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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	CASE NO. AVU-E-04-01 CASE NO. AVU-G-04-01 EXHIBIT NO. 8 ROBERT J. LAFFERTY

FOR AVISTA CORPORTATION

(ELECTRIC ONLY)

(SCHEDULES 33, 34 & 35 OF THIS EXHIBIT ARE CONFIDENTIAL)

CASE NO. AVU-E-04-01

EXHIBIT NO. 8
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Mitigation Measures Taken By Avista During 2001

The Company implemented a variety of measures all aimed at mitigating the Company's price exposure in the face of very low streamflow conditions and very high and volatile power prices in the forward market. The Company took a portfolio approach that included acquiring both demand-side and supply-side resources to cover its energy deficiencies.

A brief description of some of the measures taken by the Company to cover its deficiencies and mitigate increased costs is provided below.

1. **Communication of market conditions and conservation messages to customers.**
   The Company communicated the challenges facing the electric utility industry and Avista to its customers through bill inserts, advertisements in the local newspaper, radio and TV media beginning in December 2000. Many advertisements were run in several different media including direct mail, customer education programs, radio, TV, and print. In a mid-June 2001 survey, 87% of Avista customers recalled seeing Company advertising specifically about conservation, and 73% of those customers said they had taken some action to reduce energy use as a result of the advertising messages.

2. **Escalation of energy efficiency efforts.**
   The Company accelerated its energy efficiency efforts. The programs targeted measures that offered retail customers immediate electric savings through proven efficiency technologies. Over 688,000 compact fluorescent lamps were distributed, 8,350 rooftop HVAC units were tuned, and 952 gas water heaters were installed. These programs, and other efficiency measures, tripled the amount of energy savings the Company would otherwise achieve on an annual basis.

3. **Retail Buy-Back Programs.**
   The Company received approval from the Commission to implement three "buy-back" programs, including programs for industrial customers, irrigation customers, and all other customers. The buy-back programs were designed to provide benefits to the specific customers reducing their load, as well as all other customers of the Company. At the time the programs were put into place they represented a lower-cost means to serve load requirements than purchasing additional energy in the wholesale market. The IPUC approved the Company's request to terminate the all-customer program early, because it was no longer economic.

4. **Filed for a modification of the air permit for the Rathdrum combustion turbines.**

As the Company entered 2001, it could operate the two Rathdrum units a total of 6600 hours per unit per year. Because of the high electric market prices, the Company filed to extend the hours of operation for Rathdrum to 8424 hours per unit per year. Otherwise, Avista would have had to shut the units down once the operating hour limit was reached. During the first half of 2001, the Company proceeded to operate Rathdrum at full load in anticipation of receiving the permit modification. Running the units at full load avoided making additional expensive purchases from the wholesale market. The Company received the new permit in October 2001.

5. **Purchased spare parts for Rathdrum to reduce down-time during maintenance.**

Because of the increased operation of the Rathdrum turbines, it was necessary to schedule maintenance on the units in the spring of 2001. Under normal conditions, the Company would ship out key parts of one unit at a time to be reconditioned while other on-site maintenance was performed on the unit. The normal maintenance schedule would have been 12 to 14 weeks. Because of the high price of power, however, the Company located and purchased a spare set of parts to reduce the down-time for maintenance to only four weeks. The Company avoided additional high-priced purchases from the wholesale market during the weeks that maintenance would have otherwise occurred.

6. **Gained permission for increased operation of Northeast Combustion Turbines.**

Under the existing air emissions permit for the Northeast Turbines, the units are allowed to run approximately 500 hours per year. On the initiative of the Company, Avista was able to successfully negotiate agreements that granted permission to run the units for additional hours. The Company received permission to run the units for additional hours in August and September 2000, and beginning again February 21, 2001 and continuing through the Governor's Energy Supply Alert.

8. **Delayed delivery of BPA exchange obligation under the WNP-3 agreement.**

Under a provision of the WNP-3 Agreement, the Bonneville Power Administration (BPA) called on over 200,000 MWh of energy for the months of January - April and June 2001, to be provided by Avista at a price based on the operating costs of the Northeast Combustion Turbines. Through negotiations initiated by Avista, BPA agreed to delay the delivery of energy until the fourth quarter of 2001, and relieve Avista of further obligations under the Settlement Agreement for the 2000/2001 operating year. At the time of the transaction, the estimated benefits to Avista's customers by delaying the deliveries were $6.1 million. On an actual basis, the benefits were calculated to be $44.8 million.

Mitigation Measures Taken By Avista During 2001

9. Inter-Month Exchanges: Purchase and sale.

In April 2001 Avista was near load/resource balance for the third quarter of 2001, but was deficient energy in July and surplus in September. On April 18, 2001, the Company entered into an exchange transaction, where Avista purchased 50 aMW from a third party for July 2001 at $490/MWH, and sold 50 aMW to the same party for September at $480/MWH. The difference in price was caused by the difference in market prices for the two months. The simultaneous sale of energy in September preserved, or hedged, the value of the surplus, as compared to a simple purchase of energy in July to cover the deficiency.

10. Inter-Month Exchange: Exchange of energy.

On April 12, 2001, the Company entered into an exchange transaction, where Avista agreed to deliver 60 aMW to a third party in September 2001, in exchange for receipt of 50 aMW from the same party in July 2001. Avista was energy deficient in July, but surplus in September. The market price was higher in July than in September, which accounted for the difference in the energy deliveries. The agreement to exchange energy in this manner, preserved, or hedged, the value of the surplus in September, as compared to a simple purchase of energy in July at a cost of approximately $490/MWH to cover the deficiency.

11. Leased temporary generation resources (30 MW of capability).

The Company selected a variety of generation projects that could be installed quickly and run on natural gas or diesel fuel. The Company leased 20 diesel units (20 megawatts) and located them at Avista's Devil's Gap substation, and also leased six units (10 megawatts) that ran on a combination of natural gas and diesel, and located them at Avista's Kettle Falls generating station site. These units were dispatchable and did not have to run if purchasing energy in the short term market was less costly. The decision to pursue these projects allowed the Company to avoid additional high-cost purchases of energy from the short-term wholesale market, and represented a "call option" to the Company for the amount of energy available from the units.

12. Purchased additional small generation resources.

In addition to the leased projects, the Company acquired generation sites and equipment, and initiated permitting on new generation to be owned by Avista. Projects were selected that could be installed quickly. The Company completed the Boulder Park project that includes six gas-fired reciprocating engines for a total of 25 MW. The Company also initiated plans to install a 23 MW combustion turbine at Othello, Washington and two gas-fired reciprocating engines at the Spokane Industrial Park (SIP). Subsequent to the drop in the electric power market in the second half of 2001, the Othello project and the SIP Project were cancelled. The decision to pursue these projects allowed the Company to avoid additional high-cost purchases of energy from the short-term wholesale market, and represented a "call option" to the Company for the amount of energy available from the units.

Mitigation Measures Taken By Avista During 2001

As is evident from the list above, the Company implemented a wide variety of measures, involving both demand-side and supply-side resources, to cover its energy deficiencies caused primarily by the record-low streamflow conditions, and to mitigate the costs associated with the high and volatile power prices.

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Boulder Park – Initial Economic Analysis

THIS PAGE CONTAINS CONFIDENTIAL MATERIALS AND IS SEPARATELY FILED

Exhibit No. 8, Schedule 33 Pages 1 – 8
R. Lafferty
Avista Corporation

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Small Generation Projects – Rejected Projects

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Boulder Park – Re-evaluation

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CASE NO. AVU-E-04-01

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AVISTA Corporation

FILE KETTLE FALLS CT PROJECT

Interoffice Memorandum
Energy Resources

DATE: February 14, 2001

TO: Thomas Dempsey

FROM: Steve Silkworth

SUBJECT: Kettle Falls CT Installation – Revised Economic Evaluation

Thomas – Attached to this memo are the revised economic evaluation results for the proposed combustion turbine addition to the Kettle Falls site. I revised this memo to reflect the economics based upon actual forward market strip prices for electricity and natural gas. In the previous analysis, I used the same price forecast that was prepared by RW Beck consultants for the recent Request for Proposal evaluation. This forecast is 12 weeks old and does not capture recent upswing in the spark spreads.

For easy reference, also attached is a spreadsheet with the annual electric and natural gas prices used in the evaluation.

Three Cases Analyzed:

1. Simple cycle only
2. Simple cycle with HRSG and steam sent to feedwater heater in KFGS
3. Combined cycle with Staco mini-steam turbine, steam then sent to DA.

Economics

The project economics was evaluated by the method used in Avista's recent Request for Proposal process. This method consisted of:

- Forward strip electric and natural gas prices through 2007 then hourly electric and monthly natural gas price forecast provided by RW Beck through 2025.
- Dispatch of the machine was calculated on an hourly basis by using the Prosym production cost model from February 2002 to December 2025.
- Plant characteristics such as heat rate, VOM and O&M costs, planned maintenance, and capital costs were provided by the Generation and Production department.
- All other costs were modeled consistent with the company's Standard Assumptions Manual and revenue requirements model.

Economic Results (2001 $'s)

	Net Benefit Nominal Levelized $/MWh	Net Benefit Real Levelized $/MWh	Net Present Value $ (000's)
1. Simple Cycle Only	12.5	9.8	3,151
2. Simple cycle with HRSG and steam sent to feedwater heater	16.1	12.6	10,601
3. Combined cycle with Staco mini-steam turbine, steam then sent to DA	15.1	11.8	11,258

The results indicate that in all cases, the project returns a positive present value. In other words, each of the cases are lower in cost than equivalent market purchases over the project lives. Cases 2 and 3 have a payback of approximately three years.

If you have any questions, please call me on extension 8093.

Distribution:
Ed Groce
Clint Kalich
Jason Thackston
Jerry Parmentier
Steve Wenke

Kettle Falls Upgrade

Avista Corporation

Economic Analysis Detail

Assumptions

Installed Cost			10,000	$000s			Fixed Charge			0.00	per kW-month			Variable O&M			2.00	2001$/MWh				Electric Wheeling Losses			1.9	percent		
Project Capacity			9.8	MW			Fixed O&M			0.00	2003$ per kW-month																		
Heat Rate			8,750	Btu/kWh			Escalation Rates							Insurance Cost			0.0	0.3% of installed cost ($000s)				Nominal Discount Rate			7.8	percent		
Peak Gas Useage			2,048	000s dth			Fixed O&M			2.5	percent			Gas Transport			0.00	2000 $/dth				Real Discount Rate			5.1	percent		
							Variable O&M			2.5	percent			Electric Wheeling			0	$/MW-month thru 2006										
							Transportation			2.0	percent			General Inflation			2.5	percent										

			Fixed Costs												Total Fixed Costs			Less			Variable Costs				Total Project Cost
			Capital Recovery and Miscellaneous				Operations & Maintenance								Before 10%	After 10%	After 10%	Operating	Net					after Credits
	Year	Energy	Project	Fixed Chrg.	Total Costs		Fixed	Grams	Etrans	PrTax	Insur.	Total Costs			Credit	Credit	Credit	Margin	Project Benefit		Gas	O&M	Total Variable		
		(GWh)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($/MWh)		($000s)	($000s)	($/MWh)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($/MWh)
1	2001	0.0	0	0	0	#DIV/0!	0	0	0	0	0	0	#DIV/0!		0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	0	#DIV/0!
2	2002	71.9	1,766	0	1,766	24.6	0	0	0	136	0	136	1.9		1,902	1,902	26.5	7,336	5,435	75.6	3,472	146	3,619	50.3	5,522	76.8
3	2003	77.6	1,700	0	1,700	21.9	0	0	0	132	0	132	1.7		1,832	1,832	23.6	4,147	2,316	29.8	3,183	163	3,326	42.9	5,158	66.5
4	2004	75.8	1,635	0	1,635	21.6	0	0	0	127	0	127	1.7		1,762	1,762	23.2	2,818	1,053	13.9	3,015	164	3,179	41.9	4,841	63.8
5	2005	70.6	1,565	0	1,565	22.2	0	0	0	122	0	122	1.7		1,687	1,687	23.9	2,087	400	5.7	2,721	156	2,878	40.8	4,565	64.7
6	2006	62.1	1,495	0	1,495	24.1	0	0	0	117	0	117	1.9		1,613	1,613	26.0	1,385	(226)	(3.7)	2,400	141	2,541	40.9	4,154	66.9
7	2007	58.8	1,433	0	1,433	25.2	0	0	0	113	0	113	2.0		1,546	1,546	27.2	1,049	(497)	(8.7)	2,187	133	2,319	40.8	3,865	68.0
8	2008	75.9	1,373	0	1,373	18.1	0	0	0	108	0	108	1.4		1,481	1,481	19.5	1,782	300	4.0	1,931	182	2,113	27.8	3,594	47.4
9	2009	75.8	1,329	0	1,329	17.5	0	0	0	103	0	103	1.4		1,432	1,432	18.9	1,816	383	5.1	2,004	186	2,191	28.9	3,623	47.7
10	2010	76.6	1,286	0	1,286	16.8	0	0	0	99	0	99	1.3		1,385	1,385	18.1	1,880	495	6.5	2,097	193	2,290	29.9	3,675	48.0
11	2011	76.7	1,243	0	1,243	16.2	0	0	0	94	0	94	1.2		1,337	1,337	17.4	1,893	556	7.2	2,183	199	2,381	31.1	3,718	48.5
12	2012	76.4	1,201	0	1,201	15.7	0	0	0	89	0	89	1.2		1,290	1,290	16.9	2,117	827	10.8	2,265	203	2,468	32.3	3,758	49.2
13	2013	75.5	1,157	0	1,157	15.3	0	0	0	85	0	85	1.1		1,241	1,241	16.4	1,857	616	8.2	2,329	205	2,535	33.6	3,776	50.0
14	2014	75.4	1,114	0	1,114	14.8	0	0	0	80	0	80	1.1		1,194	1,194	15.8	1,894	700	9.3	2,428	211	2,637	35.0	3,831	50.8
15	2015	75.1	1,073	0	1,073	14.3	0	0	0	75	0	75	1.0		1,148	1,148	15.3	1,860	712	9.5	2,532	215	2,747	36.6	3,895	51.9
16	2016	74.8	1,031	0	1,031	13.8	0	0	0	70	0	70	0.9		1,101	1,101	14.7	1,844	742	9.9	2,636	220	2,856	38.2	3,957	52.9
17	2017	73.7	987	0	987	13.4	0	0	0	66	0	66	0.9		1,053	1,053	14.3	1,824	771	10.5	2,709	222	2,931	39.8	3,984	54.1
18	2018	73.2	944	0	944	12.9	0	0	0	61	0	61	0.8		1,005	1,005	13.7	1,824	819	11.2	2,793	227	3,020	41.3	4,025	55.0
19	2019	71.9	899	0	899	12.5	0	0	0	56	0	56	0.8		956	956	13.3	1,783	827	11.5	2,842	228	3,070	42.7	4,026	56.0
20	2020	69.8	854	0	854	12.2	0	0	0	52	0	52	0.7		905	905	13.0	2,094	1,189	17.0	2,870	227	3,097	44.4	4,002	57.4
21	2021	68.1	809	0	809	11.9	0	0	0	47	0	47	0.7		856	856	12.6	2,066	1,211	17.8	2,918	228	3,146	46.2	4,002	58.8
22	2022	66.4	769	6	769	11.6	0	0	0	42	0	42	0.6		811	811	12.2	3,035	1,224	18.4	2,958	228	3,186	48.0	3,997	60.2
23	2023	66.3	742	0	742	11.2	0	0	0	38	0	38	0.6		780	780	11.8	3,008	1,228	18.5	3,076	233	3,309	49.8	4,089	61.7
24	2024	65.5	719	0	719	11.0	0	0	0	33	0	33	0.5		752	752	11.5	3,009	1,257	19.2	3,175	236	3,412	52.1	4,184	63.8
25	2025	65.3	698	0	698	10.7	0	0	0	28	0	28	0.4		726	726	11.1	1,968	1,242	19.0	3,300	242	3,542	54.2	4,268	65.4
2001$																										
Net Present Value			13,141	0	13,141		0	0	0	979	0	979			14,120	14,120		25,378	11,258		26,334	1,835	28,170		42,290	
Nominal Levelized Cost ($/MWh)						17.8							1.3				18.9			19.1				37.7		56.6
Real Levelized Cost ($/MWh)						13.8							1.0				14.8			11.8				28.5		44.3

Kettle Falls Upgrade

Avista Corporation

Economic Analysis Detail

Assumptions

Installed Cost	8,500	$000s	Fixed Charge	0.00	per kW-month	Variable O&M	2.00	2001$/MWh
Project Capacity	9.5	MW	Fixed O&M	0.00	2003$ per kW-month			
Heat Rate	8,750	Btu/kWh	Escalation Rates			Insurance Cost	0.0	0.3% of installed cost ($000s)
Peak Gas Usage	1,995	000s dth	Fixed O&M	2.8	percent	Gas Transport	0.00	2000 $/dth
			Variable O&M	2.5	percent	Electric Wheeling	0	$/MW-month thru 2006
			Transportation	2.0	percent	General Inflation	2.5	percent

Electric Wheeling Losses	1.9	percent
Nominal Discount Rate	7.8	percent
Real Discount Rate	5.1	percent

Fixed Costs

	Year	Energy (GWh)	Capital Recovery and Miscellaneous: Project ($000s)	Fixed Chrg. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Operations & Maintenance: Fixed ($000s)	Gtrans ($000s)	Etrans ($000s)	PrTax ($000s)	Insur. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)
1	2001	0.0	0	0	0	#DIV/0!	0	0	0	0	0	0	#DIV/0!
2	2002	63.3	1,506	0	1,506	23.8	0	0	0	116	0	116	1.8
3	2003	68.3	1,450	0	1,450	21.2	0	0	0	112	0	112	1.6
4	2004	66.7	1,394	0	1,394	20.9	0	0	0	108	0	108	1.6
5	2005	62.1	1,334	0	1,334	21.5	0	0	0	104	0	104	1.7
6	2006	54.7	1,275	0	1,275	23.3	0	0	0	100	0	100	1.8
7	2007	49.9	1,221	0	1,221	24.5	0	0	0	96	0	96	1.9
8	2008	66.8	1,170	0	1,170	17.5	0	0	0	92	0	92	1.4
9	2009	66.6	1,133	0	1,133	17.0	0	0	0	88	0	88	1.3
10	2010	67.4	1,097	0	1,097	16.3	0	0	0	84	0	84	1.2
11	2011	67.4	1,060	0	1,060	15.7	0	0	0	80	0	80	1.2
12	2012	67.2	1,024	0	1,024	15.2	0	0	0	76	0	76	1.1
13	2013	66.4	987	0	987	14.9	0	0	0	72	0	72	1.1
14	2014	66.3	951	0	951	14.3	0	0	0	68	0	68	1.0
15	2015	66.1	916	0	916	13.9	0	0	0	64	0	64	1.0
16	2016	65.6	880	0	880	13.4	0	0	0	60	0	60	0.9
17	2017	64.8	843	0	843	13.0	0	0	0	56	0	56	0.9
18	2018	64.4	807	0	807	12.5	0	0	0	52	0	52	0.8
19	2019	63.3	769	0	769	12.2	0	0	0	48	0	48	0.8
20	2020	61.5	730	0	730	11.9	0	0	0	44	0	44	0.7
21	2021	59.9	692	0	692	11.6	0	0	0	40	0	40	0.7
22	2022	58.4	656	0	656	11.3	0	0	0	36	0	36	0.6
23	2023	58.3	635	0	635	10.9	0	0	0	32	0	32	0.5
24	2024	57.8	616	0	616	10.7	0	0	0	28	0	28	0.5
25	2025	57.6	599	0	599	10.4	0	0	0	24	0	24	0.4
2001$													
Net Present Value			11,211	0	11,211		0	0	0	832	0	832	
Nominal Levelized Cost ($/MWh)						17.0							1.3
Real Levelized Cost ($/MWh)						13.3							1.0

	Year	Total Fixed Costs: Before 10% Credit ($000s)	After 10% Credit ($000s)	After 10% Credit ($/MWh)	Less Operating Margin ($000s)	Net Project Benefit ($000s)	Net Project Benefit ($/MWh)	Variable Costs: Gas ($000s)	O&M ($000s)	Total Variable ($000s)	Total Variable ($/MWh)	Total Project Cost after Credit ($000s)
1	2001	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	0
2	2002	1,822	1,822	28.8	8,470	4,848	76.6	3,055	130	3,185	50.3	4,607
3	2003	1,562	1,562	22.9	3,878	2,116	31.0	2,783	144	2,927	42.9	4,488
4	2004	1,502	1,502	22.5	2,613	1,011	15.2	2,652	144	2,796	41.9	4,298
5	2005	1,438	1,438	23.2	1,868	430	6.9	2,393	138	2,531	40.8	3,969
6	2006	1,375	1,375	25.1	1,253	(122)	(2.2)	2,114	124	2,238	40.9	3,613
7	2007	1,317	1,317	26.4	955	(362)	(7.2)	1,920	116	2,037	40.8	3,354
8	2008	1,262	1,262	18.9	1,600	338	5.1	1,699	160	1,859	27.9	3,121
9	2009	1,220	1,220	18.3	1,631	411	6.1	1,764	164	1,928	28.9	3,148
10	2010	1,181	1,181	17.5	1,689	508	7.5	1,846	170	2,015	29.9	3,196
11	2011	1,140	1,140	16.9	1,700	559	8.3	1,920	174	2,095	31.1	3,235
12	2012	1,100	1,100	16.4	1,894	794	11.8	1,993	178	2,171	32.3	3,271
13	2013	1,059	1,059	15.9	1,671	612	9.2	2,049	181	2,230	33.6	3,289
14	2014	1,019	1,019	15.4	1,695	676	10.2	2,135	185	2,320	35.0	3,339
15	2015	980	980	14.8	1,671	692	10.5	2,228	189	2,417	36.6	3,397
16	2016	940	940	14.3	1,655	715	10.9	2,319	193	2,512	38.2	3,452
17	2017	899	899	13.9	1,638	739	11.4	2,384	195	2,580	39.8	3,479
18	2018	859	859	13.3	1,639	781	12.1	2,457	199	2,657	41.3	3,515
19	2019	817	817	12.9	1,602	785	12.4	2,500	201	2,701	42.7	3,518
20	2020	774	774	12.6	1,881	1,107	18.0	2,528	200	2,728	44.4	3,502
21	2021	732	732	12.2	1,851	1,119	18.7	2,565	200	2,765	46.2	3,497
22	2022	694	694	11.9	1,822	1,128	19.3	2,603	200	2,803	48.0	3,497
23	2023	667	667	11.4	1,796	1,129	19.4	2,708	205	2,913	49.9	3,580
24	2024	644	644	11.2	1,803	1,159	20.1	2,790	208	2,998	52.1	3,642
25	2025	623	623	10.8	1,768	1,145	19.9	2,909	213	3,122	54.3	3,745
2001$												
Net Present Value		12,042	12,042		22,843	10,601		23,170	1,615	24,785		36,828
Nominal Levelized Cost ($/MWh)				18.3			16.1				37.7	
Real Levelized Cost ($/MWh)				14.3			12.8				29.5	

Kettle Falls Upgrade

Avista Corporation

Economic Analysis Detail

Assumptions

Installed Cost			8,500	$000s			Fixed Charge			0.00	per kW-month			Variable O&M			2.00	2001$/MWh				Electric Wheeling Losses			1.0	percent				
Project Capacity			8.6	MW			Fixed O&M			0.00	20038 per kW-month																			
Heat Rate			12,080	Btu/kWh			Escalation Rates							Insurance Cost			0.0	0.3% of installed cost ($000s)				Nominal Discount Rate			7.8	percent				
Peak Gas Useage			1,904	000s dth			Fixed O&M			2.5	percent			Gas Transport			0.00	2000 $/dth				Real Discount Rate			5.1	percent				
							Variable O&M			2.5	percent			Electric Wheeling			0	$/MW-month thru 2006												
							Transportation			2.0	percent			General Inflation			2.5	percent												

			Fixed Costs																												
			Capital Recovery and Miscellaneous				Operations & Maintenance							Total Fixed Costs			Less	Net		Variable Costs				Total Project Cost	
Year		Energy	Project	Fixed Chrg.	Total Costs		Fixed	Gtrans	Etrans	PrTax	Insur.	Total Costs		Before 10% Credit	After 10% Credit	After 10% Credit	Operating Margin	Project Benefit		Gas	O&M	Total Variable		after Credits	
		(GWh)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($/MWh)	($000s)	($000s)	#DIV/0!	($000s)	($000s)	($000s)	($/MWh)	($000s)	($/MWh)
1	2001	0.0	0	0	0	#DIV/0!	0	0	0	0	0	0	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	0	#DIV/0!
2	2002	47.8	1,193	0	1,193	24.9	0	0	0	89	0	89	1.9	1,281	1,281	26.8	4,038	3,757	97.8	3,192	98	3,290	68.8	4,572	95.
3	2003	50.1	1,142	0	1,142	22.8	0	0	0	86	0	86	1.7	1,227	1,227	24.5	2,194	966	19.3	2,822	105	2,927	58.5	4,155	83.
4	2004	44.5	1,086	0	1,086	24.4	0	0	0	82	0	82	1.9	1,168	1,168	26.3	1,255	87	1.9	2,448	98	2,545	57.2	3,713	83.
5	2005	35.4	1,022	0	1,022	28.9	0	0	0	79	0	79	2.2	1,101	1,101	31.1	872	(229)	(6.5)	1,886	78	1,964	55.5	3,066	86.
6	2006	21.1	949	0	949	45.1	0	0	0	76	0	76	3.6	1,025	1,025	48.7	533	(492)	(23.4)	1,121	48	1,169	55.5	2,194	104.
7	2007	12.6	883	0	883	70.0	0	0	0	73	0	73	5.8	956	956	76.7	416	(550)	(43.7)	671	29	701	55.6	1,667	132.
8	2008	22.6	856	0	856	38.4	0	0	0	70	0	70	3.1	937	937	41.5	853	(83)	(3.7)	772	54	826	36.6	1,763	78.
9	2009	22.1	836	0	836	37.7	0	0	0	67	0	67	3.0	903	903	40.8	862	(41)	(1.8)	786	54	840	38.0	1,743	78.
10	2010	23.7	809	0	809	34.2	0	0	0	64	0	64	2.7	874	874	36.9	888	14	0.6	871	60	931	39.3	1,804	76.
11	2011	23.1	779	0	779	33.8	0	0	0	61	0	61	2.6	840	840	36.4	880	39	1.7	882	60	941	40.8	1,782	77.
12	2012	23.2	751	0	751	32.3	0	0	0	58	0	58	2.5	809	809	34.8	1,013	204	8.8	923	62	984	42.4	1,793	77.
13	2013	22.3	720	0	720	32.2	0	0	0	55	0	55	2.5	775	775	34.7	938	63	2.8	925	61	986	44.2	1,781	78.
14	2014	21.2	689	0	689	32.6	0	0	0	52	0	52	2.5	741	741	35.0	845	104	4.9	918	59	977	46.2	1,718	81.
15	2015	20.8	660	0	660	31.7	0	0	0	49	0	49	2.3	709	709	34.0	820	111	5.3	947	60	1,007	48.3	1,715	82.
16	2016	20.7	631	0	631	30.4	0	0	0	46	0	46	2.2	677	677	32.7	795	118	5.7	885	61	1,046	50.5	1,723	83.
17	2017	20.7	602	0	602	29.1	0	0	0	43	0	43	2.1	645	645	31.2	781	136	6.6	1,025	62	1,087	52.5	1,732	83.
18	2018	20.0	572	0	572	28.6	0	0	0	40	0	40	2.0	612	612	30.6	775	163	8.1	1,031	62	1,093	54.6	1,705	85.
19	2019	19.7	543	0	543	27.5	0	0	0	37	0	37	1.9	579	579	29.4	734	155	7.9	1,053	63	1,116	56.6	1,695	85.
20	2020	20.8	516	0	516	25.1	0	0	0	34	0	34	1.6	549	549	26.7	920	371	18.1	1,125	67	1,192	58.0	1,741	84.
21	2021	19.6	484	0	484	24.7	0	0	0	31	0	31	1.6	515	515	26.3	901	386	19.7	1,111	66	1,177	59.9	1,692	86.
22	2022	18.6	455	0	455	24.5	0	0	0	27	0	27	1.5	483	483	26.0	884	401	21.6	1,083	64	1,147	61.8	1,630	87.
23	2023	18.0	434	0	434	24.2	0	0	0	24	0	24	1.4	459	459	25.5	862	403	22.4	1,089	63	1,153	64.1	1,611	89.
24	2024	18.8	414	0	414	25.0	0	0	0	21	0	21	1.3	435	435	26.3	859	424	25.6	1,039	60	1,098	66.3	1,534	92.
25	2025	19.1	397	0	397	24.8	0	0	0	18	0	18	1.1	415	415	25.7	840	425	26.4	1,051	60	1,110	68.9	1,525	94.
2015$																									
Net Present Value			8,394	0	8,394		0	0	0	636	0	636		9,030	9,030		12,181	3,151		14,537	680	15,217		24,247	
Nominal Levelized Cost ($/MWh)						33.2							2.6			35.7			12.5				60.1		95.
Real Levelized Cost ($/MWh)						26.0							2.0			28.0			9.8				47.1		76.

AVISTA Corp.

Interoffice Memorandum
Resource Optimization

DATE: September 12, 2001

TO: Ed Groce

FROM: Clint Kalich CK

SUBJECT: Re-visit of Kettle Falls CT

Per your request, following are revised economic analyses on the Kettle Falls CT. It is important here to recognize the work of Steve Silkworth, as he provided the initial economic models used. Without his efforts, I would expect this memo to take a number of additional days to generate.

Project completion, according to Tomas Dempsey, will cost $1.7 million. Although an exact figure of expenses to date was not provided, you likely recall an initial estimate of $8.5 million for the entire project. Given this assumption, just under $7 million already has been spent, ~~to date~~ or committed to be spent on the project.

To evaluate the CT project, two scenarios were performed: 1) combined-cycle operation with the existing Kettle Falls boiler and 2) simple-cycle operation. The attached spreadsheets explain that operating in simple-cycle the new CT would generate losses of approximately $250,000 on expenses of $400,000, per year. The project would generate losses through 2013 and thereafter add positive margins to the Company. Over the 24-year analysis, the net present value of the investment is a loss of $856,000 (2001$). On a per-unit basis, the nominal levelized loss is $6.3 per MWh (2001$).

In combined-cycle, the new CT project generates a positive net present value of nearly $4 million (2001$) over 24 years, or $6.7 per MWh nominal levelized. However, the project does not provide positive cash flow until 2008, losing in the earlier years on average about $90,000 on project costs of $1.0 million annually. Additionally, analyzing the CT as a combined-cycle unit presents a very optimistic picture. Given the plant's heat rate, it is likely that at most times it will not be the least-cost option to run the turbine to add heat to the Kettle Falls boiler. With gas at more than $3 per decatherm, the plant's nearly 9,000 combined-cycle heat rate puts generation at over $25 per MWh.

If you need some additional information or analysis, please give me a call.

attachments

Cc: Lloyd Meyers, Steve Wenke, Steve Silkworth

KF CT Study 09/11/01

These values were given to me from Thomas Dempsey on 9/11/01 for the Kettle Falls CT. This option burns natural gas in simple cycle
and diverts waste heat in a feedwater heater in the existing Kettle Falls boiler for heat recovery.

Heat Rate = 8845 kW/Btu (Higher Heating Value)
Capacity = 7072 kW (SCCT) + 3030 kW (Heat Recovery) = 10,102 kW
Capital required to complete the project = $1,700,000

Kettle Falls SCCT -- Heat Recovery in Kettle Falls Boiler

Avista Corporation

Economic Analysis Detail

Assumptions

Installed Cost			1,700	$000s			Fixed Charge				0.00	per kW-month			Variable O&M			2.00	2001$/MWh				Electric Wheeling Losses			1.9	percent			
Project Capacity			10.1	MW			Fixed O&M				0.00	2003$ per kW-month																		
Heat Rate			8,845	Btu/kWh			Escalation Rates								Insurance Cost			0.0	0.3% of installed cost ($000s)				Nominal Discount Rate			7.8	percent			
Peak Gas Useage			2,144	000s dth			Fixed O&M				2.5	percent			Gas Transport			0.00	2000 $/dth				Real Discount Rate			5.1	percent			
							Variable O&M				2.5	percent			Electric Wheeling			0	$/MW-month thru 2006											
							Transportation				2.0	percent			General Inflation			2.5	percent											
																						Profitability Index							
																						2.31586							

				Fixed Costs																											
				Capital Recovery and Miscellaneous				Operations & Maintenance							Total Fixed Costs				Net		Variable Costs				Total Project Cost						
	Year		Energy	Project	Fixed Chrg.	Total Costs		Fixed	Gtrans	Etrans	PrTax	Insur.	Total Costs		Before 10% Credit	After 10% Credit	After 10% Credit	Operating Margin	Project Benefit		Gas	O&M	Total Variable		after Credits						
			(GWh)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($/MWh)						
1	2001		0.0	0	0	0	#DIV/0!	0	0	0	0	0	0	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	0	#DIV/0!					
2	2002		22.3	306	0	306	13.7	0	0	0	23	0	23	1.0	329	329	14.7	246	(83)	(3.7)	881	45	726	32.5	1,056	47.3					
3	2003		19.4	293	0	293	15.1	0	0	0	22	0	22	1.2	316	316	16.2	200	(116)	(6.0)	813	39	852	33.6	867	48.8					
4	2004		23.4	290	0	290	12.4	0	0	0	22	0	22	0.9	311	311	13.3	208	(103)	(4.4)	742	47	789	33.7	1,101	47.0					
5	2005		30.2	290	0	290	9.6	0	0	0	21	0	21	0.7	311	311	10.3	244	(67)	(2.2)	937	60	997	33.1	1,309	43.4					
6	2006		23.1	269	0	269	11.7	0	0	0	20	0	20	0.8	289	289	12.6	202	(87)	(3.8)	701	46	747	32.3	1,036	44.9					
7	2007		30.2	271	0	271	9.0	0	0	0	18	0	18	0.6	290	290	9.6	277	(13)	(0.4)	902	60	962	31.9	1,252	41.5					
8	2008		40.2	278	0	278	6.9	0	0	0	18	0	18	0.5	295	295	7.3	359	64	1.6	1,171	80	1,251	31.2	1,548	38.5					
9	2009		45.0	273	0	273	6.1	0	0	0	16	0	16	0.4	291	291	6.5	467	176	3.9	1,269	90	1,359	30.2	1,650	36.7					
10	2010		45.0	267	0	267	5.9	0	0	0	17	0	17	0.4	284	284	6.3	494	210	4.7	1,313	90	1,403	31.2	1,687	37.5					
11	2011		45.0	262	0	262	5.8	0	0	0	16	0	16	0.4	278	278	6.2	502	224	5.0	1,363	90	1,453	32.3	1,730	38.5					
12	2012		45.3	257	0	257	5.7	0	0	0	15	0	15	0.3	272	272	6.0	507	235	5.2	1,428	91	1,518	33.5	1,788	39.5					
13	2013		45.0	251	0	251	5.6	0	0	0	14	0	14	0.3	265	265	5.9	514	248	5.5	1,472	90	1,562	34.7	1,827	40.6					
14	2014		81.1	313	0	313	3.9	0	0	0	14	0	14	0.2	326	326	4.0	1,322	1,196	14.7	2,667	162	3,018	37.2	3,346	41.3					
15	2015		80.9	311	0	311	3.8	0	0	0	13	0	13	0.2	323	323	4.0	1,488	1,165	14.4	2,985	162	3,147	38.9	3,470	42.9					
16	2016		81.2	309	0	309	3.8	0	0	0	12	0	12	0.1	321	321	4.0	1,484	1,143	14.1	3,123	162	3,286	40.5	3,607	44.4					
17	2017		77.9	300	0	300	3.8	0	0	0	11	0	11	0.1	311	311	4.0	1,432	1,121	14.4	3,096	156	3,252	41.7	3,563	45.7					
18	2018		78.1	297	0	297	3.8	0	0	0	10	0	10	0.1	308	308	3.9	1,415	1,107	14.2	3,216	156	3,372	43.2	3,680	47.1					
19	2019		73.2	288	0	288	3.8	0	0	0	10	0	10	0.1	298	298	4.0	1,452	1,155	15.4	3,193	150	3,344	44.5	3,641	48.4					
20	2020		75.2	284	0	284	3.8	0	0	0	9	0	9	0.1	293	293	3.9	1,496	1,203	16.0	3,277	150	3,427	45.6	3,720	49.4					
21	2021		74.8	279	0	279	3.7	0	0	0	8	0	8	0.1	287	287	3.8	1,534	1,247	16.7	3,340	150	3,490	46.6	3,777	50.5					
22	2022		74.8	276	0	276	3.7	0	0	0	7	0	7	0.1	283	283	3.8	1,575	1,292	17.3	3,423	150	3,573	47.7	3,856	51.5					
23	2023		77.9	281	0	281	3.6	0	0	0	6	0	6	0.1	288	288	3.7	1,621	1,334	17.1	3,647	156	3,803	48.8	4,091	52.5					
24	2024		78.3	282	0	282	3.6	0	0	0	6	0	6	0.1	288	288	3.7	1,671	1,383	17.7	3,758	157	3,915	50.0	4,203	53.7					
25	2025		78.1	281	0	281	3.6	0	0	0	5	0	5	0.1	286	286	3.7	1,716	1,430	18.3	3,842	156	3,998	51.2	4,284	54.9					
2001$																															
Net Present Value				2,826	0	2,826		0	0	0	166	0	166		2,993	2,993		5,648	3,837		16,247	905	17,152		20,144						
Nominal Levelized Cost ($/MWh)							4.6							0.3			5.1			6.7				28.2		34.3				
Real Levelized Cost ($/MWh)							3.8							0.2			4.0			5.3				22.9		26.9				

Kettle Falls SCCT -- Simple Cycle Only

Avista Corporation

Economic Analysis Detail

Assumptions

Installed Cost	1,700	$000s	Fixed Charge	0.00	per kW-month	Variable O&M	2.00 2001$/MWh
Project Capacity	6.6	MW	Fixed O&M	0.00	2003$ per kW-month		
Heat Rate	12,080	Btu/kWh	Escalation Rates			Insurance Cost	0.0 0.3% of installed cost ($000s)
Peak Gas Useage	1,813	000s dth	Fixed O&M	2.5	percent	Gas Transport	0.00 2000 $/dth
			Variable O&M	2.5	percent	Electric Wheeling	0 $/MW-month thru 2006
			Transportation	2.0	percent	General Inflation	2.5 percent

Electric Wheeling Losses	1.8	percent
Nominal Discount Rate	7.8	percent
Real Discount Rate	5.1	percent
Profitability Index	-0.50380	

Fixed Costs

Row		Year	Energy (GWh)	Capital Recovery and Miscellaneous: Project ($000s)	Fixed Chrg. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Operations & Maintenance: Fixed ($000s)	Gtrans ($000s)	Etrans ($000s)	PrTax ($000s)	Insur. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)
18	1	2001	0.0	0	0	0	#DIV/0!	0	0	0	0	0	0	#DIV/0!
19	2	2002	2.7	276	0	276	102.0	0	0	0	23	0	23	8.6
20	3	2003	2.6	267	0	267	102.5	0	0	0	22	0	22	8.6
21	4	2004	2.6	258	0	258	98.6	0	0	0	22	0	22	8.3
22	5	2005	2.7	248	0	248	91.7	0	0	0	21	0	21	7.7
23	6	2006	2.7	239	0	239	88.3	0	0	0	20	0	20	7.4
24	7	2007	2.7	230	0	230	85.0	0	0	0	19	0	19	7.1
25	8	2008	7.3	231	0	231	31.7	0	0	0	18	0	18	2.5
26	9	2009	7.3	221	0	221	30.3	0	0	0	18	0	18	2.4
27	10	2010	10.0	218	0	218	21.8	0	0	0	17	0	17	1.7
28	11	2011	7.3	206	0	206	28.3	0	0	0	16	0	16	2.2
29	12	2012	7.2	198	0	198	27.8	0	0	0	15	0	15	2.1
30	13	2013	7.2	190	0	190	26.5	0	0	0	14	0	14	2.0
31	14	2014	22.4	220	0	220	9.9	0	0	0	14	0	14	0.6
32	15	2015	22.5	215	0	215	9.6	0	0	0	13	0	13	0.6
33	16	2016	22.5	209	0	209	9.3	0	0	0	12	0	12	0.5
34	17	2017	22.4	203	0	203	9.1	0	0	0	11	0	11	0.5
35	18	2018	19.8	190	0	190	9.6	0	0	0	10	0	10	0.5
36	19	2019	19.8	184	0	184	9.3	0	0	0	10	0	10	0.5
37	20	2020	19.9	177	0	177	8.9	0	0	0	9	0	9	0.4
38	21	2021	19.8	171	0	171	8.6	0	0	0	8	0	8	0.4
39	22	2022	19.9	165	0	165	8.3	0	0	0	7	0	7	0.4
40	23	2023	19.8	161	0	161	8.1	0	0	0	6	0	6	0.3
41	24	2024	19.8	157	0	157	8.0	0	0	0	6	0	6	0.3
42	25	2025	19.9	155	0	155	7.8	0	0	0	5	0	5	0.2
43														
44	2001$													
45	Net Present Value			2,235	0	2,235		0	0	0	166	0	166	
46	Nominal Levelized Cost ($/MWh)						18.5							1.2
47	Real Levelized Cost ($/MWh)						13.0							1.0

Row	Year	Total Fixed Costs: Before 10% Credit ($000s)	After 10% Credit ($000s)	After 10% Credit ($/MWh)	Less Operating Margin ($000s)	Net Project Benefit ($000s)	Net Project Benefit ($/MWh)	Variable Costs: Gas ($000s)	O&M ($000s)	Total Variable ($000s)	Total Variable ($/MWh)	Total Project after Credit ($000s)
18	2001	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	0
19	2002	299	299	110.6	28	(271)	(100.2)	110	5	116	42.7	416
20	2003	290	290	111.1	21	(268)	(102.9)	109	5	114	43.7	404
21	2004	279	279	107.0	20	(259)	(99.3)	110	5	115	44.3	395
22	2005	269	269	99.3	24	(245)	(90.6)	112	5	118	43.5	387
23	2006	259	259	95.6	20	(239)	(88.2)	110	5	116	42.7	375
24	2007	249	249	92.1	28	(222)	(81.9)	108	5	113	41.8	363
25	2008	249	249	34.2	48	(201)	(27.6)	285	15	300	41.2	548
26	2009	238	238	32.6	98	(140)	(19.2)	248	15	263	36.2	501
27	2010	235	235	23.6	110	(125)	(12.6)	366	20	386	38.6	621
28	2011	221	221	30.5	107	(115)	(15.8)	267	15	282	38.7	503
29	2012	213	213	29.7	107	(106)	(14.8)	274	14	288	40.2	501
30	2013	205	205	28.5	108	(97)	(13.5)	284	14	299	41.7	503
31	2014	234	234	10.5	477	243	10.9	1,052	45	1,097	49.0	1,331
32	2015	228	228	10.1	450	222	9.9	1,106	45	1,151	51.2	1,379
33	2016	221	221	9.8	424	202	9.0	1,154	45	1,199	53.4	1,421
34	2017	215	215	9.6	402	188	8.4	1,197	45	1,242	55.5	1,456
35	2018	201	201	10.2	389	188	9.5	1,099	40	1,139	57.6	1,340
36	2019	193	193	9.8	401	208	10.5	1,127	40	1,168	59.0	1,360
37	2020	186	186	9.4	412	226	11.4	1,161	40	1,201	60.4	1,387
38	2021	179	179	9.0	423	244	12.3	1,191	40	1,230	61.9	1,409
39	2022	172	172	8.7	434	262	13.2	1,220	40	1,260	63.4	1,432
40	2023	167	167	8.5	446	279	14.1	1,243	40	1,283	64.8	1,450
41	2024	163	163	8.3	459	296	15.0	1,275	40	1,315	66.5	1,478
42	2025	159	159	8.0	472	312	15.7	1,314	40	1,353	68.1	1,513
43												
44												
45	Net Present Value	2,401	2,401		1,606	(856)		4,618	186	4,804		7,205
46	Nominal Levelized Cost ($/MWh)			17.8			(8.3)				35.5	
47	Real Levelized Cost ($/MWh)			13.9			(5.0)				27.8	

AVISTA Corp.

Interoffice Memorandum
Resource Optimization

DATE: April 8, 2002

TO: Bob Lafferty

FROM: Clint Kalich

SUBJECT: Revisit of September 12, 2001 Kettle Falls CT Analysis

On September 12, 2001 I prepared an analysis of the Kettle Falls CT based on the remaining capital expenditures necessary to complete the project. The results of the analysis showed an NPV of nearly $4 million over 25 years in combined-cycle operation, and a loss of $850 thousand in simple cycle. My September 12, 2001 memorandum explained that "analyzing the CT as a combined-cycle unit (CCCT) presents a very optimistic picture [of project economics]." This statement was not intended to imply that the economics in simple-cycle operation were the appropriate measure of project value, but only that the CCCT configuration over-states the true value of the plant. In fact, at the time I felt the analysis supported completing the project based on the range of the results.

At the time of the earlier memorandum, I was not able to properly represent the plant's physical characteristics in Prosym. In the CCCT case the waste heat from the simple-cycle is injected into the existing Kettle Falls boiler. However, unlike more traditional CCCT plants, the "opportunity cost" of displaced fuel is not natural gas. The boiler at Kettle Falls is limited to approximately 47 megawatts. The CCCT operation therefore reduces the amount of wood fuel burned by the main plant. Because the wood fuel is substantially lower in cost than natural gas, the economic benefit of CCCT operation is therefore reduced. For example, if natural gas costs $3.00 per decatherm and wood fuel costs $1.50 per decatherm, the waste heat from simple-cycle operation is worth half as much as it would be was the boiler capability not limited.

Based upon additional experience gained since the time of the initial analysis, the true physical nature of the new CT now can be modeled. Per your request, I re-ran project economics based upon the same forward market information used in the original analysis last September.

The results show that when the project is modeled true to its engineering (i.e., CCCT displacing wood fuel), the NPV was $0.7 million, with the plant operating at most on average at half of its available hours. Although significantly lower than the CCCT value of $4 million modeled in September of last year, the analysis clearly shows the Kettle Falls CT to be economic over its life.

During my work in reviewing the original economics, I noticed that the forward prices used in the evaluation did not tie into the R.W. Beck price forecast until 2014. In most analyses of this term (e.g., 2000 RFP) we've started using the R.W. Beck values in 2008. Were we to use the long-term R.W. Beck price forecast beginning in 2008, the economic value of the plant would rise to $2.9 million NPV.

attachment

Kettle Falls CCCT -- Heat Recovery in Kettle Falls Boiler

Avista Corporation

Economic Analysis Detail

Installed Cost	1,700	$000s	Fixed Charge	0.00	per kW-month			
Project Capacity	9.5	MW	Fixed O&M	0.00	2003$ per kW-month			
Heat Rate	8,845	Btu/kWh	Escalation Rates					
Peak Gas Useage	2,017	000s dth	Fixed O&M	2.5	percent			
			Variable O&M	2.5	percent			
			Transportation	2.0	percent			

Assumptions

Variable O&M	2.00	2001$/MWh	Electric Wheeling Losses	1.9	percent
Insurance Cost	0.0	0.3% of installed cost ($000s)	Nominal Discount Rate	7.8	percent
Gas Transport	0.00	2000 $/dth	Real Discount Rate	5.1	percent
Electric Wheeling	0	$/kW-month thru 2006			
General Inflation	2.5	percent			
			Profitability Index	0.38610	

	Year	Energy (GWh)	Capital Recovery and Miscellaneous: Project ($000s)	Fixed Chrg. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Fixed Costs — Operations & Maintenance: Fixed ($000s)	Gtrans ($000s)	Etrans ($000s)	PrTax ($000s)	Insur. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Total Fixed Costs: Before 10% Credit ($000s)	After 10% Credit ($000s)	After 10% Credit ($/MWh)	Less Operating Margin ($000s)	Net Project Benefit ($000s)	Net Project Benefit ($/MWh)	Variable Costs: Gas ($000s)	O&M ($000s)	Total Variable ($000s)	Total Variable ($/MWh)	Total Project Cost after Credits ($000s)	Total Project Cost after Credits ($/MWh)
1	2001	0.0	0	0	0	#DIV/0!	0	0	0	0	0	0	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	0	#DIV/0!
2	2002	13.8	294	0	294	21.3	0	0	0	23	0	23	1.7	317	317	23.0	114	(203)	(14.7)	420	69	489	35.4	806	58
3	2003	11.8	283	0	283	23.9	0	0	0	22	0	22	1.8	305	305	25.8	89	(216)	(18.3)	373	59	432	36.6	737	62
4	2004	12.1	273	0	273	22.6	0	0	0	22	0	22	1.8	295	295	24.4	87	(209)	(17.2)	385	61	446	36.8	741	61
5	2005	14.2	267	0	267	18.8	0	0	0	21	0	21	1.5	288	288	20.2	97	(190)	(13.4)	438	71	510	35.9	798	56
6	2006	12.0	254	0	254	21.2	0	0	0	20	0	20	1.7	274	274	22.8	81	(193)	(16.1)	364	60	424	35.4	698	58
7	2007	18.4	255	0	255	13.9	0	0	0	19	0	19	1.0	275	275	14.9	110	(164)	(8.9)	547	92	639	34.7	914	49
8	2008	21.3	251	0	251	11.8	0	0	0	18	0	18	0.9	269	269	12.7	143	(126)	(5.9)	614	106	721	33.9	990	46
9	2009	25.5	249	0	249	9.8	0	0	0	18	0	18	0.7	266	266	10.4	197	(69)	(2.7)	721	127	848	33.3	1,114	43
10	2010	25.7	242	0	242	9.4	0	0	0	17	0	17	0.7	259	259	10.1	212	(47)	(1.8)	753	129	882	34.3	1,141	44
11	2011	25.7	236	0	236	9.2	0	0	0	16	0	16	0.6	251	251	9.8	214	(38)	(1.5)	780	128	908	35.4	1,160	45
12	2012	25.6	229	0	229	8.9	0	0	0	15	0	15	0.6	244	244	9.5	215	(29)	(1.1)	810	128	938	36.6	1,182	46
13	2013	23.9	219	0	219	9.2	0	0	0	14	0	14	0.6	234	234	9.8	216	(18)	(0.7)	783	119	902	37.8	1,136	47
14	2014	50.1	266	0	266	5.3	0	0	0	14	0	14	0.3	279	279	5.6	756	477	9.5	1,786	251	2,037	40.6	2,316	46
15	2015	46.3	253	0	253	5.5	0	0	0	13	0	13	0.3	266	266	5.7	728	462	10.0	1,710	232	1,942	41.9	2,208	47
16	2016	45.0	246	0	246	5.5	0	0	0	12	0	12	0.3	258	258	5.7	708	450	10.0	1,740	225	1,965	43.7	2,223	49
17	2017	44.5	240	0	240	5.4	0	0	0	11	0	11	0.3	251	251	5.7	690	439	9.9	1,787	222	2,009	45.2	2,261	50
18	2018	42.3	230	0	230	5.4	0	0	0	10	0	10	0.2	241	241	5.7	675	434	10.3	1,760	212	1,972	46.6	2,213	52
19	2019	43.3	226	0	226	5.1	0	0	0	10	0	10	0.2	236	236	5.3	743	508	11.5	1,826	221	2,047	46.2	2,282	51
20	2020	46.2	223	0	223	4.8	0	0	0	9	0	9	0.2	232	232	5.0	1,000	767	16.6	1,930	231	2,161	46.8	2,393	51
21	2021	44.8	216	0	216	4.8	0	0	0	8	0	8	0.2	224	224	5.0	985	761	17.0	1,953	224	2,177	48.6	2,401	53
22	2022	44.3	211	0	211	4.8	0	0	0	7	0	7	0.2	219	219	4.9	965	747	16.9	2,007	221	2,228	50.4	2,447	55
23	2023	44.2	210	0	210	4.7	0	0	0	6	0	6	0.1	216	216	4.9	946	730	16.5	2,089	221	2,310	52.3	2,527	57
24	2024	43.8	208	0	208	4.7	0	0	0	6	0	6	0.1	214	214	4.9	822	708	16.2	2,149	219	2,368	54.0	2,582	58
25	2025	41.8	201	0	201	4.8	0	0	0	5	0	5	0.1	206	206	4.9	898	692	16.6	2,114	209	2,323	55.6	2,528	60
2001$																									
Net Present Value			2,508	0	2,508		0	0	0	166	0	166		2,674	2,674		3,298	673		8,222	1,282	10,504		13,178	
Nominal Levelized Cost ($/MWh)						7.5							0.5			8.0			2.0				31.4		39
Real Levelized Cost ($/MWh)						5.9							0.4			6.3			1.6				24.6		30