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Sent: Thursday, January 06, 2005 5:04 PM
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Subject: Project No. 3698354 - BC Hydro Call for Tender - Green Island Energy Ltd. Evidence

GIE Evidence Jan604.pdf (389 K... | Appendix 1 - Schedule revised.... | S. Ebnet CV.doc (42 KB) | P. R. Willis CV.doc (36 KB) | D. R. Morrow CV.doc (21 KB)

Attached for filing with the Commission is the Evidence of Green Island Energy Ltd., Appendix 1 Development Schedule and the resumes of Messrs. S. Ebnet, P. Willis and D. Morrow.

Regards,
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Barrister and Solicitor

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Evidence
of
Green Island Energy Ltd.

Executive Summary

- The combination of Green Island Energy Ltd.'s 75 MW biomass project, the 47 MW Ladysmith Peaker Plant and 130 MW from Norske Canada's DMP – together comprising the Tier 2 Option A portfolio - would provide the same amount of capacity (252 MW) as the Duke Point Power project, but at just 53% of the cost. Green Island's analysis found all Tier 2 Options evaluated with the BC Hydro QEM model resulted in a lower NPV cost for generation than the Duke Point Power project.

- As required by the CFT, Green Island assumes all of the risk of price and delivery of fuel to its project. All of the portfolio options discussed in this evidence present considerably less fuel risk than the Duke Point Power project and less Greenhouse Gas (GHG) emissions to offset. Minimizing fuel risk and environmental impacts provides obvious and positive benefits to the ratepayers responsible for those costs over the 25-year term of the proposed EPA.

- The reliability provided by the Tier 2 Option A portfolio is significantly better than the reliability that the DPP plant will be capable of achieving.

- Green Island's Gold River Project was never evaluated under the Quantitative Evaluation Methodology ("QEM") because BC Hydro determined that there were no other projects to combine with the Gold River Power Project and Ladysmith Peaker to achieve the minimum required 150 MW portfolio size.

1. Tier 2 Portfolios

This evidence discusses four possible "Tier 2" portfolios.

The Tier 2 Option A portfolio would be comprised of Green Island Energy Ltd.'s ("Green Island") 75 MW Gold River Power Project (the "Gold River Power Project"), the 47 MW Ladysmith Peaker Plant ("Ladysmith") and 130 MW from Norske Canada's Demand Management Program ("NCDMP") for only two years. Green Island submits that the Tier 2 Option A portfolio provides the most cost-effective solution for Vancouver Island.

The Tier 2 Option B portfolio would be a combination of the 75 MW Gold River Power Project and 47 MW Ladysmith, without NCDMP. Providing 122 MW of cost-effective dependable capacity, the Tier 2 Option B portfolio exceeds the 115 MW minimum aggregate capacity that the Commission encouraged BC Hydro to accept before considering "other resource additions" than on-Island generation." (BCUC letter 23 January 2004, page 4). The Tier 2 Option B portfolio also satisfies the conditions for the exercise of CFT clause 17.3 – as both projects met the Mandatory Criteria and were assessed not to have a high development risk.

The Tier 2 Option C portfolio would be comprised of the 75 MW Gold River Power Project and two 47 MW Ladysmith Peakers – together providing aggregate capacity of 169 MW. Both the Gold River and Ladysmith projects satisfied all Mandatory Criteria and would have been evaluated under the QEM, but for the aggregate capacity being less than 150 MW. Green Island submits that the cost-effectiveness of a doubled Ladysmith project could and should be evaluated on the basis of the bid details for the single Ladysmith project.

The Tier 2 Option D portfolio would be made up of the 75 MW Gold River Power Project, 47 MW Ladysmith and the 48 MW Campbell River cogen expansion – for combined capacity of 170 MW. Green Island recognizes that the Campbell River cogen expansion was disqualified in the CFT process. If it is established that the Campbell River project was disqualified due to unduly stringent Mandatory Criteria, Green Island submits that the Commission should consider it for inclusion in an approved portfolio.

2. Resource Option Bias Disadvantaged the Gold River Project

Inherent resource option bias in the CFT process favored VIGP-like projects and disadvantaged the Gold River Power Project.

i. Fuel Risk: Fixed Price Versus Tolling

One important aspect of the appropriate selection of a portfolio to serve Vancouver Island's electricity needs is that of fuel risk. The Duke Point Power project ("DPP") is a natural gas fired plant of 252 MW, which is expected to operate at about 80% capacity factor. In "equivalent MW at 100% CF" this would be 252 * 0.8 = 201.6 MW.

By comparison, the Tier 2 resources would similarly be computed as:
Ladysmith Peaker - 47 * 0.2 = 9.4 MW (equivalent)
Campbell River cogen expansion - 48 * 0.7 = 33.6 MW (equivalent)

Gold River Power Project - no gas usage
Norske DMP - no gas usage

Summing for the Tier 2 Option A portfolio, consisting of Gold River Power Project + Ladysmith Peaker + Norske DMP = 9.4 MW equivalent gas usage, which is less than 5% of the DPP project gas risk. Even the highest gas usage option, Tier 2 Option D consisting of Gold River Power Project + Ladysmith Peaker + Campbell River cogen expansion, would give 43 MW equivalent gas usage - only 20% of the DPP project gas risk. In addition, it may be possible to further mitigate gas risk for the Ladysmith Peaker plant by storing in line pack or LNG form for such periodic and infrequent usage relative to the assumed 80% online time and associated gas consumption of DPP.

The CFT required Green Island, as a proponent of a non-gas-fired generation project, to submit a fixed bid price for the majority of their costs while the majority of the energy charge price risk for VIGP-like projects is not borne by the bidder, but by the ratepayers of BC. Table No. 1 below illustrates the unfair advantage provided to gas-fired generation projects with the tolling option - the escalation risk for 66% of the total DPP project costs is borne by the ratepayers. In Green Island's case, 49% of the project costs are fixed over the 25-year lifetime of the project and the balance is limited to the CPI.

Table No. 1

	GIE			**Duke Point**		
	NPV ($000)	**Escalation Risk**	**% of Total Project Costs**	**NPV ($000)**	**Escalation Risk**	**% of Total Project Costs**
Capacity Charges	$245,365	Fixed	49%	$363,585	Fixed	25%
Fixed O&M Charges	$191,911	Escalation limited to CPI	38%	$99,184	Escalation Limited to CPI	7%
Variable Costs of Dispatch	$63,691	Escalation Limited to CPI	13%	$954,175	Majority of Risk Borne by Rate Payer	66%
Startup Costs	$0		0%	$27,626	Escalation Limited to CPI	2%
Total	**$500,967**			**$1,444,570**		
Electricity Market Value (NPV $000)	$380,136			$1,130,266		
Net Tender Cost	$120,832			$314,304		

It is clear that any of the portfolio options discussed in this evidence presents considerably less fuel risk than the DPP project. Minimizing fuel risk has obvious and positive benefits to the ratepayers responsible for those costs over the 25-year term of the proposed EPA.

ii. Availability Requirement

A biomass project such as the Gold River Power Project requires one major shutdown and one minor shutdown per year in order to maintain high availability over a peak operating period. The major shutdown of 2 weeks could be scheduled for May, one of BC Hydro's non-peak months. A minor shutdown of 4 days would be required in October or November to ensure high availability during the peak winter season.

The payment terms of the EPA penalize a project if during any month the availability is less than 97% over that month. This requirement applies for 9 months of the year, making it difficult for Green Island to deal with. However, due to its ability to store dryer-than-average biomass fuel Green Island was able to devise a method for satisfying both the technical requirements of a biomass project and the CFT conditions. This method involved changing the operating range from 95% - 105% to 95% – 115%. If Green Island would have been allowed to operate at 115% of contract capacity for short periods of time the 97% availability could have been maintained even during the month of October when a minor shutdown would be scheduled. Table No. 2 below illustrates the concept.

Table No. 2

	Hours	**Load Condition**	**Energy Generated (MWh)**
Operating Hours	648	115%	55,890
Outage Hours	96	0%	
Hours in Month	744		55,800
Availability for Month			100%

BC Hydro would not allow that contract change and as Table No. 3 below indicates 97% availability could not be obtained with an operating range of 95 to 105%.

Table No. 3

	Hours	**Load Condition**	**Energy Generated (MWh)**
Operating Hours	648	105%	51,030
Outage Hours	96	0%	
Hours in Month	744		55,800
Availability for Month			91%

The inflexibility regarding the permissible operating range is unfair to biomass projects because gas-fired projects are allowed a wider than 95 to 105% operating range as a result of temperature variations. If the terms of the CFT had provided similar consideration to biomass projects due to variations in moisture content in fuel Green Island would be able to accommodate the 97% availability requirement at a lower cost. As the CFT made no such accommodation, quite unfairly, Green Island was forced to assume a project design with a capacity considerably higher than contract capacity. This in turn required Green Island to only bid 75 MW of capacity output as opposed to the normal 85MW net output that the Gold River Power Project could generate. Holding back the extra 10 MW to insure the 97% availability of 9 months of the year also resulted in Green Island having to bid a slightly higher capacity charge in order to maintain the financing coverage ratios required by the project lender.

iv. Fuel Supply Certainty

Green Island's Gold River Power Project satisfied all of BC Hydro's extensive Mandatory Criteria for adequate certainty of fuel supply, as required for the VI CFT.

Green Island sought absolute certainty that its long-term fuel supply will be reliable.

Accordingly, particular emphasis was placed on fuel supply for the Gold River Power Project to the extent that fuel supply reliability is actually one of the Gold River Power Project's strongest attributes, differentiating it from other typical biomass projects.

The Gold River Power Project is located at the Gold River Pulp mill site, which has a deep-sea port. This enables fuel to be supplied from the entire west coast of North America by ocean carrying ships, as well as barge and truck in more regional markets. The combustion equipment has been designed to accommodate a wide range of fuels including hog fuel, dry wood waste and refuse derived fuels (RDF). Thus the Gold River Power Project's facilities enable Primary, Secondary and even Tertiary level redundancy strategies to be put in place for fuel supply certainty as well as sourcing, handling and transportation aspects of the fuel supply. The Gold River Power Project has also been designed for more than two months of fuel storage on site.

Green Island has established formal business relationships with a number of large-scale fuel providers of dry wood waste and RDF. Green Island has made 25-year arrangements for port facilities and implemented long-term agreements with shipping and transportation companies. Accordingly, in addition to physical redundancy in facility design, primary, secondary and third level business redundancy has been established with fuel providers. This enables Green Island to have a guaranteed supply of fuel over the duration of the Initial Term (25 years), as well as negotiating ability over the full term (35 years) so that a competitive fuel supply price can be maintained.

Green Island will assume complete fuel supply certainty risk for the full duration of an EPA.

3. Unduly Stringent Mandatory Criteria in CFT Process

If the Campbell River cogen expansion bid for 48 MW had been considered, Tier 2 Option D – comprised of the Gold River Power Project, Ladysmith and the Campbell River cogen expansion - would have resulted in a portfolio with an aggregate capacity of 170 MW. Such a portfolio would have been within the 150 MW to 300 MW range relied upon by BC Hydro.

It is an open question whether the Campbell River cogen expansion bid was disqualified on the basis of failing to meet Mandatory Criteria that were unduly stringent.

4. Tier 2 Portfolios are Less Cost than DPP

Green Island has calculated the Net Present Value ("NPV") of the Tier 2 Option A Portfolio consisting of the 75 MW Gold River Power Plant, the 47 MW Ladysmith Peaker and 130 MW NCDMP. Our economic analysis indicates that the Tier 2 Option A portfolio is only 53% of the cost of the DPP project - that significantly lower cost would provide a major benefit to the ratepayers.

Table No. 4 below summarizes our analysis.

Table No. 4

Comparison Table - Tier 1 Versus Tier 2A

Tier 2A – Green Island Energy (GIE) and Ladysmith Peaker (LP) and Norske Canada Demand Management Project (NCDMP)

(2006 beginning of year dollars)		
Tier 1 - Duke Point Power	**NPV ($000)**	**References**
Net Tender Cost 252 MW of Capacity	314,000	QEM Model Results - Appendix 3 from EPA
VIGP Asset Sale Adder	(50,000)	BCH-CFT Report, Table 3
Firm Gas Transportation Adder	131,000	BCH Response to BCUC IR 1.23.5 (Present Value at 8% Discount)
BCTC Network Costs	13,000	BCH-CFT Report, Table 3
Total Portfolio Cost	408,000	
Tier 2A - GIE, LP and NCDMP		
Net Tender Costs of GIE and LP 122 MW of Capacity	190,000	QEM Model Results Using GIE Bid Data and Estimated Data for LM6000 Peaker
VIGP Salvage Value	(14,000)	BCH-CFT Report, Page 5
BCTC Network Upgrade Costs GIE, LP and NCDMP	7,450	Preliminary Interconnection Report Prepared for Green Island Energy by BCTC Plus $ 5 million estimate for Interconnection of LP
Gas Transportation Costs for Peaker	10,000	Estimate by Intervenor
NCDMP Curtailable Load Costs 130 MW of Capacity	21,000	Norske submission to BCTC Capital Planning Hearing
Total Portfolio Cost	214,450	
Percent of Tier 1	53%	

i. Economic Comparison Explanation

The CFT was designed to add 150 to 300 MW of dependable capacity to Vancouver Island by May 2007. The Quantitative Evaluation Model established by BC Hydro to evaluate VI-CFT tenders was also designed to evaluate tender submissions on that basis.

Accordingly, our economic analysis compares the cost of DPP's 252 MW capacity addition with a 252 MW capacity addition using Tier 2 resources.

As a bidder, Green Island possesses the QEM model and has used it for this analysis. Green Island acknowledges that the QEM model is confidential and accordingly is not permitted to release its model runs to all Intervenors. However, Green Island will provide its model runs to the BCUC in a separate confidential document. **These runs will include all of Green Island's price tender information.**

ii. DPP Assumptions

Green Island's analysis used DPP project values provided in Appendix 3 of the EPA released by BC Hydro.

iii. Green Island Data

Our analysis used Green Island's tendered bid prices.

iv. Ladysmith Peaker Plant Assumptions

At the time of filing this evidence, EPCOR's tendered bid remains confidential. However, information on GE's LM6000 gas turbine, which is the most commonly used unit for peaker applications, is widely available. Therefore, for purposes of this analysis, Green Island was required to make certain key cost assumptions as follows:

Capacity (including consideration for degradation)	- 47 MW
Capital Cost Payment	- $8,600 per MW per Month
Operating and Maintenance Cost Payment	- $2,800 per MW per Month
Non-Fuel Energy Costs	- $3.50 per MWh
Heat Rate	- 9,900 GJ/GWh

The Tier 2 Option A portfolio matches the DPP project capacity. Green Island has also performed an analysis that compares the Tier 2 Option B portfolio – the Gold River Power Project and the Ladysmith Peaker - with DPP. The results are provided in Table No. 5 below. Our analysis indicates that this combination of 122 MW is less than 50% of the cost of the DPP project.

Table No. 5

Comparison Table - Tier 1 Versus Tier 2B **Tier 2B – Green Island Energy (GIE) and Ladysmith Peaker (LP)**		
(2006 beginning of year dollars)		
Tier 1 - Duke Point Power	**NPV ($000)**	**References**
Net Tender Cost 252 MW of Capacity	314,000	QEM Model Results - Appendix 3 from EPA
VIGP Asset Sale Adder	(50,000)	BCH-CFT Report, Table 3
Firm Gas Transportation Adder	131,000	BCH Response to BCUC IR 1.23.5 (Present Value at 8% Discount)
BCTC Network Costs	13,000	BCH-CFT Report, Table 3
Total Portfolio Cost	408,000	
Tier 2B – GIE and LP		
Net Tender Costs of GIE and LP 122 MW of Capacity	190,000	QEM Model Results Using GIE Bid Data and Estimated Data for LM6000 Peaker
VIGP Salvage Value	(14,000)	BCH-CFT Report, Page 5
BCTC Network Upgrade Costs GIE and LP	8,000	Preliminary Interconnection Report Prepared for Green Island Energy by BCTC Plus $ 5 million estimate for Interconnection of LP
Gas Transportation Costs for LP	10,000	Estimate by Intervenor
Total Portfolio Cost	194,000	
Percent of Tier 1	48%	

Green Island has included an analysis of two other Tier 2 possibilities. Tier 2 Option C – the Gold River Power Project and **two** Ladysmith Peakers. This alternative is 68% of the cost of DPP. Tier 2 Option D is the Gold River Power Project, the single Ladysmith Peaker and the Campbell River Cogen Expansion. This alternative is 65% of the DPP project cost.

We have performed these different analyses to demonstrate that many different combinations of Tier 2 are less expensive than Tier 1.

Table No. 6

Comparison Table - Tier 1 Versus Tier 2C		
Tier 2C – Green Island Energy (GIE) and 2 Ladysmith Peakers (LPs)		
(2006 beginning of year dollars)		
Tier 1 - Duke Point Power	**NPV ($000)**	**References**
Net Tender Cost Capacity 252 MW	314,000	QEM Model Results - Appendix 3 from EPA
VIGP Asset Sale Adder	(50,000)	BCH-CFT Report, Table 3
Firm Gas Transportation Adder	131,000	BCH Response to BCUC IR 1.23.5 (Present Value at 8% Discount)
BCTC Network Costs	13,000	BCH-CFT Report, Table 3
Total Portfolio Cost	408,000	
Tier 2C – GIE, and 2 LPs		
Net Tender Costs of GIE and 2 LPs Capacity 169 MW	258,000	QEM Model Results Using GIE Bid Data and Estimated Data for LM6000 Peaker
VIGP Salvage Value	(14,000)	BCH-CFT Report, Page 5
BCTC Network Upgrade Costs GIE and 2 LPs	13,000	Preliminary Interconnection Report Prepared for Green Island Energy by BCTC Plus $ 5 million estimate for Interconnection of Peaker
Gas Transportation Costs for 2 LPs	20,000	Estimate by Intervenor
Total Portfolio Cost	277,000	
Percent of Tier 1	68%	

Table No. 7

Comparison Table - Tier 1 Versus Tier 2D **Tier 2D – Green Island Energy (GIE) and Ladysmith Peaker and Campbell River Cogen Expansion (CRCE)**		
(2006 beginning of year dollars)		
Tier 1 - Duke Point Power	**NPV ($000)**	**References**
Net Tender Cost Capacity 252 MW	314,000	QEM Model Results - Appendix 3 from EPA
VIGP Asset Sale Adder	(50,000)	BCH-CFT Report, Table 3
Firm Gas Transportation Adder	131,000	BCH Response to BCUC IR 1.23.5 (Present Value at 8% Discount)
BCTC Network Costs	13,000	BCH-CFT Report, Table 3
Total Portfolio Cost	408,000	
Tier 2D – GIE, LP, and CRCE		
Net Tender Costs of GIE, LP and CRCE 170 MW Capacity	259,000	QEM Model Results Using GIE Bid Data and Estimated Data for LM6000 Peaker and CRCE
VIGP Salvage Value	(14,000)	BCH-CFT Report, Page 5
BCTC Network Upgrade Costs for GIE, LP and CRCE	9,000	Preliminary Interconnection Report Prepared for Green Island Energy by BCTC Plus $ 5 million estimate for Interconnection of Peaker
Gas Transportation Costs for LP and CRCE	10,000	Estimate by Intervenor
Total Portfolio Cost	264,000	
Percent of Tier 1	65%	

5. Tier 2 Portfolios Provide Greater Reliability than DPP

i. Background

Norske's DMP notes the N-1 criterion for supply. In that case, only a single contingency is removed from the supply-demand balance and the system is judged for adequacy under that scenario. British Columbia Transmission Corporation ("BCTC") noted in their Report #SP2004-51, December 2004 that the use of the N-1 criterion is but one aspect of a complete probabilistic assessment of the reliability of an electrical system. BCTC further notes that a significant risk of failure may result during times of maintenance or other shortfall – all risk doesn't necessarily arise only at the time of system peak.

This timing of increased difficulty serving loads can most readily be seen from a reserve graph wherein the system loads are plotted in chronological order throughout the year, and all system resources, including derates, units out for maintenance and other aggravating circumstances are plotted for each hour.

Although BC Hydro has not provided enough information to plot a reserve graph for an entire year, it is possible from a load duration curve to estimate how much impact new unit additions have, though not when the impact might be felt throughout the year. In its Response to Green Island IR 1.11.8, BC Hydro has provided a load duration curve for F2008, the first year in which significant risk of an outage has been identified. First, it must be recognized that any year has some risk of failure, in that certain combinations of unit outages, line derates or failures can conspire to render the system unable to serve all the demands placed upon it. F2008 is a year in which those types of events, combined with system load growth have amounted to a credible risk of some load not being supplied.

Green Island will demonstrate that a Tier 2 portfolio made up of the Gold rive power Plant and a peaking plant (or two), especially when augmented by some of Norske's DSM measures, has a noticeably better impact on system ability to supply the range of likely loads placed upon it than does the DPP project.

ii. Reliability impact comparison of Tier 2 versus DPP

- In Response to Green Island IR 1.11.8 BC Hydro provided a load duration curve (LDC) for F2008 that shows the amount of capacity and demand and indicates some hours that are at risk for non-supply of energy (i.e. those on the left edge of the graph).

- Due to a lack of detail in the data provided, estimates only can be made of the numerical results taken from the LDC. Tabular information was requested, but not supplied by BC Hydro to this point in time.

- From the LDC provided, it can be seen that the greatest risk of a shortfall in supply – when demand that exceeds normal line loading and installed generating equipment capacity of about 1900 MW of capacity - occurs for approximately 360 hours per year.

- Even if the AC cable overload capability is included, it appears that about 285 MW of demand lies <u>above</u> the supply curve at the peak.

- It also appears that the following ranges apply for the MW thresholds on that graph:
  - Load exceeds the 1990 MW of capacity level for about 160 hours / year;
  - Load exceeds the 2050 MW of capacity level for 70 hours / year;
  - Load exceeds the 2100 MW of capacity level for 40 hours / year;
  - Load exceeds the 2150 MW for of capacity level 20 hours / year;
  - Load exceeds the 2200 MW of capacity level for 10 hours / year;

Load exceeds the 2250+ MW of capacity level for 1- 4 hours, assumed to be 3 hours per year; and

- 2275 MW is the absolute peak.

There is an apparent discrepancy on the graph in Response to Green Island IR 1.11.8, in that BC Hydro shows supply at 2000+ MW, whereas the computation for supply yields 1990 MW [450 Hydro, 240 ICP, 1200 AC cable + 100 AC overload]. Due to the flatness of the curve this small capacity difference has quite an impact on number of hours in a given range. Despite this, the analysis shows a similar effect when comparing the DPP project and Tier 2 portfolios.

It can be seen that the ranges of being "at risk for being short of supply", assuming supply capacity as 1990 MW, can be taken from the above information directly i.e. the Load Model would be:

- 0-60 MW short of capacity for about 90 hours (160 hours – 70 hours)
- similarly 60-110 MW short for 30 hours,
- 110-160 MW for 20 hours,
- 160-210 MW for 10 hours,
- 210-260 MW for 7 hours,
- 260-285 MW for 3 hours

From this, we can surmise what impact an additional supply portfolio would have in serving this load at risk. (Assuming the balance of the load is already covered, though in detail, we note there are risks associated with the balance of the load – supply arrangement. These are set aside for this comparison, though they would favor the Tier 2 portfolios even more if included.)

Several Tier 2 portfolios were considered for supply. These include the following assumptions:

- GIE 75 MW, reliability of service at this level of 97% or greater, taken as 0.97.

- Peaker 47 MW, reliability at this level of 98.5% or greater, taken as 0.985, (reflecting manufacturer expected outage rates for LM6000 units in simple cycle mode). In one case, the addition of a second peaker plant was simulated, to see the effect on reliability of this second plant.

- Calpine combined cycle plant, 48 MW bid, reliability taken as 98%.

- Norske load curtailment, 30-210 MW – knowledge of the relative reliability of components within this range are not known, though it is reasonable to presume that DSM measures are generally very highly reliable. Reliability taken as 99.5% for 30-140 MW and 99% for 140-210 MW range. Each is known to have limited hours of availability. The reliability impact will be modeled with only the first Norske "block" considered, providing a portfolio of 262 MW, (75+47+140) for easy comparison to the VIGP block of 252 MW.

iii. Operational Dispatch

- It is assumed that in operational dispatch, the Gold River Power Plant would be operating essentially all the hours that it is available, i.e. no reaction time required as it is already running.

- The peaker would be dispatched to suit the predicted needs of the system, hence the peaker reaction time of several minutes would not be a problem as it would be dispatched prior to immediate need and the hydro system adjusted to suit specific loading.

- Calpine's plant would be assumed to be readily dispatched, though quite possibly with slower reaction time than the peaker, and also possibly with some restrictions on number of startup events per year.

- The Norske DSM component would be dispatched last, for a minimum number of hours, and should be available to suit whatever shortfall should arise in a very rapid manner. Such shortfall would include the residual hours not supplied by the other Tier 2 generating units while on Forced Outage Hours (FOH) or for hours in which the incremental load requirements exceed the 122 MW available from the other two units.

iv. General Comments

- To do a proper probabilistic load – supply assessment would require reliability data on all supply choices and would allow a model to convolve all supply risks into a single matrix. BC Hydro has not supplied sufficient data to allow such an assessment, so instead, Green Island is forced to demonstrate its reliability points as a means of comparison between the DPP project and Tier 2 portfolios as they serve the <u>incremental</u> load, above what the balance of the system is capable of supplying given the N-1 condition assumed during construction of the graph in Green Island IR 1.11.8.

- Several alternative Tier 2 portfolios were constructed, to indicate that the Gold River Power Plant is fundamental to the arrangement and to demonstrate that it is ably supported by various combinations of possible peakers, DSM or other plants.

v. Results of Analysis

Tier 1 portfolio, consisting of one unit of 252 MW, with unit availability of 97%, i.e., forced outage rate (FOR) of about 3%. [scheduled maintenance time set aside]
There are only 2 states for this configuration, either the unit is running or not. So a table of probabilities of such operational states could be shown in Table No. 8 as:

Table No. 8: Duke Point probability table

Supply on	State probability	Cumulative Probability
252.0	0.970000	1.000000
0.0	0.030000	0.030000

From this we can see that any load less than or equal to 252 MW could be served 97% of the time and any load greater than 252 MW could never be served, i.e. it would have a 100% probability of not being served in its entirety, thus constituting "not served status". From the above information on incremental loads above the balance of system resources, we can see that of the top 160 hours of load demand, only 3 hours are above the level of 260 MW, and perhaps one or two more hours are in the range of 252-260 MW. However, these levels represent only a part of the total likelihood of non-supply. From the probability table we note that 3% of the time there might be a forced outage of the unit, which cannot be predicted or mitigated with any degree of certainty. Hence, about 3% of the time, the loads below 252 MW are not served also. Adding this outage to the level of hours of load not served, we get the total of hours of expected non-supply. That is:
0.03 * 157 hours + 1.0 * 3 hours = 4.7 + 3 = 7.7 hours of time when supply is expected to be incapable of meeting demand. Now some of these hours of non-supply will be for less than the entire capacity of the unit, but that doesn't really matter if the unit is not present to support the load. However it does mean that for quite a number of hours, the load that needs support is in fact less than the maximum of 252 MW.

In such situations it would seem reasonable that a smaller generating unit, or combination of units, would be able to serve these smaller loads more effectively – as the likelihood of several smaller units not being present is much less than the likelihood of just one unit failing. Based on this observation, Tier 2 alternatives could be expected to produce a higher probability of serving the load needs over a wide range of load levels that more likely mimic actual operation. To test this hypothesis, a reliability assessment of Tier 2 options were conducted using the same basic assumptions on load and system supply as for Tier 1. The results are below, for convenience the components of all Tier 2 options are summarized below. (see previous discussion about units above for more detail). Tier 2 portfolios, listed in Table No. 8, consist of:

Table No. 9: Tier 2, List of Options

Tier 2 Option	GIE 75 MW, FOR=3%	Ladysmith Peaker 47 MW, FOR=1.5%	Campbell River cogen expansion 48 MW, FOR=2%	NCDMP (DSM) 140 MW, FOR=0.5%
A	X	X		X
B	X	X		
C	X	X2		
D	X	X	X	
E	X	X2	X	
F	X	X	X	X

[Again, scheduled maintenance time is set aside for purposes of this analysis]

For most of the options, there are at least 3 "supply resources". As a result, there are many more possible states for these configurations than was found in Table No. 8. Using Option A as an example, there would be 8 possible states, that is each unit can be off independently, or combinations of two can be off, or all three on or all three off. A straightforward enumeration of possibilities shows the operational states and probabilities is shown in Table No. 10 below:

Table No. 10: Tier 2, Option A probability table

Supply on	State probability	Cumulative Probability
262.0	0.950673	1.000000
215.0	0.014477	0.049327
187.0	0.029402	0.034850
140.0	0.000448	0.005448
122.0	0.004777	0.005000
75.0	0.000073	0.000223
47.0	0.000148	0.000150
0.0	0.000002	0.000002

From Table No. 10, we can see that if the load is say 60 MW, the two bottom states will be unable to serve it (look along the left column for 0.0 and 47.0), and the probability of such occurrence is given as 0.000150 (the cumulative chance of either state occurring). All other states would be able to successfully serve the load. Put another way, a 60 MW load has (1 - 0.000150) chance of being served, i.e. 0.99985 or expressed as a percentage, this is **99.985%** probability of being served by some combination of the Tier 2 resources in that option. This is vastly greater than 97% probability under the Tier 1 portfolio.

Extending this same approach for the load levels and hours of expected load demand identified in the load model above (taken from the Load duration curve provided by BC

Hydro); it can be shown that the expected number of hours of any and all load levels less than 262 MW not being served is about 0.7 hours of the 160 hours. Add to that the 3 hours of load levels expected to be in the range of 260-285 MW above system resource, and the total time of expected unserved load is 3.7 hours – again a far cry better than the 7.7 hours for Tier 1.

Just to restate a point made above, for all load levels in the range of 0-260 MW or so; this Tier 2 portfolio will have only <u>0.7 hours</u> of expected unserved load, compared to 4.7 hours of expected unserved load for Tier 1 for approximately the same range of load. That is, the Tier 2 portfolio is <u>substantially</u> better at serving the load needs throughout the expected range than is Tier 1.

Similar analysis was performed for each of the Tier 2 options presented above. The results are summarized in Table No. 11 below.

Table No. 11: Summary of probability of unserved incremental load for Tier 1 and Tier 2 options

Tier 2 Option	Probability of unserved load	Expected hours of unserved load	Summary of Configuration	MW considered within Portfolio
A	0.023260	3.7	GIE + Peaker + DSM	262
B	0.275288	44.0	GIE + Peaker	122
C	0.138529	22.2	GIE + two Peakers	169
D	0.139223	22.3	GIE + Peaker + cc plant	170
E	0.031146	5.0	GIE + two Peakers + cc plant	217
F	0.001995	0.3	GIE + Peaker + cc plant + DSM	310
Duke Point	0.048188	7.7	VIGP style cc power plant	252

Table No. 11 gives the reliability for a range of capability of the incremental capacity from slightly less than, to slightly greater than, the VI CFT range of 150 – 300 MW. As there is no acceptable index of reliability established, there is no specific criteria to use for "what is enough". However, the BC Hydro CFT did indicate that any load combination between 150 MW and 300 MW would be considered acceptable, suggesting that the values from Options C and D are close to the lowest level of reliability that should be considered acceptable. By this measure, one can see that Option B would fail the simple criteria, though in fact it is capable of serving loads up to 122 MW very well.

What is clear from the results above is that any of the Tier 2 portfolios that include approximately the same capacity as the Tier 1 portfolio, (i.e. Options A, E or F) have considerably better reliability than can be demonstrated from the single large unit of Tier 1. It is also clear that gaining additional reliability benefits are most easily accomplished by adding other peaking plants or DSM measures. These resources are specialized to provide this service and do so at optimal cost for installed capacity.

vi. Reliability Summary

In summary, it can be seen that it is quite easy to construct a Tier 2 portfolio that has a substantially better impact on the reliability of the system to the support loads demanded of it by the consumer base than does the Tier 1 DPP project. In particular, the Gold River Power Plant with one Peaker is a solid installed base of generating equipment, which if augmented by the DSM proposal by Norske, provides excellent support to all load levels likely to be experienced on Vancouver Island for the sample year chosen.

6. Tier 2 Portfolios are Cleaner, Cheaper and Faster than DPP

Each of the Tier 2 portfolios addressed in this evidence, all of which include the Gold River Project, are superior to the DPP project on the basis of desirable criteria beyond cost and reliability. The Tier 2 portfolios, comprised of smaller well-developed projects, offer greater certainty of being on-line prior to May 2007. Such portfolios would also avoid approximately 95% of the GHG emissions that would be produced by the DPP project.

7. **State of Readiness**

The Gold River Power Project is already well advanced and fully capable of being online in the summer of 2006. The Gold River Power Project schedule can be broken into several distinct phases as described below. This conservative schedule was established in response to BC Hydro's disinterest in acquiring any generation output in advance of the March, 2007 CFT online date. The achievable commercial online date for Gold River Power Project is 14 to 16 months from time of an EPA award.

Initial Development Activities

The Gold River Power Project development is far along and proceeding such that it can be on-line well in advance of the required COD. The following activities have been accomplished:

- The rights to the mill site and all equipment have been purchased.

- A Project Team has been established that is experienced and competent.

- Feasibility studies have been completed.

- Sandwell completed the preliminary engineering and design work for the project.

- North American Energy Service, a highly qualified and reputable power plant operator is under contract to operate the Gold River Power Project

- Fuel sources and supply volumes have been studied.

- Fuel Supply Agreements and Memoranda of Understanding for 25-year fuel supplies have been secured for 200% of the Project's fuel needs.

- Shipping company has been selected along with alternate shipping company

- The preliminary interconnection study has been completed by the BCTC.

- An option to purchase a 100 MW STG has been secured.

- An option to purchase a bag house has been secured.

The project site already has BCTC transmission access, and no new transmission lines need be built to serve the project.

- The Project has local support from the Village of Gold River and the First Nations.

- City zoning ordinances and business licenses for the Project have been obtained

- Phase 1 air and effluent permits have been issued. Phase 2 permit amendment is exempt from EAO review, has completed the technical report and public consultation process and is in process with assistance from the BC Governments Fast-Track program.

- Project financing has been arranged and the lender has signed an engagement letter for both pre-construction and term financing.

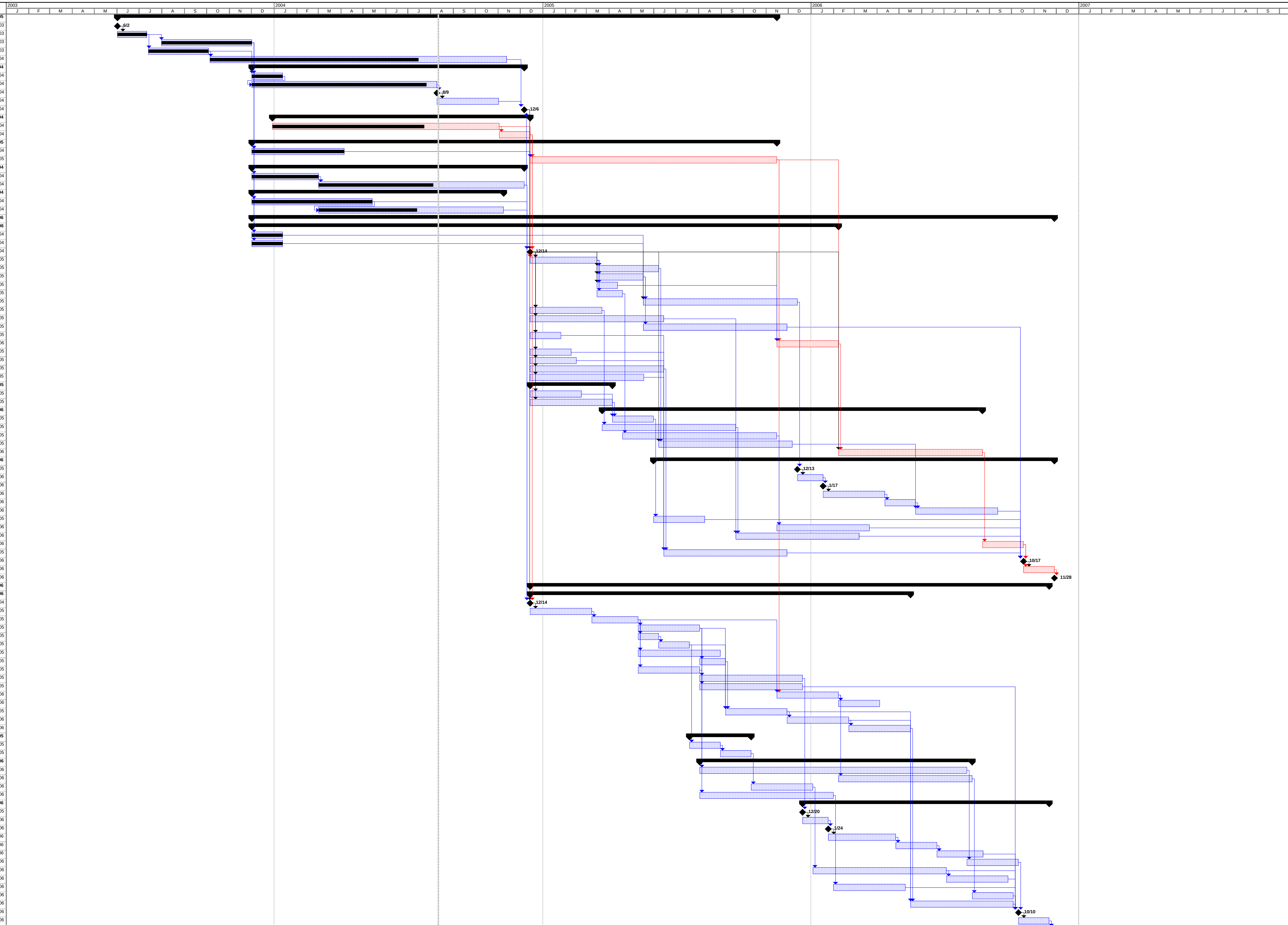
- Several qualified and bondable Engineering, Procurement and Construction (EPC) contractors have been evaluated and a fixed prices bid has been received.

The development schedule for the Gold River Project is attached as Appendix 1 to this evidence.

Gold River Power Project
Green Island Energy

Complete Project Development Schedule
Wed 8/11/04

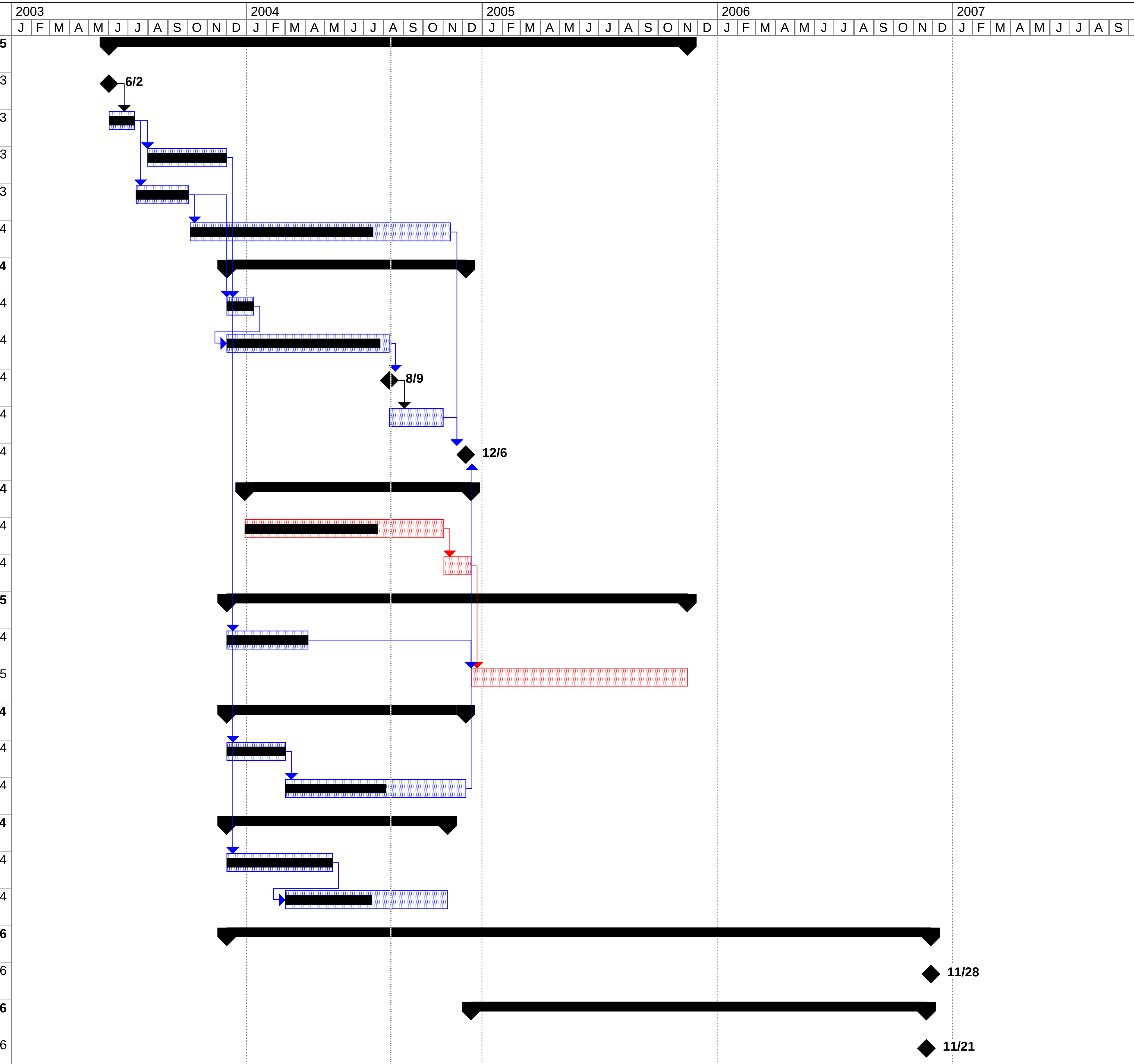
ID	Info	Task Name	Duration	Start	Finish
1		**Development**	**642 days**	**Mon 6/2/03**	**Tue 11/15/05**
2	✓	Site acquistion	0 days	Mon 6/2/03	Mon 6/2/03
3	✓	Select Project Team	30 days	Mon 6/2/03	Fri 7/11/03
4	✓	Preliminary Engineering	87 days	Fri 8/1/03	Mon 12/1/03
5	✓	Fuel Studies	60 days	Mon 7/14/03	Fri 10/3/03
6		Fuel Contracting	290 days	Mon 10/6/03	Fri 11/12/04
7		**Financing**	**265 days**	**Tue 12/2/03**	**Mon 12/6/04**
8	✓	Develop Proforma	30 days	Tue 12/2/03	Mon 1/12/04
9		Select Lender	9 mons	Tue 12/2/03	Mon 8/9/04
10		Lender selected	0 days	Mon 8/9/04	Mon 8/9/04
11		Lender due diligence	60 days	Tue 8/10/04	Mon 11/1/04
12		Lender commitment	0 days	Mon 12/6/04	Mon 12/6/04
13		**Obtain EPA**	**251 days**	**Tue 12/30/03**	**Tue 12/14/04**
14		BC Hydro VI CFT EPA	221 days	Tue 12/30/03	Tue 11/2/04
15		BCUC EPA Approval	30 days	Wed 11/3/04	Tue 12/14/04
16		**Interconnection**	**511 days**	**Tue 12/2/03**	**Tue 11/15/05**
17	✓	Preliminary BCTC study	90 days	Tue 12/2/03	Mon 4/5/04
18		BCTC Interconnection Study	12 mons	Wed 12/15/04	Tue 11/15/05
19		**EPC Contractor**	**265 days**	**Tue 12/2/03**	**Mon 12/6/04**
20	✓	Shortlist EPC Contractor	65 days	Tue 12/2/03	Mon 3/1/04
21		Refine Design & EPC Select	10 mons	Tue 3/2/04	Mon 12/6/04
22		**Permitting**	**245 days**	**Tue 12/2/03**	**Mon 11/8/04**
23	✓	Air and Effluent Permits - Phase 1	118 days	Tue 12/2/03	Thu 5/13/04
24		Air and Effluent Permits - Phase 2	9 mons	Tue 3/2/04	Mon 11/8/04
25		**Project Phase 1 Construction**	**781 days**	**Tue 12/2/03**	**Tue 11/28/06**
26		**Detail Engineering Phase 1**	**571 days**	**Tue 12/2/03**	**Tue 2/7/06**
27	✓	Purchase STG Option	30 days	Tue 12/2/03	Mon 1/12/04
28	✓	Purchase Baghouse Option	30 days	Tue 12/2/03	Mon 1/12/04
29		Notice to Proceed EPC Contract	0 days	Tue 12/14/04	Tue 12/14/04
30		Prepare Flowsheets	65 days	Wed 12/15/04	Tue 3/15/05
31		TG Condenser Purch	60 days	Wed 3/16/05	Tue 6/7/05
32		Prepare GA's	45 days	Wed 3/16/05	Tue 5/17/05
33		Transformer. specs and Purch	20 days	Wed 3/16/05	Tue 4/12/05
34		Cooling Tower Spec. & Purch	25 days	Wed 3/16/05	Tue 4/19/05
35		Powerhouse & Baghouse Detail Design	30 wks	Wed 5/18/05	Tue 12/13/05
36		Fuel Sys. Specs & Purch	70 days	Wed 12/15/04	Tue 3/22/05
37		Fuel System Details	130 days	Wed 12/15/04	Tue 6/14/05
38		Piping & Misc. Detail Design	140 days	Wed 5/18/05	Tue 11/29/05
39		E/I Field Assessments	6 wks	Wed 12/15/04	Tue 1/25/05
40		Electrical Substation Design	60 days	Wed 11/16/05	Tue 2/7/06
41		Electrical Specs & Purchasing	8 wks	Wed 12/15/04	Tue 2/8/05
42		Instrumentation Specs & Purch	45 days	Wed 12/15/04	Tue 2/15/05
43		Electr. Instr. & Controls Design	130 days	Wed 12/15/04	Tue 6/14/05
44		Field Engineering	111 days	Wed 12/15/04	Wed 5/18/05
45		**Power Boiler Work Package**	**80 days**	**Wed 12/15/04**	**Tue 4/5/05**
46		Detail Specs. & Inspections	10 wks	Wed 12/15/04	Tue 2/22/05
47		Aux. Equip. Design	16 wks	Wed 12/15/04	Tue 4/5/05
48		**Main Equip. Deliveries**	**370 days**	**Wed 3/23/05**	**Tue 8/22/06**
49		Boiler deliveries	8 wks	Wed 4/6/05	Tue 5/31/05
50		Fuel conveying system	26 wks	Wed 3/23/05	Tue 9/20/05
51		Cooling Tower	30 wks	Wed 4/20/05	Tue 11/15/05
52		Condenser	26 wks	Wed 6/8/05	Tue 12/6/05
53		Transformer & Switchyard	28 wks	Wed 2/8/06	Tue 8/22/06
54		**Construction**	**390 days**	**Wed 6/1/05**	**Tue 11/28/06**
55		**Start of Phase 1 Construction**	0 days	Tue 12/13/05	Tue 12/13/05
56		STG#1 Foundations	5 wks	Wed 12/14/05	Tue 1/17/06
57		**Phase 1 Foundations Complete**	0 days	Tue 1/17/06	Tue 1/17/06
58		Steel del. & Fabrication	12 wks	Wed 1/18/06	Tue 4/11/06
59		Steel Erection & Floors	6 wks	Wed 4/12/06	Tue 5/23/06
60		Equipment Installation	16 wks	Wed 5/24/06	Tue 9/12/06
61		Boiler Refurbishment	10 wks	Wed 6/1/05	Tue 8/9/05
62		Cooling tower Installation	90 days	Wed 11/16/05	Tue 3/21/06
63		Fuel System Installation	120 days	Wed 9/21/05	Tue 3/7/06
64		Electrical Substation	8 wks	Wed 8/23/06	Tue 10/17/06
65		Elctr. & Instrumentation	120 days	Wed 6/15/05	Tue 11/29/05
66		**Phase 1 Mechanical complete**	0 days	Tue 10/17/06	Tue 10/17/06
67		Commissioning & Startup	30 days	Wed 10/18/06	Tue 11/28/06
68		**Phase 1 On-line**	0 days	Tue 11/28/06	Tue 11/28/06
69		**Project Phase 2 Construction**	**505 days**	**Tue 12/14/04**	**Tue 11/21/06**
70		**Detail Design Phase 2**	**370 days**	**Tue 12/14/04**	**Tue 5/16/06**
71		Notice to Proceed EPC	0 days	Tue 12/14/04	Tue 12/14/04
72		Prepare Flowsheets	60 days	Wed 12/15/04	Tue 3/8/05
73		Prepare GA's	45 days	Wed 3/9/05	Tue 5/10/05
74		STG#2 Spec. & Purchasing	60 days	Wed 5/11/05	Tue 8/2/05
75		Select boiler contractor	20 days	Wed 5/11/05	Tue 6/7/05
76		Boiler refurbishment design details	30 days	Wed 6/8/05	Tue 7/19/05
77		Design RDF Storage Bldg	80 days	Wed 5/11/05	Tue 8/30/05
78		Cooling Tower Spec. & Purch	25 days	Wed 8/3/05	Tue 9/6/05
79		Fuel Sys. Specs & Purch	60 days	Wed 5/11/05	Tue 8/2/05
80		Fuel System Details	100 days	Wed 8/3/05	Tue 12/20/05
81		Piping & Misc. Detail Design	100 days	Wed 8/3/05	Tue 12/20/05
82		Electrical Substation Design	60 days	Wed 11/16/05	Tue 2/7/06
83		Electrical Specs & Purch	40 days	Wed 2/8/06	Tue 4/4/06
84		Instrumentation Specs & Purch	60 days	Wed 9/7/05	Tue 11/29/05
85		Electr. Instr. & Controls Design	60 days	Wed 11/30/05	Tue 2/21/06
86		Field Engineering	60 days	Wed 2/22/06	Tue 5/16/06
87		**Recovery Boiler Work Package**	**60 days**	**Wed 7/20/05**	**Tue 10/11/05**
88		Boiler mod. Specs & Inspections	6 wks	Wed 7/20/05	Tue 8/30/05
89		Aux. Equip. Design	30 days	Wed 8/31/05	Tue 10/11/05
90		**Main Equip. Deliveries**	**265 days**	**Wed 8/3/05**	**Tue 8/8/06**
91		STG Delivery	52 wks	Wed 8/3/05	Tue 8/1/06
92		Transformers	26 wks	Wed 2/8/06	Tue 8/8/06
93		Boiler Deliveries	12 wks	Wed 10/12/05	Tue 1/3/06
94		Fuel System Components	26 wks	Wed 8/3/05	Tue 1/31/06
95		**Construction**	**240 days**	**Tue 12/20/05**	**Tue 11/21/06**
96		Start of Phase 2 Construction	0 days	Tue 12/20/05	Tue 12/20/05
97		RDF Storage Foundations	25 days	Wed 12/21/05	Tue 1/24/06
98		**Phase 2 Foundations Complete**	0 days	Tue 1/24/06	Tue 1/24/06
99		RDF Steel Fabrication	66 days	Wed 1/25/06	Wed 4/26/06
100		RDF Steel Erection	8 wks	Thu 4/27/06	Wed 6/21/06
101		RDF Equipment Installation	45 days	Thu 6/22/06	Wed 8/23/06
102		STG #2 Installation	10 wks	Wed 8/2/06	Tue 10/10/06
103		Boiler Refurbishment	26 wks	Wed 1/4/06	Tue 7/4/06
104		Cooling tower Modifications	60 days	Wed 7/5/06	Tue 9/26/06
105		Fuel System Installation	70 days	Wed 2/1/06	Tue 5/9/06
106		Electrical Substation	8 wks	Wed 8/9/06	Tue 10/3/06
107		Elctr. & Instrumentation	100 days	Wed 5/17/06	Tue 10/3/06
108		**Phase 2 Mechanical Complete**	0 days	Tue 10/10/06	Tue 10/10/06
109		Commissioning & Start up	30 days	Wed 10/11/06	Tue 11/21/06
110		**Phase 2 On Line**	0 days	Tue 11/21/06	Tue 11/21/06



Gold River Power Project
Green Island Energy

Front-End Development Schedule
Wed 8/11/04

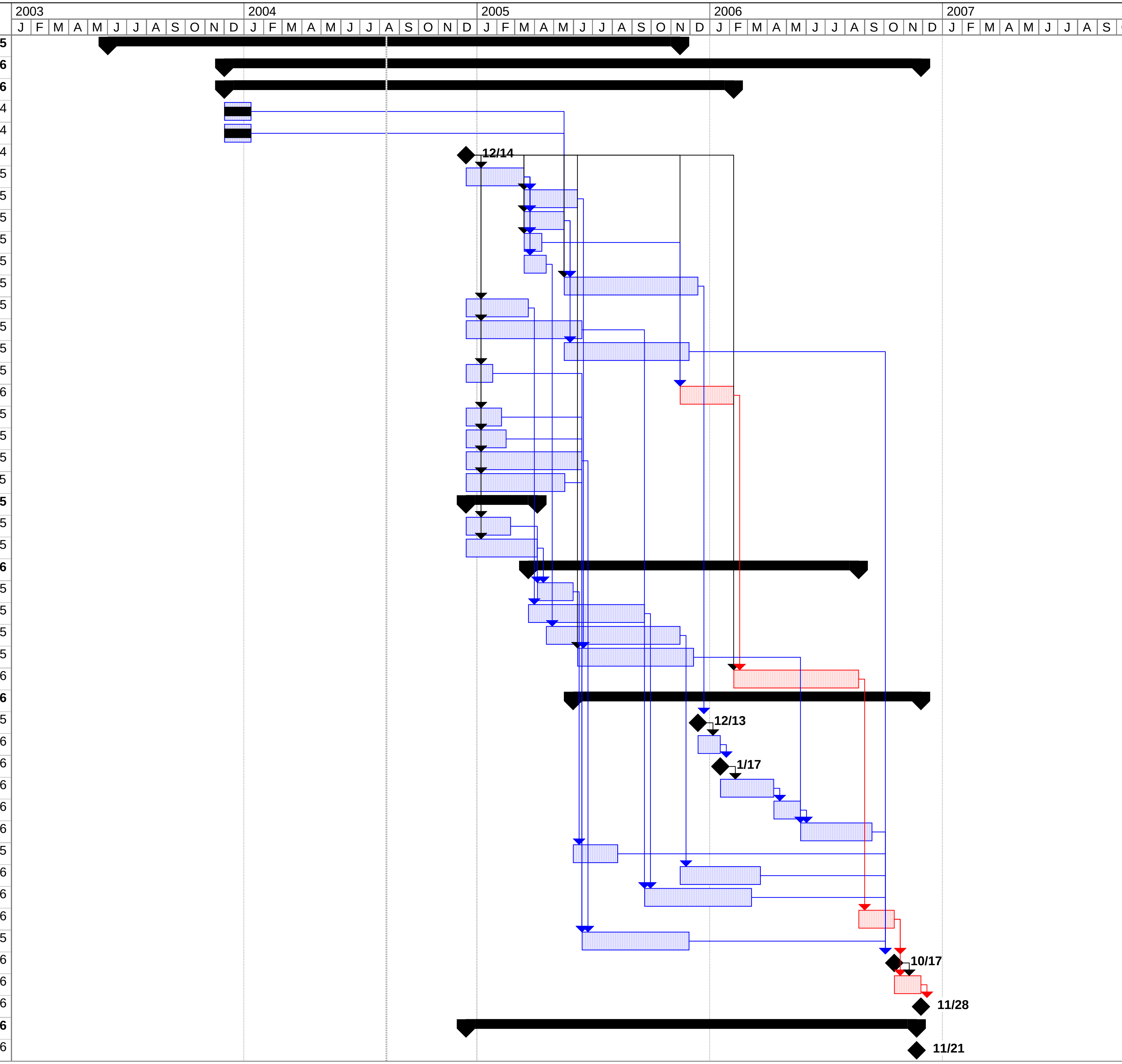
ID	Task Name	Duration	Start	Finish
1	**Development**	**642 days**	**Mon 6/2/03**	**Tue 11/15/05**
2	Site acquistion	0 days	Mon 6/2/03	Mon 6/2/03
3	Select Project Team	30 days	Mon 6/2/03	Fri 7/11/03
4	Preliminary Engineering	87 days	Fri 8/1/03	Mon 12/1/03
5	Fuel Studies	60 days	Mon 7/14/03	Fri 10/3/03
6	Fuel Contracting	290 days	Mon 10/6/03	Fri 11/12/04
7	**Financing**	**265 days**	**Tue 12/2/03**	**Mon 12/6/04**
8	Develop Proforma	30 days	Tue 12/2/03	Mon 1/12/04
9	Select Lender	9 mons	Tue 12/2/03	Mon 8/9/04
10	Lender selected	0 days	Mon 8/9/04	Mon 8/9/04
11	Lender due diligence	60 days	Tue 8/10/04	Mon 11/1/04
12	Lender commitment	0 days	Mon 12/6/04	Mon 12/6/04
13	**Obtain EPA**	**251 days**	**Tue 12/30/03**	**Tue 12/14/04**
14	BC Hydro VI CFT EPA	221 days	Tue 12/30/03	Tue 11/2/04
15	BCUC EPA Approval	30 days	Wed 11/3/04	Tue 12/14/04
16	**Interconnection**	**511 days**	**Tue 12/2/03**	**Tue 11/15/05**
17	Preliminary BCTC study	90 days	Tue 12/2/03	Mon 4/5/04
18	BCTC Interconnection Study	12 mons	Wed 12/15/04	Tue 11/15/05
19	**EPC Contractor**	**265 days**	**Tue 12/2/03**	**Mon 12/6/04**
20	Shortlist EPC Contractor	65 days	Tue 12/2/03	Mon 3/1/04
21	Refine Design & EPC Select	10 mons	Tue 3/2/04	Mon 12/6/04
22	**Permitting**	**245 days**	**Tue 12/2/03**	**Mon 11/8/04**
23	Air and Effluent Permits - Phase 1	118 days	Tue 12/2/03	Thu 5/13/04
24	Air and Effluent Permits - Phase 2	9 mons	Tue 3/2/04	Mon 11/8/04
25	**Project Phase 1 Construction**	**781 days**	**Tue 12/2/03**	**Tue 11/28/06**
68	**Phase 1 On-line**	0 days	Tue 11/28/06	Tue 11/28/06
69	**Project Phase 2 Construction**	**505 days**	**Tue 12/14/04**	**Tue 11/21/06**
110	**Phase 2 On Line**	0 days	Tue 11/21/06	Tue 11/21/06



Gold River Power Project
Green Island Energy

Phase 1 Development Schedule
Wed 8/11/04

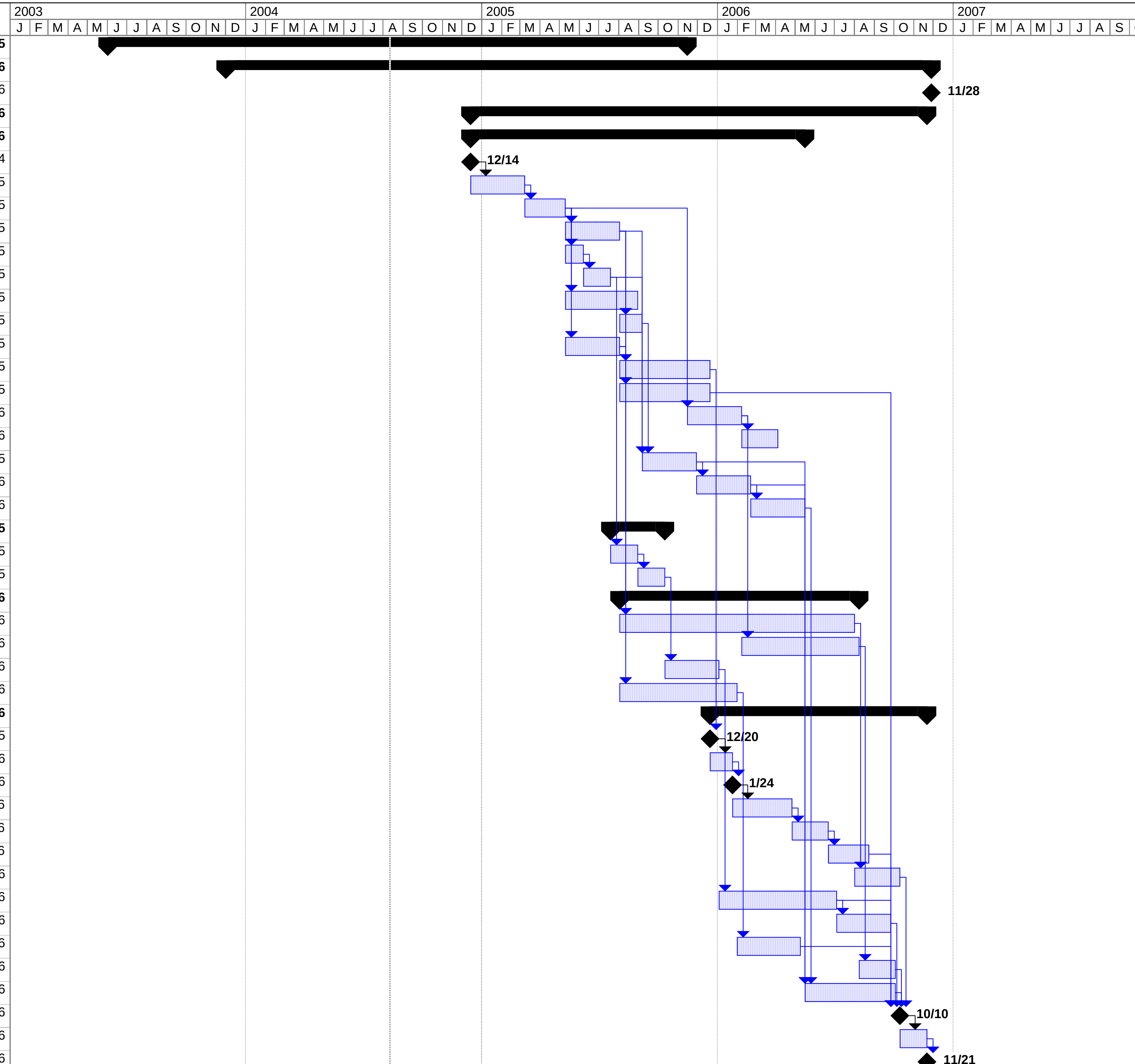
ID		Task Name	Duration	Start	Finish
1		**Development**	**642 days**	**Mon 6/2/03**	**Tue 11/15/05**
25		**Project Phase 1 Construction**	**781 days**	**Tue 12/2/03**	**Tue 11/28/06**
26		**Detail Engineering Phase 1**	**571 days**	**Tue 12/2/03**	**Tue 2/7/06**
27	✓	Purchase STG Option	30 days	Tue 12/2/03	Mon 1/12/04
28	✓	Purchase Baghouse Option	30 days	Tue 12/2/03	Mon 1/12/04
29		Notice to Proceed EPC Contract	0 days	Tue 12/14/04	Tue 12/14/04
30		Prepare Flowsheets	65 days	Wed 12/15/04	Tue 3/15/05
31		TG Condenser Purch	60 days	Wed 3/16/05	Tue 6/7/05
32		Prepare GA's	45 days	Wed 3/16/05	Tue 5/17/05
33		Transformer. specs and Purch	20 days	Wed 3/16/05	Tue 4/12/05
34		Cooling Tower Spec. & Purch	25 days	Wed 3/16/05	Tue 4/19/05
35		Powerhouse & Baghouse Detail Design	30 wks	Wed 5/18/05	Tue 12/13/05
36		Fuel Sys. Specs & Purch	70 days	Wed 12/15/04	Tue 3/22/05
37		Fuel System Details	130 days	Wed 12/15/04	Tue 6/14/05
38		Piping & Misc. Detail Design	140 days	Wed 5/18/05	Tue 11/29/05
39		E/I Field Assessments	6 wks	Wed 12/15/04	Tue 1/25/05
40		Electrical Substation Design	60 days	Wed 11/16/05	Tue 2/7/06
41		Electrical Specs & Purchasing	8 wks	Wed 12/15/04	Tue 2/8/05
42		Instrumentation Specs & Purch	45 days	Wed 12/15/04	Tue 2/15/05
43		Electr. Instr. & Controls Design	130 days	Wed 12/15/04	Tue 6/14/05
44		Field Engineering	111 days	Wed 12/15/04	Wed 5/18/05
45		**Power Boiler Work Package**	**80 days**	**Wed 12/15/04**	**Tue 4/5/05**
46		Detail Specs. & Inspections	10 wks	Wed 12/15/04	Tue 2/22/05
47		Aux. Equip. Design	16 wks	Wed 12/15/04	Tue 4/5/05
48		**Main Equip. Deliveries**	**370 days**	**Wed 3/23/05**	**Tue 8/22/06**
49		Boiler deliveries	8 wks	Wed 4/6/05	Tue 5/31/05
50		Fuel conveying system	26 wks	Wed 3/23/05	Tue 9/20/05
51		Cooling Tower	30 wks	Wed 4/20/05	Tue 11/15/05
52		Condenser	26 wks	Wed 6/8/05	Tue 12/6/05
53		Transformer & Switchyard	28 wks	Wed 2/8/06	Tue 8/22/06
54		**Construction**	**390 days**	**Wed 6/1/05**	**Tue 11/28/06**
55		**Start of Phase 1 Construction**	0 days	Tue 12/13/05	Tue 12/13/05
56		STG#1 Foundations	5 wks	Wed 12/14/05	Tue 1/17/06
57		**Phase 1 Foundations Complete**	0 days	Tue 1/17/06	Tue 1/17/06
58		Steel del. & Fabrication	12 wks	Wed 1/18/06	Tue 4/11/06
59		Steel Erection & Floors	6 wks	Wed 4/12/06	Tue 5/23/06
60		Equipment Installation	16 wks	Wed 5/24/06	Tue 9/12/06
61		Boiler Refurbishment	10 wks	Wed 6/1/05	Tue 8/9/05
62		Cooling tower Installation	90 days	Wed 11/16/05	Tue 3/21/06
63		Fuel System Installation	120 days	Wed 9/21/05	Tue 3/7/06
64		Electrical Substation	8 wks	Wed 8/23/06	Tue 10/17/06
65		Elctr. & Instrumentation	120 days	Wed 6/15/05	Tue 11/29/05
66		**Phase 1 Mechanical complete**	0 days	Tue 10/17/06	Tue 10/17/06
67		Commissioning & Startup	30 days	Wed 10/18/06	Tue 11/28/06
68		**Phase 1 On-line**	0 days	Tue 11/28/06	Tue 11/28/06
69		**Project Phase 2 Construction**	**505 days**	**Tue 12/14/04**	**Tue 11/21/06**
110		**Phase 2 On Line**	0 days	Tue 11/21/06	Tue 11/21/06



Gold River Power Project
Green Island Energy

Phase 2 Development Schedule
Wed 8/11/04

ID		Task Name	Duration	Start	Finish
1		**Development**	**642 days**	**Mon 6/2/03**	**Tue 11/15/05**
25		**Project Phase 1 Construction**	**781 days**	**Tue 12/2/03**	**Tue 11/28/06**
68		**Phase 1 On-line**	0 days	Tue 11/28/06	Tue 11/28/06
69		**Project Phase 2 Construction**	**505 days**	**Tue 12/14/04**	**Tue 11/21/06**
70		**Detail Design Phase 2**	**370 days**	**Tue 12/14/04**	**Tue 5/16/06**
71		Notice to Proceed EPC	0 days	Tue 12/14/04	Tue 12/14/04
72		Prepare Flowsheets	60 days	Wed 12/15/04	Tue 3/8/05
73		Prepare GA's	45 days	Wed 3/9/05	Tue 5/10/05
74		STG#2 Spec. & Purchasing	60 days	Wed 5/11/05	Tue 8/2/05
75		Select boiler contractor	20 days	Wed 5/11/05	Tue 6/7/05
76		Boiler refurbishment design details	30 days	Wed 6/8/05	Tue 7/19/05
77		Design RDF Storage Bldg	80 days	Wed 5/11/05	Tue 8/30/05
78		Cooling Tower Spec. & Purch	25 days	Wed 8/3/05	Tue 9/6/05
79		Fuel Sys. Specs & Purch	60 days	Wed 5/11/05	Tue 8/2/05
80		Fuel System Details	100 days	Wed 8/3/05	Tue 12/20/05
81		Piping & Misc. Detail Design	100 days	Wed 8/3/05	Tue 12/20/05
82		Electrical Substation Design	60 days	Wed 11/16/05	Tue 2/7/06
83		Electrical Specs & Purch	40 days	Wed 2/8/06	Tue 4/4/06
84		Instrumentation Specs & Purch	60 days	Wed 9/7/05	Tue 11/29/05
85		Electr. Instr. & Controls Design	60 days	Wed 11/30/05	Tue 2/21/06
86		Field Engineering	60 days	Wed 2/22/06	Tue 5/16/06
87		**Recovery Boiler Work Package**	**60 days**	**Wed 7/20/05**	**Tue 10/11/05**
88		Boiler mod. Specs & Inspections	6 wks	Wed 7/20/05	Tue 8/30/05
89		Aux. Equip. Design	30 days	Wed 8/31/05	Tue 10/11/05
90		**Main Equip. Deliveries**	**265 days**	**Wed 8/3/05**	**Tue 8/8/06**
91		STG Delivery	52 wks	Wed 8/3/05	Tue 8/1/06
92		Transformers	26 wks	Wed 2/8/06	Tue 8/8/06
93		Boiler Deliveries	12 wks	Wed 10/12/05	Tue 1/3/06
94		Fuel System Components	26 wks	Wed 8/3/05	Tue 1/31/06
95		**Construction**	**240 days**	**Tue 12/20/05**	**Tue 11/21/06**
96		Start of Phase 2 Construction	0 days	Tue 12/20/05	Tue 12/20/05
97		RDF Storage Foundations	25 days	Wed 12/21/05	Tue 1/24/06
98		**Phase 2 Foundations Complete**	0 days	Tue 1/24/06	Tue 1/24/06
99		RDF Steel Fabrication	66 days	Wed 1/25/06	Wed 4/26/06
100		RDF Steel Erection	8 wks	Thu 4/27/06	Wed 6/21/06
101		RDF Equipment Installation	45 days	Thu 6/22/06	Wed 8/23/06
102		STG #2 Installation	10 wks	Wed 8/2/06	Tue 10/10/06
103		Boiler Refurbishment	26 wks	Wed 1/4/06	Tue 7/4/06
104		Cooling tower Modifications	60 days	Wed 7/5/06	Tue 9/26/06
105		Fuel System Installation	70 days	Wed 2/1/06	Tue 5/9/06
106		Electrical Substation	8 wks	Wed 8/9/06	Tue 10/3/06
107		Eltcr. & Instrumentation	100 days	Wed 5/17/06	Tue 10/3/06
108		**Phase 2 Mechanical Complete**	0 days	Tue 10/10/06	Tue 10/10/06
109		Commissioning & Start up	30 days	Wed 10/11/06	Tue 11/21/06
110		**Phase 2 On Line**	0 days	Tue 11/21/06	Tue 11/21/06



SEAN EBNET
Vice President Energy Development

Green Island Energy Ltd.
Four Bentall Center
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Vancouver, BC Canada V7X 1J1

PROFESSIONAL HISTORY

As a Bachelors of Science graduate from the University of Washington, Sean Ebnet began his career an Environmental Scientist, working for 15 years as a business and environmental consultant to private industry, first nation tribes, public utility agencies, and governmental organizations. Mr. Ebnet has been principally involved with development and licensing of numerous municipal water and power utility projects throughout western United States, Canada and Alaska. In his years working as a private consultant on various natural resource issues and advising agency steering committees, he received peer recognition for bringing innovative solutions to industry while integrating public resource needs with sound environmental stewardship programs. Mr. Ebnet has project managed on energy and water development projects, conducted investigative reporting and feasibility studies, performed expert witness testimonies, held public and town hall meetings, designed project mitigation packages, and excelled in resolving conflicts between polarized interest groups.

As VP of business development for Alternative Energy Group LLC., Mr. Ebnet is responsible for the initial screening, research, and packaging of power projects and qualifying them for a variety of private source financing options. Preferring to stay involved on the front end of project development, Mr. Ebnet works to identify economically viable projects and assemble solid management teams capable of developing, managing, and operating sustainable power generation investments.

In addition to his involvement with Alternative Energy Group, Mr. Ebnet also serves as the VP of Energy Development for the ownership group of Green Island Energy Ltd. In this capacity Mr. Ebnet has worked to secure the necessary resources to develop the Gold River Power Project. This includes building the project management team required to engineer, construct, and operate the power generating facility, acquiring the necessary environmental permits and zoning ordinances, procurement of long term fuel supply agreement, research and contracting for transportation options, negotiate equipment purchase agreements, participate in Utility Commission hearings, author submission documents, develop government and business alliances, and implement corporate strategies.

Prior to his involvement with Green Island Energy Ltd. and Alternative Energy Group LLC., Mr. Ebnet worked for Duke Engineering & Services, a subsidiary of Duke Power. As a consultant Mr. Ebnet has over ten years of experience as project manager and field supervisor assisting numerous public and private utilities as part of FERC hydroelectric relicensing studies. Mr. Ebnet has an additional five years experience working as a federal biologist conducting species inventories, habitat suitability modeling, resource assessments and management planning.

WORK HISTORY

Green Island Energy Ltd.
Vancouver, British Columbia
Vice President 2002 - current
Project managing the development of the Gold River Power Project. Responsibilities include oversight of management team, EPC contractor, plant operator, permitting, fuel supply procurement and various contracting obligations.

Alternative Energy Investment Group LLC.
Seattle, Washington
Vice President Business Development 2000 - current
Responsible for the due diligence screening, research, and arranging private financing of alternative and sustainable power projects in North America. Work to identify economically viable projects and assemble solid management teams capable of developing, managing, and operating sustainable power generation investments.

ClearWater Project.
San Diego, California
Executive Director 1998 - 2001
Helped organize and launch this non-profit program on behalf of singer/songwriter Jewel Kilcher and their mother/manager Lenedra Carroll in 1999. Represented the interests of the Clearwater Project at the State of the World Forum, United Nations, and Natural Resource Defense Council events. Oversaw international fundraising efforts and project aid and assistance programs.

Duke Engineering and Services (DE&S)
Bellingham, Washington
Senior Project Manager 1996 - 1998
Worked as senior project manager assisting numerous public and private utilities in project development and feasibility assessments.

Cascades Environmental Services Inc.
Bellingham, Washington
Senior Environmental Scientist/ Project Manager 1994 - 1996
Worked as senior environmental scientist and project manager for several FERC hydroelectric relicensing projects in the Pacific Northwest.

United States Forest Service.
Mt. Baker Snoqualimie National Forest
Bellingham, Washington
Biologist 1988 - 1991
Worked as a federal biologist conducting threatened and endangered species inventories, habitat suitability modeling, resource assessments and management planning.

EDUCATION

B.S., University of Washington, Seattle
A.S., Green River Community College, Auburn

CERTIFICATIONS

- NEPA/SEPA Environmental Assessment Process -
  WA Department of Ecology
- Habitat Conservation Planning (HCP) -
  U.S. Fish and Wildlife Service
- Habitat Evaluation Procedures (HEP) -
  National Biological Service
- Habitat Suitability Index Modeling (HSI) -
  National Biological Service
- Watershed Analysis Training -
  WA Department of Natural Resources
- Biological Statistics and Computer Modeling
  Statsoft, Inc.

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Summary

Paul Willis has more than 30 years experience in the energy field. This experience encompasses energy management, marketing, research and development, project management, detailed and conceptual design, and commissioning and acceptance.   He has participated in the implementation of a number of thermal power projects from detailed design work to arranging power sale contracts. He has designed and assisted in the implementation of a number of Industrial Demand Side Management programs. He is President of Willis Energy Services Ltd., an engineering consulting firm that works with large energy users to improve efficiency, with utilities and government agencies to promote conservation and with Independent Power Producers in the implementation of power projects. His technical expertise is in the areas of heat transfer, combustion, industrial process systems, and the optimization of large power and heating systems.

Professional Experience

Willis Energy Services Limited

Vancouver, British Columbia
President and Founder ***1988 - Present***
Advises industry on energy efficiency options in such areas as cogeneration, pumping and fan systems, process heating, compressed air, boiler and heat pump systems. Assisted BC Hydro in developing procedures and programs for purchasing electricity from independent power projects, including large and small wood waste and natural gas fired project. Organized and managed BC Hydro's and Portland General Electric Process Improvement Programs under which the utilities invest in any electricity reducing project that is economically attractive to an industrial customer and themselves. Conducted and participated in a number of research and development projects in the energy management area for the Canadian Electrical Association. Assists lndependent Power Producers in the implementation of new generation projects.

BC Hydro

Vancouver, British Columbia
Program Manager ***1986 - 1988***
Managed a program designed to sell surplus interruptible electricity to industrial customers. This assignment required an assessment of the value of this surplus electricity to BC Hydro and then selling this product at a profit to industrial customers.

Energy Management Engineer ***1982 - 1986***
Provided advice to industrial customers in the area of industrial process heating, particularly heat recovery equipment, boiler systems and large heat pumps. In this function, organized a number of energy management seminars and trade shows.

Project Engineer ***1976 - 1982***
Member of a team for technical work in a pressurized fluidized bed development project. Over a period of four years, became thoroughly acquainted with all design aspects of fluidized bed technology as

applied to utilizing low-grade coal. Responsible for a large scale test program involving BC Hydro using another utility's boiler to test burn 6000 tons of coal from an untried deposit, and for the development of specifications for a 560 MW steam generator to burn a low grade coal that had not been previously used for power generation.

Participated in extensive planning and design work for 2000 MW coal fired project at Hat Creek.

Participated in the investigation of large coal gasification and liquefaction study using Hat Creek Coal.

Planning Engineering ***1975***
Worked as a Generation Planning engineer in BC Hydro's Generation Planning Department evaluating a number of thermal power options.

Design Engineer ***1974***
Participated in commissioning and was responsible for an acceptance and efficiency test of a 160 MW oil and gas fired steam generator.

Babcock and Wilcox

Cambridge, Ontario
Proposal Engineer ***1972 - 1974***
Responsible for the conceptual design and cost estimate of steam generators for a number of power plants including coal fires units in New Zealand and Thailand.

Design Engineer ***1970 - 1972***
As part of the boiler design department, performed combustion, heat transfer, fluid flow, piping flexibility and structural steel design calculations.

Education

University of Waterloo

Waterloo, Ontario
B.Sc. Mechanical Engineering

Organizations

- Professional Engineers of British Columbia
- American Society of Heating, Refrigeration and Air-conditioning Engineers
- Canadian Institute of Energy
- Independent Power Association of B.C.
- British Columbia Electrical Association

David R. Morrow

David was trained in Mechanical Engineering, obtaining his Bachelor's (With Distinction) in 1984 and Master's degree in 1992. His experience in the energy sector began in 1984 with Dow Chemical, assisting in the Power Plant at Fort Saskatchewan. He moved to Edmonton Power in 1987, where he directed the Generation Planning group until 1994. Since then he has had progressively more responsible positions within the Business Development group, culminating in the position of Vice President, Power Development and Acquisition for EPCOR Power Development Corp from 2000 to 2003.

In his role as Vice President, David's responsibility was to develop business opportunities for EPCOR. This experience started in 1996 with the acquisition of Aqualta, the former City of Edmonton Water Department, now known as EPCOR Water Services. Since then he has been responsible for the development of the generation side of the business. Projects completed include: the 416 MW Joffre Cogeneration plant, the 13 MW Taylor Coulee Chute hydro plant, the 250 MW Frederickson combined cycle plant, the purchase of the 7 MW Brown Lake hydro plant, the construction of the Weather Dancer 1 wind turbine at Brockett, the 33 MW Miller Creek Hydro project and key aspects of the development of the 455 MW Genesee 3 coal plant. While doing these projects, David has overseen the creation of an effective team of business developers within EPCOR. Now operating his own firm, David is developing improved techniques for minimizing the risks inherent in developing new projects and providing consulting services for development projects.

While with EPCOR David has investigated projects in a number of other geographic locations in Canada and the US. In particular David's experience includes projects in Alberta, Ontario, Pacific Northwest, and British Columbia.

His work demands have provided valuable experience from identifying business prospects and sites, to initial feasibility assessment, financial modeling, permitting, transmission studies, capital cost estimations, fuel supply negotiations, business case preparation, raising funds for capital works, taxation effective planning, construction management oversight and much more.

Most recently David led an EPCOR team making two bids to the VI CFT. These consisted of a large combined cycle power plant and a smaller peaking power plant.