EXHIBIT D

Location of Coyote Springs Plant Relative to Avista Utilities Service Area

SEE CASE FILE

FOR MAP(S)

EXHIBIT E

Excerpts from 2000 Updated Integrated Resource Plan

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

July 12, 2000

AVISTA CORPORATION

1997 Integrated Resource Plan Update

I. Introduction:

Avista's last Integrated Resource Plan (IRP) was filed with the Commission on August 25, 1997. That plan showed that the company was surplus for many years into the future. Since then many things have changed in the electric utility industry and for Avista. Therefore, the company has prepared this updated IRP to include those significant changes. As discussed later, this updated IRP will also serve as the basis for a Request- for-Proposal (RFP) that Avista plans to issue.

The following information has been presented at various TAC meetings and will become a integral part of the next IRP.

II. 1997 IRP Update

1. Load Forecast

The 2000 electric sales forecast was prepared during the summer of 1999. The forecast of firm sales to the core-market is one of the most critical elements and was presented and discussed at the TAC meeting. Avista Utilities utilizes econometric models to produce sales and customer forecasts. Econometric models are systems of algebraic equations which relate past economic growth and development in the geographic communities served electricity with past customer growth and consumption.

The electrical energy forecast shows an annual average load of 1013 aMW in 2001 increasing to 1159 aMW in 2009. The peak forecast shows 1594 MW in 2001 with 1851 MW in the year 2009. The ten-year compound growth rate for residential usage is 2.3 percent, commercial is 3.9 percent and industrial is 1.6 percent. The overall total energy forecast has a compound growth rate of 1.9 percent.

The annual load forecast numbers, for both peak and energy, through the year 2009 can be found on the Requirements and Resources tabulation sheet.

2. Resource Assessment

Centralia:
The sale of the Centralia coal-fired plant resulted in the loss of 201 MW of capacity and 177 aMW of annual energy from Avista's resource portfolio. The company entered into a short-term contract with TransAlta, the new owners of Centralia, to replace a majority of the generation lost with the sale of the plant. The term of this contract starts in July 2000 and extends through December 2003.

costs and discharge less pollutants into the air than other fossil fuel plants. As shown in Appendix B, the Northwest Power Planning Council costs for natural gas fired generation projects range from approximately 41 mills to 43 mills.

At this point in time the following resources would not pass the initial screening. The following costs are nominal life-cycle, levelized costs.

- Nuclear: Costs are over the 100 mills per kilowatt-hour range. The total cost and the lack of public acceptance make this resource option unacceptable.
- Coal: Costs are 80 to 90 mills. The total cost and cost uncertainty in air quality issues make this resource option unacceptable.
- Wind: Costs are 60 to 80 mills. There are indications that costs are declining but our studies show there are not favorable sites in our service territory so transmission costs would have to be added. Because wind is intermittent the resource would have to be discounted for lack of capacity component. This would make this resource option unacceptable.
- Geothermal: Costs are 80 to 100 mills making this resource option unacceptable.
- Solar: Costs are over 240 mills making this resource option unacceptable.

These costs are presented for general comparison purposes. The company will solicit resource bids from the market in an upcoming Request-for-Proposals (RFP). The company is hoping for innovative bids from project developers. The RFP bids will be evaluated against the information that has been gathered both internally and externally.

8. Load and Resource Summary

General:
Included is Avista's annual Requirements and Resources (Load and Resource Summary) that shows the company's load and resource position on an annual basis for the next ten years (see Appendix D). It is dated June 1, 2000 and will be the same one used in the 2000 IRP. The peak column is the January peak (the highest forecasted peak for the year) and the average column is the annual 12-month average for the year. The resource peak numbers are what could be expected as maximum capacity outputs during January. The hydro peak and energy numbers are from the final regulation done by the Northwest Power Pool and reflect the reservoir levels in January per the hydro regulation study (one-year critical period, 1936-37 water). The average energy numbers are the expected 12-month averages for the loads, resources and contracts.

All the requirements are shown at the top of the page. Most of the purchases and sales contracts end by the year 2004. The peak and average forecasted loads are shown on line 1 labeled System Load. Line 17 Reserves are Avista's planning reserves and are part of the total Requirements (as described in Section 3).

The Resource section is comprised of the resources and purchase contracts. Line 19 shows the system hydro and line 20 is the contract hydro from the mid-Columbia PUD projects (with critical water conditions). The mid-Columbia numbers decrease due to the Priest Rapids contract ending in 2005 and the Wanapum contract ending in 2009. Avista is hopeful that a contract extension can be negotiated with Grant County PUD. Lines 24 and 25 are the company's existing simple-cycle combustion turbines, and lines 33 and 34 are the expected thermal generation output from Kettle Falls and Colstrip.

Line 29 shows the BPA residential exchange contract and the 47 MW flat delivery of power to the company from BPA. There is no dispatchability or flexibility with this contract. Although this contract has not been signed, Avista feels it is firm enough to be included.

Line 44 is the Surplus (Deficit) numbers calculated by subtracting the Total Requirements from the Total Resource numbers. In the year 2004 Avista is 287 MW deficit on peak and 318 aMW deficit on energy under critical water planning criteria.

Resource Flexibility:
Flexible generation resources are a key component to meet the requirements of Avista's customers. As depicted in the charts on pages 8 and 9 in Appendix E, Avista experiences load changes of 100 MW or more during several hours of each day. Loads must be ramped up and down under a variety of seasonal and load conditions. In order to meet the load, flexible resources (Cabinet Gorge, Noxon Rapids, Long Lake, Mid Columbia contract hydro, and the Rathdrum Combustion turbines) are dispatched. Even with these resources, Avista still must purchase peak energy products to meet customer demand during different times. The market today tends to offer standard heavy load hour and light load hour products that do not meet load shaping or following needs.

2004 Study:
A detailed tabulation of the load and resource requirements study of the year 2004 is also attached (see Appendix E). We chose the year 2004 for an in-depth study because, as mentioned above, many of the larger supply and requirements contracts have ended and future requirements change (for the most part) due to load growth.

This study is shown in two parts. The first study shows on and off peak loads and resource requirements monthly under critical and normal hydro conditions. The second study goes into even further detail. We created an hourly Surplus-Deficiency duration Curve for the year 2004 using PROSYM to gain the following information. By using the Northwest Power Pool's sixty year hydro generation study for our system, PROSYM runs 720 (sixty years X 12 months/year) hydro scenarios into the forecast net system load, all known contracts, and existing resources. The information gained from this model output shows the company's resource requirements to meet load under many different hydro conditions. This duration curve will be used to analyze how new resource additions will "fit" into the company's requirements without any affect from market conditions. As stated before, standard economic modeling must be performed after dispatch information is gained from PROSYM modeling.

Load growth expectations based on the forecasted methodologies are explained under Section 1. Avista doesn't expect drastic changes in our load beyond the normal load growth that has been experienced. But the future is uncertain and Avista needs to be flexible enough to handle unforeseen changes. For example, the company could lose load by having Avista's larger retail customers install cogeneration, like WSU or Potlatch deciding to serve their own load from existing generating facilities. Or if partial deregulation was to come to our region, Avista could pick up some industrial loads thereby increasing the load requirements.

Appendix D

Exhibit D – Annual Load and Resource Forecast

		AVISTA CORP.																			
Requirements and Resources																					
figures in MW		2000		2001		2002		2003		2004		2005		2006		2007		2008		2009	
Line No.	REQUIREMENTS	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg
1	System Load	1557	1008	1594	1013	1557	971	1572	982	1608	1007	1649	1033	1692	1059	1743	1091	1796	1124	1851	1159
2	PacifiCorp Exchange	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3
3	Puget #2	100	75	67	50	33	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	PacifiCorp 1994	0	9	0	9	0	9	0	9	0	9	0	9	0	9	0	9	0	0	0	0
5	PGE #1	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0
6	Snohomish 10 yr	100	88	100	88	100	88	100	88	100	88	100	88	100	88	0	0	0	0	0	0
7	Cogentrix 57 mo	100	100	100	75	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Nichols Pumping	0	7	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	West Kootenay	125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Eugene Water & Electric	10	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	PGE Sale	25	25	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Pend Oreille	6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Montana Sale	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Duke Sale	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Clark2 PUD	250	137	250	85	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	City of Cheney	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Reserves	246	0	249	0	246	0	247	0	251	0	255	0	259	0	264	0	270	0	275	0
18	TOTAL REQUIREMENTS	2871	1662	2737	1470	2086	1096	2069	1082	2109	1107	2154	1133	2201	1159	2157	1103	2216	1127	2276	1162
	RESOURCES																				
19	System Hydro	936	313	936	313	936	313	936	313	936	313	936	313	936	313	936	313	936	313	936	313
20	Contract Hydro	195	76	195	76	195	76	195	76	195	76	195	71	140	50	140	50	140	50	140	44
21	Can Ent Return	-10	-5	-10	-5	-10	-5	-10	-5	-15	-5	-15	-4	-11	-4	-10	-4	-10	-4	-10	-3
22	Small Power	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11
23	Cogeneration	59	55	59	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Northeast CTs	69	5	69	5	69	5	69	5	69	5	69	5	69	5	69	5	69	5	69	5
25	Rathdrum CTs	176	62	176	62	176	62	176	62	176	62	176	62	176	62	176	62	176	62	176	62
26	PacifiCorp Exchange	50	3	50	3	50	3	50	3	50	3	50	3	50	3	50	3	50	3	50	3
27	BPA/Avista Exchange	32	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Entitlement & Supplemental	5	0	4	0	4	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0
29	BPA Res. Exchange	0	0	0	12	47	47	47	47	47	47	47	47	47	72	149	149	149	149	149	149
30	BPA-WNP #3	82	41	82	41	82	41	82	41	82	41	82	41	82	41	82	41	82	41	82	41
31	CSPE	10	5	9	5	9	5	8	1	0	0	0	0	0	0	0	0	0	0	0	0
32	TransAlta-Centralia	200	138	200	143	200	143	200	143	0	0	0	0	0	0	0	0	0	0	0	0
33	Thermal- Kettle Falls	48	45	48	45	48	45	48	45	48	45	48	45	48	45	48	45	48	45	48	45
34	Colstrip	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191
35	SEMPRA	0	19	0	19	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	BPA 5 yr. Purchase	115	115	115	86	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Idaho Purchase	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Duke Purchase	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	MIECO	25	25	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Cinergy Services, Inc.	0	14	0	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Energy Services, Inc.	0	50	0	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Enron	50	50	50	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43	TOTAL RESOURCES	2476	1425	2442	1267	2040	944	2039	933	1822	789	1822	785	1771	789	1874	866	1874	866	1874	861
44	SURPLUS (DEFICIT)	-395	-237	-295	-203	-46	-152	-30	-149	-287	-318	-332	-348	-430	-370	-283	-237	-342	-261	-402	-301

EXHIBIT F

Letter of Intent

Avista Corp.
1411 East Mission PO Box 3727
Spokane, Washington 99220-3727
Telephone 509-489-0500
Toll Free 800-727-9170

AVISTA Corp.

June 24, 2004

Mirant Oregon, LLC
c/o Mirant California
1350 Treat Blvd., Suite 500
Walnut Creek, CA 94597
Attn: Anne M. Cleary, President

Dear Ms. Cleary:

Enclosed please find two signed originals of the Letter of Intent for the potential purchase of Coyote Springs Unit 2 from Mirant Oregon, LLC. Please sign both originals and return one to me.

If you have any questions, please call me at 509 495-8093 or Ron Peterson at 509 495-8045.

Sincerely,

St S Silkworth

Steven G. Silkworth
Wholesale Power Manager

Enclosure

AVISTA
Corp.

Confidential and Proprietary

June 25, 2004

Mirant Oregon, LLC
c/o Mirant California
1350 Treat Blvd., Suite 500
Walnut Creek, CA 94597
Attn: Anne M. Cleary, President

Ladies and Gentlemen:

This letter of intent (***"Letter of Intent"***), effective on the date when executed by all the Parties hereto (the ***"Effective Date"***), will evidence the current mutual intent, as set forth in Article I below, of MIRANT OREGON, LLC, a Delaware limited liability company (***"Mirant"***), and AVISTA CORPORATION, a Washington corporation (***"Avista"***), with respect to the potential purchase (the ***"Transaction"***) by Avista of Mirant's 50% undivided ownership interest, as tenant-in-common, in the Coyote Springs Unit 2 generation facility (the ***"Facility"***), consisting of an approximately 280 MW gas-fired, combined-cycle power plant, in Boardman, Oregon, including Mirant's undivided ownership interest in certain components shared with the adjacent Coyote Springs Unit 1 generation facility owned by Portland General Electric. Mirant and Avista are sometimes referred to individually as a ***"Party"*** herein and collectively as the ***"Parties."*** Mirant is wholly owned by Mirant Americas, Inc. ("MAI"). MAI and certain of its affiliates have filed voluntary petitions for relief under chapter 11 of title 11 of the United States Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Northern District of Texas (the "Bankruptcy Court") and continue to operate their respective businesses as debtors and debtors in possession.

Attached to this Letter of Intent as Exhibit A is a proposal for the Transaction (the "***Proposal***") under which Mirant and Avista are prepared to complete the Transaction if they are able to reach mutually satisfactory definitive agreements for consummation of the Transaction and if they evidence their willingness to proceed with the Transaction by executing and delivering those agreements.

The matters set forth in Article I and Exhibit A are not intended to and do not constitute a binding agreement of the Parties to consummate the Transaction. Any such binding agreement between the Parties will only arise upon the negotiation, execution and delivery of mutually satisfactory definitive agreements and the satisfaction of the conditions set forth therein, including without limitation, the satisfactory completion by the Parties of their respective due diligence inquiries and the approval of such agreements by the Parties' respective board of directors or other required internal approval, all required regulatory approvals and satisfaction of certain requirements of the Bankruptcy Code, including approval of the Bankruptcy Court and any requisite approvals pursuant to MAI's postpetition debtor in possession financing facility.

The matters set forth in Article II do constitute binding agreements of the Parties.

Article I
Transaction Documents

1. **Definitive Agreements.** The Parties will exercise good-faith efforts to diligently negotiate an Asset Purchase Agreement with respect to the Facility and such other definitive agreements necessary to accomplish the Transaction (collectively, the ***"Definitive Agreements"***). The Parties anticipate that Definitive Agreements, if entered into, will include provisions substantially similar to those set forth in the Proposal, together with such other provisions as the Parties may conclude are necessary or appropriate for the consummation of the Transaction.

2. **No Obligation to Enter.** Neither Party is obligated by this Letter of Intent to enter into any of the Definitive Agreements with the other Party with respect to the Transaction or any other matter.

Article II
Binding Provisions

1. **Confidentiality.** The Parties agree that this Letter of Intent and the matters identified in it are "Confidential Information" under the provisions of that certain Confidentiality Agreement dated of even date herewith, between Mirant and Avista (the ***"Confidentiality Agreement"***), and that the terms and conditions of the Confidentiality Agreement remain in full force and effect.

2. **Term.** Unless extended or earlier terminated by mutual written agreement of the Parties, this Letter of Intent shall remain in effect during the period from the Effective Date until the earliest to occur of (a) the execution of Definitive Agreements, (b) the date on which either party provides the other with written notice that negotiations toward Definitive Agreements are terminated, or (c) July 31, 2004, (the earliest to occur of such dates being referred to herein as the ***"Termination Date"***).

3. **Restricted Dealings.** During the term of this Letter of Intent, Mirant agrees not to, and agrees to cause its affiliates and representatives not to, solicit or entertain offers from, negotiate with or in any manner encourage, discuss, accept or consider any proposal of any other person or entity relating to the sale, acquisition or transfer of Mirant's interest in the Facility. During the term of this Letter of Intent, Avista agrees not to, and agrees to cause its affiliates and representatives not to, solicit or entertain offers from, negotiate with or in any manner encourage, discuss, accept or consider any proposal of any other person or entity relating to the sale or transfer by Avista (or its affiliates or representatives) of all or part of a power generation asset in Boardman, Oregon or within the surrounding 50 miles thereof. In the event that the parties execute Definitive Agreements, it is understood that the Transaction contemplated thereby will be subject to higher or otherwise better offers submitted in connection with a Bankruptcy Court supervised auction and sale approval process; provided that such process shall be conducted in accordance with the procedures set forth in such Definitive Agreements, as more specifically contemplated on Exhibit A.

4. **Capital and Operating Expenses.** For the avoidance of doubt, the obligations of the Parties to fund capital and operating expenses of the Facility shall be as provided in the Co-Tenancy and Joint Operating Agreement, dated as of January 1, 2003 between the Parties (the ***"Operating Agreement"***). Notwithstanding the foregoing, for the period from the date of this Letter of Intent until the closing under Definitive Agreements (provided the Transaction is consummated): (i) any capital expenditures made by Mirant shall be repaid to Mirant in full at such closing, and (ii) any prepaid operating expenditures made by Mirant shall be repaid to Mirant as part of a working capital adjustment under the Definitive Agreements.

5. **Expenses.** Each Party shall bear its own costs and expenses associated with negotiating and performing under this Letter of Intent; provided however, that if the Parties execute Definitive Agreements, Avista will be entitled to customary bidding protections and procedures as set forth in Exhibit A. For the avoidance of doubt, the expenses of Coyote Springs 2, LLC, a Delaware limited liability company (the ***"Project Company"***) associated with negotiating this Letter of Intent and any Definitive Agreements and the execution of the Transaction (including without limitation the fees and expenses of Heller Ehrman White & McAuliffe LLP, counsel to the Project Company, shall be borne by the Project Company which shall be funded 50% by Mirant and 50% by Avista for this purpose.

6. **Approval.** Neither Party shall be bound by any of the Definitive Agreements until (a) such Party's respective board of directors, or other required internal approval process, shall have approved such Definitive Agreements, (b) such Party shall have executed such Definitive Agreements, and (c) all conditions precedent to the effectiveness of such Definitive Agreements shall have been satisfied, including without limitation any conditions precedent relating to (i) the obtaining of any and all requisite federal, state or local regulatory orders, consents or approvals and (ii) payment by Mirant of its outstanding obligations pursuant to the Operating Agreement. Without limiting in any manner the foregoing, the Parties acknowledge and agree that in no event shall either Party be obligated to proceed with the Transaction, and that each may, prior to the execution and delivery of such Definitive Agreements, decline to proceed with the Transaction in its sole discretion.

7. **Entire Agreement.** The binding portions of this Letter of Intent, together with the Proposal, constitute the entire agreement of the Parties relating to the subject matter hereof and supersede all prior discussions, agreements or understandings, whether oral or written, relating to such subject matter. There are no other written or oral agreements or understandings among the Parties with respect to the Transaction. Any waiver of any term or amendment of this Letter of Intent must be written and signed by both Parties. The binding provisions of this Letter of Intent may not be waived except in writing by the Party who has the right to enforce such provisions; provided, however, that Paragraphs 6, 9 and 12 may not be waived under any circumstances. No failure to exercise, no delay in exercising, and no course of dealing or trade custom with respect to, any provision of this Letter of Intent shall be deemed to waive any such provision.

8. **Governing Law.** This letter of intent shall be governed by and construed in accordance with the laws of the State of New York, without giving effect to conflict of laws principles.

9. **Non-Inclusive; Non-Binding.** Neither this Letter of Intent, the attached Proposal, nor any other proposal, correspondence or course of dealing identifies all matters upon which agreement must be reached in order for the Transaction to be completed or for any Definitive Agreements to be finalized and executed. Except with respect to the obligations of the Parties expressly set forth in Article II, this Letter of Intent does not create and is not intended to create a binding and enforceable contract between the Parties as to the Transaction or any obligation to enter into or proceed with the Transaction, and may not be relied upon by a Party as the basis for a contract by estoppel or otherwise with respect to any matter. A binding commitment with respect to the Transaction can only result from the execution and delivery of Definitive Agreements.

10. **Assignment.** Neither Party may assign or otherwise transfer its interest in this Letter of Intent without the prior written consent of the other Party.

11. **Relationship of the Parties.** The Parties shall not be deemed in a relationship of partners or joint venturers by virtue of this Letter of Intent, nor shall either Party be an agent, representative, trustee or fiduciary of the other. Neither Party shall have any authority under this Letter of Intent to bind the other to any agreement or obligation.

12. **Limitation of Liability**. UNDER NO CIRCUMSTANCES SHALL EITHER PARTY HERETO BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, WHETHER BY STATUTE, IN TORT OR CONTRACT OR OTHERWISE, IN CONNECTION WITH THE TRANSACTIONS CONTEMPLATED HEREBY.

13. **Confidentiality; Press Releases.** Each of the Parties agrees that, except as required by law, it will not disclose to any person other than its representatives the identity of the other Parties as it relates to the negotiation of the Transaction. Neither Party shall issue a press release or make any public statement with respect to the Transaction without the prior approval of the other Party, which approval shall not be unreasonably withheld or delayed.

If the provisions of Article I and Exhibit A correctly set forth our current understanding as to the non-binding nature of our discussions regarding Definitive Agreements, and the provisions of Article II set forth our binding agreements with respect to the matters set forth therein, please execute both originals of this Letter of Intent in the space provided below, retain one fully-executed original for your file, and return one of the other originals to the undersigned. This Letter of Intent may be executed in counterparts, and all such counterparts together shall constitute but one agreement.

Very truly yours,

AVISTA CORPORATION

By: Ronald R. Peterson
Name: Ronald R. Peterson
Title: Vice President Energy Resources

AMC **Acknowledged, Agreed to and Accepted,**
this 12th day of ~~June~~ JULY, 2004:

MIRANT OREGON, LLC

By: Anne M Cleary
Name: Anne M. Cleary
Title: President

Exhibit A
Proposed Terms and Conditions

1. Purchase Price.	The Purchase Price for Mirant's 50% undivided ownership interest, as tenant-in-common, in the Facility will be in the form of a cash payment by Avista to Mirant in an amount equal to US$62,500,000.00 in immediately available funds to be made at closing. If Mirant agrees to sell, and Avista agrees to buy, Mirant's 50% ownership interest in the Project Company as part of the Transaction, Mirant and Avista will agree upon a mutually acceptable price.
2. No Financing Contingency.	Avista has ample funds available to support its offer; accordingly, Avista's offer is not subject to any financing contingency.
3. Deposit.	Upon completion of due diligence and execution of Definitive Agreements, Avista shall deposit into escrow with a third party custodian reasonably satisfactory to Mirant an amount to be agreed that will be in immediately available funds (the ***"Deposit"***). If the Transaction is consummated, the Deposit shall be applied as a partial payment of the Purchase Price. If the Transaction is not consummated for any reason (other than due to a breach by Avista of the Definitive Agreements that leads to termination of the Definitive Agreements in accordance with their terms), the Deposit shall be refunded to Avista.
4. Closing.	Subject to, among other things, receipt of any required third-party, governmental or other regulatory approvals and satisfaction of Mirant's outstanding funding obligations, if any, pursuant to the Operating Agreement, it is anticipated that the transaction could be closed within 45-60 days of the date that a motion is filed by MAI and/or its debtor affiliates with the Bankruptcy Court seeking appropriate approval of the Transaction. Closing shall occur within 5 Business Days after all conditions precedent have been satisfied.
5. Approvals	Avista shall be responsible for filing all necessary Hart-Scott-Rodino ("HSR"), Federal Electric Regulatory Commission ("FERC") and Oregon Energy Facility Siting Council approvals. Mirant shall use commercially

	reasonable efforts to assist Avista in obtaining all regulatory approvals. MAI and Mirant shall use their commercially reasonable efforts to obtain Bankruptcy Court approval of orders, both in form and substance acceptable to Avista, (a) approving bidding protections and procedures, as described in paragraph 7 hereof, and (b) authorizing the consummation of the Transaction, each within the time periods prescribed in the Definitive Agreements.
6. Related Transmission Agreements	It is understood that the power transmission agreements listed on Annex I hereto are currently held by MAI or its debtor affiliates for the benefit of Mirant's 50% interest in the Facility. The parties agree that, to the extent possible and economically practicable, MAI or its debtor affiliates will transfer or assign such agreements or otherwise make available such power transmission service as part of the Transaction. The parties recognize that any assignment of such agreements may require (i) the filing of a motion by MAI and/or its debtor affiliates with the Bankruptcy Court for approval of such assignment and (ii) FERC approval. The parties further agree that to the extent possible and economically practicable, MAI or its debtor affiliates will transfer or assign any requests MAI or its debtor affiliates have pending for long-term transmission service from the Bonneville Power Administration or other transmission providers.
7. Timing	The Parties anticipate that the Transaction will be subject to higher or otherwise better offers submitted in connection with a Bankruptcy Court supervised auction and sale approval process (Parties shall consider jointly whether auction process will be run through the Bankruptcy Court). Accordingly, the Parties anticipate the following steps in the Transaction: • Execution of this Letter of Intent; • Negotiation and execution of mutually acceptable Definitive Agreements; • Filing of motion by MAI and/or its debtor affiliates with the Bankruptcy Court to seek approval of the Transaction and customary bidding protections and procedures, including without limitation, customary overbid protections and payment of a termination fee expected to be in the range of 2-3% of the Purchase Price (the

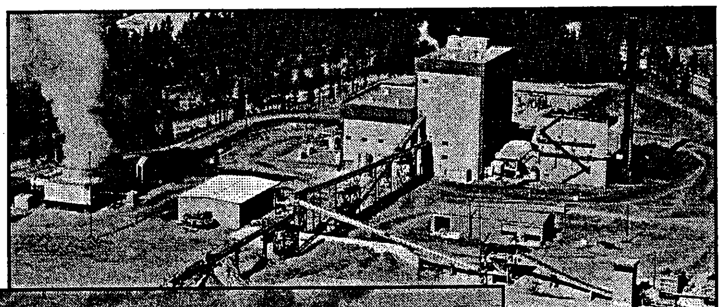
	"Termination Fee") and payment of Avista's reasonable fees and expenses up to a cap to be agreed, including attorneys fees and expenses, in certain specified circumstances to be defined in the Definitive Agreements; provided, that in the event the auction process is not run through the Bankruptcy Court, the parties will provide for such bidding protections and procedures in the Definitive Agreements. • Filing of all requisite regulatory approvals, including without limitation Hart-Scott-Rodino filing, FERC filing and approval from the Oregon Energy Facility Siting Council for permission to transfer the Site Certificate.
8. Approval of Third Person Purchaser	It is understood, that if in accordance with the procedures referenced above Mirant's interest in the Facility is to be transferred to a person other than Avista, such transfer shall be to a third party that meets certain minimum qualifications substantially based on those set forth in the definition of a Third Person Purchaser in the Operating Agreement and as Mirant and Avista shall agree otherwise in the Definitive Agreements.
9. Documentation.	It is anticipated that the Transaction will be subject to the same basic documentation that similar transactions between the parties or their affiliates have used previously. Mirant and Avista acknowledge and agree that neither party may retain Heller Erhman White & McAuliffe LLP in relation to the Transaction, however Heller Erhman White & McAuliffe LLP may be retained solely by Coyote Springs 2, LLC for assistance in providing form documents and in seeking appropriate approvals (including those set forth in paragraph 4 of this Proposal) and the Project Company shall be responsible for Heller Ehrman's fees and expenses. Both Mirant and Avista shall retain separate counsel to assist and advise on the Definitive Agreements and the Transaction generally.

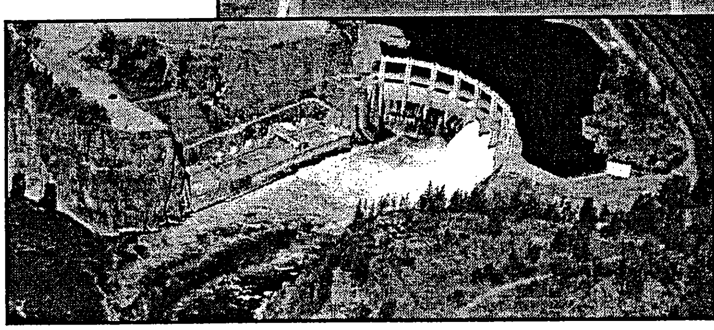
EXHIBIT G

2003 Integrated Resource Plan Excerpts
re Preferred Resource Mix

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

AVISTA®
Corp.





2003 Integrated Resource Plan

Exhibit G
Page 1 of 2

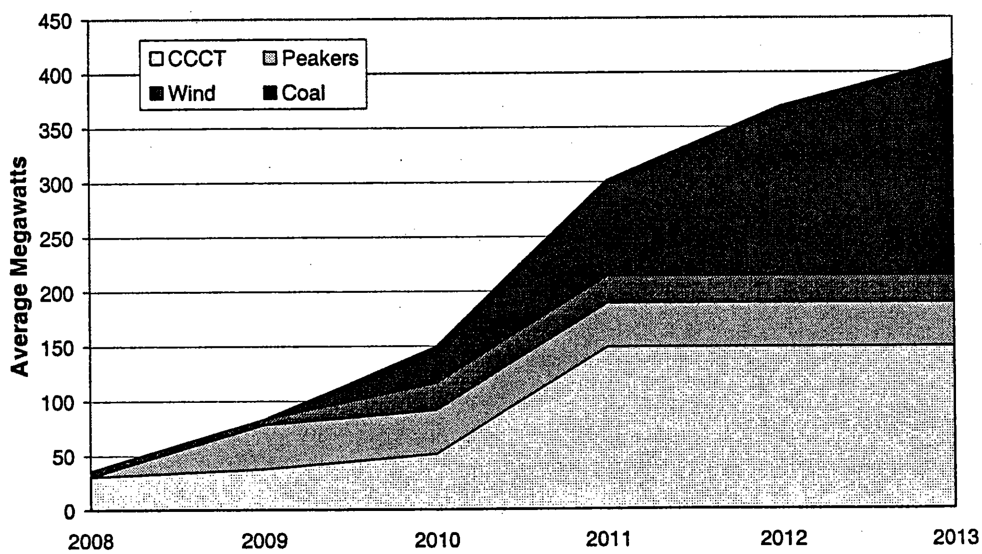
The Preferred Resource Mix

Based on the conditions and limitations listed above, the LP Module determined a preferred mix of new resources to meet the Company's future requirements. The *Preferred Resource Strategy* includes the following mix of resources and quantities during the first ten years of the study (2004-2013):

- 149 aMW of CCCT
- 25 aMW of wind
- 197 aMW coal
- 40 aMW of SCCT

By the end of the first ten years, a total of 411 aMW are developed. A depiction of the *Preferred Resource Strategy* is included in the following graph. Significant annual deficiencies do not develop until 2008, so the chart details only the years 2008 through 2013.

Chart 7.6
Preferred Resource Mix (in aMW)
2008-2013



After 2013, only coal is selected as a result of a change in the relationship between natural gas and coal prices. Natural gas prices over the IRP term increase faster than coal, making coal generation less costly in later years. In total, between 2014 and 2023, an additional 566 aMW of coal resources are selected in the *Preferred Resource Strategy*.

Costs of Preferred Resource Strategy Versus "No Additions"

Expected cost over the IRP term has traditionally been the benchmark of least-cost planning; and generally includes capital recovery, operation and maintenance, fuel, and transmission costs. This IRP continues to focus on expected power supply cost on a net present value (NPV) basis. Under *No Additions*, where no resource acquisitions are made, the ten-year NPV of the power

EXHIBIT H

August/September 2004 Loads and Resources Position

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

Avista Utilities

Long-Term Energy Load and Resource Tabulation (aMW)

2005-2024

August 13, 2004

Long-Term Energy Load and Resource Tabulation (aMW)
CONFIDENTIAL

Last Updated August 13, 2004	Notes	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
AVERAGE LOAD & HYDRO PLANNING											
REQUIREMENTS											
System Load	1	(1,008)	(1,041)	(1,063)	(1,093)	(1,126)	(1,156)	(1,187)	(1,212)	(1,237)	(1,265)
Contract Obligations	2	(61)	(59)	(59)	(59)	(59)	(57)	(57)	(56)	(56)	(56)
Total Requirements		(1,069)	(1,100)	(1,122)	(1,152)	(1,185)	(1,213)	(1,244)	(1,268)	(1,293)	(1,320)
RESOURCES											
Contract Rights	4	216	233	236	235	236	235	131	113	113	106
Hydro	3	532	511	511	511	505	481	477	461	460	459
Base Load Thermals	5	241	234	234	242	232	236	240	235	234	238
Gas Dispatch Units	6	162	157	162	154	162	157	162	154	162	157
Total Resources		1,151	1,136	1,143	1,143	1,135	1,109	1,010	963	970	961
POSITION		82	36	21	(10)	(50)	(104)	(234)	(304)	(324)	(360)
CONTINGENCY PLANNING											
Confidence Interval	7	(163)	(160)	(160)	(160)	(159)	(155)	(155)	(151)	(151)	(151)
WNP-3 Obligation	8	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)
Peaking Resources	9	139	135	138	138	137	134	138	138	137	138
CONTINGENCY NET POSITION		27	(21)	(32)	(63)	(104)	(156)	(282)	(349)	(369)	(404)

Notes:

1. Load estimates are from the 2005 load forecast (07-27-2004) including the forecast for net Potlatch load.
2. Includes Nichols Pumping and Canadian Entitlement Return contracts. Does not include WNP-3 Obligation.
3. Average (60-year) hydro generation for system hydro (Clark Fork and Spokane River projects) and contract hydro (Mid-Columbia) based on NWPP 2003-04 Headwater Benefits Study, modified for daily spill. Mid-C numbers reflect the Priest Rapids and Wanapum contract extensions beginning in 2005.
4. Includes small PURPA contracts, Upriver, El Paso 2004-2006 25 MW flat, Duke 2004-2006 50 MW flat, Morgan Stanley 2004-2006 25 MW flat, El Paso 2007-2010 75 MW flat, BP Energy 2007-2010 25 MW flat, Grant Displacement, PPM Wind, and WNP-3 Receipt.
5. Includes Colstrip and Kettle Falls at full capability, adjusted for maintenance and forced outage.
6. Includes Coyote Springs 2, Coyote Springs 2 duct burner, Boulder Park, and Kettle Falls CT at full capability, adjusted for maintenance and forced outage.
7. The confidence interval represents the 12-month average of reserve energy necessary to ensure no more than a 10 percent probability of loads exceeding, and/or hydro underperforming, during a given month.
8. Represents highest level of potential obligation to BPA generally exercised under low hydro conditions.
9. Includes Northeast and Rathdrum at full capability, adjusted for forced outage and maintenance.
   Northeast is limited to 1,700 hours of operation per year, which has been applied to the period of highest typical market prices.

Avista Utilities

Long-Term Peak Load and Resource Tabulation (MW)

2005-2024

September 1, 2004

Long-Term Capacity Load and Resource Tabulation (MW)
CONFIDENTIAL

Last Updated September 1, 2004	Notes	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
PEAK LOAD AND RESOURCE PLANNING											
REQUIREMENTS											
System Load	1	(1,549)	(1,604)	(1,637)	(1,683)	(1,723)	(1,779)	(1,813)	(1,864)	(1,903)	(1,945)
Contracts Obligations	2	(170)	(166)	(166)	(166)	(161)	(161)	(159)	(159)	(159)	(159)
Total Requirements		(1,718)	(1,770)	(1,803)	(1,849)	(1,884)	(1,940)	(1,972)	(2,023)	(2,062)	(2,104)
RESOURCES											
Contracts Rights	4	212	212	215	215	216	215	97	98	98	98
Hydro Resources	3	1,108	1,101	1,093	1,093	1,039	1,032	1,001	979	992	991
Base Load Thermals	5	275	275	275	275	275	275	275	275	275	275
Gas Dispatch Units	6	171	166	166	170	166	166	171	166	166	170
Peaking Units	7	243	243	243	243	243	243	243	243	243	243
Total Resources		2,008	1,997	1,992	1,996	1,939	1,932	1,786	1,761	1,774	1,777
PEAK POSITION		289	227	189	147	55	(9)	(186)	(262)	(289)	(327)

RESERVE PLANNING											
Planning Reserve Margin	8	(245)	(250)	(254)	(258)	(262)	(268)	(271)	(276)	(280)	(285)
RESERVE PEAK POSITION		45	(23)	(65)	(111)	(208)	(277)	(457)	(538)	(569)	(612)

Notes:

All data based on monthly peak deficits from period November through February.

1. Load estimates are from the 2005 peak load forecast (07-27-2004) including the forecast for net Potlatch load.
2. Includes Nichols Pumping, Canadian Entitlement Return, and PGE Capacity contracts.
3. Peak hydro generation for system hydro (Clark Fork and Spokane River projects, excluding maintenance) and contract hydro (Mid-Columbia, including maintenance). Mid-C numbers reflect the Priest Rapids and Wanapum contract extensions beginning in 2005.
4. Includes small PURPA contracts, Upriver, El Paso 2004-2006 25 MW flat, Duke 2004-2006 50 MW flat, Morgan Stanley 2004-2006 25 MW flat, El Paso 2007-2010 75 MW flat, BP Energy 2007-2010 25 MW flat, Grant Displacement, and WNP-3 Receipt.
5. Includes Colstrip and Kettle Falls, adjusted for maintenance.
6. Includes 50% of Coyote Springs 2 and Coyote Springs 2 duct burner, Boulder Park, and Kettle Falls CT, adjusted for maintenance.
7. Includes Northeast and Rathdrum, adjusted for maintenance.
8. Includes 10% of peak load (to approximate load variability) and 90 MW (to approximate the risk of river freeze-up and partial forced outages).

EXHIBIT I

May 2004 Analysis

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

May 2004 Analysis

Value Analysis

AURORA was utilized to dispatch 50% of Coyote Springs 2 (including the duct burner) against 20-year sets of fixed hourly market prices starting in 2005, as described further below. AURORA incorporated the plant's dispatch characteristics (e.g., minimum up time) to simulate hourly operation and ultimately determine the value of the resource versus each set of market prices.

The electric and natural gas prices utilized in AURORA were initially based on monthly forward prices taken from NUCLEUS on April 8, 2004. These prices were shaped hourly based on prices from the 2003 Idaho General Rate Case. The resulting prices matched forward prices on a monthly basis, but retained the hourly shape from the rate case. Electric and natural gas prices were tied directly to NUCLEUS forward prices through 2008, and escalated at 3% thereafter.

Numerous price scenarios, representing potential future spark spreads[1], were then created and used as input prices for individual AURORA runs. Spark spread modifications were implemented through changes to natural gas prices. Ultimately, four scenarios were used to represent likely potential futures. These scenarios are described below:

1. *Increasing Spark Spread*
   In this scenario spark spreads increased over time. Electric prices increased at 3% while natural gas prices increased at 2% through the end of the study. This resulted in a gradual increase in the spark spread through 2024. The resulting average spread was 9,453 BTU/kWh, growing from 8,572 in 2005 to 10,346 in 2024. This scenario was designed to reflect a market where electric prices are rising faster than gas prices.

2. *Forwards/IRP Spark Spread*
   Spark spreads in this scenario were tied to forward prices through 2008. After 2008, annual spreads were matched with those from the 2003 Integrated Resource Plan (IRP). The average spark spread for this scenario was 10,928, growing from 8,165 in 2005 to 12,476 in 2024. This scenario was designed to capture the most expected short and long-term prices. Forward prices were used because they represent the actual prices available for purchases in the current forward market. IRP prices were used because the IRP included significant analysis to estimate long-term market conditions.

3. *10,500 Spark Spread*
   In this scenario the annual spark spread was set to 10,500 for the duration of the study. As with the other scenarios, the spread still maintained the monthly shape inherent in the forwards. This scenario was designed to represent a market where a CCCT would be marginally cost-effective through the entire duration of the study.

4. *IRP Prices*
   Spark spreads in this scenario were taken directly from the 2003 IRP. The resulting average was 12,482 BTU/kWh. This scenario effectively compares the plant against the avoided costs that have been established for PURPA contracts.

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[1] For the purposes of this document, the term "spark spread" is used to describe the heat rate implied by the relationship between natural gas and electric market prices. The spark spread for a given time period is the electric price divided by the natural gas price multiplied by 1,000 (e.g., $45 / $5 * 1000 = 9000 Btu/kWh).

The results for each scenario were adjusted by two factors. First, $2 million per year was added as an estimate for the value of the optimization of turbine fuel purchases through "heat rate swaps" (transactions in the forward gas and electric markets to either buy fuel for the plant and sell power or sell fuel from the plant and buy the power, depending on the spark spread). Next, margins generated by the plant during Q2 of each year through 2008 were removed to represent a conservative possibility that transmission may be restricted during certain periods in that quarter. Transmission issues are further detailed later in the document.

The results for each scenario were input into a revenue requirements model and a marginal benefit value, compared to the breakeven purchase price, was determined. Refer to the following table for the detailed results.

Table 3 – Detailed Scenario Results

Scenario	Average Spark Spread (Btu/kWh)	Base Value[1] ($000)	Base Value[1] ($/kW)	W/ Option Value[2] ($000)	W/ Option Value[2] ($/kW)	W/O Q2 Trans[3] ($000)	W/O Q2 Trans[3] ($/kW)
Increasing Spark	9,453	21,322	150	46,144	324	46,159	324
Forwards/IRP Spark	10,928	43,164	303	67,986	478	67,966	478
10,500 Spark	10,500	45,633	321	70,455	495	70,471	495
IRP Prices	12,482	92,101	647	116,923	822	116,385	818

(1) Value taken directly from AURORA model runs.
(2) Includes estimate of $2 million for value of heat rate swaps.
(3) Assumes no generation during Q2 through 2008.

The second scenario, "Forwards/IRP Spark," was determined to be the most expected representation of future market prices because it incorporates the best representations of short-term and long-term market conditions. Forward prices, because they represent actual prices for gas and electricity in the current forward market, are the best representation of short-term prices. But since forwards are only available for two to three years out, they are not adequate to represent long-term market conditions. The 2003 IRP, on the other hand, incorporated significant analysis utilizing the AURORA model to estimate long-term market conditions.

As shown in Table 3 above, the resulting breakeven market value for 50% of Coyote Springs 2 was roughly $68 million.

* Note: See CS2 Acquisition of Second Half – 2004, Book 2, tab labeled "Option Value Back-Cast Analysis" (9-24-04) for a description of the option value analysis

Coyote Springs 2 Balance of Plant Analyses

Scenario	Heat Rate	Base Value		W/ Option Value*		W/O Q2 Trans**	
	(Btu/kWh)	($000)	($/kW)	($000)	($/kW)	($000)	($/kW)
Increasing Spark	9,453	21,322	150	46,144	324	46,159	324
Forwards/IRP Spark	10,928	43,164	303	67,986	478	67,966	478
10,500 Spark	10,500	45,633	321	70,455	495	70,471	495
IRP Prices	12,482	92,101	647	116,923	822	116,385	818

Scenario	Description
Increasing Spark	Spark spread grows after forwards - electric price escalates at 3%, gas at 2%.
Forwards/IRP Spark	Spark spread based on forwards thru 2008, then based on 2003 IRP.
10,500 Spark	Average spark spread has been increased to 10,500 BTU/kWh.
IRP Prices	Electric and natural gas prices are based on 2003 IRP.

* Includes conservative estimate of $2MM for value of heat rate swaps.

** Assumes no transmission is available during Q2 through 2008.

05-07-2004
JRF

Electric and Natural Gas Prices Used for 50% CS2 Analysis

	Increasing Spark			Fwd/IRP Spark			10,500 Spark			IRP Prices		
Year	Elec	Gas	IHR	Elec	Gas	IHR	Elec	Gas	IHR	Elec	Gas	IHR
2005	42.74	4.99	8,572	42.74	5.23	8,165	42.74	4.09	10,451	34.86	4.05	8,603
2006	42.31	4.64	9,119	42.31	4.92	8,606	42.31	3.84	11,010	36.42	3.97	9,184
2007	42.31	4.90	8,629	42.31	5.25	8,064	42.31	4.10	10,328	38.25	4.19	9,124
2008	42.31	4.89	8,653	42.31	5.28	8,010	42.31	4.13	10,254	42.41	4.37	9,713
2009	43.65	4.88	8,944	43.65	4.46	9,795	43.65	4.16	10,494	46.29	4.48	10,336
2010	44.98	4.98	9,032	44.98	4.33	10,394	44.98	4.28	10,498	49.98	4.57	10,946
2011	46.33	5.08	9,126	46.33	4.23	10,955	46.33	4.41	10,497	52.60	4.75	11,070
2012	47.73	5.18	9,212	47.73	4.20	11,371	47.73	4.55	10,500	55.13	4.67	11,812
2013	49.16	5.29	9,298	49.16	4.35	11,289	49.16	4.68	10,499	57.48	4.89	11,745
2014	50.62	5.39	9,390	50.62	4.34	11,654	50.62	4.82	10,496	58.29	4.91	11,879
2015	52.16	5.50	9,484	52.16	4.43	11,768	52.16	4.97	10,501	59.65	5.08	11,751
2016	53.72	5.61	9,577	53.72	4.59	11,702	53.72	5.12	10,500	62.73	5.27	11,906
2017	55.33	5.72	9,666	55.33	4.64	11,917	55.33	5.27	10,500	64.67	5.35	12,091
2018	56.98	5.84	9,756	56.98	4.83	11,807	56.98	5.43	10,498	64.73	5.54	11,685
2019	58.70	5.96	9,852	58.70	4.88	12,037	58.70	5.59	10,499	66.95	5.59	11,971
2020	60.48	6.08	9,951	60.48	4.93	12,258	60.48	5.76	10,502	69.24	5.71	12,123
2021	62.28	6.19	10,053	62.28	5.16	12,060	62.28	5.93	10,499	70.35	5.92	11,892
2022	64.15	6.32	10,148	64.15	5.46	11,744	64.15	6.11	10,501	71.24	5.96	11,955
2023	66.08	6.45	10,250	66.08	5.30	12,478	66.08	6.29	10,502	75.32	6.18	12,193
2024	68.05	6.58	10,346	68.05	5.45	12,476	68.05	6.48	10,500	245.00	6.50	37,663

Rate Impacts

An analysis was performed to determine the rate impacts of the selected scenario at various purchase prices. The table below shows the estimated rate impacts for the breakeven price of $68 million, based upon the "Forwards/IRP Spark" scenario and the purchase price of $62.5 million that was negotiated as a basis for the non-binding letter of intent to purchase the second half of the Coyote Springs 2 project.

Table 4 – Estimated Rate Impacts

	$68 MM ($250/kW)		$62.5 MM ($375/kW)	
Year	($000)	(percent)	($000)	(percent)
2005	9,849	2.2%	8,847	2.0%
2006	8,218	1.8%	7,248	1.5%
2007	9,467	1.9%	8,533	1.8%
2008	9,368	1.9%	8,468	1.7%
2009	3,582	0.7%	2,715	0.5%
2010	1,470	0.3%	635	0.1%
2011	(587)	-0.1%	(1,391)	-0.2%
2012	(2,404)	-0.4%	(3,179)	-0.5%
2013	(2,860)	-0.5%	(3,605)	-0.6%
2014	(4,559)	-0.7%	(5,276)	-0.8%
2015	(5,647)	-0.8%	(6,334)	-1.0%
2016	(6,304)	-0.9%	(6,962)	-1.0%
2017	(7,644)	-1.1%	(8,273)	-1.1%
2018	(8,151)	-1.1%	(8,751)	-1.2%
2019	(9,655)	-1.2%	(10,226)	-1.3%
2020	(11,238)	-1.4%	(11,780)	-1.5%
2021	(11,466)	-1.4%	(11,979)	-1.4%
2022	(11,354)	-1.3%	(11,838)	-1.4%
2023	(14,595)	-1.6%	(15,050)	-1.7%
2024	(15,636)	-1.6%	(16,062)	-1.7%
NPV	0		(7,477)	

Coyote Springs 2 Rate Impacts

Year	$62.5MM ($439/kW) ($000)	$62.5MM ($439/kW) (percent)	$53MM ($375/kW) ($000)	$53MM ($375/kW) (percent)	$71MM ($500/kW) ($000)	$71MM ($500/kW) (percent)	$107MM ($750/kW) ($000)	$107MM ($750/kW) (percent)
2005	8,847	2.0%	7,171	1.6%	10,431	2.3%	16,950	3.8%
2006	7,248	1.5%	5,625	1.2%	8,781	1.9%	15,093	3.2%
2007	8,533	1.8%	6,970	1.4%	10,010	2.1%	16,091	3.3%
2008	8,468	1.7%	6,961	1.4%	9,890	2.0%	15,748	3.1%
2009	2,715	0.5%	1,264	0.2%	4,086	0.8%	9,729	1.8%
2010	635	0.1%	(763)	-0.1%	1,955	0.4%	7,391	1.3%
2011	(1,391)	-0.2%	(2,737)	-0.5%	(119)	0.0%	5,116	0.9%
2012	(3,179)	-0.5%	(4,475)	-0.8%	(1,955)	-0.3%	3,087	0.5%
2013	(3,605)	-0.6%	(4,853)	-0.8%	(2,427)	-0.4%	2,424	0.4%
2014	(5,276)	-0.8%	(6,474)	-1.0%	(4,143)	-0.6%	518	0.1%
2015	(6,334)	-1.0%	(7,484)	-1.1%	(5,248)	-0.8%	(775)	-0.1%
2016	(6,962)	-1.0%	(8,064)	-1.2%	(5,922)	-0.9%	(1,639)	-0.2%
2017	(8,273)	-1.1%	(9,326)	-1.3%	(7,279)	-1.0%	(3,185)	-0.4%
2018	(8,751)	-1.2%	(9,755)	-1.3%	(7,803)	-1.0%	(3,898)	-0.5%
2019	(10,226)	-1.3%	(11,181)	-1.4%	(9,323)	-1.2%	(5,608)	-0.7%
2020	(11,780)	-1.5%	(12,687)	-1.6%	(10,923)	-1.3%	(7,396)	-0.9%
2021	(11,979)	-1.4%	(12,838)	-1.5%	(11,169)	-1.3%	(7,830)	-0.9%
2022	(11,838)	-1.4%	(12,647)	-1.4%	(11,073)	-1.3%	(7,923)	-0.9%
2023	(15,050)	-1.7%	(15,812)	-1.7%	(14,331)	-1.6%	(11,370)	-1.2%
2024	(16,062)	-1.7%	(16,775)	-1.8%	(15,388)	-1.6%	(12,615)	-1.3%
Net Present Values								
20 Years	*(7,477)*		*(20,113)*		*4,461*		*53,609*	
5 Years	*29,099*		*22,855*		*34,997*		*59,282*	

NOTES:

1) Includes conservative estimate of $2MM for value of heat rate swaps.
2) Assumes no transmission is available during Q2 through 2008.
3) Assumes $450MM base revenue requirement, escalating @ 4% per year.
4) Spark spreads based on forward prices through 2008, IRP prices thereafter.

05-18-2004
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50% of Coyote Springs 2 (CCCT and Duct Burner)

Economic Analysis Detail

Assumptions

Installed Cost	62,500	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	187.50	2004 $000s	Nominal Discount	8.2 percent
Installed Cost	439	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5 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	2,000	2004 $000s		
Gas Usage Rate	25.4	000s dth/day	Transportation	3.0	percent					

	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	714.2	11,936	0	11,936	16.7	3,078	0	852	193	4,122	5.8	16,058	5,151	2,060	(8,847)	(12.4)	28,763	40.3	44,822	62.8
2	2006	723.5	11,544	0	11,544	16.0	3,170	0	822	199	4,191	5.8	15,735	6,365	2,122	(7,248)	(10.0)	27,606	38.2	43,341	59.9
3	2007	689.3	11,178	0	11,178	16.2	3,265	0	793	205	4,263	6.2	15,441	4,722	2,185	(8,533)	(12.4)	27,877	40.4	43,318	62.8
4	2008	690.8	10,831	0	10,831	15.7	3,363	0	764	211	4,338	6.3	15,169	4,450	2,251	(8,468)	(12.3)	28,229	40.9	43,398	62.8
5	2009	809.4	10,481	0	10,481	12.9	3,464	0	734	217	4,415	5.5	14,896	9,863	2,319	(2,715)	(3.4)	28,210	34.9	43,106	53.3
6	2010	880.9	10,225	0	10,225	11.6	3,568	0	705	224	4,497	5.1	14,721	11,699	2,388	(635)	(0.7)	29,885	33.9	44,606	50.6
7	2011	929.7	9,951	0	9,951	10.7	3,675	0	676	231	4,581	4.9	14,532	13,463	2,460	1,391	1.5	30,936	33.3	45,468	48.9
8	2012	944.7	9,656	0	9,656	10.2	3,785	0	646	238	4,669	4.9	14,325	14,971	2,534	3,179	3.4	31,324	33.2	45,649	48.3
9	2013	941.4	9,399	0	9,399	10.0	3,899	0	617	245	4,760	5.1	14,159	15,155	2,610	3,605	3.8	32,349	34.4	46,508	49.4
10	2014	946.3	9,103	0	9,103	9.6	4,015	0	587	252	4,855	5.1	13,958	16,546	2,688	5,276	5.6	32,549	34.4	46,506	49.1
11	2015	947.1	8,832	0	8,832	9.3	4,136	0	558	260	4,954	5.2	13,786	17,351	2,768	6,334	6.7	33,274	35.1	47,059	49.7
12	2016	949.0	8,587	0	8,587	9.0	4,260	0	529	267	5,056	5.3	13,643	17,754	2,852	6,962	7.3	34,522	36.4	48,164	50.8
13	2017	948.0	8,302	0	8,302	8.8	4,388	0	499	275	5,162	5.4	13,464	18,801	2,937	8,273	8.7	34,942	36.9	48,406	51.1
14	2018	947.1	8,059	0	8,059	8.5	4,519	0	470	284	5,273	5.6	13,332	19,058	3,025	8,751	9.2	36,240	38.3	49,573	52.3
15	2019	949.1	7,780	0	7,780	8.2	4,655	0	441	292	5,388	5.7	13,168	20,278	3,116	10,226	10.8	36,776	38.8	49,944	52.6
16	2020	954.0	7,510	0	7,510	7.9	4,795	0	411	301	5,507	5.8	13,017	21,587	3,209	11,780	12.3	37,488	39.3	50,504	52.9
17	2021	949.4	7,277	0	7,277	7.7	4,939	0	382	310	5,630	5.9	12,907	21,581	3,306	11,979	12.6	38,969	41.0	51,876	54.6
18	2022	946.7	7,069	0	7,069	7.5	5,087	0	352	319	5,758	6.1	12,828	21,261	3,405	11,838	12.5	40,989	43.3	53,817	56.8
19	2023	951.8	6,728	0	6,728	7.1	5,239	0	323	329	5,891	6.2	12,619	24,183	3,507	15,050	15.8	40,207	42.2	52,827	55.5
20	2024	954.7	6,489	0	6,489	6.8	5,396	0	294	339	6,029	6.3	12,518	24,967	3,612	16,062	16.8	41,552	43.5	54,070	56.6
Net Present Value			94,371	0	94,371		37,083	0	6,256	2,327	45,666		140,037	122,777	24,822	7,561		307,192		447,230	
Nominal Levelized Cost ($/MWh)						11.0						5.3					0.9		35.7		52.0
Real Levelized Cost ($/MWh)						8.9						4.3					0.7		28.9		42.1

Coyote Springs 2 Rate Impacts

Year	$36MM ($250/kW) ($000)	(percent)	$53MM ($375/kW) ($000)	(percent)	$71MM ($500/kW) ($000)	(percent)	$107MM ($750/kW) ($000)	(percent)
2005	3,911	0.9%	7,171	1.6%	10,431	2.3%	16,950	3.8%
2006	2,469	0.5%	5,625	1.2%	8,781	1.9%	15,093	3.2%
2007	3,929	0.8%	6,970	1.4%	10,010	2.1%	16,091	3.3%
2008	4,033	0.8%	6,961	1.4%	9,890	2.0%	15,748	3.1%
2009	(1,557)	-0.3%	1,264	0.2%	4,086	0.8%	9,729	1.8%
2010	(3,481)	-0.6%	(763)	-0.1%	1,955	0.4%	7,391	1.3%
2011	(5,355)	-0.9%	(2,737)	-0.5%	(119)	0.0%	5,116	0.9%
2012	(6,996)	-1.2%	(4,475)	-0.8%	(1,955)	-0.3%	3,087	0.5%
2013	(7,278)	-1.2%	(4,853)	-0.8%	(2,427)	-0.4%	2,424	0.4%
2014	(8,805)	-1.4%	(6,474)	-1.0%	(4,143)	-0.6%	518	0.1%
2015	(9,720)	-1.5%	(7,484)	-1.1%	(5,248)	-0.8%	(775)	-0.1%
2016	(10,205)	-1.5%	(8,064)	-1.2%	(5,922)	-0.9%	(1,639)	-0.2%
2017	(11,373)	-1.6%	(9,326)	-1.3%	(7,279)	-1.0%	(3,185)	-0.4%
2018	(11,707)	-1.6%	(9,755)	-1.3%	(7,803)	-1.0%	(3,898)	-0.5%
2019	(13,039)	-1.7%	(11,181)	-1.4%	(9,323)	-1.2%	(5,608)	-0.7%
2020	(14,450)	-1.8%	(12,687)	-1.6%	(10,923)	-1.3%	(7,396)	-0.9%
2021	(14,507)	-1.7%	(12,838)	-1.5%	(11,169)	-1.3%	(7,830)	-0.9%
2022	(14,222)	-1.6%	(12,647)	-1.4%	(11,073)	-1.3%	(7,923)	-0.9%
2023	(17,293)	-1.9%	(15,812)	-1.7%	(14,331)	-1.6%	(11,370)	-1.2%
2024	(18,161)	-1.9%	(16,775)	-1.8%	(15,388)	-1.6%	(12,615)	-1.3%

Net Present Values

	$36MM ($250/kW)	$53MM ($375/kW)	$71MM ($500/kW)	$107MM ($750/kW)
20 Years	*(44,686)*	*(20,113)*	*4,461*	*53,609*
5 Years	*10,713*	*22,855*	*34,997*	*59,282*

NOTES:

1) Includes conservative estimate of $2MM for value of heat rate swaps.
2) Assumes no transmission is available during Q2 through 2008.
3) Assumes $450MM base revenue requirement, escalating @ 4% per year.
4) Spark spreads based on forward prices through 2008, IRP prices thereafter.

04-28-2004
JRF

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

Economic Analysis Detail

Assumptions											
Installed Cost	35,570	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	106.71	2004 $000s	Nominal Discount	8.2	percent
Installed Cost	250	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5	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	2,000	2004 $000s			
Gas Usage Rate	25.4	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	714.2	7,450	0	7,450	10.4	3,078	0	485	110	3,672	5.1	11,122	5,151	2,060	(3,911)	(5.5)	28,763	40.3	39,886	55.8
2 2006	723.5	7,205	0	7,205	10.0	3,170	0	468	113	3,751	5.2	10,956	6,365	2,122	(2,469)	(3.4)	27,606	38.2	38,563	53.3
3 2007	689.3	7,004	0	7,004	10.2	3,265	0	451	117	3,833	5.6	10,837	4,722	2,185	(3,929)	(5.7)	27,877	40.4	38,714	56.2
4 2008	690.8	6,816	0	6,816	9.9	3,363	0	435	120	3,918	5.7	10,734	4,450	2,251	(4,033)	(5.8)	28,229	40.9	38,963	56.4
5 2009	809.4	6,619	0	6,619	8.2	3,464	0	418	124	4,005	4.9	10,624	9,863	2,319	1,557	1.9	28,210	34.9	38,833	48.0
6 2010	880.9	6,509	0	6,509	7.4	3,568	0	401	127	4,096	4.6	10,606	11,699	2,388	3,481	4.0	29,885	33.9	40,490	46.0
7 2011	929.7	6,377	0	6,377	6.9	3,675	0	384	131	4,190	4.5	10,568	13,463	2,460	5,355	5.8	30,936	33.3	41,504	44.6
8 2012	944.7	6,220	0	6,220	6.6	3,785	0	368	135	4,288	4.5	10,508	14,971	2,534	6,996	7.4	31,324	33.2	41,832	44.3
9 2013	941.4	6,097	0	6,097	6.5	3,899	0	351	139	4,389	4.7	10,486	15,155	2,610	7,278	7.7	32,349	34.4	42,835	45.5
10 2014	946.3	5,935	0	5,935	6.3	4,015	0	334	143	4,493	4.7	10,428	16,546	2,688	8,805	9.3	32,549	34.4	42,977	45.4
11 2015	947.1	5,799	0	5,799	6.1	4,136	0	318	148	4,601	4.9	10,400	17,351	2,768	9,720	10.3	33,274	35.1	43,673	46.1
12 2016	949.0	5,687	0	5,687	6.0	4,260	0	301	152	4,713	5.0	10,400	17,754	2,852	10,205	10.8	34,522	36.4	44,922	47.3
13 2017	948.0	5,536	0	5,536	5.8	4,388	0	284	157	4,829	5.1	10,365	18,801	2,937	11,373	12.0	34,942	36.9	45,307	47.8
14 2018	947.1	5,428	0	5,428	5.7	4,519	0	267	161	4,948	5.2	10,376	19,058	3,025	11,707	12.4	36,240	38.3	46,617	49.2
15 2019	949.1	5,283	0	5,283	5.6	4,655	0	251	166	5,072	5.3	10,355	20,278	3,116	13,039	13.7	36,776	38.8	47,131	49.7
16 2020	954.0	5,147	0	5,147	5.4	4,795	0	234	171	5,200	5.5	10,347	21,587	3,209	14,450	15.1	37,488	39.3	47,834	50.1
17 2021	949.4	5,047	0	5,047	5.3	4,939	0	217	176	5,332	5.6	10,380	21,581	3,306	14,507	15.3	38,969	41.0	49,349	52.0
18 2022	946.7	4,974	0	4,974	5.3	5,087	0	201	182	5,469	5.8	10,443	21,261	3,405	14,222	15.0	40,989	43.3	51,433	54.3
19 2023	951.8	4,767	0	4,767	5.0	5,239	0	184	187	5,610	5.9	10,377	24,163	3,507	17,293	18.2	40,207	42.2	50,585	53.1
20 2024	954.7	4,662	0	4,662	4.9	5,396	0	167	193	5,756	6.0	10,418	24,967	3,612	18,161	19.0	41,552	43.5	51,970	54.4
Net Present Value		60,813	0	60,813		37,083	0	3,561	1,324	41,968		102,781	122,777	24,822	44,818		307,192		409,973	
Nominal Levelized Cost ($/MWh)					7.1						4.9					5.2		35.7		47.7
Real Levelized Cost ($/MWh)					5.7						4.0					4.2		28.9		38.6

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

Economic Analysis Detail

Assumptions											
Installed Cost	53,355	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	160.07	2004 $000s	Nominal Discount	8.2	percent
Installed Cost	375	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5	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	2,000	2004 $000s			
Gas Usage Rate	25.4	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	714.2	10,412	0	10,412	14.6	3,078	0	727	165	3,970	5.6	14,382	5,151	2,060	(7,171)	(10.0)	28,763	40.3	43,145	60.4
2 2006	723.5	10,070	0	10,070	13.9	3,170	0	702	170	4,042	5.6	14,112	6,365	2,122	(5,625)	(7.8)	27,606	38.2	41,719	57.7
3 2007	689.3	9,761	0	9,761	14.2	3,265	0	677	175	4,117	6.0	13,878	4,722	2,185	(6,970)	(10.1)	27,877	40.4	41,754	60.6
4 2008	690.8	9,468	0	9,468	13.7	3,363	0	652	180	4,195	6.1	13,663	4,450	2,251	(6,961)	(10.1)	28,229	40.9	41,892	60.6
5 2009	809.4	9,169	0	9,169	11.3	3,464	0	627	186	4,276	5.3	13,446	9,863	2,319	(1,264)	(1.6)	28,210	34.9	41,655	51.5
6 2010	880.9	8,963	0	8,963	10.2	3,568	0	602	191	4,361	5.0	13,324	11,699	2,388	763	0.9	29,885	33.9	43,208	49.0
7 2011	929.7	8,737	0	8,737	9.4	3,675	0	577	197	4,448	4.8	13,186	13,463	2,460	2,737	2.9	30,936	33.3	44,122	47.5
8 2012	944.7	8,490	0	8,490	9.0	3,785	0	552	203	4,539	4.8	13,029	14,971	2,534	4,475	4.7	31,324	33.2	44,352	46.9
9 2013	941.4	8,278	0	8,278	8.8	3,899	0	527	209	4,634	4.9	12,912	15,155	2,610	4,853	5.2	32,349	34.4	45,261	48.1
10 2014	946.3	8,027	0	8,027	8.5	4,015	0	502	215	4,732	5.0	12,759	16,546	2,688	6,474	6.8	32,549	34.4	45,308	47.9
11 2015	947.1	7,802	0	7,802	8.2	4,136	0	476	222	4,834	5.1	12,636	17,351	2,768	7,484	7.9	33,274	35.1	45,909	48.5
12 2016	949.0	7,602	0	7,602	8.0	4,260	0	451	228	4,940	5.2	12,542	17,754	2,852	8,064	8.5	34,522	36.4	47,063	49.6
13 2017	948.0	7,363	0	7,363	7.8	4,388	0	426	235	5,049	5.3	12,412	18,801	2,937	9,326	9.8	34,942	36.9	47,354	49.9
14 2018	947.1	7,166	0	7,166	7.6	4,519	0	401	242	5,163	5.5	12,328	19,058	3,025	9,755	10.3	36,240	38.3	48,569	51.3
15 2019	949.1	6,932	0	6,932	7.3	4,655	0	376	249	5,281	5.6	12,213	20,278	3,116	11,181	11.8	36,776	38.8	48,989	51.6
16 2020	954.0	6,707	0	6,707	7.0	4,795	0	351	257	5,403	5.7	12,110	21,587	3,209	12,687	13.3	37,488	39.3	49,598	52.0
17 2021	949.4	6,520	0	6,520	6.9	4,939	0	326	265	5,529	5.8	12,049	21,581	3,306	12,838	13.5	38,969	41.0	51,018	53.7
18 2022	946.7	6,358	0	6,358	6.7	5,087	0	301	272	5,660	6.0	12,018	21,261	3,405	12,647	13.4	40,989	43.3	53,007	56.0
19 2023	951.8	6,062	0	6,062	6.4	5,239	0	276	281	5,796	6.1	11,858	24,163	3,507	15,812	16.6	40,207	42.2	52,065	54.7
20 2024	954.7	5,869	0	5,869	6.1	5,396	0	251	289	5,936	6.2	11,805	24,967	3,612	16,775	17.6	41,552	43.5	53,357	55.9
Net Present Value		82,976	0	82,976		37,083	0	5,341	1,987	44,410		127,386	122,777	24,822	20,213		307,192		434,578	
Nominal Levelized Cost ($/MWh)					9.7						5.2					2.4		35.7		50.6
Real Levelized Cost ($/MWh)					7.8						4.2					1.9		28.9		40.9

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

Economic Analysis Detail

Assumptions												
Installed Cost	71,140	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	213.42	2004 $000s	Nominal Discount	8.2	percent
Installed Cost	500	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5	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	2,000	2004 $000s			
Gas Usage Rate	25.4	000s dth/day	Transportation	3.0	percent						

			Fixed Costs: Capital Recovery and Miscellaneous				Fixed Costs: 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	714.2	13,375	0	13,375	18.7	3,078	0	970	220	4,267	6.0	17,642	5,151	2,060	(10,431)	(14.6)	28,763	40.3	46,405	65.0
2	2006	723.5	12,936	0	12,936	17.9	3,170	0	936	226	4,332	6.0	17,268	6,365	2,122	(8,781)	(12.1)	27,606	38.2	44,875	62.0
3	2007	689.3	12,517	0	12,517	18.2	3,265	0	903	233	4,401	6.4	16,918	4,722	2,185	(10,010)	(14.5)	27,877	40.4	44,795	65.0
4	2008	690.8	12,119	0	12,119	17.5	3,363	0	869	240	4,472	6.5	16,592	4,450	2,251	(9,890)	(14.3)	28,229	40.9	44,821	64.9
5	2009	809.4	11,720	0	11,720	14.5	3,464	0	836	247	4,547	5.6	16,267	9,863	2,319	(4,086)	(5.0)	28,210	34.9	44,477	55.0
6	2010	880.9	11,417	0	11,417	13.0	3,568	0	802	255	4,625	5.3	16,042	11,699	2,388	(1,955)	(2.2)	29,885	33.9	45,926	52.1
7	2011	929.7	11,097	0	11,097	11.9	3,675	0	769	262	4,706	5.1	15,804	13,463	2,460	119	0.1	30,936	33.3	46,739	50.3
8	2012	944.7	10,759	0	10,759	11.4	3,785	0	736	270	4,791	5.1	15,550	14,971	2,534	1,955	2.1	31,324	33.2	46,873	49.6
9	2013	941.4	10,458	0	10,458	11.1	3,899	0	702	278	4,879	5.2	15,337	15,155	2,610	2,427	2.6	32,349	34.4	47,687	50.7
10	2014	946.3	10,119	0	10,119	10.7	4,015	0	669	287	4,971	5.3	15,090	16,546	2,688	4,143	4.4	32,549	34.4	47,639	50.3
11	2015	947.1	9,805	0	9,805	10.4	4,136	0	635	295	5,067	5.3	14,872	17,351	2,768	5,248	5.5	33,274	35.1	48,146	50.8
12	2016	949.0	9,517	0	9,517	10.0	4,260	0	602	304	5,166	5.4	14,683	17,754	2,852	5,922	6.2	34,522	36.4	49,205	51.8
13	2017	948.0	9,189	0	9,189	9.7	4,388	0	568	313	5,270	5.6	14,459	18,801	2,937	7,279	7.7	34,942	36.9	49,401	52.1
14	2018	947.1	8,903	0	8,903	9.4	4,519	0	535	323	5,377	5.7	14,281	19,058	3,025	7,803	8.2	36,240	38.3	50,521	53.3
15	2019	949.1	8,582	0	8,582	9.0	4,655	0	502	333	5,489	5.8	14,071	20,278	3,116	9,323	9.8	36,776	38.8	50,847	53.6
16	2020	954.0	8,268	0	8,268	8.7	4,795	0	468	342	5,605	5.9	13,873	21,587	3,209	10,923	11.5	37,488	39.3	51,361	53.8
17	2021	949.4	7,992	0	7,992	8.4	4,939	0	435	353	5,726	6.0	13,718	21,581	3,306	11,169	11.8	38,969	41.0	52,687	55.5
18	2022	946.7	7,742	0	7,742	8.2	5,087	0	401	363	5,851	6.2	13,593	21,261	3,405	11,073	11.7	40,989	43.3	54,582	57.7
19	2023	951.8	7,357	0	7,357	7.7	5,239	0	368	374	5,981	6.3	13,339	24,163	3,507	14,331	15.1	40,207	42.2	53,546	56.3
20	2024	954.7	7,075	0	7,075	7.4	5,396	0	334	385	6,116	6.4	13,192	24,967	3,612	15,388	16.1	41,552	43.5	54,743	57.3
Net Present Value			105,138	0	105,138		37,083	0	7,121	2,649	46,853		151,991	122,777	24,822	(4,392)		307,192		459,183	
Nominal Levelized Cost ($/MWh)						12.2						5.5					(0.5)		35.7		53.4
Real Levelized Cost ($/MWh)						9.9						4.4					(0.4)		28.9		43.3

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

Economic Analysis Detail

Assumptions											
Installed Cost	106,710	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	320.13	2004 $000s	Nominal Discount	8.2	percent
Installed Cost	750	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5	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	2,000	2004 $000s			
Gas Usage Rate	25.4	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	714.2	19,300	0	19,300	27.0	3,078	0	1,454	330	4,862	6.8	24,161	5,151	2,060	(16,950)	(23.7)	28,763	40.3	52,925	74.1
2	2006	723.5	18,667	0	18,667	25.8	3,170	0	1,404	340	4,914	6.8	23,581	6,365	2,122	(15,093)	(20.9)	27,606	38.2	51,187	70.7
3	2007	689.3	18,030	0	18,030	26.2	3,265	0	1,354	350	4,969	7.2	22,999	4,722	2,185	(16,091)	(23.3)	27,877	40.4	50,875	73.8
4	2008	690.8	17,423	0	17,423	25.2	3,363	0	1,304	360	5,027	7.3	22,450	4,450	2,251	(15,748)	(22.8)	28,229	40.9	50,679	73.4
5	2009	809.4	16,822	0	16,822	20.8	3,464	0	1,254	371	5,089	6.3	21,910	9,863	2,319	(9,729)	(12.0)	28,210	34.9	50,120	61.9
6	2010	880.9	16,324	0	16,324	18.5	3,568	0	1,204	382	5,154	5.9	21,478	11,699	2,388	(7,391)	(8.4)	29,885	33.9	51,362	58.3
7	2011	929.7	15,817	0	15,817	17.0	3,675	0	1,153	394	5,222	5.6	21,039	13,463	2,460	(5,116)	(5.5)	30,936	33.3	51,975	55.9
8	2012	944.7	15,298	0	15,298	16.2	3,785	0	1,103	406	5,294	5.6	20,591	14,971	2,534	(3,087)	(3.3)	31,324	33.2	51,915	55.0
9	2013	941.4	14,819	0	14,819	15.7	3,899	0	1,053	418	5,369	5.7	20,189	15,155	2,610	(2,424)	(2.6)	32,349	34.4	52,538	55.8
10	2014	946.3	14,303	0	14,303	15.1	4,015	0	1,003	430	5,449	5.8	19,752	16,546	2,688	(518)	(0.5)	32,549	34.4	52,300	55.3
11	2015	947.1	13,812	0	13,812	14.6	4,136	0	953	443	5,532	5.8	19,344	17,351	2,768	775	0.8	33,274	35.1	52,618	55.6
12	2016	949.0	13,347	0	13,347	14.1	4,260	0	903	456	5,619	5.9	18,966	17,754	2,852	1,639	1.7	34,522	36.4	53,488	56.4
13	2017	948.0	12,842	0	12,842	13.5	4,388	0	853	470	5,710	6.0	18,552	18,801	2,937	3,185	3.4	34,942	36.9	53,494	56.4
14	2018	947.1	12,379	0	12,379	13.1	4,519	0	802	484	5,806	6.1	18,185	19,058	3,025	3,898	4.1	36,240	38.3	54,426	57.5
15	2019	949.1	11,880	0	11,880	12.5	4,655	0	752	499	5,906	6.2	17,786	20,278	3,116	5,608	5.9	36,776	38.8	54,563	57.5
16	2020	954.0	11,390	0	11,390	11.9	4,795	0	702	514	6,010	6.3	17,400	21,587	3,209	7,396	7.8	37,488	39.3	54,888	57.5
17	2021	949.4	10,936	0	10,936	11.5	4,939	0	652	529	6,120	6.4	17,056	21,581	3,306	7,830	8.2	38,969	41.0	56,025	59.0
18	2022	946.7	10,509	0	10,509	11.1	5,087	0	602	545	6,233	6.6	16,743	21,261	3,405	7,923	8.4	40,989	43.3	57,732	61.0
19	2023	951.8	9,948	0	9,948	10.5	5,239	0	552	561	6,352	6.7	16,300	24,163	3,507	11,370	11.9	40,207	42.2	56,508	59.4
20	2024	954.7	9,489	0	9,489	9.9	5,396	0	502	578	6,476	6.8	15,965	24,967	3,612	12,615	13.2	41,552	43.5	57,517	60.2
Net Present Value			149,463	0	149,463		37,083	0	10,682	3,973	51,738		201,200	122,777	24,822	(53,601)		307,192		508,392	
Nominal Levelized Cost ($/MWh)						17.4						6.0					(6.2)		35.7		59.2
Real Levelized Cost ($/MWh)						14.1						4.9					(5.0)		28.9		47.9

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

Economic Analysis Detail

Assumptions											
Installed Cost	67,986	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	203.96	2004 $000s	Nominal Discount	8.2	percent
Installed Cost	478	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5	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	2,000	2004 $000s			
Gas Usage Rate	25.4	000s dth/day	Transportation	3.0	percent						

			Fixed Costs																		
			Capital Recovery and Miscellaneous				Operations & Maintenance									Net					
	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		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	725.2	12,869	0	12,869	17.7	3,078	0	927	210	4,214	5.8	17,083	5,183	2,060	(9,840)	(13.6)	29,177	40.2	46,260	63.8
2	2006	744.3	12,463	0	12,463	16.7	3,170	0	895	216	4,281	5.8	16,744	6,395	2,122	(8,227)	(11.1)	28,342	38.1	45,086	60.6
3	2007	696.7	12,042	0	12,042	17.3	3,265	0	863	223	4,350	6.2	16,392	4,750	2,185	(9,456)	(13.6)	28,158	40.4	44,550	63.9
4	2008	698.1	11,663	0	11,663	16.7	3,363	0	831	230	4,423	6.3	16,086	4,478	2,251	(9,357)	(13.4)	28,511	40.8	44,597	63.9
5	2009	809.4	11,268	0	11,268	13.9	3,464	0	799	236	4,499	5.6	15,767	9,863	2,319	(3,585)	(4.4)	28,210	34.9	43,976	54.3
6	2010	880.9	10,982	0	10,982	12.5	3,568	0	767	244	4,578	5.2	15,560	11,699	2,388	(1,473)	(1.7)	29,885	33.9	45,444	51.6
7	2011	929.7	10,679	0	10,679	11.5	3,675	0	735	251	4,660	5.0	15,339	13,463	2,460	584	0.6	30,936	33.3	46,275	49.8
8	2012	944.7	10,356	0	10,356	11.0	3,785	0	703	258	4,746	5.0	15,103	14,971	2,534	2,402	2.5	31,324	33.2	46,426	49.1
9	2013	941.4	10,072	0	10,072	10.7	3,899	0	671	266	4,836	5.1	14,907	15,155	2,610	2,857	3.0	32,349	34.4	47,257	50.2
10	2014	946.3	9,748	0	9,748	10.3	4,015	0	639	274	4,929	5.2	14,677	16,546	2,688	4,557	4.8	32,549	34.4	47,225	49.9
11	2015	947.1	9,450	0	9,450	10.0	4,136	0	607	282	5,025	5.3	14,475	17,351	2,768	5,644	6.0	33,274	35.1	47,749	50.4
12	2016	949.0	9,177	0	9,177	9.7	4,260	0	575	291	5,126	5.4	14,303	17,754	2,852	6,302	6.6	34,522	36.4	48,825	51.4
13	2017	948.0	8,865	0	8,865	9.4	4,388	0	543	300	5,230	5.5	14,096	18,801	2,937	7,642	8.1	34,942	36.9	49,038	51.7
14	2018	947.1	8,595	0	8,595	9.1	4,519	0	511	309	5,339	5.6	13,934	19,058	3,025	8,149	8.6	36,240	38.3	50,175	53.0
15	2019	949.1	8,289	0	8,289	8.7	4,655	0	479	318	5,452	5.7	13,741	20,278	3,116	9,653	10.2	36,776	38.8	50,517	53.2
16	2020	954.0	7,991	0	7,991	8.4	4,795	0	447	327	5,569	5.8	13,561	21,587	3,209	11,236	11.8	37,488	39.3	51,048	53.5
17	2021	949.4	7,731	0	7,731	8.1	4,939	0	415	337	5,691	6.0	13,422	21,581	3,306	11,465	12.1	38,969	41.0	52,391	55.2
18	2022	946.7	7,496	0	7,496	7.9	5,087	0	383	347	5,817	6.1	13,314	21,261	3,405	11,352	12.0	40,989	43.3	54,303	57.4
19	2023	951.8	7,128	0	7,128	7.5	5,239	0	351	358	5,948	6.2	13,076	24,163	3,507	14,594	15.3	40,207	42.2	53,284	56.0
20	2024	954.7	6,861	0	6,861	7.2	5,396	0	320	368	6,084	6.4	12,946	24,967	3,612	15,634	16.4	41,552	43.5	54,497	57.1
Net Present Value			101,276	0	101,276		37,083	0	6,805	2,531	46,420		147,696	122,874	24,822	(0)		308,630		456,326	
Nominal Levelized Cost ($/MWh)						11.8						5.4					(0.0)		35.8		53.0
Real Levelized Cost ($/MWh)						9.5						4.4					(0.0)		29.0		42.9

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

Economic Analysis Detail

Assumptions											
Installed Cost	67,966	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	203.90	2004 $000s	Nominal Discount	8.2	percent
Installed Cost	478	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5	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	2,000	2004 $000s			
Gas Usage Rate	25.4	000s dth/day	Transportation	3.0	percent						

			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 (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)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($/MWh)	($000s)	($/MWh)
1	2005	714.2	12,846	0	12,846	18.0	3,078	0	926	210	4,214	5.9	17,060	5,151	2,060	(9,849)	(13.8)	28,763	40.3	45,823	64.2
2	2006	723.5	12,424	0	12,424	17.2	3,170	0	894	216	4,281	5.9	16,705	6,365	2,122	(8,218)	(11.4)	27,606	38.2	44,311	61.2
3	2007	689.3	12,025	0	12,025	17.4	3,265	0	862	223	4,350	6.3	16,375	4,722	2,185	(9,467)	(13.7)	27,877	40.4	44,252	64.2
4	2008	690.8	11,646	0	11,646	16.9	3,363	0	830	229	4,423	6.4	16,069	4,450	2,251	(9,368)	(13.6)	28,229	40.9	44,298	64.1
5	2009	809.4	11,265	0	11,265	13.9	3,464	0	799	236	4,499	5.6	15,764	9,863	2,319	(3,582)	(4.4)	28,210	34.9	43,973	54.3
6	2010	880.9	10,979	0	10,979	12.5	3,568	0	767	243	4,578	5.2	15,557	11,699	2,388	(1,470)	(1.7)	29,885	33.9	45,441	51.6
7	2011	929.7	10,676	0	10,676	11.5	3,675	0	735	251	4,660	5.0	15,336	13,463	2,460	587	0.6	30,936	33.3	46,272	49.8
8	2012	944.7	10,354	0	10,354	11.0	3,785	0	703	258	4,746	5.0	15,100	14,971	2,534	2,404	2.5	31,324	33.2	46,423	49.1
9	2013	941.4	10,069	0	10,069	10.7	3,899	0	671	266	4,835	5.1	14,904	15,155	2,610	2,860	3.0	32,349	34.4	47,254	50.2
10	2014	946.3	9,746	0	9,746	10.3	4,015	0	639	274	4,928	5.2	14,674	16,546	2,688	4,559	4.8	32,549	34.4	47,223	49.9
11	2015	947.1	9,448	0	9,448	10.0	4,136	0	607	282	5,025	5.3	14,473	17,351	2,768	5,647	6.0	33,274	35.1	47,746	50.4
12	2016	949.0	9,175	0	9,175	9.7	4,260	0	575	291	5,126	5.4	14,301	17,754	2,852	6,304	6.6	34,522	36.4	48,823	51.4
13	2017	948.0	8,863	0	8,863	9.3	4,388	0	543	299	5,230	5.5	14,093	18,801	2,937	7,644	8.1	34,942	36.9	49,035	51.7
14	2018	947.1	8,593	0	8,593	9.1	4,519	0	511	308	5,339	5.6	13,932	19,058	3,025	8,151	8.6	36,240	38.3	50,173	53.0
15	2019	949.1	8,287	0	8,287	8.7	4,655	0	479	318	5,452	5.7	13,739	20,278	3,116	9,655	10.2	36,776	38.8	50,515	53.2
16	2020	954.0	7,990	0	7,990	8.4	4,795	0	447	327	5,569	5.8	13,559	21,587	3,209	11,238	11.8	37,488	39.3	51,046	53.5
17	2021	949.4	7,729	0	7,729	8.1	4,939	0	415	337	5,691	6.0	13,420	21,581	3,306	11,466	12.1	38,969	41.0	52,389	55.2
18	2022	946.7	7,495	0	7,495	7.9	5,087	0	383	347	5,817	6.1	13,312	21,261	3,405	11,354	12.0	40,989	43.3	54,301	57.4
19	2023	951.8	7,126	0	7,126	7.5	5,239	0	351	358	5,948	6.2	13,074	24,163	3,507	14,595	15.3	40,207	42.2	53,282	56.0
20	2024	954.7	6,860	0	6,860	7.2	5,396	0	319	368	6,084	6.4	12,944	24,967	3,612	15,636	16.4	41,552	43.5	54,496	57.1
Net Present Value			101,182	0	101,182		37,083	0	6,803	2,531	46,417		147,599	122,777	24,822	(0)		307,192		454,791	
Nominal Levelized Cost ($/MWh)						11.8						5.4					(0.0)		35.7		52.9
Real Levelized Cost ($/MWh)						9.5						4.4					(0.0)		28.9		42.8

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

Economic Analysis Detail

Assumptions											
Installed Cost	70,455	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	211.36	2004 $000s	Nominal Discount	8.2	percent
Installed Cost	495	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5	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	2,000	2004 $000s			
Gas Usage Rate	25.4	000s dth/day	Transportation	3.0	percent						

			Fixed Costs																		
			Capital Recovery and Miscellaneous				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	893.8	13,244	0	13,244	14.8	3,078	0	960	218	4,255	4.8	17,500	11,441	2,060	(3,999)	(4.5)	28,423	31.8	45,923	51.4
2	2006	937.6	12,856	0	12,856	13.7	3,170	0	927	224	4,321	4.6	17,177	12,526	2,122	(2,529)	(2.7)	28,235	30.1	45,411	48.4
3	2007	862.3	12,400	0	12,400	14.4	3,265	0	894	231	4,390	5.1	16,790	10,922	2,185	(3,682)	(4.3)	27,642	32.1	44,432	51.5
4	2008	862.7	12,002	0	12,002	13.9	3,363	0	861	238	4,462	5.2	16,464	10,697	2,251	(3,516)	(4.1)	27,914	32.4	44,378	51.4
5	2009	888.4	11,660	0	11,660	13.1	3,464	0	828	245	4,537	5.1	16,196	11,593	2,319	(2,285)	(2.6)	28,997	32.6	45,193	50.9
6	2010	888.8	11,322	0	11,322	12.7	3,568	0	795	252	4,615	5.2	15,937	11,956	2,388	(1,593)	(1.8)	29,886	33.6	45,823	51.6
7	2011	890.1	11,001	0	11,001	12.4	3,675	0	762	260	4,696	5.3	15,697	12,302	2,460	(935)	(1.1)	30,820	34.6	46,517	52.3
8	2012	891.4	10,694	0	10,694	12.0	3,785	0	728	268	4,781	5.4	15,476	12,733	2,534	(209)	(0.2)	31,802	35.7	47,277	53.0
9	2013	888.5	10,388	0	10,388	11.7	3,899	0	695	276	4,870	5.5	15,258	13,063	2,610	415	0.5	32,635	36.7	47,893	53.9
10	2014	890.4	10,093	0	10,093	11.3	4,015	0	662	284	4,962	5.6	15,055	13,442	2,688	1,074	1.2	33,694	37.8	48,749	54.7
11	2015	888.1	9,792	0	9,792	11.0	4,136	0	629	293	5,058	5.7	14,850	13,870	2,768	1,788	2.0	34,607	39.0	49,457	55.7
12	2016	891.3	9,504	0	9,504	10.7	4,260	0	596	301	5,157	5.8	14,661	14,339	2,852	2,529	2.8	35,788	40.2	50,450	56.6
13	2017	889.1	9,206	0	9,206	10.4	4,388	0	563	310	5,261	5.9	14,467	14,712	2,937	3,182	3.6	36,759	41.3	51,226	57.6
14	2018	892.5	8,921	0	8,921	10.0	4,519	0	530	320	5,369	6.0	14,290	15,146	3,025	3,881	4.3	37,996	42.6	52,286	58.6
15	2019	885.8	8,618	0	8,618	9.7	4,655	0	497	329	5,481	6.2	14,099	15,600	3,116	4,617	5.2	38,867	43.9	52,966	59.8
16	2020	893.0	8,345	0	8,345	9.3	4,795	0	464	339	5,597	6.3	13,943	16,138	3,209	5,405	6.1	40,356	45.2	54,299	60.8
17	2021	889.1	8,050	0	8,050	9.1	4,939	0	430	349	5,718	6.4	13,768	16,555	3,306	6,092	6.9	41,370	46.5	55,139	62.0
18	2022	891.6	7,772	0	7,772	8.7	5,087	0	397	360	5,844	6.6	13,616	17,067	3,405	6,856	7.7	42,732	47.9	56,348	63.2
19	2023	889.8	7,486	0	7,486	8.4	5,239	0	364	371	5,974	6.7	13,460	17,570	3,507	7,617	8.6	43,923	49.4	57,383	64.5
20	2024	892.4	7,213	0	7,213	8.1	5,396	0	331	382	6,109	6.8	13,322	18,161	3,612	8,452	9.5	45,390	50.9	58,712	65.8
Net Present Value			104,648	0	104,648		37,083	0	7,053	2,623	46,759		151,407	126,585	24,822	(0)		314,796		466,203	
Nominal Levelized Cost ($/MWh)						12.2						5.4					(0.0)		36.6		54.2
Real Levelized Cost ($/MWh)						9.8						4.4					(0.0)		29.6		43.8

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

Economic Analysis Detail

Assumptions

Installed Cost	70,471	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	211.41	2004 $000s	Nominal Discount	8.2	percent
Installed Cost	495	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5	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	2,000	2004 $000s			
Gas Usage Rate	25.4	000s dth/day	Transportation	3.0	percent						

		Fixed Costs																			
		Capital Recovery and Miscellaneous				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	746.7	13,036	0	13,036	17.5	3,078	0	960	218	4,256	5.7	17,292	11,257	2,060	(3,975)	(5.3)	24,012	32.2	41,304	55.3
2 2006	751.1	12,606	0	12,606	16.8	3,170	0	927	224	4,321	5.8	16,927	12,161	2,122	(2,644)	(3.5)	22,966	30.6	39,893	53.1
3 2007	746.6	12,234	0	12,234	16.4	3,265	0	894	231	4,390	5.9	16,624	10,813	2,185	(3,626)	(4.9)	24,125	32.3	40,749	54.6
4 2008	748.1	11,837	0	11,837	15.8	3,363	0	861	238	4,462	6.0	16,299	10,595	2,251	(3,453)	(4.6)	24,418	32.6	40,718	54.4
5 2009	888.4	11,662	0	11,662	13.1	3,464	0	828	245	4,537	5.1	16,199	11,593	2,319	(2,287)	(2.6)	28,997	32.6	45,195	50.9
6 2010	888.8	11,325	0	11,325	12.7	3,568	0	795	252	4,615	5.2	15,940	11,956	2,388	(1,596)	(1.8)	29,886	33.6	45,826	51.6
7 2011	890.1	11,003	0	11,003	12.4	3,675	0	762	260	4,696	5.3	15,700	12,302	2,460	(938)	(1.1)	30,820	34.6	46,519	52.3
8 2012	891.4	10,696	0	10,696	12.0	3,785	0	729	268	4,781	5.4	15,478	12,733	2,534	(211)	(0.2)	31,802	35.7	47,280	53.0
9 2013	888.5	10,390	0	10,390	11.7	3,899	0	696	276	4,870	5.5	15,260	13,063	2,610	413	0.5	32,635	36.7	47,895	53.9
10 2014	890.4	10,095	0	10,095	11.3	4,015	0	662	284	4,962	5.6	15,057	13,442	2,688	1,072	1.2	33,694	37.8	48,752	54.8
11 2015	888.1	9,794	0	9,794	11.0	4,136	0	629	293	5,058	5.7	14,852	13,870	2,768	1,786	2.0	34,607	39.0	49,459	55.7
12 2016	891.3	9,506	0	9,506	10.7	4,260	0	596	301	5,158	5.8	14,663	14,339	2,852	2,527	2.8	35,788	40.2	50,452	56.6
13 2017	889.1	9,208	0	9,208	10.4	4,388	0	563	310	5,261	5.9	14,469	14,712	2,937	3,181	3.6	36,759	41.3	51,228	57.6
14 2018	892.5	8,922	0	8,922	10.0	4,519	0	530	320	5,369	6.0	14,291	15,146	3,025	3,880	4.3	37,996	42.6	52,288	58.6
15 2019	885.8	8,620	0	8,620	9.7	4,655	0	497	329	5,481	6.2	14,101	15,600	3,116	4,615	5.2	38,867	43.9	52,968	59.8
16 2020	893.0	8,347	0	8,347	9.3	4,795	0	464	339	5,598	6.3	13,944	16,138	3,209	5,403	6.1	40,356	45.2	54,300	60.8
17 2021	889.1	8,052	0	8,052	9.1	4,939	0	431	349	5,718	6.4	13,770	16,555	3,306	6,091	6.9	41,370	46.5	55,140	62.0
18 2022	891.6	7,773	0	7,773	8.7	5,087	0	397	360	5,844	6.6	13,617	17,067	3,405	6,855	7.7	42,732	47.9	56,349	63.2
19 2023	889.8	7,487	0	7,487	8.4	5,239	0	364	371	5,974	6.7	13,461	17,570	3,507	7,616	8.6	43,923	49.4	57,384	64.5
20 2024	892.4	7,214	0	7,214	8.1	5,396	0	331	382	6,109	6.8	13,323	18,161	3,612	8,450	9.5	45,390	50.9	58,713	65.8
Net Present Value		104,003	0	104,003		37,083	0	7,054	2,624	46,761		150,764	125,942	24,822	(0)		300,893		451,657	
Nominal Levelized Cost ($/MWh)					12.5						5.6					(0.0)		36.1		54.2
Real Levelized Cost ($/MWh)					10.1						4.5					(0.0)		29.2		43.9

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

Economic Analysis Detail

Assumptions											
Installed Cost	46,144	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	138.43	2004 $000s	Nominal Discount	8.2	percent
Installed Cost	324	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5	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	2,000	2004 $000s			
Gas Usage Rate	25.4	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	746.9	9,208	0	9,208	12.3	3,078	0	629	143	3,849	5.2	13,057	6,486	2,060	(4,511)	(6.0)	28,705	38.4	41,762	55.9
2	2006	772.3	8,920	0	8,920	11.6	3,170	0	607	147	3,924	5.1	12,844	7,859	2,122	(2,864)	(3.7)	27,847	36.1	40,691	52.7
3	2007	744.2	8,660	0	8,660	11.6	3,265	0	586	151	4,002	5.4	12,662	6,533	2,185	(3,943)	(5.3)	28,231	37.9	40,892	54.9
4	2008	749.9	8,405	0	8,405	11.2	3,363	0	564	156	4,083	5.4	12,487	6,529	2,251	(3,708)	(4.9)	28,483	38.0	40,971	54.6
5	2009	759.2	8,165	0	8,165	10.8	3,464	0	542	160	4,166	5.5	12,332	7,579	2,319	(2,434)	(3.2)	28,838	38.0	41,169	54.2
6	2010	762.9	7,954	0	7,954	10.4	3,568	0	520	165	4,253	5.6	12,207	8,073	2,388	(1,746)	(2.3)	29,582	38.8	41,789	54.8
7	2011	768.4	7,754	0	7,754	10.1	3,675	0	499	170	4,344	5.7	12,098	8,589	2,460	(1,049)	(1.4)	30,390	39.6	42,489	55.3
8	2012	777.4	7,573	0	7,573	9.7	3,785	0	477	175	4,437	5.7	12,010	9,133	2,534	(344)	(0.4)	31,399	40.4	43,410	55.8
9	2013	777.2	7,379	0	7,379	9.5	3,899	0	455	181	4,535	5.8	11,913	9,639	2,610	335	0.4	32,043	41.2	43,957	56.6
10	2014	781.6	7,195	0	7,195	9.2	4,015	0	434	186	4,635	5.9	11,830	10,210	2,688	1,068	1.4	32,876	42.1	44,706	57.2
11	2015	786.8	7,014	0	7,014	8.9	4,136	0	412	192	4,740	6.0	11,754	10,811	2,768	1,826	2.3	33,783	42.9	45,536	57.9
12	2016	798.7	6,849	0	6,849	8.6	4,260	0	390	197	4,848	6.1	11,697	11,481	2,852	2,635	3.3	35,010	43.8	46,707	58.5
13	2017	800.8	6,665	0	6,665	8.3	4,388	0	369	203	4,960	6.2	11,624	12,085	2,937	3,398	4.2	35,828	44.7	47,452	59.3
14	2018	807.6	6,492	0	6,492	8.0	4,519	0	347	209	5,076	6.3	11,568	12,739	3,025	4,196	5.2	36,884	45.7	48,452	60.0
15	2019	811.9	6,315	0	6,315	7.8	4,655	0	325	216	5,196	6.4	11,511	13,454	3,116	5,059	6.2	37,843	46.6	49,353	60.8
16	2020	829.8	6,169	0	6,169	7.4	4,795	0	304	222	5,320	6.4	11,490	14,248	3,209	5,967	7.2	39,470	47.6	50,959	61.4
17	2021	833.2	5,992	0	5,992	7.2	4,939	0	282	229	5,449	6.5	11,441	14,995	3,306	6,860	8.2	40,419	48.5	51,860	62.2
18	2022	842.4	5,832	0	5,832	6.9	5,087	0	260	236	5,583	6.6	11,414	15,799	3,405	7,789	9.2	41,721	49.5	53,135	63.1
19	2023	859.6	5,690	0	5,690	6.6	5,239	0	239	243	5,721	6.7	11,411	16,643	3,507	8,739	10.2	43,409	50.5	54,820	63.8
20	2024	877.3	5,556	0	5,556	6.3	5,396	0	217	250	5,863	6.7	11,419	17,568	3,612	9,761	11.1	45,241	51.6	56,660	64.6
Net Present Value			74,202	0	74,202		37,083	0	4,619	1,718	43,420		117,622	92,800	24,822	0		311,626		429,248	
Nominal Levelized Cost ($/MWh)						9.7						5.7					0.0		40.6		55.9
Real Levelized Cost ($/MWh)						7.8						4.6					0.0		32.8		45.2

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

Economic Analysis Detail

Assumptions											
Installed Cost	46,159	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	138.48	2004 $000s	Nominal Discount	8.2	percent
Installed Cost	324	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5	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	2,000	2004 $000s			
Gas Usage Rate	25.4	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	727.4	9,177	0	9,177	12.6	3,078	0	629	143	3,849	5.3	13,027	6,449	2,060	(4,518)	(6.2)	28,006	38.5	41,033	56.4
2	2006	734.7	8,862	0	8,862	12.1	3,170	0	607	147	3,924	5.3	12,786	7,838	2,122	(2,827)	(3.8)	26,590	36.2	39,377	53.6
3	2007	726.6	8,632	0	8,632	11.9	3,265	0	586	151	4,002	5.5	12,634	6,496	2,185	(3,952)	(5.4)	27,601	38.0	40,235	55.4
4	2008	731.4	8,376	0	8,376	11.5	3,363	0	564	156	4,083	5.6	12,458	6,491	2,251	(3,716)	(5.1)	27,827	38.0	40,286	55.1
5	2009	759.2	8,167	0	8,167	10.8	3,464	0	542	161	4,167	5.5	12,334	7,579	2,319	(2,436)	(3.2)	28,838	38.0	41,172	54.2
6	2010	762.9	7,956	0	7,956	10.4	3,568	0	521	165	4,254	5.6	12,209	8,073	2,388	(1,749)	(2.3)	29,582	38.8	41,791	54.8
7	2011	768.4	7,756	0	7,756	10.1	3,675	0	499	170	4,344	5.7	12,100	8,589	2,460	(1,051)	(1.4)	30,390	39.6	42,491	55.3
8	2012	777.4	7,575	0	7,575	9.7	3,785	0	477	175	4,438	5.7	12,013	9,133	2,534	(346)	(0.4)	31,399	40.4	43,412	55.8
9	2013	777.2	7,381	0	7,381	9.5	3,899	0	456	181	4,535	5.8	11,915	9,639	2,610	333	0.4	32,043	41.2	43,959	56.6
10	2014	781.6	7,196	0	7,196	9.2	4,015	0	434	186	4,635	5.9	11,832	10,210	2,688	1,066	1.4	32,876	42.1	44,708	57.2
11	2015	786.8	7,016	0	7,016	8.9	4,136	0	412	192	4,740	6.0	11,756	10,811	2,768	1,824	2.3	33,783	42.9	45,538	57.9
12	2016	798.7	6,851	0	6,851	8.6	4,260	0	390	197	4,848	6.1	11,699	11,481	2,852	2,634	3.3	35,010	43.8	46,708	58.5
13	2017	800.8	6,666	0	6,666	8.3	4,388	0	369	203	4,960	6.2	11,626	12,085	2,937	3,396	4.2	35,828	44.7	47,454	59.3
14	2018	807.6	6,493	0	6,493	8.0	4,519	0	347	209	5,076	6.3	11,569	12,739	3,025	4,195	5.2	36,884	45.7	48,453	60.0
15	2019	811.9	6,316	0	6,316	7.8	4,655	0	325	216	5,196	6.4	11,512	13,454	3,116	5,058	6.2	37,843	46.6	49,355	60.8
16	2020	829.8	6,171	0	6,171	7.4	4,795	0	304	222	5,321	6.4	11,491	14,248	3,209	5,966	7.2	39,470	47.6	50,961	61.4
17	2021	833.2	5,993	0	5,993	7.2	4,939	0	282	229	5,449	6.5	11,443	14,995	3,306	6,858	8.2	40,419	48.5	51,862	62.2
18	2022	842.4	5,833	0	5,833	6.9	5,087	0	260	236	5,583	6.6	11,416	15,799	3,405	7,788	9.2	41,721	49.5	53,137	63.1
19	2023	859.6	5,692	0	5,692	6.6	5,239	0	239	243	5,721	6.7	11,412	16,643	3,507	8,737	10.2	43,409	50.5	54,821	63.8
20	2024	877.3	5,557	0	5,557	6.3	5,396	0	217	250	5,863	6.7	11,420	17,568	3,612	9,760	11.1	45,241	51.6	56,661	64.6
Net Present Value			74,091	0	74,091		37,083	0	4,620	1,719	43,422		117,513	92,691	24,822	(0)		308,932		426,445	
Nominal Levelized Cost ($/MWh)						9.7						5.7					(0.0)		40.4		55.8
Real Levelized Cost ($/MWh)						7.9						4.6					(0.0)		32.7		45.2

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

Economic Analysis Detail

Assumptions											
Installed Cost	116,923	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	350.77	2004 $000s	Nominal Discount	8.2	percent
Installed Cost	822	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5	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	2,000	2004 $000s			
Gas Usage Rate	25.4	000s dth/day	Transportation	3.0	percent						

			Fixed Costs										Total Fixed	Operating	Option	Net				Total Project	
			Capital Recovery and Miscellaneous				Operations & Maintenance						Costs	Margin	Value	Project Benefit		Total Variable Costs		Costs	
	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)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($/MWh)	($000s)	($/MWh)
1	2005	754.2	20,766	0	20,766	27.5	3,078	0	1,594	361	5,032	6.7	25,799	4,589	2,060	(19,149)	(25.4)	23,862	31.6	49,661	65.8
2	2006	822.5	20,215	0	20,215	24.6	3,170	0	1,539	372	5,081	6.2	25,296	6,235	2,122	(16,938)	(20.6)	25,573	31.1	50,869	61.8
3	2007	787.7	19,517	0	19,517	24.8	3,265	0	1,484	383	5,132	6.5	24,649	6,554	2,185	(15,909)	(20.2)	25,877	32.9	50,525	64.1
4	2008	820.6	18,933	0	18,933	23.1	3,363	0	1,429	395	5,186	6.3	24,120	9,272	2,251	(12,597)	(15.4)	27,981	34.1	52,101	63.5
5	2009	817.5	18,307	0	18,307	22.4	3,464	0	1,374	407	5,244	6.4	23,551	12,330	2,319	(8,903)	(10.9)	28,637	35.0	52,188	63.8
6	2010	825.4	17,715	0	17,715	21.5	3,568	0	1,319	419	5,305	6.4	23,021	15,381	2,388	(5,251)	(6.4)	29,515	35.8	52,536	63.7
7	2011	759.6	17,044	0	17,044	22.4	3,675	0	1,264	431	5,370	7.1	22,414	17,071	2,460	(2,884)	(3.8)	28,265	37.2	50,679	66.7
8	2012	785.9	16,481	0	16,481	21.0	3,785	0	1,209	444	5,438	6.9	21,919	19,930	2,534	545	0.7	28,812	36.7	50,731	64.6
9	2013	726.8	15,861	0	15,861	21.8	3,899	0	1,154	458	5,510	7.6	21,371	21,028	2,610	2,266	3.1	27,953	38.5	49,324	67.9
10	2014	692.6	15,227	0	15,227	22.0	4,015	0	1,099	471	5,586	8.1	20,813	21,958	2,688	3,832	5.5	26,759	38.6	47,572	68.7
11	2015	675.0	14,666	0	14,666	21.7	4,136	0	1,044	486	5,666	8.4	20,332	22,170	2,768	4,607	6.8	27,076	40.1	47,407	70.2
12	2016	724.3	14,231	0	14,231	19.6	4,260	0	989	500	5,749	7.9	19,980	23,444	2,852	6,315	8.7	30,016	41.4	49,996	69.0
13	2017	738.2	13,705	0	13,705	18.6	4,388	0	934	515	5,837	7.9	19,542	24,546	2,937	7,940	10.8	31,069	42.1	50,611	68.6
14	2018	660.6	13,024	0	13,024	19.7	4,519	0	879	531	5,929	9.0	18,953	23,723	3,025	7,795	11.8	28,865	43.7	47,818	72.4
15	2019	674.5	12,494	0	12,494	18.5	4,655	0	824	546	6,026	8.9	18,520	25,344	3,116	9,941	14.7	29,814	44.2	48,334	71.7
16	2020	711.1	12,025	0	12,025	16.9	4,795	0	769	563	6,127	8.6	18,152	26,543	3,209	11,600	16.3	32,041	45.1	50,193	70.6
17	2021	717.5	11,516	0	11,516	16.0	4,939	0	714	580	6,233	8.7	17,749	26,003	3,306	11,560	16.1	33,421	46.6	51,170	71.3
18	2022	798.2	11,134	0	11,134	13.9	5,087	0	659	597	6,343	7.9	17,477	25,919	3,405	11,847	14.8	37,440	46.9	54,918	68.8
19	2023	737.6	10,488	0	10,488	14.2	5,239	0	604	615	6,459	8.8	16,946	28,669	3,507	15,229	20.6	35,948	48.7	52,894	71.7
20	2024	975.7	10,595	0	10,595	10.9	5,396	0	549	634	6,579	6.7	17,174	188,859	3,612	175,297	179.7	50,178	51.4	67,352	69.0
Net Present Value			160,801	0	160,801		37,083	0	11,704	4,353	53,140		213,941	189,119	24,822	(0)		278,201		492,142	
Nominal Levelized Cost ($/MWh)						21.9						7.2					(0.0)		37.8		66.9
Real Levelized Cost ($/MWh)						17.7						5.8					(0.0)		30.6		54.2

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

Economic Analysis Detail

Assumptions

Installed Cost	116,385	2004 $000s	Fixed Charge	0	2004$ per kW-mo	Insurance Cost	349.15	2004 $000s	Nominal Discount	8.2	percent
Installed Cost	818	2004 $/kW	Fixed O&M	1.75	2004$ per kW-mo	Gas Transport	0.00	2004 $/dth/day	Real Discount	5.5	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	2,000	2004 $000s			
Gas Usage Rate	25.4	000s dth/day	Transportation	3.0	percent						

			Fixed Costs																		
			Capital Recovery and Miscellaneous				Operations & Maintenance						Total Fixed Costs	Operating Margin	Option Value	Net Project Benefit		Total Variable Costs		Total Project Costs	
	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)	($000s)	($000s)	($000s)	($000s)	($/MWh)	($000s)	($/MWh)	($000s)	($/MWh)
1	2005	660.4	20,547	0	20,547	31.1	3,078	0	1,586	360	5,023	7.6	25,570	4,320	2,060	(19,190)	(29.1)	21,155	32.0	46,726	70.8
2	2006	703.0	19,966	0	19,966	28.4	3,170	0	1,532	370	5,072	7.2	25,038	5,852	2,122	(17,064)	(24.3)	22,188	31.6	47,226	67.2
3	2007	681.7	19,282	0	19,282	28.3	3,265	0	1,477	382	5,123	7.5	24,405	6,192	2,185	(16,028)	(23.5)	22,712	33.3	47,117	69.1
4	2008	700.9	18,672	0	18,672	26.6	3,363	0	1,422	393	5,178	7.4	23,850	8,734	2,251	(12,865)	(18.4)	24,199	34.5	48,049	68.6
5	2009	817.5	18,230	0	18,230	22.3	3,464	0	1,367	405	5,236	6.4	23,466	12,330	2,319	(8,817)	(10.8)	28,637	35.0	52,103	63.7
6	2010	825.4	17,641	0	17,641	21.4	3,568	0	1,313	417	5,297	6.4	22,938	15,381	2,388	(5,169)	(6.3)	29,515	35.8	52,454	63.6
7	2011	759.6	16,973	0	16,973	22.3	3,675	0	1,258	429	5,362	7.1	22,335	17,071	2,460	(2,805)	(3.7)	28,265	37.2	50,600	66.6
8	2012	785.9	16,412	0	16,412	20.9	3,785	0	1,203	442	5,431	6.9	21,842	19,930	2,534	621	0.8	28,812	36.7	50,654	64.5
9	2013	726.8	15,795	0	15,795	21.7	3,899	0	1,149	456	5,503	7.6	21,298	21,028	2,610	2,340	3.2	27,953	38.5	49,251	67.8
10	2014	692.6	15,164	0	15,164	21.9	4,015	0	1,094	469	5,579	8.1	20,743	21,958	2,688	3,903	5.6	26,759	38.6	47,501	68.6
11	2015	675.0	14,605	0	14,605	21.6	4,136	0	1,039	483	5,658	8.4	20,264	22,170	2,768	4,675	6.9	27,076	40.1	47,340	70.1
12	2016	724.3	14,173	0	14,173	19.6	4,260	0	985	498	5,742	7.9	19,915	23,444	2,852	6,380	8.8	30,016	41.4	49,931	68.9
13	2017	738.2	13,650	0	13,650	18.5	4,388	0	930	513	5,830	7.9	19,480	24,546	2,937	8,002	10.8	31,069	42.1	50,549	68.5
14	2018	660.6	12,971	0	12,971	19.6	4,519	0	875	528	5,923	9.0	18,894	23,723	3,025	7,854	11.9	28,865	43.7	47,759	72.3
15	2019	674.5	12,444	0	12,444	18.4	4,655	0	820	544	6,019	8.9	18,463	25,344	3,116	9,997	14.8	29,814	44.2	48,278	71.6
16	2020	711.1	11,978	0	11,978	16.8	4,795	0	766	560	6,121	8.6	18,099	26,543	3,209	11,653	16.4	32,041	45.1	50,139	70.5
17	2021	717.5	11,472	0	11,472	16.0	4,939	0	711	577	6,227	8.7	17,698	26,003	3,306	11,610	16.2	33,421	46.6	51,120	71.2
18	2022	798.2	11,092	0	11,092	13.9	5,087	0	656	594	6,337	7.9	17,429	25,919	3,405	11,895	14.9	37,440	46.9	54,870	68.7
19	2023	737.6	10,448	0	10,448	14.2	5,239	0	602	612	6,453	8.7	16,902	28,669	3,507	15,274	20.7	35,948	48.7	52,849	71.6
20	2024	975.7	10,558	0	10,558	10.8	5,396	0	547	631	6,574	6.7	17,132	188,859	3,612	175,339	179.7	50,178	51.4	67,310	69.0
Net Present Value			159,620	0	159,620		37,083	0	11,650	4,333	53,066		212,686	187,864	24,822	0		267,550		480,236	
Nominal Levelized Cost ($/MWh)						22.3						7.4					0.0		37.5		67.2
Real Levelized Cost ($/MWh)						18.1						6.0					0.0		30.3		54.4