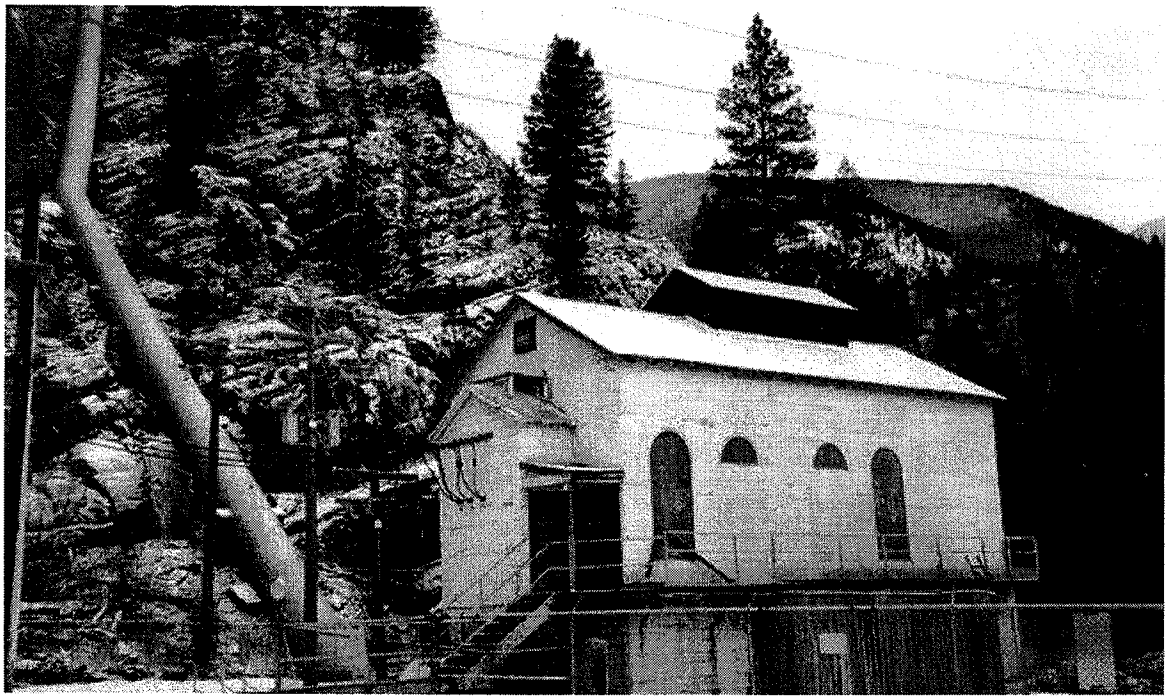
Business Case

ABERFELDIE GENERATING FACILITY



Purpose: To evaluate the options associated with the Aberfeldie site, including status quo operation, redevelopment, and decommissioning

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EXECUTIVE SUMMARY

The Aberfeldie facility is over 80 years old and the wood-stave pipeline and powerhouse equipment at the plant have reached their end of life. The long-term options for the Aberfeldie station have been reviewed including status-quo operation, redevelopment, and decommissioning. Each alternative has distinct risk and financial implications that are discussed in this business case discussion.

Based on economic analysis, **redevelopment** of the Aberfeldie facility in the **21–24 MW** range is considered the most cost effective option at approximately **$42/MWh.** A plant could be built at a capital cost of a **$45-50 million** and would provide an average **increase of 63–70 GWh per year** over the existing facility. The commercial operation date could be as early as April 2007.

1 BACKGROUND

The Aberfeldie Hydroelectric Development is located 30 km east of Cranbrook in southeastern British Columbia. It is situated on the Bull River about 10 km upstream from its confluence with the Kootenay River. The existing 5 MW development consists of a dam, pipeline, penstock, and powerhouse, as well as a small headpond that extends 1.5 km up the narrow valley. The mean annual flow of the river is about 33 m^3/s while the current utilisation for power generation is only 7.5m^3/s. Due to continued siltation of the headpond, the storage capacity of the reservoir is significantly reduced and the plant operates essentially as a run-of-river facility with water flowing over the spillway about 80% of the year.

Expansion of the Aberfeldie Hydroelectric Development was previously studied in 1969, and again in 1991. In both cases additional capacity was recommended.

The history of the Aberfeldie Hydroelectric Development is as follows:

1922 – The original Aberfeldie Dam, located about 1.5 km upstream of the existing dam, was built along with the powerplant.

1953 – The old dam suffered severe damage from avalanches and was replaced by the present concrete gravity dam. In addition, the penstock and surge tank were rebuilt, the generating units and TIVs were overhauled, the P&C panels were replaced, and a new 2.4 kV switchgear was installed.

1968 – The East Kootenay Power Company, the then-owner of the development, was acquired by BC Hydro and Aberfeldie Dam has been operated by BC Hydro since that time.

1970 – The wood-stave penstock was replaced.

1999 – Due to fear of breaching the dam due to excessive silt build-up, the dam was anchored to the underlying bedrock.

2003 – A wood-stave pipeline replacement project was initiated and was then modified to include redevelopment.

2 BUSINESS CASE

2.1 Business Case Options

Status Quo Operation

The status quo analysis considered the costs (capital and ongoing OM&A) associated with continued operation of the facility as a 5 MW (nominal) capacity plant. Given the age of the facility, however, most components will require replacement in the near future. As such, the status-quo alternative is more aptly referred to as a partial redevelopment (like for like) that will maintain (at a cost) the equipment which currently is in poor condition.

Redevelopment

Five different sized redevelopment projects were analyzed: 17 MW, 21 MW, 24 MW, 28 MW, and 30 MW. The upper bound of 30 MW represents the largest possible facility at the site without making modifications to the transmission network. The other facility sizes represent specific plant configurations (3 x 7 MW, or 3 x 8 MW, etc.) that attempt to optimize the capital cost vs. energy output tradeoff.

Decommissioning

The decommissioning option would involve capital costs for decommissioning the plant, as well as ongoing operating costs for surveillance of the dam (which would likely remain in place) and for grants in lieu of property taxes. The final capital cost would depend on the level of site remediation required (e.g., due to hazardous materials or other environmental concerns). Since the decommissioning alternative provides zero energy delivery but incurs both capital and ongoing costs, it would only be attractive if none of the alternative options could provide economic generation.

2.2 Business Case Assumptions

The cost and operating assumptions for each option are summarized in Table 1. The capital costs are the P_{50} costs, and are shown in 2004$, without corporate overhead or IDC.[1]

[1] The Cash (NPV, Levelized Cost) analysis portrayed herein does not include IDC or corporate overhead, while the Accounting analysis and Expenditure Authorization Request (EAR) do. This is explained further in Section 4.

Table 1

Aberfeldie Redevelopment - Project Modeling Assumptions							
	Status Quo	Redevelopment					De-Comm.
Project Capacity	5 MW	17 MW	21 MW	24 MW	28 MW	30 MW	
Generation (MWh / Yr)	34,230	87,388	97,781	103,730	112,528	117,826	
Construction							
Capital Cost ($M)	12.02	31.87	35.75	38.65	44.07	50.84	1.57
Construction Start	Apr-05	Apr-05	Apr-05	Apr-05	Apr-05	Apr-05	Oct-05
Outage Starts	May-05	May-05	May-05	May-05	May-05	May-05	Oct-05
Return to Service (5MW)	Oct-06	Oct-06	Oct-06	Oct-06	Oct-06	Oct-06	
Return to Full Service	Apr-07	Apr-07	Apr-07	Apr-07	Apr-07	Apr-07	
Operations ($000s / year)							
Water Rentals	At Statutory rate, assuming current BCH increase is approved						
Property Taxes / Grants	115	333	360	377	423	546	80
Operations	370	278	324	324	370	370	30

2.3 FINANCIAL ANALYSIS

The value of each option was calculated in two ways: (i) by determining the levelized cost of the energy to be delivered, and (ii) by calculating the net present value of the project assuming that the energy generated is valued at BC Hydro's forecast market value[2]. The results for each alternative are provided in Table 2 below.

Table 2

Aberfeldie Redevelopment - Evaluation Results						
0.5 cms						
Project Results (25 Year)	5 MW	17 MW	21 MW	24 MW	28 MW	30 MW
Generation	34,230	87,388	97,781	103,730	112,528	117,826
NPV $M	3.43	11.01	11.68	11.63	9.85	4.84
Levelized $/MWh, 2005$	44.51	39.80	39.98	40.32	42.14	45.91
Incremental Costs ($/MWh)						
	Expand To					
Expand From	5 MW	17 MW	21 MW	24 MW	28 MW	30 MW
5 MW	X	36.41	37.24	38.02	40.98	46.56
17 MW		X	41.53	43.26	50.67	64.28
21 MW			X	46.28	57.10	76.08
24 MW				X	64.42	88.65
28 MW					X	128.89
30 MW						X

[2] Based on BC Hydro June 2004 Average Price Forecast. The results over the full range of gas and electricity price forecasts are tested in the Scenarios section of this business case.

NPV Analysis

The positive NPV values for each of the above alternatives indicates that redevelopment would be economic and therefore preferable over decommissioning (which would incur costs for zero energy delivery). The decommissioning option was dropped from further analysis.

Of the redevelopment options examined, the 17 MW, 21 MW, and 24 MW options look to be most acceptable from an NPV standpoint.

Levelized Cost Analysis

In selecting a plant size, the most important consideration is incremental cost as opposed to average cost. Incremental cost represents the cost associated with the additional energy available from increasing a project size to a greater capacity level (see Table 2). For example, the incremental cost of energy for a 17 MW facility over a 5 MW project is $36.41/MWh, while the incremental cost of a 28 MW facility over the existing 5 MW facility size is $40.98/MWh.

Table 3 further summarizes the annual energy generated by different plant sizes and the incremental costs associated with each expansion. These data are also shown graphically in Figure 1. The incremental cost of energy curve indicates that an expansion up to 24 MW is economic considering BC Hydro's alternative cost of energy procurement[3]. That is, the incremental costs associated with these alternatives would be less than $50/MWh. The incremental expansion from 24 to 28 MW is unlikely to be economic, while the expansion from 28 to 30 MW is clearly not economic.

Table 3

Decision	Incremental Annual Energy (GWh)	Cost ($/MWh)
Refurbish 5 MW, rather than decommission	34.23	44.51
Build 17 MW, rather than 5 MW	53.16	36.41
Build 21 MW, rather than 17	10.39	41.53
Build 24 MW, rather than 21	5.93	46.28
Build 28 MW, rather than 24	8.80	64.42
Build 30 MW, rather than 28	5.30	128.89

[3] Target price of approximately $50/MWh determined by (i) levelized BC Hydro average price forecast, and (ii) the average first year price of awarded contracts from the latest green call for tender

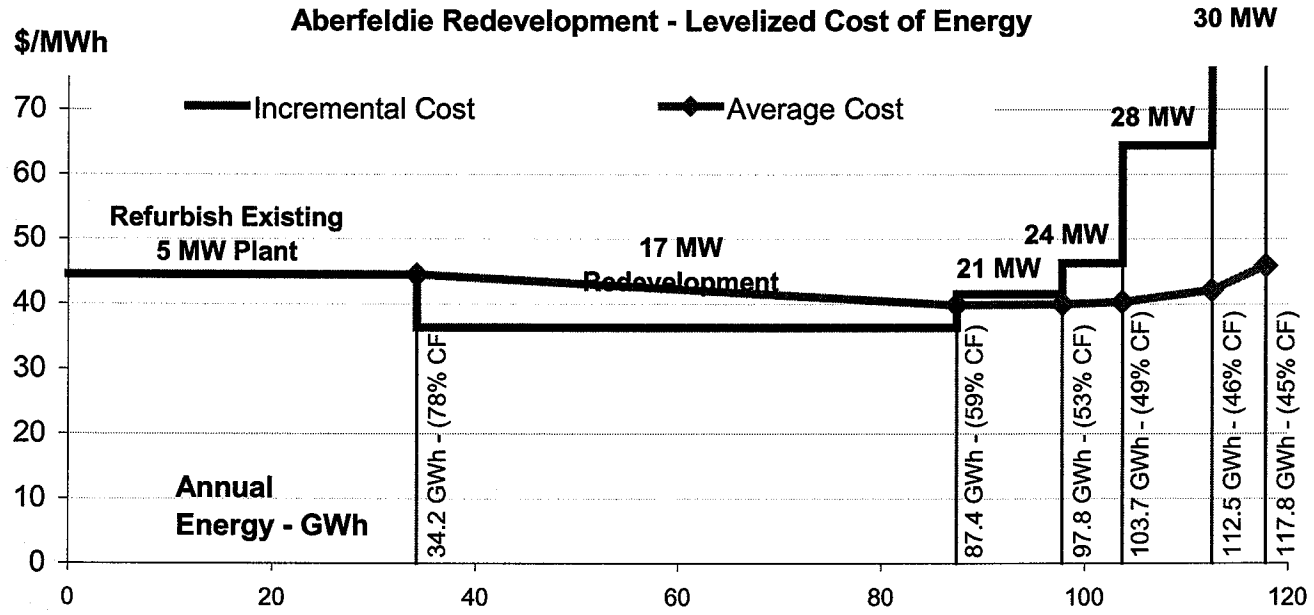


Figure 1

3 SENSITIVITY ANALYSIS

Like any capital project, variations in capital costs will affect the value of the Aberfeldie redevelopment. In addition, the project will require a renewed or amended water license and the minimum flow release of the new water license is uncertain. The analysis is based on an assumed minimum flow release of 0.5 m^3/s, which is anticipated to be the most likely outcome. Finally, the forecast value of energy and the evaluation term will also affect the NPV and levelized cost of the redevelopment.

3.1 Capital Cost

For evaluation purposes, "P_{50}" capital costs were assumed which represent the value for which there is an equal probability of over- or under-spending. Higher capital costs will increase the levelized cost of energy and lower the NPV, while lower capital costs will have the opposite effect. As a sensitivity test, BC Hydro Engineering also provided "P_{90}" cost estimates – an estimate for which there is a 10% probability of overspending and a 90% probability of underspending the estimated cost. The results if costs should come in at the P_{90} level are presented in table 4 below:

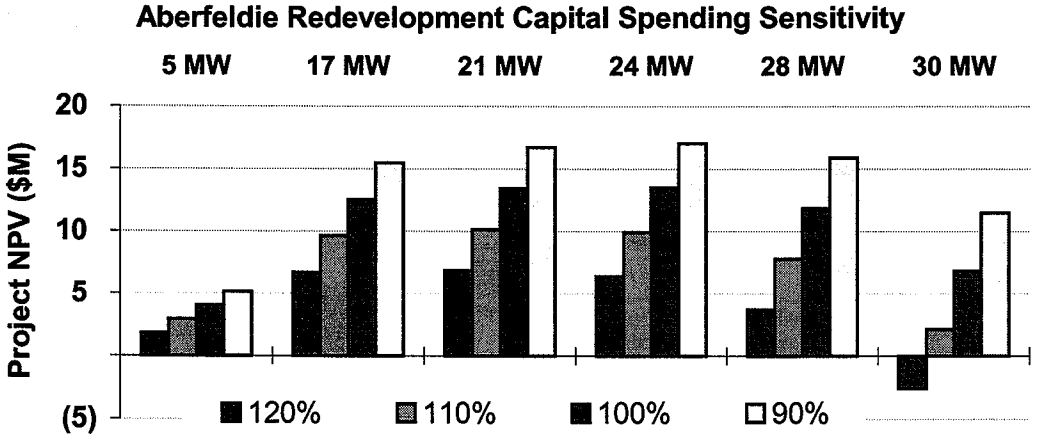
Table 4

Aberfeldie Redevelopment - Evaluation Results						
Capital Costs at P_{90} Estimate						
Project Results (25 Year)	**5 MW**	**17 MW**	**21 MW**	**24 MW**	**28 MW**	**30 MW**
Generation	34,230	87,388	97,781	103,730	112,528	117,826
NPV $M	2.45	8.39	8.74	8.46	6.23	0.66
Levelized $/MWh, 2005$	46.76	42.28	42.47	42.87	44.82	48.87
Incremental Costs ($/MWh)						
	Expand To					
Expand From	**5 MW**	**17 MW**	**21 MW**	**24 MW**	**28 MW**	**30 MW**
5 MW	X	39.05	39.88	40.72	43.87	49.83
17 MW		X	44.16	46.17	54.08	68.67
21 MW			X	49.70	61.07	81.38
24 MW				X	68.77	94.76
28 MW					X	137.91
30 MW						X

The sensitivity analysis indicates that even though the average cost of energy remains acceptable up to the 30 MW project size, the incremental costs are slightly higher than the $50/MWh target at the 24 to 28 MW increment.

As a further comparison, the NPV of the project was also calculated for a range of capital costs, from a 10% under-run to a 20% over-run. As shown in Figure 2, the NPV remains positive for all capital spending patterns for expansions up to and including 28 MW, and remains positive for all but the 120% capital spending case for the 30 MW project. The other point to note is that although the 5 MW refurbishment always carries a positive value, it is consistently lower than the value of the 17 MW to 28 MW options for any given spending pattern. Although the 5 MW project requires a small outlay of capital, it represents a wasted opportunity.

Figure 2



3.2 Minimum Flow Release

As noted above, we will not know the minimum required release for Aberfeldie until we secure a new water license[4]. The highest minimum discharge considered in the recent WUP for Aberfeldie was 0.5 m^3/s, although the consultative committee has not recommended a minimum flow requirement pending further monitoring and consideration of lower-cost alternatives. Our Base Case assumption is a 0.5 m^3/s minimum discharge, to match the WUP value, although this is less than would normally be required for a greenfield development. A typical new development would require a minimum release of between 5% and 10% of MAD (or 1.55 m^3/s to 3.10 m^3/s) or greater. As a sensitivity test, we have also calculated the cost of energy and the Net Present Value of the various project alternatives for these required flow levels, and the results are presented in figures 6 and 6a. Minimum flow requirements have a disproportionate impact on higher capacity projects, since they reduce the high generation opportunities that give value to increased capacity.

Table 5a

Aberfeldie Redevelopment - Evaluation Results						
1.55 cms						
Project Results (25 Year)	**5 MW**	**17 MW**	**21 MW**	**24 MW**	**28 MW**	**30 MW**
Generation	34,230	82,362	92,743	98,336	107,143	112,349
NPV $M	3.43	8.15	8.83	8.58	6.81	1.75
Levelized $/MWh, 2005$	44.51	41.83	41.80	42.19	43.94	47.84
Incremental Costs ($/MWh)						
	Expand To					
Expand From	**5 MW**	**17 MW**	**21 MW**	**24 MW**	**28 MW**	**30 MW**
5 MW	X	39.69	40.03	40.80	43.64	49.47
17 MW		X	41.58	44.14	51.32	65.15
21 MW			X	48.87	58.34	77.63
24 MW				X	64.35	89.11
28 MW					X	131.01
30 MW						X

[4] A new license is required for the incremental water usage, over and above the current license restriction of usage. We will maintain the existing license.

Table 5b

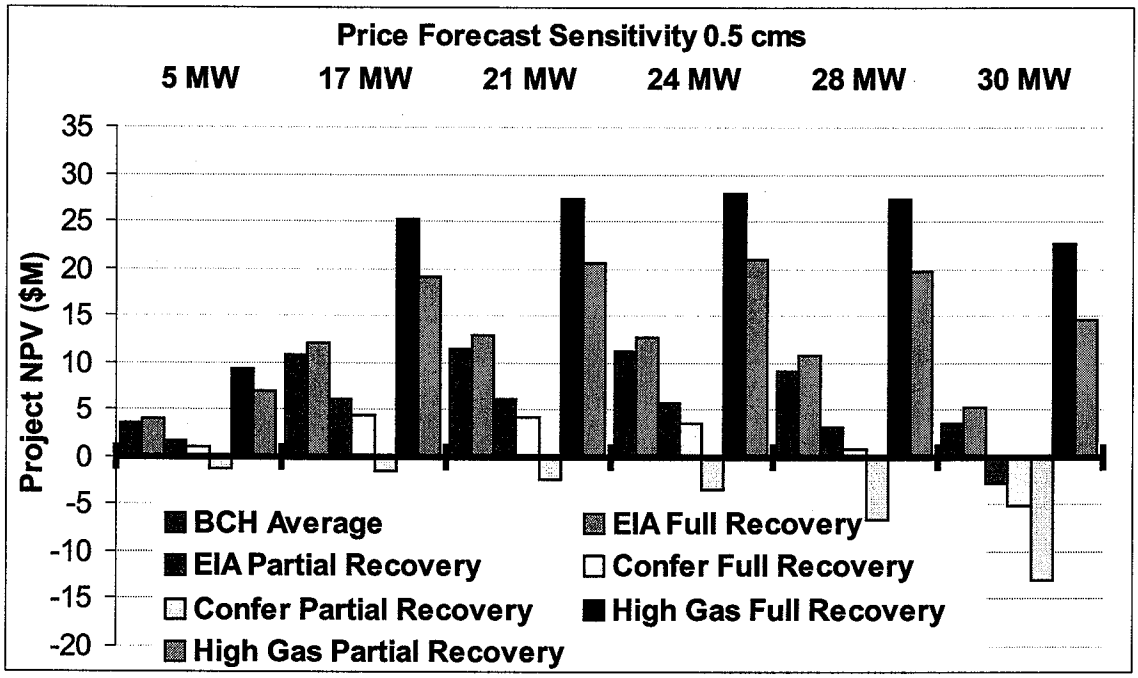
Aberfeldie Redevelopment - Evaluation Results						
3.10 cms						
Project Results (25 Year)	**5 MW**	**17 MW**	**21 MW**	**24 MW**	**28 MW**	**30 MW**
Generation	34,230	74,635	84,947	90,165	98,856	103,920
NPV $M	3.43	3.75	4.41	3.95	2.14	(3.00)
Levelized $/MWh, 2005$	44.51	45.44	45.02	45.41	47.07	51.17
Incremental Costs ($/MWh)						
	Expand To					
Expand From	**5 MW**	**17 MW**	**21 MW**	**24 MW**	**28 MW**	**30 MW**
5 MW	X	46.32	45.41	46.02	48.59	54.82
17 MW		X	41.84	45.24	52.37	66.56
21 MW			X	51.97	60.19	80.00
24 MW				X	65.12	90.63
28 MW					X	134.42
30 MW						X

3.3 Price Forecast

The current BC Hydro price forecast provides forecast electricity prices by month for the next 20 years, segregated between High Load Hours and Low Load Hours. The forecast includes a forecast for two views of the future electricity market: one forecast is based on the assumption that natural gas prices will continue to set the marginal price of electricity; the other is based on the assumption that the natural gas and electricity markets will decouple, so that the spark spread will narrow over time. Possible events giving rise to such decoupling include: a shift to other generation technologies (or a dramatic improvement in gas-fired generation technology); or regulatory action such as price caps, monetized reserve margins, and capacity trading markets to allow energy to be priced at marginal cost rather than a full recovery cost. Each market forecast is developed for one of four different gas-price paths, resulting in a BC Hydro price forecast that includes an average price (the simple average of all forecasts and all market conditions) as well as eight supplementary forecasts. The 'average' forecast has been used for project evaluation material discussed thus far. The supplementary forecasts for examination of price sensitivity are shown in Figure 3.

The project value changes markedly depending on the price forecast used. The greatest variation in value is found in the 30 MW option with a range of over $35 million separating the high value of $25.8 million and the low value of a -$9.8 million value. These extremes are found for the "High Gas, Full Recovery" forecast (high gas prices in a full capital cost recovery electricity market) and the "Confer, Partial Recovery" forecast (low gas prices coupled with a market that trades electricity at marginal cost only). These two forecasts present levelized electricity prices ranging from $47.82 to $64.28 / MWh (starting from Fiscal 2006, in real FY06$). The impact of price forecasts is consistent for all of the project size alternatives; the range of outcomes diminishes with decreased project size, since the impact of electricity selling prices is proportional to output. The three mid-range projects have very similar (and the highest) expected values, although the 21 and 24 MW options are preferred over the 28 MW option since the latter provides a slightly lower best outcome and a significantly lower worst outcome.

Figure 3



3.4 Evaluation Term

Although not a sensitivity in the normal sense, the term of the financial evaluation is of interest. Forecasts of the electricity market are required to estimate the value of the plant's output. These forecasts, however, extends for only 20 years and are increasingly unreliable as they extend further in time. For the purposes of this analysis, the forecast was extended by five years assuming a linear trend and a NPV evaluation was conducted for a 25-year term. This is considerably shorter than the economic life of the assets. The price of energy calculation is not subject to these same considerations, assuming that no significant capital spending is required after the initial installation, and the levelized cost can be calculated over a term approximating the asset life. The 50-year term average and incremental cost of energy for the various project options are summarized in Table 6. These costs would not change the relative preference for projects, but they do provide another comparison against the alternative cost of supply.

Table 6

Aberfeldie Redevelopment - Levelized Cost over 50-Year Term

Project Size		5 MW	17 MW	21 MW	24 MW	28 MW	30 MW
Average Cost	$/MWh	43.79	38.08	38.25	38.52	40.22	43.78
Incremental Cost	$/MWh		34.06	39.67	43.09	60.86	121.14

4 ACCOUNTING IMPLICATIONS

The levelized costs of energy from the facility include the capital costs as spent as well as the cash operating costs over the term of the evaluation. In addition to the capital actually spent, the book value of the Aberfeldie facility for financial accounting purposes will include allocations for corporate overhead and interest accrued during construction (IDC). The corporate overhead charge is simply an allocation of existing costs, and has no real impact on the cost of energy from Aberfeldie. We do not need to consider this amount in the levelization calculation, although it is relevant in calculating Aberfeldie's cost of energy on an accounting basis. There is an accounting adjustment for a write off of assets which will be redundant after the facility is redeveloped – it is included in the amounts requested under the EAR, but it is a non-cash cost, and does not affect the levelization calculation. The capital cost estimates also includes the costs of dismantling and removing existing assets –these are a real cost of the project, but for accounting purposes they will be treated as a one-time Operations and Maintenance cost. After reflecting these adjustments, the cost as spent compares to the requested approval as shown in Table 7.

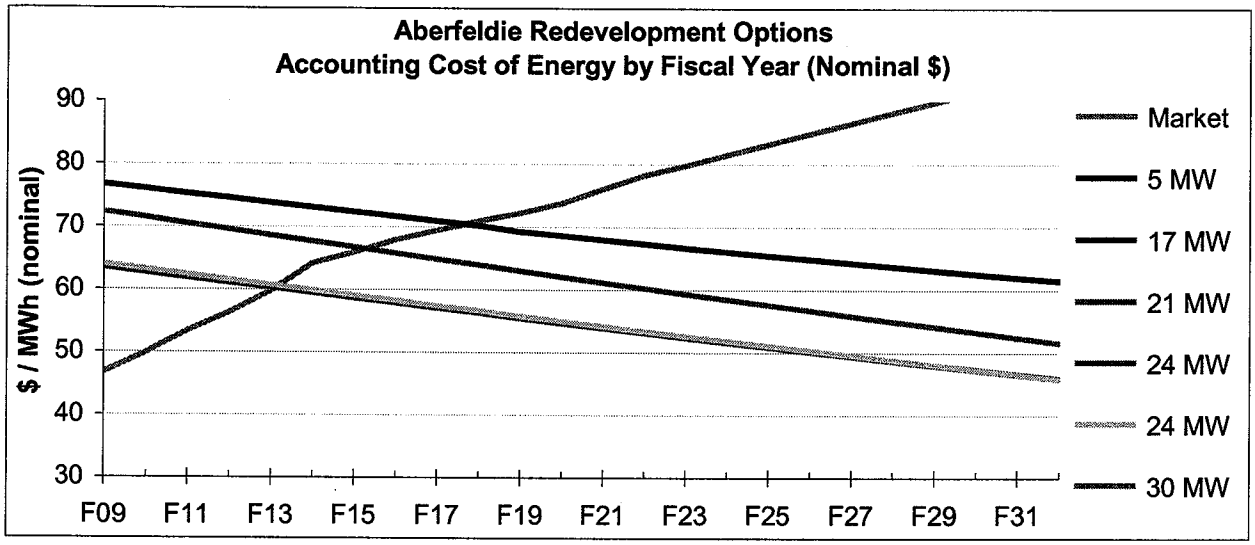
Table 7

Aberfeldie Redevelopment						
Financial Analysis compared to Accounting Impact						
	5 MW	**17 MW**	**21 MW**	**24 MW**	**28 MW**	**30 MW**
Capital Costs (2004$ 000's)	12,016	31,873	35,747	38,645	44,074	50,836
Inflation during Construction	495	1,313	1,472	1,592	1,815	2,094
IDC	685	1,907	2,146	2,856	2,658	3,074
Capital as Spent (Cash Analysis)	13,196	35,093	39,365	43,093	48,547	56,004
Capital Overhead *(included in EAR)*	754	2,098	2,360	2,543	2,923	3,381
Asset Write Off	512	512	512	512	512	512
EAR Funding Request	14,462	37,703	42,237	46,148	51,983	59,898
One-Time OMA Cost *(a/c adjustment)*	(380)	(917)	(917)	(917)	(917)	(917)
Net Assets (Accounting Analysis)	14,082	36,786	41,321	45,232	51,066	58,981

The cost of energy for financial statement (accounting) purposes includes the operating costs of the facility, plus depreciation and the asset-related charges of interest and return on equity. The asset-related charges are based on net book value, which declines over time, and since they are the largest component of the cost stream the overall cost declines over time as well. Figure 4 shows the cost of energy from the facility, calculated on an accounting basis for each full fiscal year after the in-service date, for all size options[5]:

[5] Note that the accounting cost of energy for the 17, 21, and 24 MW plants are virtually identical, and the 17 MW results are hidden beneath the other two.

Figure 4



Although the accounting cost shown above is higher than our heritage contract target of $25/MWh (in real 2004$) production from Aberfeldie will displace anticipated energy purchases. Since on average these purchases will be at market, as soon as the accounting cost of energy from Aberfeldie is below market (Fiscal 2013) the lower-cost energy from Aberfeldie will average down our overall cost of energy. A summary of the Income Statement impact of the 24 MW option is shown in table 8 below:

Table 8

Aberfeldie Redevelopment Financial Statement Summary - 24 MW									
	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017
Cost of Energy	636	636	636	636	636	636	636	636	636
Facility Costs	352	360	367	374	382	389	397	405	413
Taxes & Grants In Lieu	410	418	426	435	443	452	461	471	480
Depreciation	1,241	1,241	1,241	1,241	1,241	1,240	1,240	1,240	1,240
Capital Charge	3,993	3,892	3,791	3,690	3,589	3,488	3,387	3,286	3,185
Total Costs	6,633	6,548	6,462	6,376	6,291	6,206	6,122	6,038	5,954
$ / MWh	63.95	63.12	62.30	61.47	60.65	59.83	59.02	58.21	57.40
Avoided Purchases	(4,631)	(4,919)	(5,276)	(5,580)	(5,897)	(6,389)	(6,562)	(6,768)	(6,925)
$ / MWh	46.67	49.85	53.28	56.24	59.74	64.08	65.88	67.85	69.41
Cost Increase (Savings)	2,002	1,628	1,186	797	394	(183)	(440)	(730)	(970)

5 PROJECT RISKS

The project risks associated with redevelopment of the facility are outlined in Table 9 below.

TABLE 9: Risk Identification and Mitigation Strategy

	Description of Risk	Mitigation Strategy	Residual Risk (after mitigation)
Project Implementation	Capital – Cost exceeds current estimate either when tendered or upon COD	- Firm Price Contract - Liquidated Damages	- Project cancellation if material increase at Tender - Contract Extras after Tender
	Perfomance – The units do not meet the current expected ouput either upon design tender or COD	- Performance Guarantee - Liquidated Damages	- Medium Probability Medium Impact
	Schedule – The Commercial Operation Date (COD) is not achieved	- Schedule Guarantees - Schedule review prior to award	- Low Probability Medium Impact
	Contracting Strategy (EPCM) – No single contractor to wrap warranty / construction risk	- Consider single contractor or wrap strategy	- Low Probability Medium Impact
	Contractor Credit – Default of Counterparty	- Credit review prior to award - Adequate surety	- Low Probability Medium Impact
Project Development	First Nations – Agreement on impact / mitigation / compensation cannot be reached	- Early consultation	- Medium Risk - High Impact – may result in project cancellation
	[redacted]	[redacted]	[redacted]
	Water License	- Early involvement, characterize as extension of recent WUP	- Medium Probability Medium Impact
	Environmental Assessment	- Early consultation	- Medium Probability Low Impact

6 REGULATORY AND LICENSING STRATEGY

The following is a summary of the regulatory and licensing requirements for redevelopment of the Aberfeldie facility:

1. Water license - Land & Water BC Inc.
2. Environment Authorization - Canadian Environmental Assessment Act (CEAA) Screening led by Department of Fisheries and Oceans (DFO)

[redacted]

4. First Nations / Public Consultation

6.1 Water License

An application for a new water license was submitted to the Water Comptroller in July 2004. This ensures that Land and Water BC is aware of the possible redevelopment, and that any competing water license on the Bull River is not be granted without consultation with BC Hydro.

The new water license will not be granted until the Environmental Authorization is obtained, operations related issues are resolved (likely through a Water Use Planning methodology), fish and animal habitat impact studies are completed, and First Nations Discussions / Public Consultations occur.

6.2 Environmental Authorization

There is no requirement for a provincial environmental authorization for projects less than 50 MW in size. There is, however, a requirement for a federal environmental authorization led by DFO, commonly referred to as a CEAA screening. The primary mandate for this process is to ensure that there is no net impact to fish or fish habitat. A consultative process[6] will be undertaken to work through the CEAA screening process. As well, both contaminated sites studies and two environmental studies (animal and fish habitat impacts studies) will be required.

[redacted]

7 FIRST NATIONS / PUBLIC CONSULTATION

First Nations and public consultations will be required as part of the any redevelopment effort.

The Ktunaxa-Kinbasket Tribal Council (KKTC) participated in the WUP Consultative Committee and the consensus decision on how to operate the current facility. Expectations from First Nations, where

[6] The consultation processes for the CEAA screening and Water License requirements involve the same primary participants. As such, it is likely that only one consultative process will need to occur.

modifications to the facility are being considered, would likely result in a variety of requests to accommodate their interests. For example, First Nations would typically seek revenue sharing, economic development opportunities during and after construction, and may request that the facility be removed if an increase in environmental impacts is being proposed. While it is doubtful that KKTC, would attempt to stop a redevelopment they would certainly seek accommodations to their interests as outlined above.

Communication and consultations with the public on the possibility of redevelopment has been initiated. In Summer 2004 a presentation was given to the Regional District of East Kootenay and a letter was sent to the WUP Consultative Committee members about the project and time frame.

8 RECOMENDATIONS

Generation recommends proceeding with the redevelopment of the Aberfeldie facility, with an in-service target of April 2007. Based on the analysis and sensitivities presented herein, the preferred sizing would be a facility in the 21-24 MW range. Based on current cost estimates, the 24 MW option is preferred, as the incremental cost of energy up to that size remains below the cost of our alternative supply.

The final configuration, size, and cost will not be known until firm proposals are received. If at that time the costs exceed the P_{50} estimate of $46 M, or the estimated benefits are not available, the options at Aberfeldie would need to be reassessed.

9 NEXT STEPS

The following is a high level schedule of events, if BC Hydro's Board of Directors approve a redevelopment of the Aberfeldie facility.

BOD Meeting	October 20, 2004
Permitting Completion	March, 2005
Licensing Completion	May, 2005
Begin Procurement	August, 2005
Commercial Operation	April, 2007