EXHIBIT J

September 2004 Analysis

Application of Avista Corporation
Case No. AVU-E-05-1

September 2004 Analysis

50% of Coyote Springs 2 (CCCT and Duct Burner)—Annual Value less Q2

Economic Analysis Detail

Assumptions

Installed Cost	66,657	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	199.97	2004 $000s	Nominal Discount	8.22 percent
Installed Cost	469	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.50 percent
Project Capacity	142.26	MW	Escalation Rates			General Inflation	3.0	percent		
Heat Rate	7,341	Btu/kWh	Fixed O&M	3.0	percent	Option Value	2,000	2004 $000s		
Gas Usage Rate	25.1	000s dth/day	Transportation	3.0	percent					

		Fixed Costs																			
		Capital Recovery and Miscellaneous				Operations & Maintenance															
Year	Energy (GWh)	Project ($000s)	Fixed Chrg. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Fixed ($000s)	Gtrans ($000s)	PrTax ($000s)	Insur. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Total Fixed Costs ($000s)	Operating Margin ($000s)	Option Value ($000s)	Net Project Benefit ($000s)	Net Project Benefit ($/MWh)	Total Variable Costs ($000s)	Total Variable Costs ($/MWh)	Total Project Costs ($000s)	Total Project Costs ($/MWh)
1 2005	697.6	12,699	0	12,699	18.2	3,077	0	908	206	4,192	6.0	16,891	3,569	2,060	(11,261)	(16.1)	30,247	43.4	47,137	67.6
2 2006	731.2	12,375	0	12,375	16.9	3,169	0	877	212	4,259	5.8	16,633	4,585	2,122	(9,926)	(13.6)	30,971	42.4	47,604	65.1
3 2007	713.1	11,868	0	11,868	16.6	3,264	0	846	219	4,329	6.1	16,197	4,122	2,185	(9,889)	(13.9)	28,834	40.4	45,031	63.1
4 2008	715.4	11,447	0	11,447	16.0	3,362	0	814	225	4,402	6.2	15,849	3,994	2,251	(9,604)	(13.4)	28,152	39.4	44,001	61.5
5 2009	790.0	11,048	0	11,048	14.0	3,463	0	783	232	4,478	5.7	15,526	12,147	2,319	(1,060)	(1.3)	27,597	34.9	43,123	54.6
6 2010	792.9	10,714	0	10,714	13.5	3,567	0	752	239	4,558	5.7	15,272	14,407	2,388	1,523	1.9	28,122	35.5	43,394	54.7
7 2011	777.9	10,345	0	10,345	13.3	3,674	0	721	246	4,641	6.0	14,985	15,897	2,460	3,371	4.3	27,640	35.5	42,626	54.8
8 2012	777.8	10,016	0	10,016	12.9	3,784	0	689	253	4,727	6.1	14,743	16,632	2,534	4,423	5.7	27,752	35.7	42,494	54.6
9 2013	744.2	9,691	0	9,691	13.0	3,898	0	658	261	4,817	6.5	14,508	15,824	2,610	3,926	5.3	27,805	37.4	42,313	56.9
10 2014	727.1	9,316	0	9,316	12.8	4,015	0	627	269	4,910	6.8	14,226	16,330	2,688	4,792	6.6	26,783	36.8	41,009	56.4
11 2015	747.3	9,059	0	9,059	12.1	4,135	0	595	277	5,007	6.7	14,067	17,054	2,768	5,756	7.7	28,242	37.8	42,309	56.6
12 2016	749.6	8,810	0	8,810	11.8	4,259	0	564	285	5,108	6.8	13,919	16,960	2,852	5,893	7.9	29,842	39.8	43,761	58.4
13 2017	756.9	8,527	0	8,527	11.3	4,387	0	533	294	5,213	6.9	13,740	18,202	2,937	7,398	9.8	30,727	40.6	44,468	58.8
14 2018	746.4	8,204	0	8,204	11.0	4,519	0	501	302	5,322	7.1	13,527	17,613	3,025	7,111	9.5	30,784	41.2	44,311	59.4
15 2019	750.4	7,914	0	7,914	10.5	4,654	0	470	312	5,436	7.2	13,350	18,765	3,116	8,530	11.4	31,526	42.0	44,876	59.8
16 2020	768.7	7,659	0	7,659	10.0	4,794	0	439	321	5,553	7.2	13,213	20,169	3,209	10,165	13.2	32,992	42.9	46,205	60.1
17 2021	761.8	7,381	0	7,381	9.7	4,938	0	407	331	5,676	7.5	13,057	19,216	3,306	9,465	12.4	33,964	44.6	47,021	61.7
18 2022	759.9	7,119	0	7,119	9.4	5,086	0	376	340	5,802	7.6	12,921	18,548	3,405	9,032	11.9	35,263	46.4	48,184	63.4
19 2023	771.2	6,829	0	6,829	8.9	5,239	0	345	351	5,934	7.7	12,763	21,002	3,507	11,747	15.2	35,986	46.7	48,749	63.2
20 2024	772.6	6,562	0	6,562	8.5	5,396	0	313	361	6,070	7.9	12,632	21,686	3,612	12,666	16.4	37,182	48.1	49,814	64.5
Net Present Value		98,469	0	98,469		37,017	0	6,664	2,478	46,159		144,628	119,847	24,781	0		286,847		431,475	
Nominal Levelized Cost ($/MWh)					13.5						6.3					0.0		39.5		59.4
Real Levelized Cost ($/MWh)					10.9						5.1					0.0		31.9		48.0

50% of Coyote Springs 2 (CCCT and Duct Burner)—Annual Value less Q2

Economic Analysis Detail

Assumptions

Installed Cost	73,557	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	220.67	2004 $000s	Nominal Discount	8.22	percent
Installed Cost	517	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.50	percent
Project Capacity	142.26	MW	Escalation Rates			General Inflation	3.0	percent			
Heat Rate	7,341	Btu/kWh	Fixed O&M	3.0	percent	Option Value	2,000	2004 $000s			
Gas Usage Rate	25.1	000s dth/day	Transportation	3.0	percent						

			Fixed Costs																		
			Capital Recovery and Miscellaneous				Operations & Maintenance						Total Fixed	Operating	Option	Net				Total Project	
	Year	Energy	Project	Fixed Chrg.	Total Costs		Fixed	Gtrans	PrTax	Insur.	Total Costs		Costs	Margin	Value	Project Benefit		Total Variable Costs		Costs	
		(GWh)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($/MWh)	($000s)	($/MWh)
1	2005	704.4	13,505	0	13,505	19.2	3,077	0	1,003	227	4,307	6.1	17,812	4,517	2,060	(11,235)	(15.9)	23,074	32.8	40,886	58.0
2	2006	749.8	13,171	0	13,171	17.6	3,169	0	968	234	4,371	5.8	17,542	6,133	2,122	(9,287)	(12.4)	24,382	32.5	41,924	55.9
3	2007	767.2	12,772	0	12,772	16.6	3,264	0	933	241	4,439	5.8	17,211	7,287	2,185	(7,739)	(10.1)	25,389	33.1	42,600	55.5
4	2008	781.9	12,409	0	12,409	15.9	3,362	0	899	248	4,510	5.8	16,919	9,581	2,251	(5,087)	(6.5)	26,758	34.2	43,677	55.9
5	2009	790.0	12,037	0	12,037	15.2	3,463	0	864	256	4,583	5.8	16,621	12,147	2,319	(2,155)	(2.7)	27,597	34.9	44,218	56.0
6	2010	792.9	11,666	0	11,666	14.7	3,567	0	830	263	4,660	5.9	16,326	14,407	2,388	469	0.6	28,122	35.5	44,448	56.1
7	2011	777.9	11,260	0	11,260	14.5	3,674	0	795	271	4,741	6.1	16,001	15,897	2,460	2,356	3.0	27,640	35.5	43,641	56.1
8	2012	777.8	10,896	0	10,896	14.0	3,784	0	761	280	4,824	6.2	15,721	16,632	2,534	3,445	4.4	27,752	35.7	43,472	55.9
9	2013	744.2	10,537	0	10,537	14.2	3,898	0	726	288	4,912	6.6	15,449	15,824	2,610	2,985	4.0	27,805	37.4	43,254	58.1
10	2014	727.1	10,127	0	10,127	13.9	4,015	0	691	297	5,003	6.9	15,130	16,330	2,688	3,888	5.3	26,783	36.8	41,913	57.6
11	2015	747.3	9,837	0	9,837	13.2	4,135	0	657	305	5,098	6.8	14,934	17,054	2,768	4,888	6.5	28,242	37.8	43,176	57.8
12	2016	749.6	9,553	0	9,553	12.7	4,259	0	622	315	5,196	6.9	14,749	16,960	2,852	5,062	6.8	29,842	39.8	44,591	59.5
13	2017	756.9	9,235	0	9,235	12.2	4,387	0	588	324	5,299	7.0	14,534	18,202	2,937	6,604	8.7	30,727	40.6	45,262	59.8
14	2018	746.4	8,878	0	8,878	11.9	4,519	0	553	334	5,406	7.2	14,284	17,613	3,025	6,354	8.5	30,784	41.2	45,068	60.4
15	2019	750.4	8,554	0	8,554	11.4	4,654	0	519	344	5,517	7.4	14,071	18,765	3,116	7,810	10.4	31,526	42.0	45,597	60.8
16	2020	768.7	8,265	0	8,265	10.8	4,794	0	484	354	5,632	7.3	13,897	20,169	3,209	9,481	12.3	32,992	42.9	46,889	61.0
17	2021	761.8	7,952	0	7,952	10.4	4,938	0	449	365	5,752	7.6	13,704	19,216	3,306	8,818	11.6	33,964	44.6	47,668	62.6
18	2022	759.9	7,655	0	7,655	10.1	5,086	0	415	376	5,876	7.7	13,532	18,548	3,405	8,421	11.1	35,263	46.4	48,795	64.2
19	2023	771.2	7,331	0	7,331	9.5	5,239	0	380	387	6,006	7.8	13,337	21,002	3,507	11,172	14.5	35,986	46.7	49,323	64.0
20	2024	772.6	7,030	0	7,030	9.1	5,396	0	346	399	6,140	7.9	13,170	21,686	3,612	12,128	15.7	37,182	48.1	50,352	65.2
Net Present Value			106,291	0	106,291		37,017	0	7,354	2,734	47,105		153,396	128,615	24,781	0		270,859		424,255	
Nominal Levelized Cost ($/MWh)						14.5						6.4					0.0		36.9		57.8
Real Levelized Cost ($/MWh)						11.7						5.2					0.0		29.8		46.7

50% of Coyote Springs 2 (CCCT and Duct Burner)—Annual Value less Q2

Economic Analysis Detail

Assumptions

Installed Cost	44,413	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	133.24	2004 $000s	Nominal Discount	8.22	percent
Installed Cost	312	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.50	percent
Project Capacity	142.26	MW	Escalation Rates			General Inflation	3.0	percent			
Heat Rate	7,341	Btu/kWh	Fixed O&M	3.0	percent	Option Value	2,000	2004 $000s			
Gas Usage Rate	25.1	000s dth/day	Transportation	3.0	percent						

Year	Energy	Capital Recovery and Miscellaneous: Project	Fixed Chrg.	Total Costs		O&M: Fixed	Gtrans	PrTax	Insur.	Total Costs		Total Fixed Costs	Operating Margin	Option Value	Net Project Benefit		Total Variable Costs		Total Project Costs	
	(GWh)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($/MWh)	($000s)	($/MWh)
1 2005	697.5	8,994	0	8,994	12.9	3,077	0	605	137	3,820	5.5	12,814	3,557	2,060	(7,196)	(10.3)	30,251	43.4	43,065	61.7
2 2006	707.5	8,778	0	8,778	12.4	3,169	0	584	141	3,895	5.5	12,674	3,865	2,122	(6,687)	(9.5)	30,713	43.4	43,387	61.3
3 2007	716.2	8,442	0	8,442	11.8	3,264	0	564	146	3,974	5.5	12,416	3,818	2,185	(6,413)	(9.0)	29,285	40.9	41,701	58.2
4 2008	727.3	8,158	0	8,158	11.2	3,362	0	543	150	4,055	5.6	12,213	3,910	2,251	(6,052)	(8.3)	28,724	39.5	40,938	56.3
5 2009	549.1	7,669	0	7,669	14.0	3,463	0	522	154	4,140	7.5	11,808	6,830	2,319	(2,659)	(4.8)	23,652	43.1	35,460	64.6
6 2010	514.6	7,409	0	7,409	14.4	3,567	0	501	159	4,227	8.2	11,636	8,342	2,388	(906)	(1.8)	23,190	45.1	34,826	67.7
7 2011	493.2	7,152	0	7,152	14.5	3,674	0	480	164	4,318	8.8	11,470	9,714	2,460	704	1.4	22,613	45.9	34,084	69.1
8 2012	468.8	6,888	0	6,888	14.7	3,784	0	459	169	4,412	9.4	11,301	10,592	2,534	1,824	3.9	21,719	46.3	33,019	70.4
9 2013	431.3	6,593	0	6,593	15.3	3,898	0	438	174	4,510	10.5	11,103	11,080	2,610	2,587	6.0	20,057	46.5	31,160	72.2
10 2014	395.3	6,289	0	6,289	15.9	4,015	0	417	179	4,611	11.7	10,900	11,810	2,688	3,597	9.1	18,215	46.1	29,115	73.7
11 2015	424.4	6,156	0	6,156	14.5	4,135	0	397	184	4,716	11.1	10,873	12,409	2,768	4,305	10.1	19,945	47.0	30,818	72.6
12 2016	430.3	5,986	0	5,986	13.9	4,259	0	376	190	4,825	11.2	10,811	12,553	2,852	4,593	10.7	20,888	48.5	31,699	73.7
13 2017	443.8	5,834	0	5,834	13.1	4,387	0	355	196	4,938	11.1	10,772	13,366	2,937	5,532	12.5	22,196	50.0	32,967	74.3
14 2018	448.2	5,617	0	5,617	12.5	4,519	0	334	202	5,054	11.3	10,671	13,376	3,025	5,730	12.8	22,151	49.4	32,822	73.2
15 2019	440.2	5,408	0	5,408	12.3	4,654	0	313	208	5,175	11.8	10,583	14,321	3,116	6,854	15.6	22,263	50.6	32,846	74.6
16 2020	458.1	5,273	0	5,273	11.5	4,794	0	292	214	5,300	11.6	10,573	15,073	3,209	7,710	16.8	23,929	52.2	34,503	75.3
17 2021	446.9	5,036	0	5,036	11.3	4,938	0	271	220	5,429	12.1	10,466	15,069	3,306	7,909	17.7	23,453	52.5	33,918	75.9
18 2022	490.4	4,948	0	4,948	10.1	5,086	0	250	227	5,563	11.3	10,512	14,881	3,405	7,774	15.9	26,085	53.2	36,597	74.6
19 2023	493.1	4,780	0	4,780	9.7	5,239	0	230	234	5,702	11.6	10,482	16,417	3,507	9,443	19.1	27,033	54.8	37,514	76.1
20 2024	506.0	4,629	0	4,629	9.1	5,396	0	209	241	5,845	11.6	10,474	17,191	3,612	10,329	20.4	28,339	56.0	38,813	76.7
Net Present Value		68,583	0	68,583		37,017	0	4,440	1,651	43,108		111,691	86,910	24,781	0		240,853		352,544	
Nominal Levelized Cost ($/MWh)					13.8						8.7					0.0		48.5		71.0
Real Levelized Cost ($/MWh)					11.2						7.0					0.0		39.2		57.4

50% of Coyote Springs 2 (CCCT and Duct Burner)—Annual Value

Economic Analysis Detail

Assumptions

Installed Cost	69,986	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	209.96	2004 $000s	Nominal Discount	8.22	percent
Installed Cost	492	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.50	percent
Project Capacity	142.26	MW	Escalation Rates			General Inflation	3.0	percent			
Heat Rate	7,341	Btu/kWh	Fixed O&M	3.0	percent	Option Value	2,000	2004 $000s			
Gas Usage Rate	25.1	000s dth/day	Transportation	3.0	percent						

			Fixed Costs																		
			Capital Recovery and Miscellaneous				Operations & Maintenance														
	Year	Energy (GWh)	Project ($000s)	Fixed Chrg. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Fixed ($000s)	Gtrans ($000s)	PrTax ($000s)	Insur. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Total Fixed Costs ($000s)	Operating Margin ($000s)	Option Value ($000s)	Net Project Benefit ($000s)	Net Project Benefit ($/MWh)	Total Variable Costs ($000s)	Total Variable Costs ($/MWh)	Total Project Costs ($000s)	Total Project Costs ($/MWh)
1	2005	718.1	13,295	0	13,295	18.5	3,077	0	954	216	4,247	5.9	17,542	3,606	2,060	(11,876)	(16.5)	31,102	43.3	48,644	67.7
2	2006	776.2	12,998	0	12,998	16.7	3,169	0	921	223	4,313	5.6	17,311	4,629	2,122	(10,561)	(13.6)	32,785	42.2	50,096	64.5
3	2007	744.3	12,442	0	12,442	16.7	3,264	0	888	229	4,382	5.9	16,824	4,169	2,185	(10,469)	(14.1)	30,041	40.4	46,864	63.0
4	2008	749.4	12,005	0	12,005	16.0	3,362	0	855	236	4,454	5.9	16,459	4,036	2,251	(10,172)	(13.6)	29,432	39.3	45,891	61.2
5	2009	928.9	11,734	0	11,734	12.6	3,463	0	822	243	4,529	4.9	16,263	12,902	2,319	(1,043)	(1.1)	31,960	34.4	48,223	51.9
6	2010	943.1	11,401	0	11,401	12.1	3,567	0	789	251	4,607	4.9	16,009	15,253	2,388	1,632	1.7	32,888	34.9	48,896	51.8
7	2011	923.5	11,004	0	11,004	11.9	3,674	0	756	258	4,689	5.1	15,693	16,723	2,460	3,490	3.8	32,189	34.9	47,882	51.8
8	2012	932.4	10,680	0	10,680	11.5	3,784	0	724	266	4,774	5.1	15,454	17,475	2,534	4,555	4.9	32,744	35.1	48,197	51.7
9	2013	875.4	10,312	0	10,312	11.8	3,898	0	691	274	4,863	5.6	15,175	16,814	2,610	4,249	4.9	32,261	36.9	47,436	54.2
10	2014	862.5	9,924	0	9,924	11.5	4,015	0	658	282	4,955	5.7	14,879	17,383	2,688	5,192	6.0	31,310	36.3	46,189	53.6
11	2015	885.2	9,654	0	9,654	10.9	4,135	0	625	291	5,051	5.7	14,705	18,071	2,768	6,134	6.9	32,825	37.1	47,530	53.7
12	2016	907.9	9,440	0	9,440	10.4	4,259	0	592	299	5,151	5.7	14,590	18,095	2,852	6,356	7.0	35,501	39.1	50,091	55.2
13	2017	928.3	9,167	0	9,167	9.9	4,387	0	559	308	5,255	5.7	14,422	19,391	2,937	7,907	8.5	36,958	39.8	51,380	55.3
14	2018	901.0	8,803	0	8,803	9.8	4,519	0	526	318	5,363	6.0	14,165	18,582	3,025	7,442	8.3	36,489	40.5	50,654	56.2
15	2019	900.5	8,495	0	8,495	9.4	4,654	0	493	327	5,475	6.1	13,970	19,882	3,116	9,028	10.0	37,211	41.3	51,181	56.8
16	2020	927.8	8,246	0	8,246	8.9	4,794	0	460	337	5,591	6.0	13,837	21,278	3,209	10,651	11.5	39,136	42.2	52,973	57.1
17	2021	933.3	7,985	0	7,985	8.6	4,938	0	428	347	5,712	6.1	13,697	20,462	3,306	10,070	10.8	40,818	43.7	54,515	58.4
18	2022	934.9	7,732	0	7,732	8.3	5,086	0	395	357	5,838	6.2	13,570	19,666	3,405	9,501	10.2	42,657	45.6	56,227	60.1
19	2023	950.7	7,433	0	7,433	7.8	5,239	0	362	368	5,968	6.3	13,401	22,170	3,507	12,276	12.9	43,538	45.8	56,939	59.9
20	2024	951.8	7,160	0	7,160	7.5	5,396	0	329	379	6,104	6.4	13,264	22,878	3,612	13,226	13.9	44,955	47.2	58,219	61.2
Net Present Value			104,442	0	104,442		37,017	0	6,997	2,602	46,615		151,058	126,276	24,781	0		325,058		476,115	
Nominal Levelized Cost ($/MWh)						12.2						5.5					0.0		38.1		55.8
Real Levelized Cost ($/MWh)						9.9						4.4					0.0		30.8		45.1

50% of Coyote Springs 2 (CCCT and Duct Burner)—Annual Value

Economic Analysis Detail

Assumptions

Installed Cost	77,576	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	232.73	2004 $000s	Nominal Discount	8.22	percent
Installed Cost	545	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.50	percent
Project Capacity	142.26	MW	Escalation Rates			General Inflation	3.0	percent			
Heat Rate	7,341	Btu/kWh	Fixed O&M	3.0	percent	Option Value	2,000	2004 $000s			
Gas Usage Rate	25.1	000s dth/day	Transportation	3.0	percent						

		Fixed Costs																			
		Capital Recovery and Miscellaneous				Operations & Maintenance															
Year	Energy	Project	Fixed Chrg.	Total Costs		Fixed	Gtrans	PrTax	Insur.	Total Costs		Total Fixed Costs	Operating Margin	Option Value	Net Project Benefit		Total Variable Costs		Total Project Costs	
	(GWh)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($/MWh)	($000s)	($/MWh)
1 2005	809.1	14,320	0	14,320	17.7	3,077	0	1,057	240	4,374	5.4	18,694	4,815	2,060	(11,819)	(14.6)	26,104	32.3	44,797	55.4
2 2006	872.8	13,987	0	13,987	16.0	3,169	0	1,021	247	4,437	5.1	18,424	6,525	2,122	(9,778)	(11.2)	27,907	32.0	46,331	53.1
3 2007	895.5	13,574	0	13,574	15.2	3,264	0	984	254	4,503	5.0	18,078	7,757	2,185	(8,135)	(9.1)	29,129	32.5	47,207	52.7
4 2008	919.8	13,215	0	13,215	14.4	3,362	0	948	262	4,572	5.0	17,787	10,239	2,251	(5,297)	(5.8)	31,072	33.8	48,859	53.1
5 2009	928.9	12,823	0	12,823	13.8	3,463	0	911	270	4,645	5.0	17,467	12,902	2,319	(2,247)	(2.4)	31,960	34.4	49,427	53.2
6 2010	943.1	12,449	0	12,449	13.2	3,567	0	875	278	4,720	5.0	17,169	15,253	2,388	472	0.5	32,888	34.9	50,056	53.1
7 2011	923.5	12,011	0	12,011	13.0	3,674	0	839	286	4,799	5.2	16,810	16,723	2,460	2,372	2.6	32,189	34.9	49,000	53.1
8 2012	932.4	11,648	0	11,648	12.5	3,784	0	802	295	4,881	5.2	16,529	17,475	2,534	3,479	3.7	32,744	35.1	49,273	52.8
9 2013	875.4	11,243	0	11,243	12.8	3,898	0	766	304	4,967	5.7	16,210	16,814	2,610	3,214	3.7	32,261	36.9	48,471	55.4
10 2014	862.5	10,817	0	10,817	12.5	4,015	0	729	313	5,057	5.9	15,874	17,383	2,688	4,197	4.9	31,310	36.3	47,184	54.7
11 2015	885.2	10,509	0	10,509	11.9	4,135	0	693	322	5,150	5.8	15,659	18,071	2,768	5,180	5.9	32,825	37.1	48,484	54.8
12 2016	907.9	10,257	0	10,257	11.3	4,259	0	656	332	5,247	5.8	15,504	18,095	2,852	5,442	6.0	35,501	39.1	51,005	56.2
13 2017	928.3	9,947	0	9,947	10.7	4,387	0	620	342	5,349	5.8	15,295	19,391	2,937	7,033	7.6	36,958	39.8	52,253	56.3
14 2018	901.0	9,544	0	9,544	10.6	4,519	0	583	352	5,454	6.1	14,998	18,582	3,025	6,609	7.3	36,489	40.5	51,487	57.1
15 2019	900.5	9,199	0	9,199	10.2	4,654	0	547	363	5,564	6.2	14,763	19,882	3,116	8,235	9.1	37,211	41.3	51,974	57.7
16 2020	927.8	8,912	0	8,912	9.6	4,794	0	510	373	5,678	6.1	14,590	21,278	3,209	9,898	10.7	39,136	42.2	53,726	57.9
17 2021	933.3	8,613	0	8,613	9.2	4,938	0	474	385	5,796	6.2	14,410	20,462	3,306	9,358	10.0	40,818	43.7	55,228	59.2
18 2022	934.9	8,322	0	8,322	8.9	5,086	0	437	396	5,920	6.3	14,242	19,666	3,405	8,829	9.4	42,657	45.6	56,899	60.9
19 2023	950.7	7,986	0	7,986	8.4	5,239	0	401	408	6,048	6.4	14,033	22,170	3,507	11,644	12.2	43,538	45.8	57,571	60.6
20 2024	951.8	7,675	0	7,675	8.1	5,396	0	365	420	6,181	6.5	13,856	22,878	3,612	12,635	13.3	44,955	47.2	58,811	61.8
Net Present Value		113,491	0	113,491		37,017	0	7,756	2,884	47,656		161,148	136,366	24,781	0		316,750		477,898	
Nominal Levelized Cost ($/MWh)					12.9						5.4					0.0		36.1		54.4
Real Levelized Cost ($/MWh)					10.4						4.4					0.0		29.2		44.0

50% of Coyote Springs 2 (CCCT and Duct Burner)—Annual Value

Economic Analysis Detail

Assumptions

Installed Cost	45,665	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	136.99	2004 $000s	Nominal Discount	8.22	percent
Installed Cost	321	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.50	percent
Project Capacity	142.26	MW	Escalation Rates			General Inflation	3.0	percent			
Heat Rate	7,341	Btu/kWh	Fixed O&M	3.0	percent	Option Value	2,000	2004 $000s			
Gas Usage Rate	25.1	000s dth/day	Transportation	3.0	percent						

		Fixed Costs: Capital Recovery and Miscellaneous				Fixed Costs: Operations & Maintenance									Net				Total Project	
Year	Energy	Project	Fixed Chrg.	Total Costs		Fixed	Gtrans	PrTax	Insur.	Total Costs		Total Fixed Costs	Operating Margin	Option Value	Project Benefit		Total Variable Costs		Costs	
	(GWh)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($/MWh)	($000s)	($/MWh)
1 2005	718.1	9,244	0	9,244	12.9	3,077	0	622	141	3,841	5.3	13,084	3,594	2,060	(7,430)	(10.3)	31,113	43.3	44,197	61.5
2 2006	729.5	9,024	0	9,024	12.4	3,169	0	601	145	3,916	5.4	12,940	3,903	2,122	(6,915)	(9.5)	31,632	43.4	44,571	61.1
3 2007	740.0	8,681	0	8,681	11.7	3,264	0	579	150	3,994	5.4	12,675	3,856	2,185	(6,634)	(9.0)	30,221	40.8	42,896	58.0
4 2008	754.8	8,395	0	8,395	11.1	3,362	0	558	154	4,075	5.4	12,470	3,949	2,251	(6,270)	(8.3)	29,769	39.4	42,238	56.0
5 2009	581.4	7,913	0	7,913	13.6	3,463	0	537	159	4,159	7.2	12,071	7,003	2,319	(2,750)	(4.7)	25,002	43.0	37,073	63.8
6 2010	542.5	7,640	0	7,640	14.1	3,567	0	515	164	4,246	7.8	11,886	8,532	2,388	(966)	(1.8)	24,407	45.0	36,293	66.9
7 2011	519.3	7,374	0	7,374	14.2	3,674	0	494	168	4,336	8.3	11,710	9,899	2,460	649	1.2	23,778	45.8	35,488	68.3
8 2012	499.2	7,114	0	7,114	14.3	3,784	0	472	174	4,430	8.9	11,544	10,791	2,534	1,781	3.6	23,086	46.2	34,629	69.4
9 2013	472.4	6,835	0	6,835	14.5	3,898	0	451	179	4,527	9.6	11,362	11,534	2,610	2,782	5.9	21,912	46.4	33,274	70.4
10 2014	439.2	6,530	0	6,530	14.9	4,015	0	429	184	4,628	10.5	11,159	12,297	2,688	3,826	8.7	20,185	46.0	31,344	71.4
11 2015	466.4	6,389	0	6,389	13.7	4,135	0	408	190	4,733	10.1	11,122	12,809	2,768	4,456	9.6	21,861	46.9	32,982	70.7
12 2016	482.6	6,239	0	6,239	12.9	4,259	0	386	195	4,841	10.0	11,080	13,044	2,852	4,816	10.0	23,348	48.4	34,428	71.3
13 2017	497.3	6,086	0	6,086	12.2	4,387	0	365	201	4,953	10.0	11,039	13,826	2,937	5,723	11.5	24,780	49.8	35,819	72.0
14 2018	498.0	5,853	0	5,853	11.8	4,519	0	343	207	5,069	10.2	10,923	13,770	3,025	5,873	11.8	24,530	49.3	35,452	71.2
15 2019	487.2	5,634	0	5,634	11.6	4,654	0	322	213	5,190	10.7	10,824	14,896	3,116	7,188	14.8	24,567	50.4	35,391	72.6
16 2020	504.8	5,496	0	5,496	10.9	4,794	0	300	220	5,314	10.5	10,810	15,539	3,209	7,939	15.7	26,279	52.1	37,089	73.5
17 2021	504.1	5,278	0	5,278	10.5	4,938	0	279	226	5,443	10.8	10,722	15,682	3,306	8,266	16.4	26,347	52.3	37,068	73.5
18 2022	559.0	5,214	0	5,214	9.3	5,086	0	258	233	5,577	10.0	10,791	15,435	3,405	8,050	14.4	29,598	53.0	40,388	72.3
19 2023	551.9	5,020	0	5,020	9.1	5,239	0	236	240	5,715	10.4	10,734	16,899	3,507	9,671	17.5	30,132	54.6	40,866	74.0
20 2024	566.2	4,869	0	4,869	8.6	5,396	0	215	247	5,858	10.3	10,727	17,710	3,612	10,595	18.7	31,582	55.8	42,309	74.7
Net Present Value		70,895	0	70,895		37,017	0	4,565	1,697	43,280		114,174	89,393	24,781	0		256,602		370,776	
Nominal Levelized Cost ($/MWh)					13.2						8.1					0.0		47.8		69.1
Real Levelized Cost ($/MWh)					10.7						6.5					0.0		38.6		55.8

In addition to the basic value of the one-half portion of Coyote Springs 2 (CS2) combined cycle combustion turbine project captured in the Aurora hourly dispatch model, the Company also estimated the value that results from trading in and out of the fueled state for the CS2 project. When a natural gas plant is fueled, based on economics, it may later be un-fueled (electricity purchased and natural gas sold) when the relative market implied heat rate economics change. Subsequently, if the relative electric and natural gas prices again change, the plant may be fueled again. These "heat rate swaps" are driven by the changing relative forward price economics of the plant. These option value swap transactions add to the overall plant economics.

The Company developed a back-cast model to estimate some potential values for different historic data periods. The model output is an estimate of potential option values for half of the CS2 plant using different sets of historic data. The model used historical daily forward electric and natural gas price curves from the Company's power transaction records system (Nucleus). Mid-Columbia prices were used for electric power. Since the Company has tracked daily forward Rathdrum prices, and because those prices are close to natural gas prices at Stanfield, those prices were used for forward natural gas prices. Three different periods were modeled including a 37-month, a 25-month, and a 13-month period. Monthly flat forward electric and natural gas prices for each of the twelve forward months were captured for each trading day (typically five days per week) of the period being modeled. The plant's corresponding cost to generate was calculated using forward natural gas prices, estimated O&M costs and the plant's net heat rate[1]. The cost to generate ($/MWh) is calculated as follows:

(Net heat rate/1000) x (natural gas price/Dth) + (O&M cost/MWh)

For each trading day, a "generate vs. buy" comparison was made for each forward month between the cost to generate and market price of power. For any given forward month, the initial status of the plant is assumed to be off-line, or "unfueled." Therefore, the first decision that the model had to make is when to purchase fuel and sell electric energy, or "fuel" the plant. When the initial decision was made to fuel the plant for a forward month, the total margin value ($/MWh) was then calculated based on the following formula:

(Electric market price/MWh – cost to generate/MWh) x plant availability x hours in the month

As the model moved through the trading days, if the plant became uneconomic for a forward month for which was previously fueled, the model would unfuel the plant (sell natural gas and purchase electric power) and calculate the margin ($/MWh) based on the following formula:

(Cost to generate/MWh – electric market price/MWh) x plant capability x hours in the month

[1] Net hear rate includes the BPA transmission losses of 1.9% to deliver CS2 power to Avista's system or the Mid-Columbia.

As the model moved through the trading days, the state of the plant (fueled or unfueled) was tracked for each forward month. As opportunities arose, the plant was either unfueled or fueled based on the changing forward prices for the 12-month forward period. The model was limited to the extent it could only fuel or unfuel the plant when the value of the deal was greater than or equal to $1/MWh threshold.

Also, in order to avoid capturing value that was already accounted for in the Aurora hourly dispatch analysis, the status of the plant must always have been in an unfueled state before the forward month became the current month in order to avoid double counting. To ensure this, the model checked to see if the plant was in an unfueled state. If the plant was in a fueled state, then the value of the last fueling transaction was removed, including the value it created, in order to return the plant to the unfueled state.

Results for the three periods modeled for the second half of CS2 were as follows:

	7-1-01 thru 7-31-04	7-1-02 thru 7-31-04	7-1-03 thru 7-31-04
Total Value	$ 33,781,422	$ 12,955,663	$ 5,665,707
Average Value/month	$ 913,011	$ 518,227	$ 435,824
Average Value/year	$ 10,956,137	$ 6,218,718	$ 5,229,884

The Company chose to use $2 million per year as conservative value that would escalate with inflation over the period of the economic analysis.

CSII Acquisition Rate Impact Analysis
September 21, 2004 Update

Year	Revenue Reqment ($000s)	Rate Impact ($000)	Rate Impact (percent)
2005	450,000	10,499	2.3%
2006	468,000	9,188	2.0%
2007	486,720	9,179	1.9%
2008	506,189	8,920	1.8%
2009	526,436	401	0.1%
2010	547,494	(2,159)	-0.4%
2011	569,394	(3,983)	-0.7%
2012	592,169	(5,012)	-0.8%
2013	615,856	(4,493)	-0.7%
2014	640,490	(5,337)	-0.8%
2015	666,110	(6,278)	-0.9%
2016	692,754	(6,394)	-0.9%
2017	720,464	(7,877)	-1.1%
2018	749,283	(7,567)	-1.0%
2019	779,254	(8,965)	-1.2%
2020	810,425	(10,577)	-1.3%
2021	842,842	(9,855)	-1.2%
2022	876,555	(9,400)	-1.1%
2023	911,617	(12,093)	-1.3%
2024	948,082	(12,990)	-1.4%
	Net Present Values		
20 Years	***5,850,503***	***(5,744)***	-0.1%
5 Years	***1,923,151***	***31,563***	1.6%

NOTES:

1) Excludes potential Q2 revenues through 2008

2) Assumes $450MM base revenue requirement, escalating @ 4% per year.

EXHIBIT K

Navigant Consulting Analysis and Valuation

Application of Avista Corporation
Case No. AVU-E-05-1

Navigant Consulting Inc.

Review of Avista Valuation and Methodology

and

Independent Analysis and Valuation

of the

Coyote Springs II Facility

September 24, 2004

NAVIGANT
CONSULTING

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Introduction

Scope of Engagement – Coyote Springs II Asset Valuation

Review of Avista Methodology and Analysis

Navigant Consulting Inc. (NCI) was engaged to provide a review and assessment of Avista Corporation's internal valuation of the Coyote Springs II (CSII) combined cycle facility located in Morrow County, Oregon. Avista is currently in negotiations with Mirant to purchase Mirant's 50% interest in the facility, which Avista currently co-owns with Mirant.

NCI Independent Analysis and Valuation

In addition to providing an assessment of Avista's valuation methodology, Avista requested that NCI perform an independent valuation of the facility, including a base case valuation and a high and low scenario to the base case results. NCI's valuation results reflect the combined revenue components associated with intrinsic, or plant dispatch value, and extrinsic, or option value.

Comparable Market Asset Transactions

Avista has also requested that NCI provide applicable, public information pertaining to recent power plant transactions occurring in the Pacific Northwest and Western US region.

Executive Summary

NCI performed a review of Avista's valuation analyses and methodology, a review of recent generation transactions in the market, and performed an independent valuation of 50% of the Coyote Springs II facility.

Avista's base case results reflect a valuation of $66.7 million ($468/kW) for 50% of the CSII facility. NCI finds Avista's base case valuation reflects a reasonable valuation approach, methodology, and result.

Our review of recent generation transactions consummated in the Western US region reflects an average price of $569/kW for twenty-one transactions. NCI's independent analyses and valuation reflect a base case valuation of $67.2 million ($472/kW) for 50% of the CSII facility.

Based upon our review of the Avista analyses, our own independent analyses, and comparable generation transactions consummated in the market, NCI believes that Avista's negotiated purchase price of $62.5 million for 50% of the Coyote Springs II facility is reasonable and compares favorably to other transactions consummated in the regional market. The negotiated purchase price is below the Avista and NCI base case valuation results of $66.7 million and $67.2 million respectively, and below the average generation transaction price of $569/kW for the Western US region.

Review of Avista's Methodology and Analysis

Avista Fundamental Price Forecasting Process

As part of the overall scope to assess Avista's internal valuation process, NCI performed a review and assessment of the methodology that Avista employed to develop the fundamental valuation criteria and the results to ensure the approach was reasonable, and reviewed their financial models to determine the accuracy of their calculations. This process included discussions with Avista modeling personnel and subsequent evaluations to confirm that the described methodology was applied in the valuation process. NCI reviewed Avista's working spreadsheet models and discounted cash flow models to assess the reasonableness of Avista's overall valuation methodology and the accuracy of their modeling efforts. NCI did not perform an audit or confirmation of modeling algorithms, financial, or other assumptions as part of this assessment.

The key elements of NCI's assessment and review included (a) a comprehensive review of the fundamental pricing methodology used to determine intrinsic, or dispatch value, of the CSII facility; (b) an assessment of the methodology employed to determine extrinsic value; and (c) a review of the financial model that incorporated both the intrinsic and extrinsic valuations to determine an overall net present value based upon a twenty year study period.

Fundamental Power Pricing Methodology Overview

As the basis for the fundamental analysis performed for the CSII valuation, Avista utilized the production cost modeling results from their 2003 IRP process. For this process, Avista simulated the entire Western Electricity Coordinating Council (WECC) utilizing AURORA, an hourly chronological dispatch model that incorporates plant operating and cost characteristics and regional load profiles to simulate the operation of the electric system and derive a forecast of market clearing prices for each defined load region. To incorporate the effects of market uncertainty in the simulation process, Avista generated 200 sets of unique inputs to model 200 simulation iterations in AURORA, thus providing a comprehensive spectrum of potential outcomes given specific sensitivity assumptions. The average of these 200 simulations became the basis for the valuation that supported the valuation of the Coyote Springs facility.

After using AURORA to generate power prices on an hourly basis, Avista utilized AURORA as a dispatch model, using the generated power prices as fixed inputs and dispatching the CSII facility against these hourly prices, given plant fuel and other operational costs. The results from this process reflect the revenue, dispatch cost, and volumetric inputs into Avista's CSII financial spreadsheet model as one of five sensitivities performed in evaluating the CSII facility.

Post simulation analyses of the AURORA forecasted power-pricing results provided the framework for an additional analytical approach directed at evaluating the impacts of a range of potential outcomes on the CSII financial valuation. Avista analyzed the hourly pricing results from the AURORA model simulations to determine the implied market spark-spreads for each hour over a twenty-year period, reflecting the seasonal profiles and characteristics inherent to the simulation process. This analysis of the fundamental AURORA simulations was then incorporated into a process that developed a range of potential market spark-spreads under different scenarios and, from this process, modeled multiple sensitivities to determine the financial impacts on CSII through changing market implied heat rates, or spark-spreads, over time.

The process involved holding the power prices from the IRP simulation fixed through the study period, and effectively changing the market spark-spread profile (relative to the IRP results) by adjusting natural gas prices to reflect the characteristics of several potential market spark-spread trends. Key sensitivities included developing a flat and expanding market spark-spread profile, relative to the simulated results, and dispatching the CSII facility against each of these spark-spread scenarios within the AURORA model to determine the hourly dispatch volumes and overall revenue impacts for the CSII facility.

A range of potential market spark-spread profiles was developed using this process, incorporating the initial shape implicit in the IRP simulations as the framework for developing each scenario. Scenarios included spark-spread profiles reflecting market-based, discoverable prices that escalate with inflation; a flat spark-spread profile through the study period, and an expanding spark-spread profile over the study period.

The CSII base case scenario reflected a blended spark-spread profile, incorporating market-based spark-spreads as observed through the discoverable traded markets for power and gas through 2008, and incorporated the prospective spark-spread profile derived from the 2003 AURORA IRP simulation results from 2009 through the remainder of the fundamental valuation period.

Extrinsic Valuation Development Overview

Avista also included an extrinsic component to the revenue side of the CSII valuation, reflecting the additional value associated with optimizing the facility and associated commodity positions during the twenty-year time horizon.

Avista applied an empirical approach to reflect the potential value captured through arbitraging forward natural gas and power positions over time, reflecting the potential optimization associated with reversing fixed forward positions to capture differentials between forward and spot prices. This approach was developed through analyzing differences between forward and daily settlement prices for Mid C power and Rathdrum natural gas pricing (which tracks closely to Stanfield). Upon locking a forward power and gas position, the analysis sought to optimize these fixed commodity positions (forward power sales and natural gas purchases) relative to the resulting daily settlement prices. As the daily settlement data reflected an opportunity to reverse forward positions (power or gas) at a profit, the transaction was reversed and the potential profit calculated for that day. The annual sum of these potential monthly transactions became the basis for Avista's option or swap value for 2005, and this amount was carried forward and escalated at the assumed rate of inflation for the duration of the evaluation period.

Discounted Cash Flow Analysis Overview

Avista incorporated the intrinsic revenue results of AURORA modeling, spark-spread sensitivities, for both forward and fundamental pricing, as well as estimated extrinsic revenue into a 20 year discounted cash flow model to calculate the net present value associated with 50% of the CSII facility to derive a total base case valuation of $66.7 million.

Navigant Consulting Inc. Assessment of Avista's Methodology and Results

Intrinsic Valuation Methodology and Results

Avista's utilization of AURORA to develop a forecast of hourly fundamental power prices, as well as utilizing AURORA as a dispatch model to evaluate the CSII plant dispatch against various pricing scenarios, reflects a reasonable approach to developing a range of potential market scenarios and stressing an intrinsic valuation using an industry standard model. The model incorporates chronological economic dispatch logic with regional load dynamics to dispatch system resources on an hourly basis, producing an hourly marginal price to service load for each modeled region. The process that Avista employed to simulate 200 discrete sensitivities in AURORA provided a comprehensive range of possible outcomes that were averaged into a single hourly point estimate, effectively capturing a significant range of sensitivities that may impact, either positively or negatively, regional power prices and the resultant CSII asset valuation.

Additionally, NCI has reviewed Avista's methodology for developing their spark-spread profile analyses and finds the approach to be both reasonable and effective in capturing the impacts of a range of potential market spark-spread scenarios. Approaching the CSII valuation in light of stressing prospective plant dispatch against a range of potential market spark-spreads (e.g. shaped, flat, and expanding profiles) affords the ability to quickly assess potential structural changes in market implied heat rates that could result from multiple and/or compounding factors.

NCI finds that Avista's intrinsic valuation methodology and results reflect a reasonable approach and outcome for a range of scenarios to base their valuation of the CSII facility.

Extrinsic Valuation Methodology and Results

Avista included swap or arbitrage value in their valuation that reflects the potential value that could have resulted from arbitraging the difference between entering into a fixed forward position in both natural gas and power, as reflected in the forwards price, and any subsequent daily opportunities to reverse these fixed positions at a profit, relative to the actual settlement prices.

For their analysis, Avista utilized a back-casting methodology to estimate the potential value arising from unwinding forward positions at a profit in the daily market. Their model incorporated historical forward electric and natural gas prices and the corresponding daily settlement prices over several pricing periods. For each trading day after the forward position was fixed, a buy vs. generate analysis was made between the cost to generate electricity from the CSII facility and the market price of power. If the plant reflected an uneconomic operating profile, relative to daily power and gas settlement prices, the model would reverse these forward positions (e.g. sell purchased natural gas and purchase electric power from the market to fulfill the power sale obligation) and calculate the resulting margin or net savings.

Three different pricing intervals were modeled including a 37-month, a 25-month, and a 13-month period, and the results for these three historical intervals for 50% of the CSII facility ranged between $5 and $11 million annually. Avista included $2 million in annual swap value that escalates with inflation over the study period in their valuation of CSII.

NCI believes that historical observations are very valuable and provide a reasonable basis for potential near-term profit-maximizing opportunities. However, to forecast extrinsic value beyond the near-term horizon, and to maintain continuity between intrinsic and extrinsic valuation methodologies, NCI recommends a fundamental approach to extrinsic valuation as the preferred framework for forecasting value over the study period.

Arbitrage reflects a risk-neutral transaction environment in which the underlying premise assumes forward positions for power and natural gas that are hedged for the duration of the valuation period. Reversing these fixed positions to capture profit above the original transaction value, through a series of risk-neutral transactions when feasible, reflects an underlying assumption that the plant is hedged, either bilaterally or in the forward market, through the study period. If an arbitrage methodology is employed to determine extrinsic value, then the intrinsic valuation should also reflect a forward hedged position. Applying a merchant or spot market approach to the intrinsic valuation methodology requires similar treatment to derive an extrinsic valuation; the methodologies for intrinsic and extrinsic valuation should reflect a consistent view of the underlying position assumed, either hedged or open. Additionally, assessing the potential for prospective arbitrage value based solely upon historical data, and the opportunities reflected in that data, are reasonable for the near-term but do not provide a fundamental framework for estimating value for the outer years of the study period.

While such historical observations are very valuable and reflect a reasonable basis for potential near-term profit-maximizing opportunities, NCI recommends a fundamental analysis approach incorporating both historical and prospective data to provide a more robust framework to forecast extrinsic value for periods extending beyond the near-term. NCI performed a fundamental extrinsic analysis as part of its valuation of CSII, and a complete discussion of this methodology is provided later in this report.

Discounted Cash Flow Valuation Assessment

NCI reviewed Avista's discounted cash flow analysis to determine that (a) the results from the intrinsic and extrinsic valuations were included in the cash flow assumptions, (b) to assess the reasonableness and accuracy of the cash flow model, and (c) to review the inclusion of other cost components in the valuation.

In addition to the revenue assumptions derived from intrinsic and extrinsic sources, the cash flow model included assumptions relating to fixed operating and A&G costs, depreciation, interest expense, income tax, property taxes, miscellaneous revenue and expense items, revenue requirements, and applicable escalation and discount rates. NCI did not audit or confirm these assumptions and does not present an opinion as to the accuracy or reasonableness of these assumptions; they reflect information provided by Avista's corporate and regulatory functional groups.

In reviewing the discounted cash flow analysis, Avista's valuation includes fixed O&M on an annual basis that reflects, in part, a long-term service agreement with the OEM. Avista's valuation does not reflect any other capital improvements to the facility during the study period, and does not include any terminal or residual value associated with the CSII asset at the end of the study period.

Regarding residual or terminal value, even though scheduled and major maintenance intervals are covered through a service agreement, typically these agreements are structured to maintain the normal operation of the plant through the duration of the agreement, and do not reflect a final maintenance interval that essentially leaves the plant owner with a newly overhauled facility at the end of the term. In the absence of analysis to determine the potential condition of the facility at the end of the study period in light of the terms of the service agreement, NCI agrees with Avista's approach to assign no terminal or residual value to the facility.

NCI finds Avista's approach and results to discounting cash flows over the study period to be reasonable and reflects the net present value of discounting all revenue and cost cash flow components at the assumed discount rate through the study period.

Navigant Consulting Inc. Independent Analysis and Valuation

NCI intrinsic valuation methodology overview

Developing energy price forecasts through modeling the dispatch and operation of generating assets requires a sophisticated and detailed market simulation tool. For this simulation process, NCI utilizes PROSYM for preparing its forecast of energy clearing prices and individual plant valuation assessments. PROSYM is a detailed chronological production-cost model designed to simulate plant bidding behavior and calculate resulting energy clearing prices. PROSYM integrates generation and transmission analyses, and has been designed for use in wholesale market price forecasting, unit profitability assessment, transmission congestion management, and system cost control studies. PROSYM offers detailed unit generation and revenue forecasts, unit bidding strategy development, regional and bus level location market price forecasts, transmission congestion and expansion studies, FTR bidding and valuation, emission allowance utilization and price impacts, maintenance planning and optimization, reliability assessment, and market price volatility assessment.

The Intrinsic Valuation Discussion, located in the appendices, provides a comprehensive overview of NCI's intrinsic valuation methodology and assumptions.

NCI extrinsic (option) valuation methodology overview

In addition to developing fundamental energy price forecasts through modeling security-constrained economic dispatch and operation of generating assets utilizing PROSYM, NCI has developed a sophisticated approach to modeling the prospective spread option value of a power plant utilizing a monte carlo simulation process that incorporates prospective pricing developed in the intrinsic valuation process as an input to evaluate the overall time value of the open, underlying commodity positions through the study period. Since the majority of option value is limited to peak operational hours, NCI's option value methodology reflects the 5 day, 16 hour interval of a typical week production cycle as reflected from the PROSYM pricing results.

Key inputs into NCI's option valuation model include:

- Daily power prices – hourly results from PROSYM simulation model are used as the basis for daily peak prices.
- Monthly natural gas prices – inputs utilized in the PROSYM model are reflected in the option valuation model.
- Correlation between power and natural gas prices – Correlations were calculated between Mid C and Stanfield daily settlements from August 2001 through July 2004 (the non-crisis period) and represent the going forward correlation assumption for the study period.
- Standard deviation of power and natural gas prices – For the CSII valuation, NCI utilized a relative standard deviation methodology to develop prospective

volatility (as measured by standard deviation). This methodology provides a reasonable framework to develop prospective standard deviations for daily power and natural gas prices as reflected by the historical standard deviation of Mid C and Stanfield daily settlements from August 2001 through July 2004 (the non-crisis period).

- Mean reversion assumption – Daily power and natural gas prices within each month are correlated to reflect mean reversion of prospective daily prices within the simulation process.
- Lognormal distribution of prices – NCI assumes a lognormal distribution of underlying prices for power and natural gas.
- Plant operating characteristics – Plant operational parameters, including capacity, heat rates, and variable O&M (including applicable escalation).

These key input assumptions are correlated and simulated in a daily Monte Carlo model for each year of the study period. The plant is struck, on a 16-hour basis, against the stochastic pricing results (power and natural gas) occurring from random draws of daily power and natural gas prices. When the plant is essentially in-the-money, relative to the stochastically generated power and natural gas prices, the option is struck and the daily results are tabulated. The model defines extrinsic value as the positive difference between the daily static intrinsic results and the stochastic modeling results occurring through 5,000 simulated iterations.

The result is a mean estimation of annual option value that essentially reflects a forward start theory that avoids the compounding effects of escalating volatility resulting over time. Additionally, the methodology remains consistent with the intrinsic valuation approach that reflects an unhedged, merchant valuation through the study period.

NCI Independent Valuation Results

The following chart depicts NCI's independent valuation results for 50% of the Coyote Springs II facility, reflecting intrinsic and extrinsic value, discounted consistent with Avista's net present value methodology and applicable financial assumptions:

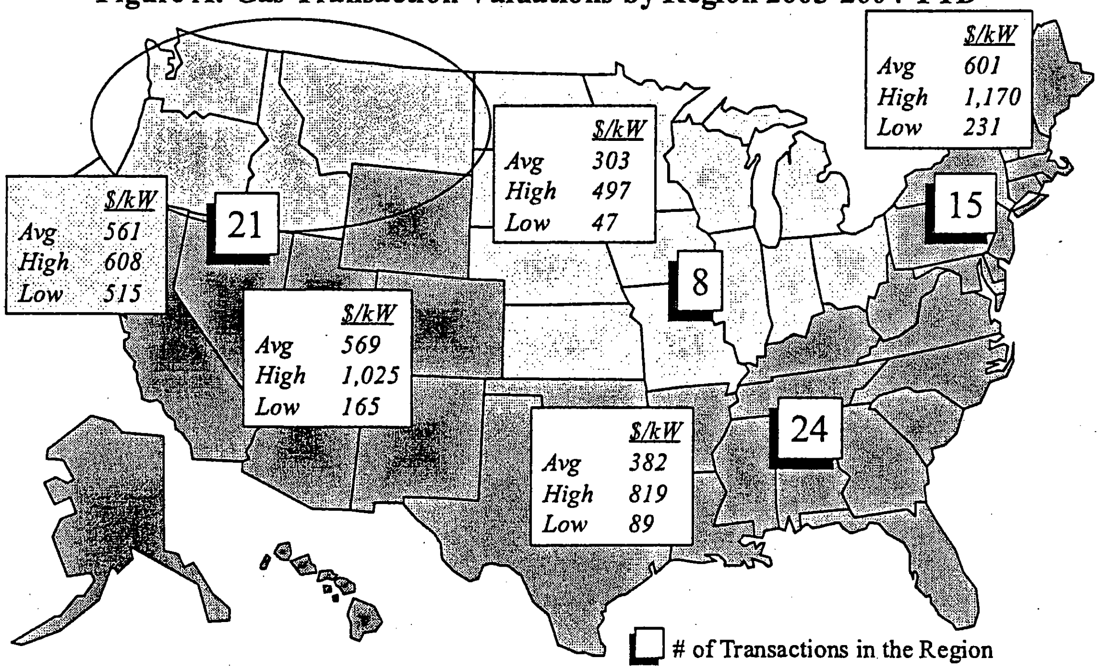
Scenario	NPV ($1,000) based upon Avista pro forma structure	$/kW
Base Case	$67,187	$472
High Scenario	$111,053	$781
Low Scenario	$34,161	$240

Comparable Market Transaction Data

Background

Approximately 68 separate generation asset transactions have taken place since January 2003. While many of these transactions have involved multiple facilities, the majority of the deals have been for single facility locations. Of these deals, twenty-one have occurred in the western portion of the U.S. Almost half of those transactions involved facilities located in California. The majority of generation asset transactions have occurred in the southern region of the U.S with the central states having experienced the fewest number of plants changing hands (See Figure A). Among the facilities that have been sold over the last twenty months, forty-three of the sixty-eight transactions that have taken place involved a gas-fired facility (63%). The remaining 37% consisted of a mix of coal (15%), nuclear (7%), wind (6%), geothermal (6%), and hydro (3%) resources.

Figure A: Gas Transaction Valuations by Region 2003-2004 YTD



The value of gas asset transactions continues to vary widely depending on a number of factors including the physical plant location and the presence and duration of off-take agreements. Gas asset transactions that include long-term purchase contracts have been going at nearly twice the price of pure merchant assets. The national average for gas asset transactions has been $520/kW on a nominal basis during this period. In the western half of the U.S., the average value of these transactions has been $569/kW. Regional differences in the value of individual gas plants are directly correlated with the forecasted trajectory of electricity market prices. In the largely coal dominated regions of the Midwest and South, there are fewer perceived opportunities to dispatch gas-fired facilities due to the reduced number of hours that gas is expected to be on the margin.

This is in contrast to the Pacific Northwest where the volatility of hydro availability has continued to provide opportunities for the dispatch of gas-fired facilities. The higher valuations in the $500 to $600/kW range for gas assets in this region suggest this is the market's perception of where prices are expected to move in the future.

Specific deals in the Pacific Northwest have been limited relative to other parts of the country. Since early 2003, there were only four separate asset transactions that occurred (See Table 1). Three out of the four involved the transfer of gas assets between the respective buyer and seller. The two gas transactions where the terms of the deal were disclosed indicated an average valuation of about $560/kW.

Table 1: List of Recent Pacific Northwest Generation Asset Transactions

Asset(s)	State(s)	Fuel Type	MW	$/kW	Seller	Buyer	PPA?	Date (Announcement)	Total Deal Value $M
Klondike	OR	Wind	24	$ 700	Golden NW Aluminum (Brett Wilcox)	Pacificorp	LT	1/30/2003	16.8
Tenaska Frontier, Ferndale, Ulch, Cogen	TX, WA, Pakistan	Gas	132	n/a	Dynegy	Tenaska	LT	7/1/2003	Not disclosed
Frederickson	WA	Gas	125	$ 608	EPCOR	Puget Sound Energy		10/22/2003	76
12 plants	NJ, NY, FL, PA, OR, MA, CO	Wind / Gas / Coal	1,082	$ 515	NEGT	(Denali Power LLC) Caithness, ArcLight		8/2/2004	557
Average				$ 608					

Conclusion

Avista's base case valuation of $66.7 million ($468/kW) for the remaining 50% of Coyote Springs II, reflects a reasonable valuation for this facility and compares favorably to the other transactions consummated in the Pacific Northwest, which have averaged $561/kW. However, the number of comparable transactions in the Pacific Northwest is severely limited and there are not enough deals in this specific market to develop a sufficient data set. Therefore, it is more appropriate to compare this purchase price to the broader western region, in which twenty-one comparable transactions have taken place during this period. That comparison suggests that Avista's valuation of Coyote Springs II is reasonable when compared to this broader market, in which transactions have averaged approximately $569/kW.

NCI's independent analyses and base case valuation results reflect a value of $67.2 million ($472/kW) for 50% of the Coyote Springs II facility, and suggests that this reflects a reasonable outcome based upon (a) the assumptions underlying NCI's security-constrained economic dispatch of the WECC electrical system to determine the intrinsic value associated with operating the CSII facility within this market, and (b) the results of combining the forecasted results from the security-constrained economic dispatch with historical data from the region to forecast the potential extrinsic value that may be realized in this market given these underlying assumptions and methods.

Therefore, based upon our review of the Avista analyses, our own independent analyses, and comparable generation transactions consummated in the market, NCI believes that Avista's negotiated purchase price of $62.5 million for 50% of the Coyote Springs II facility is reasonable. The negotiated purchase price is below the Avista and NCI base case valuation results of $66.7 million and $67.2 million respectively.

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Appendices

NCI Fundamental Simulation Scenario Assumptions

Scenario 1 – Bearish power prices and generation investment conditions

Economy and Electricity Demand - low growth

Under this scenario, NCI assumed slow economic growth during the initial three years of the study period. Electricity demand growth will also be stagnant reflecting expected correlation with a slow economy. For this scenario, we assumed zero growth in electricity demand for the first study year, one-half of the base case growth rate for the second study year, with resumption of the base case growth rate in the third and subsequent study period years.

Power Supply

In the interest of conservatism, despite reduced electricity demand, this scenario will assume the same power supply base as that used in the base case.

Fuel Prices

To reflect bearish power price conditions, fuel prices (natural gas and oil) are lower under this scenario than that seen in the base case (mixed impact on generator profitability, but generally negative for combined-cycle units in the WECC). Natural gas prices are 20% lower than the base case assumptions across all months/years, which reflects approximately one standard deviation based on historical natural gas price performance.

Scenario 2 – Bullish power prices and generation investment conditions

Economy and Electricity Demand - high growth

Under this scenario, NCI assumed more rapid economic growth during the initial three years of the study period. Electricity demand growth is also higher, reflecting expected correlation with an expanding economy. For this scenario, we assumed higher growth in regions where prospective population growth is expected to be strongest (Southwest, CA). A two percent higher electricity demand growth rate was assumed in this scenario than in the base case for the first study year, 1.5 percent higher in the second study year, and 1 percent higher in the third study year. In regions with stronger population growth, we assumed an additional 0.5% to the growth demand growth rates for the first five years of the study. In subsequent years, electricity demands grow at the base case growth rates for the relevant years.

The market is allowed to benefit from power prices that are higher than required to attract new entry for a period of four years between 2010 and 2014, and reverts toward the nominal cost of new entrant economics beyond this over-recovery period. This assumption reflects the potential reluctance of participants to make capital investments until market prices remain above the investment threshold for an extended period.

Power Supply

In this scenario, NCI mothballs/retires generating units (other than peaking units required to maintain system integrity/reserve margins) that do not earn adequate profits in the first 5 study years. Adequate profits were measured as an operating loss less than $10/kW year. In this scenario, we also implemented a delayed entry response, such that new entry would not occur until two years after power prices have been high enough to sustain investment profitability for new projects.

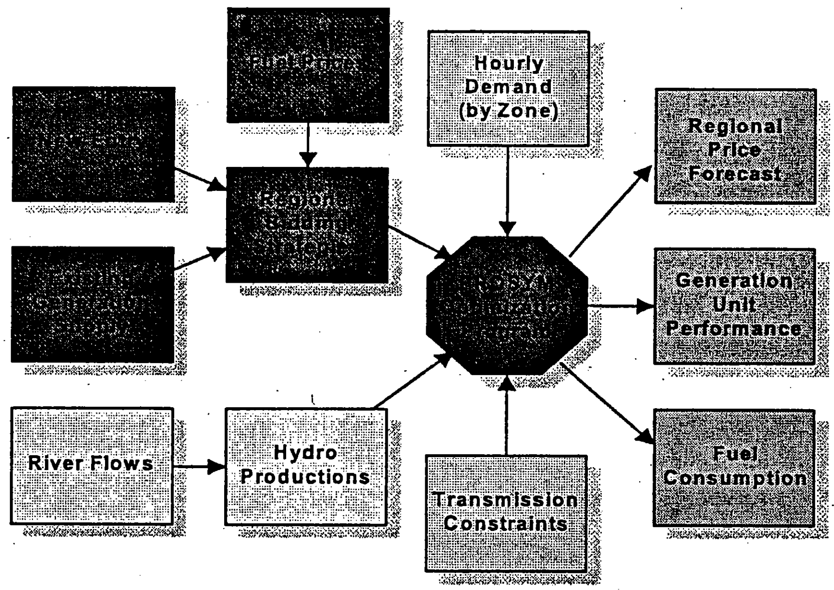
Fuel Prices

To reflect bullish power price conditions, fuel prices (natural gas and oil) are higher under this scenario than in the base case (mixed impact on generator profitability, but generally increased profits for combined-cycle units operating in the WECC). Natural gas prices under this scenario are 20% higher than in the base case, which reflects approximately one standard deviation based on historical price performance.

NCI Intrinsic Valuation Discussion

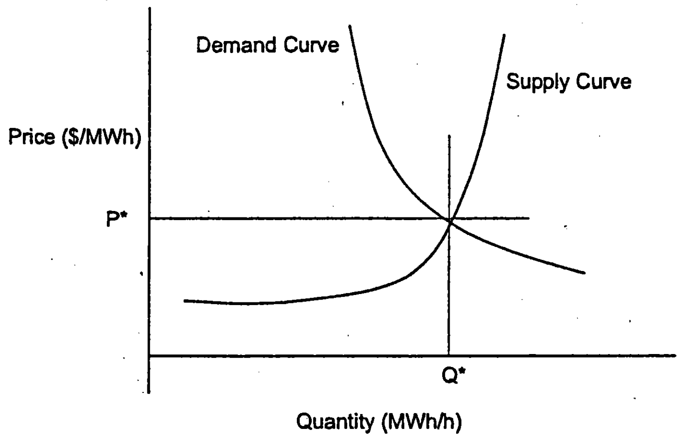
Using PROSYM, an hourly simulation is performed with sufficient detail related to the subject market area and neighboring areas to ensure that bilateral transactions and economic energy purchases are captured in the marginal clearing price calculation. The diagram below and subsequent discussion provides an overview of the energy simulation process.

Overview of Primary Inputs and Simulation Outputs



Translating the energy-clearing price calculation method described above into fundamental economic theory, the energy-clearing price calculated for any given hour reflects the price at the intersection of the supply and demand curves for energy in that hour, as illustrated below. The marginal energy-clearing price is calculated for each separate power market and constrained transmission area, as dictated by the prevailing transmission constraints for that hour.

Illustration of Hourly Energy-clearing Price Process



In the above figure, the hourly clearing price P*, represents the bid price of the unit of supply needed to meet the last increment of the total system demand of Q*. In effect, the PROSYM model prepares energy market supply and demand curves similar to those illustrated above for each of the 8,760 hours for each year of analysis, in each case calculates the clearing price at the intersection of the supply and demand curves. Thus, the algorithm used by the PROSYM model is consistent with the fundamental economic theory of supply and demand equilibrium that underlies the anticipated market behavior in the bid-based energy market in various restructured markets.

The following provides an overview of the modeling assumptions used by NCI in developing the fundamental pricing used in the Coyote Springs II asset valuation. For each of these assumptions, NCI relies on the most recent, reliable, and objective information in preparing this assessment.

1. Demand/Energy Forecasts

NCI relies upon a number of sources for its peak demand and energy forecasts. In regions where ISO-prepared demand forecasts are unavailable, we generally rely upon the demand forecasts submitted to the regional reliability councils as part of the OE-411 filings. In that case, the control area operators within each respective region prepare the underlying demand forecasts. In limited cases, NCI obtains demand forecasts directly from load-serving entities operating in a given region, or prepares a load forecast independently. The demand forecasts underlying the projections are weather-normalized so that extreme events are not reflected. The forecasts generally assume constant load factors unless a given load-serving entity has projected significant changes in its customer's consumption profiles.

2. Hourly Load Profiles

The PROSYM model requires hourly load information for each of the various regional control areas included in the subject analysis. NCI relies on the most recent data information available for hourly load representation, and is derived from the respective FERC Form No. 714 filings for many of the U.S. power systems, and other regulatory filings for the Canadian utility systems. Where data is not readily available, NCI relies on information contained in the PROSYM database, scaled appropriately to reflect demand and energy growth. PROSYM derives hourly load profiles by averaging five years of actual hourly loads for each utility taking into account weekdays, weekends, and holidays. For example, a peak on a Monday won't be averaged with a Sunday load but will be representational of that typical Monday.

3. Existing Resource Capabilities

NCI relies on most recent ISO and NERC studies as the primary source for all generating unit capacity ratings. PROSYM was populated with both the summer and winter generating plant capability ratings defined in these reports. Additionally, any known changes to the future ratings of the existing plants are also incorporated in the unit database.

4. Hydroelectric and Pumped Storage Resources

Hydroelectric resources are modeled to produce median-year levels of energy production. Monthly forecasts of median-year hydro energy generation are developed based on each hydro resource's historical production levels. Run-of-river hydro energy production is scheduled throughout the day. Pumped Storage hydro energy production is scheduled by PROSYM during the highest demand periods of each month to capture the highest value for the system.

5. Existing Generating Unit Outage Parameters

In most cases, generator maintenance and forced outage parameters are the average of 1992 to 1996 NERC GADS data, weighted for plant size, plant type, and fuel type. The maintenance schedules for U.S. nuclear units are based on the actual schedule reported by the Nuclear Regulatory Commission. Maintenance parameters include both the frequency and duration of maintenance outages (mean time between maintenance periods, and mean time to repair). PROSYM optimizes maintenance outages to eliminate unlikely outage combinations over periods of weeks, months or years depending on specification. Thus, if a generator has a maintenance rate of 5% and the model is set to converge maintenance schedules on a monthly basis, it will be out 5% of the hours in each month of the simulation resulting in 12 starts per year. If however, the model is specified to converge maintenance on a yearly basis, that generator will be out on maintenance 5% of the hours of the year, and the number of starts and duration of each outage will depend on the specification of the minimum, maximum, and mean time to repair. PROSYM also allows fixed maintenance schedules to be input over periods of one to several years. However, for most studies, the convergent maintenance method is preferred as it allows more accurate comparisons across scenarios.

6. Existing Unit Heat Rates

For existing plant heat rates, NCI relies on a number of sources of information, including heat rate information included in the PROSYM database. This information is primarily based on the U.S. Environmental Protection Agency's CEMS data, as well as information provided in various reports, FERC Form 1 filings, and internal analysis and judgment. PROSYM dispatches generators on heat rate curves that reflect minimum, mid, and full-load heat rates.

7. Fixed and Variable O&M Costs

Fixed and variable O&M costs for generators are based on information contained in the PROSYM database, and confirmed by NCI. This information is based on a variety of sources including FERC Form 1 filings, internal engineering studies, and other sources.

8. New Entrant Timing/Amount Assumptions

A significant amount of merchant generation is being developed in several regions throughout the US, and based on the current status of these proposed projects and NCI's assessment of the likelihood of each being developed, a number of these projects are included in the analysis. In general, NCI has assessed the permitting, financing, and construction stages of each project's development to form an opinion of whether the project should be included in the analysis.

9. New Entrant Installed Cost and Operating Assumptions

Provided below is a summary of the new entry cost and operating assumptions. This cost information is based on several sources, including a recent survey of merchant plant project developers, industry publications, and internal engineering estimates. NCI's philosophy on adding new entry in market simulations is to only add projects in locations where either the total market revenues can support a new project, or where there is a shortfall in capacity and either the required reserve margin will not be met or there is insufficient capacity to meet regional load pockets, resulting in energy not served.

- NCI estimates the going forward average cost for turnkey plant installations are as follows:
  - Combustion turbine installed cost of $400/ kW
  - Combined cycle facilities $600/ kW
- NCI believes that most new capacity going forward will reflect lower-cost technologies (installed and operational costs), and observe going forward new entrant installed costs, and variable operational costs, to be consistent with current FA and EA technologies and configurations.

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10. Inflation Assumptions

NCI assumes an annual inflation rate of 2.5% for the U.S. This is consistent with sources that NCI has reviewed, including data reported by the Bureau of Economic Analysis, and the Bureau of Labor Statistics, and the Congressional Budget Office's *Budget and Economic Outlook: Fiscal Years 2002-2011,* dated January 2001. In this report, the Congressional Budget Office projects Consumer Price Index ("CPI") growth of 2.6% per year. Inflation estimates are used to escalate the fixed and variable O&M expenses for each generating unit, and therefore has an underlying influence on the inherent escalation of forecasted wholesale power prices.

11. Unit Retirement Assumptions

There are economic retirements that are likely to occur over the next several years. These retirements may be due to significant environmental compliance cost or plants that are located within supply pockets and do not receive sufficient revenue to meet projected revenue requirements. During the simulation process, NCI monitors each plant's revenue to determine whether it has meet or exceeded its cost requirements for the year. Plants that experience a revenue shortfall in any two consecutive years (other than peaking resources that are required to maintain system integrity/reserves) are candidates for retirement. Barring any strategic, system reliability, or other reason for supporting the plant on ongoing basis, the plant is removed from the simulation after two consecutive years of significant revenue shortfall.

12. Nuclear Plant Assumptions

As a base case assumption, NCI assumes that all nuclear plants will remain in commercial operation through their reported licensing term.

13. Transmission Topology Assumptions

NCI has specified transmission areas in the PROSYM model that provides valuable information on the congestion costs associated with each of the transmission-constrained regions. Transmission limitations between each of the congestion zones and market areas are based on several recent studies as prepared by the various ISO/IMOs, NERC, and utilities within the control area. As a result of these studies and internal review, NCI has segmented the WECC into transmission areas by NERC sub regions.

14. Emission Allowance Assumptions

Emission allowance costs are an important consideration in simulating plant operation and preparing a price forecast. NCI closely monitors the trading activity of U.S. SO_2 and NO_x allowances as part of this process. Based on recent trading information, and NCI's own research on complacence and equipment costs, the following chart reflects NCI's price forecast for these emission allowances in nominal dollars:
When simulating the variable cost dispatch of generation units, NCI models NO_x emissions by assuming that all generators have initial allowance allocations at the rate of .15 lbs per MMBtu. The incremental NO_x emissions that are priced above the initial allowances are then calculated as the maximum of a) the NO_x rate - .15, or b) 0. The resultant incremental emissions allowances are priced at the assumed NO_x allowance

price per ton. This approach provides a representation of the initial emissions allowances that are allocated to each generator, but does not provide full recognition of unused allowances that can either be transferred to other units within a company portfolio or traded in the secondary market.

15. Natural Gas Price Forecast Methodology

Using inputs and assumptions specific to NCI, a proprietary model[1] is used to estimate natural gas prices at a number of market nodes and supply points across North America. Among other items, the outputs of this model reflect the monthly, marginal, or market-clearing, gas prices at each node. The differences between these gas prices are the projected basis differentials at each point.

To conform the model output to current market conditions, NCI makes a number of objective and subjective adjustments:

- First, a current forward NYMEX natural gas curve for the prospective 18 – 36 month period is used representing the model output for Henry Hub, and merged into the model output.
- Second, the model is sensitive to oil commodity price assumptions. To the extent NCI views the natural gas price response to be excessive, year-to-year gas price movements are tempered.
- Third, the model output is sensitive to significant changes in pipeline capacity. The price impacts of capacity additions are often smoothed, reflecting NCI's view that changes resulting in large market perturbations would likely be smoothed in reality.
- Finally, the proportional changes in Henry Hub commodity prices are applied to the individual pricing nodes to maintain the implicit volatility and prevent smoothing the basis differentials. All price projections beyond 2020 are held constant in real terms.

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[1] This model is licensed and operated by Energy and Environmental Analysis, Inc.

50% of Coyote Springs 2 (CCCT and Duct Burner)

Economic Analysis Detail

Assumptions

Installed Cost	67,187	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	201.56	2004 $000s	Nominal Discount	8.22 percent
Installed Cost	472	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.50 percent
Project Capacity	142.3	MW	Escalation Rates			General Inflation	3.0	percent		
Heat Rate	7,444	Btu/kWh	Fixed O&M	3.0	percent	Option Value	0	2004 $000s		
Gas Usage Rate	25.4	000s dth/day	Transportation	3.0	percent					

Pre-tax Option value NPV 241 2004 $/kW

			Fixed Costs																		
			Capital Recovery and Miscellaneous				Operations & Maintenance						Total Fixed	Operating	Option	Net				Total Project	
	Year	Energy	Project	Fixed Chrg.	Total Costs		Fixed	Gtrans	PrTax	Insur.	Total Costs		Costs	Margin	Value	Project Benefit		Total Variable Costs		Costs	
		(GWh)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($/MWh)	($000s)	($/MWh)
1	2005	624.2	12,694	0	12,694	20.3	3,078	0	916	208	4,201	6.7	16,895	5,678	2,558	(8,658)	(13.9)	28,294	45.3	45,189	72.4
2	2006	619.0	12,399	0	12,399	20.0	3,170	0	884	214	4,268	6.9	16,667	5,079	2,797	(8,791)	(14.2)	29,700	48.0	46,366	74.9
3	2007	638.3	11,838	0	11,838	18.5	3,265	0	853	220	4,338	6.8	16,176	5,241	2,280	(8,655)	(13.6)	26,501	41.5	42,677	66.9
4	2008	646.4	11,542	0	11,542	17.9	3,363	0	821	227	4,411	6.8	15,953	5,646	2,528	(7,779)	(12.0)	28,477	44.1	44,429	68.7
5	2009	718.4	11,424	0	11,424	15.9	3,464	0	789	234	4,487	6.2	15,911	9,004	2,945	(3,962)	(5.5)	33,864	47.1	49,775	69.3
6	2010	795.5	11,357	0	11,357	14.3	3,568	0	758	241	4,566	5.7	15,923	13,744	3,560	1,381	1.7	40,021	50.3	55,944	70.3
7	2011	839.3	10,789	0	10,789	12.9	3,675	0	726	248	4,649	5.5	15,438	16,969	3,462	4,992	5.9	35,456	42.2	50,894	60.6
8	2012	766.8	10,588	0	10,588	13.8	3,785	0	695	255	4,735	6.2	15,323	14,903	3,643	3,222	4.2	38,283	49.9	53,606	69.9
9	2013	772.3	10,201	0	10,201	13.2	3,899	0	663	263	4,825	6.2	15,025	16,984	3,984	5,942	7.7	37,097	48.0	52,122	67.5
10	2014	727.7	10,237	0	10,237	14.1	4,015	0	632	271	4,918	6.8	15,155	16,111	4,388	5,344	7.3	44,723	61.5	59,878	82.3
11	2015	744.5	9,991	0	9,991	13.4	4,136	0	600	279	5,015	6.7	15,005	15,375	4,458	4,828	6.5	46,436	62.4	61,442	82.5
12	2016	737.0	9,603	0	9,603	13.0	4,260	0	568	287	5,116	6.9	14,718	15,448	4,390	5,120	6.9	45,195	61.3	59,914	81.3
13	2017	729.4	9,215	0	9,215	12.6	4,388	0	537	296	5,221	7.2	14,435	15,520	4,407	5,492	7.5	43,954	60.3	58,390	80.0
14	2018	721.9	8,827	0	8,827	12.2	4,519	0	505	305	5,330	7.4	14,157	15,593	4,386	5,822	8.1	42,713	59.2	56,870	78.8
15	2019	714.3	8,440	0	8,440	11.8	4,655	0	474	314	5,443	7.6	13,882	15,665	4,479	6,261	8.8	41,473	58.1	55,355	77.5
16	2020	706.8	8,053	0	8,053	11.4	4,795	0	442	323	5,560	7.9	13,613	15,737	4,578	6,703	9.5	40,232	56.9	53,844	76.2
17	2021	702.9	7,761	0	7,761	11.0	4,939	0	410	333	5,682	8.1	13,443	16,278	4,756	7,591	10.8	40,975	58.3	54,418	77.4
18	2022	698.9	7,469	0	7,469	10.7	5,087	0	379	343	5,809	8.3	13,278	16,819	4,866	8,407	12.0	41,718	59.7	54,996	78.7
19	2023	695.0	7,177	0	7,177	10.3	5,239	0	347	353	5,940	8.5	13,118	17,359	5,100	9,341	13.4	42,461	61.1	55,579	80.0
20	2024	691.1	6,886	0	6,886	10.0	5,396	0	316	364	6,076	8.8	12,962	17,900	5,186	10,123	14.6	43,205	62.5	56,167	81.3
Net Present Value			102,163	0	102,163		37,022	0	6,717	2,497	46,237		148,400	114,046	34,354	(0)		350,206		498,606	
Nominal Levelized Cost ($/MWh)						14.8						6.7		77%	23%		(0.0)		50.7		72.2
Real Levelized Cost ($/MWh)						12.0						5.4					(0.0)		41.0		58.4

50% of Coyote Springs 2 (CCCT and Duct Burner)

Economic Analysis Detail

Assumptions

Installed Cost	34,161	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	102.48	2004 $000s	Nominal Discount	8.22	percent
Installed Cost	240	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.50	percent
Project Capacity	142.3	MW	Escalation Rates			General Inflation	3.0	percent			
Heat Rate	7,444	Btu/kWh	Fixed O&M	3.0	percent	Option Value	0	2004 $000s			
Gas Usage Rate	25.4	000s dth/day	Transportation	3.0	percent						

Pre-tax Option value NPV 178 2004 $/kW

			Fixed Costs: Capital Recovery and Miscellaneous				Fixed Costs: Operations & Maintenance						Total Fixed Costs	Operating Margin	Option Value	Net Project Benefit		Total Variable Costs		Total Project Costs	
	Year	Energy	Project	Fixed Chrg.	Total Costs		Fixed	Gtrans	PrTax	Insur.	Total Costs										
		(GWh)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($/MWh)	($000s)	($/MWh)
1	2005	574.8	6,850	0	6,850	11.9	3,078	0	466	106	3,649	6.3	10,498	3,814	1,905	(4,780)	(8.3)	21,129	36.8	31,627	55.0
2	2006	554.1	6,679	0	6,679	12.1	3,170	0	450	109	3,728	6.7	10,407	3,692	2,043	(4,672)	(8.4)	21,361	38.6	31,768	57.3
3	2007	600.4	6,418	0	6,418	10.7	3,265	0	433	112	3,810	6.3	10,229	4,277	1,741	(4,210)	(7.0)	20,200	33.6	30,429	50.7
4	2008	606.6	6,293	0	6,293	10.4	3,363	0	417	115	3,896	6.4	10,189	3,821	1,823	(4,545)	(7.5)	21,689	35.8	31,878	52.5
5	2009	664.2	6,288	0	6,288	9.5	3,464	0	401	119	3,984	6.0	10,272	5,573	2,130	(2,569)	(3.9)	25,532	38.4	35,804	53.9
6	2010	755.5	6,364	0	6,364	8.4	3,568	0	385	122	4,075	5.4	10,439	7,744	2,478	(217)	(0.3)	30,896	40.9	41,335	54.7
7	2011	793.2	6,021	0	6,021	7.6	3,675	0	369	126	4,170	5.3	10,191	10,722	2,386	2,917	3.7	27,404	34.6	37,596	47.4
8	2012	721.1	5,942	0	5,942	8.2	3,785	0	353	130	4,268	5.9	10,210	8,908	2,586	1,285	1.8	29,267	40.6	39,477	54.7
9	2013	720.7	5,731	0	5,731	8.0	3,899	0	337	134	4,369	6.1	10,101	10,073	2,702	2,674	3.7	28,319	39.3	38,420	53.3
10	2014	674.3	5,826	0	5,826	8.6	4,015	0	321	138	4,474	6.6	10,301	9,723	3,172	2,595	3.8	33,734	50.0	44,035	65.3
11	2015	685.9	5,718	0	5,718	8.3	4,136	0	305	142	4,583	6.7	10,301	9,595	3,372	2,666	3.9	34,901	50.9	45,202	65.9
12	2016	678.2	5,508	0	5,508	8.1	4,260	0	289	146	4,695	6.9	10,203	9,494	3,347	2,639	3.9	33,941	50.0	44,144	65.1
13	2017	670.5	5,298	0	5,298	7.9	4,388	0	273	151	4,811	7.2	10,109	9,393	3,367	2,651	4.0	32,981	49.2	43,090	64.3
14	2018	662.8	5,088	0	5,088	7.7	4,519	0	257	155	4,931	7.4	10,019	9,293	3,357	2,630	4.0	32,020	48.3	42,040	63.4
15	2019	655.1	4,879	0	4,879	7.4	4,655	0	241	160	5,056	7.7	9,934	9,192	3,268	2,526	3.9	31,060	47.4	40,994	62.6
16	2020	647.4	4,669	0	4,669	7.2	4,795	0	225	164	5,184	8.0	9,853	9,091	3,318	2,556	3.9	30,100	46.5	39,953	61.7
17	2021	656.2	4,561	0	4,561	6.9	4,939	0	209	169	5,317	8.1	9,878	10,746	3,617	4,485	6.8	31,246	47.6	41,123	62.7
18	2022	665.1	4,453	0	4,453	6.7	5,087	0	193	174	5,454	8.2	9,907	12,400	3,840	6,333	9.5	32,392	48.7	42,298	63.6
19	2023	673.9	4,345	0	4,345	6.4	5,239	0	177	180	5,596	8.3	9,941	14,055	4,092	8,206	12.2	33,538	49.8	43,478	64.5
20	2024	682.7	4,237	0	4,237	6.2	5,396	0	161	185	5,742	8.4	9,979	15,709	4,330	10,060	14.7	34,684	50.8	44,663	65.4
Net Present Value			56,994	0	56,994		37,022	0	3,415	1,270	41,707		98,701	73,363	25,339	(0)		265,281		363,982	
Nominal Levelized Cost ($/MWh)						8.8						6.5		74%	26%		(0.0)		41.2		56.5
Real Levelized Cost ($/MWh)						7.1						5.2					(0.0)		33.3		45.7

50% of Coyote Springs 2 (CCCT and Duct Burner)

Economic Analysis Detail

Assumptions

Installed Cost	111,053	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	333.16	2004 $000s	Nominal Discount	8.22	percent
Installed Cost	781	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.50	percent
Project Capacity	142.3	MW	Escalation Rates			General Inflation	3.0	percent			
Heat Rate	7,444	Btu/kWh	Fixed O&M	3.0	percent	Option Value	0	2004 $000s			
Gas Usage Rate	25.4	000s dth/day	Transportation	3.0	percent						

Pre-tax Option value NPV 311 2004 $/kW

	Year	Energy (GWh)	Fixed Costs: Capital Recovery and Miscellaneous: Project ($000s)	Fixed Chrg. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Operations & Maintenance: Fixed ($000s)	Gtrans ($000s)	PrTax ($000s)	Insur. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Total Fixed Costs ($000s)	Operating Margin ($000s)	Option Value ($000s)	Net Project Benefit ($000s)	Net Project Benefit ($/MWh)	Total Variable Costs ($000s)	Total Variable Costs ($/MWh)	Total Project Costs ($000s)	Total Project Costs ($/MWh)
1	2005	724.5	20,509	0	20,509	28.3	3,078	0	1,514	343	4,934	6.8	25,443	9,457	3,385	(12,601)	(17.4)	38,901	53.7	64,344	88.8
2	2006	719.4	20,014	0	20,014	27.8	3,170	0	1,461	353	4,985	6.9	24,999	10,187	3,663	(11,149)	(15.5)	41,132	57.2	66,131	91.9
3	2007	752.4	19,132	0	19,132	25.4	3,265	0	1,409	364	5,038	6.7	24,170	10,924	3,288	(9,958)	(13.2)	36,842	49.0	61,013	81.1
4	2008	740.9	18,563	0	18,563	25.1	3,363	0	1,357	375	5,095	6.9	23,657	13,411	3,731	(6,516)	(8.8)	38,511	52.0	62,168	83.9
5	2009	834.6	18,312	0	18,312	21.9	3,464	0	1,305	386	5,155	6.2	23,466	18,208	4,270	(989)	(1.2)	46,313	55.5	69,779	83.6
6	2010	908.6	18,059	0	18,059	19.9	3,568	0	1,253	398	5,218	5.7	23,277	26,660	5,150	8,533	9.4	53,598	59.0	76,875	84.6
7	2011	884.3	17,522	0	17,522	19.8	3,675	0	1,200	410	5,285	6.0	22,807	25,104	5,180	7,477	8.5	54,506	61.6	77,313	87.4
8	2012	860.0	17,006	0	17,006	19.8	3,785	0	1,148	422	5,355	6.2	22,361	23,549	4,824	6,012	7.0	55,415	64.4	77,775	90.4
9	2013	835.7	16,500	0	16,500	19.7	3,899	0	1,096	435	5,429	6.5	21,929	21,993	5,056	5,120	6.1	56,323	67.4	78,252	93.6
10	2014	811.4	15,996	0	15,996	19.7	4,015	0	1,044	448	5,507	6.8	21,503	20,438	4,644	3,578	4.4	57,232	70.5	78,735	97.0
11	2015	787.1	15,493	0	15,493	19.7	4,136	0	992	461	5,589	7.1	21,081	18,882	5,321	3,122	4.0	58,140	73.9	79,221	100.6
12	2016	779.8	14,876	0	14,876	19.1	4,260	0	939	475	5,674	7.3	20,550	19,113	5,279	3,842	4.9	56,677	72.7	77,227	99.0
13	2017	772.5	14,259	0	14,259	18.5	4,388	0	887	489	5,764	7.5	20,023	19,343	5,205	4,525	5.9	55,213	71.5	75,236	97.4
14	2018	765.2	13,642	0	13,642	17.8	4,519	0	835	504	5,858	7.7	19,501	19,574	5,210	5,283	6.9	53,750	70.2	73,251	95.7
15	2019	757.8	13,026	0	13,026	17.2	4,655	0	783	519	5,957	7.9	18,983	19,804	5,395	6,216	8.2	52,287	69.0	71,269	94.0
16	2020	750.5	12,410	0	12,410	16.5	4,795	0	731	535	6,060	8.1	18,469	20,035	5,546	7,111	9.5	50,823	67.7	69,293	92.3
17	2021	736.8	11,874	0	11,874	16.1	4,939	0	678	551	6,168	8.4	18,042	19,864	5,673	7,495	10.2	51,044	69.3	69,086	93.8
18	2022	723.1	11,339	0	11,339	15.7	5,087	0	626	567	6,280	8.7	17,619	19,693	5,759	7,833	10.8	51,264	70.9	68,883	95.3
19	2023	709.4	10,804	0	10,804	15.2	5,239	0	574	584	6,398	9.0	17,202	19,523	5,809	8,130	11.5	51,485	72.6	68,687	96.8
20	2024	695.6	10,270	0	10,270	14.8	5,396	0	522	602	6,520	9.4	16,790	19,352	5,951	8,513	12.2	51,705	74.3	68,495	98.5
Net Present Value			162,461	0	162,461		37,022	0	11,103	4,128	52,253		214,714	170,454	44,260	(0)		469,302		684,016	
Nominal Levelized Cost ($/MWh)						21.6						7.0		79%	21%		(0.0)		62.5		91.1
Real Levelized Cost ($/MWh)						17.5						5.6					(0.0)		50.5		73.6

EXHIBIT L

Purchase and Intent Agreement

12/13/04

Purchase and Sale

of the Undivided

50% Ownership Interest of

Mirant Oregon, LLC in Coyote Springs 2

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