Alaska Hydro Corporation

More Creek Hydroelectric Project
Prefeasibility Study

March 2018
E6348

SIGMA ENGINEERING LTD
1444 Alberni Street, 4th Floor, Vancouver, BC, Canada V6G 2Z4
Phone: (604) 688-8271 Fax: (604) 688-1286

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

PREFACE

This study has been prepared exclusively for Alaska Hydro Corporation for the purposes of assessing the proposed More Creek hydroelectric project. No third party is entitled to rely on this analysis without the express written permission of Sigma Engineering Ltd and Alaska Hydro Corporation.

This study has been updated from the original June 2015 version. The update has revised the dam type from a roller compacted concrete gravity dam to an arch type dam based on Golder Associates' September 2017 dam prefeasibility study. As well, the dam location has been moved 400m downstream to a location originally studied by BC Hydro. Power generation estimates have not been affected by these design revisions. Project cost estimates and financial models have been updated to reflect additional pricing information and inflation.

1. BACKGROUND

Alaska Hydro Corp. (AHC) requires a prefeasibility study for the proposed More Creek hydroelectric project, located approximately 10 km northwest from Bob Quinn Lake in the Skeena region of British Columbia.

The 75 MW project consists of access roads, an intake, a dam, a tunnel and penstock, powerhouse and generating equipment, transmission line and interconnection to the Bob Quinn BC Hydro substation (see Figures 1 and 2).

Below we describe our methodology and assumptions in developing a model to estimate the projected revenues (hydrology and generation model), and our considerations for developing prefeasibility cost estimates for the project.

2. HYDROLOGY

The hydrology is based on flow data from the Water Survey Canada (WSC) streamflow gauge '08CG005 – More Creek near the mouth'. The gauge was located near the proposed intake site and was active from 1972 to 1995 and has a set of 19 complete years of daily flow data available. The drainage area of WSC 08CG005 is 844 km², which is the same as the drainage at the intake of the proposed project. Thus the flow data from the WSC gauge are used without any adjustments as the basis of the hydrology at the site.

The mean monthly and annual flows at the site are shown in Table 1 below:

Table 1. Mean Monthly and Annual Flows at proposed intake

	1974	1975	1977	1978	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	Average
Jan	5.3	8.7	8.0	5.8	6.7	12.3	5.8	6.0	4.4	6.0	4.9	8.0	7.6	7.5	7.4	7.2	8.3	6.8	6.6	**7.0**
Feb	4.5	7.5	8.2	5.0	8.2	8.7	4.9	4.9	5.6	4.8	4.0	6.4	5.5	7.2	5.3	6.8	8.3	6.8	4.6	**6.2**
Mar	4.5	6.2	6.3	4.0	5.8	7.5	4.3	4.3	5.3	5.0	7.5	5.4	4.9	6.1	5.5	4.5	12.4	5.9	8.6	**6.0**
Apr	7.5	6.0	14.1	9.1	12.1	8.9	5.3	12.6	9.0	6.0	9.0	10.2	14.6	11.9	14.5	13.4	18.6	17.6	16.2	**11.4**
May	29.6	36.6	43.9	33.0	58.7	67.5	24.5	56.3	49.4	37.1	36.4	38.5	57.0	47.3	59.5	67.5	50.6	102.9	56.3	**50.1**
Jun	64.9	100.6	108.3	110.3	153.7	105.2	129.2	132.7	98.4	99.3	105.5	87.5	110.9	122.8	127.8	134.5	163.2	139.7	98.7	**115.4**
Jul	89.1	172.3	135.3	120.1	138.0	135.3	150.8	119.5	115.7	160.1	162.8	150.3	126.6	144.1	137.1	125.4	196.3	151.2	132.0	**140.1**
Aug	104.3	91.1	150.2	119.6	96.6	114.6	105.0	106.7	130.7	98.2	93.2	88.0	109.4	128.4	140.9	112.5	100.7	105.3	117.6	**111.2**
Sep	87.9	32.7	49.2	45.3	71.3	127.3	68.2	53.3	37.5	59.2	47.2	80.2	68.6	77.5	97.2	76.0	45.3	57.5	113.7	**68.2**
Oct	104.7	17.3	29.7	69.2	98.0	41.4	43.9	26.5	31.3	26.5	74.0	51.0	43.6	41.3	29.5	50.0	27.4	69.5	37.1	**48.0**
Nov	30.7	11.4	10.7	17.3	24.2	30.1	12.2	16.0	9.7	10.1	20.4	24.8	15.9	18.8	16.4	14.3	16.4	20.9	18.3	**17.8**
Dec	12.0	5.3	6.8	7.0	16.1	9.7	7.4	6.0	6.2	4.7	4.9	13.3	9.7	11.7	10.4	11.7	9.8	10.6	7.6	**9.0**
Annual	45.7	41.6	47.9	45.8	57.8	56.0	47.1	45.6	42.3	43.4	47.9	47.3	48.1	52.4	54.6	52.3	55.1	58.3	51.7	**49.5**

3. GENERATION AND REVENUE ESTIMATES

A spreadsheet model is used to calculate the monthly and annual generation at the site. The model uses 19 complete years of daily flows as the basis of the calculations.

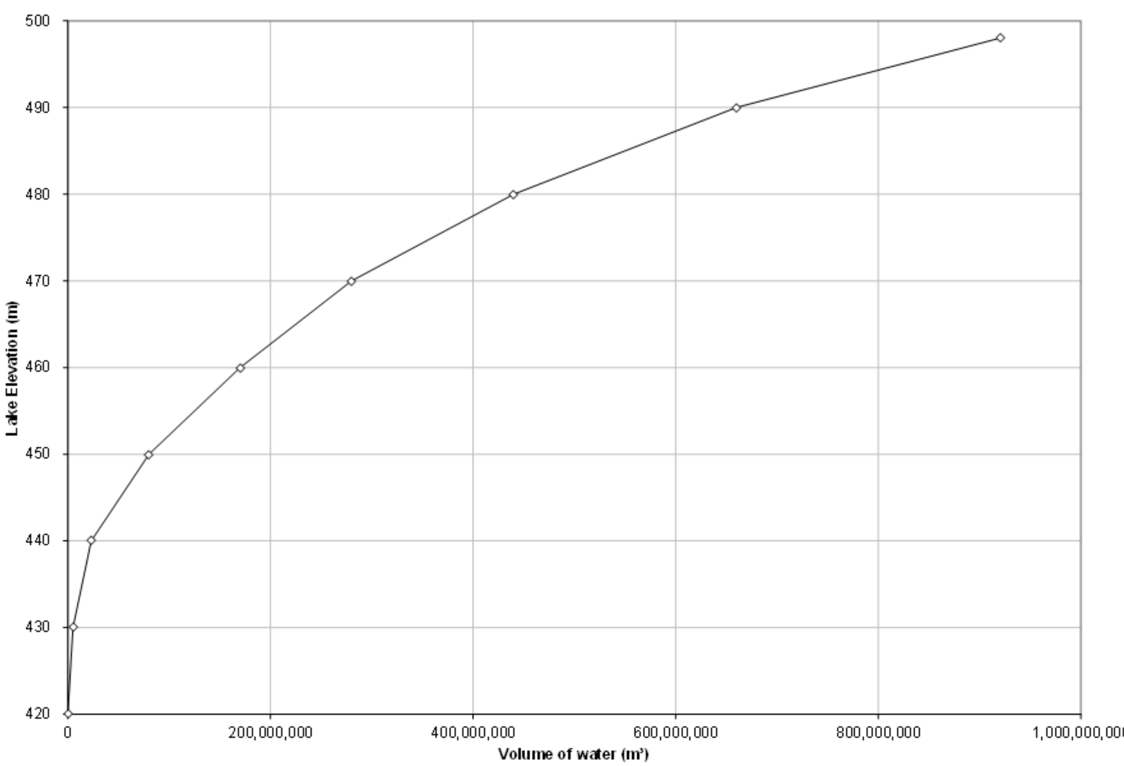
Assumptions

The basic assumptions used in the model are:

Design flow	80	m^3/s
Dam crest elevation	498	m
Minimum lake level	468	m
Mean tailwater level	380	m
Gross head	88 - 118	m
Instream flow release	2.476	m^3/s (5% of mean annual flow)
Minimum turbine flow	20	m^3/s
Installed Capacity	75.2	MW
Generating equipment efficiency	86.45%	
Friction head loss (waterway)	6%	

The following lake storage curve is used (Figure 3). The curve was developed based on available 1:20,000 mapping.

Figure 3. More Creek Reservoir Storage Curve



The 30 m of available storage is equivalent to approximately 90 days of storage at the design flow. The simple operation of the plant would dictate that excess water is stored during the summer months and used in the fall and winter months.

However, this operation assumes that the electricity price is the same throughout the year. Since at this stage, the electricity pricing scheme is not known, the model used the current BC Standing Offer Program (SOP) monthly delivery time adjustments to vary the electricity price through the year.

The model used monthly targets for the design flow to simulate the operation of the plant and maximize the average annual generation and revenue. Our preliminary analysis determined that the following monthly targets for the design flow resulted in the maximum generation at the plant:

Table 2. Monthly targets for turbine flow

	Flow (m^3/s)
Jan	80
Feb	80
Mar	70
Apr	40
May	45
Jun	35
Jul	45
Aug	60
Sep	80
Oct	70
Nov	70
Dec	80

The resulting monthly and annual generation estimates are shown in Table 3 below:

Table 3. Generation estimates (GWh)

	1974	1975	1977	1978	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	Average
Jan	52.7	25.1	2.7	20.9	20.8	48.3	46.2	37.1	10.9	2.7	8.1	35.5	28.1	25.2	45.7	45.1	46.0	23.7	46.6	30.1
Feb	46.4	1.3	2.7	1.3	2.7	31.1	9.6	0.0	1.3	0.0	0.0	1.3	1.3	2.7	6.8	4.0	10.9	2.7	12.4	7.3
Mar	41.3	2.3	2.3	1.2	1.2	2.3	1.2	1.2	1.2	2.3	3.5	1.2	1.2	1.2	2.3	1.2	5.9	1.2	3.5	4.1
Apr	20.9	1.3	4.7	2.7	4.0	3.4	1.3	4.7	2.7	0.7	2.7	4.0	4.7	4.0	5.4	4.7	7.4	6.7	6.1	4.9
May	13.6	15.9	21.3	15.9	21.5	20.8	9.8	21.3	20.7	13.0	14.4	15.2	22.4	19.7	20.7	22.4	18.3	23.6	22.2	18.6
Jun	18.2	18.7	18.9	19.0	20.2	19.7	19.1	19.7	18.9	19.1	19.0	18.6	19.4	19.5	19.8	19.7	19.9	21.3	19.1	19.4
Jul	25.9	29.0	28.1	28.0	30.0	28.7	29.1	29.1	27.7	28.7	28.7	28.1	28.5	29.1	29.3	29.5	30.8	30.5	28.2	28.8
Aug	36.6	40.8	40.8	40.0	41.8	40.9	41.2	40.5	39.8	40.8	40.9	39.9	40.3	41.2	41.5	41.3	42.0	42.0	40.3	40.7
Sep	48.7	52.2	53.6	51.9	53.8	54.0	53.7	53.0	51.8	52.7	52.5	51.7	52.9	54.1	54.2	54.0	53.4	53.8	53.1	52.9
Oct	45.1	45.2	47.1	46.1	48.8	48.2	47.8	46.3	45.2	46.5	46.9	46.7	46.9	48.4	48.3	48.4	47.0	47.7	48.3	47.1
Nov	43.3	41.0	43.7	43.5	46.2	45.4	44.7	42.8	41.1	42.7	44.6	43.5	43.7	45.2	45.1	45.4	43.6	45.7	45.2	44.0
Dec	47.6	32.7	47.5	47.3	52.2	50.9	49.2	46.2	34.2	45.9	49.0	48.0	47.8	50.4	50.1	50.6	47.7	51.1	50.2	47.3
Annual	440.3	305.6	313.4	317.8	343.1	393.8	352.9	342.0	295.5	295.1	310.3	333.7	337.1	340.7	369.1	366.5	372.8	350.0	375.1	345.0

If an electricity price of $100/MWh is assumed the same throughout the year, then the average annual revenue would be $34.5 million. Note the lowest and highest annual revenue are $29.5 and $44.0 million respectively.

Applying the current BC Hydro monthly delivery adjustment factors, the average annual revenue would be about $34.8 million, ranging from $29.8 to $44.4 million.

Note that if the electricity price variance through the year is different from that of the current SOP, the monthly target for the turbine flow may differ from the ones shown above. Also, the impact of any monthly variation of electricity prices may fluctuate depending on price change and plant operation.

Impact on Forest Kerr hydro project

The operation of the More Creek hydro project would potentially increase the generation of the existing Forrest Kerr project, located downstream from the More Creek powerhouse. The storage of water during the summer months, when Forrest Kerr would typically be spilling water, and the subsequent release of the stored water over the winter months would increase the Forrest Kerr generation potential.

The operational details of the Forrest Kerr project are not available to us. A high level estimate of the potential additional generation at Forrest Kerr is based on converting the additional flow (m^3/s) to power (MW) using a factor of 0.80. The additional average annual generation at the Forrest Kerr project, using the above assumptions, is estimated at about 149 GWh.

4. CONSTRUCTION COST ESTIMATE

A prefeasibility cost estimate for the project has been developed based on the conceptual level design and layout shown in Figure 2. Any consideration of additional design options or optimizations is outside the scope of this study.

Sigma has attempted to indicate potential areas for future consideration. The geotechnical characteristics in the area of the proposed dam will have a considerable impact on the selected type of dam and the associated cost. The access to the project area is from an existing road and bridges over Iskut River which is shown on online mapping. It appears that the road may be subject to seasonal flooding. For the purposes of this study, it is assumed that the road will be accessible and that technical issues will be addressed in future studies.

The attached Table 4 shows the prefeasibility construction cost estimate for the project.

Table 4. Prefeasibility Cost Estimate

More Creek Cost Estimate

ACTIVITY	Qty	Unit	Unit Cost	Total	SubTotal	Contingency %	Contingency $	Total
A Access Roads								
Access Road to Power House	0.5	km	165,000	82,500				
Access Road, Powerhouse to Intake	1	km	600,000	600,000	**682,500**	**20%**	**136,500**	**819,000**
B Intake Structure								
Clearing, Grubbing, Stripping, Scaling	1	LS	3,000,000	3,000,000				
Archdam Concrete	130,000	m^3	342	44,460,000				
Aggregate Supply	97,500	m^3	50	4,875,000				
Apron Concrete	4,200	m^3	1,500	6,300,000				
Reinforced Concrete	1,800	m^3	1,700	3,060,000				
Trashracks	280	m^2	2,100	588,000				
Spillway Gates	360	m^2	10,500	3,780,000				
Intake gate	36	m^2	10,600	381,600				
Diversion	1	LS	3,700,000	3,700,000				
Control Building	1	LS	100,000	100,000				
Power supply to intake area	1,000	m	265	265,000	**70,509,600**	**20%**	**14,101,920**	**84,611,520**
C Penstock								
Tunnel (Power Tunnel 500m, Diversion Tunnel 370m)	1	LS	18,100,000	18,100,000	**18,100,000**	**15%**	**2,715,000**	**20,815,000**
D Powerhouse Structural								
Concrete foundation and terminal anchor block	1	LS	14,850,000	14,850,000				
Building with Crane- supplyand install	1	LS	4,750,000	4,750,000	**19,600,000**	**15%**	**2,940,000**	**22,540,000**
E Powerhouse Generation Equipment								
Turbines, Generators, TIV and Bifurcation	1	LS	12,500,000	12,500,000				
Mechanical Installation	1	LS	1,500,000	1,500,000				
Balance of Plant	1	LS	16,000,000	16,000,000	**30,000,000**	**10%**	**3,000,000**	**33,000,000**
F Transmission Line								
3 phase 138kV to Bob Quinn	13	km	475,000	6,175,000				
BCH Interconnection Fee	1	LS	8,500,000	8,500,000	**14,675,000**	**20%**	**2,702,500**	**17,377,500**
G Work Camp								
Work Camp	47,500	Man-Days	212	10,070,000	**10,070,000**	**20%**	**2,014,000**	**12,084,000**
TOTAL CONSTRUCTION COSTS					**163,637,100**		**$ 27,609,920**	**$ 191,247,020**

General Comments

A. Access Roads

Pricing based on recent project built on Vancouver Island.

B. Intake Structure

Reinforced concrete pricing based on pricing for recent projects.

Pricing for mass concrete was based on estimates provided by Golder Associates in their September 2017 report on the More Creek Dam. The Golder report evaluated multiple dam options (earth fill, rock fill, gravity and arch), with an ach type being selected as the most economical.

Pricing for trashracks, intake gate is based on price per square foot from a recent project.

Radial gate pricing based on square foot pricing of smaller gates.

Power supply to intake area assumed typical 25 kV line costs.

C. Tunneling

The 500m long penstock tunnel is 5.5m x 5.5m. The 370m long diversion tunnel is 12m x 12m. Cost for the two tunnels is based on a cost estimate provided to Sigma by CanMine Contracting LP.

D. Powerhouse Structural

Cost estimates are prorated from actual costs for small plants, with an adjustment for economy of scale.

E. Powerhouse Generation Equipment

Cost estimate for generating equipment is based on quote from Chongqing Yunhe Hydropower Inc. plus an allowance for $1 million for trifurcation. The turbine quote was for 3 horizontal Francis units with generators and a bypass valve to meet environmental criteria.

Balance of plant cost estimate is based on prorated cost of smaller plants discounted by 25% for economy of scale. Balance of plant includes all electrical items not in Turbine-Generator package. Includes controls, switchgear, transformers to 138kV, auxiliary transformers, grounding, plant wiring, etc.

F. Transmission Line

Cost estimate for 3 phase 138 kV line to Bob Quinn is based on unit cost of 69kV line for a recent project, increased for voltage.

An allowance is made for the BCH interconnection price which is very difficult to estimate at this stage.

G. Work Camp

Pricing per man-day is based on quote from full service camp provider. Estimate of number of man-days is based on the total project construction cost.

Limitations

The estimates presented in Table 4 do not include or allow costs for the following:

- Possible fish screens
- Trashrack automatic racking
- A seepage blanket, or grouting, to prevent leakage around the dam
- Plunge pool construction for spillway (may be required depending on site conditions, however the rock foundation is expected to be of good quality)
- Wildlife and First Nations compensation
- Clearing of reservoir. It is assumed to be zero (trees sold for value equal to clearing cost)
- Potential relocation of a Nova Gold (Galore Creek) road that may be flooded. This road may not be needed beyond the More Creek dam location, unless the mine project is restarted.

5. FINANCIAL ANALYSIS

The financial analysis of the project is based on a 40-year period. Sigma used a spreadsheet financial analysis model that has been developed and used for hydroelectric projects in BC. The analysis takes into account the estimated construction costs and escalating annual operating costs (O&M, administration, property/liability insurance, water rent, property and school taxes).

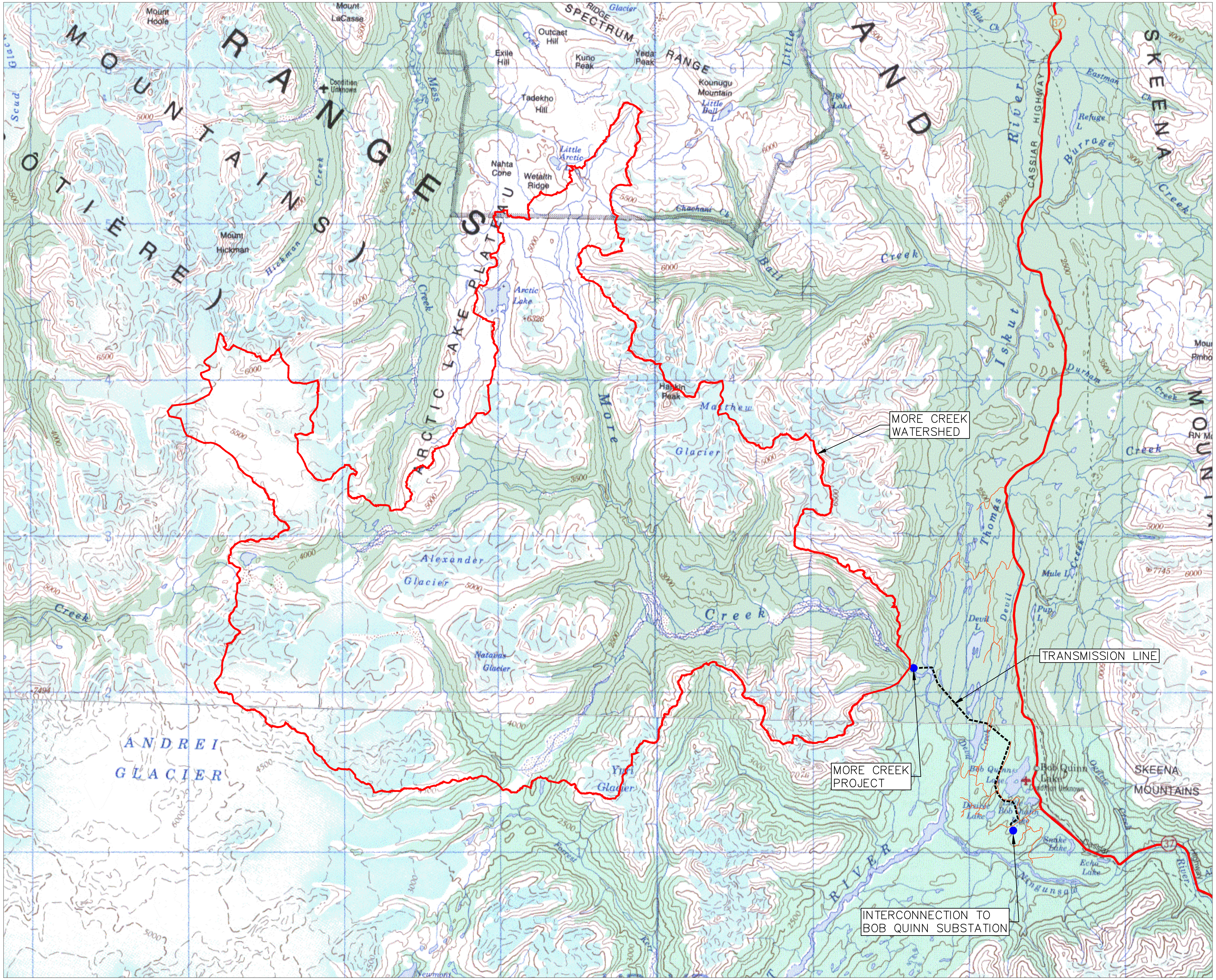
The analysis does not include any land acquisition and permitting costs, royalty payments or wheeling fees. The analysis indicates the expected net present value (NPV) and internal rate of return (IRR) for the project (see Appendix A).

Assumptions

- The annual gross generation from Table 3 is used.
- The construction cost from the previous sections is used.
- The capital cost of the project includes cost estimates for Project Management, Engineering and Finance costs, expressed as a percentage of the construction cost. The estimates are based on typical costs for hydroelectric project in BC. The capital cost also includes an inflation adjustment from 2018 to 2020.
- The annual operating costs include the following, all adjusted annually for inflation:
  - Administration and Operation and Maintenance Cost as 1% of the Capital Cost
  - Insurance cost. Based on typical industry rates, which need to be confirmed by insurance professionals.
  - Water Rent based on 2017 rates.

  - Property and School Taxes. Typical BC rates are used which will need to be confirmed at a later stage.

- The analysis assumes 20% equity, 25 year amortization, an effective interest rate of 5.5% and an electricity price of $100/MWh.



NOTES

1. BASE MAP FROM NTS 104B ISKUT RIVER & 104G TELEGRAPH CREEK, ORIGINAL SCALE 1:250,000
2. COORDINATE SYSTEM = UTM ZONE 9, NAD 83

0 5 10 15 20km

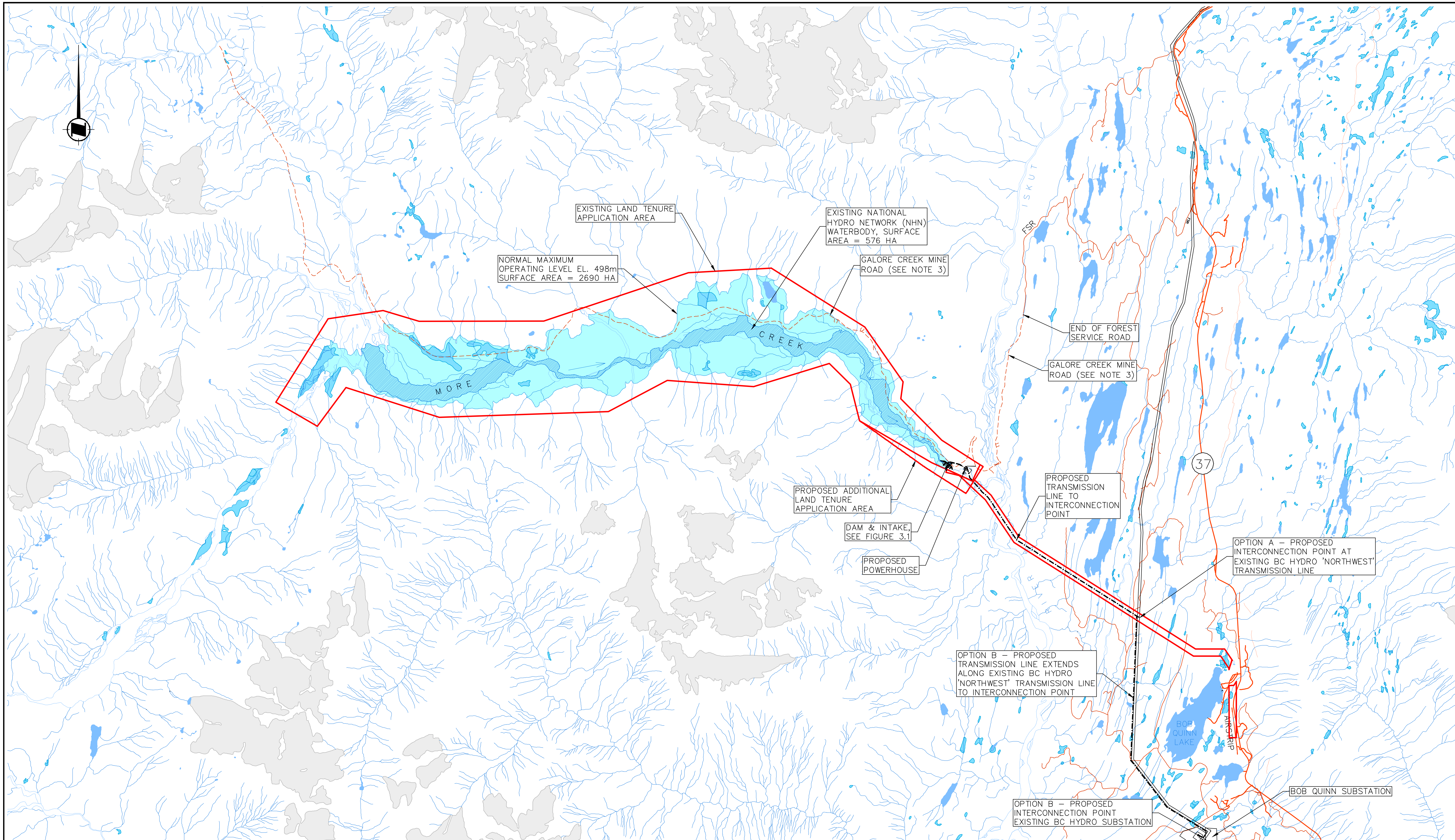
SCALE

SIGMA ENGINEERING LTD

ALASKA HYDRO CORPORATION
MORE CREEK HYDROELECTRIC PROJECT

LOCATION PLAN & WATERSHED

DATE	JUN 15	PROJ.	E6348
DWN.	ND/DGC	DWG.	FIGURE 1



NOTES:

1. WATERCOURSES AND LAKES FROM BMGS, ILMB, CANADIAN HYDRO NETWORK 1.0–CL4–NC4; SOURCE DATA = BC–TRIM; SOURCE SCALE = 1:20,000
2. ADDITIONAL BASEMAP LAYERS DOWNLOADED FROM THE BC DATA DISTRIBUTION SERVICE.
3. GALORE CREEK MINE ROAD APPROXIMATED FROM GOOGLE EARTH.
4. COORDINATE SYSTEM = UTM ZONE 9, NAD 83

0 2 4 6 8 km

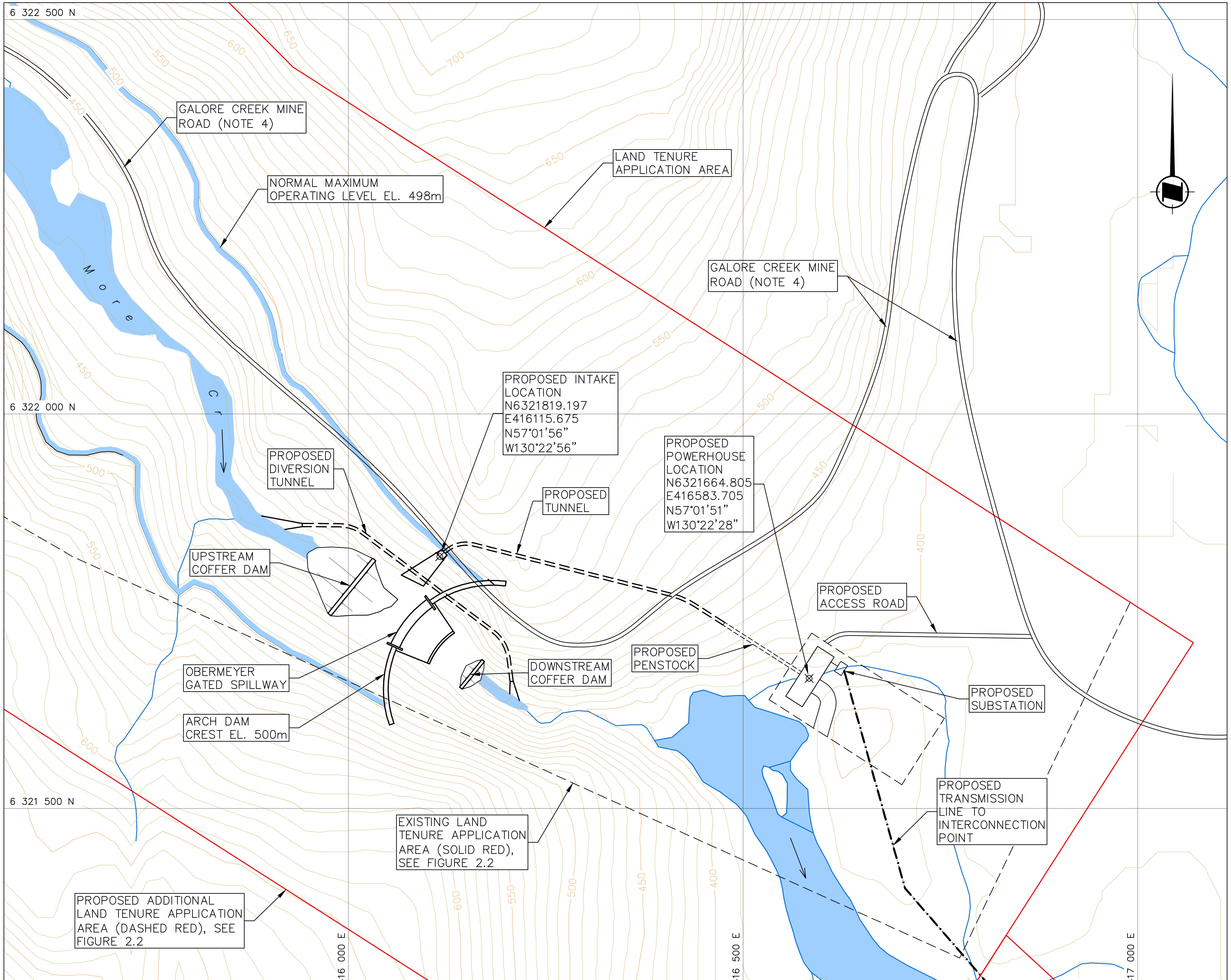
LEGEND

- ROAD (DIGITAL ROAD ATLAS)
- ROAD (FOREST SERVICE)
- TRAIL
- ROAD (ESTIMATED, SEE NOTE 3)
- GLACIER

SIGMA ENGINEERING LTD

ALASKA HYDRO CORPORATION
MORE CREEK HYDROELECTRIC PROJECT
PROJECT LAYOUT

DATE	APR 2017	PROJ.	E6348		
DWN.	KV/DGC	DWG.	FIGURE 2.1	REV.	3



NOTES

1. CONTOURS FROM BMGS, ILMB, CANADIAN DIGITAL ELEVATION DATA, GEOBASE 1.0; SOURCE DATA = BC–TRIM; SOURCE SCALE = 1:20,000; CONTOUR INTERVAL SHOWN = 10m
2. WATERCOURSES AND LAKES FROM BMGS, ILMB, CANADIAN HYDRO NETWORK 1.0–CL4–NC4; SOURCE DATA = BC–TRIM; SOURCE SCALE = 1:20,000.
3. ADDITIONAL BASEMAP LAYERS DOWNLOADED FROM THE BC DATA DISTRIBUTION SERVICE.
4. GALORE CREEK MINE ROAD APPROXIMATED FROM GOOGLE EARTH.
5. COORDINATE SYSTEM = UTM ZONE 9, NAD 83

0 100 200 300 400m

SCALE

SIGMA ENGINEERING LTD

ALASKA HYDRO CORPORATION
MORE CREEK HYDROELECTRIC PROJECT
GENERAL ARRANGEMENT

DATE	AUG 17	PROJ.	E6348		
DWN.	DGC	DWG.	FIGURE 3.1	REV.	3

APPENDIX A

Financial Analysis

Last Revised 28-Feb-18
Spreadsheet by: Sigma

ALASKA HYDRO CORPORATION - MORE CREEK HYDRO PROJECT
PRELIMINARY FINANCIAL ANALYSIS FOR POWER SALES

BASIC PARAMETERS

Table 1

POWER PRODUCTION DETAILS

Gross Head 118m, Design Flow 80 m³/s
Base Case IFR 5% of MAF (2.476m³/s)

Hydro Power Plant Rated Capa	**75,255**	kW
Max Power Supplied to BCH	75,255	kW
Power Plant Load Factor	50.3%	
Avg Annual Generation	37,822	kW
Net Annual Power Sales	**331.320**	GWh/yr
Gross Generation	*345.000*	*GWh/yr*
Daily vs Real time adjustment	*0.0%*	
Station Service	*200*	*kW*
Transformer/powerline losses	*2.5%*	
Outages (sched., unsch.)	*1.0%*	

CAPITAL COST

Access Roads	682,500		
Intake structure	70,509,600		
Tunneling	**18,100,000**		
Powerhouse	19,600,000		
Generation Equipment	**30,000,000**		
Transmission Line/Interconn.	14,675,000		
Work Camp	10,070,000		
Contingencies	27,609,920	191,247,020	
Project Management	3,824,940	2%	
Engineering, Consultants	15,299,762	8%	
Finance Costs (incl IDC)	17,212,232	9%	
Land and Permitting	0	227,583,954	(sub-total)
Inflation (2 yrs at 2.3%)	10,589,254		
	============		
Total Capital Cost in 2017 $:	$238,173,208		
Cost per Installed kW	3,165		

LONG TERM PROJECT VALUE

Hydro Plant Design Life	40	Years
Depreciation Rate	2.5%	per Year
Annual Book Depreciation	$5,954,330	

ANNUAL OPERATING COSTS

Admin., O&M as a Percent of Capital Cost		
Daily Admin., Operation & Maintenance	incl	
Annual Overhaul & Equip. Repair	1.00%	
First Year Total O & M Cost (incl. admin)	$2,381,732	
O & M Inflation Rate	2.3%	
Insurance		
Property Value for Insurance Purposes		
100% of Capital Cost	$238,173,208	
Property Insurance	1.50	$/1000
General Liability	$10,000,000	
Liability Insurance	6.00	$/1000
First Year Insurance	$417,260	
Insurance Inflation Rate	2.3%	
Water Rent		
Water Tax on Engy Produced (<160GWh)	1.339	$/MWh
Water Tax on Engy Produced (>160GWh)	6.243	$/MWh
Water Tax on Installed Capacity	4.461	$/kW
First Year Water Rent	$1,619,504	
Water Rent Inflation Rate	2.3%	
(based on 2017 Rental Rates)		
Property and School Taxes		
Assessed Property Value		
45% of Capital Cost less Equip (est.)	$85,532,943	
School Tax (est.)	13.600	$/1000
Municipal & Property Tax (est.)	11.054	$/1000
First Year Tax Assessment	$2,108,704	
Tax Inflation Rate	2.3%	

Internal Rate of Return	29.26%
Before Tax Cashflow Net Present Value @ 10%	105,296,538
Debt Service Coverage in Year 1	1.92

FINANCING DETAILS

Total Capital Cost	238,173,208	
Equity Input	20.0%	
Equity Amount	47,634,642	
Finance Amount	190,538,566	
Amortization Period	25	Years
Reference Interest Rate	3.50%	Prime Rate
Interest Rate over Refer.	2.00%	
Effective Interest Rate	5.50%	
Annual Payment	$14,204,527	

REVENUE DETAILS

	Energy Payment CPI (BC)	Price (cents/kWh)
2018	100.0	10.00
CPI rate		2.30%
Delivery Time adjustment		1.019

2018 EPA signing (effective date)

Last Revised 28-Feb-18

Spreadsheet by: Sigma

ALASKA HYDRO CORPORATION - MORE CREEK HYDRO PROJECT
PRELIMINARY FINANCIAL ANALYSIS FOR POWER SALES

OPERATING COSTS AND REVENUE

Table 2

		OPERATING COSTS									REVENUE			
Proj Year	Calendar Year Beginning Jan 1	Operation and Maintenance	Insurance	Water Rent	Regional Taxes		Plant Operating Cost $	Plant Operating Cost cents/kWh		Annual Operating Cost $	Average Annual Generation kW	Annual Generation MWh	Revenue cents/kWh	Revenue $
		A	B	C	D	E	F	G	H	I	J	K	L	M
1	2021	2,381,732	417,260	1,619,504	2,108,704		6,527,200	1.97		6,527,200	37,822	331,320	10.19	33,764,835
2	2022	2,436,512	426,857	1,656,753	2,157,204		6,677,325	2.02		6,677,325	37,822	331,320	10.31	34,153,130
3	2023	2,492,552	436,674	1,694,858	2,206,819		6,830,904	2.06		6,830,904	37,822	331,320	10.43	34,550,357
4	2024	2,549,880	446,718	1,733,840	2,257,576		6,988,014	2.11		6,988,014	37,822	331,320	10.55	34,956,719
5	2025	2,608,528	456,993	1,773,718	2,309,500		7,148,739	2.16		7,148,739	37,822	331,320	10.68	35,372,428
6	2026	2,668,524	467,503	1,814,514	2,362,619		7,313,160	2.21		7,313,160	37,822	331,320	10.80	35,797,698
7	2027	2,729,900	478,256	1,856,247	2,416,959		7,481,362	2.26		7,481,362	37,822	331,320	10.94	36,232,750
8	2028	2,792,688	489,256	1,898,941	2,472,549		7,653,434	2.31		7,653,434	37,822	331,320	11.07	36,677,808
9	2029	2,856,919	500,509	1,942,617	2,529,418		7,829,463	2.36		7,829,463	37,822	331,320	11.21	37,133,102
10	2030	2,922,628	512,020	1,987,297	2,587,595		8,009,540	2.42		8,009,540	37,822	331,320	11.35	37,598,867
11	2031	2,989,849	523,797	2,033,005	2,647,109		8,193,760	2.47		8,193,760	37,822	331,320	11.49	38,075,346
12	2032	3,058,615	535,844	2,079,764	2,707,993		8,382,216	2.53		8,382,216	37,822	331,320	11.64	38,562,783
13	2033	3,128,964	548,169	2,127,598	2,770,277		8,575,007	2.59		8,575,007	37,822	331,320	11.79	39,061,431
14	2034	3,200,930	560,776	2,176,533	2,833,993		8,772,232	2.65		8,772,232	37,822	331,320	11.94	39,571,549
15	2035	3,274,551	573,674	2,226,593	2,899,175		8,973,994	2.71		8,973,994	37,822	331,320	12.10	40,093,399
16	2036	3,349,866	586,869	2,277,805	2,965,856		9,180,396	2.77		9,180,396	37,822	331,320	12.26	40,627,251
17	2037	3,426,913	600,367	2,330,195	3,034,070		9,391,545	2.83		9,391,545	37,822	331,320	12.43	41,173,382
18	2038	3,505,732	614,175	2,383,789	3,103,854		9,607,550	2.90		9,607,550	37,822	331,320	12.60	41,732,075
19	2039	3,586,364	628,301	2,438,616	3,175,243		9,828,524	2.97		9,828,524	37,822	331,320	12.77	42,303,617
20	2040	3,668,850	642,752	2,494,704	3,248,273		10,054,580	3.03		10,054,580	37,822	331,320	12.94	42,888,304
21	2041	3,753,233	657,536	2,552,083	3,322,984		10,285,835	3.10		10,285,835	37,822	331,320	13.13	43,486,440
22	2042	3,839,558	672,659	2,610,781	3,399,412		10,522,409	3.18		10,522,409	37,822	331,320	13.31	44,098,332
23	2043	3,927,868	688,130	2,670,829	3,477,599		10,764,425	3.25		10,764,425	37,822	331,320	13.50	44,724,298
24	2044	4,018,209	703,957	2,732,258	3,557,583		11,012,007	3.32		11,012,007	37,822	331,320	13.69	45,364,662
25	2045	4,110,627	720,148	2,795,099	3,639,408		11,265,283	3.40		11,265,283	37,822	331,320	13.89	46,019,753
26	2046	4,205,172	736,711	2,859,387	3,723,114		11,524,384	3.48		11,524,384	37,822	331,320	14.09	46,689,912
27	2047	4,301,891	753,656	2,925,153	3,808,746		11,789,445	3.56		11,789,445	37,822	331,320	14.30	47,375,484
28	2048	4,400,834	770,990	2,992,431	3,896,347		12,060,602	3.64		12,060,602	37,822	331,320	14.51	48,076,825
29	2049	4,502,053	788,723	3,061,257	3,985,963		12,337,996	3.72		12,337,996	37,822	331,320	14.73	48,794,296
30	2050	4,605,601	806,863	3,131,666	4,077,640		12,621,770	3.81		12,621,770	37,822	331,320	14.95	49,528,269
31	2051	4,711,530	825,421	3,203,694	4,171,426		12,912,071	3.90		12,912,071	37,822	331,320	15.18	50,279,124
32	2052	4,819,895	844,406	3,277,379	4,267,369		13,209,049	3.99		13,209,049	37,822	331,320	15.41	51,047,248
33	2053	4,930,752	863,827	3,352,759	4,365,518		13,512,857	4.08		13,512,857	37,822	331,320	15.64	51,833,039
34	2054	5,044,160	883,695	3,429,872	4,465,925		13,823,652	4.17		13,823,652	37,822	331,320	15.89	52,636,904
35	2055	5,160,175	904,020	3,508,760	4,568,641		14,141,596	4.27		14,141,596	37,822	331,320	16.14	53,459,257
36	2056	5,278,859	924,813	3,589,461	4,673,720		14,466,853	4.37		14,466,853	37,822	331,320	16.39	54,300,524
37	2057	5,400,273	946,083	3,672,019	4,781,216		14,799,591	4.47		14,799,591	37,822	331,320	16.65	55,161,141
38	2058	5,524,479	967,843	3,756,475	4,891,184		15,139,981	4.57		15,139,981	37,822	331,320	16.91	56,041,551
39	2059	5,651,542	990,104	3,842,874	5,003,681		15,488,201	4.67		15,488,201	37,822	331,320	17.19	56,942,211
40	2060	5,781,528	1,012,876	3,931,260	5,118,766		15,844,429	4.78		15,844,429	37,822	331,320	17.46	57,863,587
TOTALS		153,598,734	26,909,231	104,442,388	135,991,028	0	420,941,382	2.47		420,941,382	37,822	331,320	11.47	1,764,049,690

Spreadsheet I 28-Feb-18

ALASKA HYDRO CORPORATION - MORE CREEK HYDRO PROJECT
PRELIMINARY FINANCIAL ANALYSIS FOR POWER SALES

CASH FLOW

Table 3

Proj Year	Calendar Year Beginning Jan 1	Interest A	Capital Repayment B	Capital Balance C	Project Book Value D	Annual Operating Cost $ E	Total Annual Cost $ F	Total Annual Cost cents/kWh G	Total Annual Revenue $ H	Before Tax Cash Flow I	Annual Income J
				190,538,566						-47,634,642	0
1	2021	10,479,621	3,724,906	186,813,660	238,173,208	6,527,200	20,731,726	6.26	33,764,835	13,033,108	10,803,684
2	2022	10,274,751	3,929,775	182,883,885	232,218,877	6,677,325	20,881,852	6.30	34,153,130	13,271,278	11,246,724
3	2023	10,058,614	4,145,913	178,737,972	226,264,547	6,830,904	21,035,430	6.35	34,550,357	13,514,926	11,706,509
4	2024	9,830,588	4,373,938	174,364,033	220,310,217	6,988,014	21,192,541	6.40	34,956,719	13,764,178	12,183,786
5	2025	9,590,022	4,614,505	169,749,528	214,355,887	7,148,739	21,353,266	6.44	35,372,428	14,019,163	12,679,337
6	2026	9,336,224	4,868,303	164,881,226	208,401,557	7,313,160	21,517,687	6.49	35,797,698	14,280,012	13,193,984
7	2027	9,068,467	5,136,059	159,745,166	202,447,226	7,481,362	21,685,889	6.55	36,232,750	14,546,861	13,728,590
8	2028	8,785,984	5,418,543	154,326,624	196,492,896	7,653,434	21,857,961	6.60	36,677,808	14,819,847	14,284,059
9	2029	8,487,964	5,716,563	148,610,061	190,538,566	7,829,463	22,033,990	6.65	37,133,102	15,099,112	14,861,344
10	2030	8,173,553	6,030,973	142,579,088	184,584,236	8,009,540	22,214,067	6.70	37,598,867	15,384,800	15,461,443
11	2031	7,841,850	6,362,677	136,216,411	178,629,906	8,193,760	22,398,287	6.76	38,075,346	15,677,059	16,085,406
12	2032	7,491,903	6,712,624	129,503,786	172,675,576	8,382,216	22,586,743	6.82	38,562,783	15,976,040	16,734,334
13	2033	7,122,708	7,081,819	122,421,968	166,721,245	8,575,007	22,779,534	6.88	39,061,431	16,281,897	17,409,386
14	2034	6,733,208	7,471,319	114,950,649	160,766,915	8,772,232	22,976,759	6.93	39,571,549	16,594,789	18,111,778
15	2035	6,322,286	7,882,241	107,068,408	154,812,585	8,973,994	23,178,521	7.00	40,093,399	16,914,878	18,842,789
16	2036	5,888,762	8,315,764	98,752,644	148,858,255	9,180,396	23,384,922	7.06	40,627,251	17,242,329	19,603,763
17	2037	5,431,395	8,773,131	89,979,512	142,903,925	9,391,545	23,596,072	7.12	41,173,382	17,577,311	20,396,112
18	2038	4,948,873	9,255,654	80,723,859	136,949,594	9,607,550	23,812,077	7.19	41,732,075	17,919,998	21,221,321
19	2039	4,439,812	9,764,715	70,959,144	130,995,264	9,828,524	24,033,051	7.25	42,303,617	18,270,566	22,080,950
20	2040	3,902,753	10,301,774	60,657,370	125,040,934	10,054,580	24,259,107	7.32	42,888,304	18,629,198	22,976,641
21	2041	3,336,155	10,868,371	49,788,999	119,086,604	10,285,835	24,490,362	7.39	43,486,440	18,996,078	23,910,119
22	2042	2,738,395	11,466,132	38,322,867	113,132,274	10,522,409	24,726,936	7.46	44,098,332	19,371,396	24,883,198
23	2043	2,107,758	12,096,769	26,226,098	107,177,943	10,764,425	24,968,952	7.54	44,724,298	19,755,347	25,897,786
24	2044	1,442,435	12,762,091	13,464,006	101,223,613	11,012,007	25,216,533	7.61	45,364,662	20,148,128	26,955,889
25	2045	740,520	13,464,006	0	95,269,283	11,265,283	25,469,810	7.69	46,019,753	20,549,944	28,059,620
26	2046	0	0	0	89,314,953	11,524,384	11,524,384	3.48	46,689,912	35,165,528	29,211,197
27	2047	0	0	0	83,360,623	11,789,445	11,789,445	3.56	47,375,484	35,586,039	29,631,709
28	2048	0	0	0	77,406,292	12,060,602	12,060,602	3.64	48,076,825	36,016,222	30,061,892
29	2049	0	0	0	71,451,962	12,337,996	12,337,996	3.72	48,794,296	36,456,300	30,501,970
30	2050	0	0	0	65,497,632	12,621,770	12,621,770	3.81	49,528,269	36,906,499	30,952,169
31	2051	0	0	0	59,543,302	12,912,071	12,912,071	3.90	50,279,124	37,367,053	31,412,723
32	2052	0	0	0	53,588,972	13,209,049	13,209,049	3.99	51,047,248	37,838,200	31,883,870
33	2053	0	0	0	47,634,642	13,512,857	13,512,857	4.08	51,833,039	38,320,183	32,365,853
34	2054	0	0	0	41,680,311	13,823,652	13,823,652	4.17	52,636,904	38,813,251	32,858,921
35	2055	0	0	0	35,725,981	14,141,596	14,141,596	4.27	53,459,257	39,317,661	33,363,330
36	2056	0	0	0	29,771,651	14,466,853	14,466,853	4.37	54,300,524	39,833,671	33,879,341
37	2057	0	0	0	23,817,321	14,799,591	14,799,591	4.47	55,161,141	40,361,550	34,407,220
38	2058	0	0	0	17,862,991	15,139,981	15,139,981	4.57	56,041,551	40,901,570	34,947,240
39	2059	0	0	0	11,908,660	15,488,201	15,488,201	4.67	56,942,211	41,454,011	35,499,680
40	2060	0	0	0	5,954,330	15,844,429	15,844,429	4.78	66,795,082	50,950,653	44,996,322
TOTALS		164,574,604	190,538,566			420,941,382	776,054,552	6.75	1,772,981,185	996,926,633	949,291,992
								Net Present Value @ 10%		105,296,538	144,431,835
								Internal Rate of Return		29.26%	#DIV/0!

Note: Sale for 1.5 x book value assumed in Year 40