW with average docking at 13.5 hours/day. The total generation required for the cruise ships was estimated at about 27.0 GW.h. This economic analysis also estimated the total cost of diesel generation on cruise ships at $0.334/kW.h, including about $0.321/kW.h fuel costs and $0.013/kW.h operating and maintenance expenses; the fuel cost was estimated to increase by 3.75%/year and operating and maintenance expenses by 2.75%/year bringing the total generation cost to $0.464/kW.h in 2025 and $0.556/kW.h in 2030.

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9 Princess Cruisers, http://www.princess.com/news/backgrounders_and_fact_sheets/factsheet/Princess-Ships-Clear-the-Air-with-Shore-Power-Connections.html#.U5nakHJdVbE

10 http://www.cliaalaska.org/safetyenvironment/air/

11 American Association of Port Authorities, http://www.aapa-ports.org/files/SeminarPresentations/06_Cruise_Dow.pdf

12 Personal communication, June 2014

13 The recent press release by the Greater Victoria Harbour Authority indicates that one side of one pier at Ogden Point could be outfitted for $9.5 million, servicing less than one third of total cruise calls.

14 See May 29, 2014 Media Release: "Scrubber Technology Supercedes Shore Power as Preferred Option for Ogden Point: Substantial Investment Deemed Unsuitable for Victoria" at http://gvha.v3.ca/uploaded/scrubber_technology_supercedes_shore_power_option_for_ogden_point.pdf

15 Scrubbers are the term used to describe marine exhaust gas cleaning system which remove sulphur oxides form ships' engines and boiler exhaust gases.

16 The application dated as September 18, 2012.The copy of the application and supporting documents are available at ftp://ftp.aidea.org/RENEWABLE%20ENERGY%20FUND/Round%206%2009242012/918_West%20Creek%20Hydroelectric%20Project/, ftp site of Alaska Industrial Development and Export Authority.

Recent analysis of cruise ships loads as provided by AP&T[17] assumes (as reasonably representative) an average load for each cruise ship of approximately 6.5 MW. Based on information provided by AP&T, eight of the cruise ships scheduled to dock in Skagway in 2014 already have equipment to enable ships to connect to shore power[18] and the other cruise ships docking in Skagway could (if shore power is economically viable) likely also be modified within 1-2 years to receive shoreline power[19].

Figures 6 and 7 below provide estimated potential load requirements for all cruise ships at Skagway that is assumed for assessing the Alaska-Yukon transmission connection, based on the 2014 schedule and an assumed average load at 6.5 MW for each cruise ship. The figures also show the portion of the load for the cruise ships already equipped to connect to shore power.

- Estimated total annual energy requirements for all cruise ships at Skagway approximates 30.0 GW.h[20] with about 10.7 GW.h required for those ships already equipped to connect to shore power.
- Assuming all ships are equipped, the highest peak load occurs at 32.5 MW on September 1st, and the rest of the summer the peak load is about 26 MW.
- In some cases, all docked cruise ships are currently equipped with shore power connections. For example, on May 29 the total estimated load requirements peaks at 26 MW, and all cruise ships scheduled to dock on that day are currently equipped with shore power connection.
- In contrast, in some cases none of the cruise ships docking are currently equipped with shore power connection (for example, June 11).

The Municipality of Skagway Round 6 Funding Application for the West Creek Project discussed concepts for power sale agreements with cruise lines that assumed rates that would be less than the cost of self-generation by the cruise ship, but that would provide an adequate return to the Municipality and the State, i.e., a rate at about 25 cents/kW.h or 90% of the cost of diesel on-board generation by these ships.[21] However, it is noted that a preliminary review of rates in other jurisdictions where shore power is available to cruise ships indicates much lower shore power rates between 8c/kWh and 10c/kWh.

- BC Hydro's F2015 and F2016 Revenue Requirements Rate Application shows Shore Power rates of 8.298 cents/kWh and 8.795 cents/kWh in F2015 and F2016, respectively.

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[17] Personal communication, June 2014.
[18] Princess lines: Golden Princess, Star Princess, Grand Princess and Island Princess; Holland America: Zuiderdam, Oosterdam; and Disney line: Disney Wonder. Princess Cruisers also notes that since 2001, Princess has invested nearly $7 million in equipment alone to enable its vessels to connect to shore power. The 11 ships currently equipped with this technology and three remaining are to be equipped with shore line power in the future.
[19] Alaska Cruise Association also notes [http://www.cliaalaska.org/safetyenvironment/air/] that the Federal Environmental Protection Agency (EPA) has imposed new fuel standards for ships traveling within the 200 nautical miles of the U.S. coast in what is called the North American Emission Control Area (ECA). Beginning in 2015, ships will be required to use fuel containing only 0.1 percent sulfur while traveling within the ECA. Currently, the EPA requires ships to use 1 percent sulfur fuel inside the ECA's boundaries. The future requirements may also encourage cruise ships to modify to receive shore power.
[20] Only for Skagway. The load requirements for Haines area are estimated to be about 1.7 GW.h/year for all ships.
[21] The Municipality's preliminary economic analysis for the Project in 2007 assumed a sales price of $0.252/kWh in 2015 (90% of the expected cost of self-generation by cruise ships with diesel fuel)., escalating at 2.75% per year.

- Alaska Electric Light and Power (AEL&P) provides shore power to Juneau. The shore power for cruise ships are charged at "no-firm" energy rate. Per rate tariff 424-1, effective April 1, 2014 the interruptible forecast sales to Princess Cruise lines estimated at for the period from April 1, 2014 to June 30, 2014 at 1.5 GW.h with rate of $0.10/kW.h.

- Effective April 1, 2014 Nova Scotia Power Incorporated tariff for shore power ranges between 9.056 cents/kW.h and 10.174 cents/kW.h.

Table 1: Skagway Cruise Ship Schedule for 2014

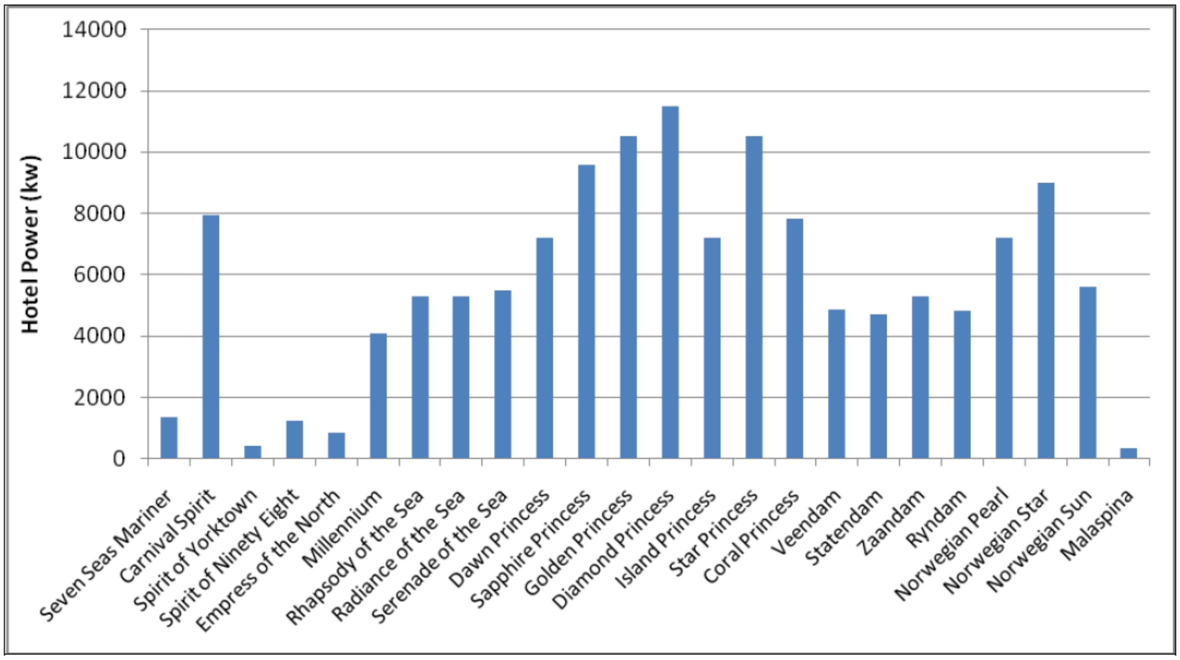
Cruise Lines	Ships	Calls	Capacity	Passengers	Hotel mode power (MW)
Alaskan Dream	Admiralty Dream	3	58	174	
	Alaskan Dream	3	40	120	
	Baranof Dream	5	49	245	
American Cruise	American Spirit	6	100	600	
Carnival	Carnival Miracle	20	2124	42,480	8
Celebrity	Century	2	1814	3,628	
	Millennium	16	1950	31,250	4
	Solstice	19	2850	54,150	
Disney	Disney Wonder	15	2600	39,000	10.3
Holland America	Oosterdam	11	1916	21,076	11.6
	Statendam	10	1258	12,580	4.5
	Volendam	21	1440	30,240	
	Zaandam	20	1440	28,800	5.2
	Zuiderdam	20	1848	36,960	
Norwegian	Norwegian Jewel	18	2376	42,768	9
	Norwegian Pearl	20	2466	49,320	7.2
	Norwegian Sun	19	2002	38,038	5.5
Oceania	Regatta	2	664	1,368	
Princess	Coral Princess	18	1970	35,460	7.8
	Crown Princess	18	3080	55,440	
	Golden Princess	20	2600	52,000	10.5
	Grand Princess	18	2600	46,800	
	Island Princess	18	1970	35,460	9.1
	Pacific Princess	18	680	12,240	
	Star Princess	12	2600	31,200	10.5
Radisson	Seven Seas Navigator	13	500	6,500	1.3
Royal Caribbean	Radiance of the Sea	17	2501	42,517	5.2
	Rhapsody of the Sea	16	2435	38,960	5.2
Silversea	Silver Shadow	17	382	6,494	
Un-Cruise	SS Legacy	8	88	704	
Total	30	423	48,401	796,572	

Notes:

1. Hotel mode power requirements are from 2008 Air Pollution Emission Inventory (February 2, 2010). Source: http://dec.alaska.gov/water/cruise_ships/pdfs/Skagway2008_Final_Emissions_Report.pdf.

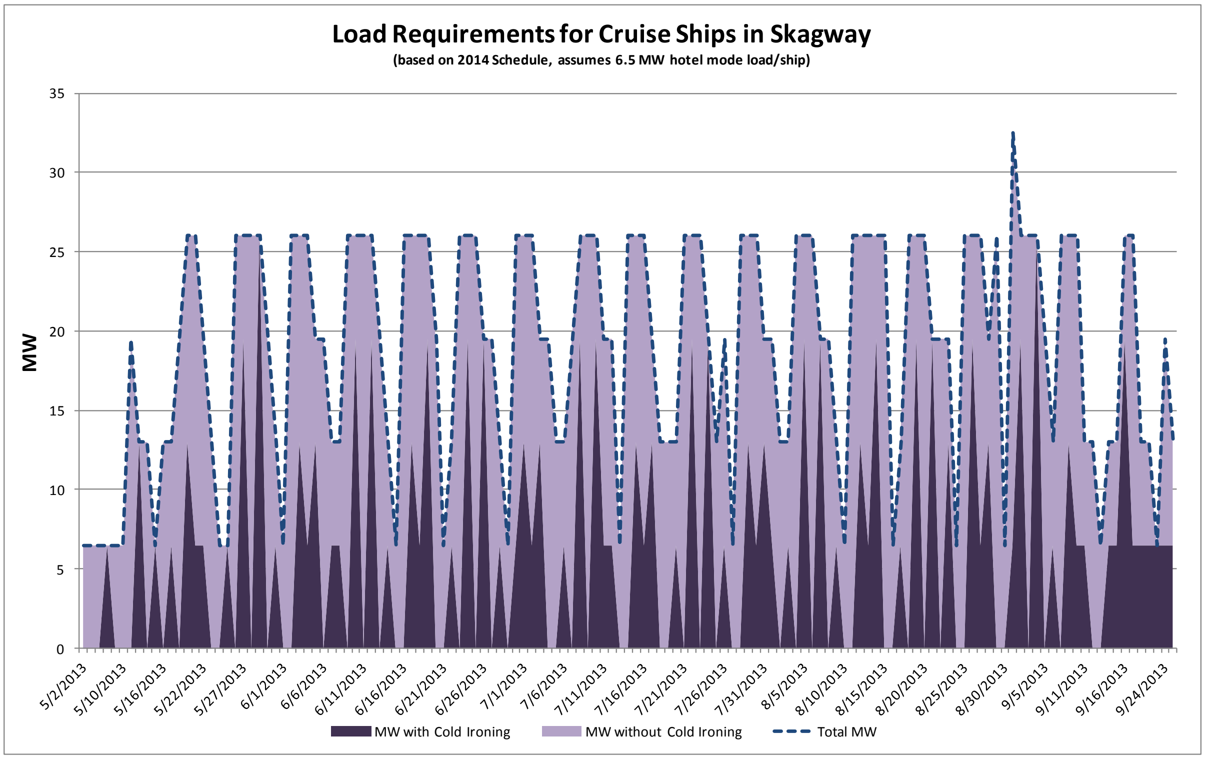
2. Hotel mode power requirements for Disney Wonder, Oosterdam and Island Princess are Shore Power Feasibility Study prepared by AECOM for Greater Victoria Harbour Authority at http://gvha.v3.ca/uploaded/aecom%20shore%20power%20feasbility%20study%20final.pdf.

Figure 5: Hotel Power of Cruise Ships in Skagway (2008 Information)[22]



[22] 2008 Air Pollution Emission Inventory (February 2, 2010), Figure 2 on page 5, http://dec.alaska.gov/water/cruise_ships/pdfs/Skagway2008_Final_Emissions_Report.pdf.

Figure 6: Load Requirements for Cruise Ships in Skagway based on 2014 Schedule (MW)[23]



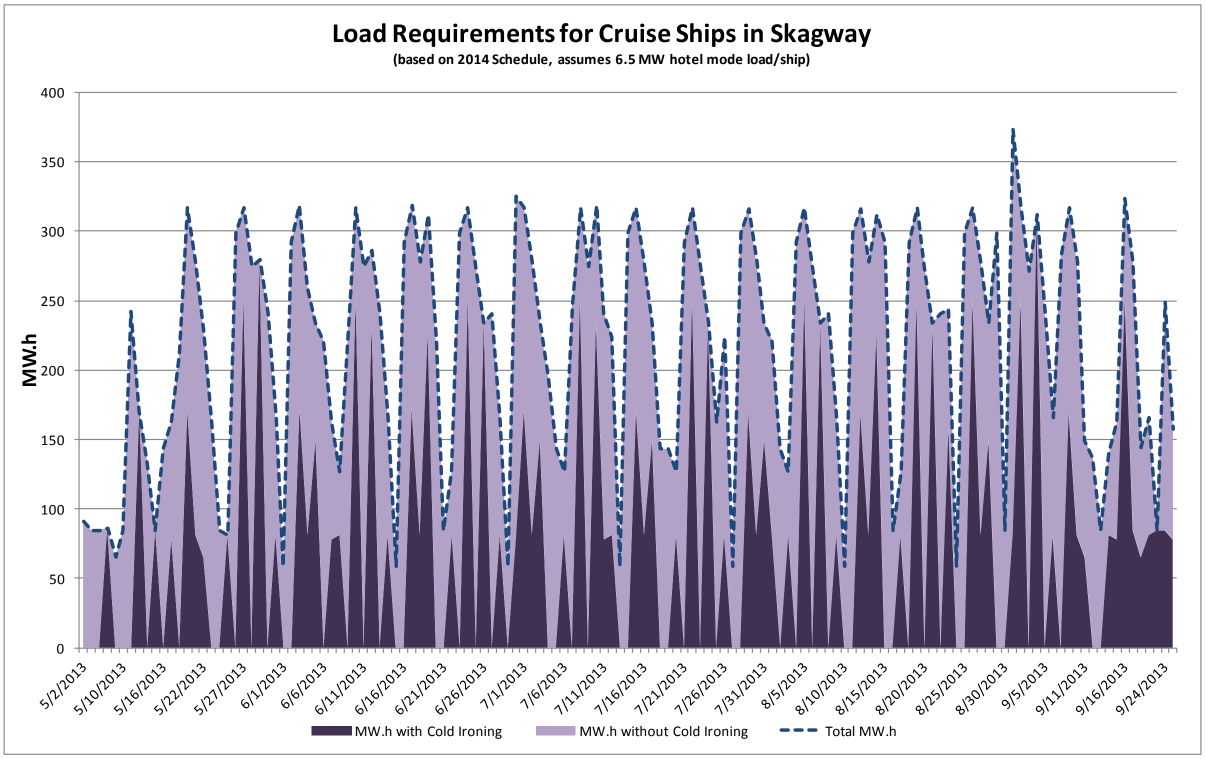
	May-02	May-12	May-13	May-14	May-15	May-27	May-28	May-29	May-30	May-31	Jun-10	Jun-11	Jun-12	Jun-17	Jun-18	Jun-19
Total MW	6.5	19.5	13	13	6.5	26	26	26	19.5	13	26	26	26	26	26	26
With Cold Ironing (MW)	0	0	13	0	6.5	19.5	0	26	0	6.5	19.5	0	19.5	13	6.5	19.5
Without Cold Ironing (MW)	6.5	19.5	0	13	0	6.5	26	0	19.5	6.5	6.5	26	6.5	13	19.5	6.5

	Jun-22	Jun-28	Jun-29	Jun-30	Jul-01	Jul-12	Jul-13	Jul-14	Jul-15	Jul-16	Jul-26	Jul-27	Jul-28	Aug-02	Aug-03	Aug-04
Total MW	13	13	6.5	26	26	19.5	6.5	26	26	26	19.5	6.5	26	13	13	26
With Cold Ironing (MW)	6.5	6.5	0	6.5	13	6.5	0	0	13	6.5	6.5	0	0	0	6.5	0
Without Cold Ironing (MW)	6.5	6.5	6.5	19.5	13	13	6.5	26	13	19.5	13	6.5	26	13	6.5	26

	Aug-07	Aug-13	Aug-14	Aug-15	Aug-16	Aug-27	Aug-28	Aug-29	Aug-30	Sep-01	Sep-12	Sep-13	Sep-14	Sep-20	Sep-23	Sep-24
Total MW	19.5	26	26	26	6.5	26	19.5	26	6.5	32.5	13	6.5	13	13	6.5	19.5
With Cold Ironing (MW)	19.5	6.5	19.5	0	0	6.5	13	0	0	6.5	0	0	6.5	6.5	6.5	6.5
Without Cold Ironing (MW)	0	19.5	6.5	26	6.5	19.5	6.5	26	6.5	26	13	6.5	6.5	6.5	0	13

[23] Prepared based on information provided by AP&T, which assumes 2014 schedule and the average load at 6.5 MW/ship. In order to reduce the table size some of the days in the table were suppressed.

Figure 7: Load Requirements for Cruise Ships in Skagway based on 2014 Schedule (MW.h)[24]



	May-02	May-12	May-13	May-14	May-15	May-27	May-28	May-29	May-30	May-31	Jun-10	Jun-11	Jun-12	Jun-17	Jun-18	Jun-19
Total MW.h	91	242	171	133	85	317	275	280	241	166	317	275	286	319	278	312
With Cold Ironing (MW.h)			171		85	252		280		81	252		234	172	81	228
Without Cold Ironing (MW.h)	91	242	0	133	0	65	275	0	241	85	65	275	52	146	197	85

	Jun-22	Jun-28	Jun-29	Jun-30	Jul-01	Jul-12	Jul-13	Jul-14	Jul-15	Jul-16	Jul-26	Jul-27	Jul-28	Aug-02	Aug-03	Aug-04
Total MW.h	127	166	59	325	317	224	59	299	317	278	224	59	299	143	127	293
With Cold Ironing (MW.h)	81	81		78	171	81			171	81	81				81	
Without Cold Ironing (MW.h)	46	85	59	247	146	143	59	299	146	197	143	59	299	143	46	293

	Aug-07	Aug-13	Aug-14	Aug-15	Aug-16	Aug-27	Aug-28	Aug-29	Aug-30	Sep-01	Sep-12	Sep-13	Sep-14	Sep-20	Sep-23	Sep-24
Total MW.h	234	278	312	293	85	278	234	299	85	374	137	85	140	166	85	249
With Cold Ironing (MW.h)	234	81	228			81	150			81			81	81	85	85
Without Cold Ironing (MW.h)	0	197	85	293	85	197	85	299	85	293	137	85	59	85	0	164

[24] Prepared based on information provided by AP&T, which assumes 2014 schedule and average load at 6.5 MW/ship. In order to reduce the table size some of the days in the table were suppressed.

1.2 YUKON GRID

Yukon grid fossil fuel (diesel or natural gas using LNG) generation requirements for the period to 2030 are reviewed in this section.

Yukon Integrated Grid Annual Forecast Scenarios

Yukon Energy is the main generator and transmitter of electrical energy in Yukon. Yukon Energy's most recent 2011 Resource Plan load forecast update through to 2030 (prepared in November 2013 and used in Yukon Energy's Whitehorse-Diesel Natural Gas Conversion Project Application filed in December 2013) is provided as Attachment A.

Forecast grid thermal generation in the updated Yukon Energy Resource Plan reflects the extent to which forecast grid loads exceed long-term average generation from existing and committed grid hydro and wind generation. Almost all thermal generation on the Yukon grid occurs over the winter months (from November to May). Concentration of diesel generation outside of the summer months (from June to October) is a key feature of the Yukon grid under a wide range of load and water conditions and reflects seasonal variation on grid loads and seasonal variation in grid hydro generation for existing and committed facilities.

Forecast grid fossil fuel thermal generation requirements over the planning period for the four load forecast scenarios included in the most recent updated Resource Plan load forecast update are summarized in Table 2 and Figure 8 below. This Base Case forecast shows expected default fossil fuel generation requirements after load reductions from DSM programs[25] - but prior to development of any new non-diesel generation supply capacity on the grid.

Over the period of the 2011 Resource Plan preparation considerable attention was directed at the potential connection of the Victoria Gold mine north of Keno as well as the Carmacks Copper mine west of the Carmacks-Stewart Transmission Line. Although the Victoria Gold mine completed its YESAB review process, the project has stalled currently at the financing and final engineering phase. The Carmacks Copper mine project has also apparently stalled at this time, and it appears that no new YESAB Project Proposal has yet been filed for this project.

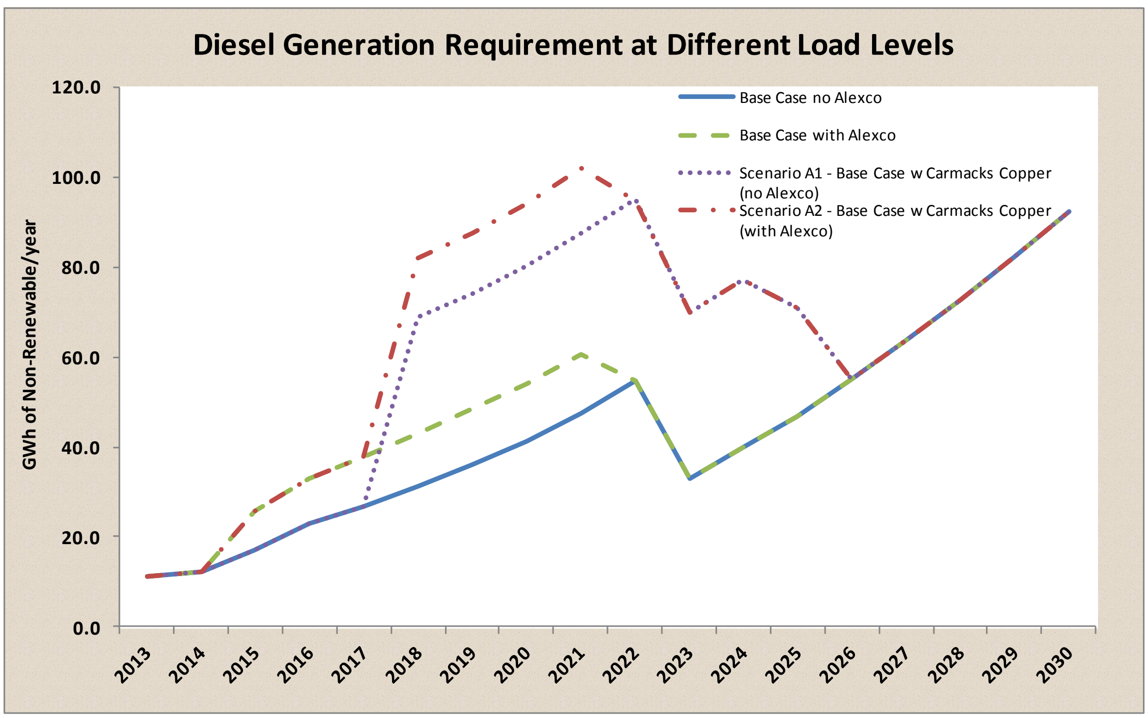
[25] DSM/SSE is assumed at 32% of annual load growth based on Yukon Electricity Conservation and Demand Management Potential Review (CPR) report prepared by ICF Marbek (January 2012); to reflect proposed DSM plans (YECL 2013-15 GRA goal of 8.5 GWh/year sustained electricity savings by 2018), impact reduced for the first year (2015) taking ¼ of the assumed 32%, 2/3 for 2016 and at full 32% starting form 2017.

Table 2 Forecast Yukon Grid Default Fossil Fuel Generation Requirement[1]
Four Load Forecast Scenarios (2013-2030)

Year	2013	2015	2020	2025	2030
Base Case (no Alexco Mine[2])	11 GW.h	17 GW.h	41 GW.h	47 GW.h	93 GW.h
Base Case (with Alexco Connected[3])	11 GW.h	26 GW.h	54 GW.h	47 GW.h	93 GW.h
Base Case with Carmacks Copper Mine (No Alexco mine[4])	11 GW.h	17 GW.h	80 GW.h	71 GW.h	93 GW.h
Base Case with Carmacks Copper (with Alexco mine connected)	11 GW.h	26 GW.h	94 GW.h	93 GW.h	93 GW.h

1. Default fossil fuel generation requirement based on long-term average hydro and wind generation, prior to development of any new non-fossil fuel generation supply capacity on the grid (beyond what is permitted in 2013).
2. Non-industrial growth at 2.26%/year for 2015, 2.45%/year for 2016-2020 inclusive, at 2.28% for 2021-2025 inclusive, at 3.13%/year for 2026 and thereafter based on load estimates in Yukon Electricity Conservation and Demand Management Potential Review (CPR) report prepared by ICF Marbek (January 2012) for hydro grid ; Minto generation load (including grid losses) at 34.6 GW.h/year in 203, 38 GW.h/year for 204, 40.2 GW.h/year for 2015 and at 43.5 GW.h/year for 2016-2022. Alexco generation load (includes grid losses) at 9 GW.h for 2013 and no load thereafter.
3. Assumes Alexco reopens in 2015 with loads similar to what had been forecast in the past, with generation load (including grid losses) at 15.2 GW.h for 2015, at 17.4 GW.h for 2016 through 2021 (no load thereafter).
4. Base Case with Carmacks Copper mine, starting January 1, 2018 with generation load (including grid losses) of 54.4 GW.h/year that continues until the end of 2014, and 27 GW.h/year for 2025, and no load thereafter.

Figure 8: Diesel Generation Requirements at Different Forecast Loads: 2013-2030



Source: Yukon Energy Updated Resource Plan Forecast (see Attachment A). Default diesel generation includes all fossil fuel generation (e.g., includes natural gas generation using LNG from BC or Alberta) and assumes long-term average hydro and wind generation with no new renewable generation capacity.

Diesel generation forecasts for each load scenario reflect long-term average hydro generation, i.e., the average hydro generation over 28 to 31 recorded water year conditions[26] at the assumed load, as estimated by the power benefits model used by YEC for grid generation planning.

Historically, diesel generation was the default grid thermal generation option in Yukon. However, with the planned construction of the Whitehorse Diesel-Natural Gas Conversion Project in 2014, the default thermal generation option is expected to be met almost entirely by use of lower cost natural gas (supplied by liquefied natural gas from B.C. or Alberta).

Load Sensitivity re: Demand Side Management/Supply Side Enhancement (DSM/SSE)

As noted in the footnote above, the updated load forecast assumes DSM/SSE at 32% of annual load growth based on the Yukon Electricity Conservation and Demand Management Potential Review (CPR) report prepared by ICF Marbek (January 2012) and proposed DSM plans (YECL 2013-15 GRA goal of 8.5 GWh/year sustained electricity savings by 2018), with the impact reduced for the first year (2015) taking ¼ of the assumed 32%, 2/3 for 2016 and at full 32% starting from 2017. The load forecasts provided in Attachment A are net of DSM/SSE.

Table C-1 in Attachment A provides assumed DSM/SSE for each year for load forecast purposes, which is assumed to be 0.6 GW.h in 2015, increasing to 8.4 GW.h by 2018, 14.6 GW.h in 2020, 34.3 GW.h in 2025 and 59.5 GW.h in 2030[27]. Table 3 below provides diesel requirement with DSM/SSE and without DSM/SSE under four different load scenarios.

Figure 9 illustrates the difference in diesel requirement with and without DSM/SSE under the following load scenarios:

- Base Case (without Alexco)
- Scenario A1 (with Carmacks Copper but without Alexco)

[26] The long-term average (LTA) diesel generation estimates for 2013 and 2014 years are based on the YECSIM-based table used for the approved 2012 GRA diesel generation forecasts, which uses 28 recorded water year conditions through to 2008, Aishihik 10-year rolling average for 1999-2008, and Mayo Lake rating curve based on licence conditions assuming no outlet channel constraints. The diesel generation estimates for 2015 and beyond are based on YECSIM power benefits model runs with updated recorded water year conditions for 1981-2011 (30 years), Aishihik 10-year rolling average for 2002-2011, and Mayo Lake rating curve based on Mayo Lake outlet channel existing conditions (recent study by KGS shows that sediments in Mayo Lake outlet channel from over 50 year operation constrains water flow through channel at low lake levels).

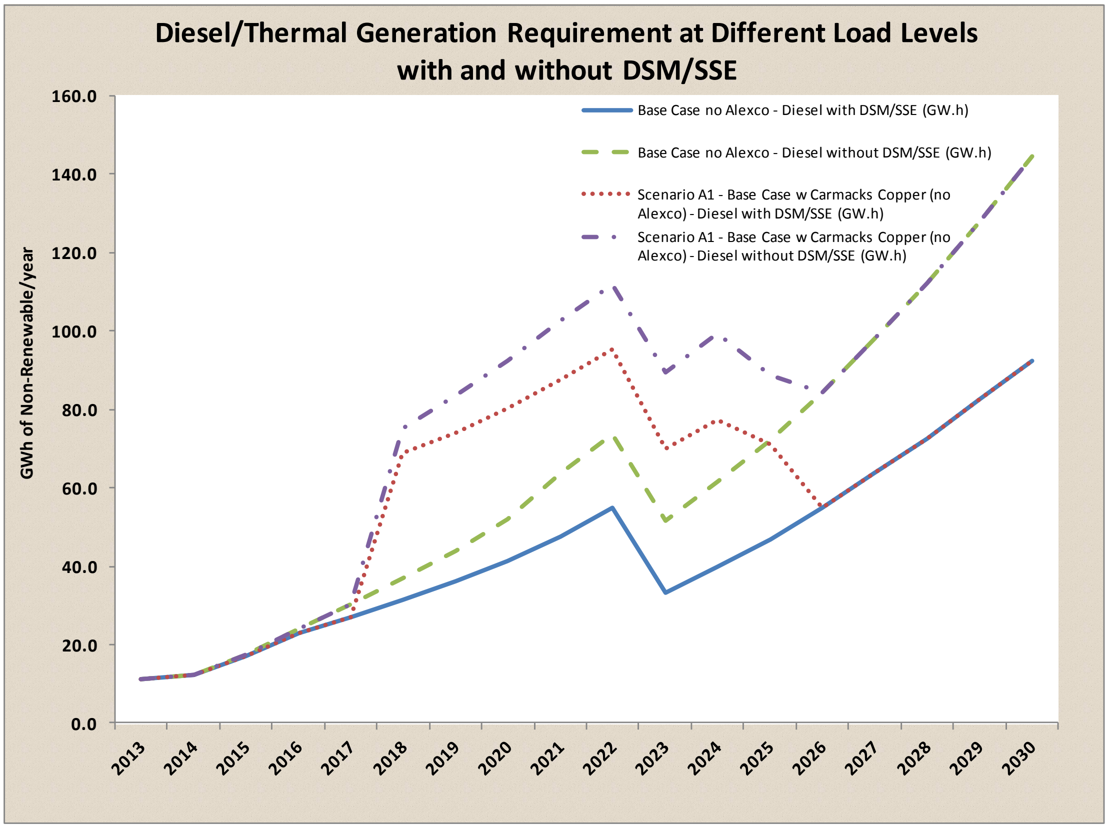
[27] Under Yukon Five Year Demand Side Management Plan provided in YECL 2012-15 GRA (calculated based on Appendix G1, Exhibit C 11 and Exhibit 55 for residential sector, and Exhibit 20 and Exhibit 57 in Appendix G3 for commercial sector) the lower Achievable Potential DSM/SSE for hydro grid estimated to be at about 10.4 GW.h in 2015, 23.9 GW.h in 2020, 40.1 GW.h in 2025 and 63.7 GW.h in 2030.

Table 3: Long-Term Average Thermal Generation at Different Forecast Loads with and without DSM/SSE: 2013-2030[28]

Forecast Years	Base Case no Alexco		Base Case with Alexco		Scenario A1 - Base Case w Carmacks Copper (no Alexco)		Scenario A2 - Base Case w Carmacks Copper (with Alexco)	
	Diesel with DSM/SSE (GW.h)	Diesel without DSM/SSE (GW.h)	Diesel with DSM/SSE (GW.h)	Diesel without DSM/SSE (GW.h)	Diesel with DSM/SSE (GW.h)	Diesel without DSM/SSE (GW.h)	Diesel with DSM/SSE (GW.h)	Diesel without DSM/SSE (GW.h)
2013	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
2014	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3
2015	17.0	17.2	25.7	26.0	17.0	17.2	25.7	26.0
2016	22.9	24.2	33.1	34.6	22.9	24.2	33.1	34.6
2017	26.9	30.3	37.6	41.5	26.9	30.3	37.6	41.5
2018	31.4	36.8	42.8	49.1	68.9	74.9	81.8	88.5
2019	36.1	43.9	48.3	57.0	74.1	83.4	87.6	97.8
2020	41.1	51.9	54.0	64.9	80.1	92.4	94.2	107.2
2021	47.4	63.7	60.7	74.3	87.5	102.7	102.2	116.8
2022	54.7	73.8	54.7	73.8	95.2	111.9	94.8	113.7
2023	33.1	51.5	33.1	51.5	69.8	89.4	69.8	89.4
2024	39.8	61.5	39.8	61.5	77.2	99.2	77.2	99.2
2025	46.8	72.0	46.8	72.0	71.0	88.9	71.0	88.9
2026	55.0	84.4	55.0	84.4	55.0	84.4	55.0	84.4
2027	63.6	97.8	63.6	97.8	63.6	97.8	63.6	97.8
2028	72.7	112.2	72.7	112.2	72.7	112.2	72.7	112.2
2029	82.3	127.7	82.3	127.7	82.3	127.7	82.3	127.7
2030	92.5	144.6	92.5	144.6	92.5	144.6	92.5	144.6

[28] The long-term average diesel (or thermal) generation estimates are prepared based on forecast diesel generation with DSM/SSE load scenarios and subject to further refinements/adjustments as required. Please see Attachment A to the Background Paper #1.

Figure 9: Diesel/Thermal Generation Requirements at Different Forecast Loads with and without DSM/SSE: 2013-2030



Consideration of Electrically Heated Residential and Commercial Buildings

As indicated in notes to Table 2 above, the updated load forecast uses non-industrial growth at 2.45%/year for 2016-2020 inclusive, at 2.82%/year for 2021-2025 inclusive, at 3.13%/year for 2026 and thereafter based on Reference Case growth rate for Hydro Grid in Yukon Electricity Conservation and Demand Management Potential Review (CPR) report prepared by ICF Marbek (January 2012).

ICF Marbek in its Report notes[29] that the load growth for Reference Cases are higher than YEC's 2011 20-Year Resource Plan[30] largely because projections of construction of electrically heated residential dwellings and commercial buildings have been revised since the publication of YEC's Resource Plan forecast. This indicates that the near-term load forecast provided in Attachment A already reflects load for potential space heating for residential and commercial buildings.

Figure 10 and 11 below provides a breakdown of the Reference Case load from ICF Marbek's CPR Report, which shows a large increase in electricity consumption for space heating for both residential and commercial rate classes in 2030 compared to 2010 (base year for Marbek's load forecast). ICF Marbek notes that space heating is expected to rise to 24% of residential electricity consumption. The growth in

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[29] Appendix A - Conservation Potential Review Technical Summary, page 21 for Residential and page 30 for Commercial, Yukon Five Year Demand Side Management Plan provided in YECL 2012-15 GRA.
[30] The initial update to 20-year Resource Plan (December 2011) used 2.26% growth rate for non-industrial load.

the commercial sector's electricity consumption is expected to be driven in large part by increases in space heating electricity consumption, which is projected to grow 179% between 2010 and 2030. This growth is expected to be caused by a large number of new electrically heated buildings being introduced to the building stock. The move toward electric space heating in new buildings is predicted to cause a 211% increase in electricity consumption for water heating because owners of electrically heated buildings rarely invest in fossil fuel infrastructure for water heating only. In terms of absolute contribution, space heating is expected to account for the largest portion of overall load growth (approximately one-third of total commercial sector load growth).

Figure 10: ICF Marbek Reference Case Load Forecast Residential Section End Use

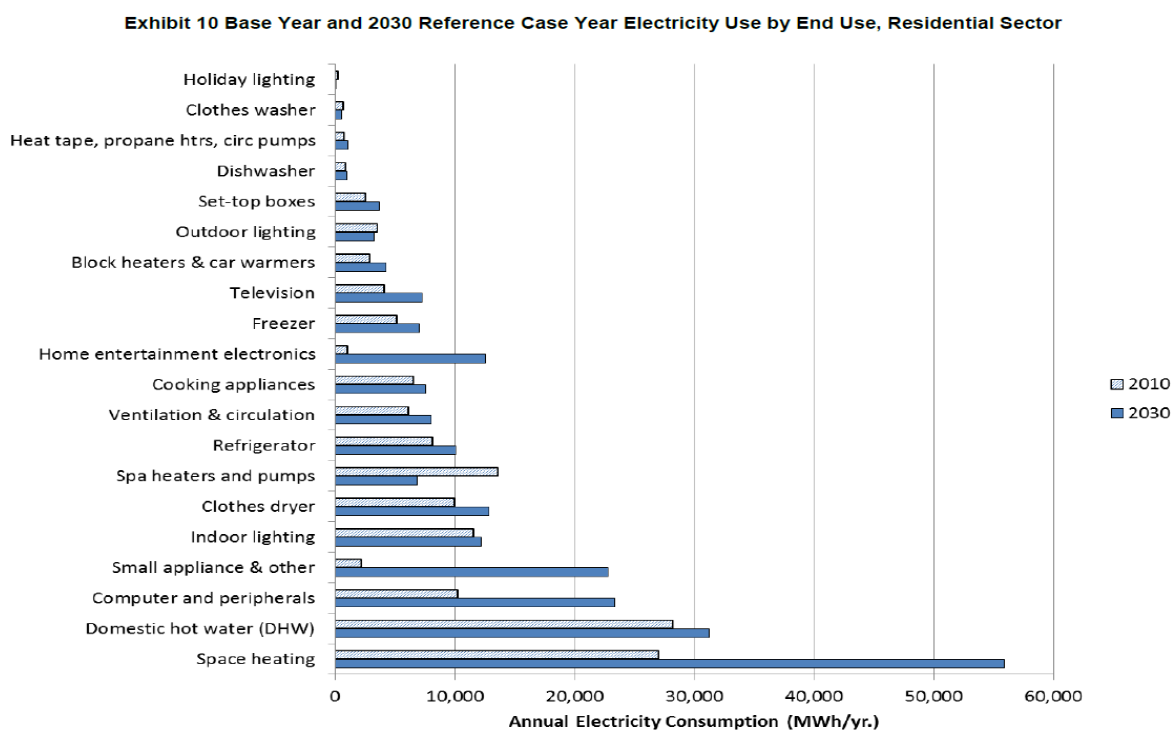
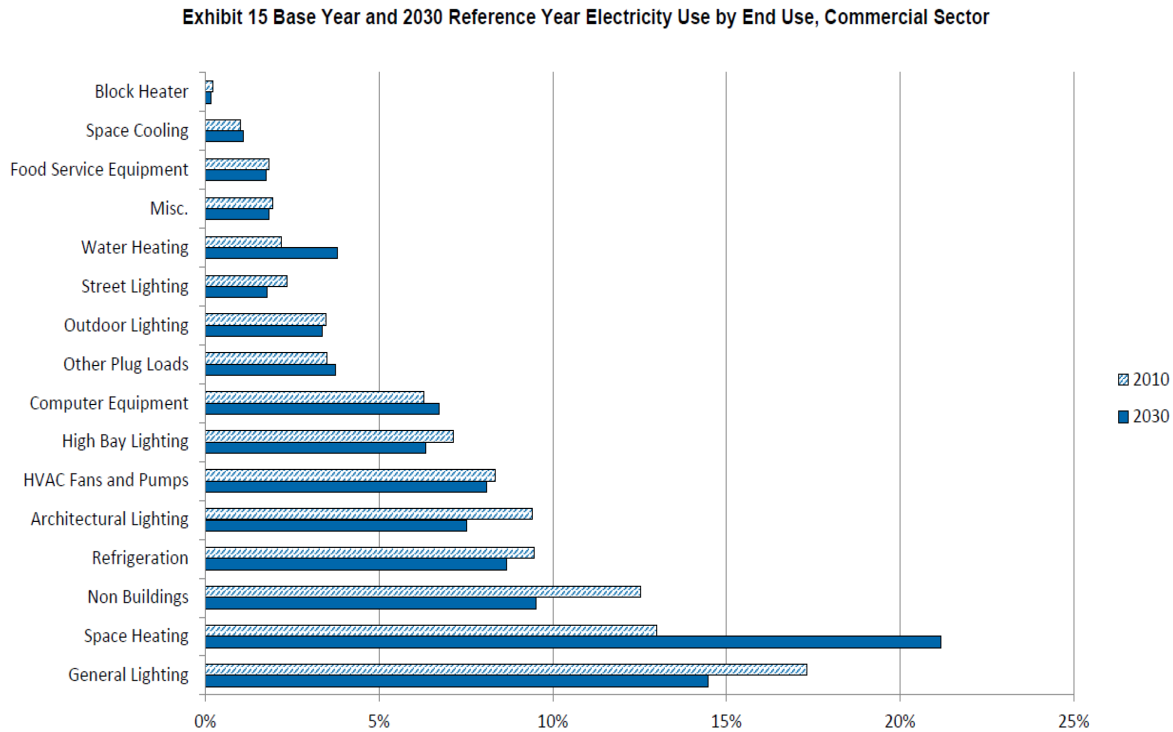


Figure 11: ICF Marbek Reference Case Load Forecast Commercial Section End Use



ATTACHMENT A - UPDATED NEAR-TERM GRID LOAD SCENARIOS

The 2011 Resource Plan grid load scenarios as set out in Appendix A to the Overview of 20-Year Resource Plan: 2011-2030 are updated on an ongoing basis (the last update was March 2013). The November 2013 update includes four scenarios to reflect the timing for connection or reopening of mines[31] and the load update for non-industrial and existing mine loads.

Line losses for the Integrated Grid are assumed at 8.7% for all load, including industrial load - this is consistent with 2012/13 GRA approved forecast.

1. Two Base Case load scenarios are examined (assume no connection of major new mines):

    a. **Base Case no Alexco after fall 2013:**

        i. Updated non-industrial forecast load for 2013 and 2014[32], reflecting the following:

            - Non-industrial growth at 2.26%/year for 2015, at 2.45%/year for 2016-2020 inclusive, at 2.82%/year for 2021-2025 inclusive, at 3.13%/year for 2026 and thereafter; and
            - DSM/SSE assumed at 32% of annual load growth based on Yukon Electricity Conservation and Demand Management Potential Review (CPR) report prepared by ICF Marbek (January 2012); to reflect proposed DSM plans (YECL 2013-15 GRA goal of 8.5 GW.h/year sustained electricity savings by 2018), impact reduced for the first year (2015) taking ¼ of the assumed 32%, 2/3 for 2016, and at full 32% starting from 2017.

        ii. Minto generation load (includes grid losses) at 34.6 GW.h/2013, 38.0 GW.h/2014, 40.2 GW.h/2015 and at 43.5 GW.h/year for 2016-2022 (no load thereafter)[33]; and

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[31] This update does not include Whitehorse Copper Tailings (WHCT), Brewery Creek and Victoria Gold new industrial loads based on current information WHCT development is currently too uncertain to include in the update. Brewery Creek development was cancelled in early 2013. Victoria Gold received its Quartz Mining Licence for the Eagle Gold Project in September 2013; however, the timing for development is uncertain due to financial market conditions (2016 is the current stated focus to start production).

[32] Non-industrial load forecast for 2013 is based on January-October preliminary actuals and November-December updated forecasts. The 2013 updated YEC non-industrial load forecast (340 GW.h excluding grid losses) is about 2 GW.h lower than 2013 GRA approved forecast due to lower wholesales; however, the GRA approved wholesales forecast included 5.1 GW.h related to WHCT (which did not connect in 2013), i.e., overall updated non-industrial load for 2013 is forecast about 3 GW.h higher than the approved GRA forecast with January-October actuals as reported reflecting warmer than normal temperature conditions. The 2014 forecast is based on YEC's latest update which uses 2.26% growth rate over weather normalized 2013 full-year-forecast wholesales (308.5 GW.h) reduced by 4.36 GW.h to reflect Fish Lake Unit #1 being in operation in 2014. The non-industrial growth rates remain unchanged from the March 2013 update: 2011 Resource Plan forecast annual growth rate for non-industrial load for 2014 and 2015; annual growth rates for 2016-2020, 2021-2025 and 2026-2030 are from Marbek's final CPR report.

[33] Minto generation load forecast reflects updates reviewed with Minto in fall 2013.

iii. Alexco generation load (includes grid losses) at 9 GW.h for 2013 and no load thereafter[34].

b. **Base Case with Alexco:**

i. This scenario assumes Alexco reopens in 2015 with loads similar to what had been forecast in the past, with generation load (includes grid losses) at 15.2 GW.h for 2015, at 17.4 GW.h for 2016 though 2021 (no load thereafter)[35].

2. Load scenarios with connection of major new mines[36]:

a. **Scenario A1 – no Alexco:** Base Case with Carmacks Copper mine, starting January 1, 2018 with generation load (including grid losses) of 54.4 GW.h/yr that continues until the end of 2024 and 27 GW.h/yr for 2025 (no load thereafter)[37].

b. **Scenario A2 - with Alexco:** Scenario A1 plus Alexco load.

Table C-1 below summarizes Integrated Gird load scenarios for 2013-2030 years.

[34] In July 2013 Alexco Resource Corp. announced that it will close Bellekeno mine for winter and will reopen in spring of 2014 assuming the silver market has improved. Although the project could reopen in 2014, there is no current basis for addressing a 2014 forecast update - and the time of reopening of the mine is very uncertain. To address this uncertainty, two separate cases were prepared for the Base Case with and without Alexco. The case with Alexco assumes mine re-opening in 2015.
[35] On December 5, 2013 Alexco announced a strategy to initiate development of the Flame & Moth mine in 2014 as a first step to achieving commercial production from this deposit in 2015; recommissioning of the Bellekeno mine would begin later in 2014 so that this mine would be ready to simultaneously go into production along with Flame & Moth near the beginning of 2015. The current grid load update has not attempted to assess Alexco loads specific to this recent announcement.
[36] Scenario A1 assumes no Victoria Gold compared to Scenario A in March 2013 update, which included Victoria Gold mine. Victoria Gold received its Quartz Mining Licence for the Eagle Gold Project in September 2013; however, the timing for development is uncertain due to financial market conditions (2016 is the current stated focus to start production).
[37] Carmacks Copper has recently re-started its regulatory review processes, with an announced filing of a revised application planned this year or early 2014 with YESAB, followed shortly thereafter with revised filing with the YWB. PPA discussions occurred in the past – Carmacks Copper will be required to pay all costs required for grid connection plus a contribution to CSTP capital costs. The timing for connection of this mine remains uncertain, but could potentially occur by Q1 2018.

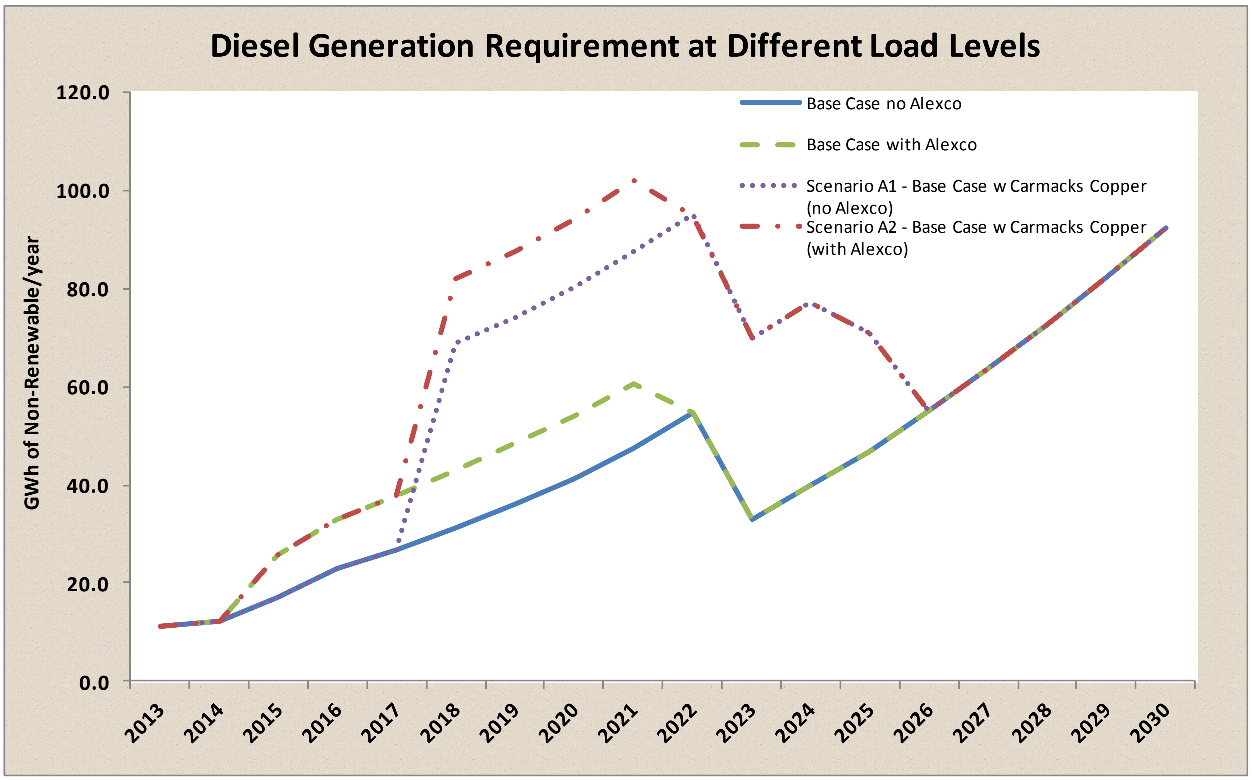
Table C-1: Updated Grid Load Scenarios

Forecast Years	Base Case no Alexco			Base Case with Alexco			Scenario A1 - Base Case w Carmacks Copper (no Alexco)			Scenario A2 - Base Case w Carmacks Copper (with Alexco)			Non-Industrial DSM/SSE (GW.h)
	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	
2013	369.9	43.5	413.4	369.9	43.5	413.4	369.9	43.5	413.4	369.9	43.5	413.4	0.0
2014	377.9	38.0	416.0	377.9	38.0	416.0	377.9	38.0	416.0	377.9	38.0	416.0	0.0
2015	386.1	40.2	426.3	386.1	55.4	441.5	386.1	40.2	426.3	386.1	55.4	441.5	0.6
2016	393.9	43.5	437.3	393.9	60.9	454.7	393.9	43.5	437.3	393.9	60.9	454.7	2.5
2017	400.9	43.5	444.3	400.9	60.9	461.7	400.9	43.5	444.3	400.9	60.9	461.7	5.4
2018	408.0	43.5	451.5	408.0	60.9	468.9	408.0	97.8	505.9	408.0	115.2	523.3	8.4
2019	415.4	43.5	458.9	415.4	60.9	476.3	415.4	97.8	513.2	415.4	115.2	530.6	11.5
2020	422.9	43.5	466.4	422.9	60.9	483.8	422.9	97.8	520.7	422.9	115.2	538.1	14.6
2021	431.8	43.5	475.3	431.8	60.9	492.7	431.8	97.8	529.6	431.8	115.2	547.0	18.4
2022	441.0	43.5	484.4	441.0	43.5	484.4	441.0	97.8	538.8	441.0	97.8	538.8	22.2
2023	450.4		450.4	450.4		450.4	450.4	54.4	504.7	450.4	54.4	504.7	26.1
2024	460.0		460.0	460.0		460.0	460.0	54.4	514.4	460.0	54.4	514.4	30.1
2025	470.0		470.0	470.0		470.0	470.0	27.0	496.9	470.0	27.0	496.9	34.3
2026	481.3		481.3	481.3		481.3	481.3		481.3	481.3		481.3	39.0
2027	493.0		493.0	493.0		493.0	493.0		493.0	493.0		493.0	43.9
2028	505.1		505.1	505.1		505.1	505.1		505.1	505.1		505.1	48.9
2029	517.6		517.6	517.6		517.6	517.6		517.6	517.6		517.6	54.1
2030	530.4		530.4	530.4		530.4	530.4		530.4	530.4		530.4	59.5

Figure C-1 and Table C-2 provide the forecast diesel generation requirement during the 20-year planning period for each of the load scenarios, assuming no new non-diesel generation resources.

1. The forecast diesel generation for each scenario is based on updated load for 2013-2030 (Table A-1), and long-term average (LTA) diesel requirements as reviewed below. Actual diesel requirements in any year will be affected by actual water and weather conditions.
2. LTA YECSIM model run with Aishihik 10-year rolling average rule, and no new renewable resources[38]. Potential displacement of diesel by natural gas (LNG) is not considered.

Figure C-1: Diesel Generation Requirements at Different Forecast Loads: 2013-2030



Diesel generation forecasts for each load scenario reflect long-term average hydro generation, i.e., the average hydro generation over 28 to 31 recorded water year conditions[39] at the assumed load, as estimated by the power benefits model used by YEC for grid generation planning.

Table C-2: Long-Term Average Diesel Generation at Different Forecast Loads: 2013-2030

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[38] For example, excludes Mayo Lake, Marsh Lake, or other new hydro enhancement or other renewable energy projects. The earliest potential timing currently estimated for securing new hydro generation benefits from the Mayo Lake Project is winter 2015/16 (thermal energy savings in 2016), and from the Marsh Lake project is winter 2016/17 (thermal energy savings in 2017). The combined impact of both projects would likely reduce long-term average diesel generation by approximately 10 GW.h/year.

[39] The long-term average (LTA) diesel generation estimates for 2013 and 2014 years are based on YECSIM-based table used for the approved 2012 GRA diesel generation forecasts, which uses 28 recorded water year conditions through to 2008, Aishihik 10-year rolling average for 1999-2008, and Mayo Lake rating curve based on licence conditions assuming no outlet channel constraints. The diesel generation estimates for 2015 and beyond are based on YECSIM power benefits model runs with updated recorded water year conditions for 2001-2011, Aishihik 10-year rolling average for 2002-2011, and Mayo Lake rating curve based on Mayo Lake outlet channel existing conditions (recent study by KGS shows that sediments in Mayo Lake outlet channel from over 50 year operation constrains water flow through channel at low lake levels).

Forecast Years	Base Case no Alexco		Base Case with Alexco		Scenario A1 - Base Case w Carmacks Copper (no Alexco)		Scenario A2 - Base Case w Carmacks Copper (with Alexco)	
	Total Generation (GW.h)	Diesel (GW.h)	Total Generation (GW.h)	Diesel (GW.h)	Total Generation (GW.h)	Diesel (GW.h)	Total Generation (GW.h)	Diesel (GW.h)
2013	413.4	11.2	413.4	11.2	413.4	11.2	413.4	11.2
2014	416.0	12.3	416.0	12.3	416.0	12.3	416.0	12.3
2015	426.3	17.0	441.5	25.7	426.3	17.0	441.5	25.7
2016	437.3	22.9	454.7	33.1	437.3	22.9	454.7	33.1
2017	444.3	26.9	461.7	37.6	444.3	26.9	461.7	37.6
2018	451.5	31.4	468.9	42.8	505.9	68.9	523.3	81.8
2019	458.9	36.1	476.3	48.3	513.2	74.1	530.6	87.6
2020	466.4	41.1	483.8	54.0	520.7	80.1	538.1	94.2
2021	475.3	47.4	492.7	60.7	529.6	87.5	547.0	102.2
2022	484.4	54.7	484.4	54.7	538.8	95.2	538.8	94.8
2023	450.4	33.1	450.4	33.1	504.7	69.8	504.7	69.8
2024	460.0	39.8	460.0	39.8	514.4	77.2	514.4	77.2
2025	470.0	46.8	470.0	46.8	496.9	71.0	496.9	71.0
2026	481.3	55.0	481.3	55.0	481.3	55.0	481.3	55.0
2027	493.0	63.6	493.0	63.6	493.0	63.6	493.0	63.6
2028	505.1	72.7	505.1	72.7	505.1	72.7	505.1	72.7
2029	517.6	82.3	517.6	82.3	517.6	82.3	517.6	82.3
2030	530.4	92.5	530.4	92.5	530.4	92.5	530.4	92.5

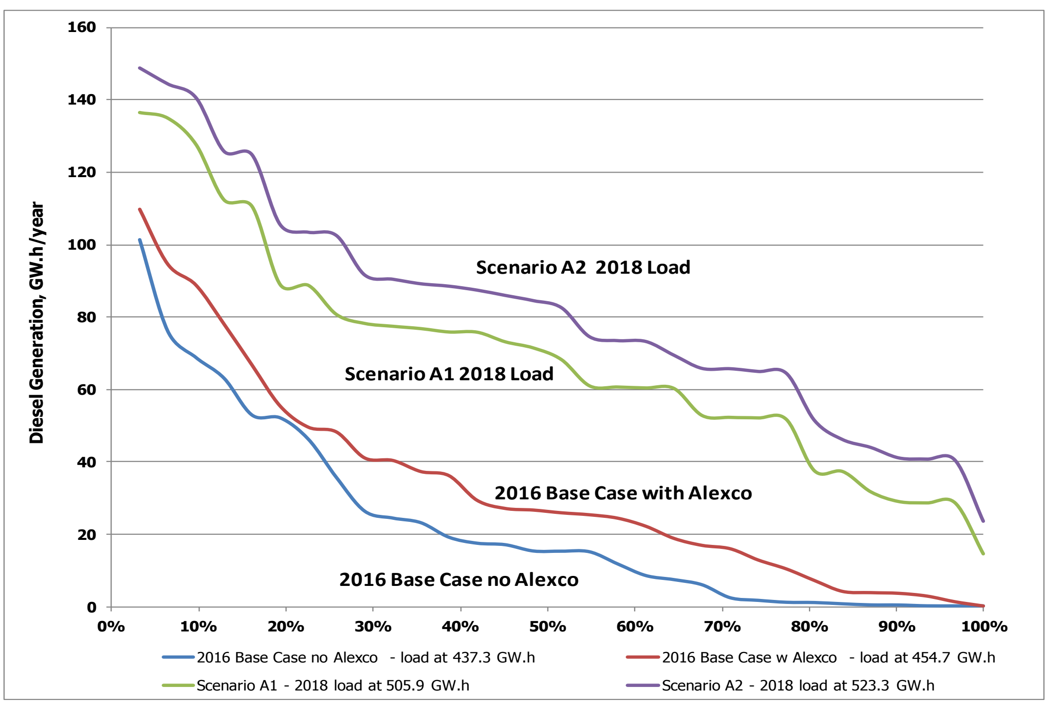
Table C-3 and Figure C-2 review potential diesel generation variability for the year 2016 under Base Case loads and for the year 2018 under Scenario A loads for each of the 31 water years:

- The left side of Table C-3 shows, for the load in the stated year and load scenario, the annual variability of average diesel generation for each of the 31 water years of record (1981-2011); in each scenario, 1995 to 2000 is a string of six consecutive notable drought condition years. At the bottom of each scenario the long-term average (LTA) annual diesel generation is shown, based on the overall average for the 31 water years (same as shown in Table C-2).
- The right side of Table C-3 shows, for load in the stated year and load scenario, the percent of the 31 water years (i.e., how many years of the 31 years) when the annual average diesel generation required is not less than specified level.
- Figure C-2 shows the annual load duration curve for diesel generation over the 31 water years for each load scenario (reflects right side of Table C-3).

Table C-3: Forecast Diesel Generation Variability (GW.h) Depending on Water Year Conditions - Load Scenarios for 2016/2018 and 31 Water Years of Record

	Average diesel generation required (GW.h)				Distribution of Annual Water Year Loads					
Water Year	2016 Base Case no Alexco - load at 437.3 GW.h	2016 Base Case w Alexco - load at 454.7 GW.h	Scenario A1 - 2018 load at 505.9 GW.h	Scenario A2 - 2018 load at 523.3 GW.h		% of Years not less than	2016 Base Case no Alexco - load at 437.3 GW.h	2016 Base Case w Alexco - load at 454.7 GW.h	Scenario A1 - 2018 load at 505.9 GW.h	Scenario A2 - 2018 load at 523.3 GW.h
1981	0.1	4.2	28.9	41.2	1	3%	101.4	109.9	136.5	148.8
1982	1.6	10.4	68.2	84.6	2	6%	76.1	94.7	135.0	144.3
1983	0.3	22.2	60.2	73.3	3	10%	68.8	88.9	127.7	140.6
1984	5.9	49.6	88.9	102.5	4	13%	63.1	78.1	112.4	125.7
1985	24.4	41.1	75.8	88.6	5	16%	52.8	66.8	110.5	124.8
1986	46.2	40.4	73.1	86.0	6	19%	52.1	55.4	88.9	105.5
1987	11.7	16.9	51.6	65.0	7	23%	46.2	49.6	88.7	103.4
1988	15.2	24.5	52.2	64.5	8	26%	35.6	48.3	80.7	102.5
1989	2.3	7.2	31.6	44.1	9	29%	26.3	41.1	78.2	91.7
1990	1.1	12.9	52.1	65.9	10	32%	24.4	40.4	77.4	90.5
1991	0.3	2.9	37.4	51.5	11	35%	23.1	37.3	76.8	89.2
1992	0.1	0.2	14.5	23.7	12	39%	19.1	36.2	75.8	88.6
1993	0.6	1.3	28.6	40.9	13	42%	17.4	29.4	75.8	87.5
1994	0.1	3.7	80.7	103.4	14	45%	17.0	27.1	73.1	86.0
1995	35.6	78.1	127.7	140.6	15	48%	15.3	26.7	71.4	84.6
1996	63.1	94.7	135.0	148.8	16	52%	15.2	25.9	68.2	82.6
1997	68.8	88.9	112.4	124.8	17	55%	15.0	25.4	60.9	74.6
1998	76.1	66.8	110.5	125.7	18	58%	11.7	24.5	60.6	73.5
1999	101.4	109.9	136.5	144.3	19	61%	8.5	22.2	60.4	73.3
2000	52.8	48.3	76.8	89.2	20	65%	7.3	18.9	60.2	69.5
2001	23.1	16.0	37.2	46.2	21	68%	5.9	16.9	52.7	65.9
2002	26.3	27.1	52.7	65.8	22	71%	2.3	16.0	52.2	65.8
2003	15.0	29.4	75.8	87.5	23	74%	1.6	12.9	52.1	65.0
2004	52.1	55.4	88.7	105.5	24	77%	1.1	10.4	51.6	64.5
2005	19.1	25.9	77.4	90.5	25	81%	1.0	7.2	37.4	51.5
2006	15.3	37.3	78.2	91.7	26	84%	0.6	4.2	37.2	46.2
2007	17.0	36.2	60.6	73.5	27	87%	0.3	3.9	31.6	44.1
2008	17.4	25.4	60.4	69.5	28	90%	0.3	3.7	28.9	41.2
2009	1.0	3.9	28.6	40.5	29	94%	0.1	2.9	28.6	40.9
2010	8.5	18.9	60.9	74.6	30	97%	0.1	1.3	28.6	40.5
2011	7.3	26.7	71.4	82.6	31	100%	0.1	0.2	14.5	23.7
Average	22.9	33.1	68.9	81.8			22.9	33.1	68.9	81.8

Figure C-2: Duration Curve – Required Diesel Generation Hydro Grid Annual Water Variability



Projected annual grid capacity MW surplus (shortfall) under each load scenario is provided in Table C-4, assuming existing plant and planned diesel unit retirements and applying YEC's approved N-1 and LOLE capacity planning criteria[40]. Assumed diesel unit retirements as set out in the 2011 Resource Plan[41] are reviewed below, using projected shortfalls under the Base Case[42] to demonstrate the impact of assumed retirements:

- 2015 Base Case shortfall of 7.0 MW: reflects following 8 MW of diesel unit retirements:
    - Mirrlees WD#1 and WD#2 retired in 2014/2015 (2011 Resource Plan rating of 3.50 and 4.5 MW=8 MW total). [Unit capacities for these units and all other units included in this analysis reflect current de-rated status where relevant; rated capacity for WD#1 and WD#2=9.07 MW].
    - Replacing of these units with at least the same capacity would resolve the 2015 shortfall.
- 2020 Base Case shortfall of 20.7 MW: reflects following 14.31 MW of diesel unit retirements:
    - The above Mirrlees retirements (8 MW) plus.
    - Dawson retirement of 3 units (total 2.56 MW retired in 2017, 2018 and 2020).
    - Mayo retirement of 2 units (total 1.7 MW in 2019).
    - Faro retirement of 2 units (2.05 MW in 2019 and 2020).
- 2025 Base Case shortfall of 45.6 MW: reflects following 29.81 MW of diesel unit retirements:
    - The above 14.31 MW retired by 2020 plus.
    - Whitehorse retirement of 4 units (total 11.5 MW - last Mirrlees (4.5 MW) and 3 EMDs).
    - Faro Mirrlees unit (4.0 MW in 2021).
- 2030 Base Case shortfall of 63.6 MW: reflects following 35.61 MW of diesel unit retirements:
    - The above 29.81 MW retired by 2025 plus.
    - Whitehorse CAT (3.0 MW in 2026).
    - Faro CAT (2.8 MW in 2027).

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[40] The N-1 capacity planning criteria focuses only on non-industrial peak load during winter (i.e., industrial peak load is excluded), and hydro generation firm capacity during winter. The N-1 event assumes loss of the Aishihik transmission line, i.e., all generation capacity at Aishihik (37 MW) and at Haines Junction (1.75 MW) is assumed not to be available to meet grid peak load excluding Haines Junction load (approximately 1 MW). Estimated shortfalls reflect re-enforcing of L172 currently being undertaken.

[41] Current integrated grid generating unit capacities and expected retirement dates are set out in Table 2-3 of the Yukon Energy 20-Yeart Resource Plan: 2011-2030 (December 2011). All YEC diesel units are expected to be retired by 2030 other than a 1.40 MW CAT at Dawson (expected to be retired in 2031).

[42] For both with and without Alexco cases under N-1 capacity requirement. YEC's 2011 Resource Plan update estimated that under the updated assessments Loss of Load Expectation [LOLE] affects planning requirements when industrial loads exceed 13 MW. Under Base Case scenario total industrial peak load is forecast to be below 13 MW [Minto at 5.3 MW and Alexco at 2.7 MW].

Table C-4: Grid Capacity Planning - Forecast MW Surplus (Shortfall) by Load Scenario: 2013-2030

Forecast Years	Base Case no Alexco			Base Case with Alexco			Scenario A1 - Base Case w Carmacks Copper (no Alexco)			Scenario A2 - Base Case w Carmacks Copper (with Alexco)		
	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)
2013	81.0	4.6	4.6	73.8	4.6	4.6	73.8	4.6	4.6	73.8	4.6	4.6
2014	80.6	-0.8	-0.8	80.6	-0.8	-0.8	80.6	-0.8	-0.8	80.6	-0.8	-0.8
2015	82.8	-7.0	-7.0	85.4	-7.0	-7.0	82.8	-7.0	-7.0	85.4	-7.0	-7.0
2016	84.3	-8.5	-8.5	87.0	-8.5	-8.5	84.3	-8.5	-8.5	87.0	-8.5	-8.5
2017	85.7	-10.9	-10.9	88.4	-10.9	-10.9	85.7	-10.9	-10.9	88.4	-10.9	-10.9
2018	87.2	-13.0	-13.0	89.8	-13.0	-13.0	94.4	-13.0	-13.0	97.1	-13.0	-15.3
2019	88.6	-17.0	-17.0	91.3	-17.0	-17.0	95.9	-17.0	-17.0	98.6	-17.0	-19.3
2020	90.2	-20.7	-20.7	92.8	-20.7	-20.7	97.4	-20.7	-20.7	100.1	-20.7	-22.9
2021	91.9	-31.0	-31.0	94.6	-31.0	-31.0	99.2	-31.0	-31.0	101.9	-31.0	-33.2
2022	93.8	-32.8	-32.8	93.8	-32.8	-32.8	101.1	-32.8	-32.8	101.1	-32.8	-32.8
2023	90.4	-34.7	-34.7	90.4	-34.7	-34.7	97.6	-34.7	-34.7	97.6	-34.7	-34.7
2024	92.3	-36.6	-36.6	92.3	-36.6	-36.6	99.6	-36.6	-36.6	99.6	-36.6	-36.6
2025	94.3	-45.6	-45.6	94.3	-45.6	-45.6	101.6	-45.6	-45.6	101.6	-45.6	-45.6
2026	96.6	-50.9	-50.9	96.6	-50.9	-50.9	96.6	-50.9	-50.9	96.6	-50.9	-50.9
2027	98.9	-56.1	-56.1	98.9	-56.1	-56.1	98.9	-56.1	-56.1	98.9	-56.1	-56.1
2028	101.3	-58.5	-58.5	101.3	-58.5	-58.5	101.3	-58.5	-58.5	101.3	-58.5	-58.5
2029	103.8	-61.0	-61.0	103.8	-61.0	-61.0	103.8	-61.0	-61.0	103.8	-61.0	-61.0
2030	106.4	-63.6	-63.6	106.4	-63.6	-63.6	106.4	-63.6	-63.6	106.4	-63.6	-63.6

Notes:

1. Non-industrial peak numbers for 2014-2030 are calculated based on YEC's three year average non-industrial load factor (2011-2013).
2. Minto at 4.8 MW in 2014, increasing to 5.3 in 2015 and shut-down in 2022; the cases with Alexco assume 2.7 MW load for 2015-2021; Carmacks Copper assumed at 7.3 MW.
3. Yukon Grid installed winter firm capacity at 114.49 MW by end of 2013 excluding Fish Lake Hydro and Haines Junction diesel. Total retirements are at 35.6 MW over 2014-2030.
4. The N-1 event assumes loss of the Aishihik transmission line, i.e., all generation capacity at Aishihik (37 MW) and at Haines Junction (1.75 MW) is assumed not to be available to meet grid peak load excluding Haines Junction load (approximately 1 MW).

BACKGROUND PAPER #2 – SUPPLY OPTIONS

Supply options are reviewed below based on available information, first for Alaska, second for Yukon, and third for fossil fuel price projections.

2.1 ALASKA

The Southeast Alaska Integrated Resource Plan ("SEIRP") provides a list of potential hydro developments and transmission projects; Table 1 below provides a list of potential hydro projects for the Upper Lynn Canal area as reviewed in the SEIRP.

Table 1: Available Projects from Screened Potential Hydro Project List[1]

Project	Location	Capacity (MW)	Potential Annual Generation (GW.h)	Capital Cost $million	Capital Cost $million/ MW
Connelly Lake	Haines	12.0	39.8	36.8-55.2	3-4.6
Schubee Lake	Skagway	4.9	25.0	36-54	7.3-11
Walker Lake	Chilkat Valley	1.0 (run-of-river)	2.8	6.1-9.1	6.1-9.1
West Creek	Skagway	25.0	76.6	112-168	4.5-6.7

The SEIRP lists the development level for the above projects and indicates that none of the projects are at feasibility level or design level of information[2]; the following is noted regarding the development level for the above projects:

- **Level 5 - "Superficial: low confidence for cost estimate":** West Creek (Skagway) and Schubee Lake (Skagway)
- **Level 4 - "Previous study information is outdated":** Walker Lake[3] (Chilkat Valley)
- **Level 3 - "Reconnaissance level of information of current design":** Connelly Lake (Haines)

[1] Southeast Alaska Integrated Resource Plan, Table 10-4, page 10-11.
[2] Southeast Alaska Integrated Resource Plan, Table 10-7, page 10-36.
[3] Tlingit-Haida Regional Electrical Authority (THREA) applied for funding to conduct feasibility, design, and obtain a FERC license for the Walker Lake Hydro Project. THREA filed a preliminary FERC permit application on June 11, 2012 since it has municipal preference. THREA proposes to work with Inside Passage Electric Cooperative (IPEC) the certificated utility for the service area of Klukwan and the Chilkat Valley. The proposed project includes constructing two small dams at Walker Lake; intake and reservoir outlet works; a 24" penstock of approximately 12,000 feet in length; a powerhouse with installed capacity of approximately 1 MW; a tailrace of approximately 50' length; and a 12.4 KV underground transmission line of approximately 4 miles in length interconnecting with the existing transmission system of IPEC.

Limited information is available on timing of the projects listed above. However, the following is noted from publicly available sources regarding the results of recent funding applications and studies conducted for each potential project:

- **Connelly Lake** - AP&T was issued a Preliminary Permit from FERC for the Connelly Lake Hydroelectric Project on March 19, 2012. In a June 13, 2013 letter to FERC, AP&T indicated that it was surrendering its permit, and noted "although AP&T believes this project site to be technologically feasible, currently there is not enough electrical load to make it economical. This coupled with the lack of local support will not allow project development to occur in the near term[4]". The Alaska Renewable Energy Fund Status Report, Rounds 1-6 indicates that surveys were discontinued in January 2013. Work was expected to be completed on financial feasibility and design to meet a July 2014 deadline for providing a feasibility report.
- **Schubee Lake Hydro-electric Project -** The Schubee Lake project is at a preliminary stage of development, with only a reconnaissance-level cost estimate[5]. However, assessments to date have indicated the project would be expensive and technically difficult to pursue[6]. Economic analysis undertaken by AP&T indicates that the project has a weighted benefit cost ratio between 0.81 [using AP&T model] and 0.67 [using AEA model][7]. Available information indicates the project was ruled out by AP&T as an alternative to Connelly Lake. The Alaska Renewable Energy Fund Status Report, Rounds 1-6 notes "a feasibility report was completed and the project was found to be uneconomic."
- **West Creek Hydro-electric Project** – The 2011 AEA Round 5 Funding Application provides a design and construction schedule which indicates a potential in service date of 2018, assuming start of Phase II Feasibility Analysis in Q3 of 2012[8]. AP&T has indicated that the project would take at least 10 years to get licenced and permitted[9]. The AEA review team, while recommending funding the West Creek Feasibility in Round 5, ranked the project 37 out of 41 total renewable projects considered for funding in that year. The AEA Renewable Energy Fund Round 5 report indicated an Applicant Benefit/Cost ratio at that time of 1.88 and an AEA calculated benefit/cost ratio of 1.49.
- **Walker Lake Hydro-electric Project** – In 2014, the Tlingit-Haida Regional Electrical Authority (THREA) applied for funding for a Feasibility Study and Conceptual design in an

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[4] http://www.aptalaska.com/upload/pdf/061313.surrender.of.permit.pdf
[5] Economic Analysis of the Schubee Lake Hydroelectric Project, undertaken by AP&T (March 2013), Renewable Energy Fund Grant #7040067.
[6] An April 4, 2013 Chilkat Valley News article indicates Schubee Lake was ruled out as an alternative to Connelly Lake as it would be "both expensive and extremely difficult". The article notes a report by HDR Alaska Inc determined that "not only would construction and operation of a hydro plant at Schubee Lake be difficult due to its remoteness, high alpine location, and lack of a road, at about $15,300 per kilowatt,' the project is expensive by today's standards.'" See, Chilkat Valley News "AP&T: Studies rule out Schubee Lake Hydro", April 4, 2013, Volume 43, Number 13.
[7] Economic Analysis of the Schubee Lake Hydroelectric Project, undertaken by AP&T (March 2013), Renewable Energy Fund Grant #7040067, page 6.
[8] The design and construction schedule included in the 2011 AEA Funding Application indicates, were the project to proceed, that Phase II Feasibility Analysis would take approximately 1 year; Phase III Final Permitting and Design would take approximately 2 years and Phase IV construction would take approximately 2 years.
[9] See "Alaska Power & telephone files with FERC on hydropower project", by Editors of Electric Light & Power/ POWERGRID International (April 25, 2014) at http://www.elp.com/articles; see also, "AP&T Files FERC Preliminary Permit for West Creek Hydro Project Near Skagway" (April 21, 2014) in SitNews at http://www.sitnews/us.

effort to further prove the Walker Lake Hydro project and apply for a FERC licence. The project did not pass the minimum stage 2 funding criteria. Concerns noted in the AEA review were that the AEA had already funded reconnaissance and feasibility assessments for possible hydro projects in the region including Connelly Lake, Schubee Lake, West Creek Hydro and Burro Creek. These projects were found not to be economically feasible, mainly from lack of market to justify the capital costs. In the case of Walker Lake, the demand for the project power would be a fraction of the potential annual energy available and as a result the project would spill nearly year round, and would displace very little diesel generation.

The SEIRP (Figure 10-18) indicates that there are no new hydro generation resources available in the Upper Lynn Canal area before 2034, with diesel generation reaching approximately 10 GWh/year under the high load scenario.

West Creek Hydro

AP&T is currently reviewing the feasibility of the West Creek Hydro Project as a potential supply option, and has recently filed an application with FERC for a preliminary permit[10]. The Project, as described in the application, is expected to provide 25 MW of capacity with estimated generation of 110 GWh/ year, and would be located on West Creek and the West Branch Taiya River, near Skagway, Alaska and would consist of the of the following facilities:

- A 1,500-foot-long, 175-foot-high concrete gravity dam creating a 895-acre reservoir having a total storage capacity of 86,000 acre-feet at a normal maximum operating elevation of 780 feet mean sea level;
- A water intake structure on the dam leading to a 15,900-foot-long, 10-foot-diameter, unlined tunnel;
- A 60-foot by 150-foot powerhouse containing two turbine/generation units rated for a total of 25 megawatts;
- A 100-foot-long by 80-foot-wide open channel tailrace returning water to the West Branch Taiya River;
- A submarine 3.9-mile-long, 34.5-kilovolt transmission line extending from the powerhouse to a landing for a substation on Nahku Bay connected to an existing transmission line owned by the applicant (the point of interconnection); and
- Appurtenant facilities.

The stated purpose for the Project is as follows:

- To supply electricity to cruise ships that dock in Skagway during the summer months, in order to displace on-board use of petroleum fuels and reduce emissions that may cause significant environmental degradation.

[10] http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20140317-5039. Filing date is March 14, 2014. The purpose of the permit is to grant the permit holder priority to file a license application during the permit term. The period of the permit is 36 months.

- To supply electricity to the local utility in order to supplement existing generation.
- To potentially supply Yukon Territory, Canada with electricity in order to displace thermal generation requirements on the Yukon Grid.

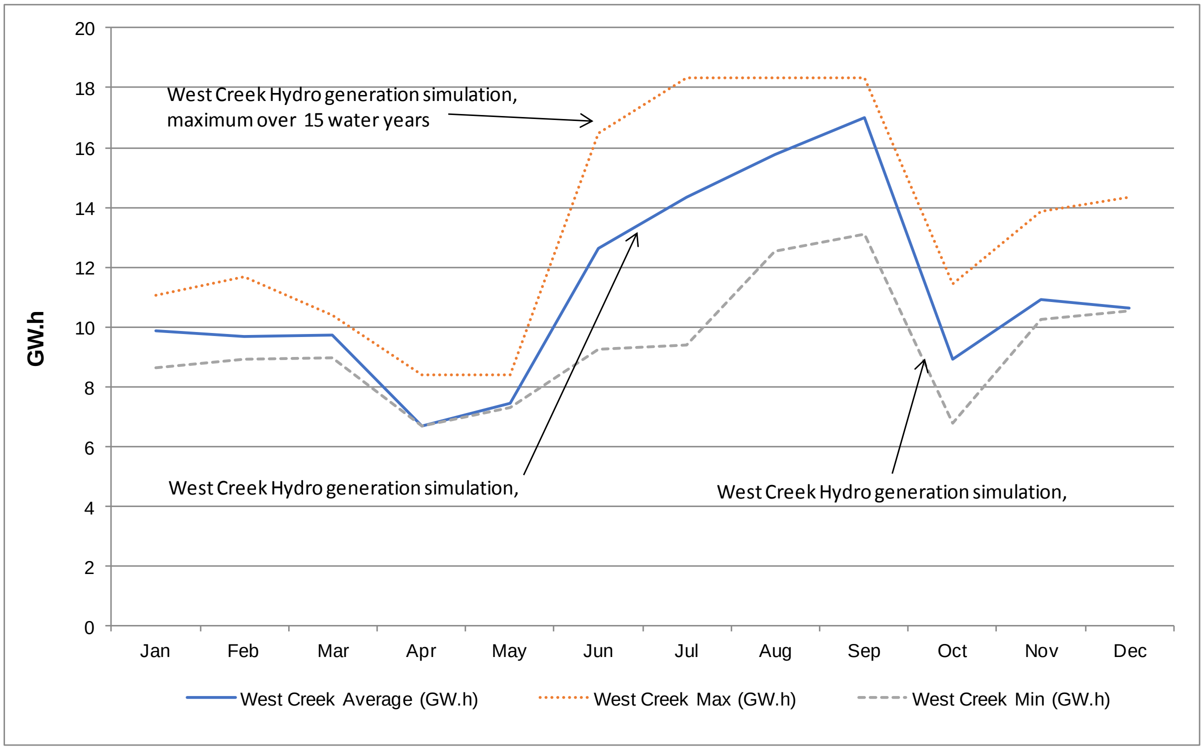
The SEIRP indicates that the Skagway-Haines grid requirement for diesel generation is minimal over the SEIRP planning period (from 2011 to 2061) as shown in Figure 1 provided in Background Paper #1. While the cruise ship load is material during the summer months, it is not present from the end of September through the end of April. As such, the West Creek Hydro project justification requires the following:

- Construction of a transmission corridor to Yukon; and
- Sufficient thermal generation requirement in Yukon that can be cost-effectively displaced through electricity shipped from the West Creek Hydro facility, through the transmission corridor to Yukon.

The latest simulation analysis provided for the current study by Access Consulting Group shows that the maximum Hydro generation from West Creek Hydro can reach 161 GW.h/year, with minimum at 112 GW.h, and an average over 15 water years at 134 GW.h[11]. Figure 1 below shows the range of simulated generation over the year for West Creek Hydro based on flow data measured from 1963 to 1977.

[11] The simulation is prepared by Access Consulting Group using USGS flow data measured from 1963 to 1977, adjusted to basin area at dam site and assumes head at 200 m (varies between 190 and 225 m minus head losses, assumed to be approximately 5 m), turbine efficiency at 85%, installed capacity at 25 MW (design flow of 15 m^3/s), maximum water level variation at 37 m and riparian flow of 10% of average monthly flow. Other assumption for the simulation include maximize winter generation, storage volume constantly utilised from mid-November to mid-April, filling of reservoir in June (20%), July (40%) and August (40%), and maintain reservoir full until mid-November.

Figure 1: West Creek Hydro Simulated Generation Ranges over the Year (GW.h/month)



It is estimated that the life cycle cost of energy of the West Creek Hydro Project with transmission to Yukon at 138 kV at average load at 134 GW.h with the assumptions used for long-term hydro options discussed below (includes assumed full utilization of all long-term average generation capability) would be equal to about 9.2 cents/kW.h[12], which is comparable to the small and medium size long-term hydro options discussed further below.

Comments provided the AEA review team (regarding the 2011 Funding Application by the Municipality of Skagway) indicate the following concerns regarding the Project[13]:

- While reduced air emissions from diesel generation by the cruise ships is stated as a major benefit of the project, when the EPA mandated change in cruise ship fuel from bunker oil to ultra low sulfur diesel is implemented, the air quality issues associated with docking of cruise ships will decrease substantially, reducing the public benefit of the project.

[12] Estimated based on assumptions used in Yukon Energy's 2011 Resource Plan for long-term hydro projects, i.e. full utilization of the potential annual energy, annual O&M costs at 0.5% of total capital cost, average cost of capital at 5.45% with assumed project economic life of 65 years. The capital cost assumed at $140 million based on economic analysis for the West Creek Hydro project provided as part of Renewable Energy Fund Round 6 Grant Application of Municipality of Skagway before Alaska Energy Authority and assumed transmission cost ($2014) from Skagway to Whitehorse at $81 million (average of estimates for transmission, plus substation cost as provided in Background Paper #3). The analysis assumes 10% line losses. With the same assumptions and annual energy of 110 GW.h, the annual energy assumed in AP&T's application before FERC for preliminary permit, the life cycle cost would be about 11.2 cents/kW.h.

[13] See, http://www.skagwaynews.com/SNEWStopstories020813.html

- The AEA expressed concerns (similar to those it made regarding Connelly Lake, Schubee Lake, and Burro Creek[14] reconnaissance and feasibility assessments) with regard to finding a suitable market that would make the project economic. [The West Creek application in this instance focused only on the cruise ship power loads and sought a subsidy to cover 80% of the project's estimated capital cost.]
- The AEA questioned the amount of public benefit to be received (regarding supply of shore-based cruise ship loads) versus the high capital cost and high technical, business, and regulatory risks of the proposed project.
- The AEA noted permitting risks related to potential project effects on the viewscapes and upstream waters of the Klondike Gold Rush National Park.

Further discussion regarding potential power sales (benefits and risks) is provided in Background Paper #1 at pages 1-6 to 1-7.

Other Transmission Line Project Options

The SEIRP assessed a potential transmission connection between southeast Alaska communities, including connection of Haines to Juneau, and indicated that the costs for a transmission line between Haines and Juneau could be about $244 million (2011$)[15] for 85.3 miles[16] of 69 kV transmission line (about 137 km or $1.78 million/km).

The SEIRP notes that potential transmission projects were considered from the perspective of a "public benefit investment" (page 12-1 of SEIRP); potential objectives include providing lower cost hydroelectric power to Southeast Alaska communities, and reduction diesel generation. The Haines to Juneau transmission line assumes about 4.8 GW.h of annual load moving across the transmission line, with 3.8 GW.h load moving from the Juneau to Haines area and about 1 GW.h moving from Haines to Juneau with project benefit/cost ratio at 0.1 (page 12-52 of SEIRP). In summary, economic benefits from such as connection are estimated at only about 10% of the estimated costs.

[14] Burro Creek Holdings, LLC (BCH) received a grant from the Alaska Energy Authority in 2009 to perform a feasibility study of upgrading the existing 15-kilowatt (kW) run-of-river hydroelectric system on Burro Creek. A range of new larger run-of-river projects at Burro Creek were investigated in this study. The run-of-river configurations considered in the study ranged in installed capacity from 430 kilowatts up to 7.3 megawatts (MW). The study notes the market for energy from a Burro Creek project was not well defined, and" the amount and seasonal availability of energy from Burro Creek does not mesh well with the needs of existing markets in the Upper Lynn Canal region. Existing markets include Haines and Skagway, served by Alaska Power Company (APC) (a subsidiary of Alaska Power and Telephone, Inc. (AP&T)), and the Chilkat Valley communities served by Inside Passage Electric Cooperative, Inc. (IPEC). However, by themselves, these existing markets are too small to justify a new project at Burro Creek and would need to be combined with potential market opportunities such as providing shore power to cruise ships at Skagway, connect of mine loads and potential interconnection to the Yukon grid.

[15] SEIRP, page 12-36, Table 12-8.

[16] SEIRP, page 12-41, Table 12-12. The cost estimated to be about $2.8 million/mile. Table 12-1 of SEIRP provides generic cost of transmission line which estimated to be about $0.446 million/mile when use wood poles and $0.481 million/mile when use steel poles.

2.2 YUKON

Summer Surplus Hydro Generation

Due to Yukon's predominantly hydro-based grid system forecast diesel generation requirements are concentrated in the winter months, while over the summer months the Yukon grid continues to have surplus hydro generation available.

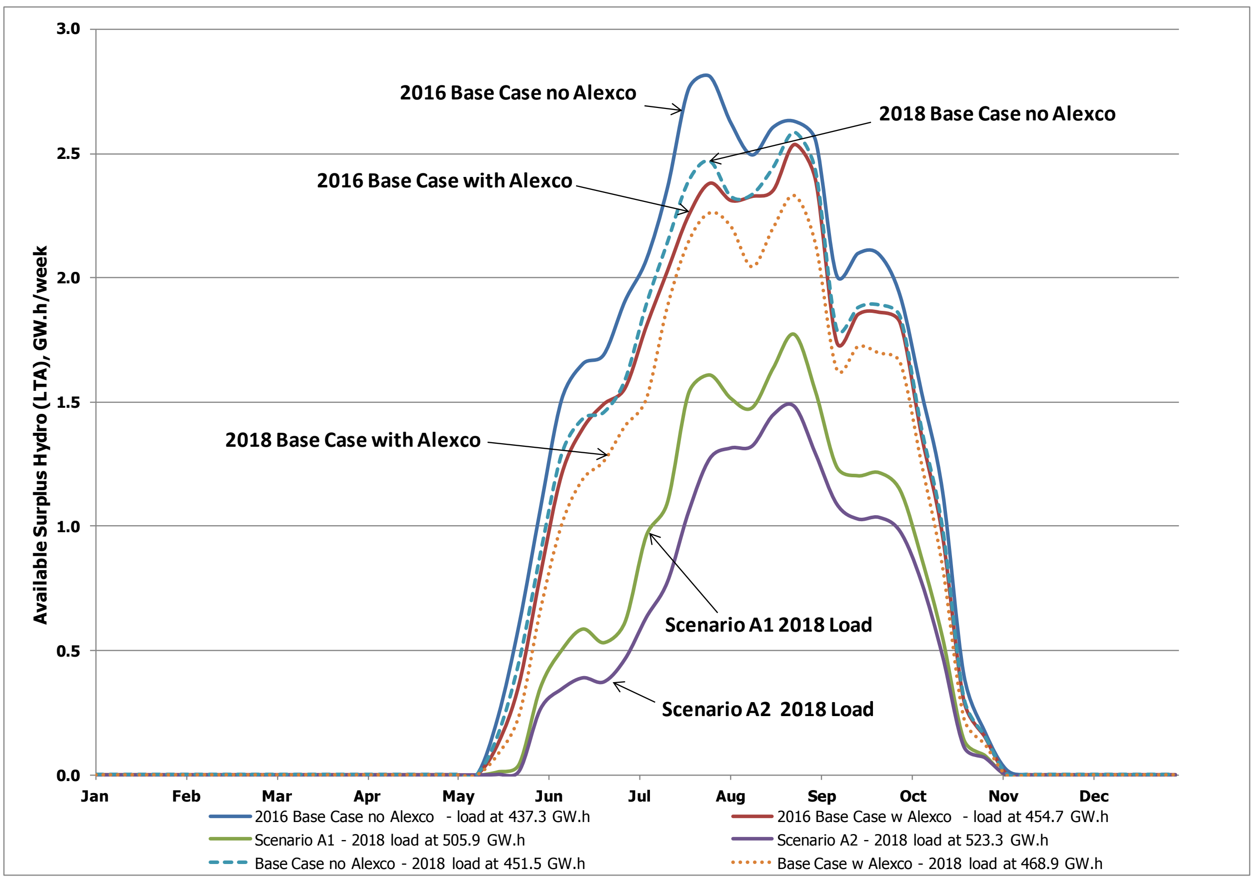
Figure 2 shows the annual available surplus hydro by week for the four load scenarios as forecast in 2016 and 2018, assuming long-term average hydro generation. Based on long-term average hydro availability, available surplus hydro under the four load scenarios reviewed in Background Paper #1 is estimated to be as follows in 2016 and 2018:

- **2016 Load Forecast**
    - At Base Case load for 2016 without Alexco [generation load at 437.3 GW.h] the annual surplus hydro is estimated to be about 43 GW.h available from early June to mid-October [available summer weekly surplus averages about 6.5 MW starting in early June, gradually increasing to 10 MW by mid-June and to 16 MW by end of July and gradually decreasing to 7 MW by mid-October];
    - At Base Case load for 2016 with Alexco [generation load at 454.7 GW.h] the annual surplus hydro is estimated to be about 37 GW.h available from early June to mid-October [available summer weekly surplus averages about 5 MW starting in early June, gradually increasing to about 9 MW by mid-June and to 15 MW by end of August and gradually decreasing to about 6 MW by mid-October];
- **2018 Load Forecast**
    - At Base Case load for 2018 without Alexco [generation load at 451.5 GW.h] the annual surplus hydro is estimated to be about 38 GW.h available from early June to mid-October [available summer weekly surplus averages about 5 MW starting in early June, gradually increasing to about 9 MW by mid-June and to 15 MW by end of August and gradually decreasing to about 6 MW by mid-October];
    - At Base Case load for 2018 with Alexco [generation load at 468.9 GW.h] the annual surplus hydro is estimated to be about 34 GW.h available from early June to mid-October [available summer weekly surplus averages about 4 MW starting in early June, gradually increasing to about 7.5 MW by mid-June and to 14 MW by end of August and gradually decreasing to about 5 MW by mid-October];
    - At Scenario A1 load for 2018 [generation load at 505.9 GW.h] the annual surplus hydro is estimated to be about 22.3 GW.h mostly available from early July to end of September [available summer weekly surplus averages about 2 MW starting in early June, gradually increasing to about 6.5 MW by mid-July and to 10 MW by end of August and gradually decreasing to about 3 MW by mid-October];
    - At Scenario A2 load for 2018 [generation load at 523.3 GW.h] the annual surplus hydro is estimated to be about 18 GW.h mostly available from early July to end of

September [available summer weekly surplus averages about 1.5 MW starting in early June, gradually increasing to about 6 MW by mid-July and to about 9 MW by end of August and gradually decreasing to about 3 MW by mid-October].

As Figure 2 shows, the surplus hydro on the Yukon grid is subject to ongoing non-industrial load growth as well as industrial load connections. Based on current near-term load forecast as provided in Attachment A in Background Paper #1, no load is expected for Minto mine starting from 2022, and no load is expected for Alexco after 2021 (if Alexco mine reconnects in 2015), and no new mines are forecast to be connected to the grid after 2025. Under these assumptions, higher summer surplus hydro availability would occur on the Yukon Grid after these dates subject to ongoing non-industrial load growth.

Figure 2: Annual Available YEC Surplus Hydro on Yukon Grid by week in 2016 and 2018 based on Long-term Average Water Conditions



Potential Near and Longer Term Supply Options

Ongoing load growth on the Yukon grid has depleted the surplus hydro available since the 1998 Faro mine shutdown, and thermal generation is once again becoming the default option to meet current energy and capacity requirements on the Yukon grid until long-term loads are sufficient to support economic new renewable generation. Figure 3 reviews the existing Yukon power infrastructure, including the integrated grid which remains isolated from any markets outside Yukon.

As reviewed in Yukon Energy's 2011 20-Year Resource Plan[17], Yukon Energy continues to pursue new renewable energy developments to displace growth in diesel generation requirements, and to implement a Demand Side Management (DSM) program to reduce load growth working with Yukon Electrical Company Limited (YECL).

- **Potential near-term hydro enhancement projects** – near term hydro enhancement projects being pursued by Yukon Energy at this time currently include Mayo Lake Enhanced Storage and Marsh Lake (Southern Lakes) Storage. Development of the two options, if and when regulatory requirements can be satisfied, would still leave material forecast long-term average diesel generation requirements.
    - **Mayo Lake Enhanced Storage** would supply 4 GWh/year (long term average) incremental energy supply to the grid. Mayo Lake Enhanced Storage Project would not provide any new firm winter capacity to the grid.
    - **Marsh Lake (Southern Lakes) Storage** would supply 6 GWh/year (long term average) incremental energy supply to the grid. Marsh Lake (Southern Lakes) Storage might potentially provide 1 MW of added firm winter grid capacity.

  Other potential near-term hydro enhancement options that were reviewed in the 2011 Resource Plan are summarized below:
    - **Atlin Storage[18]** - Work on the Atlin project ceased due to the BC Government decision to designate Atlin River as a Class A park (and expectation that the designated park will include the river).
    - **Gladstone Diversion -** through enhanced use of the existing Aishihik hydro facility, Gladstone Diversion could add maximum annual energy capability of 36.6 GW.h/year if fully utilized; however, Gladstone Diversion hydro would add minimal or no reliable capacity (due to Aishihik Transmission line vulnerability). The estimated capital cost of the project is $40 million.
    - **Amendments to the current Fisheries Act Authorization** provisions for Aishihik generation are estimated to provide potentially an additional 9 GW.h of annual energy on average from the Aishihik plant;

[17] Yukon Energy Corporation's Overview of 20-Year Resource Plan: 2011-2030 was provided during review of YEC's 2012/13 GRA in response YECL-YEC-1-18 (a).

[18] An additional 9 GW.h/year of added hydro energy could be generated at Whitehorse with regulation of the outflows of Atlin Lake within its natural range of lake levels. If 0.4 m of drawdown below the natural lake level was permitted it is estimated that a total of up to 18 GW.h/year could be generated. This project would also increase the winter hydro capacity of the Whitehorse facility by 1-2 MW.

- **Transmission connection of the Yukon grid to the Taku River Tlingit owned Pine Creek Hydro Generating Station near Atlin, B.C.** – The Project would provide a transmission connection from the Yukon grid to the Pine Creek Hydro Generating Station in order to take advantage of underutilized existing capacity, plus undeveloped capability at the generating station.
  - A 1.5 MW option would utilize surplus hydro from the existing TRTFN Pine Creek hydro plant, with annual potential of 10 GW.h/yr over a 25 kV powerline.
  - A 3.5 MW option would use the same exiting surplus hydro with a 2.2 MW expansion, with annual potential of 23 GW.h over a 35 kV powerline.
  - A 8.0 MW option would use the expanded existing hydro plant plus a new 4 MW downstream plant with annual load potential of 52 GW.h over a 69 kV powerline;

- **Potential longer-term supply options** – for future consideration when long term loads can justify such developments, Yukon Energy is also pursuing a wind development that could range up to 20 MW at Techo (formerly Ferry Hill) in the Stewart Crossing area, as well as potential future hydro generation at various potential greenfield sites.
  - **Wind –** The 2011 Resource Plan assumed that at most only one 20-21 MW scale wind project could be accommodated on the grid during the 20-year planning period, given the non-dispatchable nature of this energy supply option and the cost limits related to securing necessary added energy storage. In the context of the Yukon grid, new wind generation derives economic value by displacing diesel generation that would otherwise be required (based on long term average hydro generation estimated at the forecast grid loads). To be potentially attractive, 21 MW of new wind generation at Ferry Hill would require major new and sustained loads on the grid.

    The 2011 Resource Plan estimated that a 20-21 MW wind project on the Yukon grid would likely also require a new diesel rotary uninterruptible power supply (DRUPS) units (estimated cost of $2 million per MW). Capital costs (2010$) in the 2011 Resource Plan were estimated at $83.42 million ($3.97 million per MW[19]) before consideration of spinning reserve or other added energy storage requirements.[20] Annual operating costs (2010$) were estimated at $2.1 million (about $38/MW.h).

  - **Long-Term Hydro Options** – The 2011 Resource Plan reviewed greenfield resource supply options that could be potentially available to start construction before 2021 to provide long-term electricity supply in Yukon, subject to adequate

[19] Including 10% contingency and provision for turbine de-icing system, transmission/substation improvements (with transmission connection to Stewart Crossing south substation), development and permitting, engineering/construction management at 12% and owner's costs at 7%).

[20] In assessing a 20-21MW wind site on the Yukon grid, $10 million is added to the capital cost to provide for a minimum 5 MW of DRUPS to ensure adequate spinning reserve to integrate the site on the grid.

and reasonably assured long-term load levels to utilize the new energy supply (see Table 2). Potential greenfield sites require up to 10 years or more to plan, secure regulatory approvals and develop. To be available by 2021, such options would need to being site specific planning processes as soon as possible.

Figure 4 indicates the location of potential greenfield hydro sites that YEC has examined relative to potential future mine loads examined in the Yukon Energy 2011 Resource Plan[21]. The following are noted regarding the range of options examined in the 2011 Resource Plan.

- **Small Hydro Options (<10 MW; up to 70 GW.h/year at 20-22cents/ kW.h)** – Aside from potential transmission connection to underutilized and undeveloped hydro capacity near Atlin, B.C., small scale hydro options are identified in the Southern Lakes region (near Tutshi Lake, B.C.) at Moon Lake and Tutshi River or Tutshi (Windy Arm). Annual energy potential for each site approximates 30-39 GW.h/year with full utilization life cycle costs (with transmission to the Yukon grid) estimated at 20-23 cents/kW.h[22].
- **Medium Hydro Options (11-60 MW; over 2,070 GW.h/year at less than 15 cents/kW.h)**
  - Four sites or schemes investigated by Yukon Energy (or NCPC in the past) have estimated full utilization costs (with transmission) below 10 cents/ kW.h (2009$) and offer over 850 GW.h/year of average annual sustainable energy supply after considering duplication among these sites. These sites include Hoole Canyon with Storage [275 GW.h/year], Slate Rapids [266 GW.h/year], Granite Canyon Small [400 GW.h/year] and Finlayson [129 GW.h/year].
  - A further five medium size sites or schemes with full utilization costs between 10 and 15 cents/kW.h offer over 850 GW.h/year of additional average energy supply after considering for site modifications already addressed in the sites with costs below 10 cents/kW.h. These include Combined Slate Rapids [361 GW.h/year] and another Slate Rapids site [156 GW.h/year], Two Mile Canyon [280 GW.h/year], Ross Canyon [181 GW.h/year], and False Canyon [370 GW.h/year] [23].

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[21] Hydro sites that are protected in the Yukon First Nation Final Agreements include elements of Granite Canyon (Selkirk First Nation), Hess (Na-Cho Nyak Dun First Nation), Morley (Teslin Tlingit Council First Nation), Aishihik (includes various related projects such as the Gladstone Diversion – Champagne/Aishihik First Nation and Kluane First Nation), Drury Lake/Creek (Little Salmon/Carmack First Nation) and North Fork (Tr'ondek Hwech'in First Nation). Upper Canyon on the Frances River, Finlayson River and Hoole/Slate are classed as "interim protected" (i.e., are in traditional areas of First Nations that do not today have a land claims agreement).

[22] In Yukon Energy's 2011 Resource Plan, the life cycle costs of energy (LCOE) for hydro projects were estimated based on assumption of full utilization of the potential annual energy, capital cost in 2009$, annual O&M costs at 0.5% of total capital cost, average cost of capital at 5.45% with assumed project economic life of 65 years.

[23] The last site (False Canyon) is highly impacted by transmission distance to east of the current grid.

- A further two medium size sites north of Watson Lake have full utilization costs less than 15 cents/kW.h if exceptionally high transmission costs to connect to the existing grid are excluded. These sites are Middle Canyon [200 GW.h/year] and Upper Canyon [176 GW.h/year].

  - **Large Hydro Options (>60 MW; over 4,740 GW.h/year at less than 15 cents/kW.h)**
    - Five sites or schemes have estimated full utilization costs (with transmission) below 10 cents/kW.h (2009$) and offer over 3,540 GW.h/year of average annual sustainable energy supply after considering duplication among these sites and after considering for site modifications already addressed in the medium size sites. These include Fraser Falls Low [700 GW.h/year] and Fraser Falls High [2,100 GW.h/year]; Slate Rapids/Hoole [459 GW.h/year]; and Granite Canyon Low [600 GW.h/year] and Granite Canyon High [1,783 GW.h/year].
    - A further three medium size sites or schemes with full utilization costs between 10 and 15 cents/kW.h offer over 1,200 GW.h/year of additional average energy supply after considering for site modifications already addressed in the sites with costs below 10 cents/kW.h. These include Detour Canyon [435 GW.h/year] and Detour Canyon with Storage [585 GW.h/year], and Liard Canyon [659 GW.h/year][24].

- **Other Long-Term Options** – The 2011 Resource Plan examined other long-term resource supply options that require external action by others to be considered potentially available for development before 2021. More specifically, ability to pursue these options further requires new information (e.g., successful exploration results for geothermal[25]), new technology (e.g., a cost-effective clean coal technology, proven and cost-effective mini-nuclear plant technology and/or solar technology suitable for Yukon use), or other external action (e.g., indigenous coal development close to the grid in Yukon[26]; commitment by others to provide natural gas in southern Yukon through an Alaska Highway pipeline and/or Eagle Plains

[24] The last site (Liard Canyon) is highly impacted by transmission distance to the east of the current grid.
[25] Geothermal opportunities offer future potential to provide significant low cost, clean, and reliable long-term electricity supply in Yukon if successful exploration can define appropriate opportunities close to the grid. Section 5.1.2 of the 2011 Resource Plan reviews a preliminary resource assessment and prioritization of sites recently undertaken for Yukon energy. As reviewed in Appendix F, Attachment F2 of the 2011 Resource Plan, considerable costs would likely be required to carry out the necessary ongoing exploration and confirmation drilling to locate and then develop geothermal as a generation resource in Yukon. Funding for this type of development activity at the scale likely to be needed is not typical for a regulated utility such as Yukon Energy. Accordingly, the 2011 Resource Plan does not provide any specific major proposed activities for geothermal beyond ongoing monitoring of related activities in Yukon.
[26] Monitoring indigenous Yukon coal resource development as well as evolving clean and small scale coal technology also merits attention, given Yukon coal resources that exist in close proximity to the grid.

development[27]; commitment by others to connect Yukon's grid with grids in British Columbia[28] or Alaska). The 2011 Resource Plan concluded that these options merit ongoing monitoring of developments, but were not considered further at this time.

[27] Proponents of the Alaska Pipeline Project provided a project schedule in fall 2011 community meetings in Alaska indicating first gas in 2020 and full gas in 2021, assuming an October 2012 FERC filing and project sanction before mid-2015 (see Section 6 of the 2011 Resource Plan). There is currently no timing or plan for development of Eagle Plains, but potential options may emerge tied to development of a major new load such as the Casino mine.

[28] Appendix F, Attachment F2 of the 2011 Resource Plan reviews a conceptual-level study done for YEC of a transmission interconnection between Yukon and B.C. Four alternatives were considered, with costs ranging from $1.2 billion to $2.4 billion.

Table 1: Summary of Potential Hydro Sites

Small Hydro Projects <10MW)		Installed Capacity (MW)	Annual Energy (GWh)	Capital Cost (Million $2009)	Levelized Cost (c/kWh)
20-23 c/kWh	Moon Lake	5.8	32.9	126.8*	19.9
	Tutshi River	4.2	30.3	135.5*	23.1
	Tutshi (Windy Arm)	5.9	39.4	164.9*	21.6
	Pine Creek at Atlin	3.5-8	23-52	NA	NA
Medium Hydro Projects (<60 MW)					
< 10 c/kWh	Hoole Canyon with Storage	40.4	275	460.1	8.6
	Granite Canyon Small	60.0	400	670.3	8.7
	Slate Rapids	41.6	266	505.6	9.8
	Finlayson	17.0	128.9	233.7**	9.4
10 to 15 c/kWh	Ross Canyon	30	181	495.0	14.1
	False Canyon	58	370	1,036.3**	14.5
	Two Mile Canyon	53.1	280	696.5	12.9
	Combined Slate Rapids[1] & Hoole	50.1	351.1	728.9	10.7
	Slate Rapids[1] (powerhouse at foot of dam	22.3	156.3	441.4	14.6
Other[2]	Middle Canyon	38.0	200	773.5***	20.0
	Upper Canyon	25.2	176.6	677.2***	19.8
Large Hydro Project (>60 mW)					
< 10 c/kWh	Granite Canyon High	254.0	1,783	1,680.7	4.9
	Fraser Falls Low	100.0	700	1,340.4	9.9
	Granite Canyon Low	80.0	600	934.8	7.3
	Fraser Falls High	300.0	2,100	2,540.6	6.3
	Combined Slate Rapids & Hoole	69.4	459	849.7*	9.6
10 to 15 c/kWh	Detour Canyon	65.0	435	1,057.0	12.6
	Detour Canyon w storage At Pelly Lakes	100.0	585	1,301.0	11.5
	Liard Canyon	93.5	659	1,554.6**	12.2

Notes:

1. Powerhouse at foot of dam

2. Excluding exceptionally high transmission costs to connect to existing grid, these sites would be under 15 cents per kW.h.

* Transmission costs to connect to grid are 18% of cost for Tutshi (Windy Arm), 21% of cost for Combined Slate Rapids & Hoole Canyon, and 26-27% of cost for Moon Lake & Tutshi River.

** Transmission costs are 33% of cost for Liard Canyon, 36% of cost for Finlayson, and 38% of cost for False Canyon.

*** Transmission costs to connect to existing grid are estimated at 54-55% of cost for these sites.

Figure 3: Existing Yukon Power Infrastructure

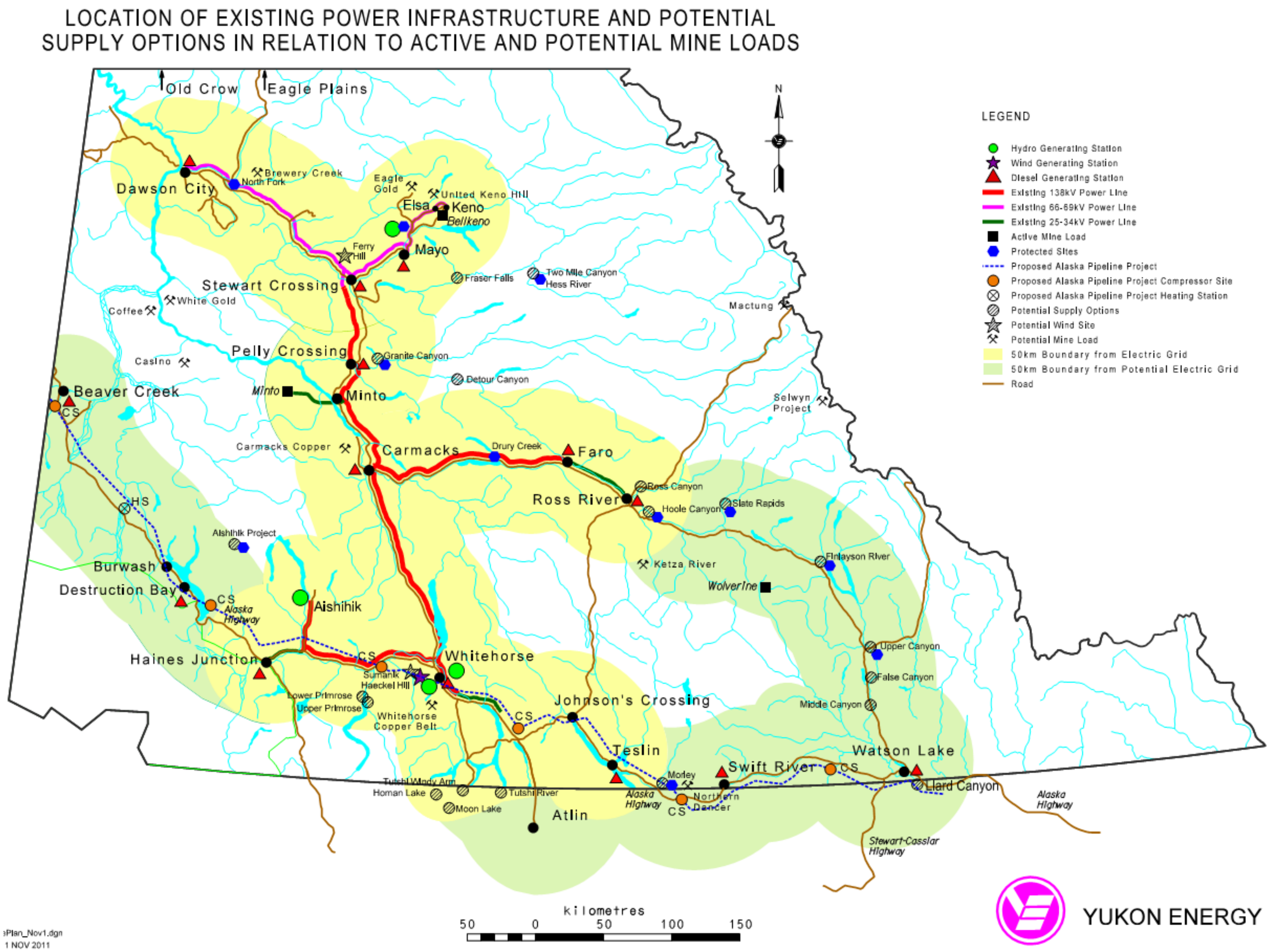
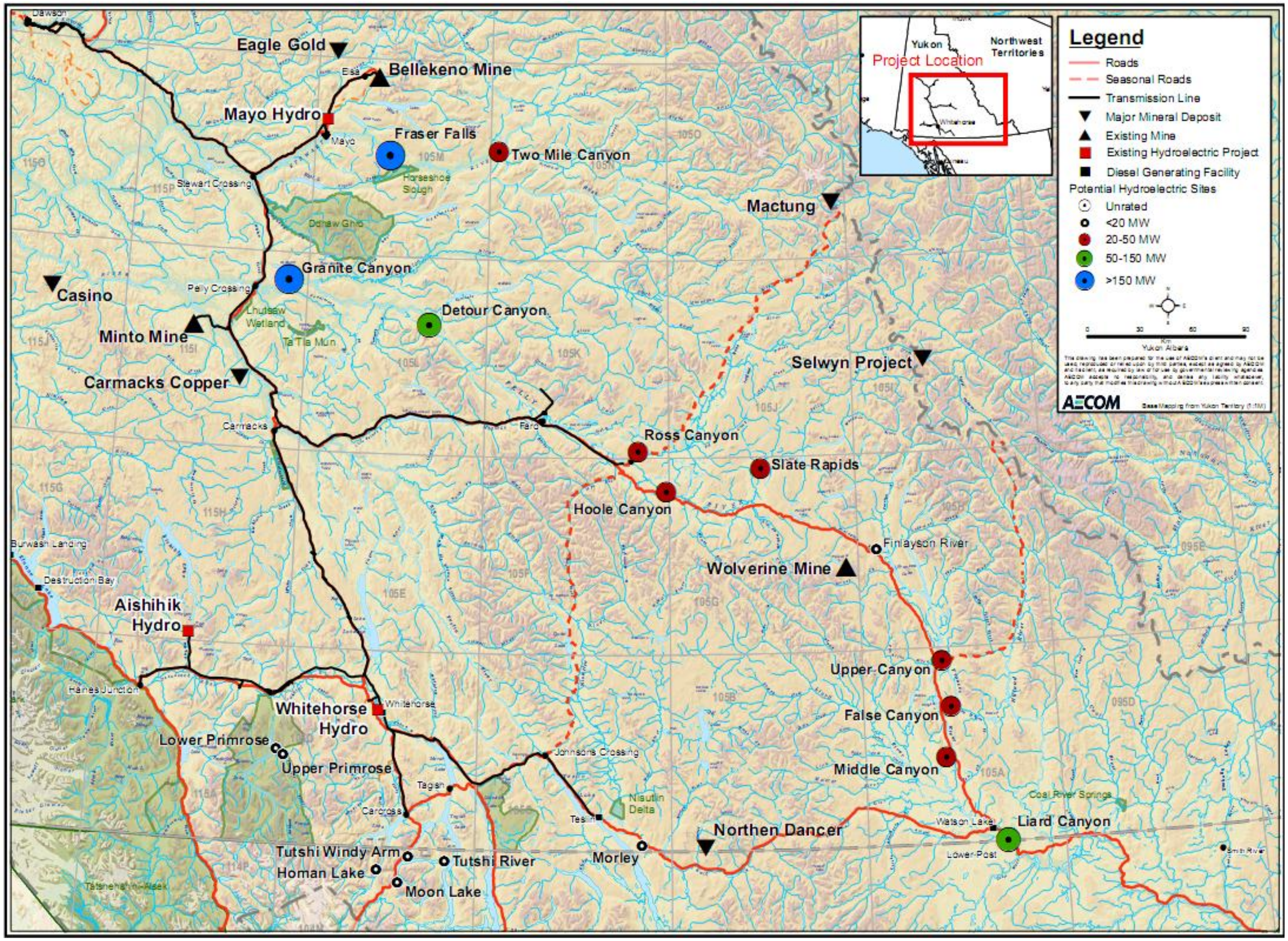


Figure 4: Location of Existing Grid, Potential Hydro Sites, and Various Existing & Potential Mines



Legend: Large Blue circles >100 MW; Purple circles 60-100 MW; Red circles 20-60 MW; Black circles <20 M.

2.3 FOSSIL FUEL PRICE PROJECTIONS

The economics of the Alaska Yukon Transmission Corridor will reflect expected benefits from cost savings due to displacement of fossil fuels (diesel and/or natural gas used for power generation) that would otherwise be required. A key factor in the assessment of such expected cost savings is the assumed projection of fossil fuel prices applicable in Yukon and Alaska.

The following Yukon diesel and LNG-based natural gas fuel costs are assumed to apply in 2015 for Yukon grid generation (based on Yukon Energy's most recent submissions to the Yukon Utilities Board)[1]:

- Diesel fuel generation costs at 30.8 cents/kW.h (reflects early 2014 diesel fuel cost and average fuel efficiency of diesel generation units on the grid).
- Natural gas fuel generation costs at 14.0 cents/kW.h (assumes LNG supply from Fortis at Tilbury BC at an AECO gas price of $4.50/MMBtu [which is higher than recent annual averages] plus $0.30/MMBtu [to reflect Sumas BC equivalent price] and assuming A-Train units for delivery to Whitehorse with a haul cost of $6.59/MMBtu; energy conversion efficiency is assumed at 40% for new reciprocating generators using natural gas.

Displacement of fossil fuel energy generation will also displace non-fuel O&M costs assumed at 1.5 cents per kW.h for the Yukon grid. Where applicable, capacity related cost savings will be separately examined.

In looking at escalation of diesel and natural gas prices beyond 2015, the most recent National Energy Board reference case projections provide a useful basis for assessment to 2035 (see Table 2) – highlighting the extent to which natural gas prices are expected to escalate more rapidly than oil prices over this period while still maintaining a large discount relative to oil on an energy equivalent basis.

[1] See Exhibit B-13 filed in the 2014 Yukon Utilities Board hearing to review the Yukon Energy Diesel-Natural Gas Conversion Project pursuant to Part 3 of the Public Utilities Act. This exhibit provides Yukon Energy's update to LNG supply costs for the Project.

Table 2 – National Energy Board Reference Case Oil Price and Gas Price: 2010 to 2035[1]

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Oil Price: WTI at Cushing (2012US$/barrel)	83.45	98.44	96.16	95.00	95.00	95.00	96.43	97.87	99.34	100.83	102.34	102.85	103.37
Oil Price: WTI at Cushing (2012US$/MMBtu assuming 5.825 MMBTU/bbl)	14.33	16.90	16.51	16.31	16.31	16.31	16.55	16.80	17.05	17.31	17.57	17.66	17.75
Gas Price: Henry Hub, LA (2012US$/MMBtu)	4.53	4.07	2.75	3.90	4.00	4.10	4.20	4.37	4.53	4.70	4.87	5.03	5.15
Ratio of Oil price to Gas price (per MMBtu)	3.2	4.2	6.0	4.2	4.1	4.0	3.9	3.8	3.8	3.7	3.6	3.5	3.4

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Oil Price: WTI at Cushing (2012US$/barrel)	103.88	104.40	104.93	105.45	105.98	106.51	107.04	107.58	108.11	108.65	109.20	109.74	110.29
Oil Price: WTI at Cushing (2012US$/MMBtu assuming 5.825 MMBTU/bbl)	17.83	17.92	18.01	18.10	18.19	18.28	18.38	18.47	18.56	18.65	18.75	18.84	18.93
Gas Price: Henry Hub, LA (2012US$/MMBtu)	5.25	5.34	5.43	5.52	5.60	5.68	5.76	5.83	5.90	5.97	6.04	6.11	6.18
Ratio of Oil price to Gas price (per MMBtu)	3.4	3.4	3.3	3.3	3.2	3.2	3.2	3.2	3.1	3.1	3.1	3.1	3.1

Source: National Energy Board of Canada http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2013/ppndcs/pxbnchmrk-eng.html

1. West Texas Intermediate crude oil price at Cushing, Oklahoma.
2. Henry Hub natural gas price near Erath, Louisiana.

[1] National Energy Board of Canada, "Canada's Energy Future 2013 – Energy Supply and Demand Projections to 2035 - an Energy Market Assessment.

BACKGROUND PAPER #3: INITIAL TRANSMISSION CORRIDOR COST ESTIMATE

In order to provide an initial assessment of potential development scenario requirements for the Alaska-Yukon transmission corridor transmission project, preliminary initial costs have been estimated at $68 to $94 million ($2014) for a 138 kV wood pole line from Skagway, Alaska to Riverside[1], Yukon, based on the following:

- Transmission line cost for 175 km transmission line at between $55 million and $76 million (about $0.314 million/km to $0.434 million/km). This estimate reflects a reasonable range based on recent experience and assuming road access and reasonably mild terrain on average for the project (see Attachment A).
- Substation cost at $13 to $18 million (assumes only need new substation at Alaska end, and that use of Yukon Energy Riverside substation will enable use of existing facilities without need for new substation costs). This estimate reflects a reasonable range for a single substation based recent Yukon Energy experience (see Attachment A).

[1] The materials distributed at the June 18, 2014 workshop incorrectly noted that the line would connect to the Riverdale substation in Yukon. This has been corrected to read the Riverside substation.

Attachment A - Background Information re: Transmission Line Project Costs

Estimates for generic transmission line capital costs in Alaska (as reviewed in the SEIRP) are as follows (excludes consideration of substation costs):

- Assuming in each case the transmission line is adjacent to an existing roadway and built on reasonably flat terrain:
    - $0.446 million/mile (about $0.277/km) for 69 kV with wood poles;
    - $0.481/mile (about $0.299/km) for 138 kV with steel poles, assuming in each case adjacent to existing roadway and reasonably flat terrain.
- In contrast, with challenging terrain and poor access, costs will jump (e.g., Haines to Juneau line is estimated to cost $2.86 million per mile).[2]

In 2009, the 93-km long Swan-Tyee 138 kV transmission line was completed in very mountainous terrain in southeast Alaska (Ketchikan-Wrangell), with no road access, at an average cost of $0.84US million/km.[3]

Experience with recent 138 kV transmission line planning and construction in Yukon (related to the recently completed Carmacks-Stewart Transmission Project over reasonably flat terrain) indicates as follows[4]:

- Excluding substation and engineering costs, transmission line costs (planning and construction) averaged $0.270 to $0.280 per km for the two segments (initial 98 km segment from Carmacks to Pelly Crossing, and subsequent 74 km segment from Pelly Crossing to Stewart).
- Substation and engineering costs for new substations at Pelly Crossing and Stewart Crossing approximated $21 million, reflecting a number of special challenges that would not normally be anticipated to occur[5].

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[2] SEIRP, Table 12-12

[3] Dryden Larue (Includes clearing, project management, owner and construction management/inspection, but excludes engineering and substation work).

[4] Based on Information Responses filed by Yukon Energy with Yukon Utilities Board during its last two General Rate Applications (LE-YEC-1-46; CW-YEC-1-26).

[5] For example, the location of the substation at Stewart Crossing was changed after the project was under construction, incurring added costs.

BACKGROUND PAPER #4 – ALASKA-YUKON FIBRE OPTIC CORRIDOR LINK

Almost all telecommunications in and out of Yukon is carried over a single fibre optic transmission system owned and operated by Northwestel. An alternative fibre link by an independent service provider is expected to improve the reliability of communications services and enable competition and innovation in the telecommunications sector thus reducing prices and improving service levels.

Feasibility Study for Alternative Yukon Fibre Optic Link

The Yukon Government commissioned a study[1] to assess the feasibility of a second, diverse fibre link into Yukon in order to improve reliability of telecommunications services and promote competition and lower service prices in the Yukon market. Based on studies undertaken to date by the Yukon Government, an alternative fibre optic link is expected to result in the following:

1. The emergence of competitive services (and resulting lower prices, innovation and additional employment); and
2. Improved reliability of services (which will reduce lost productivity due to data and internet outages; reduce lost revenue due to point of sale outages; enable new business that provide application level services to emerge; and improve the ability of business organizations to utilize cloud based services).

The study recommended that a privately owned company be established to implement a Whitehorse–Juneau fibre optic link with connections to Seattle as well as offer wholesale data and internet services in Whitehorse[2].

Capital Costs and Funding

Capital cost estimates included in the Feasibility Study for Alternative Yukon Fibre Optic Link cover fibre cables, fibre terminal equipment and IRUs5 on existing cable. Options reviewed require point-of-presence equipment such as routers and customer access links Whitehorse. The study recommends the Whitehorse via Carcross and Skagway and Juneau to an internet gateway Seattle or Portland as the fibre route option which meets the requirement for connection to a major internet gateway with the lowest initial cost (as summarized in Table 1)[3].

1 See, "Feasibility Study for Alternative Yukon Fibre Optic Link: Summary Report", Planetworks Consulting Corporation, February, 2014; other prior studies include, "Yukon Telecommunications Development Final Report", Lemay-Yates Associates for the Government of Yukon, December 14, 2012 and "Fiber One Market Assessment", BDC Consulting for Total North Communications, January 2010.

2 Feasibility Study for Alternative Yukon Fibre Optic Link, page 3 and page 15.

3 Feasibility Study for Alternative Yukon Fibre Optic Link, page 10.

Table 1 Fibre Route Options	
Option	**Approximate Initial Cost ($ Millions CDN)**
a) Whitehorse – Carcross - Skagway - Juneau - Seattle or Portland	23 to 28
b) Whitehorse – Skagway - Juneau - Prince Rupert - Vancouver	32 to 36
c) Whitehorse - Edmonton via the Dempster Highway and proposed Mackenzie Valley fibre	50

Source: Feasibility Study for Alternative Yukon Fibre Optic Link, Planetworks Consulting Corporation

The study concluded that the small telecommunications market in Yukon cannot provide sufficient revenues to support the cost of a second fibre route and therefore a large public subsidy will be required.

Consequently, in order to be feasible, the study estimated that a developer would require a one-time grant of at least $12.8 Million to cover half of the start-up costs and enable a viable business plan. The business plan assumes funding from both public and private sources, capacity sharing agreements with Northwestel, and a 10 year commitment from the Government of Yukon to purchase connection capacity from the new company.

Route Options

The study indicates that the only communications technology that can provide the required capacity and scalability is a fibre optic transmission system consisting of fibre optic cable and electronic terminal equipment. Figure 1 provides an overview of existing and proposed fibre routes in the region. A fibre optic link between Whitehorse and Juneau consisting of the following route sections is recommended[4]:

- An IRU on existing Northwestel fibre between Whitehorse and Carcross (or other cable sharing option negotiated with Northwestel);
- A new 48-strand buried fibre cable between Carcross and Skagway; and
- A new 24-strand undersea fibre cable between Skagway and Juneau.

Agreements will be required for use of Northwestel's of existing fibre between Whitehorse and Carcross. Alternatively, a new buried fibre cable along the opposite (west) side of the highway from the existing cable could be placed.

Timing and Options to Coordinate with Transmission Corridor

It is understood that planning and development of a fibre optic link between Yukon and Alaska will move forward in the very near term with a planned 2015 start date, and that plans to proceed in the near term as opposed to the longer term are relatively fixed. As such, potential synergies between development of the fibre optic cable and any transmission corridor between Yukon and Alaska would depend on the ability to justify and proceed with the transmission corridor within the near term, and

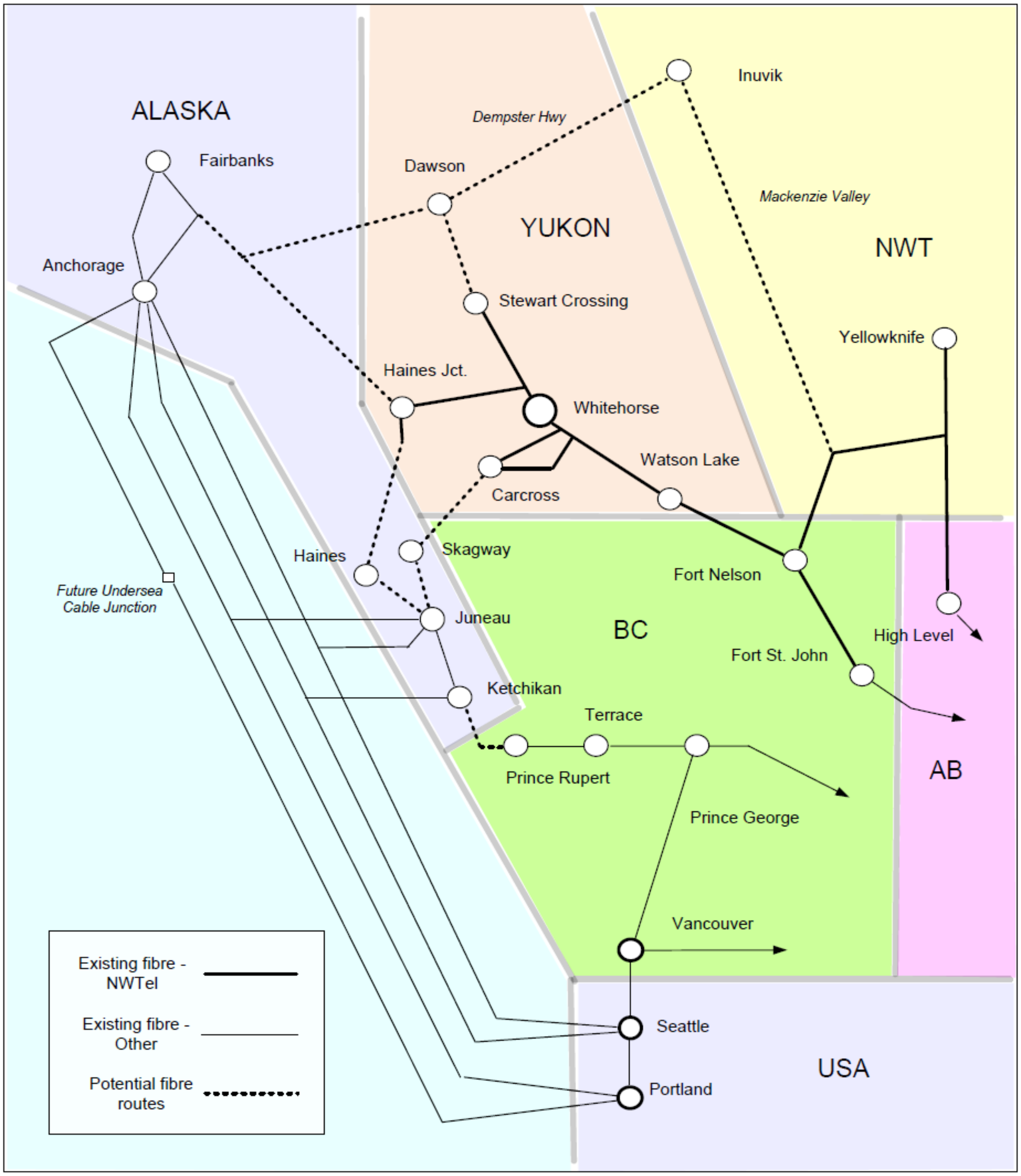
[4] Feasibility Study for Alternative Yukon Fibre Optic Link, page 8-9.

an understanding of any potential costs/benefits that may result from coordinating planning and scheduling for the two projects.

Key areas to assess in this regard include:

- What are the potential cost savings were the fibre optic link to be delayed in order to coordinate development with the transmission corridor? It is understood that if the two projects could be coordinated that instead of the fibre optic cable being buried underground, it would be strung along the transmission line - - with a material capital cost saving *(to be estimated).
- What length of delay for the fibre optic link would be tolerable or feasible?
- What is the earliest date that the fibre optic cable corridor could feasibly be constructed?
- What is the earliest date that the transmission corridor could feasibly be constructed?

Figure 1: Fibre Optic Route Options



ATTACHMENT C-2

PRELIMINARY DEVELOPMENT SCENARIOS

Potential Development Scenarios for Yukon-Alaska Transmission Line

(Concepts re: potential annual power load movements between Whitehorse and Skagway)

Scenario 1 - Development with West Creek Hydro Generation

Whitehorse, Yukon | **Skagway, Alaska**

← About 54 GW.h/yr from Alaska to Yukon

Whitehorse, Yukon

Need sufficient fossil fuel displacement opportunity
- New loads needed on grid of 25-50 GW.h/yr to proceed within next decade

Financial & Economics viability issues (beyond timing):
- Expected cost savings from fossil fuel displacement
- Competitive renewable cost options (e.g., other hydro sites)
- Supply security & charges for delivered West Creek hydro

Skagway, Alaska

Confirm West Creek Hydro volumes, timing and costs
- About 134 GWh/yr generation, less 80 GW.h/yr June to Nov (not needed in Yukon)

Financial & Economics viability issues (beyond timing):
- Net power charges to cruise ships & sustainability of loads
- Overall capital costs for new hydro & transmission
- Financing, ownership and cost recovery arrangements

Scenario 2 - Development with YEC Summer Hydro Surplus & Skagway Cruise Ship Loads

Whitehorse, Yukon | **Skagway, Alaska**

About 30 GW.h/yr from Yukon to Alaska →

Whitehorse, Yukon

Surplus Hydro (early June through September)
- Assume up to about 34-38 GW.h surplus summer hydro with current generation & loads - need LNG backup

Financial & Economics viability issues (beyond timing):
- Charges for hydro power supplies
- Charges for LNG back up generation
- Factors that reduce hydro surplus
- Upper limit on viable transmission charges

Skagway, Alaska

Energy for Cruise Ships (early May through September)
- About from 30 GW.h per season with peak load 6.5 to 32.5 MW in different weeks over the period

Financial & Economics viability issues (beyond timing):
- Diesel cost saved by ships
- Shore power connection costs
- Factors that limit cruise ship diesel displacement volumes
- Competitive cost option (LNG generation at Skagway)

Potential Development Scenarios for Yukon-Alaska Transmission Line

(Concepts re: potential annual power load movements between Whitehorse and Skagway)

Scenario 1 - Development with West Creek Hydro Generation

Whitehorse, Yukon **Skagway, Alaska**

← About 54 GW.h/yr from Alaska to Yukon

(Confirm volumes, timing and costs for West Creek Hydro development - need sufficient fossil fuel displacement opportunity on Yukon grid)

Whitehorse, Yukon

Need sufficient fossil fuel displacement opportunity (see Note 4)
- New loads needed on grid (25-50 GW.h/yr) to proceed within next decade - potential new industrial load opportunities
  - Carmacks Copper (about 54 GW.h for 7.5 years)
  - Victoria Gold (about 100 GW.h for less than 10 years)
- Financial & Economics viability issues (beyond timing):
  - Expected cost savings from fossil fuel displacement
  - Competitive renewable cost options (e.g., other hydro sites)
  - Supply security & charges for delivered West Creek hydro

Skagway, Alaska

Confirm West Creek Hydro volumes, timing and costs (see Notes 2 & 3
- About 134 GWh/yr average generation, less about 80 GW.h June to Nov (not needed in Yukon) - subject to planning to
  - Regulatory feasibility, potential earliest timing & costs
  - Seasonal and annual generation variability
- Financial & Economics viability issues (beyond timing):
  - Net power charges to cruise ships & sustainability of loads
  - Overall capital costs for new hydro & transmission
  - Financing, ownership and cost recovery arrangements

Scenario 2 - Development with YEC Summer Hydro Surplus & Skagway Cruise Ship Loads

Whitehorse, Yukon **Skagway, Alaska**

About 30 GW.h/yr from Yukon to Alaska →

(Viability upper limit on transmission charges as percent of potential capital cost ranging from $68 to over $94 million - see Note 1)

Whitehorse, Yukon

Surplus Hydro (early June through September - see Note 5)
- Assume up to about 34-38 GW.h average surplus summer hydro with current generation & loads subject to:
  - Water availability in summer (capacity and energy generation)
  - LNG back up generation capacity
  - Industrial Load on Yukon Grid in summer
- Financial & Economics viability issues (beyond timing):
  - Charges for hydro power supplies
  - Charges for LNG back up generation
  - Factors that reduce hydro surplus
  - Upper limit on viable transmission charges

Skagway, Alaska

Energy for Cruise Ships (early May through September)
- About 30 GW.h per season with peak load ranging from 6.5 to 32.5 MW (typical about 26 MW - see Note 2), subject to:
  - Shore power connection being developed
  - Conversion of ships to receive shore power
  - Ongoing cruise ship volumes & peak loads
- Financial & Economics viability issues (beyond timing):
  - Diesel cost saved by ships
  - Shore power connection costs
  - Factors that limit cruise ship diesel displacement volumes
  - Competitive cost option (LNG generation at Skagway)

Notes:

1. See Background Paper #3 re: Initial Transmission Corridor Cost Estimate, based on SEIRP estimates, other recent Alaska transmission cost experience, and the Yukon Carmacks Stewart Transmission Project costs.

2. See Background Paper #1 re: Long Term Fossil Fuel Generation Requirement Scenarios, section 1.1.2 (Figures 6 and 7); about one-third (10.7 GW.h for total season) of this load involves ships currently converted to connect to shore power (it is assumed that the balance could potentially be converted in 1-2 years under economic conditions). One recent funding application estimated diesel generation cost per kW.h for cruise ships at about 33.4 cents/kW.h (2017), including about 32.1 cents/kW.h fuel costs and 1.3 cents/kW.h operating and maintenance expenses.

3. See Background Paper #2 re: Supply Options, section 1.1 on West Creek Hydro. The Renewable Energy Fund Round 6 Grant Application for West Creek Hydro provides cost estimates for this project at $140 million. Available information for a 25 MW West Creek Hydro project estimates average generation over 15 water years of record at 134 GW.h/yr (range of 112 to 161 GW.h/yr), with about 60 GW.h on average over the four "summer" months (June 1 to September 30) and slighltly over 9 GW.h/month on average for the remaining eight months (with lowest generation in April and May at about 7 GW.h/month). Although the 2011 AEA Funding Application suggested that the project could be operational within six years after start of Phase II Feasibility Analysis (which does not appear to have yet started), AP&T has also suggested that at least ten years could be needed for licensing and permitting.

4. See Background Paper #1 re: Long Term Fossil Fuel Generation Requirement Scenarios, section 1.2. The most recent YEC updated near-term grid load scenario forecasts (filed in Decemebr 2013 re: Application under Part 3 of PUA for Proposed Whitehorse Diesel-Natural Gas Conversion Project) indicate long-term average fossil fuel (diesel or LNG) generation requirement without any new industrial loads or new renewable generation ranging from 2018 to 2026 at 31.4 to 55.0 GW.h/yr (with growing requirements thereafter). A potential new industrial load of 54 GW.h/yr in 2018 (Carmacks Copper) would increase fossil fuel generation requirements in the range of 37-40 GW.h/yr for about 7.5 years.

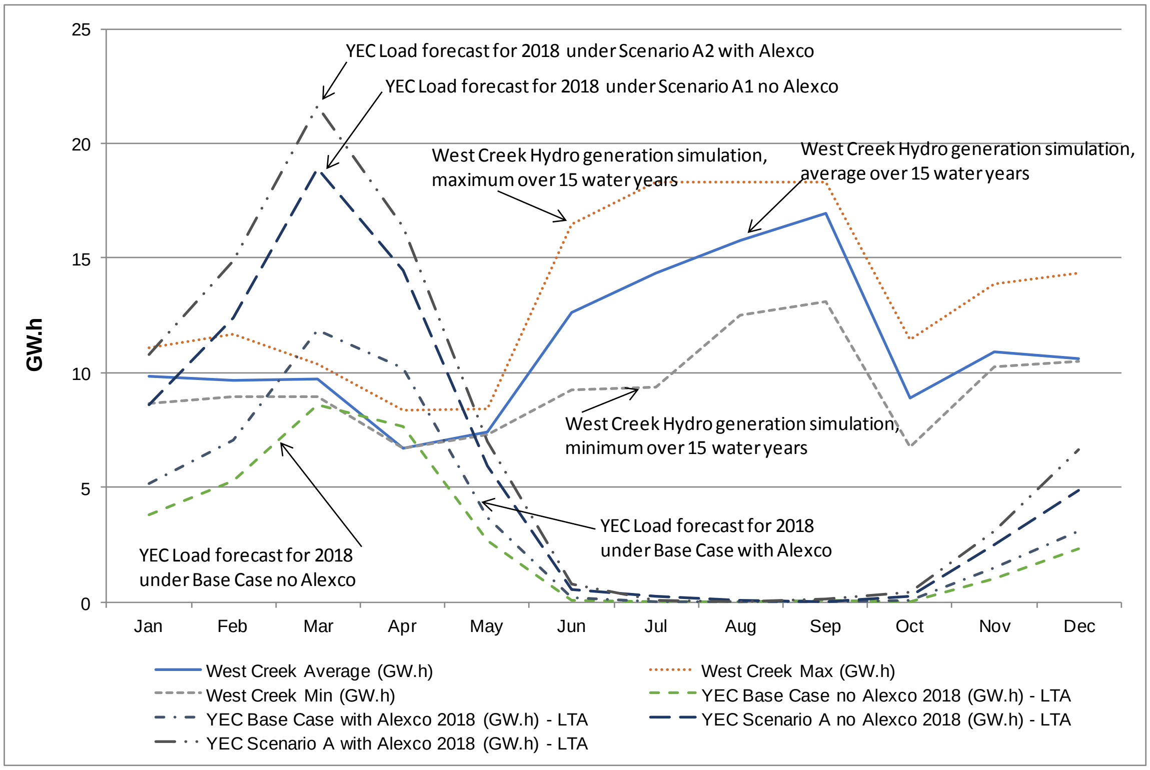
5. See Background Paper #2 re: Supply Options, section 2.2 on Yukon Summer Surplus Hydro (Figure 2). In 2018, summer surplus hydro without new mine connections ranges from 34 to 38 GW.h with average surplus per week ranging from 4 to 15 MW over the period; if Carmacks Copper mine connection occurs, this surplus is reduced to 18 to 22 GW.h over the summer period.

ATTACHMENT C-3

OTHER WORKSHOP MATERIALS

Figure 1 below compares by month the simulated West Creek long term average generation and YEC's long-term average thermal generation requirements for 2018.

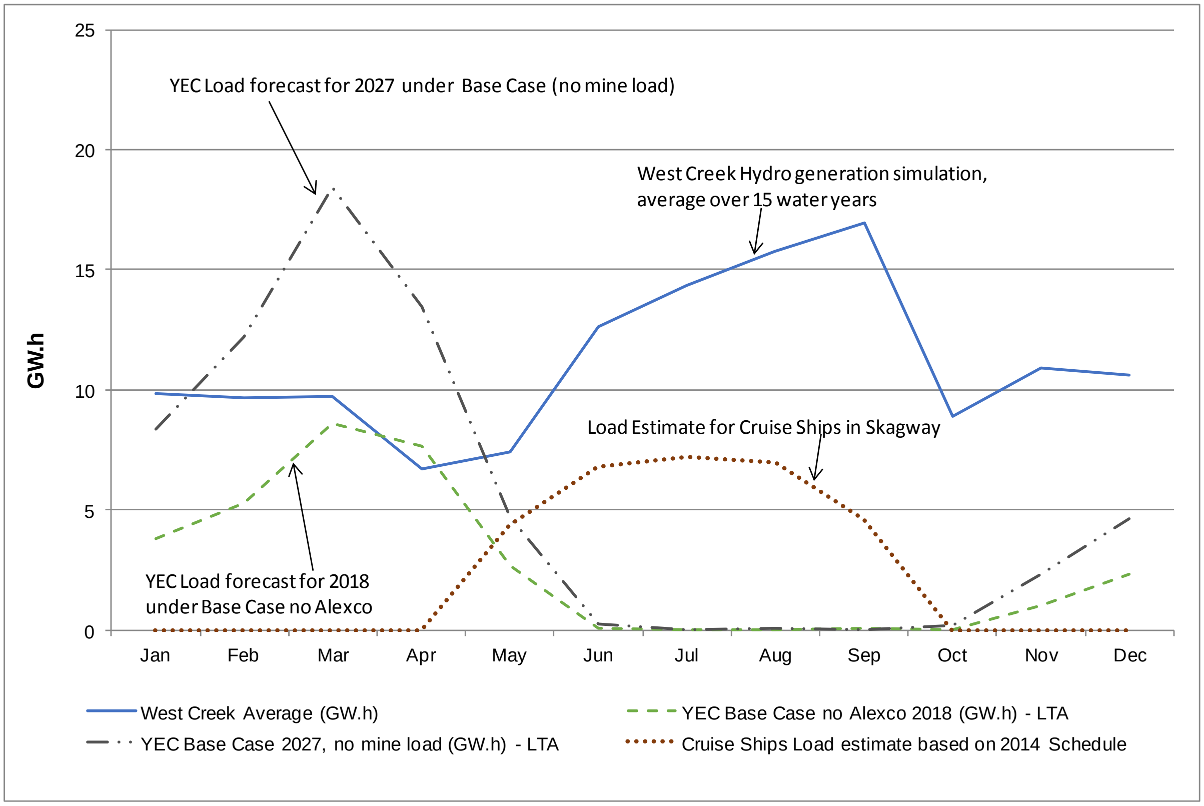
Figure 1: Comparison of YEC Thermal Generation Requirements to West Creek Hydro Simulated Generation



GW.h	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
West Creek Simulated Generation													
Minimum Annual over 15 Water Years	8.7	8.9	8.9	6.7	7.3	9.2	9.4	12.5	13.1	6.8	10.2	10.5	112.4
Average Annual over 15 Water Years	9.8	9.7	9.7	6.7	7.4	12.6	14.4	15.8	17.0	8.9	10.9	10.6	133.5
Maximum Annual over 15 Water Years	11.1	11.7	10.4	8.4	8.4	16.5	18.3	18.3	18.3	11.5	13.9	14.3	161.0
YEC Thermal Generation Requirements													
Base Case no Alexco 2018	3.8	5.3	8.6	7.7	2.7	0.1	0.0	0.0	0.1	0.0	1.1	2.3	31.6
Base Case with Alexco 2018	5.1	7.1	11.9	10.2	3.7	0.2	0.0	0.0	0.0	0.1	1.5	3.1	42.9
Scenario A1 no Alexco 2018	8.6	12.4	18.9	14.5	5.9	0.6	0.2	0.1	0.0	0.3	2.5	4.8	68.9
Scenario A2 with Alexco 2018	10.8	14.9	21.6	16.3	7.0	0.8	0.0	0.0	0.1	0.5	3.1	6.6	81.8

Figure 2 below compares by month the simulated West Creek long term average generation to YEC's long-term average thermal generation requirements for 2018 under Base Case scenario without Alexco and long-term average thermal generation requirements for 2027 without any mine load, as well as estimated load for Cruise Ships in Skagway based on schedule for 2014.

Figure 2: Comparison of YEC Thermal Generation Requirements and Cruise Ship Load to West Creek Hydro Simulated Generation



GW.h	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
West Creek Simulated Generation													
Average Annual over 15 Water Years	9.8	9.7	9.7	6.7	7.4	12.6	14.4	15.8	17.0	8.9	10.9	10.6	133.5
2018 Alaska & Yukon loads													
Cruise ship loads	0	0	0	0	4.4	6.8	7.2	7.0	4.6	0	0	0	29.9
Base Case Yukon grid no Alexco 2018	3.8	5.3	8.6	7.7	2.7	0.1	0.0	0.0	0.1	0.0	1.1	2.3	31.6
Provision for losses (10%)	0.4	0.5	0.9	0.8	0.7	0.7	0.7	0.7	0.5	0.0	0.1	0.2	6.2
Total Loads	4.2	5.8	9.5	8.4	7.7	7.6	7.9	7.6	5.2	0.0	1.2	2.6	67.7
West Creek Generation Use	4.2	5.8	9.5	6.7	7.4	7.6	7.9	7.6	5.2	0.0	1.2	2.6	65.7


SOUTHEAST ALASKA AND YUKON ECONOMIC DEVELOPMENT CORRIDOR
Potential Hydro Sites
Major Road
White Pass and Yukon Railway
First Nation Settlement Land
Chilkoot Trail National Historic Site
0 5 10 15
Kilometers
0 5 10 15
Miles
Whitehorse
ALASKA HIGHWAY
SOUTH KLONDIKE HIGHWAY
BOUNDARY RANGES
(COAST MOUNTAINS)
(CHAINE COTIERE)
PLATEAU
YUKON
BRITISH COLUMBIA
TUTSHI LAKE
MOON LAKE
TAGISH
HIGHLAND
CHILKOOT TRAIL NATIONAL HISTORIC SITE
ALASKA
WEST CREEK
DYEA
SKAGWAY
HAINES
FLORENCE RANGE
ATLIN PROVINCIAL RECREATION