Appendix 5.5
Aishihik Turbines Uprate Study
(KGS 2016)

YUKON ENERGY

AISHIHIK TURBINES UPRATE STUDY

FINAL – REV 1

KGS Group 14-1404-004

February 2016

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File No. 14-1404-004

Yukon Energy Corporation
2 Miles Canyon Road
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ATTENTION: Mr. Ron Gee
Hydrological & Civil Engineer

RE: Aishihik Turbines Uprate Study RFP #2014-053 – Final Report, Rev 1

Dear Mr. Gee:

KGS Group is pleased to submit two hard copies and a digital copy of this revised report for the Aishihik Turbines Upgrade Study. Table 1 of the report was revised to clarify the information.

Please contact the undersigned if you have any questions on the report.

We thank you for the opportunity to providing Yukon Energy Corporation with engineering services for this project.

Yours truly,

J. Lambert, P.Eng.
Senior Mechanical Engineer

DB/gr
Enclosure

EXECUTIVE SUMMARY

The Aishihik Generating Station (“AGS”) was built in the mid-1970’s. It originally consisted of two vertical Francis turbines, AH1 and AH2, manufactured by Dominion Engineering Works and coupled to General Electric generators. A third horizontal Francis unit, AH3, manufactured by Kossler/Voith was added in 2011. Both the AH1 and AH2 stators were eventually re-wound with varying amounts of additional generator capacity in 2003 and 2006 respectively; AH2 generator has more capacity than AH1 generator.

Due to their vintage, AH1 and AH2 are not as efficient as modern turbines. Combined with the fact that their associated generators having additional capacity, this provides an opportunity to increase energy production by uprating and refurbishing them with modern runners. The study examines two options: firstly, uprating only AH2 and secondly, uprating both AH1 and AH2.

The Aishihik Generating Station unit AH2 could be uprated at a cost of $3.0M with a discounted payback of 6 years. The major components to be uprated include the runner, the generator air coolers, the excitation system, and the cables from the generator to the circuit breaker and from the outdoor switchgear to the transformers. YEC could, at its discretion, add opportunity work on the balance of turbine/generator components and on the AGS balance of plant.

Alternatively, AH1 and AH2 can both be uprated with new runners for a cost of $4.7 M and a discounted payback of 8 years. The incremental amount of work to add the uprate AH1 to the scope of work is limited to the new runner and optional opportunity work since it will not require new cabling or a new excitation system.

The uprated units would provide an increase in plant capacity, which would displace diesel generation, and would increase Yukon Energy Corporation’s annual energy generation.

TABLE OF CONTENTS

PAGE

TABLES

LIST OF APPENDICES

1.0 BACKGROUND

The two original vertical Francis turbine generating units (AH1 & AH2) at the Aishihik Hydro facility were manufactured by Dominion Engineering Works Limited in 1974 and placed into service in 1975. They are 15 blade runners rated at 20,500 HP (15.3MW) at 592 feet of head. These turbines were coupled to Canadian General Electric generators rated at 15.6MVA / 14.0MW.

In 2003, the AH1 generator was rewound by General Electric, increasing its stator capacity to 17MVA / 15.3MW. The generator's capacity now matches the turbine's output of 15.3MW.

In 2006, the AH2 generator was rewound by Voith, increasing its stator capacity to 19.2MVA / 17.2MW. The generator's capacity now exceeds the turbine's output of 15.3MW.

The newer horizontal Francis turbine generating unit AH3, manufactured by Kossler/Voith, was placed into service in 2011. It produces 9,625 HP (7.180 MW) turbine at 592 feet of head and it is connected to an 8.25MVA TDPS-India generator. This unit is not considered for uprating.

Although uprating AH2 offers the greater opportunity for a single unit uprate, the benefits of fitting AH1 with a higher efficiency runner were also reviewed.

Only the components related to turbine, generator and power train capacity and efficiency uprate are examined in this report. These uprate elements are justified and costed out. A project payback is then calculated using a calculation spreadsheet provided by YEC. Opportunity work normally performed during runner and generator uprates are identified, but are not costed out, since they do not have capacity or energy benefits and payback. Similarly, project indirect costs such as camp facilities and internal YEC engineering costs are not considered.

KGS Group used an integrated multi-disciplinary team of experienced engineers to carry out the Aishihik Turbine Uprate Study. They conducted engineering reviews, sent vendors requests for information (RFI's) and compiled capital cost estimates for two options for YEC's consideration. KGS Group also performed computations of payback based on KGS calculations of energy benefits.

2.0 PRESSURE SHAFT AND TAILRACE TUNNEL HYDRAULIC STUDY

The initial task in the turbine uprate study was to conduct a high level hydraulic review of the conveyance system in order to determine the maximum flow that can be conveyed before affecting functionality and safety of the system.

2.1 HYDRAULIC REVIEW

KGS Group reviewed the existing documentation and developed a one dimensional computer model to confirm the conveyance system hydraulics. It was determined that the limiting factors for increasing plant flow capacity are the requirements to maintain the emergency evacuation path in the tailrace tunnel and to maintain the tunnel operating at less than full flow.

The current plant capacity provides 1.06 m of emergency freeboard throughout the tunnel during normal downstream river conditions. During flood conditions, no data is available about water levels in the West Aishihik River. These river water levels have the potential to limit the available emergency freeboard at the downstream end of the tailrace tunnel. Until further information about flood stages in the West Aishihik River is obtained and analyzed, no increase in plant flow is recommended.

Should the tunnel transition from partially full to full flow, there is a possibility of backwater effects such as a significant rise in tailwater level at the plant and possibly pressure transient issues. The magnitudes of these effects have not been determined. KGS Group recommends that the Turbine Rerate Specification includes a section on limiting water flow through the new runner, or runners, such that the total plant flow limit is respected under all operating conditions.

KGS Group's hydraulic review is provided in Appendix A.

2.2 TRANSIENT PRESSURE FLUCTUATIONS

A high level assessment of transient pressure fluctuations in the pressure tunnel during unit start-ups and shut-downs was not required since the maximum plant flow conditions will not change as a result of runner uprates.

3.0 TURBINE UPRATE REVIEW

KGS Group issued a Request for Information (RFI) for budget pricing, as well as technical information on a new runner for Unit 2, and other required turbine modifications or new components that may be beneficial to the efficiency or power output of the turbine. Two proposals were received, one from Alstom Power and one from Norcan Hydraulic Turbine Inc., hereafter called Alstom and Norcan. The vendor responses are presented in Appendix B.

3.1 TYPICAL OPERATION AND OPTIMIZATION OF NEW RUNNERS

The Vendors were informed that in order to provide a “spinning reserve” to accept sudden load increases on Yukon Energy Corporation’s electrical grid, the AH1 and AH2 units are typically operated at approximately 80% of their maximum power output. They may, however, be operated at relatively low power levels during periods of low demand and at maximum output during periods of high demand.

Because of the above-mentioned operation strategy, the proposed new runners should be optimized to provide, in order of importance:

1. The highest efficiency at approximately 80% gate opening.
2. The highest maximum output at full gate opening.
3. The highest efficiency at gate openings lower than 80%.

3.2 ANALYSIS OF RUNNER UPRATE OPTIONS

Based on the above criteria, Alstom and Norcan focused on obtaining higher efficiencies by taking advantage of modern design and manufacturing techniques. Both vendors offered runners that would fit within the existing runner chamber. The principal elements of the turbine that were targeted were the runner blade shapes and labyrinth seal design. Alstom also foresees potential extra improvements by changing wicket gate profiles. The future RFP to vendors should prompt them to explore these and other areas of potential efficiency gains.

Alstom and Norcan picked runners from their stock of prior designs as reference runners for Aishihik. They provided expected curves of turbine power and efficiency for a net head of 180.4 m. A summary of the budgetary proposals follow in Table 1.

TABLE 1
AISHIHIK TURBINE BUDGETARY PROPOSALS

ITEM	NORCAN	ALSTOM
Budgetary cost (not adjusted)	$497,273	$743,000
Description of new runner	40” Francis Cast CA6NM or Forged A182F6NM	40” Francis Forged martensitic steel
Fabrication method	Runner will be forged and machined.	Runner will be fabricated. Crown and band will be cast or forged and pre machined.
Proposed scope of the upgrades, beyond the provision of new runners	none	Refurbish Wicket Gates. Different runner bolting pattern. Redesign labyrinth.
Number of runner blades proposed	15	15
Performance at 180.4 m net head: • Max Power at rated flow 9.72 cms • Best efficiency • Flow at best efficiency point	 16.1 MW 93.83% 9.32 cms	 16.1 MW 93.5% 8.4 cms
Maximum runaway speed	Not given	185%
Delivery time for major equipment after placement of order	11-12 months	9-10 months
Time required for installation in the field	6-8 weeks	Not given

4.0 ENERGY AND CAPACITY BENEFITS ANALYSIS

4.1 ENERGY

The energy benefit analysis for the potential upgrades of Aishihik Generating Station (AGS) were conducted using the long term energy model YECSIM developed by KGS Group for Yukon Energy Corporation (YEC). The options for potential upgrades of AGS could include the upgrades of either AH1 or AH2 or both.

The software YECSIM is a detailed integrated power / water flow model operating on a weekly time step. It can be used for analysis of the operation and future expansion of the YEC electrical generating capacity. This model includes all assumed loads and load profiles, operating characteristics of each system power facility (e.g. unit efficiencies), licensed parameters for each plant as approved or proposed, and desired operating parameters for the system (such as reducing line losses or voltage stability), as well as the hydrological conditions. More information about the model can be found in the YECSIM User's Manual.

As required by the YECSIM model, the 3-tier systems for specification of efficiency were developed for the the existing conditions based on the original turbine and generator efficiency curve and the potential upgrade options based on the turbine and generator efficiency curves provided by vendors. The plant maximum flow was limited at the 23.7 m^3/s. The two energy demand levels for the WAF/MD integrated system, including the low energy demand level (468.1 GWh/year) and the high energy demand level (575.1 GWh/year), were used in the YECSIM model simulations.Those two energy loads could reasonably be expected to occur or be surpassed within the future 20 to 30 years starting from 2009, as described in the report for the proposed Mayo Hydro Enhancement Project prepared by YEC (Ref. 2). More information related to the YECSIM model setup is provided in Appendix C.

The hydro energy generation from the WAF/MD system for the existing conditions and the potential upgrade options were forecasted using the YECSIM model. The detailed description of the energy benefit analysis is provided in Appendix C. Table 2 below shows the modeled net hydro energy contributions to the WAF/MD integrated system for the potential upgrade options.

The model results show:

- For the upgrades of AH1 only, using Alstom turbine would generate energy benefit from 2.19 GWh/year to 2.26 GWh/year to the system, while using Norcan turbine would generate energy benefit from 0.96 GWh/year to 1.27 GWh/year to the system.
- For the upgrades of AH2 only, using Alstom turbine would generate energy benefit from 2.25 GWh/year to 2.35 GWh/year to the system, while using Norcan turbine would generate energy benefit from 1.14 GWh/year to 1.40 GWh/year to the system. The energy benefit for the upgrades of AH2 only is slightly higher than the one for the upgrade of AH1 only.
- For the upgrades of both AH1 and AH2, using Alstom turbines would generate energy benefit from 2.74 GWh/year to 3.04 GWh/year to the system, while using Norcan turbine would generate energy benefit from 1.81 GWh/year to 2.37 GWh/year to the system. The energy benefit for the upgrades of both AH1 and AH2 are higher than the one for the upgrades of either AH1 or AH2.

TABLE 2
ENERGY BENEFITS

Unit Upgrade Option	Net Energy Contribution due to the Upgrades using Alstom Turbine (GWh/year)		Net Energy Contribution due to the Upgrades using Norcan Turbine (GWh/year)	
	Low Energy* Demand	High Energy** Demand	Low Energy* Demand	High Energy** Demand
Upgrade of AH1 Only	2.26	2.19	0.96	1.27
Upgrade of AH2 Only	2.35	2.25	1.14	1.40
Upgrade of AH1 and AH2	2.74	3.04	1.81	2.37

*: Low energy demand (468.1 GWh/year)

**: High energy demand (575.1 GWh/year)

Going forward in this report, only the Alstom proposal will be analyzed for economic benefits. This proposal has the higher initial cost and the higher net energy contribution to the WAF/MD System.

4.2 CAPACITY

Incremental capacity represents an important benefit to the proposed turbine upgrade project. Although the proposed turbine capacity may exceed the existing turbine capacity, hydraulic conditions limit the effectiveness of this additional capacity. According to YEC, Aishihik GS is typically run at around 80% plant flow, so any excess turbine capacity requiring additional plant flow may not be realized. Therefore, the evaluation was based on plant capacity at 80% plant flow instead of the individual turbine capacity.

Plant capacity was estimated for each configuration based on the typical plant flow of 19 m^3/s. The estimated plant capacities for each proposed plant configuration are shown in Table 3.

TABLE 3
PLANT CAPACITY

SIMULATION SCENARIO	PLANT EFFICIENCY (%)	PLANT CAPACITY (MW)	INCREMENTAL PLANT CAPACITY (MW)
Existing Condition	87.8	29.8	-
New AH1 - Alstom	89.9	30.5	0.7
New AH1- Norcan	89.7	30.5	0.6
New AH2 - Alstom	89.9	30.5	0.7
New AH2 - Norcan	89.7	30.5	0.6
New AH1 and AH2 - Alstom	91.6	31.1	1.3
New AH1 and AH2 - Norcan	91.3	31.0	1.2

Incremental plant capacity varies depending on how many units are upgraded. Alstom units provide a marginal capacity benefit relative to Norcan units. Upgrading both AH1 and AH2 provides close to double the incremental capacity of upgrading only one unit.

For the purpose of designing electrical components, the plant capacity was evaluated at maximum flow and maximum expected net head using an optimistic estimate of conveyance system losses. For a plant flow of 23.7 m^3/s and net head of 182.2 m, the existing plant capacity is 37.2 MW. Proposed configurations range in capacity from 37.9 MW for the Norcan AH1 replacement to 38.6 MW for the Alstom 2 unit replacement.

4.3 VALUE OF CAPACITY AND ENERGY

YEC provided the following values for capacity and energy increase:

- Capacity: $2,500,000 per MW based on avoided capital cost of new natural gas generation.
- Energy: $200,000 per GWh per year based on avoided operating (i.e. variable cost) cost of natural gas.

5.0 ELECTRICAL EQUIPMENT ASSESSMENT

5.1 INTRODUCTION

This section summarizes the results of the electrical assessment carried out on the major electrical components associated to AH2 unit, with the purpose of determining if these components are able to support an uprated capacity of 19.2 MVA.

The scope of the assessment includes the generator, excitation system, medium voltage power cables, switchgear and generator step up transformers. This report assumes that as a result of a runner replacement, AH1 unit will not increase its rating beyond 17 MVA. Furthermore, it is assumed that all generators could be expected to operate at 95% of nominal voltage (13.1 kV) while operating at nominal rating.

This study was solely based on equipment ratings as provided by datasheets and nameplates. Results presented on this report have not factored equipment age, condition, or maintenance.

5.2 EXISTING ELECTRICAL ARRANGEMENT

With reference to single line diagrams P130 and S137, the Aishihik Generating Station is composed of three hydro generating units, with the following ratings:

- AH1: 17 MVA, 13.8 kV
- AH2: 19.2 MVA, 13.8 kV
- AH3: 8.25 MVA, 13.8 kV

The combined plant nominal output is 44.45 MVA.

These generators are connected to a common 13.8 kV switchgear with medium voltage (MV) power cables. This switchgear, which is located at the generator level, includes dedicated generator circuit breakers (one for each unit). This switchgear is connected to a second 13.8 kV switchgear, which is part of the substation S167, using two sets of MV power cables (feeders F1 and F2), and run vertically in cable trays. These two cable systems are normally operated in parallel.

The 13.8 kV switchgear part of substation S167 is then connected with medium voltage power cables to two generator step up transformers.

5.3 ELECTRICAL EQUIPMENT UNDER STUDY

Since the scope of the electrical review is to assess the limits of electrical components associated to AH2 unit, the following components have been analyzed:

- AH2 stator winding
- AH2 excitation system
- MV power cables interconnecting AH2 to the generator breaker switchgear
- AH2 generator circuit breaker and associated switchgear
- MV power cables interconnecting the generator breaker switchgear to the S137 switchgear
- S137 switchgear and associated circuit breakers
- MV power cables interconnecting the S137 switchgear to the generator step up transformers
- Generator step up transformers

5.4 GENERATING STATION POWER OUTPUT

In order to assess the capability of the electrical equipment associated to AH2 unit, the expected station output needs to be defined. Based on an uprate of 19.2MVA for unit AH2, the following system ampacity would be required:

5.4.1 Electrical Components Associated to AH2 Only

The electrical components associated only to AH2 need to be able to continuously carry the nominal output of AH2 unit:

- 803 A at nominal (13.8 kV) voltage
- 846 A at 13.1 kV (95% of nominal voltage)

5.4.2 Electrical Components Common to All Units

The electrical components that are associated to all units (i.e. switchgears) need to be able to continuously carry the nominal output of the three units operating in parallel and at nominal capacity:

- 1860 A at 13.8 kV (nominal voltage)
- 1959 A at 13.1 kV (95% of nominal voltage)

5.5 ELECTRICAL EQUIPMENT RATING

5.5.1 AH2 Generator Stator Winding

According to Voith's drawing 4671A49 (AH2 unit nameplate after stator rewind), AH2 stator winding is rated for 19,200 kVA at nominal 13,800 V. Since this information was provided by Voith Siemens, the Company retained by YEC to rewind the unit, KGS Group assumes this information to be accurate, and therefore, no further studies or investigations were undertaken.

5.5.2 AH2 Excitation System

The AH2 generator is equipped with a DC exciter, controlled by SR125E Basler automatic voltage regulator (AVR). As a part of the generator rewind, project the generator rotor field poles were reinsulated, however, the DC exciter was not upgraded.

Based on the documentation provided by YEC and discussions with Voith Siemens, the following conclusions can be made:

- According to the machine data provided by Voith-Siemens, to produce the rated power of 19.2 MVA, the generator rotor field voltage and field current requirement is 75 V and 720A respectively, while the DC exciter is rated at 670 A.

- The DC exciter will operate beyond its design limit to produce the rated voltage at 19.2 MVA, 0.9 power factor.

To operate AH2 unit at the uprate power of 19.2 MVA, the following two alternatives should be investigated:

- The existing exciter could be replaced with a static exciter to match the generator field requirements. The generator field leads and associated slip rings should be checked so that these are properly rated for operation at 19.2 MVA.
- The rotating DC exciter could be upgraded to meet the rewound generator field requirements. The associated AVR would need to be replaced to meet the requirement of the upgraded exciter. The generator field leads and associated slip rings should be checked so that these are properly rated for operation at 19.2 MVA.

5.5.3 AH2 MV Power Cables to Generator Breaker Switchgear

According to the information provided by YEC's drawing O111D4956 "AH2 Cable Tray and Termination Diagram, AH2 unit is connected to its generator circuit breaker with 3 x 1C 750MCM, 15 kV, copper MV power cable. Based on this drawing, these cables run in a steel ladder tray. Assuming these cables are provided with one diameter spacing, the ampacity of this feeder can be obtained from the 2015 edition of the Canadian Electrical Code, Table D17M. Based on this table, and assuming an ambient temperature of 40°C, this feeder is expected to have an ampacity of 706 A.

Since AH2 unit will have an output of 803 A at nominal voltage, the existing feeder will be overloaded. Based on the configuration provided in drawing O111D4956, this feeder will operate at its limit when AH2 operates at the following ratings:

- 16,875 kVA at nominal (13.8 kV) voltage
- 16,019 kVA at 13.1 kV (95% of nominal voltage)

To reach a nominal output of 19.2 MVA, a second, parallel run of similar cables should be installed to ensure equal load distribution. AH2 feeder cables could also be replaced for 6 X 1C 350MCM 15kV copper power cables, installed in cable tray, providing one diameter spacing, assuming an ambient tempearure of 40°C.

5.5.4 AH2 Generator Breaker

Based on the single line diagrams provided by YEC, the AH2 generator circuit breaker (equipment tag P130-52-AH2) has a rating of 1200 A. When the generator supplies its uprate nominal power rating of 19.2 MVA, this generator circuit breaker will be loaded at the following ratings:

- 67% of 1200 A at nominal (13.8 kV) voltage
- 71% of 1200 A at 13.1 kV (95% of nominal voltage)

According to these results, AH2 generator circuit breaker has sufficient rating to support an uprate capacity of 19.2 MVA.

5.5.5 Generator Breaker Switchgear

According to single line diagrams, the generator breaker switchgear, which is installed at the generator level and is common to all units, has a rating of 2000 A. When all generators supply their nominal power rating of 44.45 MVA, the generator breaker switchgear will be loaded at the following ratings:

- 93% of 2000 A at nominal (13.8 kV) voltage
- 98% of 2000 A at 13.1 kV (95% of nominal voltage)

Based on these results, the generator breaker switchgear has marginally sufficient rating to support an uprate capacity of 19.2 MVA.

5.5.6 F1 and F2 MV Power Cables

The MV power cable system that connects the generator breaker switchgear to the S167 switchgear is composed of two sets of 15 kV cables run in vertical cable trays, inside the vertical shaft leading to the surface. These cable systems, which normally operate in parallel, have the following characteristics:

- Feeder F1: 9 x 1C 750MCM Okonite Okoguard 15 kV 133%
- Feeder F2: 9 x 1C 750MCM Okonite Okoguard 15 kV 133%

When these cable systems operate in parallel, it is expected that they will equally share the load, as both systems use the same cable type and quantity. When a single cable system is in service, it will be required to carry the entire plant output. This study has assessed both operating conditions.

According to the CEC Rule 28.108 (a) conductors supplying a group of two or more motors (generators) shall have an ampacity not less than 125% of the full load current rating of the motor (generator) having the largest full load current rating, plus the full load current ratings of all the other motors (generators) in the group. For this assessment, it has been assumed that since generator outputs are limited by the water conveyance system and turbines, generators are not able to produce more than their nominal outputs (i.e. 44.45 MVA combined).

The ampacity of each feeder system was calculated based on the following assumptions:

- Cables are run in ventilated cable trays, with approximately 25% diameter spacing between each cable
- Elevator shaft temperature was assumed to be 40°C

The 2015 edition of the CEC, Table D17N, provides cable ampacities for single conductor cables in cable trays, installed in contact or spaced less than one diameter apart. Based on this table, F1 and F2 feeders are expected to have the following ampacity:

- F1 and F2 Feeders: 678 A per 750 MCM conductor (2034 A)

When all generators supply their nominal power rating of 44.45 MVA, and both cable systems are operating in parallel, and assuming equal load sharing, each cable system is expected to be loaded at the following ratings:

- F1 Feeder: 46% of 2034 A at nominal (13.8 kV) voltage

- F2 Feeder: 46% of 2034 A at nominal (13.8 kV) voltage
- F1 Feeder: 48% of 2034 A at 13.1 kV (95% of nominal voltage)
- F2 Feeder: 48% of 2034 A at 13.1 kV (95% of nominal voltage)

Based on these results, F1 and F2 feeders have sufficient excess capacity to support an uprate capacity of 19.2 MVA.

When all generators supply their nominal power rating of 44.45 MVA, and only one feeder is in service, the cable is expected to be loaded at the following rating:

- F1 or F2 Feeder: 91% of 2034 A at nominal (13.8 kV) voltage
- F1 or F2 Feeder: 96% of 2034 A at 13.1 kV (95% of nominal voltage)

According to these results, F1 or F2 feeder would be operating close to their limit when AH2 operates at uprate capacity of 19.2 MVA.

5.5.7 S167 Switchgear

According to single line diagrams, the S167 switchgear is rated 2000 A and is equipped with 2000 A circuit breakers. When all generators supply their nominal power rating of 44.45 MVA, the S167 switchgear will be loaded at the following ratings:

- 93% of 2000 A at nominal (13.8 kV) voltage
- 98% of 2000 A at 13.1 kV (95% of nominal voltage)

Based to these results, the S167 switchgear has marginally sufficient rating to support an uprate capacity of 19.2 MVA.

5.5.8 MV Power Cables to T1 and T3 Transformers

According to drawings provided by YEC and site photos, the MV power cable systems that connect the S167 switchgears to T1 annd T3 generator step up transformers have the following characteristics:

- Feeder to T1 Transformer: 9 x 1C 750 MCM 15 kV cable in cable tray
- Feeder to T3 Transformer: 9 x 1C 750 MCM 15 kV buried cables transition to overhead line and to 6 x 1C 750 MCM 15 kV cable in buried conduit.

The 2015 edition of the CEC, Table D17N for outdoor installations, provides cable ampacities for single conductor cables in cable trays, installed in contact or spaced less than one diameter apart. Based on this table, the feeder connected to T1 transformer is expected to have the following ampacity:

- Feeder to T1 Transformer 545 A per 750 MCM conductor (1635 A)

Based on this analysis, the feeder to T1 Transformer could carry the following load:

- 39.1 MVA, equivalent to 88% of the uprate plant capacity (44.45 MVA) at 13.8 kV
- 37.1 MVA, equivalent to 83% of the uprate plant capacity (44.45 MVA) at 13.1 kV

Since the feeder to T3 transformer is composed of three distinctive arrangement (underground duct, overhead line and cable in buried conduit), each arrangement is analyzed individually.

The cable run connecting the S167 switchgear to the overhead line is assumed to be an underground duct bank. For this arrangement, the feeder ampacity was estimated from IEEE Standard 835-1994, Table 342, for 25°C earth temperature, 100 load factor and average ground resitivity. Table 342 provides the following ampacity:

- Feeder to T3 Transformer (underground duct): 444 A per 750 MCM conductor (1332 A)

Based on this analysis, the feeder to T3 Transformer (underground duct) could carry the following load:

- 30.2 MVA, equivalent to 68% of the uprate plant capacity (44.45 MVA) at 13.1 kV
- 31.8 MVA, equivalent to 72% of the uprate plant capacity (44.45 MVA) at 13.8 kV

The overhead line connecting to disconnect switch S167-89-LT3 is assumed to be two parallel runs of 266 MCM ACSR (Partridge). The line ampacity was estimated from ACSR cable catalogues for 25°C ambient temperature and wind velocity of 2 ft/sec. ACSR cable catalogues provide the following ampacity:

- Feeder to T3 Transformer (overhead line): 455 A per 266 MCM conductor (910 A)

Based on this analysis, the feeder to T3 Transformer (overhead line) could carry the following load:

- 20.6 MVA, equivalent to 46% of the uprate plant capacity (44.45 MVA) at 13.1 kV
- 21.8 MVA, equivalent to 49% of the uprate plant capacity (44.45 MVA) at 13.8 kV

According to site photos, the feeder connecting the disconnect switch S167-89-LT3 to the T3 transformer runs in buried conduit. For this arrangement, the feeder ampacity was estimated from IEEE Standard 835-1994, Table 488, for 25°C earth temperature, 100 load factor and average ground resitivity. Table 488 provides the following ampacity:

- Feeder to T3 Transformer (buried conduit): 521 A per 750 MCM conductor (1042 A)

Based on this analysis, the feeder to T3 Transformer (buried conduit) could carry the following load:

- 23.6 MVA, equivalent to 53% of the uprate plant capacity (44.45 MVA) at 13.1 kV
- 24.9 MVA, equivalent to 56% of the uprate plant capacity (44.45 MVA) at 13.8 kV

Since the feeder to T3 Transformer has three different ampacities, the rating of this feeder should be assumed as the lowest of the three ampacities. Therefore, the overall ampacity of the feeder to T3 Transformer would be limited by the overhead line:

- 20.6 MVA, equivalent to 46% of the uprate plant capacity (44.45 MVA) at 13.1 kV
- 21.8 MVA, equivalent to 49% of the uprate plant capacity (44.45 MVA) at 13.8 kV

5.5.9 T1 and T3 Transformers

YEC's single line diagrams show that T1 and T3 generator step up transformers (GSU) are oil filled 30/40 MVA (ONAN/ONAF). When both transformers are operating in parallel, and assuming these transformers have similar reactances (equal load sharing), it is expected that each transformer would be loaded to 22.2 MVA or 56% of their ONAF rating.

If a single GSU is assumed in to be in service, that transformer will be loaded to 111% of its ONAF rating. If YEC expects a single GSU to be in service while the three units operate at their nominal rating, KGS Group recommends transformer temperatures be properly monitored. Transformer operation beyond its nameplate rating is normally associated with accelerated loss of service life.

5.6 ELECTRICAL CONCLUSION

From the above information and assumptions, the following conclusions can be made:

- AH2 excitation system: The DC exciter will operate beyond its design limit to produce the rated voltage at 19.2 MVA, 0.9 power factor.
- MV Power cable from AH2 to generator breaker switchgear: This feeder does not have enough ampacity to operate at 19.2 MVA. To reach a nominal output of 19.2 MVA a second, parallel run of similar cables should be installed to ensure equal load distribution. AH2 feeder cables could also be replaced for 6 X 1C 250MCM 15kV copper power cables, installed in cable tray, providing one diameter spacing, assuming an ambient temperature of 40°C.
- Generator breaker: AH2 generator circuit breaker has sufficient rating to support an uprate capacity of 19.2 MVA
- Generator Breaker Switchgear: The generator breaker switchgear has marginally sufficient rating to support an uprate capacity of 19.2 MVA.

- F1 and F2 MV power cables: F1 and F2 feeders have sufficient excess capacity to support an uprate capacity of 19.2 MVA when these feeders operate in parallel. However, F1 or F2 feeder would be operating close to their limit when a single feeder system is in service.

- S167 Switchgear: The S167 switchgear has marginally sufficient rating to support an uprate capacity of 19.2 MVA.

- MV power cables to T1 Transformer: The feeder can carry up to 37.1 MVA, equivalent to 83% of the uprate plant capacity at 13.1 kV and 39.1 MVA, equivalent to 88% of the uprate plant capacity at 13.8 kV

- MV power cables to T3 Transformer: The feeder is limited by the ampacity of the overhead line to 20.6 MVA, equivalent to 45% of the uprate plant capacity at 13.1 kV or to 21.8 MVA, equivalent to 49% of the uprate plant capacity at 13.8 kV

- T1 and T3 transformers: T1 and T3 transformers have sufficient excess capacity to support an uprate capacity of 19.2 MVA when these transformers operate in parallel. However, if a single transformer is assumed to be in service, that transformer will be loaded to 111% of its ONAF rating.

6.0 MECHANICAL EQUIPMENT ASSESSMENT

The main mechanical system that is affected by the additional power output of an upgraded runner is the generator surface air cooling system.

6.1 SURFACE AIR COOLING SYSTEM

The generator surface air coolers (SACs) are assumed to be the original ones provided by Canadian General Electric in the early circa 1973. There are four SACs per unit. They are fed with river water through a common header and 2” branch lines and they discharge to the tailrace.

Through first principle calculations, we estimate that the heat exchange rate across the SACs could increase by a maximum of 25% if the stator temperature rise increases to 80°C above ambient from its present 60°C. Given the age of the SAC piping and cooling coils, the heat exchangers could possibly be fouled and/or internally corroded. This would reduce their effectiveness in transmitting the heat from the air into the cooling water. As such, the heat exchangers should be considered near the end of their life cycle, making them unsuitable for higher duty usage. The entire SAC piping system and heat exchangers should be changed out with the unit rerate project. The T/G contractor could be asked to provide this service.

6.2 OPPORTUNITY WORK

The rerunnering project offers an opportunity to address work items identified in the 2014 Aishihik Hydro Asset Assessment Report. Table 4 contains data from Table 1: Summary of Assessment Results, in the assessment report. It identifies work items that could be performed, at YEC’s discretion, during the unit rerate outage. Although the assessment report focused on AH2, the results can be applied to AH1 in this study. A more detailed assessment of AH1 would have to be conducted if YEC decides to uprate its runner as well.

Opportunity work has no payback. The cost of performing the opportunity work is outside the scope of this report as it is not directly related to unit uprates. A discussion on the opportunity work items is provided in the section below Table 4.

TABLE 4
SUMMARY OF ASSESSMENT RESULTS

PRIORITY #	ENGINEERING DISCIPLINE	COMPONENT	ASSESSMENT RESULTS
26	Mechanical	Turbines	Study and potential replacement of turbine air, oil and water piping.
27	Mechanical	Generator	Study and potential replacement of generator air, oil and water piping.
37	Mechanical	Turbines	Study and potential replacement of addition of greasing points to reduce binding of wicket gate links and levers.
40	Mechanical	Fire Protection	Provide deluge fire suppression systems.
43	Mechanical	Turbines	Provide wicket gate shear pin detection and annunciation.
44	Mechanical	Turbine Inlet Valve (TIV)	Automation of TIVs to allow remote closure. Clean and Paint TIV
47	Electrical	P&C	Vibration Monitoring Review.
76	Civil	TIV	Monitor and potential repairs of TIV and distribution pipe leakage.

ITEM 26, TURBINE PIPING

The air, oil and water pipes and related valves and instrumentation servicing the turbines and generators are almost 40 years old. Their condition should be assessed and the remaining life estimated utilizing NDT (Ultrasonic) inspection techniques. In the event that the above program cannot be executed in its entirety, focus should be placed on the Piezometer piping and the turbine air admission piping which have visible signs of distress.

ITEM 27, GENERATOR PIPING

The air, oil and water pipes and related valves and instrumentation servicing the turbines and generators are almost 40 years old. Their condition should be assessed and the remaining life estimated utilizing NDT (Ultrasonic) inspection techniques. The generator surface air cooling pipes and heat exchangers are addressed in Subsection 6.1.

ITEM 37, GREASING POINTS

Some areas of the turbine may benefit from adding greasing points or self-lubricated materials to wicket gate levers and arms. We understand that levers and arms have bonded to each other in the past.

ITEM 40, FIRE PROTECTION

There is no fire suppression on the generators in the powerhouse. The former Halon suppression systems have been removed. We recommend providing water deluge fire suppression systems on units AH1 and AH2.

ITEM 43, WICKET GATE SHEAR PIN DETECTION

The units are currently not equipped with wicket gate shear pin breakage sensors. A broken shear pin detection and annunciation system would alert station operators or SCC of the fact that a unit may not stop turning after being shut down. Consideration should be given to adding shear pin breakage monitoring capabilities, complete with annunciation to SCC.

ITEM 44, TIV CLOSURE AUTOMATION

The AH1 and AH2 TIVs can now only be operated locally. Due to the limited access to the powerhouse and the lack of emergency closure capability at the intake, the TIVs should be remotely operable. A loss of unit control (wicket gate operation failure), or a breach in the water passage could not be stopped without sending staff into the powerhouse. This situation would more than likely be unsafe. With no way to stop the water, the plant would be flooded for some time. As such, remote operation capability should be implemented for the AH1 and AH2 TIVs. At this time, the addition of a counterweight could also be investigated to improve reliability.

ITEM 44 B, RE-PAINT TIV

The Turbine Inlet Valve for Unit AH-2 is showing signs of external surface corrosion. As such, the TIV should be tool cleaned (wire brushed) or sandblasted and re-painted.

ITEM 47, VIBRATION MONITERING REVIEW

Review minor discrepencies on the vibration monitering equipment.

ITEM 76, LEAKAGE IN TIV SUPPORTS

YEC staff have indicated that there is a water leak on unit AH2. Water reportedly leaks from between the spiral case and the concrete. During the AH2 rerunnering outage, further investigations should be carried out to determine the source of the leak. It should be noted that the leak may be from embedded sections of piezometer piping. Selectively pressurizing these tubes, or possibly the use of dyes may assist in finding the source of this leak.

7.0 ECONOMIC ANALYSIS

The economic analysis performed in the following sections utilizes the scope of work and costs described in Sections 3.0, 5.0 and 6.0 above and the capacity and energy values provided by YEC in Section 4.3. The details of the analysis, including runner costs, energy and capacity benefits, related uprate costs and payback, are given in Appendix C.

7.1 COSTS ASSOCIATED WITH RERUNNERING

KGS Group has prepared a Class 4 capital cost estimate and payback calculation for the turbine uprate project based on the value of energy provided by YEC. A Class 4 (-30%/+50%) cost estimate, as defined by AACE International, is used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval.

The Turbine Upgrade pricing in Table 5 below is the one associated with the Alstom budget proposal, since it is the most costly of the two budget prices, and it also offers the most capacity and energy benefits.

Other costs associated with the uprate project were estimated by KGS Group.

No estimates are provided for opportunity work since they do not provide a definable payback. KGS Group could provide a proposal to estimate the opportunity costs if requested to do so.

TABLE 5
BUDGET ESTIMATE TO UPRATE UNITS

ITEM	DESCRIPTION / ASSUMPTIONS	ONE UNIT	TWO UNITS
Turbine Uprate - Alstom			
Turbine field work		$250,000	$500,000
Turbine runner engineering		$106,000	$137,800
Runner and coupling bolts, supply		$343,000	$686,000
Fix labyrinths		$43,000	$86,000
Extra to T/G Vendor scope Work			
Performance / Efficiency Test		$125,000	$125,000
Crane operator and station operator		$48,000	$96,000
Drawings, manuals, etc.		$5,000	$6,500
Generator Surface Air Coolers		$50,000	$100,000
Excitation System Uprate, AH2 only		$750,000	$750,000
Cable from AH2 to Circuit Breaker		$150,000	$150,000
Cables from S167 to T1 & T2		$150,000	$150,000
Contingency No. 1*		$100,000	$200,000
Contingency No. 2*		$50,000	$100,000
Sub-Total A		$2,170,000	$3,087,300
Engineering support	12% of Sub-Total A	$260,400	$370,476
Sub-Total B		$2,430,400	$3,457,776
Goods and Services Sales Tax	5% of Sub-Total B	$121,520	$172,889
Sub-Total C		$2,291,520	$3,630,665
Contingency No.3*	30% of Sub-Total C	$687,456	$1,089,199
Total of Class 4 Estimate (-30% +50%)		**$2,978,976**	**$4,719,864**
Excluded from this estimate:			
<u>Opportunity Work</u>	<u>Other Work:</u>		
Turbine, generator, intake gates,	Camp services		
Turbine inlet valve	YEC engineering		
Distribution Pipe repairs	Project management		
Power cables and switchgear			
Generator Breaker			
Unit step-up transformer			
Controls and Protection			

* Notes:
Contingency No. 1 accounts for unforeseen items that may need to be repaired when unit is dismantled.
Contingency No. 2: T/G vendors identified scaffolding, if required, as Owner's responsibility
Contingency No. 3 accounts for unforeseen scope of work and changing market conditions.

7.2 CAPACITY AND ENERGY BENEFITS

The following economic parameters were provided by YEC for use in the payback calculations.

- One-time benefit of an increase in capacity - $2,500,000 per MW based on avoided capital cost of new natural gas generation.
- Annual benefit of an increase in annual energy - $200,000 per GWh based on avoided operating (i.e. variable cost) cost of natural gas.
- Discount rate of 7.2%.
- For paybacks less than 5 years a simple payback should be used.
- For paybacks exceeding 5 years the discounted payback should be used as the time value of money becomes more significant.

KGS Group determined capacity and energy financial benefits from the above economic parameters and the capacity and energy values determined in Section 4.0.

The time schedule of the project is assumed to be as follows:

- Year 1, engineering
- Year 2, fabrication
- Year 3, installation of first unit
- Year 4, installation of second unit.

The benefits summarized in Table 6 incorporate the following simplified cash flow assumptions:

For rerunnering a single unit:

- 10% of project costs are spent in Year 1
- 45% of project costs are spent in Year 2
- 45% of the project costs are spent in Year 3
- 100% of Capacity Benefits are credited in Year 3
- Energy Benefits are credited annually from Year 4 onwards

For rerunnering two units:

- 10% of project costs are spent in Year 1
- 30% of project costs are spent in Year 2
- 30% of the project costs are spent in Year 3
- 30% of the project costs are spent in Year 4
- 50% of Capacity Benefits are credited in Year 3
- 50% of Capacity Benefits are credited in Year 4
- 50% of Energy Benefits are credited in Year 4
- 100% of Energy Benefits are credited annually from Year 5 onwards

TABLE 6
FINANCIAL BENEFITS

BENEFIT OF INCREASED CAPACITY at 80% PLANT FLOW	Increase in Capacity MW	Value of Increase in Capacity $ per MW	One Time Benefit
Upgrade AH2	0.7	$2,500,000	$1,750,000
Upgrade AH1 and AH2	1.3	$2,500,000	$3,250,000

BENEFIT OF INCREASED ENERGY FOR LOW ENERGY DEMAND SCENARIO	Energy Benefits to the WAF+MD System (GWh/Year)	Value of Increase in Energy $ per GWh/year	Annual Benefit
Upgrade AH2	2.26	$200,000	$452,000
Upgrade AH1 and AH2	2.74	$200,000	$548,000

BENEFIT OF INCREASED ENERGY FOR HIGH ENERGY DEMAND SCENARIO	Energy Benefits to the WAF+MD System (GWh/Year)	Value of Increase in Energy $ per GWh/year	Annual Benefit
Upgrade AH2	2.15	$200,000	$430,000
Upgrade AH1 and AH2	3.04	$200,000	$608,000

7.3 PAYBACK PERIOD

Payback periods for the following options were calculated using a spreadsheet provided by Yukon Energy Corporation. The spreadsheet is presented in Appendix C.

TABLE 7
PAYBACK PERIODS

PROJECT OPTIONS	ENERGY DEMAND SCENARIO	DISCOUNTED PAYBACK PERIOD (see note)
AH2 uprate	low energy demand	6 years
AH2 uprate	high energy demand	6 years
AH1 and AH2 uprate	low energy demand	7 years
AH1 and AH2 uprate	high energy demand	6 years

Note: Payback period is measured from the start of the uprate project, not from the time the uprated unit(s) is put back into service.

A single unit uprate has a discounted payback of 6 years in both the low energy years and the high energy years. A two unit uprate project also has a discounted payback of 6 or 7 years depending on energy demands.

7.3.1 Sensitivity Analysis

KGS Group conducted a sensitivity analysis on the following:

- Capacity benefits of between $1M (high speed diesel gensets) and $10M (wind or higher cost new hydro).
- Energy benefits going from $100,000 (best possible natural gas operating cost) to $300,000 (diesel operating cost).

The analysis was conducted on the AH2 Uprate – Low Energy Demand scenario only.

TABLE 8
SENSITIVITY ANALYSIS

Base Information

Nominal Capital Cost	$2,978,976
Discount Rate	7.2%
Capacity Increase	0.7 MW
Energy Increase	2.26 GWh/year

Sensitivity to CAPACITY Value (holding energy value constant at $200,000/GWh/yr)					
	TRIAL 1	TRIAL 2	TRIAL 3	TRIAL 4	TRIAL 5
Variable Benefit, $ per MW	$1M	$2.5M	$5M	$7.5M	$10M
Payback Period, years	11	6	2	2	2
Sensitivity to ENERGY value (holding capacity value constant at $2,500,000/MW)					
	TRIAL 6	TRIAL 7	TRIAL 8	TRIAL 9	TRIAL 10
Varialbe Benefit, $/GWh/yr	$100,000	150,000	$200,000	$250,000	$300,000
Payback Period, years	11	7	6	5	5
Worst Case: Capacity Value at $1,000,000/MW and Energy value at $100,000/GWh/yr					
	TRIAL 11				
Payback Period, years	>21				

Notes and Observations on Sensitivity Analysis:

- A 2 year payback means that the project is paid back in the year that the unit is returned to service.
- The lowest Capacity Benefit of $1M per MW has a payback of 11 years.
- Once the Capacity Benefit reaches $5M per MW, the project has a payback on the first year that the unit is returned to service since this benefit exceeds the cost of the project.
- The lowest Energy Benefit of $100,000 per GWh per year has a payback of 11 years.
- The highest Energy Benefit of $300,000 per GWh per year has a payback of 5 years.
- The worst case scenario of lowest capacity and energy benefits has a payback of 24 years. This value is beyond the 21 year limit of YEC spreadsheet.

8.0 CONCLUSION

Aishihik GS Generating Unit AH2 can be uprated by installing a new Francis runner at a cost of $3.0 M resulting in a discounted payback of 6 years (3 years after uprated unit is returned to service), using current capacity and energy benefit values. This cost includes a new excitation system, generator coolers, new cables from the unit to its generator circuit breaker and possibly new cables from the outdoor switchgear to the T1 and T2 transformers.

Alternatively, both AH1 and AH2 units could be uprated with new Francis runners at a cost of $4.7 M. This option would have a discounted payback of 8 years.

The two uprate options would keep plant water discharge within existging maximum flows. Hydraulic stability during unit start-ups and shut-downs would not be affected and the height of water in the discharge tunnel would not change.

The uprate project budgetary costs in the above sections do not include expenses associated with opportunity maintenance work, or other work on the units not directly related to unit uprate objectives. They also do not cover indirect costs, such as camp facilities, and YEC engineering and project management costs.

Given the strong influence of the capacity and energy benefits on the project payback time, we recommend that YEC revisit the payback projection using updated benefit values at project evaluation time.

The payback was calculated with unit capacities at 80% in keeping with, what we undestand to be, current operating practice. The payback periods would be shorter if the calculations were done at 100% of rated output.

9.0 STATEMENT OF LIMITATIONS AND CONDITIONS

9.1 THIRD PARTY USE OF REPORT

This report has been prepared for YEC to whom this report has been addressed and any use a third party makes of this report, or any reliance on or decisions made based on it, are the responsibility of such third parties. KGS Group accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions undertaken based on this report.

9.2 CAPITAL COST ESTIMATE STATEMENT OF LIMITATIONS

The cost estimates included with this report have been prepared by KGS Group using its professional judgment and exercising due care consistent with the level of detail required for the stage of the project for which the estimate has been developed. These estimates represent KGS Group's opinion of the probable costs and are based on factors over which KGS has no control. These factors include, without limitation, site conditions, availability of qualified labor and materials, present workload of the bidders at the time of tendering and overall market conditions. KGS Group does not assume any responsibility to the Client, in contract, tort or otherwise in connection with such estimates and shall not be liable to the Client if such estimates prove to be inaccurate or incorrect.

APPENDIX A

HYDRAULIC CAPACITY REVIEW

MEMORANDUM

TO: Dave Brown, P. Eng.
Joel Lambert, P. Eng.

FROM: Dave White, P. Eng.
David Hinton, P. Eng.

DATE: May 25, 2015

PROJECT NO: 14-1404-004

RE: Aishihik Turbine Uprate Study
Hydraulic Capacity Review

1.0 INTRODUCTION

As part of the Aishihik Generating Station (GS) uprate study, KGS Group performed a high level hydraulic review of the conveyance system for Yukon Energy Corporation (YEC) in order to determine the maximum flow that can be conveyed before affecting functionality and safety of the system. This memorandum describes KGS Group's hydraulic review of the conveyance system, including a review of existing documentation and a confirmation of conveyance system hydraulics.

2.0 EXISTING CONDITIONS

The Aishihik GS was commissioned in 1975 as a two-unit hydroelectric facility located northwest of Whitehorse, Yukon. In 2011, a horizontal Francis turbine (Unit #3) was added to the GS. KGS Group has been tasked with undertaking a feasibility study to upgrade Unit #2, including how much additional flow could safely be carried by the conveyance system.

Figure 1 shows the Aishihik GS general arrangement. Flow enters the underground powerhouse through a 5.6 km long power canal, a 175 m deep intake, and a 915 m long pressure tunnel. A wye diverts water towards Unit #3, followed by two 35 m long penstocks that bifurcate to the original units. The water exits the powerhouse first through a surge chamber, then a 1,460 m long tailrace tunnel and a 900 m long tailrace channel before discharging into the West Aishihik

River. The tailrace tunnel is intended to be operated under open-channel flow conditions and doubles as an emergency exit for plant staff that, in case of an emergency can use a raft to make their way out of the powerhouse through the tunnel. The original plant had a rated flow of 19.4 m^3/s, while the current plant has a rated total flow of 23.7 m^3/s [Ref 1].

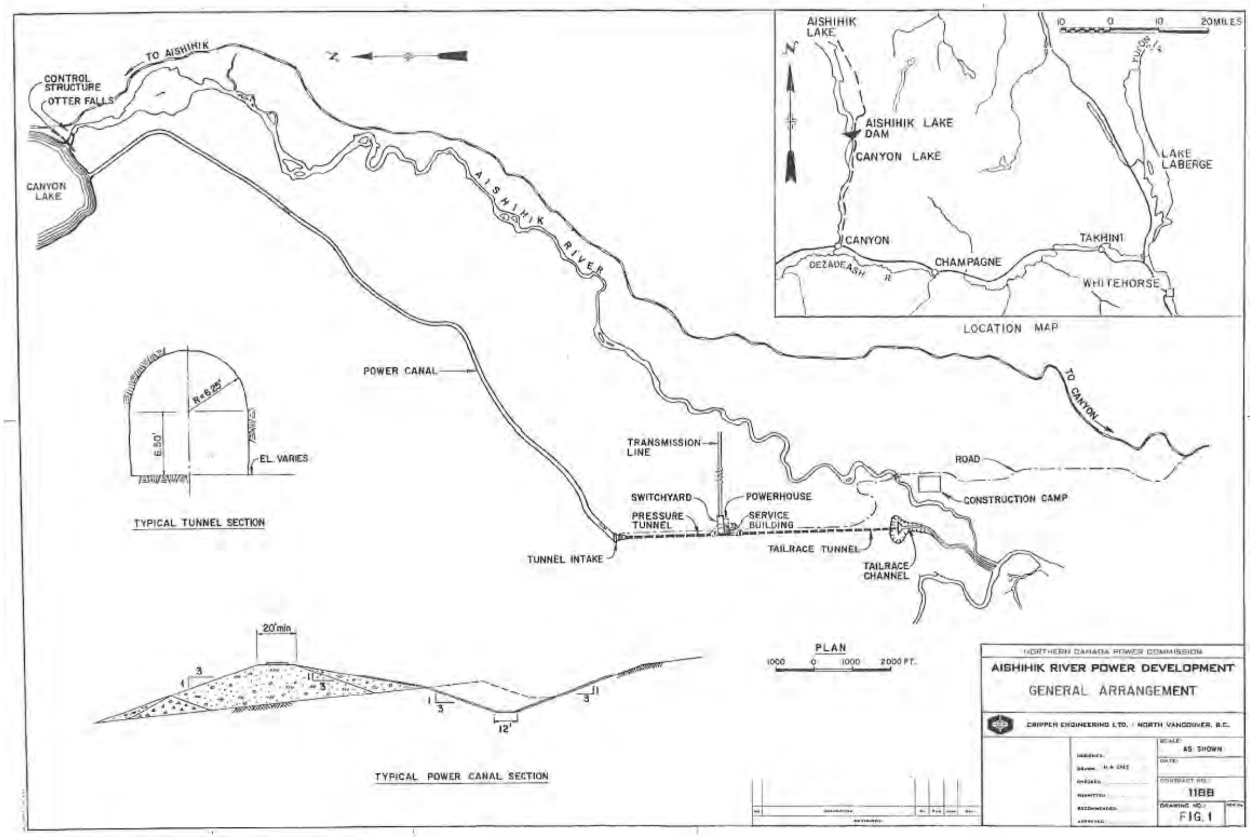

Figure 1: Aishihik GS General Arrangement

Hydraulic concerns raised by YEC of increased plant flow include:

- Reliability of tailrace tunnel as an emergency exit
- Transition of tailrace tunnel from open-channel to full flow
- Back-up of water into the powerhouse from the tailrace tunnel
- Transient pressures in the power and tailrace tunnels

The operational concerns of tailrace tunnel flow will likely limit the safe flow capacity of Aishihik

GS. As such, the tailrace tunnel and channel were the focus of this review.

The tailrace tunnel was constructed by the drill and blast method with approximately 50% of the length lined with shotcrete and 50% left exposed. The shotcrete and exposed rock sections were generally in excellent condition during an August 2008 inspection by Klohn Crippen Berger [Ref 2], however construction rails and ties were left in place, which may have a minor effect on actual tunnel dimensions. As-built tunnel dimensions are unknown, and could have a significant effect on hydraulic conveyance of the tunnel. A survey of the tailrace tunnel dimensions and invert elevations could be performed to confirm the actual tunnel area and confirm hydraulic capacity.

3.0 DEVELOPMENT OF HYDRAULIC MODEL

KGS Group developed a one-dimensional computer model of the downstream conveyance system from the powerhouse to the West Aishihik River using the XP-SWMM Software package. This software allows for accurate modelling of both closed conduit and open channel flows, and solves dynamic wave routing using the St. Venant equations. The model was developed using information obtained from the design drawings as well as the 2008 hydraulics report [Ref 2].

The Manning's n value for surface roughness of the tailrace tunnel and channel were estimated based on results from the 2008 inspection and accompanying photographs such as Photo 1 which shows the tailrace channel material. Tailrace tunnel roughness was estimated as 50% well-trimmed, normal blasted and 50% well-trimmed and shotcreted for a composite Manning's roughness of n = 0.026. Tailrace channel roughness was estimated as a Manning's roughness of n = 0.033, corresponding to a gravel bottom with dry rubble sides. Minor losses were included for the surge tank exit, and the tailrace tunnel junction and exit.

Photo 1: Tailrace Tunnel Outlet and Tailrace Channel

The hydraulic model was verified using two powerhouse tailwater levels measured by YEC and two powerhouse tailwater levels included in the design drawings at specific plant flows. West Aishihik River downstream boundary condition water levels were not measured with the powerhouse tailwater levels, so a sensitivity of river water levels was completed instead.

4.0 ANALYSIS OF RESULTS

The model was simulated for a range of West Aishihik River water levels to determine the relationship between river level and safe plant flow.

Figure 2 shows a water surface profile of the Aishihik GS downstream conveyance system flowing at full plant capacity with normal depth downstream boundary condition. Higher West Aishihik River stages could cause a backwater effect on the downstream end of the tailrace tunnel, reducing the capacity of the tunnel. No data was available for expected water levels in the West Aishihik River so the frequency of such backwater effects is unknown. Further refinement of results would require a rating curve or measured water levels at specific flows in the West Aishihik River.

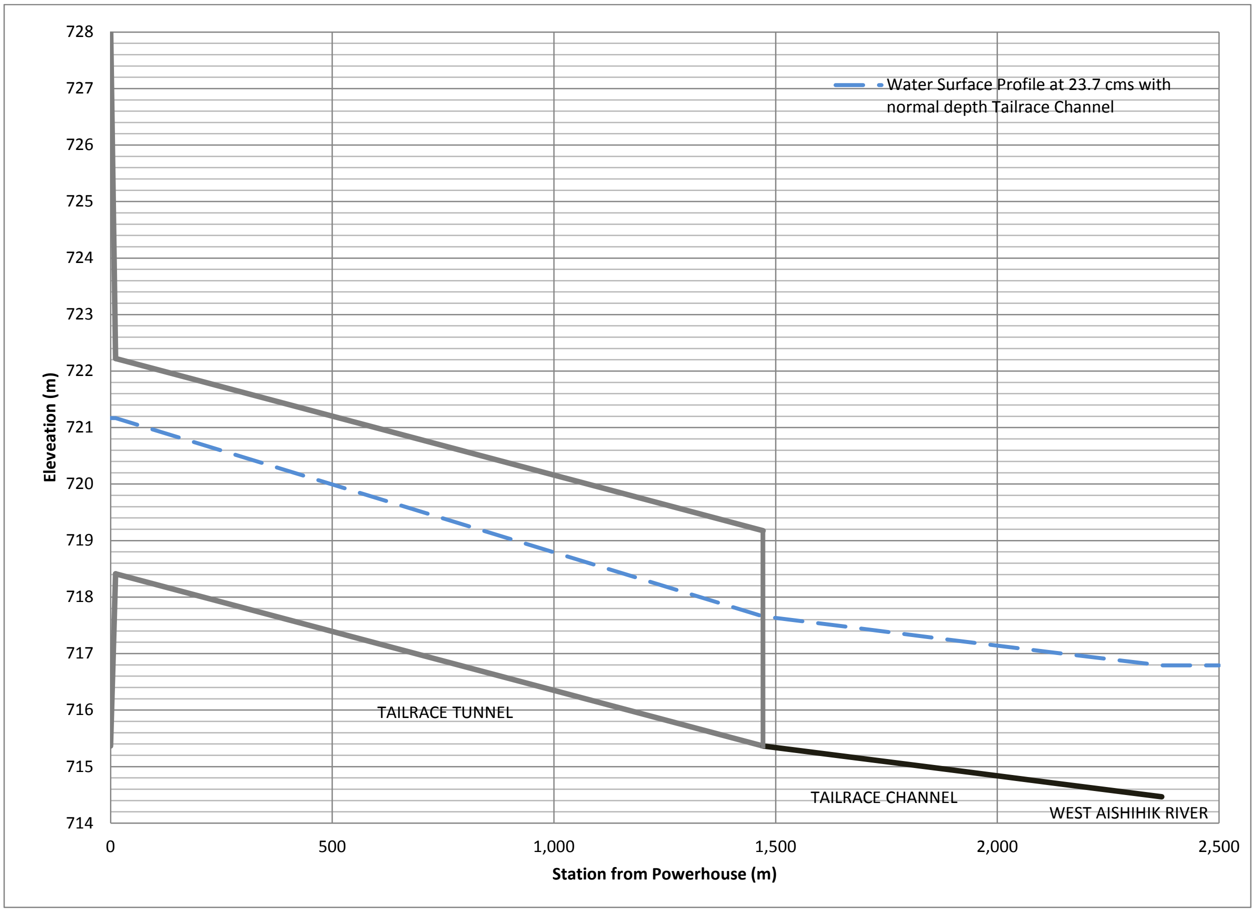

Figure 2: Aishihik GS Downstream Conveyance System Water Surface Profile

Figure 3 shows the maximum flow that can be passed through the tailrace tunnel without pressurized flow for various water levels in the West Aishihik River. Unit #3 is assumed to flow at its full capacity of 4.26 m^3/s for all the scenarios. Figure 3 indicates that as the West Aishihik River stage increases, less flow can be passed through the tailrace tunnel due to backwater effects along the tailrace channel. Depending on the river water level, the tailrace tunnel could pass more flow than the existing 19.43 m^3/s (Unit #1 and #2) with open-channel flow. As long as the tunnel maintains open-channel flow, transient pressures and backup of water into the powerhouse are not expected.

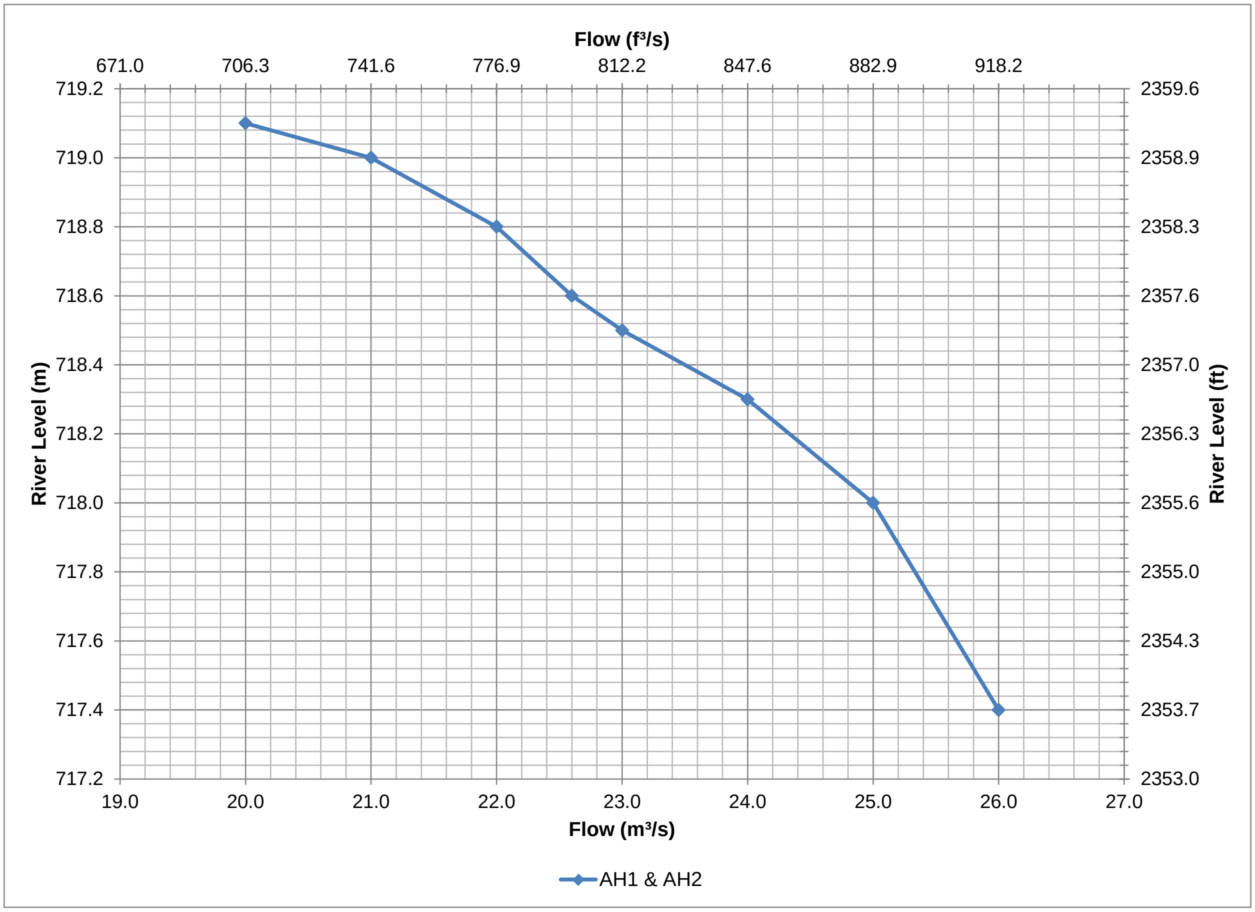

Figure 3: Maximum Flow Through Units 1 and 2 Without Pressurized Tunnel Flow

The other hydraulic concern is ensuring the tailrace tunnel remains open as a safe emergency exit at all times. This is the limiting factor for increasing flow through Unit 2. A reasonable estimate for safe tailrace tunnel flow using the powerhouse tailwater elevation-discharge equation has been compiled by Acres and is described in their February 1999 memo [Ref 3]. This relationship indicates expected powerhouse water levels under normal circumstances and is shown in Figure 4. According to this relationship, water level at the upstream end of the tailrace tunnel (ie. at the powerhouse) would be 721.17 m with current plant flow capacity. This would leave at least 1.06 m of freeboard available for emergency evacuation during normal conditions throughout the tunnel. Using the same equation, a total plant flow of 24.4 m^3/s may be possible while maintaining a 1.00 m freeboard. However, the 1.00 m freeboard may not still be available during extreme conditions if the elevated river levels drown out the tunnel outlet, so increasing plant flow would not be recommended at this point.

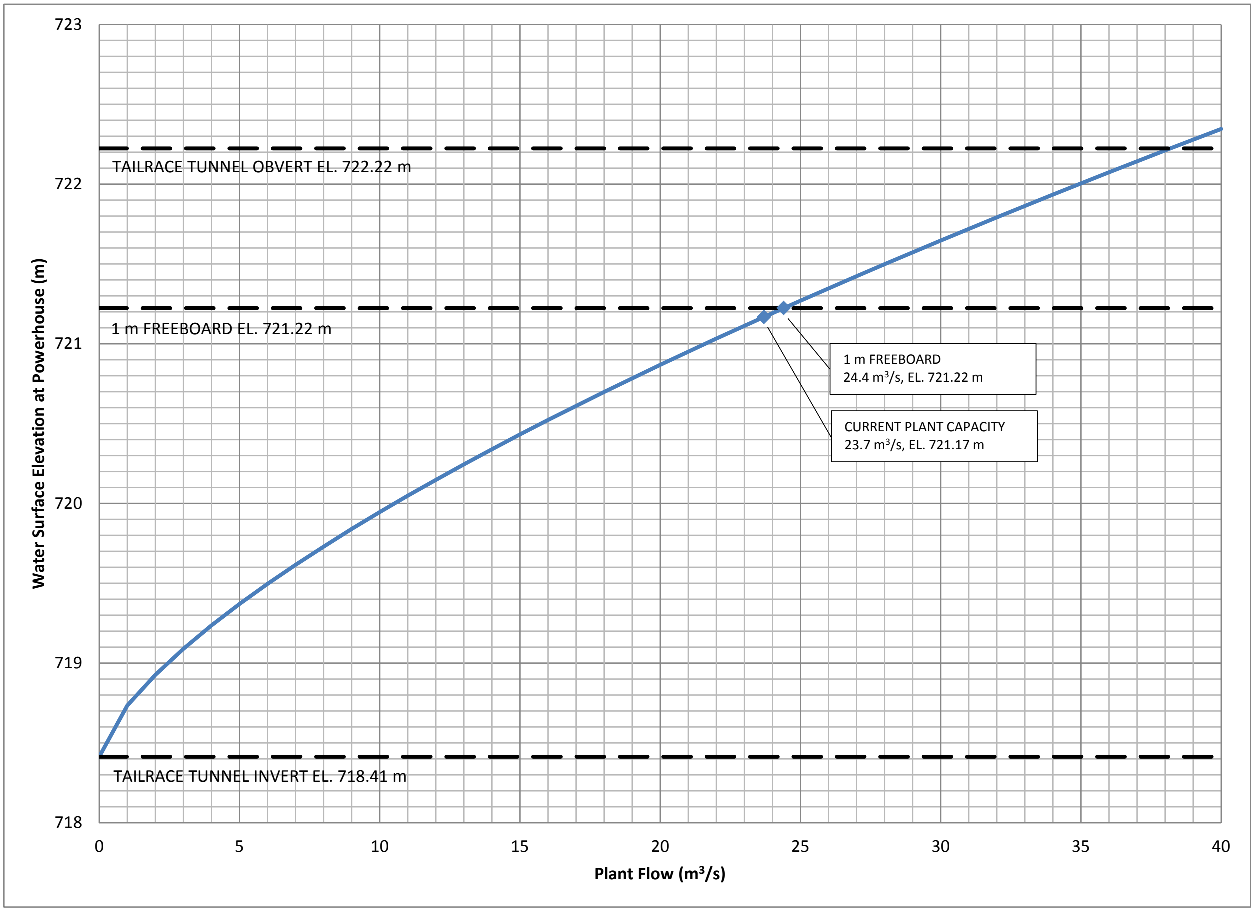

Figure 4: Powerhouse Tailwater Stage-Discharge Relationship

Without further West Aishihik River water level information, it would be impossible to confirm that the tailrace tunnel would be a safe emergency exit at all times. Although there is currently adequate freeboard during normal conditions, the extreme flood conditions of the river are unknown. It is recommended to gather additional information about flood levels in the West Aishihik River to confirm the safety of emergency evacuation under a wider range of conditions. Without further study regarding the West Aishihik River, the discharge through the Aishihik GS should not be increased beyond its current capacity.

5.0 CONCLUSIONS

KGS Group performed a high level hydraulic review of the Aishihik GS conveyance system, including a review of previous documentation and the development of a one-dimensional XP-

SWMM hydraulic model of the tailrace. From this analysis, the following conclusions about the maximum safe plant flow were drawn:

1. The limiting factor for increasing plant flow capacity is the requirement to maintain emergency evacuation access in the tailrace tunnel; however a survey of actual tailrace tunnel dimensions could be conducted to confirm the assumptions adopted in the hydraulic analysis described in this memorandum.
2. The current plant capacity of 23.7 m^3/s provides 1.06 m of emergency freeboard throughout the tailrace tunnel during normal conditions.
3. Flows as high as 24.4 m^3/s could be passed through the tunnel while still maintaining 1.00 m of emergency freeboard throughout the tunnel during normal downstream river levels.
4. During flood conditions, no data is available about expected water levels in the West Aishihik River. The river water levels have the potential to limit the available emergency freeboard at the downstream end of the tailrace tunnel.
5. Further information about flood stages in the West Aishihik River should be gathered. Until such information is obtained and analysed, no increase in plant flow is recommended.

5.0 REFERENCES

1. Hatch, “Aishihik Turbine Performance Test: Performance Test Results”, December 11, 2009.
2. Klohn Crippen Berger, “Aishihik GS Hydraulics Final Report”, November 7, 2008.
3. Acres, memo from Alfred Breland to S. G. Bridgeman. “Tailwater Elevation – Discharge Equations for Aishihik GS”, February 5, 1999.

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DPH/nf

APPENDIX B

TURBINE VENDOR BUDGETARY PROPOSALS

APPENDIX B-1

RUNNER UPGRADE RFI

Aishihik Generating Station
Potential Runner Upgrade
Request for Information
DRAFT – Rev A

KGS Group 14-1404-004
February 2015

Prepared By

Joel Lambert, P. Eng.
Senior Mechanical Engineer

Approved By

Mike Markovich, P. Eng.
Senior Mechanical Engineer

KGS Group
Winnipeg, Manitoba

TABLE OF CONTENTS

PAGE

LIST OF APPENDICES

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1.0 BACKGROUND

The Aishihik Generating Station (AGS) is located northwest of Whitehorse, Yukon. The site is accessible by an all-weather road. From the Whitehorse airport, it is approximately 122 km West on the Alaska Highway and approximately 20 km North on an un-nammed road. The closest community with services is Haines Junction, approximately 60 km away.

The AGS was constructed in 1972 and originally consisted of two 15 MW vertical Francis turbines (AH1 and AH2) with a net head of 180 metres. In 2011, a third 7 MW horizontal Francis turbine (AH3) was added.

The AGS units are located in an underground powerhouse approximately 110 metres below the surface. Water is drawn from Canyon Lake using a 5.6 km long power canal, through a concrete intake structure and a 1.1 km long tunnel. AH1 and AH2 are equipped with spherical valves that allow for isolation of the units for maintenance. Water discharges from the draft tubes, into a 1.4 km long tailrace tunnel and a 900 m tailrace channel before discharging into the West Aishihik River.

In 2003, the AH1 generator was rewound that increased the electrical capacity to 17,000 kVA. In 2006, the AH2 generator was rewound that increased the electrical capacity to 19,200 kVA. AH1 underwent a ten year overhaul in 2012 and the AH2 ten year overhaul was done in 2013.

While the project is not exclusive to the upgrade of the AH2 unit, it is perceived that it offers the greater opportunity for upgrade/uprate. It is the intent to also review the merits of upgrading both the AH1 and AH2 units.

2.0 REQUESTED INFORMATION

KGS Group has been retained by Yukon Energy Corporation to conduct a study into the potential upgrade of the turbine on Unit #2 at the Aishihik Generating Station. To this end, we are requesting budget pricing, as well as technical information on the runners you may have that are suitable, and other required turbine modifications or new components that may be beneficial to the efficiency or power output of the turbine.

Although currently at the concept study stage, the project, should it proceed, would eventually include the design, supply, manufacture, quality assurance, delivery, installation, testing, commissioning, and warranty for one or two new turbine runner(s) and any other modifications required to achieve the proposed improved performance.

To determine the feasibility of upgrades, the following preliminary information is requested:

- Budgetary cost. Please be sure to include for new coupling bolts
- Description of the proposed new runner, including number of blades, materials, and method of fabrication (single piece casting, welded etc.)
- A description of the proposed scope of the upgrades, beyond the provision of new runners
- Number of runner blades proposed
- Efficiency curves (Hill Chart) for the proposed turbines
- Sigma critical value
- Expected cavitation characteristics based on setting, referenced to limits in Figures A.1 and A.2 in IEC 60609-1-2004
- Any operational constraints, such as maximum number of hours above and below the recommended operation envelope
- Maximum runaway speed
- Expected hydraulic thrust load
- Indicate delivery time for major equipment after placement of order
- Indicate anticipated time required for installation in the field

Clearly indicate in your budgetary proposal where requested items are excluded or are not in compliance with this document.

3.0 TYPICAL OPERATION AND OPTIMIZATION OF NEW RUNNERS

In order to provide a “spinning reserve” to accept sudden load increases on Yukon Energy Corporation’s electrical grid, the AH1 and AH2 units are typically operated at approximately 80% of their maximum power output. They may, however, be operated at relatively low power levels during periods of low demand and at maximum output during periods of high demand.

Because of the above-mentioned operation strategy, the proposed new runners should be optimized to provide (in order of importance):

1. The highest efficiency at approximately 80% gate opening
2. The highest maximum output at full gate opening
3. The highest efficiency at gate openings lower than 80%

A preference will be shown for fabricated (welded) runners over one-piece cast runners. Cast runners may be accepted, depending on efficiency, cavitation and equipment guarantees.

4.0 REFERENCE FIGURES

Refer to the following drawings, in Appendix A, for more detailed information on the site and the existing turbines.

- Fig. 1: General Arrangement
- Fig. 2: Longitudinal Section
- D122: Powerhouse Area – General Arrangement
- M9-D31: Powerhouse Arrangement: Mechanical – Transverse Section
- M9-D34: Powerhouse Arrangement: Mechanical – Longitudinal Section Looking Upstream
- 222 F 30000: 20500 HP Vertical Francis Turbine Sectional Elevation
- 222 F 30001: 20500 Vertical Francis Turbine Plan
- 222 D 30014: Runner
- 222 F 20019: Turbine Shaft
- 292D653AL Large Generator

5.0 EXISTING EQUIPMENT DETAILS

In this section, elevations are reference to mean sea level.

5.1 TURBINES

Make:	Dominion Engineering Works
Rated net head:	180.4 m
Rated discharge (per unit):	9.72 m^3/s
Power at rated net head and discharge (per unit):	15 MW
Speed:	720 RPM
Number of runner blades:	15
Number of wicket gates:	20
Throat diameter:	1016 mm
Setting elevation (centreline of distributor):	715.52 m

5.2 GENERATORS

Make:	Canadian General Electric
Synchronous Speed:	720 RPM
Maximum runaway speed rating of generators:	1330 RPM
AH1 capacity:	17,000 kVA
AH2 capacity:	19,200 kVA
Power factor:	0.9

Refer to Appendix B and C for pictures of the generator nameplates.

5.3 TAILWATER RATING INFORMATION:

TWL elevation at 8.5 m^3/s:	719.9 m
TWL elevation at 21.25 m^3/s:	721.4 m
TWL elevation at 25 m^3/s:	722.0 m

6.0 CONSTRAINTS

6.1 HYDRAULIC

The rated flow of the proposed new turbine runners cannot exceed the rating of the existing runners. This is due to a limitation in the tailrace tunnel. The tailrace tunnel is designed to operate at partially filled (i.e. the tunnel has a free water surface for its entire length). Increasing the flow beyond the existing maximum values may cause the tunnel to switch to full flow, resulting in backwater effects and potential dynamic issues that would result if the flow alternated between flowing filled and partially filled.

The tailrace tunnel is also used as an emergency egress route from the underground powerhouse. For this reason, a minimum freeboard is required between the roof of the tunnel and the maximum water level.

6.2 MECHANICAL

Other than the maximum runaway speed rating of the existing generators, no mechanical limitations that would limit a runner upgrade have been identified.

If any changes to the distributor or wicket gates are recommended by the Supplier, the capacity of the servo and governor oil system would need to be confirmed.

6.3 ELECTRICAL

The switchgear, power conductors and generator step-up transformers have the sufficient capacity to accommodate the increased power generated by the upgraded units.

The excitation system is currently under review, but for the purposes of this RFI, please assume that there is no constraint on the maximum power output based on the excitation system.

7.0 OTHER RELEVANT DATA

7.1 SEISMIC INFORMATION

The design seismic coefficient (PGA) shall be 0.17g.

8.0 BASIS OF BUDGETARY COST ESTIMATE

For the purposes of the budgetary cost estimate requested, please assume the following.

8.1 SCOPE OF SUPPLY

Allow for:

- Provision of a one new runner
- Provision of new coupling bolts
- Provision of new runner blade templates in accordance with IEC 60193-1999 to measure both blade profile and angle
- Provision of all stationary parts required for the installation of the new runner and of any new turbine components to be replaced to enhance turbine performance
- The submission and review of drawings, design documentation and quality assurance documentation by Owner's Engineer.
- The provision of 3 paper copies and one electronic copy of Operating and Maintenance (O&M) manuals for all equipment supplied.

8.2 WARRANTY

Warranty work for a period of two years from substantial performance.

8.3 PERFORMANCE GUARANTEES

If the turbine re-runnering project proceeds, it is likely that the Owner will seek performance guarantees for efficiency and power output, supported by liquidated damages. The level of liquidated damages has not been determined at this point.

8.4 SITE INSTALLATION

Please include a cost estimate for complete site installation of the new runner (assuming only one runner is replaced) and any other required modifications.

Provide:

- Duration and person-days of work
- Cost for person-day of work

Indicate whether or not values include living out allowances and accommodation costs.

9.0 SUBMISSION AND CONTACT INFORMATION

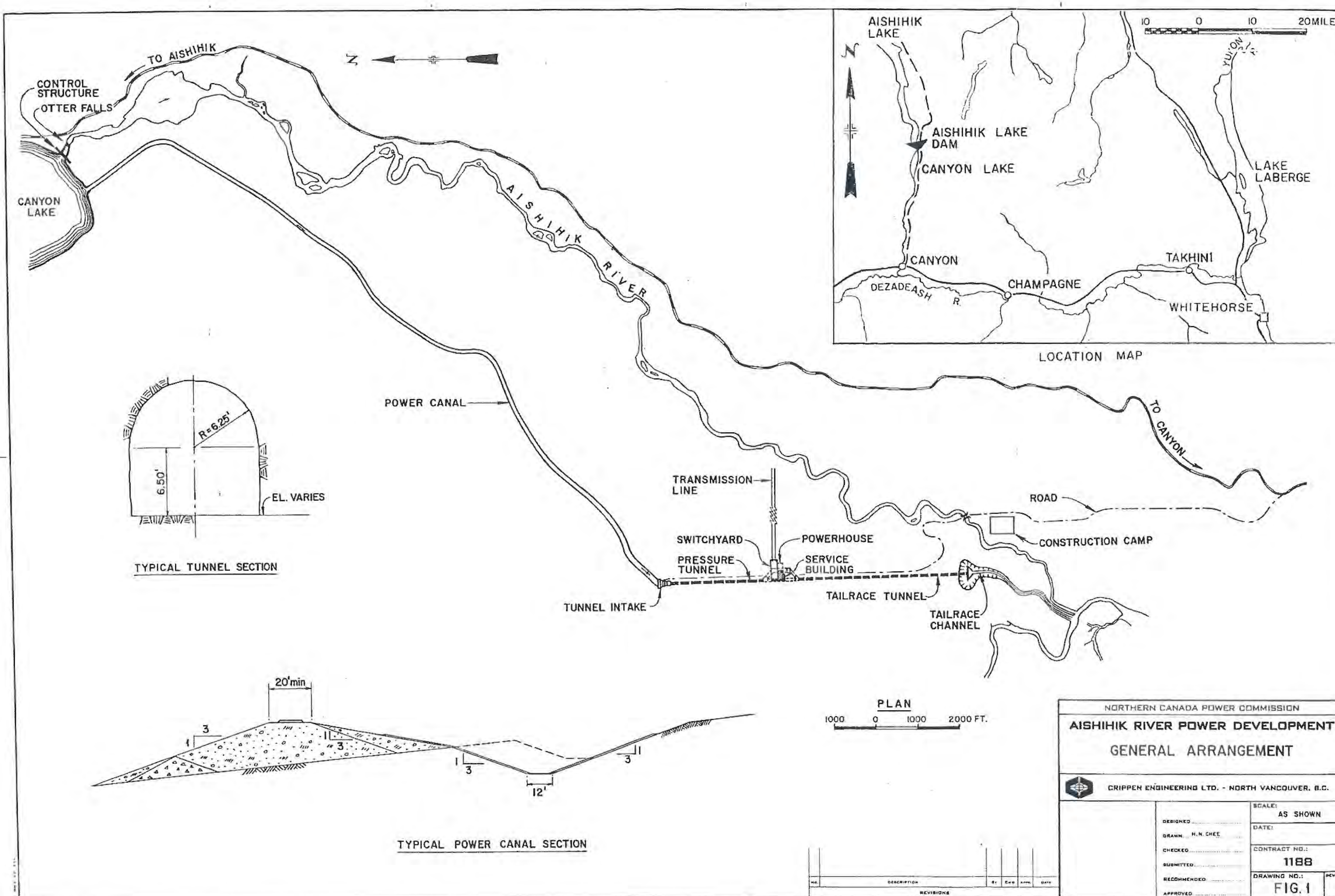
Please direct questions or submit information to:

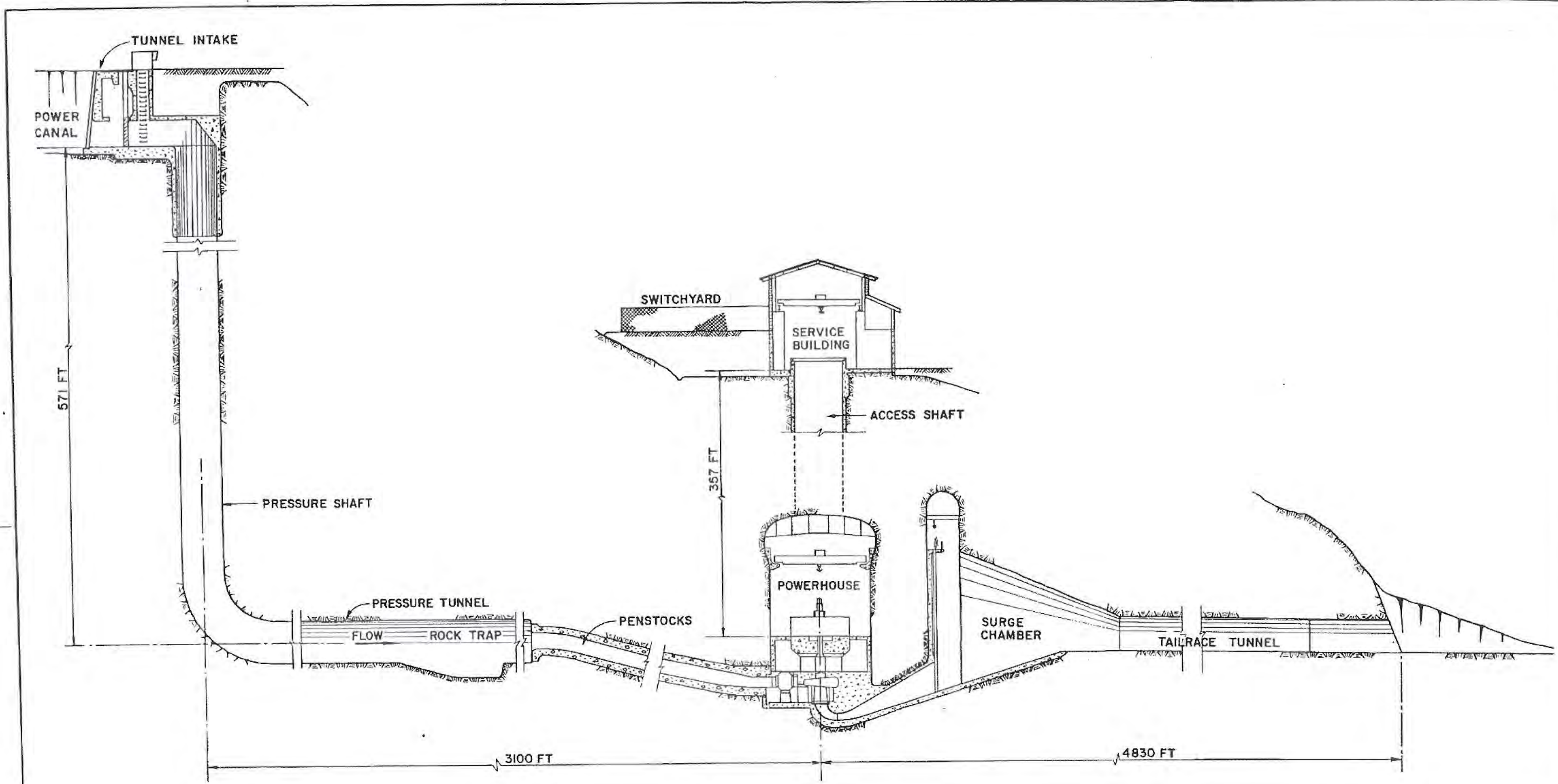
KGS Group
Attention: Joel Lambert, P.Eng.
3rd Floor, 865 Waverley Street
Winnipeg, MB
R3T 5P4
Email: jlambert@kgsgroup.com
Phone: 204-896-1209
Cell: 204-770-6411

Please provide the requested information by March 10, 2015.

APPENDIX A

REFERENCE DRAWINGS


TO AISHIHIK
CONTROL STRUCTURE
OTTER FALLS
CANYON LAKE
AISHIHIK RIVER
POWER CANAL
TO CANYON
TRANSMISSION LINE
ROAD
SWITCHYARD
POWERHOUSE
PRESSURE TUNNEL
SERVICE BUILDING
CONSTRUCTION CAMP
TUNNEL INTAKE
TAILRACE TUNNEL
TAILRACE CHANNEL
AISHIHIK LAKE
AISHIHIK LAKE DAM
CANYON LAKE
LAKE LABERGE
YUKON R.
CANYON
TAKHINI
CHAMPAGNE
DEZADEASH R.
WHITEHORSE
10 0 10 20 MILES
LOCATION MAP
R=6.25'
6.50'
EL. VARIES
TYPICAL TUNNEL SECTION
20' min
3
1
3
1
3
1
3
12'
TYPICAL POWER CANAL SECTION
PLAN
1000 0 1000 2000 FT.
REVISIONS
NORTHERN CANADA POWER COMMISSION
AISHIHIK RIVER POWER DEVELOPMENT
GENERAL ARRANGEMENT
CRIPPEN ENGINEERING LTD. - NORTH VANCOUVER, B.C.
DESIGNED
DRAWN H.N. CHEE
CHECKED
SUBMITTED
RECOMMENDED
APPROVED
SCALE: AS SHOWN
DATE:
CONTRACT NO.: 1188
DRAWING NO.: FIG. 1



NO.	DESCRIPTION	BY	CK'D	APPR.	DATE

REVISIONS

NORTHERN CANADA POWER COMMISSION

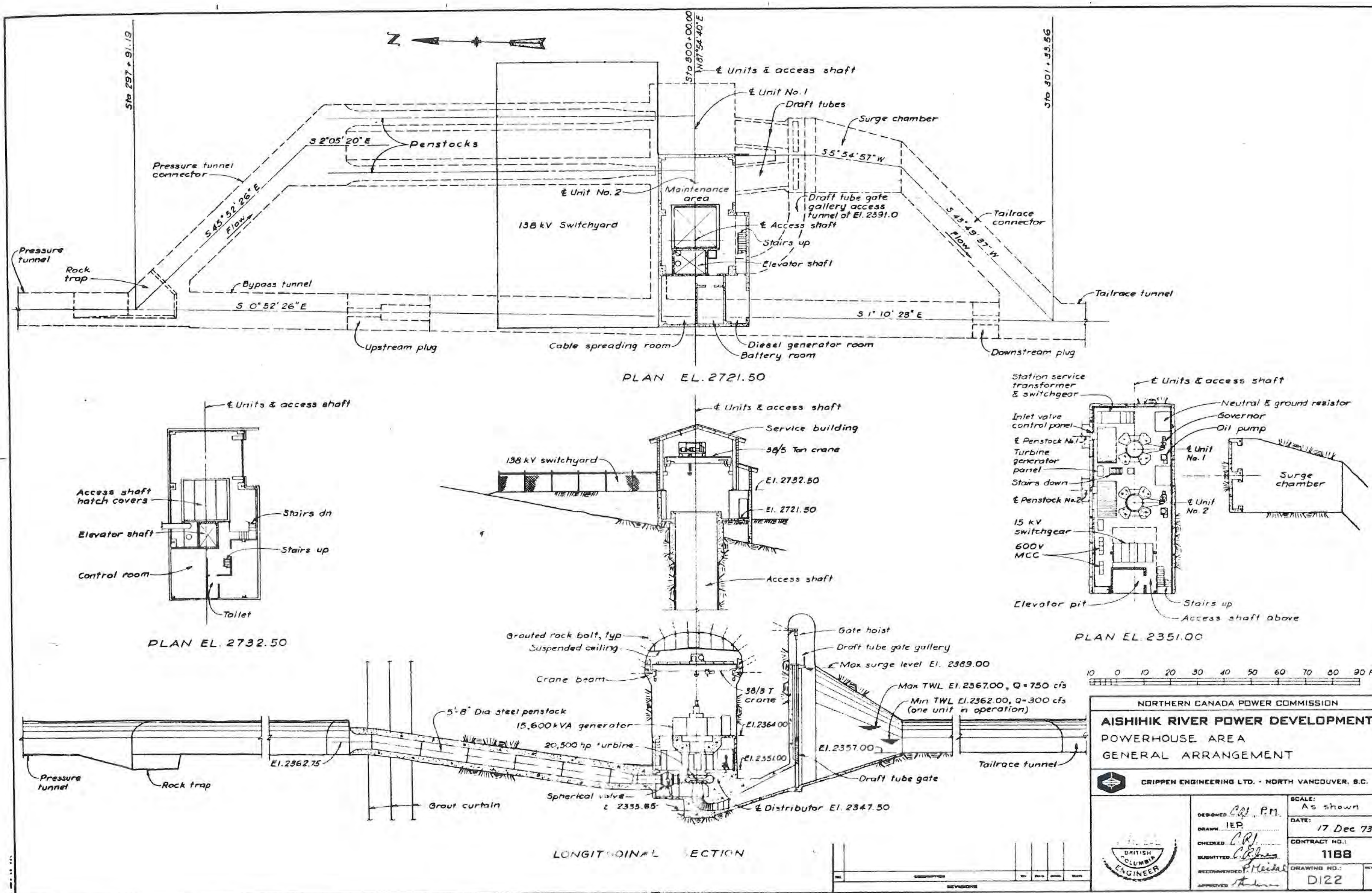
AISHIHIK RIVER POWER DEVELOPMENT

LONGITUDINAL SECTION

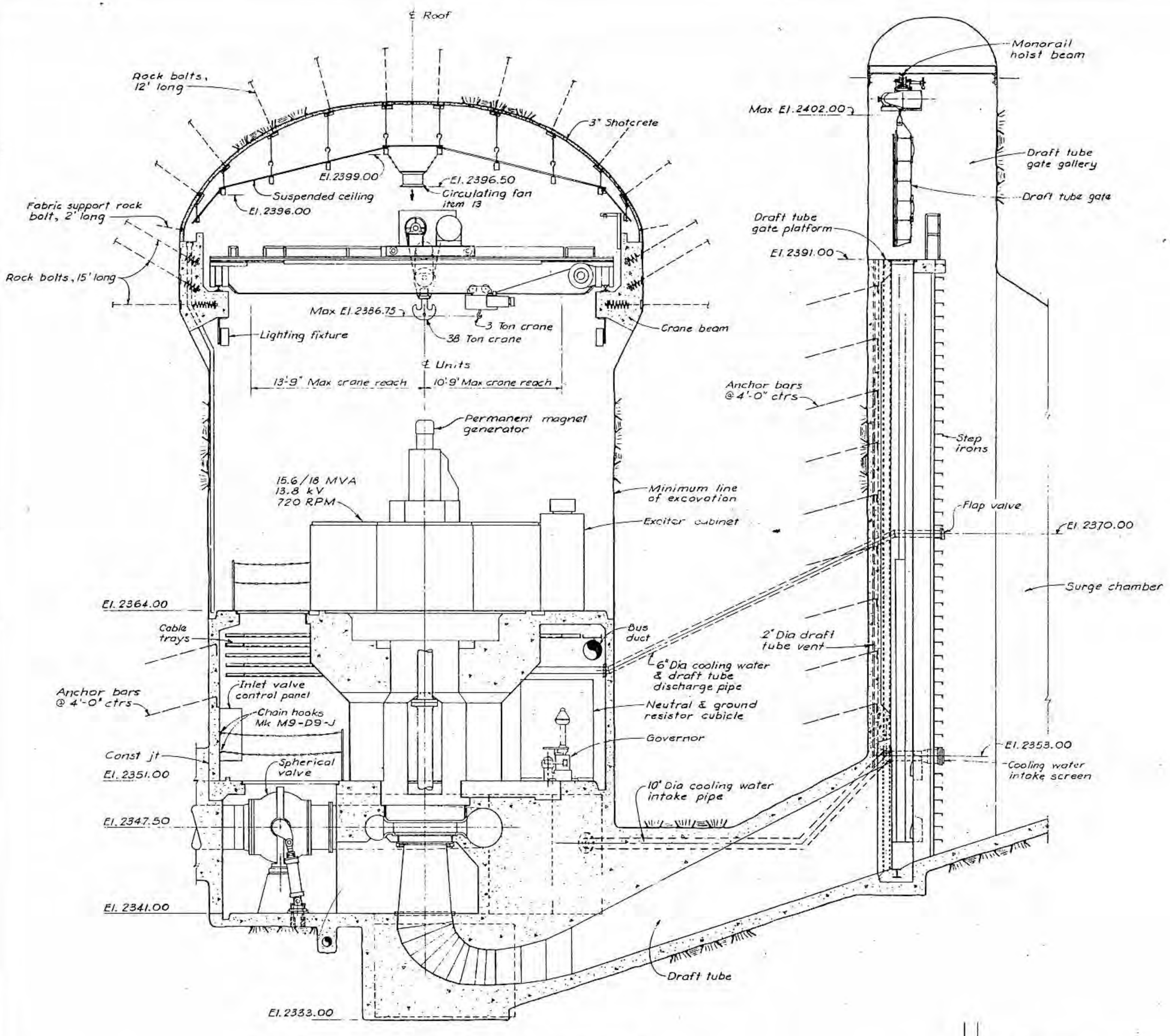
CRIPPEN ENGINEERING LTD. - NORTH VANCOUVER, B.C.

DESIGNED
DRAWN H.K. CHEE
CHECKED
SUBMITTED
RECOMMENDED
APPROVED

SCALE: —
DATE:
CONTRACT NO.: 1188
DRAWING NO.: FIG. 2
REV. No.



Z
Sta 297 + 91.19
Sta 300+00.00
N87°54'40"E
Sta 301 + 55.56
℄ Units & access shaft
℄ Unit No. 1
Draft tubes
Surge chamber
S 2°05' 20" E
Penstocks
S 5° 54' 57" W
Pressure tunnel connector
℄ Unit No. 2
Maintenance area
Draft tube gate gallery access tunnel at El. 2391.0
S 45° 52' 26" E
Flow
138 kV Switchyard
℄ Access shaft
Stairs up
Elevator shaft
S 43° 49' 37" W
Flow
Tailrace connector
Pressure tunnel
Rock trap
Bypass tunnel
S 0° 52' 26" E
S 1° 10' 23" E
Tailrace tunnel
Upstream plug
Cable spreading room
Diesel generator room
Battery room
Downstream plug
PLAN EL. 2721.50
℄ Units & access shaft
Access shaft hatch covers
Stairs dn
Elevator shaft
Stairs up
Control room
Toilet
PLAN EL. 2732.50
℄ Units & access shaft
Service building
138 kV switchyard
38/5 Ton crane
El. 2732.50
El. 2721.50
Access shaft
Station service transformer & switchgear
℄ Units & access shaft
Neutral & ground resistor
Inlet valve control panel
Governor
Oil pump
℄ Penstock No. 1
℄ Unit No. 1
Turbine generator panel
Stairs down
Surge chamber
℄ Penstock No. 2
℄ Unit No. 2
15 kV switchgear
600V MCC
Elevator pit
Stairs up
Access shaft above
PLAN EL. 2351.00
Grouted rock bolt, typ
Suspended ceiling
Crane beam
Gate hoist
Draft tube gate gallery
Max surge level El. 2389.00
Max TWL El. 2367.00, Q = 750 cfs
Min TWL El. 2362.00, Q = 300 cfs (one unit in operation)
38/5 T crane
5'-8" Dia steel penstock
15,600 kVA generator
El. 2364.00
20,500 hp turbine
El. 2351.00
El. 2357.00
Pressure tunnel
Rock trap
El. 2362.75
Tailrace tunnel
Draft tube gate
Spherical valve
℄ 2333.85
℄ Distributor El. 2347.50
Grout curtain
LONGITUDINAL SECTION
10 0 10 20 30 40 50 60 70 80 90 FT
NORTHERN CANADA POWER COMMISSION
AISHIHIK RIVER POWER DEVELOPMENT
POWERHOUSE AREA
GENERAL ARRANGEMENT
CRIPPEN ENGINEERING LTD. - NORTH VANCOUVER, B.C.
BRITISH COLUMBIA ENGINEER
DESIGNED C.R.J. P.M.
DRAWN IEP
CHECKED C.R.J.
SUBMITTED C.R. Jones
RECOMMENDED P. Meidal
SCALE: As shown
DATE: 17 Dec 73
CONTRACT NO.: 1188
DRAWING NO.: D122
REVISIONS



TRANSVERSE SECTION THRU ℄ UNIT NO. 2

NOTE:
1. For list of H & V items and legend see Dwg M10-D5.

MGBenham 30.1.76

No.	Description	By	Chk	Appr	Date
1	As built.	K.O.S.	MGB	JPD	30-1-76

REVISIONS

NORTHERN CANADA POWER COMMISSION

AISHIHIK RIVER POWER DEVELOPMENT

POWERHOUSE ARRANGEMENT: MECHANICAL
TRANSVERSE SECTION

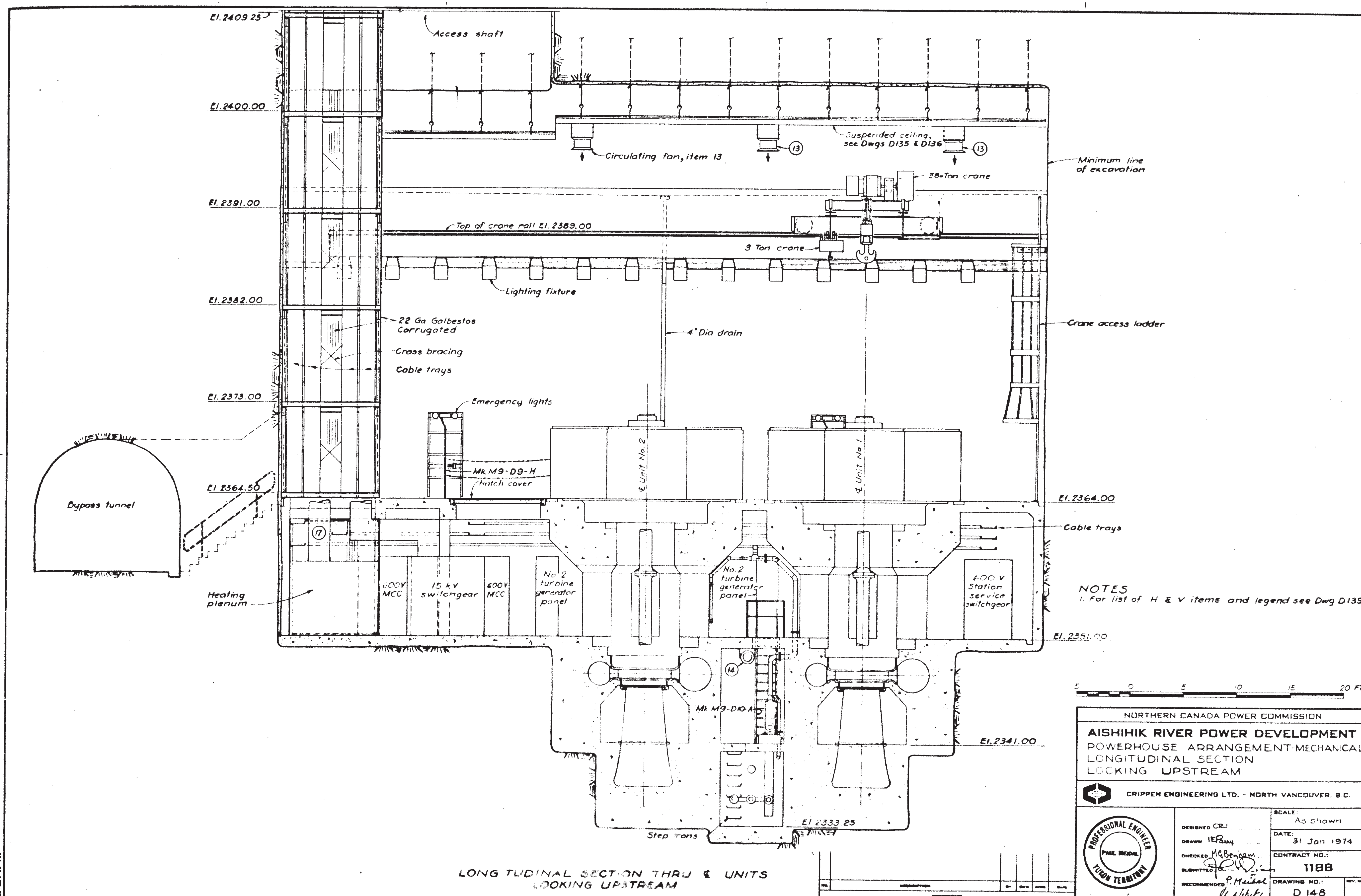
CRIPPEN ENGINEERING LTD. - NORTH VANCOUVER, B.C.

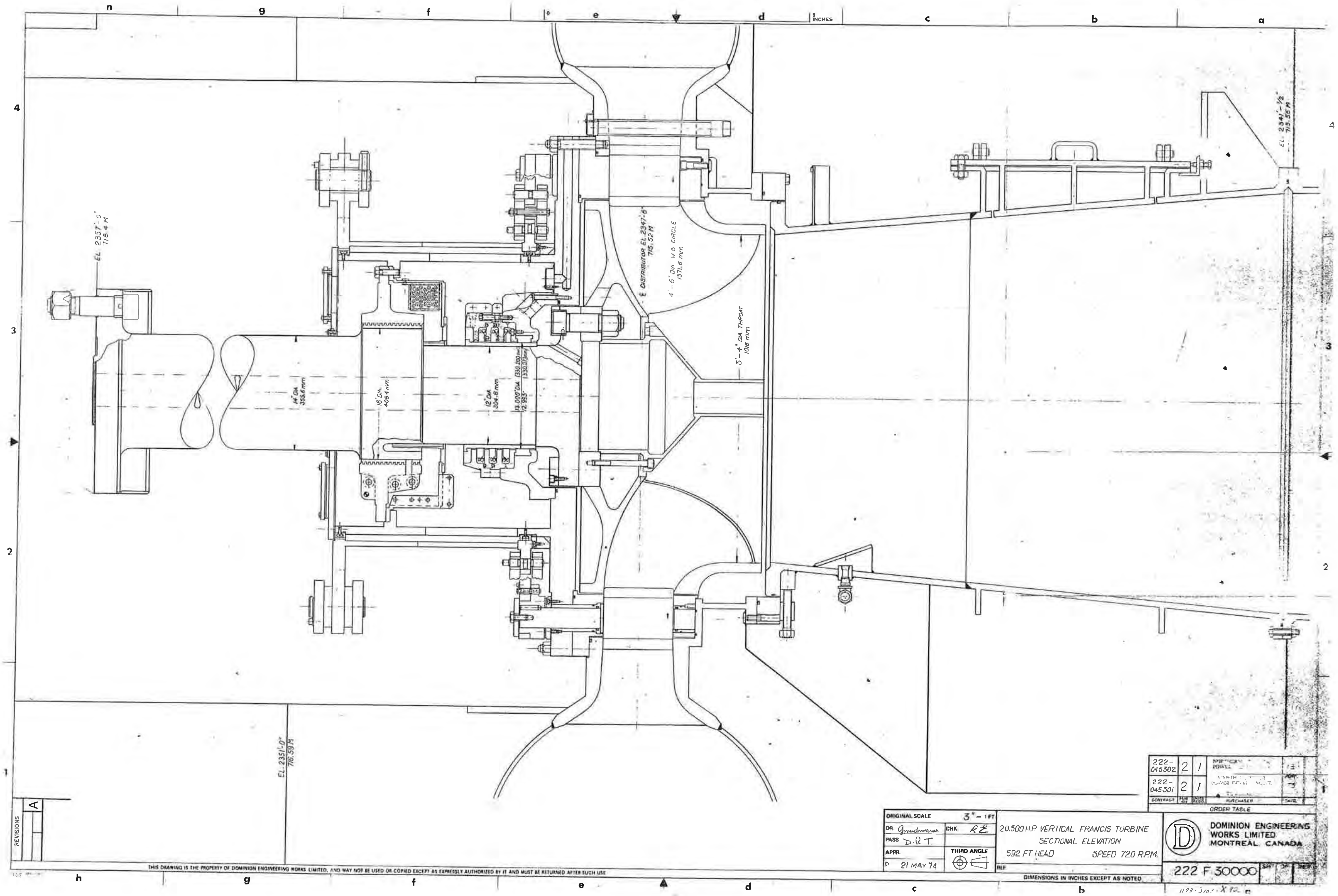
J. P. DAVIES BRITISH COLUMBIA ENGINEER

DESIGNED MGB
DRAWN I.E.P.
CHECKED JPD
SUBMITTED MGBenham
RECOMMENDED
APPROVED P. Meikle

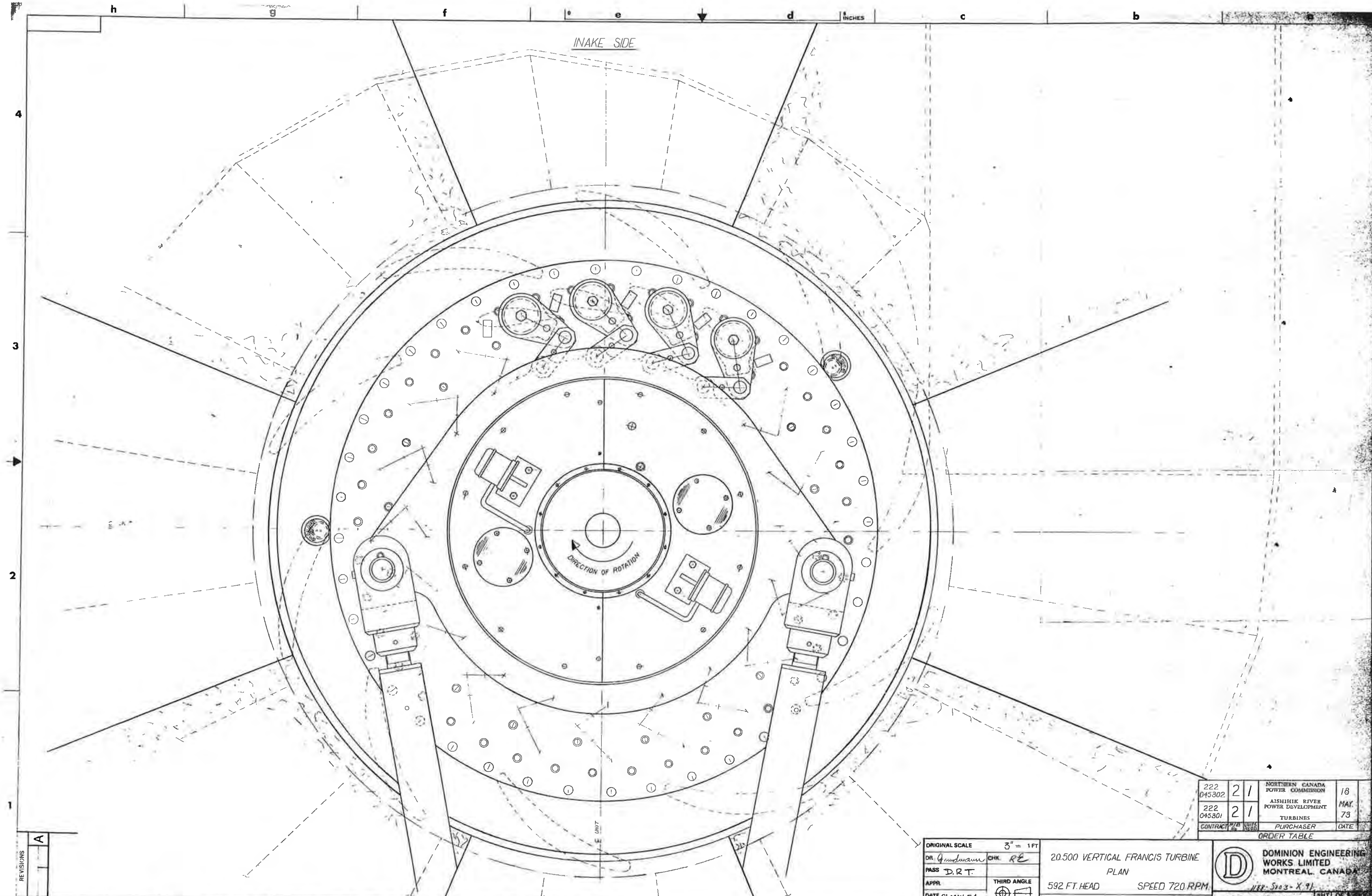
SCALE: $\frac{1}{4}$" = 1'-0"
DATE: June 24, 1974
CONTRACT NO.: 1188
DRAWING NO.: M9-D31
REV. NO.: 1

CRIPP M9 D31


El. 2409.25
Access shaft
El. 2400.00
Circulating fan, item 13
13
Suspended ceiling, see Dwgs D135 & D136
Minimum line of excavation
38-Ton crane
El. 2391.00
Top of crane rail El. 2389.00
3 Ton crane
Lighting fixture
El. 2382.00
22 Ga Galbestos Corrugated
Cross bracing
Cable trays
4" Dia drain
Crane access ladder
El. 2373.00
Emergency lights
Mk M9-D9-H
Hatch cover
℄ Unit No. 2
℄ Unit No. 1
El. 2364.50
El. 2364.00
Bypass tunnel
17
Cable trays
Heating plenum
600V MCC
15 kV switchgear
600V MCC
No 2 turbine generator panel
No. 2 turbine generator panel
600 V Station service switchgear
NOTES
1. For list of H & V items and legend see Dwg D139.
El. 2351.00
14
Mk M9-D10-A
El. 2341.00
El. 2333.25
Step irons
5 0 5 10 15 20 FT
LONGITUDINAL SECTION THRU ℄ UNITS LOOKING UPSTREAM
NORTHERN CANADA POWER COMMISSION
AISHIHIK RIVER POWER DEVELOPMENT
POWERHOUSE ARRANGEMENT-MECHANICAL
LONGITUDINAL SECTION
LOOKING UPSTREAM
CRIPPEN ENGINEERING LTD. - NORTH VANCOUVER, B.C.
PROFESSIONAL ENGINEER
PAUL MEIDAL
YUKON TERRITORY
DESIGNED CRJ
DRAWN
CHECKED MG Benham
SUBMITTED
RECOMMENDED P. Meidal
APPROVED
SCALE: As shown
DATE: 31 Jan 1974
CONTRACT NO.: 1188
DRAWING NO.: D 148
REV. No.
REVISIONS



EL. 2357'-0"
718.4 M
EL. 2341'-1/2
713.55 M
EL. 2351'-0"
716.59 M
℄ DISTRIBUTOR EL. 2347'-6"
715.52 M
4'-6" DIA. W.G. CIRCLE
1371.6 mm
3'-4" DIA. THROAT
1016 mm
14" DIA.
355.6 mm
16" DIA.
406.4 mm
12" DIA.
304.8 mm
13.000" DIA.
12.995"
INCHES
REVISIONS
A
THIS DRAWING IS THE PROPERTY OF DOMINION ENGINEERING WORKS LIMITED, AND MAY NOT BE USED OR COPIED EXCEPT AS EXPRESSLY AUTHORIZED BY IT AND MUST BE RETURNED AFTER SUCH USE
222-045302 2 1
222-045301 2 1
CONTRACT
PURCHASER
DATE
ORDER TABLE
ORIGINAL SCALE 3" = 1 FT
DR. Gmudmann
CHK. RE
PASS D.R.T.
APPR.
21 MAY 74
THIRD ANGLE
20.500 H.P. VERTICAL FRANCIS TURBINE
SECTIONAL ELEVATION
592 FT HEAD
SPEED 720 R.P.M.
REF.
DIMENSIONS IN INCHES EXCEPT AS NOTED
DOMINION ENGINEERING
WORKS LIMITED
MONTREAL CANADA
222 F 30000
SHT
OF
REV



CONTRACT			PURCHASER	DATE
222 045302	2	1	NORTHERN CANADA POWER COMMISSION AISHIHIK RIVER POWER DEVELOPMENT TURBINES	18 MAY 73
222 045301	2	1		

ORDER TABLE

ORIGINAL SCALE	3" = 1 FT
DR. Grunduan	CHK. RE
PASS D.R.T.	
APPR.	THIRD ANGLE
DATE 21 MAY 74	

20.500 VERTICAL FRANCIS TURBINE

PLAN

592 FT. HEAD SPEED 720 R.P.M.

REF.

DIMENSIONS IN INCHES EXCEPT AS NOTED

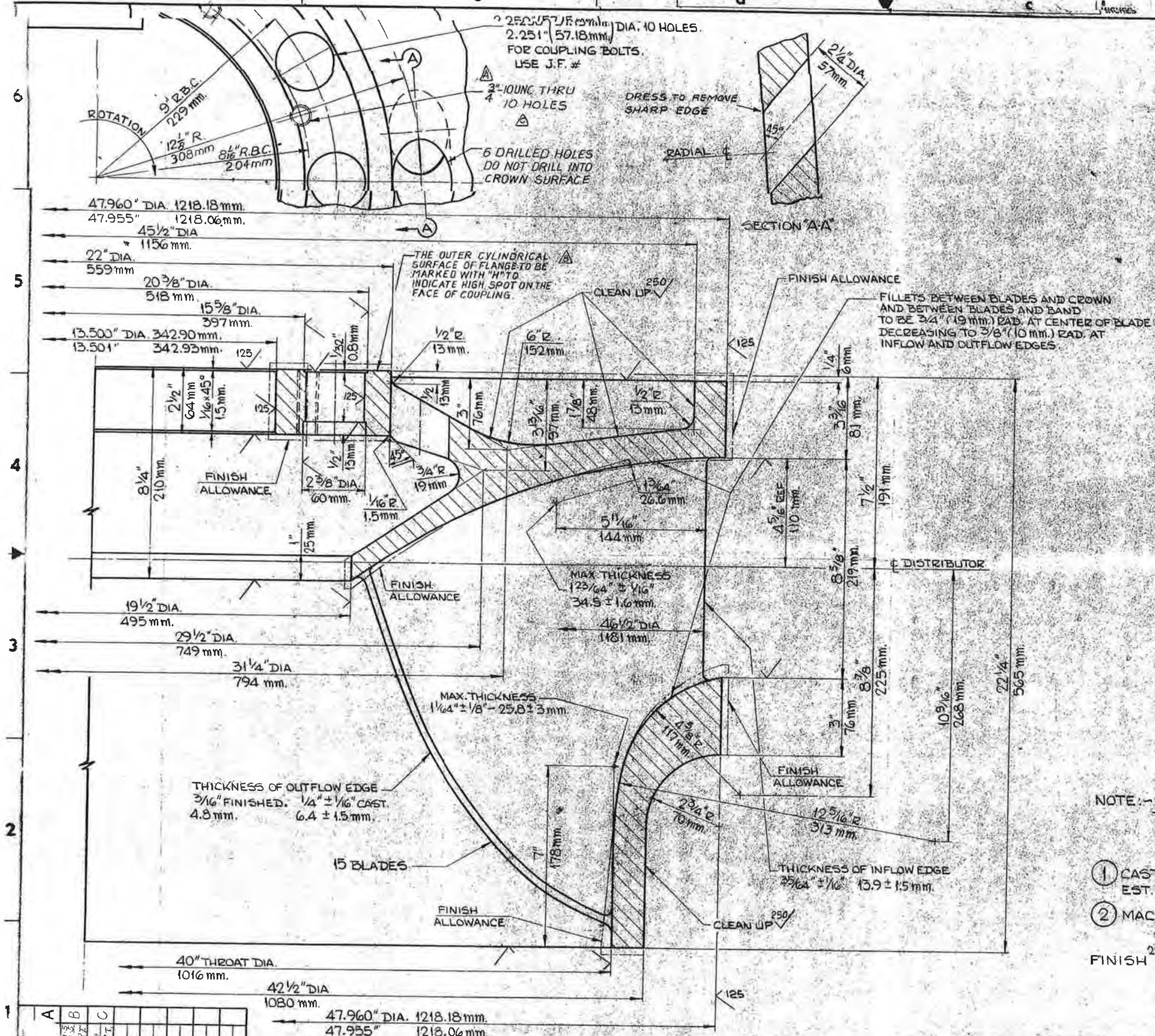
DOMINION ENGINEERING WORKS LIMITED MONTREAL, CANADA

1188-5103-X 91

222 F 30001

SHT OF

REVISIONS A



MATERIAL LIST

QUANTITIES LISTED ARE FOR ONE UNIT ONLY

PC NO	QTY	NAME	IDENT No	MATERIAL	REMARKS
1	1	RUNNER CASTING	P001	BB656C1	
2	1	RUNNER MACHINED	P002		MAKE FROM PC. 1
3	NEC	BALANCING			

ENGINEERING INSTRUCTIONS E1222QB-00401, E1214QE-00398 & E1214QE-00399

QUALITY CONTROL INSPECTION RECORD D.E.W. FORMS 13202, 13203.

FINISH OF WATER PASSAGES: 222C30015

BLADE OPENING CHECKS: 222A 30041

NOTE:- ALL DIMENSIONS TO POINT OF MAXIMUM THICKNESS OF BLADE ARE MEASURED ON FACE OF BLADE.

(1) CASTING ~ PATT. H-90618 EST. CAST. WEIGHT: 2950 # (1338 KG.)

(2) MACHINING.

FINISH 250 EXCEPT AS INDICATED.

CONTRACT	M/O No	UNITS REQD	PURCHASER	DATE
222-045302	14	1	NORTHERN CANADA POWER COMMISSION AISHIHIK RIVER POWER DEVELOPMENT TURBINES	18 MAY 73
222-045301	14	1		

ORDER TABLE

ORIGINAL SCALE	6" = 1FT		
DR.		CHK.	
PASS	D.R.T.		
APPR.		THIRD ANGLE	
DATE	6 AUG 73		

REF.

RUNNER

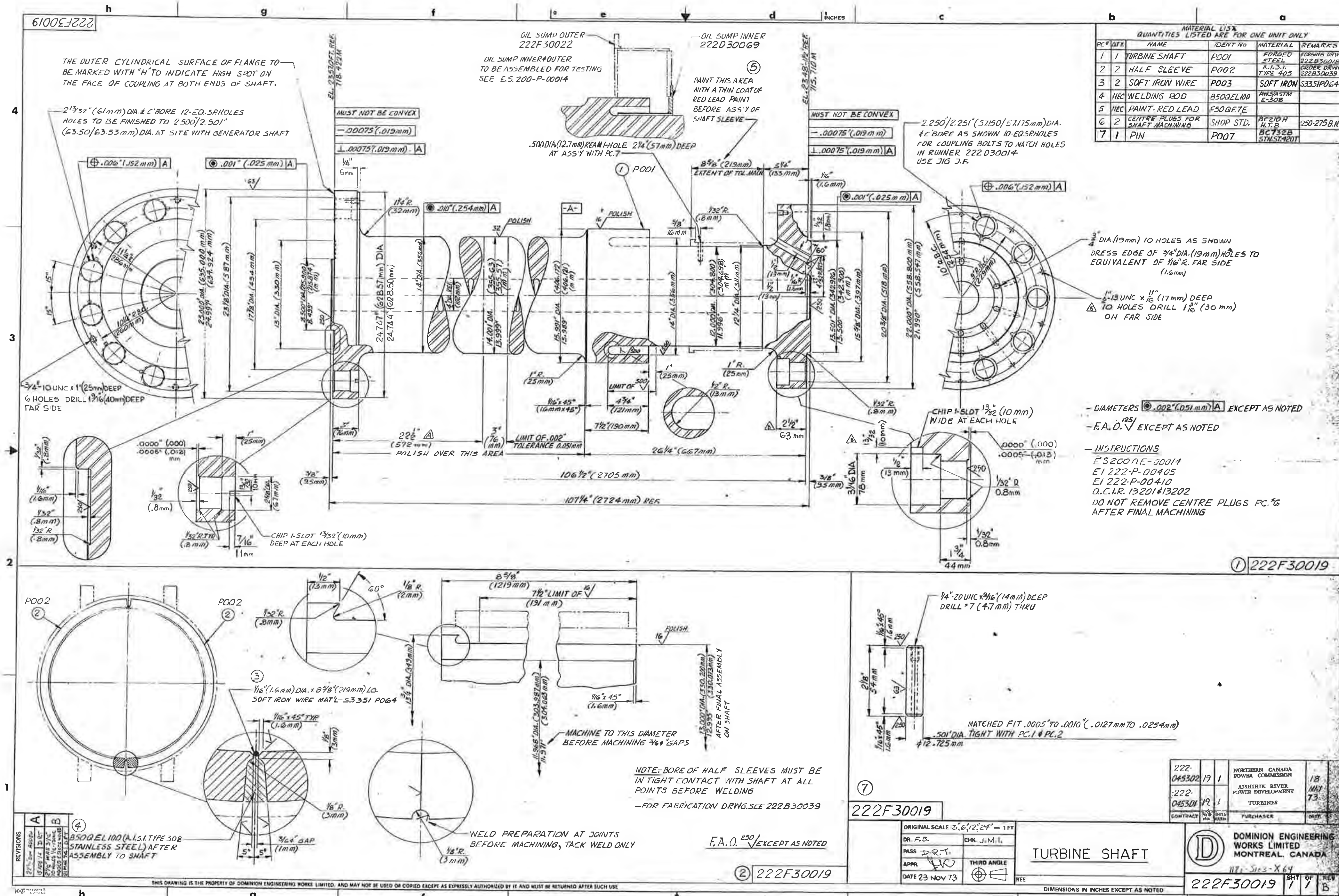
DIMENSIONS IN INCHES EXCEPT AS NOTED

DOMINION ENGINEERING WORKS LIMITED MONTREAL, CANADA

1188-5103-D37

222D30014 SHT 1 OF 1 REV C

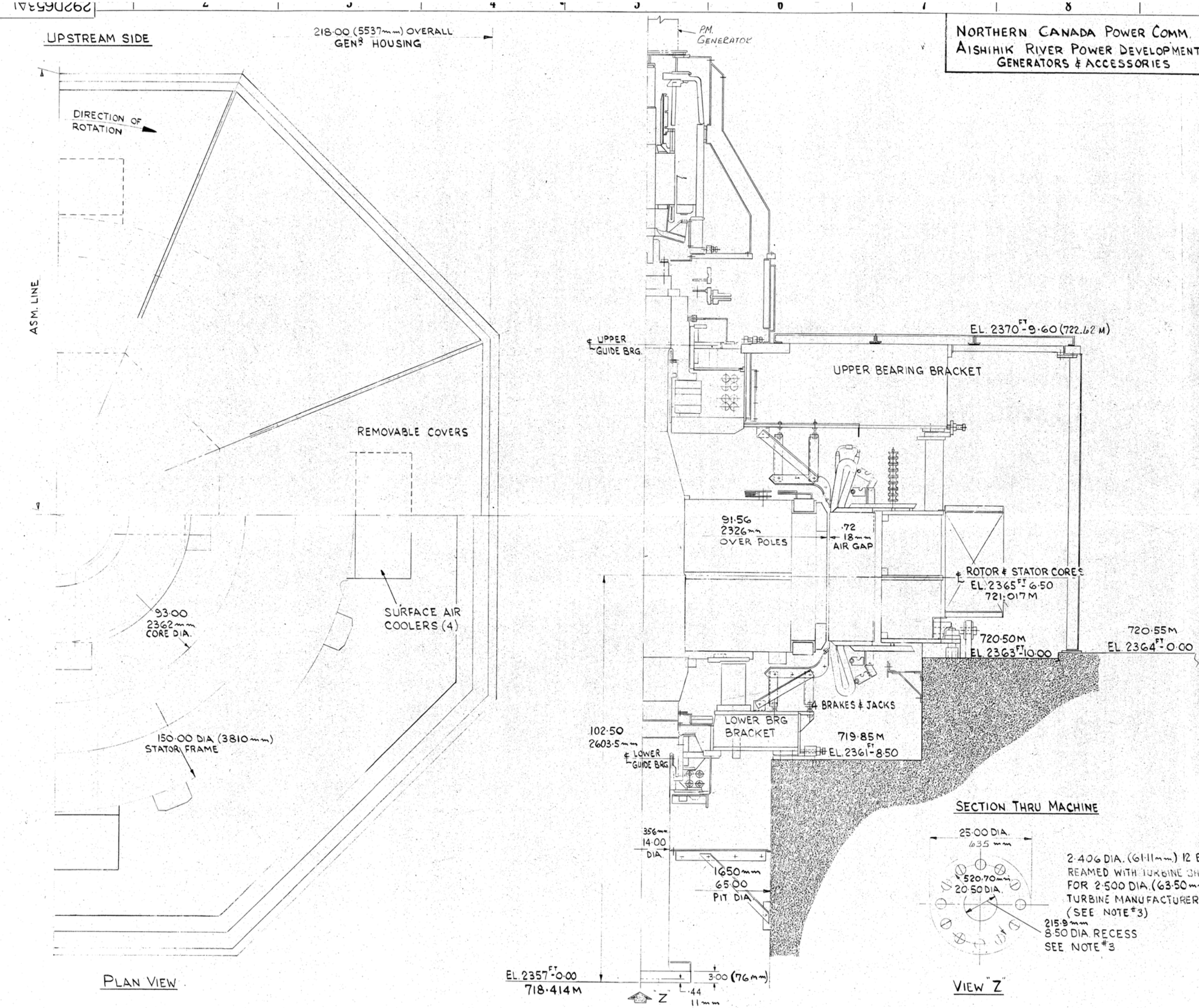
REVISIONS A B C



MATERIAL LIST
QUANTITIES LISTED ARE FOR ONE UNIT ONLY

PC#	QTY.	NAME	IDENT No	MATERIAL	REMARKS
1	1	TURBINE SHAFT	P001	FORGED STEEL	FORGING DRWG. 222B30016
2	2	HALF SLEEVE	P002	A.I.S.I. TYPE 405	ORDER DRWG. 222B30039
3	2	SOFT IRON WIRE	P003	SOFT IRON	S3351P064
4	NEC	WELDING ROD	B50QEL100	AWS/ASTM E-308	
5	NEC	PAINT-RED LEAD	F50QE7E		
6	2	CENTRE PLUGS FOR SHAFT MACHINING	SHOP STD.	BC210H H.T.B	250-275 B.H.N
7	1	PIN	P007	BC732B STN.ST.420T	

NORTHERN CANADA POWER COMM.
AISHIHIK RIVER POWER DEVELOPMENT
GENERATORS & ACCESSORIES



CANADIAN GENERAL ELECTRIC Co — 292D653AL

TITLE: GENERATOR OUTLINE

FIRST MADE FOR

MACHINE	TYPE	CLASS	FORM	P.F.	R.P.M.	VOLTS	REQ'N.	E.N.	PT.
GENERATOR	ATI	10-15600	W	·9	720	13800	9280-788	525L439	1
EXCITER	EV	4-57KW	—	—	720	85	9280-788-2	101230	1

TO BE NOTED BY PURCHASER

(1) REFER TO CONTRACT FOR MATERIAL TO BE SUPPLIED BY C.G.E. CO. THE AMOUNT OF SUCH MATERIAL IS NOT INCREASED BY ANYTHING SHOWN ON THIS DRAWING.

(2) GENERATOR HALF OF COUPLING GUARD SUPPLIED BY C.G.E. Co. TURBINE HALF OF COUPLING GUARD SUPPLIED BY D.E.W.

(3) COUPLING STUDS, REAMER, DRILLING TEMPLATE AND PIN GAUGE FOR SPIGOT SUPPLIED BY TURBINE MANUFACTURER

(4) COMBINED BRAKES & JACKS FOR ROTATING UNIT. SUPPLIED BY CGE CO.

(5) ERECTION & MAINTENANCE MANUAL — — — PGEI-10154

(6) SHIPPING DIMENSIONS OF MAJOR COMPONENTS — — — 704C687AE

(7) LIFTING CLEARANCES. WEIGHTS & DEVICES — — — 761D201AK

(8) A. WEIGHT OF ROTATING PARTS. GENERATOR. EXCITER — — — 76,600 LB
B. WEIGHT OF TURBINE SHAFT & RUNNER — — — 8,100 LB
C. HYDRAULIC THRUST * — — — 50,000 LB

(9) MAIN BRACKET DEFLECTION DUE TO WEIGHT OF
A. GENERATOR ROTOR — — — 0·0261 (·66mm)
B. GENERATOR ROTOR. TURBINE SHAFT & RUNNER — — — 0·0289 (·73mm)
C. GENERATOR ROTOR. TURBINE SHAFT & RUNNER. & HYDRAULIC THRUST. — 0·0495 (1·26mm)

(10) A. TURBINE MANUFACTURER TO ALLOW MINIMUM VERTICAL UPLIFT OF * FOR GENERATOR BEARING SERVICING.
B. TURBINE MANUFACTURER TO LIMIT VERTICAL UPLIFT TO A MAXIMUM OF *
C. VERTICAL CLEARANCES IN GENERATOR BEARINGS, SEALS & BRUSH RIGGING WILL BE * AND WILL BE CHECKED AT ASSEMBLY AND OVERHAULS.
*0.375 (9.52mm)

(11) REFERENCE DRAWINGS - GENERAL
CROSS SECTION ASSEMBLY — — — 591E106HM
FOUNDATION PLAN — — — 292D620CR
GENERATOR HOUSING ASSEMBLY — — — 292D611BK
LOCATION OF LEADS — — — 912D600AN
SCHEMATIC DIAGRAM OF MACHINE WIRING — — — 761D205CA
SCHEMATIC DIAGRAM OF CABINET WIRING — — — 767D230AB
SURFACE AIR COOLER PIPING — — — 292D660FL
AIR. OIL. WATER & FIRE PROTECTION PIPING. — — — 292D660FM
THRUST & GUIDE BEARING ASSEMBLY — — — 591E128AR
GUIDE BEARING ASSEMBLY — — — 591E128AS

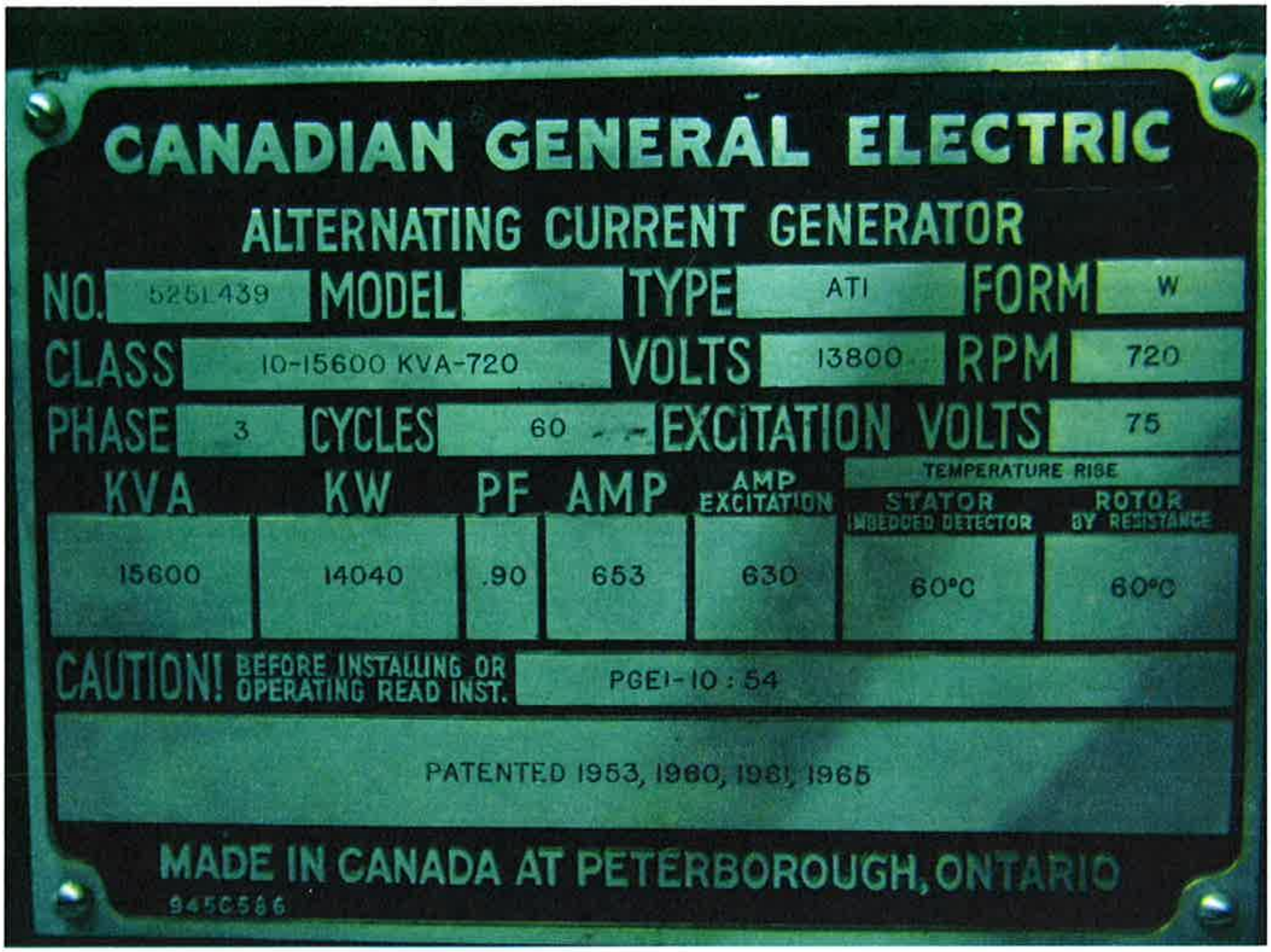
REVISIONS: COMPLETED RK — PRINTS: 24

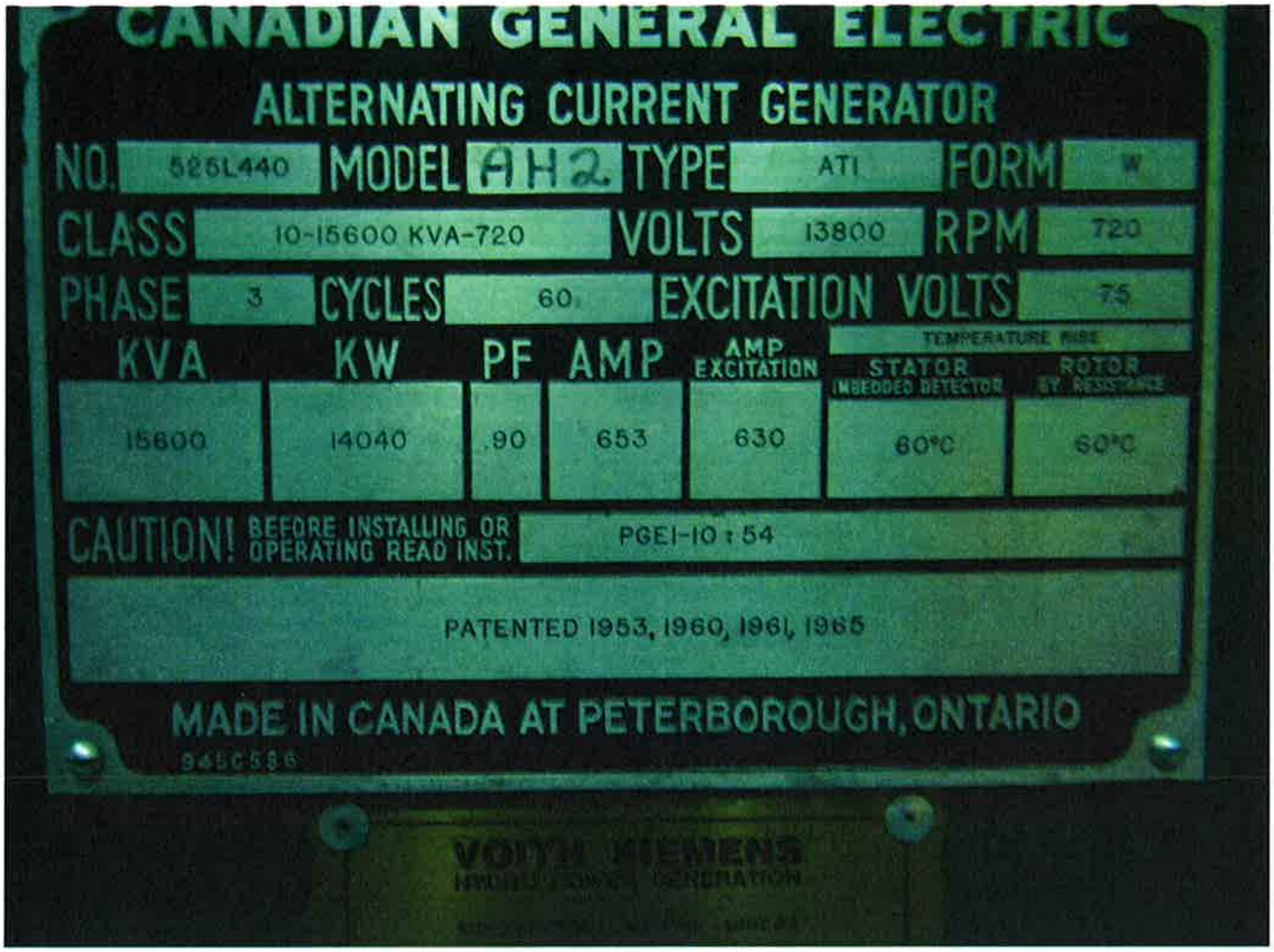
LARGE GENERATOR
PETERBOROUGH, CANADA WORKS
292D653AL

1188-5106 - D61

APPENDIX B

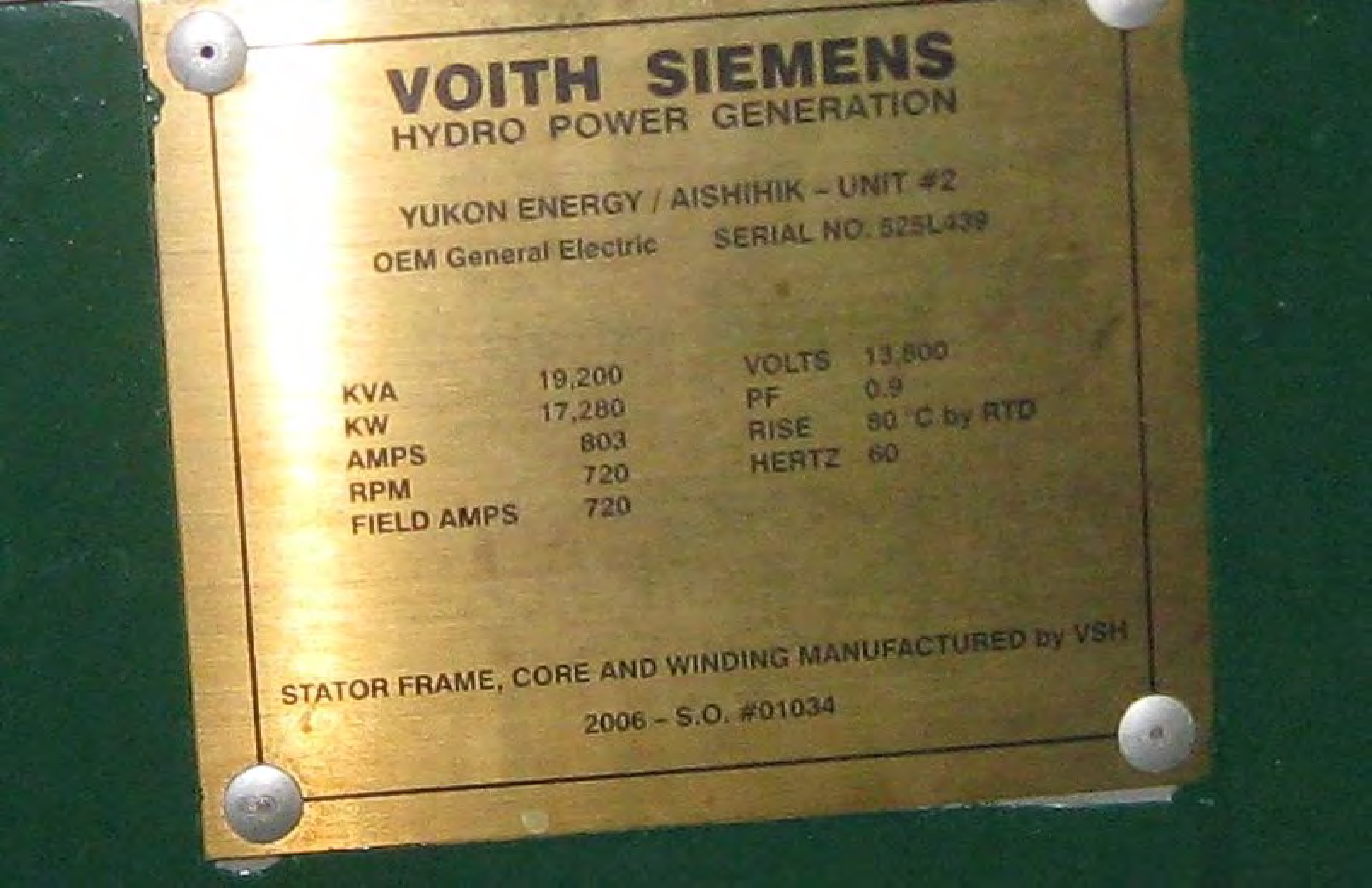
ORIGINAL GENERATOR NAMEPLATES

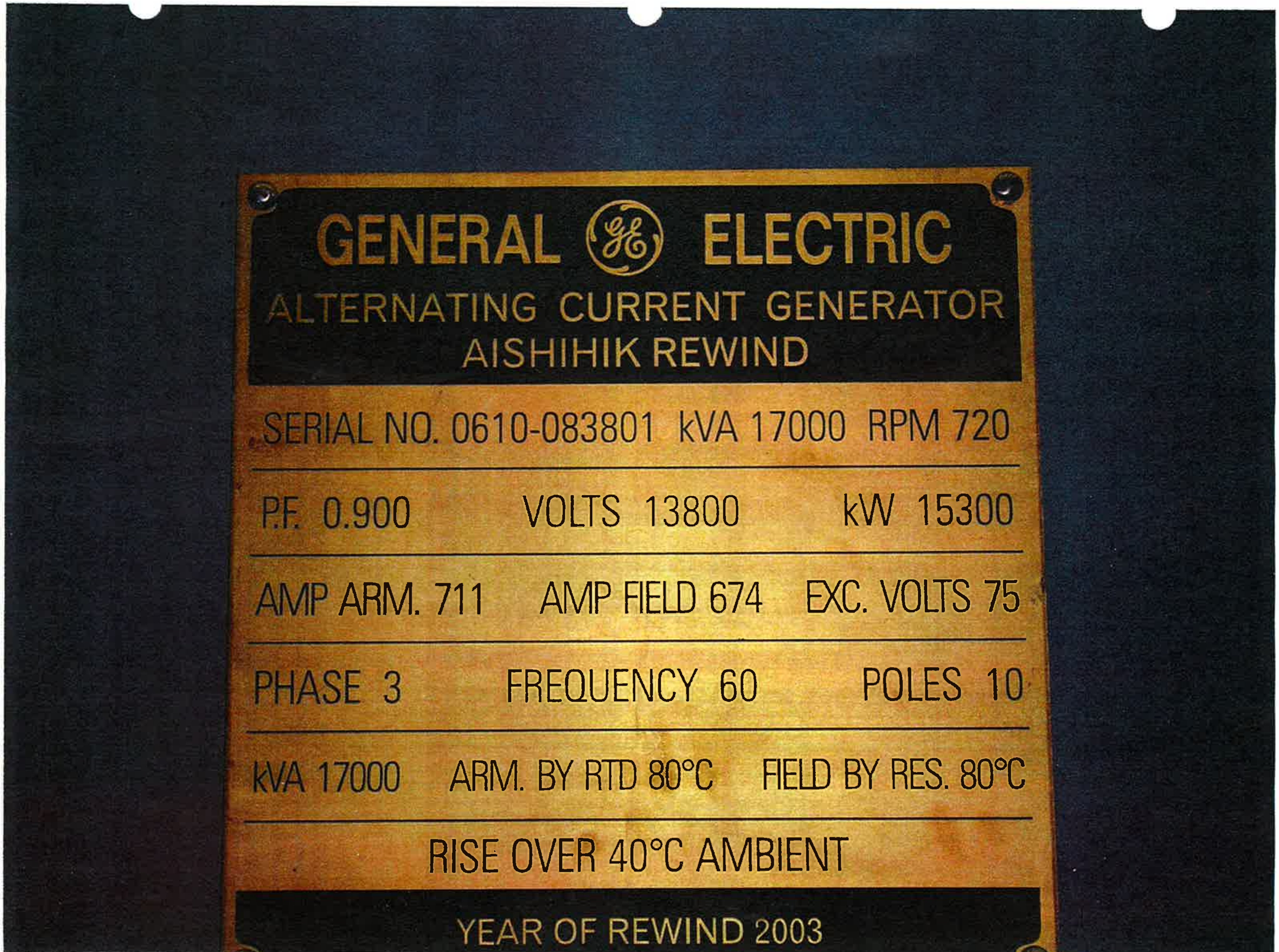

CANADIAN GENERAL ELECTRIC
ALTERNATING CURRENT GENERATOR
NO. 5251439 MODEL TYPE ATI FORM W
CLASS 10-15600 KVA-720 VOLTS 13800 RPM 720
PHASE 3 CYCLES 60 EXCITATION VOLTS 75
KVA KW PF AMP AMP EXCITATION
TEMPERATURE RISE
STATOR IMBEDDED DETECTOR
ROTOR BY RESISTANCE
15600 14040 .90 653 630 60°C 60°C
CAUTION! BEFORE INSTALLING OR OPERATING READ INST. PGEI-10:54
PATENTED 1953, 1960, 1961, 1965
MADE IN CANADA AT PETERBOROUGH, ONTARIO
945C586


CANADIAN GENERAL ELECTRIC
ALTERNATING CURRENT GENERATOR
NO. 525L440 MODEL AH2 TYPE ATI FORM W
CLASS 10-15600 KVA-720 VOLTS 13800 RPM 720
PHASE 3 CYCLES 60 EXCITATION VOLTS 75
KVA 15600
KW 14040
PF .90
AMP 653
AMP EXCITATION 630
TEMPERATURE RISE
STATOR IMBEDDED DETECTOR 60°C
ROTOR BY RESISTANCE 60°C
CAUTION! BEFORE INSTALLING OR OPERATING READ INST. PGEI-10:54
PATENTED 1953, 1960, 1961, 1965
MADE IN CANADA AT PETERBOROUGH, ONTARIO

APPENDIX C

REWIND GENERATOR NAMEPLATES


VOITH SIEMENS
HYDRO POWER GENERATION
YUKON ENERGY / AISHIHIK - UNIT #2
OEM General Electric
SERIAL NO.
KVA 19,200
KW 17,280
AMPS 803
RPM 720
FIELD AMPS 720
VOLTS 13,800
PF 0.9
RISE 80 °C by RTD
HERTZ 60
STATOR FRAME, CORE AND WINDING MANUFACTURED by VSH
2006 - S.O. #01034


GENERAL ELECTRIC
ALTERNATING CURRENT GENERATOR
AISHIHIK REWIND
SERIAL NO. 0610-083801 kVA 17000 RPM 720
P.F. 0.900 VOLTS 13800 kW 15300
AMP ARM. 711 AMP FIELD 674 EXC. VOLTS 75
PHASE 3 FREQUENCY 60 POLES 10
kVA 17000 ARM. BY RTD 80°C FIELD BY RES. 80°C
RISE OVER 40°C AMBIENT
YEAR OF REWIND 2003

APPENDIX B-2

ALSTOM PROPOSAL

1079, rue Daigneault Granby (Québec) J2J 2S4
Téléphone: 450-372-0755 Télécopie: 450-372-1316
24/7 Emergency service line : 1 855 522-0755
service.canada.smallhvdro@alstom.com

March 10th , 2015

Client :
KGS Group , Yukon Energy
Joel Lambert P.Eng.
3rd floor
865 Waverley Street
Winnipeg, Manitoba,
R3T 5P4, Canada

Site address:
Aishihik Generating Station
Yukon Territories, Canada

Telephone : 204-896-1209

E-Mail : jlambert@kgsgroup.com

Project description: Potential Runner Upgrade Request For Information 14-1404-004

Our reference: OB-Yukon Energy Aishihik Generating Station

We are pleased to submit our budgetary proposal for the supplies and works for Aishihik Generating Station runner upgrade.

At this stage, this budgetary proposal gives a preliminary indication of the conditions under which we could perform the works and DOES NOT CONSTITUTE A BINDING OFFER. Alstom reserves the right to alter any aspect of this budgetary proposal, including the pricing information.

Nevertheless we trust the information provided is sufficiently detailed to enable you to assess the benefits which you can obtain from Alstom and we confirm our keen interest in working with you.

We remain at your disposal to further discuss the contents of our budgetary proposal and to offer you a firm proposal with definitive prices, price escalation details, as well as full terms and conditions in the event that this project goes forward.

Best regards

Alex Viens 450-372-0755 ext 289

Alstom is please to respond to "*Aishihik Generating Station Potential Runner Upgrade, Request for Information, Draft revA*" 14-1404-004 to estimate the turbine performances with a new runner.

Based on the information provided by KGS for Yukon Energy, Alstom understand that the power plant has currently 3 units having the following characteristics:

Unit 1	15 MW vertical Francis runner (1972), net head= 180 m, generator rewound in 2003 to 17 000 kVA
Unit 2	15 MW vertical Francis runner (1972), net head= 180 m, generator rewound in 2006 to 19200 kVA
Unit 3	7 MW horizontal Francis runner (2011)

KGS is asked in the RFI to investigate the refurbishment of unit 2. The hydraulic characteristics of unit 2 are the following:

Original Equipment Manufacturer	Dominion Engineering Works
Rated net head:	180.4 m
Rated discharge (per unit):	9.72 m3/s *
Synchronous Speed	720 RPM
Runaway speed	1330 RPM
Nb of stay vanes	10
Nb of wicket gates	20
Nb of runner blades	15
Runner exit diameter	1016 mm
Distributor height (estimated)	218 mm
Distributor centerline elevation	715.52 m
Tailwater level (normal)	721.4 m

*The new runner cannot use more flow than 9.72 m^3/s as there is an evacuation tunnel in which the water is flowing and this tunnel cannot be more filled than now.

Alstom has studied the replacement of the runner of unit 2 and provides in this document expected performances for the rated net head of 180.4 m. Alstom has more than 100 years in hydroelectric runner design with a huge selection of projects realized worldwide. Francis, Kaplan, Pelton and Bulbs hydroelectric turbines are designed and manufactured every day 24h/day by Alstom employees all around the Globe. Vertical Francis runners represent an important part of Alstom Hydro.

Alstom takes advantage of its past experiences for the design of new runners. Indeed, the design process is based on the selection of an existing reference from which adaptations/changes are applied to reflect the situation of the turbine to refurbish. All parts of the turbines are studied, from the spiral case inlet up to the draft tube outlet. Calculations of the fluid flow with the use of computers (CFD) are part of the normal design process. For the present budgetary proposal, the expected performances were estimated using the reference Alstom runner shown on the image in Figure 1. Adaptations and changes to the chosen Alstom reference to fit Aishihik's configuration were done relying on analytic relations and experience.

Alstom has selected a reference which has a very good cavitation behavior, a high efficiency, a runaway speed close to 1330 RPM and acceptable mechanical static stresses at synchronous speed. As seen in the figure, the distributor height of the reference (in blue) is higher than Aishihik's distributor height. Alstom proposes for Aishihik a runner with the same distributor height as the current distributor height and the shift in performance induced by this change of height is already taken into account. The main characteristics of the proposed runner are given in Table 1 below.

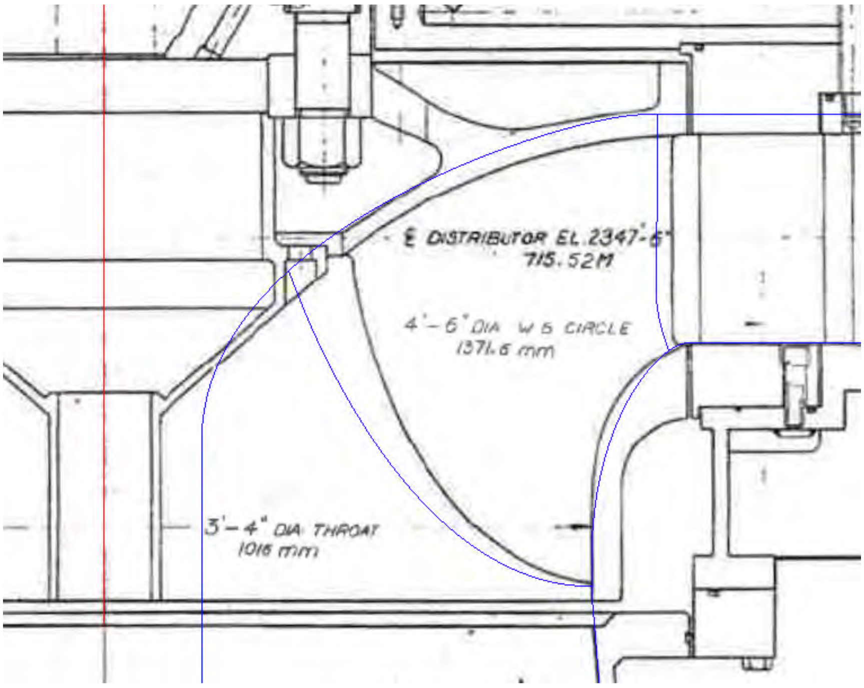


Figure 1 : Alstom reference (in blue), Aishihik in black

Table 1: Main characteristics of the proposed runner

Nb of blades	15
Distributor height	218 mm
Exit diameter	1016 mm

The proposed runner would be made from a forged martensitic stainless steel ingot. After removal of steel by machining, the final shape would be obtained. As the runner is not obtained from a casting, the numerous metal defects generally obtained from cast parts would not be found. Moreover, the mechanical solidity of the runner would be further enhanced as no welds would be done, resulting a high quality runner. Runners could be delivered within 9-10 months with this industrial scheme.

Alstom is currently manufacturing runners for Soo River G.S, a project similar to Aishihik . Dimensions of both runners are very close to each other, Figure 2 allows a better comparison of both runners. On this figure, the Soo River runner is pictured at the outlet diameter of the Aishihik runner. The outlet diameter of Soo River is 1100 mm, which is very close to the outlet diameter of the Aishihik runner. As it is seen, dimensions and overall shape are quite close to each other.

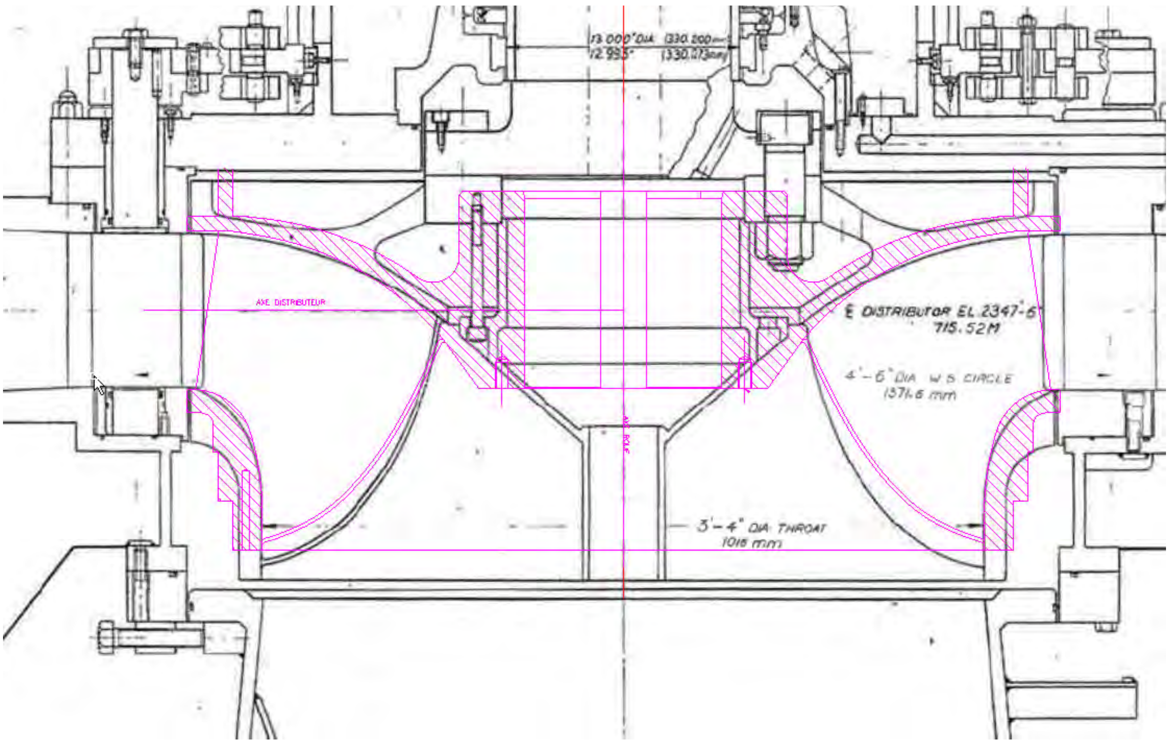


Figure 2: Comparison of Aishihik runner with Soo River runner
(Soo river in purple, Aishihik in black)

Estimation of the expected performances at Hnet=180.4 m is presented below in Figure 3. The green curve is the expected efficiency whereas the blue curve is the expected turbine power. A tailwater level of 721.4 m is assumed at this point. As mentioned earlier, the discharge cannot exceed 9.72 m^3/s. This is represented by the vertical red line. At this maximum discharge, the expected power is 16.1 MW and the efficiency is 93.5%. The peak efficiency at this head is expected to be obtained at roughly 85% of the maximum discharge, i.e. at 8.4 m^3/s.

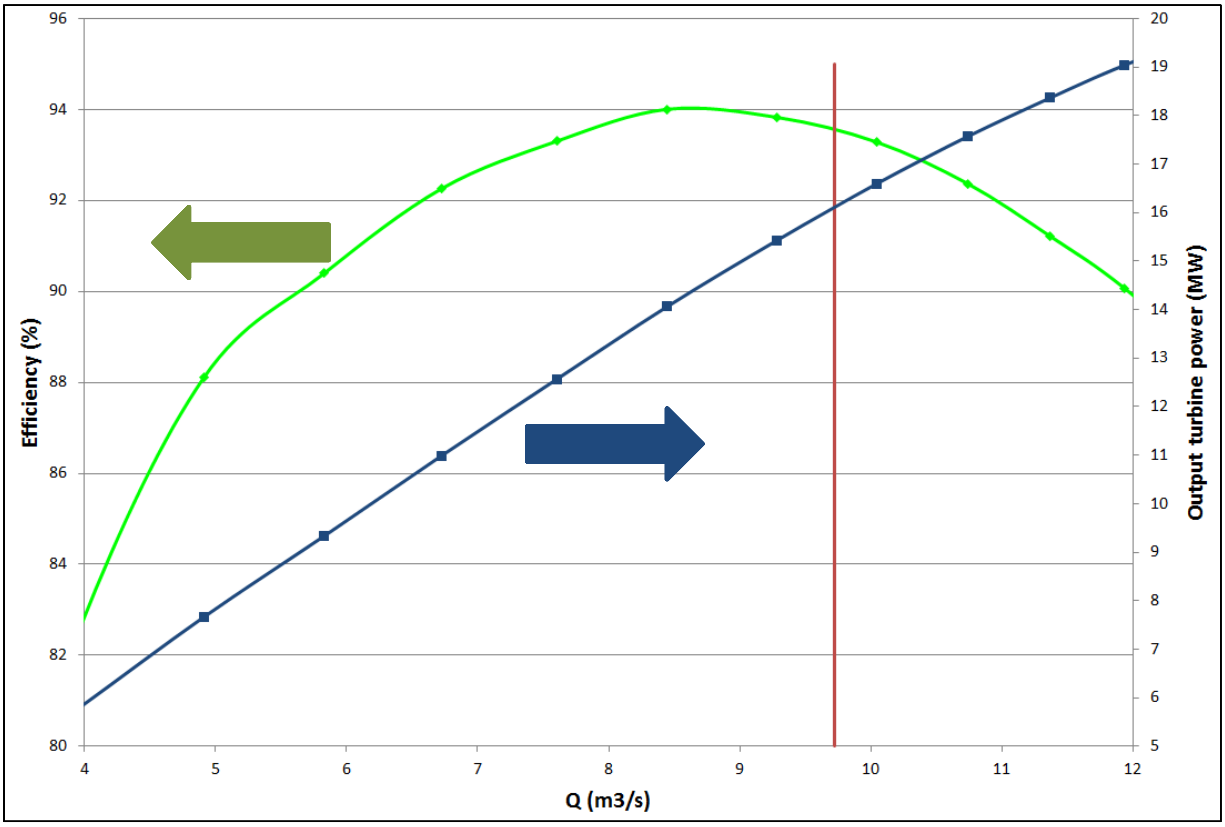


Figure 3: Expected performance for Hnet = 180.4 m and at tailwater level = 721.4 m.

The Figure 3 shows expected efficiency and power as single lines. However, at this stage of the process, a non-negligible uncertainty exists and as a consequence the efficiency line should be viewed rather as band with +0.5/-1% limits. The uncertainty comes from, on one part, the incomplete information received by Alstom.

Alstom will require some more information atop of the information already given to reduce the uncertainty. Amongst the additional required information, there are:

- The maximum and minimum net head. This information is necessary to ascertain that there is no cavitation induced at leading edge due to a net head not taken into account;

- The position of the pressure taps in the draft tube and spiral casing to measure the net head. In the drawings supplied, the draft tube appears to be much longer than Alstom's existing draft tube. This might just be wrongly assumed as the position of the end of the draft tube is not indicated;

- The installation/dismounting of the runner. Alstom has already made in the recent past another Francis runner whose shape in the meridian plane is even closer to Aishihik's shape than the shape of the first reference indicated above. The efficiency, cavitation, stability, mechanical and runaway behaviour of this runner is also very good. Its stability behavior for instance, is better than the stability behavior of the reference chosen to construct the expected performances. For this reason it seems that this second reference is also a very good starting point for Aishihik. One drawback however is the lower exit altitude of the blade near the crown. It is understood that the current runner may be dismantled from the shaft from underneath by first removing the runner cone and then removing the coupling nuts connecting the runner to the shaft. If dismantling from below is not required or unfrequently expected, we recommend indicating it in the RFQ. We will have to choose between keeping this second reference and modifying the shaft (for instance in order to have a sole central bolt to couple the runner to the shaft) and keeping the first reference identified whose trailing edge is at a higher altitude (closer to Aishihik current runner). The final choice will be a tradeoff amongst various criteria: price, stability, efficiency level, cavitation behaviour, lead time, etc. Currently there is not enough information within the KGS's document to make a choice. The evaluation criteria would be helpful in optimizing the proposed solution.

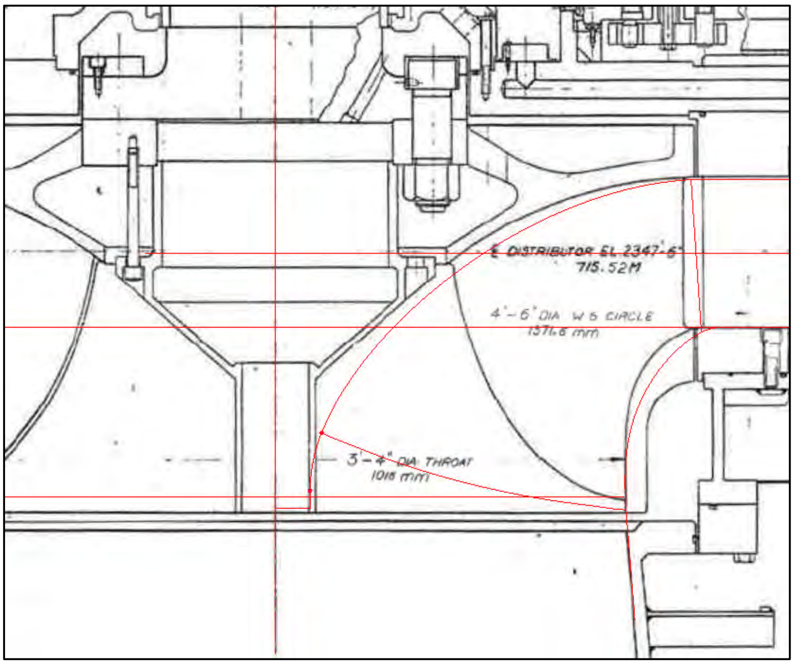


Figure 4: Alstom second possible reference for the Aishihik project

- Alstom will need drawings of gates and vanes with dimensions. For the purpose of the current performance estimate, rapid approximations were done. Refinement is required to narrow down the uncertainty;
- Volumetric losses through labyrinths for this head are important, Alstom needs to evaluate at best the expected leakage flow. The drawings supplied allowed us to see that the current configuration has both band and crown seals lengths shorter than our internal standards. Also, the radial gaps may be important and as a result the leakage flow is likely to be important. Further studies to determine if the current seal design is kept will need to be done following the reception of more complete information.

Alstom has already performed some rapid studies of the other components of the Aishihik turbine and brings attention to a potential refurbishment of the wicket gates. For instance, having gates cambered on the “opposite side” could give an estimated 0.4% to 0.8% gain in efficiency, see Figure 5 below. The efficiency gain would come from the greater inter-gates space which would allow a reduction of the water velocity and accompanying losses.

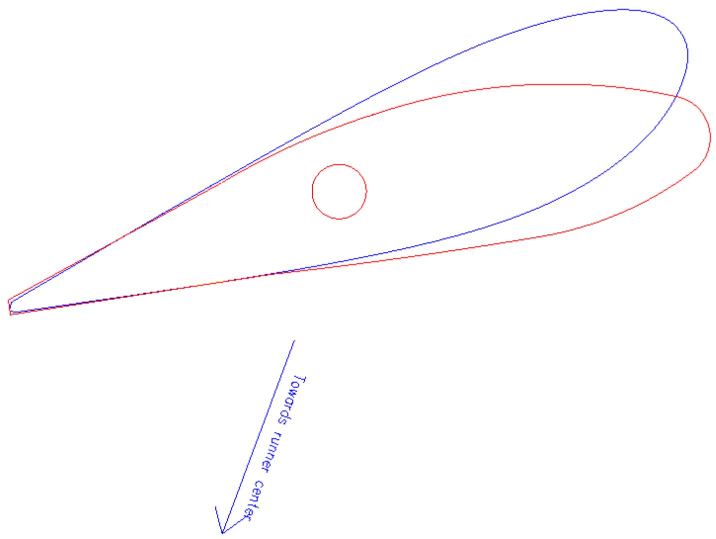


Figure 5: Comparison of the Aishihik gate (red) and a cambered gate (blue)

Alstom has a great expertise in vertical Francis turbines and we feel that our knowledge would be highly valuable for the Aishihik project. The preliminary studies performed indicate that at least two existing references would fit within Aishihik’s configuration with minor adjustments required. More complete information is required to make a final choice between the two references. In both cases the proposed efficiency would provide an increase of the maximum power. As instance, using reference #1, we estimated that the maximum power would increase from the actual 15 MW to an expected 16.1 MW with the same amount of water of 9.72 m^3/s.

Regarding the axial thrust, further studies are required. Knowing the actual capacity of the thrust bearing would be useful to make an evaluation/verification.

Indeed, following the reception of complementary information during the firm RFQ, Alstom will perform further studies to ascertain the current assumptions and to propose a new runner and related components with the best characteristics for Aishihik power plant.

<u>Work description</u>

Alstom based their budget estimation on similar projects and on drawings supplied with the RFI, more details or a site visit will be necessary to firm up the budgets. For RFI purpose we have used a schedule of 6-1 days - 12/hrs per day for site works, it is considered that workers have to travel Haines Junction every days.

For the budget purpose we have calculated replacement parts directly related to the runner replacement, if other option are valuable to Yukon Energy we will be please to quote accordingly. Alstom also suggest to perform a condition assessment of the remaining turbine components this may identify if other components need to be replaced.

Table 1 – Site scope of work included in the budgetary price of **$250 500.00**

Scope of work	**Included** ✓
1. Turbine runner replacement.	
a) EHS site analyses.	✓
b) Turbine disassembly	✓
c) Parts inspections and recommandations.	✓
d) New runner and parts installation	✓
e) Turbine reassembly	✓
f) Commissioning	✓

Table 2 –Engineering scope of work included in the budgetary price of **$106 500.00**

Scope of work	**Included** ✓
2. Turbine Runner engineering	
a) Study for an adaptation of an Alstom runner profile to Aishihik turbine distributor and shaft.	✓
b) Drawings for fixed labyrinths adaptation to Alstom runner.	✓
c) Commissioning report.	✓

Table 3 – Parts for the project for a budgetary price of **$386 500.00**

Parts for project	**Quantity**	**Parts total price**
3. Replacement parts		
a) 1 Runner, cone and bolts.	1	$343 500.00
b) 1 Fixed labyrinths set and hardware.	2	$43 000.00

Included in this budgetary estimate

- 1 mobilization and 1 demobilization of ALSTOM SITCA INC;
- Transport of the parts to Aishihik Generating Station;
- Work and parts described in tables 1, 2 & 3;
- Standard required tooling;
- Travelling, meals and lodging expenses for required labour;
- Field report;

Excluded from this estimate

- Mobilization and demobilization of ALSTOM SITCA INC. labour and tooling in case of work interruption by others;
- Repairs, modifications, machining and all related costs deemed necessary for non-conform equipment and/or drawings;
- All damages, delays, or inconveniences resulting from work performed by other contractors, sub-contractors or employees provided by the Client;
- Special tools and lifting device required for this contract;
- Procedure, equipment, labour and costs associated to work in confined space;
- Dewatering and refilling of the power station unit(s);
- Overhead crane services;
- Any NDT testing;
- Absolute turbine effiency.
- Alignment correction work;
- All machining work (of other turbine parts and all generator parts) and the related costs;
- Waiting time and related costs;
- GST and PST

The Client also agrees to provide the following

- Procedure and lockout of equipment impacted by this contract;
- Adequately maintained access to reach working site allowing for equipment to be delivered by vehicle, for the duration of the contract;
- Sufficient opening (door, roof) to access the equipment;
- An easily accessible storing area on site for maritime-type containers;
- Containers for waste (components, waste oil and grease, soiled cloth, etc.) ensuing from ALSTOM SITCA INC. work and will be responsible for its disposal;
- Electrical and pneumatic power required for this contract;
- Asbestos-free environment;
- Valid inspection certificate for overhead crane and/or all permanent lifting devices on site;
- Adequate on-site facilities including but not limited to washrooms, lunchroom and office area;
- Scaffolding including drawings and installation procedure certified by an engineer;
- All drawings, maintenance manuals, procedures and specifications in his possession, at ALSTOM SITCA INC. request.

APPENDIX B-3

NORCAN PROPOSAL

March 09, 2015

Joel Lambert, P. Eng.
KGS Group
3rd Floor
865 Waverly Street
Winnipeg, Ontario
R3T 5P4
(T) 204-896-1209
(C) 204-770-6411
jlambert@kgsgroup.com

Ref: Budget quote for the manufacturing of one (1) replacement Francis Runner for Aishihik Generating Station. Norcan Reference #15-2215 Rev 0

Dear Joel,

Norcan Hydraulic Turbine Inc. is pleased to submit the following budget proposal for the manufacturing and installation of one replacement Francis Runner for Aishihik Generating Station Unit 2 based on the supplied data on February 17, 2015 file no. 14-1404-004.

Attached, please find a general summary, pricing and detailed scope of supply. I hope this proposal meets your requirements.

If you have any questions or require clarifications, please let us know.

Sincerely,
Norcan Hydraulic Turbine Inc.

____

Henk de Ridder
Norcan Hydraulic Turbine Inc.
T613-257-4755 ext 11
F613-257-4215

TABLE OF CONTENTS

1.0 GENERAL SUMMARY

Pricing

Item	General Description	Qty	Amount (CAD/Dollar)
Equipment Supply	Manufacture one (1) 40.0" Dt Francis Runner.		(Itemized costs shall equal below sum):
	40.0" Dt Francis Runners	1 each	$268,033.00
	Delivery and Installation	1 each	$ 205,140.00
	Replacement Coupling Bolts	1 set	$ 8,600.00
	Blade Templates	1 set	$ 15,500.00
	Taxes *Not Included*		EXTRA if applicable

Notes

- Taxes are not included.
- Delivery time of 11-12 months from reception of P.O., receipt of down payment.
- Warranty for two (2) years from commissioning or thirty (30) months after delivery, whichever is sooner.
- Quote valid for 60 days.
- Quote based on existing runner removal from below. Existing removal equipment is present at site.
- Quote based on Norcan modifying existing runner removal and installation equipment to suit new runner.

2.0 DETAILED SCOPE OF SUPPLY

40.0” Dt Francis Runner 15 blade

Material
The Crown, Blades and Band components will be of cast ASTM A743 CA6NM or forged of A182 F6NM stainless steel or approved equivalent.

Construction
The Runners will be fabricated, machined, and ground in accordance with Norcan manufacturing design standards and tolerances stated in DWI050-Rev 3. The Runners will meet or exceed IEC standard publication 60193 1999-11.

For fabrication, the Crown and Band will be cast and/or forged and fully pre-machined. The Blades will be cast, pre-machined and hand ground. The Blades will be welded to the Crown and Band as follows:

The first 25% of the Blade length at the inlet and discharge will have 100% penetration. The remaining length of the Blade will have 1/3 of the Blade thickness V weld per side. A concave fillet weld will finish the Blade to Crown and Blade to Band. The fillet weld will be hand ground to the required finish with no permissible undercuts. The root weld filler material will be AWS No. 309 and the finish passes “cap” will be AWS No. E410 Ni Mo. All welders are qualified to QW-200.1, Section IX, ASME Boiler and Pressure Vessel Code or CSA W47.1. (Ref. DWI-059, DWI-013)

The Runner minimum finish will be as follows:

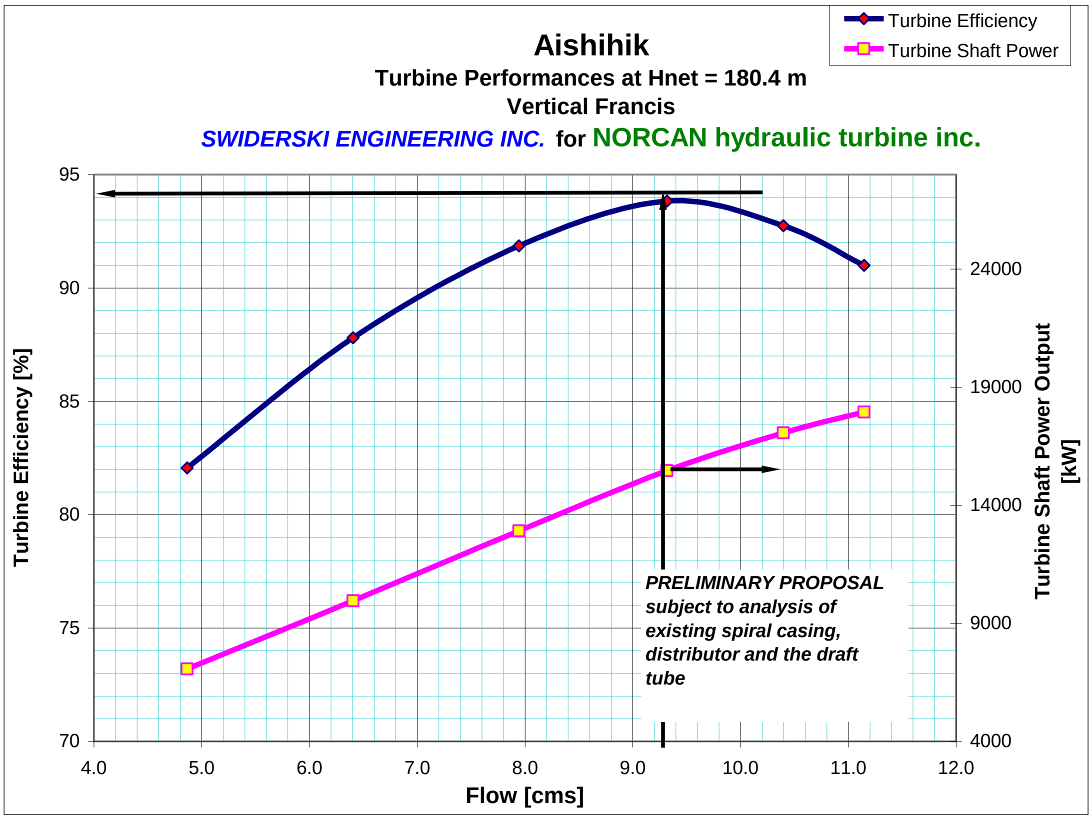
Water passages		
	Upper two thirds of the Blade	125 finish
	Lower one third of the Blade	63 finish
Runner		
	Outside finish all over with axis	250 finish
	Seal surfaces	125 finish
	All other surfaces	125 finish

Balancing
The Runner will be dynamically balanced to meet or exceed the standards of ISO 1940 G2.5. Weights shall be added or removed in such a manner that there will be no projections or depressions from the finished surfaces. No eccentric machining will be performed.

3.0 PRELIMINARY PERFORMANCE

Hnet =	591.7	ft	=	180.40	m
Dth (nom) =	40.0	in	=	1.016	m
n =	720	rpm			

Turbine Efficiency	Flow	Flow	Turbine Shaft Power	Turbine Shaft Power	
[%]	[cms]	[cfs]	[kW]	[hp]	
82.06	4.87	171.7	7065	9474	
87.80	6.41	226.0	9950	13343	
91.86	7.94	280.3	12911	17314	
93.83	9.32	328.8	15466	20741	
92.74	10.40	366.9	17061	22879	
91.00	**11.15**	**393.4**	**17946**	**24066**	CAVITATION LIMIT



Performance above is based on best guess based on data supplied.

Analysis of existing hydraulic outline will be required to determine best runner fit using CFD.

Operational history will be required of existing performance of present runner.

Runaway speed and maximum thrust to be supplied upon completion of CFD and engineering.

4.0 COMMERCIAL TERMS

Delivery

Delivery will be 11-12 months after receipt of the contract, receipt of the down payment and supplied production drawings. All delivery times start from the date of acceptance of the order and receipt of the down payment.

Installation

Installation will be 6-8 weeks from time runner is delivered to site.

Project Schedule

A detailed schedule to be presented four (4) weeks after the award of the contract.

Payment Schedule

The following terms of Payment shall apply:

20% Down payment with the order.
10% Completion and approval manufacturing drawings and inspection test plan.
20% On receipt of construction materials (Castings, Forgings).
15% Completion of Runner fabrication.
15% Manufacturing complete, Runner ready to ship
10% Mobalized and on site old runner removed
10% New runner installed and commissioned

*Payment net 30 days from invoice issue date

5.0 GENERAL CONDITIONS OF CONTRACT

(Note: Any reference to "Norcan" is a reference to Norcan Hydraulic Turbine Inc.)

Indemnification

Norcan shall indemnify and hold harmless the Customer against all claims, demands, losses, damages and costs, all as finally judicially determined, excluding loss of profit and any punitive, exemplary, indirect, consequential or special losses or damages, whether in contract or in tort or otherwise, by third parties where such claims, demands, losses, damages and costs are:

(i) attributable to bodily injury, sickness, disease, or death, or to injury to or destruction of tangible property;

(ii) caused by negligent acts or omissions of Norcan or anyone for whose acts Norcan may be liable; and

(iii) made in writing within a period of two years from the date of delivery to the Customer of each Norcan supplied equipment.

The Customer expressly waives the right to indemnity for claims other than those stated above.

The obligations of Norcan to indemnify hereunder shall be limited to an aggregate amount no greater than the amount payable to Norcan under this Contract hereinafter referred to as the "total Contract price".

The Customer shall indemnify and hold harmless Norcan and Norcan's agents and employees from and against claims, demands, losses, costs, damages, actions, suits or proceedings arising out of Norcan's performance of the work under this Contract which are attributable to a lack of or defect in title or an alleged lack of or defect in title to the place where the Norcan supplied equipment is delivered and, or installed.

Force Majeure

Any delay or failure in the performance by Norcan hereunder shall be excused and no liability whatsoever will rest with Norcan where such delay or failure is caused by Force Majeure. For the purposes of this Agreement, Force Majeure shall mean an event or cause beyond Norcan's control and shall include, but is not limited to, acts of God, riots, wars, insurrection, acts of public enemy, sabotage, terrorism, vandalism, embargo, national emergency, accident, restraint of government, governmental acts, fires, floods and other natural disasters, explosions, severe weather including hurricanes and storms, injunctions, labour strikes or inability to obtain required labour, materials or manufacturing facilities from normal sources, acts of a customer and/or owner, wrecks or delays in transportation.

Warranty

The warranty period with respect to this Contract terminates on a date which is the sooner of:

(i) that day which is 12 months from the completion of the initial test runs of the installed Norcan equipment; and,

(ii) that day which is 18 months from the date of delivery of the Norcan supplied equipment.

Norcan shall be responsible for the proper performance of its work and for the work of those for whose acts Norcan may be liable to the extent that this Contract and related documents permits such performance, save that it is understood and agreed that:

(i) Norcan accepts no liability for the design of civil works, intake and trash racks, powerhouse or foundation stability, tail race or other associated water passages or for work improperly done by others, nor does Norcan accept liability for lack of or errors in water availability, flow duration studies or the condition of the water flowing into the turbine. Furthermore, Norcan does not accept liability for damage to the turbine components due to debris (rock metal, lumber, etc.) passing through the turbine intake;

(ii) Norcan shall not be liable to remedy defects or deficiencies which have arisen as a result of the acts or omissions of those over whom Norcan does not exercise control;

(iii) This warranty is void and unenforceable unless Norcan is afforded the opportunity to complete a final inspection of the completed work within **14** (fourteen) days of installation of the Norcan supplied equipment.

Subject to the provisions of this clause Norcan shall correct promptly, at Norcan's expense, defects and deficiencies in its work which appear prior to and during the warranty period specified herein.

The Customer shall promptly give Norcan notice in writing of observed defects and deficiencies that occurred during the warranty period and Norcan shall be immediately afforded the opportunity to inspect and observe the alleged defects and deficiencies.

Where Norcan fails to correct defects or deficiencies brought to its attention for which it would otherwise be liable, it shall be liable to the Customer to pay for the reasonable costs incurred by the Customer in correcting such defects or deficiencies.

It is understood and agreed that Norcan's liability under this warranty is limited to an aggregate amount which shall not exceed 10 percent (10%) of the total Contract price.

Damages

It is agreed and understood that should turbine performance be within three percent (3%) of anticipated output, such shall not be considered a defect or deficiency in the work of Norcan and for the purposes of this Contract shall be considered to be an acceptable outcome of the performance of the work by Norcan.

Norcan shall in no event be responsible for damages for loss of profit and other punitive, exemplary, indirect, consequential or special losses or damages, whether in contract or in tort or otherwise, including, without limitation, any business or commercial losses.

To the extent that Norcan is liable for damages as a result of the performance of its work or the performance of the work by those for whom it is liable, such damages shall not exceed, in the aggregate, an amount equal to 10 percent (10%) of the total Contract price.

The above is understood and agreed to by the following:

Signed and sealed this _______ day of _______________ 20____.

In the presence of:

(Seal) (Seal)

NORCAN Hydraulic Turbine Inc.

6.0 NORCAN HYDRUALIC TURBINE INC. DIEM RATES AND TERMS.

(for the period of January 01, 2015 to December 31, 2015)

Description	Regular Rate per hour	Overtime per hour	Double time per hour
Turbine Engineering Technician	**$95.00**	**$125.00**	**$155.00**
Supervisor	**$95.00**	**$125.00**	**$155.00**
Turbine mechanic millwright	**$80.00**	**$120.00**	**$140.00**
Engineer	**$160.00**	**$210.00**	**$260.00**
Travel rate	**$60.00**	**$75.00**	**$75.00**
Drafting & Project Management	**$80.00**	**$120.00**	**$140.00**
Shop Machining (CNC)	**$105.00**	**$140.00**	**$170.00**
Shop General Machining	**$75.00**	**$110.00**	**$130.00**
Welder	**$75.00**	**$110.00**	**$130.00**
General Labour	**$55.00**	**$72.00**	**$88.00**
Field Machining: Rates as per equipment requirements			

Note: The above rates are for normal 8 hour days, Monday to Friday (Normal working hours are between 7:00 am to 6:00 pm. A 15% premium will apply to hours outside the normal hours)

Saturday - overtime for first 8 hours - double time
Sunday - double time
Statutory holidays - 2.5 * regular rate

Parts and materials at cost plus 15%

Meals & Accommodation	**$180.00 per day**
Mileage	**85¢ per Km**

General Terms:

1. Daily rates apply from the time the Norcan personnel leave the Office/Shop until their return to the Office/Shop. Should the Norcan personnel start from, return to, or proceed to a point other than the office/shop, charges for travel expenses and per diem rates shall not exceed charges that normally would have been incurred from or to the Office/Shop. Travel time will be charged at the specific base rates for up to a maximum of "8" hours per day for each day of travel.

2. Standby time: The time during which Norcan personnel are available for work, but are unable to do so because of circumstances beyond Norcan's control shall be considered as standby time and billing will be made as follows:
   - At full applicable charges plus expenses for any weekdays (whether at site or not) and for any weekend days or holidays when the Norcan personnel is kept on standby at the jobsite or put on call off-site.

3. Unless otherwise specified and negotiated during the contract, weekdays, weekend, and holidays are defined as follows:
   - Weekdays: Monday through Friday, working days
   - Weekends: Saturday through Sunday
   - Holidays: All recognized days that are celebrated in Canada
   - A Workday is classified as an 8 hour day

4. For out of country work, the weekdays, weekends and holidays must be specified and agreed to during contract negotiation.

5. No additional charges will be made for the use of expendable small tools and test equipment normally carried by Norcan personnel. However, when additional expendable tools or hardware must be purchased for a particular job, then the charge for such tools or hardware will be billed to the customer at cost plus a 15% processing fee.

6. When special equipment is required a rental fee will be charged depending on the type of equipment and the length of time required. The customer will be billed for all special transportation costs plus a 15% processing fee. The customer is responsible for the safe storage at site, the timely return, and overall condition and function of said special equipment.

7. Subcontractors: Labour and material supplied through Norcan will be billed at cost plus a 15% processing fee.

8. The customer shall provide Norcan personnel with free and unobstructed access to the jobsite.

9. The customer shall provide safe and proper working conditions in accordance with all federal, provincial and local laws, rules and regulations.

10. The customer shall provide suitable required power, washroom facilities, and safe storage space for Norcan's equipment.

11. All oil, grease, water, and normal operating items required for the operation of the equipment will be provided by the customer. Disposal of above components is the responsibility of the customer.

12. All required permits and monitoring equipment are the responsibility of the customer

13. <u>Technical Advisory Services:</u>
    These terms and conditions shall apply to Norcan's Technical Advisory Services incidental to the installation, overhaul, inspection, repair, modification or conversion of equipment which is located at the customers and/or owners location. Norcan's Technical Advisory Services function exclusively in an advisory capacity. The equipment, machinery and property shall be at all times in complete care, custody and control of the customer and/or owner. The buyer and/or customer will furnish qualified labour and supervisory personal to perform the required work.

14. <u>Force Majeure:</u>
    Any delay or failure in the performance by Norcan hereunder shall be excused and no liability whatsoever will rest with Norcan where such delay or failure is caused by Force Majeure. For the purposes of this Agreement, Force Majeure shall mean an event or cause beyond Norcan's control and shall include, but is not limited to, acts of God, riots, wars, insurrection, acts of public enemy, sabotage, terrorism, vandalism, embargo, national emergency, accident, restraint of government, governmental acts, fires, floods and other natural disasters, explosions, severe weather including hurricanes and storms, injunctions, labour strikes or inability to obtain required labour, materials or manufacturing facilities from normal sources, acts of a customer and/or owner, wrecks or delays in transportation.

15. <u>Limitation of Liability:</u>
    The remedies of the customer set forth herein are exclusive. The total liability of Norcan with respect to all claims under said services and contract, whether based on the services, contract, indemnity, tort, strict liability, or otherwise shall not exceed the purchase price of the services upon which such liability is based. Norcan shall in no event be liable for any consequential, incidental, or indirect damages arising out of said services (and the performance thereof) or out of any breach thereof, whether or not such loss or damage is based on the services, contract, indemnity, tort, strict liability, or otherwise.

APPENDIX C

ENERGY BENEFIT ANALYSIS

MEMORANDUM

TO: **Dave Brown, P. Eng.**
Joel Lambert, P. Eng.

FROM: **Junying Qu, Ph.D., P. Eng.**
David Hinton, P. Eng.

DATE: **September 10, 2015**

FILE NO: **14-1404-04**

RE: **Aishihik Turbines Uprate Study – Energy Benefits Analysis**

1.0 INTRODUCTION

KGS Group was retained by Yukon Energy Corporation (YEC) to conduct a study into the potential upgrade options of the turbine runners on AH1 and AH2 at the Aishihik Generating Station (AGS). Alstom Power and Norcan Hydraulic Turbine Inc. provided the information for new runners that could be used for the potential upgrades of AH1 and AH2. These vendors will be referred to as Alstom and Norcan hereafter.

To help assess the benefits for the potential upgrades of AH1 and/or AH2 and compare the Alstom and Norcan proposed configurations, a hydro energy benefits analysis was conducted for the following seven scenarios using the YECSIM model.

- Existing condition
- Potential upgrades of AH1 only using the runners provided by Alstom
- Potential upgrades of AH1 only using the runners provided by Norcan
- Potential upgrades of AH2 only using the runners provided by Alstom
- Potential upgrades of AH2 only using the runners provided by Norcan
- Potential upgrades of both AH1 and AH2 using the runners provided by Alstom
- Potential upgrades of both AH1 and AH2 using the runners provided by Norcan

The YECSIM software is a detailed integrated power/water flow model operating on a weekly time step developed by KGS Group for YEC. It can be used for analysis of the operation and future expansion of the YEC electrical generating system including WAF (Whitehorse-Aishihik-Faro) and MD (Mayo-Dawson) systems. This model includes all assumed loads and load profiles, operating characteristics of each system power facility (e.g., unit efficiencies), licensed parameters for each plant as approved or proposed, and desired operating parameters for the system (such as reducing line losses or voltage stability) as well as the hydrological conditions. More information about the model can be found in the YECSIM User's Manual (Ref. 1).

This memorandum documents the detailed of energy benefits analysis for the potential upgrades of AH1 and/or AH2 at AGS.

2.0 TURBINE EFFICIENCY CURVES

For the energy benefits analysis using YECSIM model, the first step is to develop a combined turbine and generator efficiency curve for the entire power plant including AH1, AH2 and AH3 at the AGS for each of those scenarios.

The AGS consists of 3 turbines, including two 15 MW vertical Francis turbines installed originally in 1972 (AH1 and AH2), and a third 7 MW horizontal Francis turbine installed in 2011 (AH3). The two units AH1 and AH2 are very similar mechanically, except AH2 has a greater electrical capacity due to a rewind of the generator in 2006 (Ref. 2). Table 1 shows the unit efficiencies, including both turbine and generator efficiencies for AH1 based on the tests carried out on AH1 by Hatch in 2009 (Ref. 2). The existing AH2 operates similarly to AH1, and is assumed to be equal for this study. Table 2 shows the unit efficiencies for AH3 provided by YEC.

TABLE 1
CALCULATED UNIT EFFICIENCIES FOR THE EXISTING AH1

Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency	Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency	Station Load (kW)	Station Flow (m^3/s)	Unit Efficiency
2000	1.99	54.62	6700	4.61	79.229	11400	7.19	86.85
2100	2.04	55.71	6800	4.66	79.491	11500	7.25	86.93
2200	2.10	56.75	6900	4.72	79.749	11600	7.31	87.01
2300	2.16	57.74	7000	4.77	80.001	11700	7.36	87.08
2400	2.22	58.69	7100	4.82	80.249	11800	7.42	87.16
2500	2.27	59.60	7200	4.88	80.492	11900	7.48	87.23
2600	2.33	60.47	7300	4.93	80.730	12000	7.53	87.30
2700	2.39	61.31	7400	4.98	80.963	12100	7.59	87.37
2800	2.45	62.10	7500	5.04	81.192	12200	7.65	87.43
2900	2.50	62.87	7600	5.09	81.416	12300	7.70	87.50
3000	2.56	63.60	7700	5.15	81.635	12400	7.76	87.56
3100	2.62	64.31	7800	5.20	81.850	12500	7.82	87.62
3200	2.68	64.98	7900	5.25	82.060	12600	7.88	87.68
3300	2.74	65.63	8000	5.31	82.265	12700	7.93	87.73
3400	2.79	66.26	8100	5.36	82.466	12800	7.99	87.79
3500	2.85	66.86	8200	5.42	82.662	12900	8.05	87.84
3600	2.91	67.44	8300	5.47	82.854	13000	8.11	87.88
3700	2.97	68.00	8400	5.52	83.041	13100	8.17	87.93
3800	3.02	68.54	8500	5.58	83.224	13200	8.23	87.97
3900	3.08	69.07	8600	5.63	83.403	13300	8.29	88.01
4000	3.14	69.57	8700	5.69	83.577	13400	8.35	88.04
4100	3.19	70.06	8800	5.74	83.746	13500	8.41	88.07
4200	3.25	70.54	8900	5.80	83.912	13600	8.47	88.10
4300	3.31	71.00	9000	5.85	84.073	13700	8.53	88.12
4400	3.36	71.44	9100	5.91	84.229	13800	8.59	88.14
4500	3.42	71.88	9200	5.96	84.382	13900	8.65	88.14
4600	3.47	72.30	9300	6.02	84.531	14000	8.72	88.15
4700	3.53	72.71	9400	6.07	84.675	14100	8.78	88.14
4800	3.58	73.11	9500	6.13	84.816	14200	8.85	88.13

Station Load (kW)	Station Flow (m³/s)	Unit Efficiency	Station Load (kW)	Station Flow (m³/s)	Unit Efficiency	Station Load (kW)	Station Flow (m³/s)	Unit Efficiency
4900	3.64	73.50	9600	6.18	84.952	14300	8.91	88.11
5000	3.69	73.88	9700	6.24	85.085	14400	8.98	88.08
5100	3.75	74.25	9800	6.30	85.214	14500	9.05	88.04
5200	3.80	74.61	9900	6.35	85.340	14600	9.12	87.99
5300	3.86	74.97	10000	6.41	85.462	14700	9.19	87.92
5400	3.91	75.31	10100	6.46	85.580	14800	9.26	87.85
5500	3.97	75.65	10200	6.52	85.695	14900	9.34	87.76
5600	4.02	75.98	10300	6.57	85.807	15000	9.42	87.65
5700	4.07	76.31	10400	6.63	85.916	15100	9.49	87.53
5800	4.13	76.63	10500	6.69	86.021	15200	9.57	87.39
5900	4.18	76.94	10600	6.74	86.124	15300	9.65	87.22
6000	4.23	77.24	10700	6.80	86.223	15400	9.74	87.04
6100	4.29	77.54	10800	6.86	86.320	15500	9.83	86.84
6200	4.34	77.84	10900	6.91	86.415	15600	9.91	86.61
6300	4.40	78.13	11000	6.97	86.506	15700	10.01	86.35
6400	4.45	78.41	11100	7.02	86.595	15800	10.10	86.07
6500	4.50	78.69	11200	7.08	86.682	15900	10.20	85.76
6600	4.56	78.96	11300	7.14	86.766	16000	10.30	85.41

Notes: Unit efficiencies include both Turbine and Generator efficiencies.

TABLE 2
CALCULATED UNIT EFFICIENCIES FOR THE EXISTING AH3

Station Load (kW)	Station Flow (m³/s)	Unit Efficiency	Station Load (kW)	Station Flow (m³/s)	Unit Efficiency
0	0.00	0.000	3600	2.34	0.839
100	0.36	0.152	3700	2.39	0.842
200	0.41	0.262	3800	2.45	0.844
300	0.47	0.346	3900	2.51	0.847
400	0.53	0.412	4000	2.56	0.850
500	0.58	0.465	4100	2.62	0.852
600	0.64	0.509	4200	2.68	0.855
700	0.70	0.546	4300	2.73	0.857
800	0.75	0.577	4400	2.79	0.859
900	0.81	0.604	4500	2.85	0.861
1000	0.87	0.627	4600	2.90	0.863
1100	0.92	0.647	4700	2.96	0.865
1200	0.98	0.666	4800	3.02	0.867
1300	1.04	0.682	4900	3.07	0.869
1400	1.09	0.696	5000	3.13	0.871
1500	1.15	0.709	5100	3.19	0.873
1600	1.21	0.721	5200	3.24	0.874
1700	1.26	0.732	5300	3.30	0.876
1800	1.32	0.742	5400	3.36	0.877
1900	1.38	0.751	5500	3.41	0.879
2000	1.43	0.759	5600	3.47	0.880
2100	1.49	0.767	5700	3.53	0.882
2200	1.55	0.774	5800	3.58	0.883

Station Load (kW)	Station Flow (m³/s)	Unit Efficiency	Station Load (kW)	Station Flow (m³/s)	Unit Efficiency
2300	1.60	0.781	5900	3.64	0.884
2400	1.66	0.787	6000	3.69	0.886
2500	1.72	0.793	6100	3.75	0.887
2600	1.77	0.798	6200	3.81	0.888
2700	1.83	0.803	6300	3.86	0.889
2800	1.88	0.808	6400	3.92	0.890
2900	1.94	0.813	6500	3.98	0.892
3000	2.00	0.817	6600	4.03	0.893
3100	2.05	0.821	6700	4.09	0.894
3200	2.11	0.825	6800	4.15	0.895
3300	2.17	0.829	6900	4.20	0.896
3400	2.22	0.832	7000	4.26	0.897
3500	2.28	0.835			

Notes: Unit efficiencies include both Turbine and Generator efficiencies.

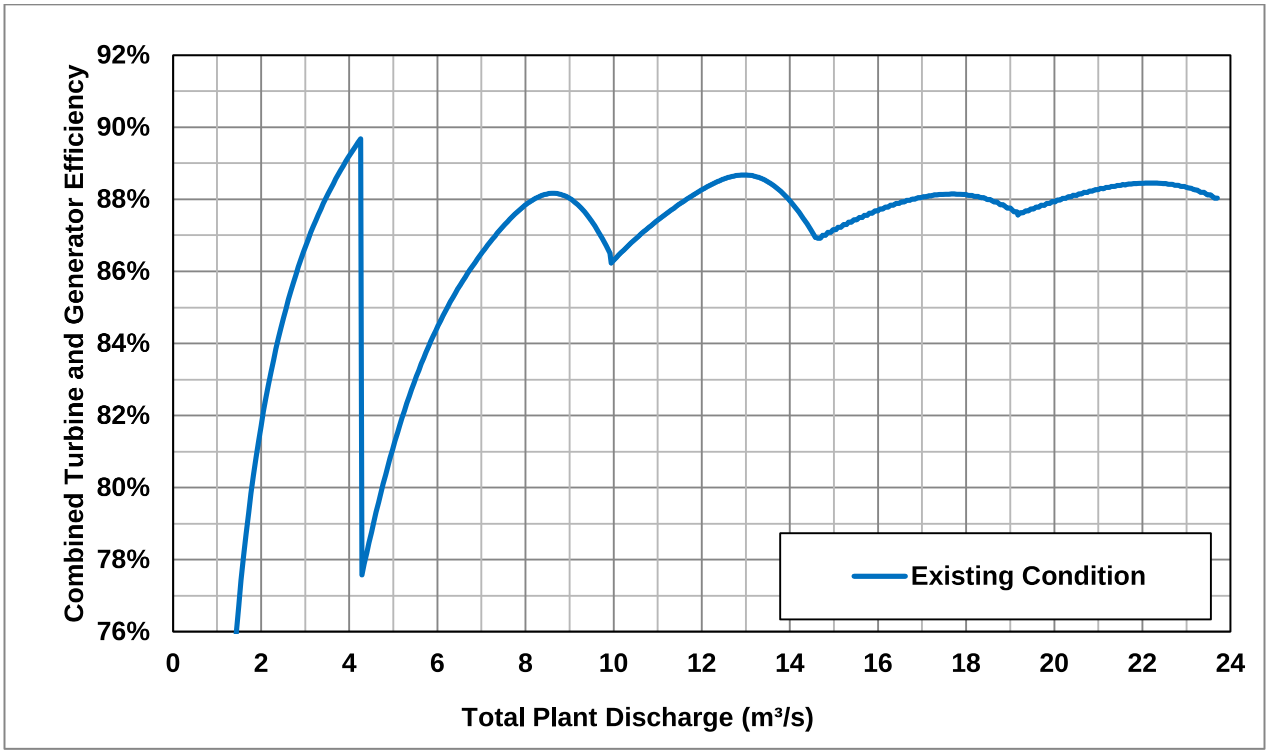
The best estimate optimized operation of AGS was determined based on the existing and proposed turbine characteristics provided by YEC. The plant was assumed to operate the most efficient combination of units for a given flow. To calculate plant output, typical net head was taken from Hatch's 2009 unit efficiency table according to Equation 1 (Ref. 3). This equation approximates net head as a function of plant output to account for increased tailwater level and headlosses with increased output.

$$Equation\ 1: \quad H_N = 187.91 - 0.12824P - 0.0012505P^2$$

Here H_N represents the net water head (m) and P represents the power output from the plant (W).

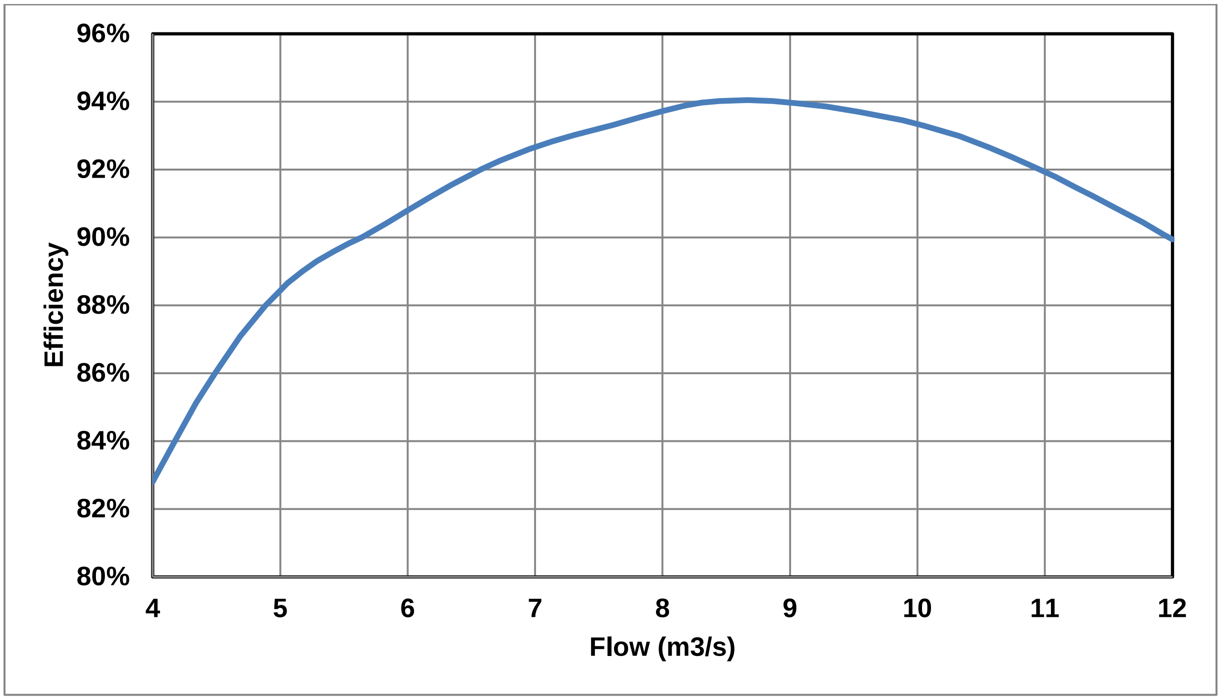
The combined turbine and generator efficiency curve for the entire existing 3 units at AGS were developed as shown in Figure 1.

FIGURE 1
COMBINED EFFICIENCY CURVE FOR EXISTING CONDITIONS



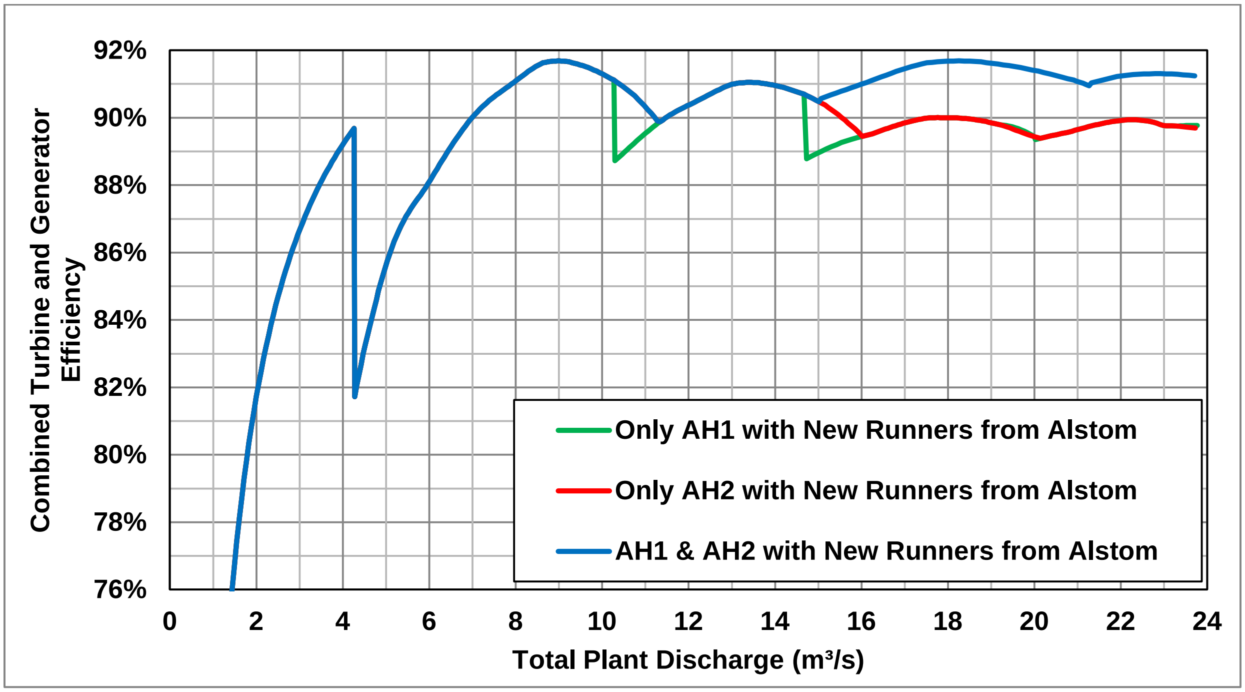
Alstom provided a preliminary performance curve for the proposed upgraded turbines as shown in Figure 2 (Ref. 3). The curve represents the best estimate efficiency at a constant head of 180.4 m but is subject to further study such as the analysis of the existing spiral casing, distributor and the draft tube. This efficiency curve was used in the model to calculate energy production using Equation 1 to approximate net head at given plant outputs.

FIGURE 2
ALSTOM EXPECTED PERFORMANCE FOR HNET = 180.4 M



A generator efficiency of 97.5% was assumed for AH1 and/or AH2 based on experience with similar generators. The AH2 generator is rated at 19,200 kVA and the AH1 generator is rated at 17,000 kVA. For the purpose of this study, a power factor of 1.0 was assumed to estimate plant operation. The developed efficiency curves for replacing AH1 and/or AH2 using Alstom runners are shown in Figure 3.

FIGURE 3
COMBINED EFFICIENCY CURVES FOR UPGRADES OF AH1 AND/OR AH2 USING ALSTOM RUNNERS



Similar to the development of efficiency curves for the upgrades using Alstom turbines, Norcan provided a preliminary performance curve for their proposed upgraded turbine as shown in Figure 4 (Ref. 4). The developed combined efficiency curves for replacing AH1 and/or AH2 using Norcan turbines are shown in Figure 5.

FIGURE 4
NORCAN PRELIMINARY PERFORMANCE FOR HNET = 180.4 M

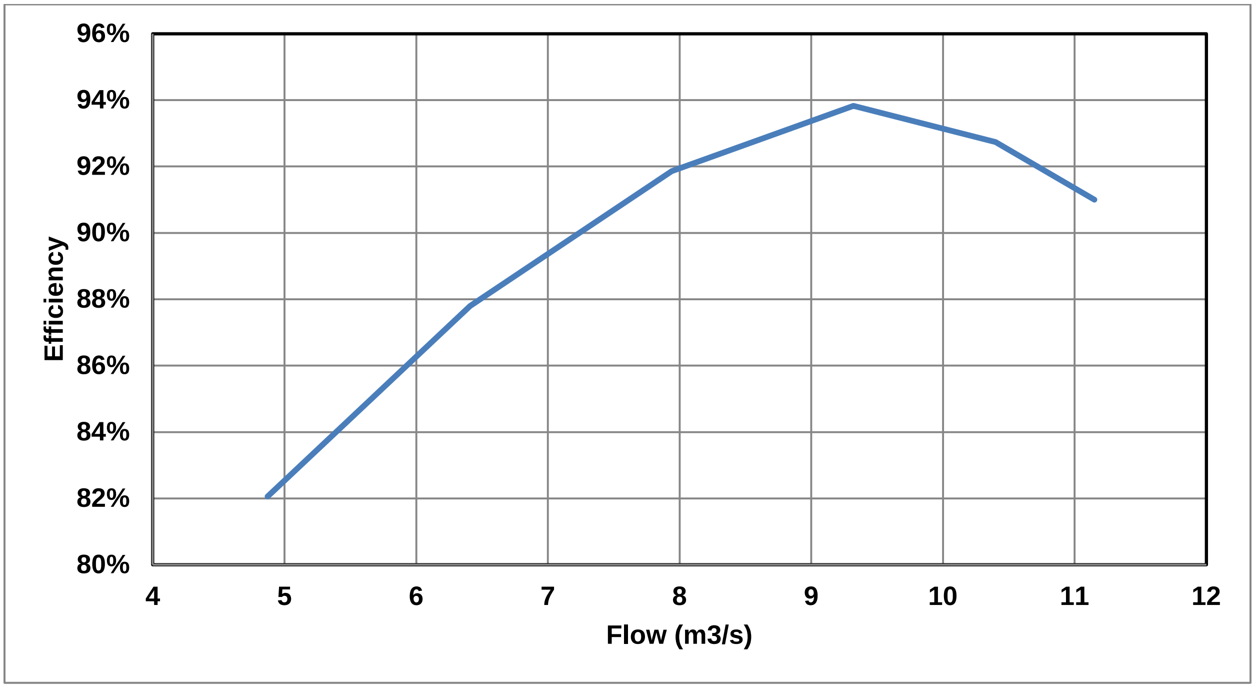
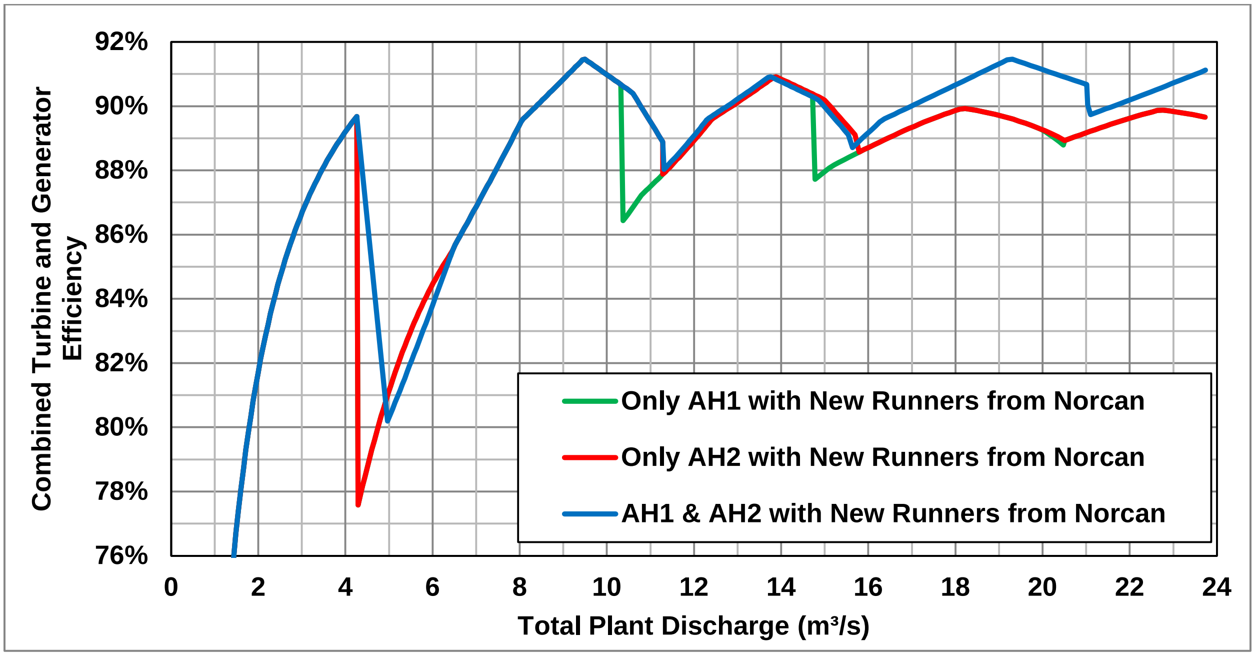


FIGURE 5
COMBINED EFFICIENCY CURVES FOR UPGRADES OF AH1 AND/OR AH2 USING NORCAN RUNNERS



For the purpose of this study, turbine efficiency curves for all three turbines were evaluated for the typical gross head and expected conveyance head losses. Plant operation was optimized for those seven scenarios based on the expected net head. Although the proposed replacement alternatives have higher flow capacity than the existing units, the total plant flow is still limited at the existing 23.7 m^3/s, which is the summation of the original turbine capacity for AH1 and AH2 (19.46 m^3/s in total) and the turbine capacity for AH3 (4.26 m^3/s) based on the data provided by YEC. Without further study, it is not recommended to increase plant flow higher than the existing limit due to the possibility that emergency evacuation through the tailrace tunnel could be compromised, as described in KGS Group's Hydraulic Capacity Memo (Ref. 6).

3.0 THREE-TIER SYSTEM FOR SPECIFICATION OF EFFICIENCY

The 3-tier system for specification of efficiency is required in the YECSIM model to provide a reasonable representation of the range of efficiencies that may occur for the hydro energy generation from a powerhouse on weekly basis. The description of the 3 tiers can be found in the YECSIM User's Manual (Ref.1). The steps to calculate the 3 tiers for the AGS are described below:

- Estimation of the Minimum Flow through the AGS:

  The minimum flow through the powerhouse was estimated to be 2.8 m^3/s at the AGS. According to the "Water Use License HY99-011, Correction to Clause 29" published by Yukon Territory Water Board in 2005, the minimum flow downstream of Canyon Pond is to be no less than 2.832 m^3/s, including Giltana Creek flows (YECSIM User's Manual - Appendix E - Aishihik). The Water Use Licence HY99-011 - Clause 25 (2000) defines that the minimum flow over Otter Falls, which is located beside the AGS, is 0.142 m^3/s from September 22 to April 30, 0.708 m^3/s from May 19 to September 7, and 0.425 m^3/s in the rest days. Usually the outflows from Aishihik Lake to Canyon Lake are greater than 2.832 m^3/s in the spring and summer. Therefore, the flow through the powerhouse can be assumed no less than 2.8 m^3/s.

- Calculation of the First Tier Efficiency:

  The first tier refers to a low range of total plant outflows. For the AGS, the low flow range was assumed from 2.8 m^3/s to 4.26 m^3/s with the operation Unit 3 only. The average energy efficiency of Unit 3 in this flow range is 0.880, which was assumed to be the first tier efficiency. The corresponding discharge for the first tier was defined as 3 m^3/s in order to keep consistent with the flow used originally for the first tier in the YECSIM model.

- Calculation of the Second Tier Efficiency:

  The second tier efficiency, which represents the majority of operation wherein the plant outflow is less than the maximum, was estimated to be the average energy efficiency in the flow range from 3 m^3/s to the maximum plant flow. The corresponding discharge for the second tier was defined as 6 m^3/s in order to keep consistent with the flow used originally for the second tier in the YECSIM model.

- Calculation of the Third Tier Efficiency:

  The third tier efficiency, which represents the operation wherein the plant outflow is at the maximum, was estimated to be the average energy efficiency for the maximum flow and the second maximum flow with all units in operation. The corresponding discharge for the third tier was defined as the maximum allowable turbine flow with all units in operation. As mentioned in the previous section, the maximum plant discharge is limited to 23.7 m³/s.

Table 3 shows the estimated 3-tier systems for specification of efficiency for those seven scenarios including the existing condition and the proposed upgrade options. The coefficients for the first tier are the same for all of the scenarios since only AH3 at Aishihik GS was assumed to be running at the low flow range. For the second tier, the upgrades of both AH1 and AH2 using Alstom turbines provide the highest efficiency value. For the third tier, the upgrades of both AH1 and AH2 using Alstom turbines still provide the highest efficiency value. The efficiencies for all of the upgrade options are higher than the existing condition.

TABLE 3
THREE-TIER SYSTEMS FOR SPECIFICATION OF EFFICIENCY FOR AGS

3-Tier System	Station Flow (m³/s)	3-Tier System for Specification of Efficiency						
		Existing Condition	Turbine Upgrades (Alstom)			Turbine Upgrades (Norcan)		
			AH1 Only	AH2 Only	AH1 and AH2	AH1 Only	AH2 Only	AH1 and AH2
Tier 1	3	0.880	0.880	0.880	0.880	0.880	0.880	0.880
Tier 2	6	0.872	0.896	0.897	0.901	0.882	0.884	0.891
Tier 3	23.7	0.880	0.896	0.897	0.913	0.897	0.897	0.911

4.0 YECSIM MODEL

For the AGS, the new 3-tier system for specification of efficiency for each scenario and the maximum plant discharge (23.7 m³/s) were used in the YECSIM model. Since the maximum plant discharge is less than the plant capacity (approximate 25.5 m³/s for the existing units, 27.8 m³/s with the upgrade of Unit 2 using the Alstom turbine and 26.6 m³/s with the upgrade of Unit 2 using the Norcan turbine), the energy loss coefficient due to force outage at the AGS was assumed to be zero in the YECSIM model. Here the forced outages refer to the outages that occur unpredictably, or result from maintenance activities that exceed the length of time available in low-load periods (Ref.1).

For the input parameters for the other generating stations including Whitehorse GS, Mayo A and Mayo B GSs and the related lakes, the default values provided in the YECSIM model as listed in Appendix D of the YECSIM User's Manual (Ref.1) were used.

Two energy loads (468.1 GWh/year and 575.1 GWh/year) were used, which could reasonably be expected to occur or be surpassed within the future 20 to 30 years starting from 2009 as described in the report for the proposed Mayo Hydro Enhancement Project prepared by YEC (Ref. 2).

The simulation conditions that were used in the YECSIM model for those seven scenarios are summarized below:

- Simulation Period (or Energy Planning Period): 20 years
- Energy Systems: WAF/MD (including Mayo B GS)
- Energy load levels
    - Low Energy Demand: 468.1 GWh/year
    - High Energy Demand: 575.1 GWh/year
- Hydrologic water years from 1987 to 2007
- Water License Limits for Aishihik Lake
    - The minimum water level in a year is no lower than 913 m more than 2 in 5 years
    - The 10-year rolling average minimum water level is no lower than 913.3 m
    - The winter drawdown limit is 1.2 m
- Water License Limits for Mayo Lake
    - The water level difference between the beginning of the winter (Week 39) and the spring next year cannot be more than 2.5 m for 3 years in a row
- Marsh Lake Operation Policy
    - The change in flow from Marsh Lake is limited to +/- 20 m^3/s in the spring
- Operation Policy of Mayo A GS
    - The special turbine efficiencies were applied in the winter
    - The turbine capacity is increased up to 15 m^3/s when spilling water

5.0 PLANT CAPACITY

Incremental capacity represents an important benefit to the proposed turbine upgrade project. Although the proposed turbine capacity may exceed the existing turbine capacity, hydraulic conditions limit the effectiveness of this additional capacity. According to YEC, Aishihik GS is typically run at around 80% plant flow, so any excess turbine capacity requiring additional plant flow may not be realized. Therefore, the evaluation was based on plant capacity at 80% plant flow instead of the individual turbine capacity.

Plant capacity was estimated for each configuration based on the typical plant flow of 19 m^3/s. Net head at plant capacity was calculated using Equation 1. The estimated plant capacities for each proposed plant configuration are shown in Table 4.

TABLE 4
PLANT CAPACITY

Simulation Scenario	Plant Efficiency	Plant Capacity	Incremental Plant Capacity
	(%)	(MW)	(MW)
Existing Condition	87.8	29.8	-
New AH1 - Alstom	89.9	30.5	0.7
New AH1- Norcan	89.7	30.5	0.6
New AH2 - Alstom	89.9	30.5	0.7
New AH2 - Norcan	89.7	30.5	0.6
New AH1 and AH2 - Alstom	91.6	31.1	1.3
New AH1 and AH2 - Norcan	91.3	31.0	1.2

Incremental plant capacity varies depending how many units are upgraded. The selection of a turbine manufacturer is not a significant factor when comparing total plant capacity. Alstom units provide a marginal capacity benefit relative to Norcan units. Upgrading both AH1 and AH2 provides close to double the incremental capacity of upgrading only one unit.

For the purpose of designing electrical components, the plant capacity was evaluated at maximum flow and maximum expected net head using an optimistic estimate of conveyance system losses. For a plant flow of 23.7 m^3/s and net head of 182.2 m, the existing plant capacity is 37.2 MW. Proposed configurations range in capacity from 37.9 MW for the Norcan AH1 replacement to 38.6 MW for the Alstom 2 unit replacement.

6.0 YECSIM MODEL RESULTS

For each run, the results for the first 5 energy load years were abandoned to avoid the effects of the initial lake levels given at the start of the simulation as described in Section 6.1.4 in the YECSIM User's Manual (Ref.1). The last load year was also abandoned to avoid the effects of backwards calculation of lake operation rule curves during the YECSIM model simulation. Therefore the weekly average hydro energy generated from the AGS and the WAF + MD system was calculated for the remaining 14 energy load years. Then the annual hydro energy generated from the AGS or the WAF + MD system is the sum of the energy generated in 52 weeks of a year. Table 5 shows the model results at the low energy load level of 468.1 GWh/year and Table 6 shows the model results at the high energy load level of 575.1 GWh/year. Usually, the energy benefits to the WAF/MD system are of more interest than the energy benefits to the AGS itself. Here only the energy benefits to the system are discussed.

TABLE 5
ENERGY BENEFITS FOR AGS UPGRADES AT LOW ENERGY DEMAND

Simulation Scenario	Energy Generated at AGS	Total Hydro Energy Generated in the WAF/MD System	Net Energy Benefit to AGS	Net Energy Benefit to the WAF/MD System
	(GWh/Year)	(GWh/Year)	(GWh/Year)	(GWh/Year)
Existing Condition	114.30	429.05	-	-
New AH1 - Alstom	116.75	431.31	2.45	2.26
New AH1 - Norcan	115.34	430.01	1.05	0.96
New AH2 - Alstom	116.85	431.40	2.55	2.35
New AH2- Norcan	115.55	430.20	1.25	1.14
New AH1 and AH2 - Alstom	117.28	431.79	2.98	2.74
New AH1 and AH2 - Norcan	116.29	430.86	1.99	1.81

TABLE 6
ENERGY BENEFITS FOR AISHIHIK GS UPGRADES AT HIGH ENERGY DEMAND

Simulation Scenario	Energy Generated at AGS	Total Hydro Energy Generated in the WAF+MD System	Net Energy Benefit to AGS	Net Energy Benefit to the WAF+MD System
	(GWh/Year)	(GWh/Year)	(GWh/Year)	(GWh/Year)
Existing Condition	118.86	451.01	-	-
New AH1 - Alstom	121.27	453.20	2.41	2.19
New AH1 - Norcan	120.27	452.28	1.41	1.27
New AH2 - Alstom	121.34	453.26	2.47	2.25
New AH2- Norcan	120.41	452.41	1.55	1.40
New AH1 and AH2 - Alstom	122.17	454.05	3.31	3.04
New AH1 and AH2 - Norcan	121.45	453.38	2.58	2.37

As shown in Tables 5 and 6, the net energy contributions to the system with the upgrades using Alstom runners are always higher than the ones with the upgrades using Norcan runners at both the low energy demand and the high energy demand for the upgrades of AH1 and/or AH2 at AGS. The net energy benefits for the upgrades of AH2 are slightly higher than the benefits for the upgrades of AH1 because AH2 has a greater electrical capacity due to a rewind of the generator in 2006. The net energy benefits for the upgrades of both AH1 and AH2 are higher than those for the upgrades of either AH1 or AH2 only.

Based on the net energy contributions provided in Tables 5 and 6, economic analysis related to the monetary values of energy benefits, capital costs and payback calculations becomes possible to assess the benefit values for the potential upgrades of AH1 and/or AH2 and choose a preferred turbine runner between Alstom and Norcan.

7.0 DISCUSSIONS AND CONCLUSIONS

Based on the energy benefits analysis, the following conclusions are made,

- For the upgrades of AH1 only, using Alstom runners would generate energy benefit from 2.19 GWh/year to 2.26 GWh/year to the system, while using Norcan runners would generate energy benefit from 0.96 GWh/year to 1.27 GWh/year to the system.
- For the upgrades of AH2 only, using Alstom runners would generate energy benefit from 2.25 GWh/year to 2.35 GWh/year to the system, while using Norcan runners would generate energy benefit from 1.14 GWh/year to 1.40 GWh/year to the system. The energy benefit for the upgrades of AH2 only is slightly higher than the one for the upgrade of AH1 only.
- For the upgrades of both AH1 and AH2, using Alstom runners would generate energy benefit from 2.74 GWh/year to 3.04 GWh/year to the system, while using Norcan runners would generate energy benefit from 1.81 GWh/year to 2.37 GWh/year to the system. The energy benefit for the upgrades of both AH1 and AH2 are higher than the one for the upgrades of either AH1 or AH2.

8.0 REFERENCES

1. Yukon Energy Corporation, “User Manual for YEC System Simulation Software (draft)”, September 2011.
2. Hatch, “Aishihik Turbine Peformance Test: Performance Test Results”, December 11, 2009.
3. Alstom, “Potential Runner Upgrade Request for Information 14-1404-004”, March 10, 2015.
4. Norcan Hydraulic Turbine Inc, “Budget quote for the manufacturing of one (1) replacement Francis Runner for Aishihik Generating Station”, March 9, 2015.
5. Yukon Energy Corporation, “Application for an Energy Project Certificate and an Energy Operation Certificate”, December 2009.

6. KGS Group, "Aishihik Rerate and Assessment Hydraulic Capacity Review", May 15, 2015.

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APPENDIX D

EXCITATION SYSTEM ASSESSMENT

MEMORANDUM

TO: JOEL LAMBERT

CC:

FROM: MONISH BHOWMIK

DATED: SEPTEMBER 18, 2015

PROJECT NO: 14-1404-004

RE: AISHIHIK TURBINE UPGRADE - EXISTING EXCITATION CAPABILITIES

1.0 BACKGROUND

Yukon Energy Corp. is currently considering a project to upgrade the turbine runner capacity to obtain uprated power from the existing Aishihik Unit 2. The Aishihik Unit 2 generator is equipped with a DC exciter and controlled by SR125E Basler AVR. Through a rewind project which was undertaken in 2006 the electrical capability of the generator was upgraded from 15.6 MVA to 19.2 MVA at 0.9 power factor. During the rewind project the unit was tested up to 16.5 MW as the available maximum mechanical power of the turbine is limited to 16.5 MW. As a part of the rewind project the generator rotor field poles were reinsulated, however, the DC exciter was not upgraded.

This memorandum is prepared to verify the capability of the existing exciter of the AH2 unit to produce 19.2 MVA at 0.9 p.f.

2.0 DOCUMENTS REVIEWED

The following documents were obtained from Yukon Energy Corp. and are used to estimate the exciter requirement for enhanced power:

1. Testing of Synchronous Unit Reactive Limits and Dynamic Testing/Model Validation for Yukon Energy Corporation, Aishihik Generating Station, prepared by Chaos electric Inc.
2. Aishihik Unit 2 Rewind & Protection Upgrade – 2006, Commissioning Report, Prepared by Ravindra P. Mutukutti, P.Eng.

3.0 FINDINGS

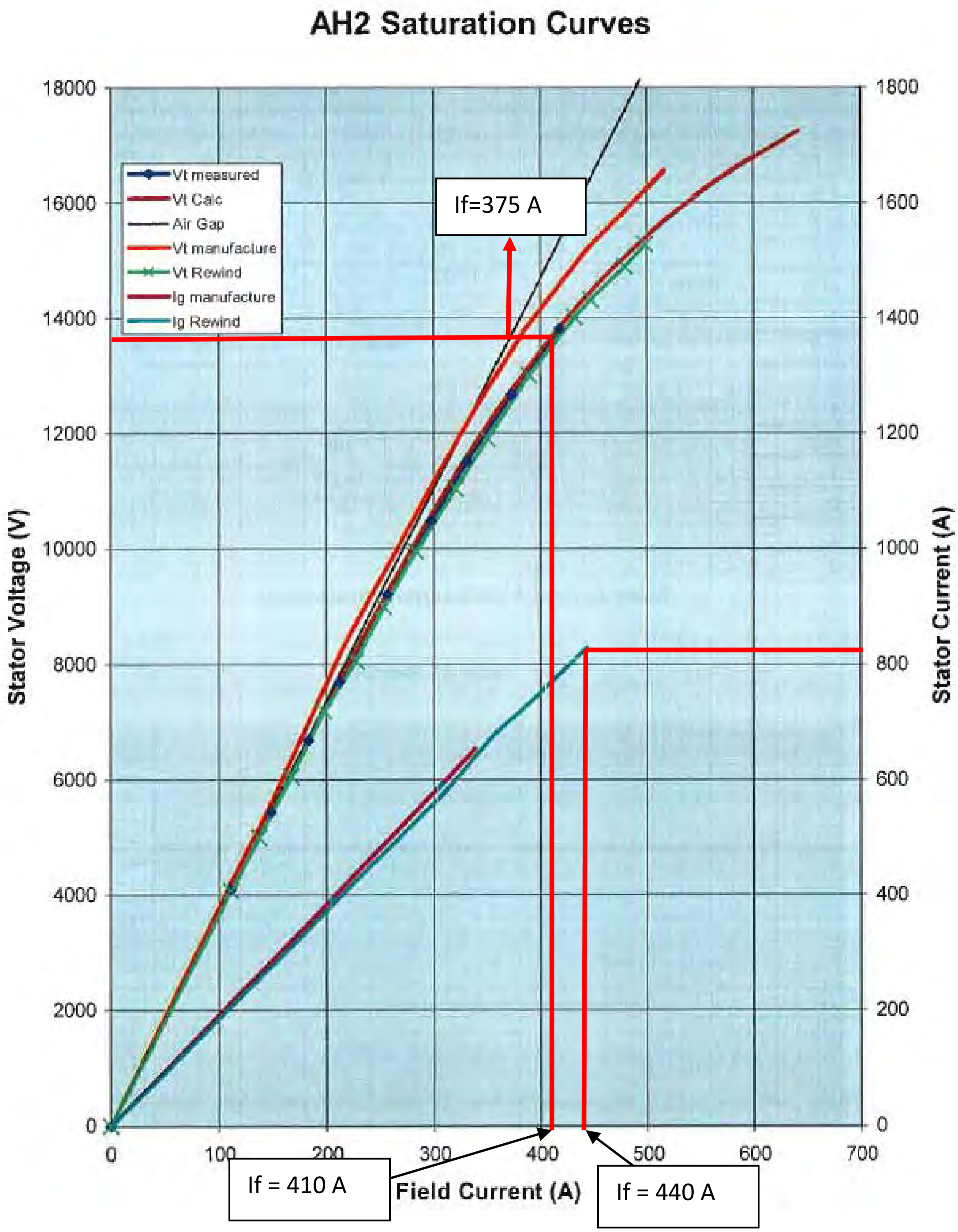
3.1 NAMEPLATE INFORMATION

The table below shows the comparison of the upgraded generator capacity and the DC exciter capacity:

Generator			
Items	**Before Upgrade**	**After Upgrade**	**Remark**
Field Voltage	75 V	75V	Stator rewind &
Field Current	630 A	720A	Rotor pole
Generator MVA	15.6 MVA	19.2 MVA	Re-insulation
Generator output current at rated condition	653 A	803 A	
Generator DC Exciter			
Volts at Full load	35 V	35 V	The DC exciter
Amps at Full Load	670 A	670 A	Was not upraded
KW	57 kW	57 kW	

3.2 OPEN CIRCUIT AND SHORT CIRCUIT SATURATION CURVE

From the review of the open circuit and short circuit saturation curve (Reference 1, Section 4.0) it was found that the field current required to produce the rated air gap line voltage (1 pu), rated open circuit terminal voltage (13.8 kV) and rated short circuit current (SCC test) is respectively 375A, 410A & 442A.

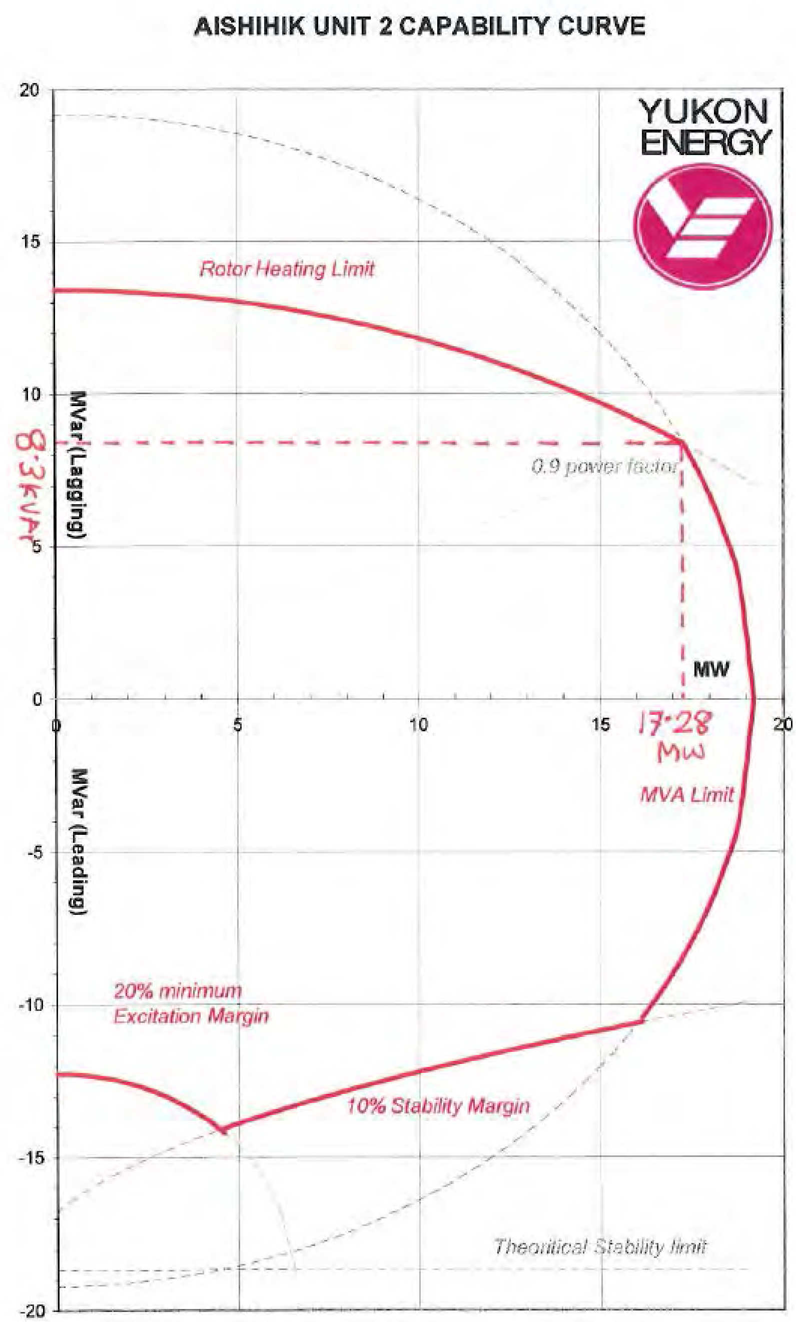


The above mentioned values were validated from the rewind commissioning report, which are provided in the following table:

Generator Short Circuit Condition			Generator Open Circuit Condition		
Field Voltage	Field Current	Stator Current	Field Voltage	Field Current	Stator Voltage
42 V	442 A	825 A	38 V	410 A	13.8 kV

3.3 GENERATOR CAPABILITY CURVE

The upgraded generator capability curve was reviewed, as provided in the generator rewind commissioning report (Reference 2, Section 2.0). According to the generator capability curve of the rewound, the generator will be able to produce 19.2 MVA at 0.9 power factor at the field voltage of 75 V and 720 A (Reference 1, section 3.2.2).



4.0 CONCLUSION

From the above information the following conclusions can be made:

- According to the rewind machine data provided by Voith-Siemens, to produce the rated power the generator rotor field voltage and field current requirement is 75 V and 720A respectively, while the DC exciter is rated at 670 A.
- The DC exciter will operate beyond its design limit to produce the rated voltage at 19.2 MVA, 0.9 power factor. This will cause rapid aging of the existing DC exciter.
- If Yukon Energy Corp. decides to operate the generator at 19.2 MVA at 0.9 power factor, a discussion with the OEM is requested to validate the impact on the DC exciter due to operation beyond its design ratings.
- If the existing exciter is operated at its maximum rating which is at 670 A, Voith-Siemens should be approached to obtained a new capability curve for the field limit of 670 A.

5.0 RECOMMENDATION

The following two alternatives are recommended related to the Aishihik Unit 2 exciter to accommodate enhanced power:

- **Alternative 1(Preferred):** The existing exciter is replaced with a static exciter to match the generator field requirement. The generator field leads and associated slip rings should be checked so that these are properly rated for enhanced power operation.
- **Alternative 2:** The rotating DC exciter is upgraded to meet the rewounded generator field requirement and the associated AVR should be replaced to meet the requirement of the upgraded exciter. The generator field leads and associated slip rings should be checked so that these are properly rated for enhanced power operation.

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APPENDIX E

BUSINESS CASE CALCULATIONS

E-1 Rerunner Costs

E-2 Capacity and Energy Benefits

E-3 Aishihik Turbine Uprate

E-4 Payback Calculations – 4 Cases:

E-4.1 One Unit (AH2) Upgrate – Low Energy Demand
E-4.2 One Unit (AH2) Uprate – High Energy Demand
E-4.3 Two Unit Uprate – Low Energy Demand
E-4.4 Two Unit Uprate – High Energy Demand

E-5 Payback Calculations, Sensitivity Analysis – 11 Trials:

E-5.0 Trial Parameters (1 – 11)
E-5.1 Trial 1 – Benefit of $1M per MW
E-5.2 Trial 2 – Benefit of $2.5M per MW
E-5.3 Trial 3 – Benefit of $5M per MW
E-5.4 Trial 4 – Benefit of $7.5M per MW
E-5.5 Trial 5 – Benefit of $10M per MW
E-5.6 Trial 6 – 100,000 $/GWh/yr
E-5.7 Trial 7 – 150,000 $/GWh/yr
E-5.8 Trial 8 – 200,000 $/GWh/yr
E-5.9 Trial 9 – 250,000 $/GWh/yr
E-5.10 Trial 10 – 300,000 $/GW/yr
E-5.11 Trial 11 – Capacity Benefit of $1M per MW

Appendix E-1
Rerunner Costs

TURBINE COSTS		
	Norcan	**Alstom**
Runner	$268,033	
Deliver and Install	$205,140	
Coupling Bolts	$8,600	
Blade Templates	$15,500	
Site Work		
a) EHS site analyses		
b) Turbine disassembly		
c) Parts inspections		Items a-f
d) New runner supply & ins tall		$250,000
e) Turbine reassembly		
f) Commissioning		
Engineering Package		
a) Adapt runner profile to Aishihik		Items a-c
b) Drawings for labyrinths		$106,500
c) Commisssioning report		
Replacement Parts		
a) Runner, cone and bolts		$343,500
b) fixed labyrinths		$43,000
Excluded from above (identified by Alstom)		
a) Mob & Demob in case of disruption	Contingency No. 1	Contingency No. 1
c) Damages or delays by others	for all excluded items	for all excluded items
d) Special tools and lifting devices		
e) Confined space tools		
f) Overhead crane services	$100,000	$100,000
g) NDT testing		
h) Absolute turbine efficiency test		
i) Alignment correction work		
j) Machining of TG parts		
k) GST and PST		
Services by Client		
a) Lockout procedures		
b) Maintain road access to site		
c) Roof/Door mods if req'd		
d) Storage Area for Sea-containers		
e) Electrical and Compressed Air Services		
f) Inspection and upgrade of cranes		
g) scaffolding by certified parties		
h) drawings, manuals, etc		
Evaluated cost	$597,273	$843,000
	Norcan	**Alstom**

NET ENERGY CONTRIBUTION FROM PROPOSED RUNNERS

Unit Upgrade Option	Net Energy Contribution Alstom Runners (GWh/year)		Net Energy Contribution Norcan Runners (GWh/year)	
	Low Energy* Demand	High Energy** Demand	Low Energy* Demand	High Energy** Demand
Upgrade of AH1 Only	2.26	2.19	0.96	1.27
Upgrade of AH2 Only	2.35	2.25	1.14	1.40
Upgrade of AH1 and AH2	2.74	3.04	1.81	2.37

BENEFITS

BENEFIT OF INCREASED CAPACITY at 80% GATE	Increase in Capacity MW	Value of Increase in Capacity $ per MW	One Time Benefit
Upgrade AH2	0.7	$2,500,000	$1,750,000
Upgrade AH1 and AH2	1.3	$2,500,000	$3,250,000

BENEFIT OF INCREASED ENERGY FOR LOW ENERGY DEMAND SCENARIO	Energy Benefits to the WAF+MD System (GWh/Year)	Value of Increase in Energy $ per GWh/year	Annual Benefit
Upgrade AH2	2.35	$200,000	$470,000
Upgrade AH1 and AH2	2.74	$200,000	$548,000

BENEFIT OF INCREASED ENERGY FOR HIGH ENERGY DEMAND SCENARIO	Energy Benefits to the WAF+MD System (GWh/Year)	Value of Increase in Energy $ per GWh/year	Annual Benefit
Upgrade AH2	2.25	$200,000	$450,000
Upgrade AH1 and AH2	3.04	$200,000	$608,000

Appendix E-3
Aishihik Turbine Uprate

Item	Description / Assumptions	One Unit	Multiplier for 2nd Unit	Two Units
Turbine Uprate - Alstom				
Turbine field work		$250,000	2.0	$500,000
Turbine runner engineering		$106,000	1.3	$137,800
Runner and coupling bolts, supply		$343,000	2.0	$686,000
Fix labyrinths		$43,000	2.0	$86,000
Extra to T/G Vendor scope Work				$0
Performance / Efficiency Test		$125,000	1.0	$125,000
Crane operator and station operator	240 hours x $200/hr	$48,000	2.0	$96,000
Drawings, manuals, etc		$5,000	1.3	$6,500
Generator Surface Air Coolers		$50,000	2.0	$100,000
Excitation System Uprate, AH2 only		$750,000	1.0	$750,000
Replace cable from AH2 to Cct Brkr.		$150,000	1.0	$150,000
Replace cables from S167 to T1 & T2	Under review.	$150,000	1.0	$150,000
Contingency No. 1*	Repairs, machining	$100,000	2.0	$200,000
Contingency No. 2**	Scaffolding	$50,000	2.0	$100,000
Sub-Total A		$2,170,000		$3,087,300
Engineering support	12% of Sub-Total A	$260,400		$370,476
Sub-Total B		$2,430,400		$3,457,776
Goods and Services Sales Tax	5% of Sub-Total B	$121,520		$172,889
Sub-Total C		$2,291,520		$3,630,665
Contingency No.3***	30% of Sub-Total C	$687,456		$1,089,199
Total of Class 4 Estimate (-30% +50%)		**$2,978,976**		**$4,719,864**
Excluded from this estimate:				
Opportunity Work	Other Work:			
Turbine, generator, intake gates,	Camp services			
Turbine inlet valve	YEC engineering			
Distribution Pipe repairs	Project management			
Power cables and switchgear				
Generator Breaker				
Unit step-up transformer				
Controls and Protection				

* Contingency No. 1 accounts for unforeseen items that may need to be repaired when unit is dismantled.
** Contingency: No. 2 accounts for scaffolding, if required, at Owner's responsibility
***Contingency No. 3 accounts for unforeseen scope of work and changing market conditions.

Discounted and Simple Payback Analysis

Project One Unit (AH2) Uprate Low Energy Demand

Date 17-Sep-15

Capital Cost -$2,978,976
Discount Rate 7.2%

Simple Payback: ***5*** years
Discounted Payback: ***6*** years

Base Year 2016
In-service Year 2018

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019		$470,000	$470,000	-$758,976	3	$381,303	-$810,691	3
2020		$470,000	$470,000	-$288,976	4	$355,627	-$455,064	4
2021		$470,000	$470,000	$181,024	5	$331,680	-$123,385	5
2022		$470,000	$470,000	$651,024	6	$309,345	$185,960	6
2023		$470,000	$470,000	$1,121,024	7	$288,514	$474,474	7
2024		$470,000	$470,000	$1,591,024	8	$269,086	$743,561	8
2025		$470,000	$470,000	$2,061,024	9	$250,966	$994,527	9
2026		$470,000	$470,000	$2,531,024	10	$234,067	$1,228,594	10
2027		$470,000	$470,000	$3,001,024	11	$218,305	$1,446,899	11
2028		$470,000	$470,000	$3,471,024	12	$203,605	$1,650,504	12
2029		$470,000	$470,000	$3,941,024	13	$189,895	$1,840,398	13
2030		$470,000	$470,000	$4,411,024	14	$177,107	$2,017,506	14
2031		$470,000	$470,000	$4,881,024	15	$165,181	$2,182,687	15
2032		$470,000	$470,000	$5,351,024	16	$154,058	$2,336,745	16
2033		$470,000	$470,000	$5,821,024	17	$143,684	$2,480,430	17
2034		$470,000	$470,000	$6,291,024	18	$134,009	$2,614,438	18
2035		$470,000	$470,000	$6,761,024	19	$124,985	$2,739,423	19
2036		$470,000	$470,000	$7,231,024	20	$116,569	$2,855,992	20

Notes: 1. Discount Rate to be used is the Blended Cost of Capital Rate for Yukon Energy

2. The simple payback period in years is the first year the the cumulative cash flow is positive in Column E

3. The discounted cash flow payback period is the first year that the Cumulative discounted cash flow (DCF) is positive in Column H

4. As the capital cost is a negative cash flow it should entered as a negative number

5. For paybacks exceeding 5 years the discounted payback should be used as the time value of money becomes more significant

Discounted and Simple Payback Analysis

Project One Unit (AH2) Uprate High Energy Demand

Date 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	5	years
Discount Rate	7.2%	***Discounted Payback:***	6	years
Base Year	2017			
In-service Year	2018			

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2017	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2018	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2019	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2020		$450,000	$450,000	-$778,976	3	$365,078	-$826,917	3
2021		$450,000	$450,000	-$328,976	4	$340,494	-$486,423	4
2022		$450,000	$450,000	$121,024	5	$317,566	-$168,858	5
2023		$450,000	$450,000	$571,024	6	$296,181	$127,324	6
2024		$450,000	$450,000	$1,021,024	7	$276,237	$403,561	7
2025		$450,000	$450,000	$1,471,024	8	$257,636	$661,197	8
2026		$450,000	$450,000	$1,921,024	9	$240,287	$901,484	9
2027		$450,000	$450,000	$2,371,024	10	$224,107	$1,125,590	10
2028		$450,000	$450,000	$2,821,024	11	$209,016	$1,334,606	11
2029		$450,000	$450,000	$3,271,024	12	$194,941	$1,529,547	12
2030		$450,000	$450,000	$3,721,024	13	$181,814	$1,711,360	13
2031		$450,000	$450,000	$4,171,024	14	$169,571	$1,880,931	14
2032		$450,000	$450,000	$4,621,024	15	$158,152	$2,039,084	15
2033		$450,000	$450,000	$5,071,024	16	$147,503	$2,186,586	16
2034		$450,000	$450,000	$5,521,024	17	$137,570	$2,324,156	17
2035		$450,000	$450,000	$5,971,024	18	$128,306	$2,452,463	18
2036		$450,000	$450,000	$6,421,024	19	$119,666	$2,572,129	19
2037		$450,000	$450,000	$6,871,024	20	$111,608	$2,683,737	20

Notes: 1. Discount Rate to be used is the Blended Cost of Capital Rate for Yukon Energy

2. The simple payback period in years is the first year the the cumulative cash flow is positive in Column E

3. The discounted cash flow payback period is the first year that the Cumulative discounted cash flow (DCF) is positive in Column H

4. As the capital cost is a negative cash flow it should entered as a negative number

5. For paybacks exceeding 5 years the discounted payback should be used as the time value of money becomes more significant

Discounted and Simple Payback Analysis

Project Two Unit Uprate Low Energy Demand

Date 17-Sep-15

Capital Cost -$4,719,864
Discount Rate 7.2%

Simple Payback: ***6*** years
Discounted Payback: ***7*** years

Base Year 2017
In-service Year 2019 & 2020

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2017	-471,986	$0	-$471,986	-$471,986	0	-$471,986	-$471,986	0
2018	-1,415,959	$0	-$1,415,959	-$1,887,946	1	-$1,320,611	-$1,792,598	1
2019	-1,415,959	$0	-$1,415,959	-$1,678,905	2	-$1,231,684	-$1,610,762	2
2020	-1,415,959	$0	-$1,415,959	-$1,195,864	3	-$1,148,744	-$1,218,879	3
2021		$0	$0	-$647,864	4	$0	-$804,233	4
2022		$548,000	$548,000	-$99,864	5	$386,724	-$417,509	5
2023		$548,000	$548,000	$448,136	6	$360,683	-$56,826	6
2024		$548,000	$548,000	$996,136	7	$336,395	$279,570	7
2025		$548,000	$548,000	$1,544,136	8	$313,743	$593,313	8
2026		$548,000	$548,000	$2,092,136	9	$292,616	$885,929	9
2027		$548,000	$548,000	$2,640,136	10	$272,912	$1,158,841	10
2028		$548,000	$548,000	$3,188,136	11	$254,535	$1,413,375	11
2029		$548,000	$548,000	$3,736,136	12	$237,395	$1,650,770	12
2030		$548,000	$548,000	$4,284,136	13	$221,409	$1,872,179	13
2031		$548,000	$548,000	$4,832,136	14	$206,500	$2,078,679	14
2032		$548,000	$548,000	$5,380,136	15	$192,594	$2,271,273	15
2033		$548,000	$548,000	$5,928,136	16	$179,625	$2,450,898	16
2034		$548,000	$548,000	$6,476,136	17	$167,530	$2,618,428	17
2035		$548,000	$548,000	$7,024,136	18	$156,249	$2,774,677	18
2036		$548,000	$548,000	$7,572,136	19	$145,727	$2,920,404	19
2037		$548,000	$548,000	$8,120,136	20	$135,914	$3,056,318	20

Notes: 1. Discount Rate to be used is the Blended Cost of Capital Rate for Yukon Energy

2. The simple payback period in years is the first year the the cumulative cash flow is positive in Column E

3. The discounted cash flow payback period is the first year that the Cumulative discounted cash flow (DCF) is positive in column H

4. As the capital cost is a negative cash flow it should entered as a negative number

5. For paybacks exceeding 5 years the discounted payback should be used as the time value of money becomes more significant

Discounted and Simple Payback Analysis

Project	Two Unit Uprate High Energy Demand	***Date***	17-Sep-15
Capital Cost	-$4,719,864	***Simple Payback:***	**5** years
Discount Rate	7.2%	***Discounted Payback:***	**6** years
Base Year	2017		
In-service Year	2019 & 2020		

Year	Capital Expense	Project Savings	Annual Cash Flow	Cumulative Cash flow	Year from In-service	Discounted Cash Flow	Cumulative DCF	Year
2017	-471,986	$0	-$471,986	-$471,986	0	-$471,986	-$471,986	0
2018	-1,415,959	$0	-$1,415,959.27	-$1,887,946	1	-$1,320,611	-$1,792,598	1
2019	-1,415,959	$0	-$1,415,959.27	-$1,678,905	2	-$1,231,684	-$1,610,762	2
2020	-1,415,959	$0	-$1,415,959.27	-$1,165,864	3	-$1,148,744	-$1,194,540	3
2021		$0	$0	-$557,864	4	$0	-$734,495	4
2022		$608,000	$608,000	$50,136	5	$429,066	-$305,429	5
2023		$608,000	$608,000	$658,136	6	$400,174	$94,745	6
2024		$608,000	$608,000	$1,266,136	7	$373,227	$467,972	7
2025		$608,000	$608,000	$1,874,136	8	$348,094	$816,066	8
2026		$608,000	$608,000	$2,482,136	9	$324,654	$1,140,721	9
2027		$608,000	$608,000	$3,090,136	10	$302,793	$1,443,514	10
2028		$608,000	$608,000	$3,698,136	11	$282,403	$1,725,917	11
2029		$608,000	$608,000	$4,306,136	12	$263,387	$1,989,304	12
2030		$608,000	$608,000	$4,914,136	13	$245,651	$2,234,955	13
2031		$608,000	$608,000	$5,522,136	14	$229,109	$2,464,064	14
2032		$608,000	$608,000	$6,130,136	15	$213,681	$2,677,745	15
2033		$608,000	$608,000	$6,738,136	16	$199,292	$2,877,037	16
2034		$608,000	$608,000	$7,346,136	17	$185,872	$3,062,910	17
2035		$608,000	$608,000	$7,954,136	18	$173,356	$3,236,266	18
2036		$608,000	$608,000	$8,562,136	19	$161,683	$3,397,948	19
2037		$608,000	$608,000	$9,170,136	20	$150,795	$3,548,744	20

Notes: 1. Discount Rate to be used is the Blended Cost of Capital Rate for Yukon Energy

2. The simple payback period in years is the first year the the cumulative cash flow is positive in Column E

3. The discounted cash flow payback period is the first year that the Cumulative discounted cash flow (DCF) is positive in Column H

4. As the capital cost is a negative cash flow it should entered as a negative number

5. For paybacks exceeding 5 years the discounted payback should be used as the time value of money becomes more significant

Appendix E - 5.0

SENSITIVITY ANALYSIS
CAPACITY
TRIAL PARAMETERS

Trial	1	2	3	4	5
Capacity, MW	0.7	0.7	0.7	0.7	0.7
Benefit	$1,000,000	$2,500,000	$5,000,000	$7,500,000	$10,000,000
One time benefit	$700,000	$1,750,000	$3,500,000	$5,250,000	$7,000,000

Trial	6	7	8	9	10
Energy	2.26	2.26	2.26	2.26	2.26
Benefit $/GWh/yr	$100,000	$150,000	$200,000	$250,000	$300,000
Annual benefit	$226,000	$339,000	$452,000	$565,000	$678,000

Trial	11
Capacity Benefit per MW	$1,000,000
Energy Benefit $/GWh/yr	$100,000

SENSITIVITY ANALYSIS
CAPACITY
TRIAL 1- Benefit of $1M per MW

Project

Date 17-Sep-15

Capital Cost -$2,978,976
Discount Rate 7.2%

Simple Payback: 8 years
Discounted Payback: 11 years

Base Year 2016
In-service Year 2018

Year	Capital Expense	Project Savings	Annual Cash Flow	Cumulative Cash flow	Year from In-service	Discounted Cash Flow	Cumulative DCF	Year
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$0	-$1,340,539	-$2,978,976	2	-$1,166,079	-$2,714,246	2
2019	$0	$700,000	$700,000	-$2,278,976	3	$567,898	-$2,146,348	3
2020		$470,000	$470,000	-$1,808,976	4	$355,627	-$1,790,721	4
2021		$470,000	$470,000	-$1,338,976	5	$331,680	-$1,459,041	5
2022		$470,000	$470,000	-$868,976	6	$309,345	-$1,149,696	6
2023		$470,000	$470,000	-$398,976	7	$288,514	-$861,182	7
2024		$470,000	$470,000	$71,024	8	$269,086	-$592,096	8
2025		$470,000	$470,000	$541,024	9	$250,966	-$341,129	9
2026		$470,000	$470,000	$1,011,024	10	$234,067	-$107,063	10
2027		$470,000	$470,000	$1,481,024	11	$218,305	$111,243	11
2028		$470,000	$470,000	$1,951,024	12	$203,605	$314,848	12
2029		$470,000	$470,000	$2,421,024	13	$189,895	$504,742	13
2030		$470,000	$470,000	$2,891,024	14	$177,107	$681,849	14
2031		$470,000	$470,000	$3,361,024	15	$165,181	$847,031	15
2032		$470,000	$470,000	$3,831,024	16	$154,058	$1,001,089	16
2033		$470,000	$470,000	$4,301,024	17	$143,684	$1,144,773	17
2034		$470,000	$470,000	$4,771,024	18	$134,009	$1,278,782	18
2035		$470,000	$470,000	$5,241,024	19	$124,985	$1,403,767	19
2036		$470,000	$470,000	$5,711,024	20	$116,569	$1,520,336	20

Appendix E - 5.2

Project	SENSITIVITY ANALYSIS CAPACITY TRIAL 2 - Benefit of $2.5M per MW	***Date***	17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***5***	years
Discount Rate	7.2%	***Discounted Payback:***	***6***	years
Base Year	2016			
In-service Year	2018			

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019	$0	$470,000	$470,000	-$758,976	3	$381,303	-$810,691	3
2020		$470,000	$470,000	-$288,976	4	$355,627	-$455,064	4
2021		$470,000	$470,000	$181,024	5	$331,680	-$123,385	5
2022		$470,000	$470,000	$651,024	6	$309,345	$185,960	6
2023		$470,000	$470,000	$1,121,024	7	$288,514	$474,474	7
2024		$470,000	$470,000	$1,591,024	8	$269,086	$743,561	8
2025		$470,000	$470,000	$2,061,024	9	$250,966	$994,527	9
2026		$470,000	$470,000	$2,531,024	10	$234,067	$1,228,594	10
2027		$470,000	$470,000	$3,001,024	11	$218,305	$1,446,899	11
2028		$470,000	$470,000	$3,471,024	12	$203,605	$1,650,504	12
2029		$470,000	$470,000	$3,941,024	13	$189,895	$1,840,398	13
2030		$470,000	$470,000	$4,411,024	14	$177,107	$2,017,506	14
2031		$470,000	$470,000	$4,881,024	15	$165,181	$2,182,687	15
2032		$470,000	$470,000	$5,351,024	16	$154,058	$2,336,745	16
2033		$470,000	$470,000	$5,821,024	17	$143,684	$2,480,430	17
2034		$470,000	$470,000	$6,291,024	18	$134,009	$2,614,438	18
2035		$470,000	$470,000	$6,761,024	19	$124,985	$2,739,423	19
2036		$470,000	$470,000	$7,231,024	20	$116,569	$2,855,992	20

Appendix E - 5.3

Project SENSITIVITY ANALYSIS
CAPACITY
TRIAL 3- Benefit of $5M per MW

Date 17-Sep-15

Capital Cost -$2,978,976
Discount Rate 7.2%

Simple Payback: 2 years
Discounted Payback: 2 years

Base Year 2016
In-service Year 2018

Year	Capital Expense	Project Savings	Annual Cash Flow	Cumulative Cash flow	Year from In-service	Discounted Cash Flow	Cumulative DCF	Year
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$3,500,000	$2,159,461	$521,024	2	$1,878,424	$330,257	2
2019	$0	$470,000	$470,000	$991,024	3	$381,303	$711,560	3
2020		$470,000	$470,000	$1,461,024	4	$355,627	$1,067,187	4
2021		$470,000	$470,000	$1,931,024	5	$331,680	$1,398,867	5
2022		$470,000	$470,000	$2,401,024	6	$309,345	$1,708,212	6
2023		$470,000	$470,000	$2,871,024	7	$288,514	$1,996,726	7
2024		$470,000	$470,000	$3,341,024	8	$269,086	$2,265,812	8
2025		$470,000	$470,000	$3,811,024	9	$250,966	$2,516,779	9
2026		$470,000	$470,000	$4,281,024	10	$234,067	$2,750,845	10
2027		$470,000	$470,000	$4,751,024	11	$218,305	$2,969,151	11
2028		$470,000	$470,000	$5,221,024	12	$203,605	$3,172,756	12
2029		$470,000	$470,000	$5,691,024	13	$189,895	$3,362,650	13
2030		$470,000	$470,000	$6,161,024	14	$177,107	$3,539,757	14
2031		$470,000	$470,000	$6,631,024	15	$165,181	$3,704,939	15
2032		$470,000	$470,000	$7,101,024	16	$154,058	$3,858,997	16
2033		$470,000	$470,000	$7,571,024	17	$143,684	$4,002,681	17
2034		$470,000	$470,000	$8,041,024	18	$134,009	$4,136,690	18
2035		$470,000	$470,000	$8,511,024	19	$124,985	$4,261,675	19
2036		$470,000	$470,000	$8,981,024	20	$116,569	$4,378,244	20

Appendix E - 5.4

Project	SENSITIVITY ANALYSIS CAPACITY TRIAL 4- Benefit of $7.5M per MW	***Date***	17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***2***	years
Discount Rate	7.2%	***Discounted Payback:***	***2***	years
Base Year	2016			
In-service Year	2018			

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$5,250,000	$3,909,461	$2,271,024	2	$3,400,676	$1,852,509	2
2019	$0	$470,000	$470,000	$2,741,024	3	$381,303	$2,233,812	3
2020		$470,000	$470,000	$3,211,024	4	$355,627	$2,589,439	4
2021		$470,000	$470,000	$3,681,024	5	$331,680	$2,921,118	5
2022		$470,000	$470,000	$4,151,024	6	$309,345	$3,230,463	6
2023		$470,000	$470,000	$4,621,024	7	$288,514	$3,518,978	7
2024		$470,000	$470,000	$5,091,024	8	$269,086	$3,788,064	8
2025		$470,000	$470,000	$5,561,024	9	$250,966	$4,039,030	9
2026		$470,000	$470,000	$6,031,024	10	$234,067	$4,273,097	10
2027		$470,000	$470,000	$6,501,024	11	$218,305	$4,491,402	11
2028		$470,000	$470,000	$6,971,024	12	$203,605	$4,695,007	12
2029		$470,000	$470,000	$7,441,024	13	$189,895	$4,884,902	13
2030		$470,000	$470,000	$7,911,024	14	$177,107	$5,062,009	14
2031		$470,000	$470,000	$8,381,024	15	$165,181	$5,227,190	15
2032		$470,000	$470,000	$8,851,024	16	$154,058	$5,381,249	16
2033		$470,000	$470,000	$9,321,024	17	$143,684	$5,524,933	17
2034		$470,000	$470,000	$9,791,024	18	$134,009	$5,658,942	18
2035		$470,000	$470,000	$10,261,024	19	$124,985	$5,783,927	19
2036		$470,000	$470,000	$10,731,024	20	$116,569	$5,900,495	20

Appendix E - 5.5

Project — SENSITIVITY ANALYSIS
CAPACITY
TRIAL 5- Benefit of $10M per MW

Date 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***2***	years
Discount Rate	7.2%	***Discounted Payback:***	***2***	years

Base Year 2016
In-service Year 2018

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$7,000,000	$5,659,461	$4,021,024	2	$4,922,928	$3,374,760	2
2019	$0	$470,000	$470,000	$4,491,024	3	$381,303	$3,756,063	3
2020		$470,000	$470,000	$4,961,024	4	$355,627	$4,111,690	4
2021		$470,000	$470,000	$5,431,024	5	$331,680	$4,443,370	5
2022		$470,000	$470,000	$5,901,024	6	$309,345	$4,752,715	6
2023		$470,000	$470,000	$6,371,024	7	$288,514	$5,041,229	7
2024		$470,000	$470,000	$6,841,024	8	$269,086	$5,310,315	8
2025		$470,000	$470,000	$7,311,024	9	$250,966	$5,561,282	9
2026		$470,000	$470,000	$7,781,024	10	$234,067	$5,795,349	10
2027		$470,000	$470,000	$8,251,024	11	$218,305	$6,013,654	11
2028		$470,000	$470,000	$8,721,024	12	$203,605	$6,217,259	12
2029		$470,000	$470,000	$9,191,024	13	$189,895	$6,407,153	13
2030		$470,000	$470,000	$9,661,024	14	$177,107	$6,584,261	14
2031		$470,000	$470,000	$10,131,024	15	$165,181	$6,749,442	15
2032		$470,000	$470,000	$10,601,024	16	$154,058	$6,903,500	16
2033		$470,000	$470,000	$11,071,024	17	$143,684	$7,047,184	17
2034		$470,000	$470,000	$11,541,024	18	$134,009	$7,181,193	18
2035		$470,000	$470,000	$12,011,024	19	$124,985	$7,306,178	19
2036		$470,000	$470,000	$12,481,024	20	$116,569	$7,422,747	20

Project

SENSITIVITY ANALYSIS
ENERGY
TRIAL 6: 100,000 $/GWh/yr

Date 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***8***	years
Discount Rate	7.2%	***Discounted Payback:***	***11***	years
Base Year	2016			
In-service Year	2018			

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019	$0	$226,000	$226,000	-$1,002,976	3	$183,350	-$1,008,644	3
2020		$226,000	$226,000	-$776,976	4	$171,004	-$837,641	4
2021		$226,000	$226,000	-$550,976	5	$159,489	-$678,152	5
2022		$226,000	$226,000	-$324,976	6	$148,749	-$529,404	6
2023		$226,000	$226,000	-$98,976	7	$138,732	-$390,671	7
2024		$226,000	$226,000	$127,024	8	$129,390	-$261,281	8
2025		$226,000	$226,000	$353,024	9	$120,677	-$140,603	9
2026		$226,000	$226,000	$579,024	10	$112,551	-$28,052	10
2027		$226,000	$226,000	$805,024	11	$104,972	$76,920	11
2028		$226,000	$226,000	$1,031,024	12	$97,904	$174,824	12
2029		$226,000	$226,000	$1,257,024	13	$91,311	$266,135	13
2030		$226,000	$226,000	$1,483,024	14	$85,162	$351,297	14
2031		$226,000	$226,000	$1,709,024	15	$79,428	$430,725	15
2032		$226,000	$226,000	$1,935,024	16	$74,079	$504,804	16
2033		$226,000	$226,000	$2,161,024	17	$69,091	$573,895	17
2034		$226,000	$226,000	$2,387,024	18	$64,438	$638,333	18
2035		$226,000	$226,000	$2,613,024	19	$60,099	$698,432	19
2036		$226,000	$226,000	$2,839,024	20	$56,052	$754,484	20

Appendix E - 5.7

Project SENSITIVITY ANALYSIS
ENERGY
TRIAL 7: 150,000 $/GWh/yr

Date 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	***6***	years
Discount Rate	7.2%	***Discounted Payback:***	***7***	years
Base Year	2016			
In-service Year	2018			

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019	$0	$339,000	$339,000	-$889,976	3	$275,025	-$916,969	3
2020		$339,000	$339,000	-$550,976	4	$256,505	-$660,464	4
2021		$339,000	$339,000	-$211,976	5	$239,233	-$421,231	5
2022		$339,000	$339,000	$127,024	6	$223,123	-$198,108	6
2023		$339,000	$339,000	$466,024	7	$208,099	$9,991	7
2024		$339,000	$339,000	$805,024	8	$194,086	$204,076	8
2025		$339,000	$339,000	$1,144,024	9	$181,016	$385,092	9
2026		$339,000	$339,000	$1,483,024	10	$168,827	$553,919	10
2027		$339,000	$339,000	$1,822,024	11	$157,458	$711,378	11
2028		$339,000	$339,000	$2,161,024	12	$146,855	$858,233	12
2029		$339,000	$339,000	$2,500,024	13	$136,966	$995,200	13
2030		$339,000	$339,000	$2,839,024	14	$127,743	$1,122,943	14
2031		$339,000	$339,000	$3,178,024	15	$119,141	$1,242,084	15
2032		$339,000	$339,000	$3,517,024	16	$111,119	$1,353,203	16
2033		$339,000	$339,000	$3,856,024	17	$103,636	$1,456,839	17
2034		$339,000	$339,000	$4,195,024	18	$96,657	$1,553,496	18
2035		$339,000	$339,000	$4,534,024	19	$90,149	$1,643,645	19
2036		$339,000	$339,000	$4,873,024	20	$84,078	$1,727,723	20

Appendix E - 5.8

Project SENSITIVITY ANALYSIS ENERGY TRIAL 8: 200,000 $/GWh/yr

Date 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	5	years
Discount Rate	7.2%	***Discounted Payback:***	6	years

Base Year 2016
In-service Year 2018

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019	$0	$452,000	$452,000	-$776,976	3	$366,700	-$825,294	3
2020		$452,000	$452,000	-$324,976	4	$342,007	-$483,287	4
2021		$452,000	$452,000	$127,024	5	$318,977	-$164,310	5
2022		$452,000	$452,000	$579,024	6	$297,498	$133,187	6
2023		$452,000	$452,000	$1,031,024	7	$277,465	$410,652	7
2024		$452,000	$452,000	$1,483,024	8	$258,781	$669,433	8
2025		$452,000	$452,000	$1,935,024	9	$241,355	$910,788	9
2026		$452,000	$452,000	$2,387,024	10	$225,103	$1,135,890	10
2027		$452,000	$452,000	$2,839,024	11	$209,945	$1,345,835	11
2028		$452,000	$452,000	$3,291,024	12	$195,807	$1,541,642	12
2029		$452,000	$452,000	$3,743,024	13	$182,622	$1,724,264	13
2030		$452,000	$452,000	$4,195,024	14	$170,325	$1,894,589	14
2031		$452,000	$452,000	$4,647,024	15	$158,855	$2,053,444	15
2032		$452,000	$452,000	$5,099,024	16	$148,158	$2,201,602	16
2033		$452,000	$452,000	$5,551,024	17	$138,181	$2,339,784	17
2034		$452,000	$452,000	$6,003,024	18	$128,877	$2,468,660	18
2035		$452,000	$452,000	$6,455,024	19	$120,198	$2,588,858	19
2036		$452,000	$452,000	$6,907,024	20	$112,104	$2,700,963	20

Appendix E - 5.9

Project SENSITIVITY ANALYSIS ENERGY TRIAL 9: 250,000 $/GWh/yr

Date 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	5	years
Discount Rate	7.2%	***Discounted Payback:***	5	years
Base Year	2016			
In-service Year	2018			

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019	$0	$565,000	$565,000	-$663,976	3	$458,375	-$733,619	3
2020		$565,000	$565,000	-$98,976	4	$427,509	-$306,110	4
2021		$565,000	$565,000	$466,024	5	$398,721	$92,611	5
2022		$565,000	$565,000	$1,031,024	6	$371,872	$464,483	6
2023		$565,000	$565,000	$1,596,024	7	$346,831	$811,314	7
2024		$565,000	$565,000	$2,161,024	8	$323,476	$1,134,790	8
2025		$565,000	$565,000	$2,726,024	9	$301,694	$1,436,484	9
2026		$565,000	$565,000	$3,291,024	10	$281,378	$1,717,862	10
2027		$565,000	$565,000	$3,856,024	11	$262,431	$1,980,292	11
2028		$565,000	$565,000	$4,421,024	12	$244,759	$2,225,052	12
2029		$565,000	$565,000	$4,986,024	13	$228,277	$2,453,329	13
2030		$565,000	$565,000	$5,551,024	14	$212,906	$2,666,235	14
2031		$565,000	$565,000	$6,116,024	15	$198,569	$2,864,804	15
2032		$565,000	$565,000	$6,681,024	16	$185,198	$3,050,001	16
2033		$565,000	$565,000	$7,246,024	17	$172,727	$3,222,728	17
2034		$565,000	$565,000	$7,811,024	18	$161,096	$3,383,824	18
2035		$565,000	$565,000	$8,376,024	19	$150,248	$3,534,072	19
2036		$565,000	$565,000	$8,941,024	20	$140,130	$3,674,202	20

Project

SENSITIVITY ANALYSIS
ENERGY
TRIAL 10: 300,000 $/GWh/yr

Date 17-Sep-15

Capital Cost	-$2,978,976	***Simple Payback:***	4	years
Discount Rate	7.2%	***Discounted Payback:***	5	years
Base Year	2016			
In-service Year	2018			

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$1,750,000	$409,461	-$1,228,976	2	$356,173	-$1,191,995	2
2019	$0	$678,000	$678,000	-$550,976	3	$550,050	-$641,944	3
2020		$678,000	$678,000	$127,024	4	$513,011	-$128,934	4
2021		$678,000	$678,000	$805,024	5	$478,466	$349,532	5
2022		$678,000	$678,000	$1,483,024	6	$446,247	$795,778	6
2023		$678,000	$678,000	$2,161,024	7	$416,197	$1,211,976	7
2024		$678,000	$678,000	$2,839,024	8	$388,171	$1,600,147	8
2025		$678,000	$678,000	$3,517,024	9	$362,032	$1,962,179	9
2026		$678,000	$678,000	$4,195,024	10	$337,654	$2,299,833	10
2027		$678,000	$678,000	$4,873,024	11	$314,917	$2,614,750	11
2028		$678,000	$678,000	$5,551,024	12	$293,711	$2,908,461	12
2029		$678,000	$678,000	$6,229,024	13	$273,933	$3,182,394	13
2030		$678,000	$678,000	$6,907,024	14	$255,487	$3,437,880	14
2031		$678,000	$678,000	$7,585,024	15	$238,283	$3,676,163	15
2032		$678,000	$678,000	$8,263,024	16	$222,237	$3,898,400	16
2033		$678,000	$678,000	$8,941,024	17	$207,272	$4,105,673	17
2034		$678,000	$678,000	$9,619,024	18	$193,315	$4,298,988	18
2035		$678,000	$678,000	$10,297,024	19	$180,297	$4,479,285	19
2036		$678,000	$678,000	$10,975,024	20	$168,156	$4,647,441	20

Appendix E - 5.11

SENSITIVITY ANALYSIS
WORST CASE
TRIAL 11-
Capacity Benefit of $1M per MW
Energy Benefit of 100,000 $/GWh/y

Project

Date 17-Sep-15

Capital Cost -$2,978,976
Discount Rate 7.2%

Simple Payback: ***13*** years
Discounted Payback: ***21*** years

Base Year 2016
In-service Year 2018

Year	*Capital Expense*	*Project Savings*	*Annual Cash Flow*	*Cumulative Cash flow*	*Year from In-service*	*Discounted Cash Flow*	*Cumulative DCF*	*Year*
2016	-$297,898	$0	-$297,898	-$297,898	0	-$297,898	-$297,898	0
2017	-$1,340,539	$0	-$1,340,539	-$1,638,437	1	-$1,250,270	-$1,548,167	1
2018	-$1,340,539	$700,000	-$640,539	-$2,278,976	2	-$557,178	-$2,105,346	2
2019		$226,000	$226,000	-$2,052,976	3	$183,350	-$1,921,995	3
2020		$226,000	$226,000	-$1,826,976	4	$171,004	-$1,750,992	4
2021		$226,000	$226,000	-$1,600,976	5	$159,489	-$1,591,503	5
2022		$226,000	$226,000	-$1,374,976	6	$148,749	-$1,442,755	6
2023		$226,000	$226,000	-$1,148,976	7	$138,732	-$1,304,022	7
2024		$226,000	$226,000	-$922,976	8	$129,390	-$1,174,632	8
2025		$226,000	$226,000	-$696,976	9	$120,677	-$1,053,954	9
2026		$226,000	$226,000	-$470,976	10	$112,551	-$941,403	10
2027		$226,000	$226,000	-$244,976	11	$104,972	-$836,431	11
2028		$226,000	$226,000	-$18,976	12	$97,904	-$738,527	12
2029		$226,000	$226,000	$207,024	13	$91,311	-$647,216	13
2030		$226,000	$226,000	$433,024	14	$85,162	-$562,054	14
2031		$226,000	$226,000	$659,024	15	$79,428	-$482,626	15
2032		$226,000	$226,000	$885,024	16	$74,079	-$408,547	16
2033		$226,000	$226,000	$1,111,024	17	$69,091	-$339,456	17
2034		$226,000	$226,000	$1,337,024	18	$64,438	-$275,018	18
2035		$226,000	$226,000	$1,563,024	19	$60,099	-$214,919	19
2036		$226,000	$226,000	$1,789,024	20	$56,052	-$158,867	20
2037		$226,000	$226,000	$2,015,024	21	$52,278	-$106,589	21
2038		$226,000	$226,000	$2,241,024	22	$48,757	-$57,832	22
2039		$226,000	$226,000	$2,467,024	23	$45,474	-$12,358	23
2040		$226,000	$226,000	$2,693,024	24	$42,412	$30,055	24
2041		$226,000	$226,000	$2,919,024	25	$39,556	$69,611	25
2042		$226,000	$226,000	$3,145,024	26	$36,892	$106,503	26
2043		$226,000	$226,000	$3,371,024	27	$34,408	$140,911	27
2044		$226,000	$226,000	$3,597,024	28	$32,091	$173,002	28
2045		$226,000	$226,000	$3,823,024	29	$29,930	$202,933	29
2046		$226,000	$226,000	$4,049,024	30	$27,915	$230,847	30
2047		$226,000	$226,000	$4,275,024	31	$26,035	$256,883	31
2048		$226,000	$226,000	$4,501,024	32	$24,282	$281,164	32
2049		$226,000	$226,000	$4,727,024	33	$22,647	$303,811	33
2050		$226,000	$226,000	$4,953,024	34	$21,122	$324,933	34
2051		$226,000	$226,000	$5,179,024	35	$19,700	$344,633	35
2052		$226,000	$226,000	$5,405,024	36	$18,373	$363,006	36