Projected Revenues and Operating Costs of Androscoggin Energy Center as of April 2004 and April 2005

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1 Introduction and Summary

Androscoggin Energy, LLC (AELLC) has applied for an abatement of the property taxes levied by the Town of Jay, Maine on the Androscoggin Energy Center (the Project) for years 2004/2005 (2004 tax year) and 2005/2006 (2005 tax year). The Town of Jay Maine has retained Corporate Valuations Inc. to prepare an appraisal of the plant for each of those tax years. In addition the Town has retained Synapse Energy Economics (Synapse) to provide Corporate Valuations with a review of expectations regarding long-term annual energy prices circa April 2004 and April 2005 respectively and the corresponding expectations regarding the Project's long term annual revenues and operating costs as of those two points in time. This report describes our review of those expectations and presents our results.

1.1 Background

Androscoggin Energy Center is a cogeneration plant located at the International Paper (IP) mill in Jay, Maine which went into service in January 2000. It consists of 3 gas-fired combustion turbines (CTs), each nominally rated at 50 MW, and 3 heat recovery steam generators.

As designed the Project was expected to operate two CTs on a baseload basis in order to produce steam for IP and electricity for sale to the market or IP as a by-product. The plant would operate the third CT to produce electricity on an "economic dispatch" basis, i.e. whenever the price it would receive for the electricity was above the variable cost of producing electricity from that CT.

The steam was to be sold to IP under a 20 year Energy Services Agreement (ESA) at a price tied to the price of the Project's natural gas supply. There were three prospective markets for the electric energy and capacity - IP for its internal load (up to a maximum of 40 MW), the wholesale markets operated by ISO-NE and electricity marketers.

The plant's gas supply requirements through 2009 were to be primarily (approximately 80%) met with gas acquired from Alberta, Canada under three gas supply contracts with fixed prices. The remaining supply was to be purchased at market based prices at various locations in Canada. The gas was to be delivered to the Project from Alberta under long-term transportation contracts with Nova Gas, TransCanada PipeLines (TCPL) and Portland Natural Gas Transmission (PNGTS).

In November 2004 AELLC filed for bankruptcy. It has identified four factors that have adversely impacted its ability to operate the facility[1]

- Loss of income due to contractual differences with IP;
- Increases in natural gas prices;

[1] AELLC, Application for Abatement of Property Taxes, January 9, 2006,

- Increased electric generating capacity in New England due to continued operation of older coal fired plants; and
- An excess of electric generating capacity in New England expected to continue until 2010.

Based upon those factors AELLC has applied for abatements of property taxes on the project for the 2004 tax year and the 2005 tax year.

1.2 Purpose and Approach

The purpose of this report is to provide Corporate Valuations with information on expectations regarding the plant's long-term revenues and costs as of April 2004 and April 2005. We understand that appraisals for property tax purposes for tax years 2004 and 2005 are based upon estimate of the Project's value as of April 2004 and April 2005 respectively.

Chapter 2 describes the Project's major sources of revenues, the operating costs it incurs to produce those revenues, and the relationship between energy prices and the Project's operations, revenues and operating costs.

Chapter 3 describes expectations regarding the Project's long-term revenues and costs as of April 2004. These expectations are based primarily on our review of long-term projections of revenues and costs prepared by AELLC as of December 19, 2003 and public forecasts of energy prices available at that time.

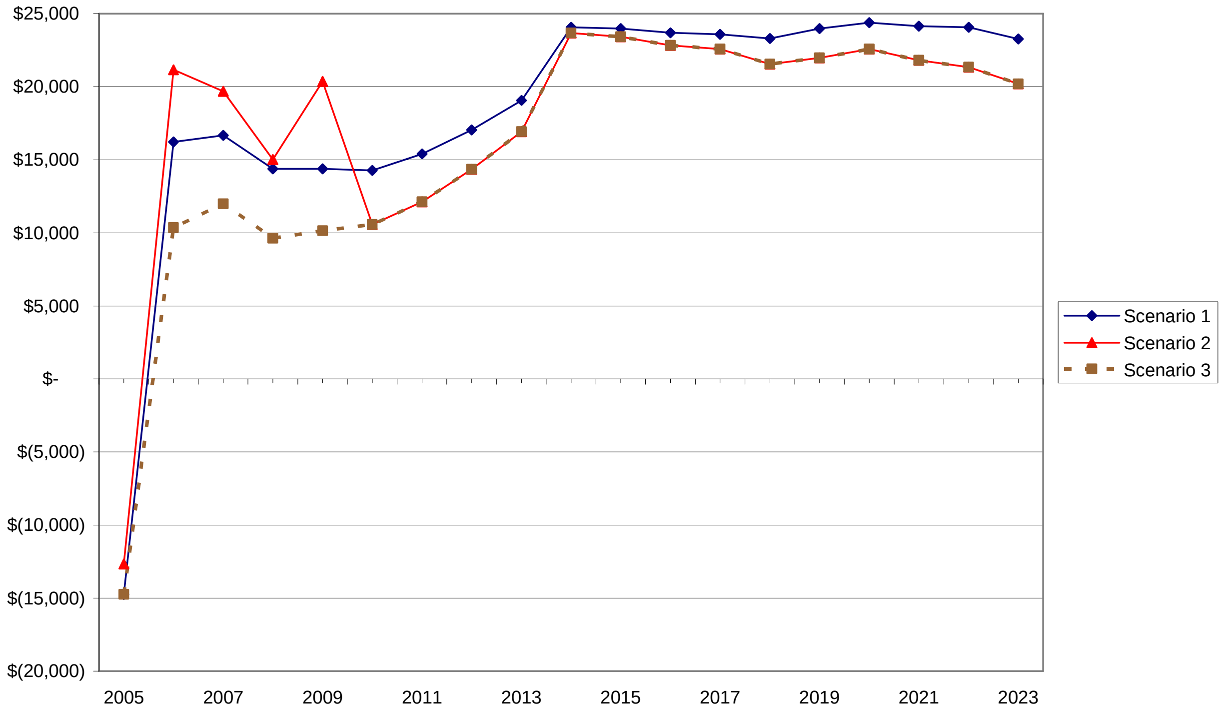
Chapter 4 describes expectations regarding the Project's long-term revenues and costs as of April 2005. These expectations are based upon public forecasts of energy prices as of early 2005, our review of the Project's configuration options, and our projections of Project revenues and operating costs under various scenarios in light of those energy market prices and configuration options.

1.3 Key Conclusions

In terms of expectations as of April 2004, the long-term projections of Project revenues and costs prepared by AELLC as of December 19, 2003 indicate that the Project was expected to have a positive operating cashflow exceeding $10 million in each year from 2005 through 2024.

Synapse prepared a set of expectations as of April 2005 for three scenarios. These expectations are based upon our review of the Project's configuration options and on forecasts of natural gas, electric energy and electric capacity prices in New England publicly available as of April 2005. Our analyses, summarized in Figure 1, indicate that the Project's operating cashflow would be positive under each scenario in most years between 2006 and 2024.

Figure 1
AELLC Annual Operating Cash Flow by Scenario (thousands of $2005)



Each scenario assumes that 2005 is a transition year during which the Project does not operate. In summary the three scenarios are as follows:

- **Scenario 1**. Effective January 2006 the Project resume production of steam as its primary product under a new steam contract with IP. All gas supply is acquired at market based prices delivered into PNGTS.
- **Scenario 2.** Effective January 2006 the Project begins producing electric energy and capacity as its primary products in a new configuration as a combined cycle plant. Gas supply is acquired under the fixed price contracts until they expire in 2009, and then at market based prices delivered into PNGTS.
- **Scenario 3.** The same assumptions as Scenario 2 except, effective January 2006, all gas supply is acquired at market based prices delivered into PNGTS .

2 Project Configuration, Revenues and Operating Costs

This Chapter describes our by review of the relationships between expectations regarding AELLC's long-term annual revenues and operating costs, its projected physical operations and long-term forecasts of energy prices.

The Project's long-term annual revenues and operating costs are a function of:

- the quantity of each product that it will produce each year;
- the price that it will receive for each product each year, and
- the costs it will incur to produce those products.

Once the Project configuration is established one can project the Project's annual revenues by projecting the annual quantities of each product and the annual prices received for those products. One can project annual operating costs by projecting the annual fixed and variable costs associated with the projected annual quantities of each product.

In its document production AELLC provided the following major sources of information on the Project's design and operation:

- R.W. Beck, *Androscoggin Cogeneration Center Independent Engineer's Report*, June 1998, pages 13 to 163 of document production.
- Androscoggin Energy LLC, *Long-Term Pro Forma - Assumptions*, February 4, 2003. Pages 6171 to 6173 of document production.
- Androscoggin Energy LLC, *Annual Operating Budget 2004*, pages 2607 to 2638 of document production
- Androscoggin Energy LLC, *Long-Term Projections*, December 19, 2003. Pages 6174 to 6201 of document production.
- Calpine Northbrook Corporation of Maine, Inc., *Androscoggin Energy LLC Technical Summary*, February 2005. Pages 2639 to 2652 of document production.

2.1 Project Configuration

The quantity of each product that the Project will produce each year and the costs it will incur to produce those products is heavily influenced by the design or configuration of the Project. AELLC can be configured to operate in one of two broad possible ways.

- The first approach is the current configuration as a cogeneration plant, producing baseload steam as its primary product. The other potential sources of revenue under this design are sale of electric capacity, electric energy, and gas acquired under long-term contracts that is surplus to its supply requirements during a particular period.

- The alternative configuration would be a "combined cycle" plant, producing electric energy and capacity as its primary products. The other potential source of revenue under this design are sale of gas acquired under long-term contracts that is surplus to its supply requirements during a particular period.

The choice of primary product and corresponding design are, in turn, a function of the price that AELLC expected to receive for the primary product(s) and the costs it expected to incur to produce those products, the largest of which are fuel commodity and transportation costs. Thus, the major factors affecting the Project's annual level of revenues and costs were its configuration, IP's steam requirements, the price of steam under its contract with IP, the market prices of natural gas, electric energy and electric capacity in New England and its gas supply strategy.

Cogeneration configuration. AELLC was designed to produce steam as its primary product and electricity as a by-product. That design was based upon AELLC's expectations regarding the prices it would receive for steam, for electric energy and for electric capacity as well as the prices it would pay for natural gas. Under that configuration the Project would:

- operate two CTs on a baseload basis to produce steam to meet IP's requirements, and sell the resulting electricity into the market or to IP as a by-product. The portion of the CT capacity and output used to produce steam reduces the quantity of electric capacity and energy available for sale; and
- maintain the third CT to back-up the other two CTs. It would "dispatch" the third CT when the variable cost of producing electricity was less than the price it would receive for that electricity.

Heat Rate. A key feature of this configuration was the apparent high efficiency at which the CTs would convert natural gas into electricity. This conversion efficiency is often expressed in terms of the 'heat rate" of the generating unit, which is expressed in terms of the quantity of fuel supply energy required to produce one unit of electricity. Fuel supply energy is expressed in British thermal units (Btu) or million Btu (MMBtu). While electricity is measured in kilowatt hours (kWh) or thousands of kWh (MWh).

A CT operating solely to produce electricity would have a heat rate in the order of 12,000 BTU/kwh (12 MMBtu/MWh). However, in the Project's cogeneration configuration the heat rate is reduced dramatically because the fuel being consumed is producing both steam and electricity, and therefore one can allocate a portion of the fuel energy to the steam produced and a portion to the electric energy produced. Under its configuration AELLC was calculating the heat rate of its two CTs running at baseload to be approximately 6,100 Btu/kWh and the heat rate of its third CT operated on an economic dispatch basis to be 7,800 Btu/kwh.[2]

[2] AELLC, Long-Term Projections, December 2003, pages 6183 and 6184 of document production.

The heat rate of the CTs is the primary determinant of the net revenues AELLC would realize from the sale of their electricity. The Project's variable cost of producing electricity from a CT would essentially be its fuel price multiplied by the heat rate of the CT. For example a gas price of $5.00/MMBtu times a heat rate of 7.8 MMBtu/MWh yields a variable electricity production cost of $39/MWh while the same gas price times a heat rate of 12 MMBtu/MWh yields a variable cost of $60/MWh. In comparison, as of April 2004 the expected long-term average annual price of electricity through 2015 was in the order of $45/MWh to $55/Mwh. Thus, at a heat rate of 7.2 AELLC would receive positive net revenue from electricity produced from its third CT while at a heat rate of 12 it would not.

Combined Cycle Configuration. The alternative configuration for the Project, if it had no steam load, would be as a "combined cycle" plant, producing electric energy as its primary product. Under this approach it would operate all 3 CTs to produce electricity on an economic dispatch basis. The initial assessment of AELLC conducted by R.W. Beck, and the ESA, both contemplated this possibility. Under that arrangement AELLC would have had a heat rate of 8,050 Btu/kWh and additional generating capacity.[3] It would achieve that heat rate because, under the ESA, AELLC had the option to produce electricity from the steam it would otherwise have sold to IP by using IP's steam turbine.

If AELLC did not have the option of using IP's steam turbine, due to the early termination of the ESA for example, it could invest in a combination of heat recovery steam generators (HSRG) and steam turbines to effectively change the design of the Project to a combined cycle configuration. Such a design could have a heat rate in the order of 7500 Btu/kWh as well as additional generating capacity, in the order of another 50 MW. The installed capital cost of the HRSG and turbines would be in the order of $10 million or more.[4]

2.2 Cogeneration Configuration – Projected Revenues and Costs

Under this configuration AELLC would receive revenue from sale of the following products:

- steam;
- electricity from its two CTs as a by-product of steam production;
- electricity from its third CT on an economic dispatch basis;
- electric capacity from all three CTs; and
- gas acquired under long-term contracts that is surplus to its supply requirements during a particular period.

[3] R W Beck Report, June 1998, Exhibit 10-13, page 160 of document production.

[4] Synapse estimate.

Projected Project revenues can be calculated from projections of quantities produced and prices received. Projected Project costs can be calculated from projections of fixed costs, unit variable costs, and quantities produced.

Physical Quantities. The Project configuration establishes the efficiencies at which the Project would convert fuel inputs into products. Using those conversion efficiencies one can forecast annual production quantities as follows:

- the quantity of steam and electricity to be produced from the two CTs can be determined from the annual quantity of steam that IP is expected to purchase;
- the quantity of electricity economically dispatched from the third CT can be determined from the projected market prices of electricity and natural gas;
- the capacity available for sale can be determined from the capacity of the two CTS used to produce steam plus the capacity of the third CT; and
- the quantity of gas needed to meet Project requirements can be determined from the total quantity of steam and electricity produced

The quantity of gas under long-term contracts surplus to Project requirements and available for resale can be determined from the total quantity of gas required and the total quantity under contract.

Prices. Projections of annual average prices of each product can be obtained either from internal, confidential forecasting models or from public forecasts prepared by organizations such as the EIA. AELLC apparently used internal models to forecast prices for its long-term projections. We used public forecasts from the EIA.

Projected prices are required for the following products:

- Steam ($/MMBtu). The projected price of steam under the ESA was the average delivered commodity price of gas divided by 84.1%.

- Electric capacity ($/MW). Electric generating units in New England are eligible to receive a payment for the reliability value of their capacity, in addition to any payments they receive for their energy production. The units must demonstrate their capacity to produce electricity in annual tests. The payments, known as Installed Capacity Market (ICAP), were approximately $0.90 per kw-month in 2004 and 2005 respectively. However, discussions had been underway for some time prior to March 2004 regarding increasing those levels in the future. ISO-NE filed a proposal in March 2004 for a payment of about $4.40 per kW month. In April 2005, litigation was underway at FERC, with estimates of future average capacity payments of around $5.50 per kW-month.

- Electric Energy ($/MWh). The EIA produces and publishes long-term forecasts of the annual average market price of electric energy in New England and other locations in its Annual Energy Outlook (AEO).

- Natural Gas for economic dispatch calculation ($/MMBtu). The EIA produces and publishes long-term forecasts of the annual average market price of natural gas paid by electric generators in New England and other locations in its AEO. Regardless of the average price that AELLC actually paid for its natural gas, AELLC would use the market price of natural gas in New England in its economic dispatch calculation to determine whether to produce electric energy from the third CT. This price represents the "opportunity cost" or replacement cost of that gas, i.e. the market value it would receive if it resold the gas rather than burn it to generate electricity.

- Natural Gas for supply cost calculation ($/MMBtu). AELLC had two basic sources of supply, gas acquired from Alberta under long term fixed price contracts that expire in 2009 and gas acquired at market prices for delivery into the Portland Natural Gas Transportation System (PNGTS) at East Hereford, Quebec. AELLC provided projections of the prices for gas under the long term supply contracts. For gas purchased at market prices delivered into PNGTS Synapse used the projected average annual price in New England less $0.20/MMBtu, consistent with the AELLC projections of December 2003.

2.3 Combined Cycle Configuration – Projected Revenues and Costs

Under this configuration AELLC would receive revenue from sale of electric energy and electric capacity from its three CTs and from the resale of gas acquired under long-term contracts that is surplus to its supply requirements during a particular period. Again, Project revenues can be calculated from projections of quantities produced and prices received. Project costs can be calculated from projections of fixed costs, unit variable costs, and quantities produced.

Physical Quantities. The combined cycle configuration establishes the efficiencies at which the Project would convert its natural gas fuel supply into electric energy. Using those conversion efficiencies one can forecast annual production quantities as follows:

- the quantity of electricity economically dispatched from the three CTs can be determined from the projected market prices of electricity and natural gas;

- all of the electric capacity of the three CTs is available for sale; and

- the quantity of gas needed to meet Project requirements can be determined from the total quantity of steam and electricity produced

Prices. The projections of annual average prices of each product would be the same as those used for the cogeneration configuration.

3 Long-Term Expectations regarding Project Revenues and Costs - April 2004

AELLC prepared a detailed long-term forecast of revenues and costs titled *Long-Term Projections* which is dated December 19, 2003. This document provides AELLC's expectations regarding the long-term viability of the Project at that time. The implicit assumption underlying these projections is that the Project would continue to operate in its cogeneration configuration, with steam as its primary product, through 2024. The document presents a detailed forecast of annual revenues and costs for the Project operating in that mode for each year from 2004 through 2024.

The document consists of five sections – operating proforma, market inputs, production assumptions, fuel prices & forecast, and major maintenance activity. The operating performance section presents the projected revenues and costs in each year based upon the underlying assumptions regarding market inputs, production, fuel prices and major maintenance. The market inputs section presents AELLC's forecast of energy prices and interest rates. The production assumptions section presents AELLC's forecast of Project physical operating levels (e.g. steam production, electric capacity) and production efficiencies (e.g., heat rate). The fuel prices and forecast presents AELLC's assumptions about gas commodity prices, pipeline transportation charges, and the relative quantities of gas it expected to acquire from each source in each year.

The forecasts of electricity and natural gas prices in New England that AELLC used in its long-term projections are consistent with forecasts of those prices publicly available at that time from the EIA. The EAI projections from AEO 2004 are provided in Attachment 1, and are compared with the AELLC forecasts in Figures 2 and 3 below.

Results. AELLC's *Long-Term Projections* dated December 19, 2003 forecasts that that the Project would have a positive operating cashflow in excess of $10 million in each year from 2005 through 2024.[5]

[5] Androscoggin Energy LLC, *Long-Term Projections*, December 19, 2003. Pages 6175 and 6178 of document production.

Figure 2. Electricity price projections circa April 2004

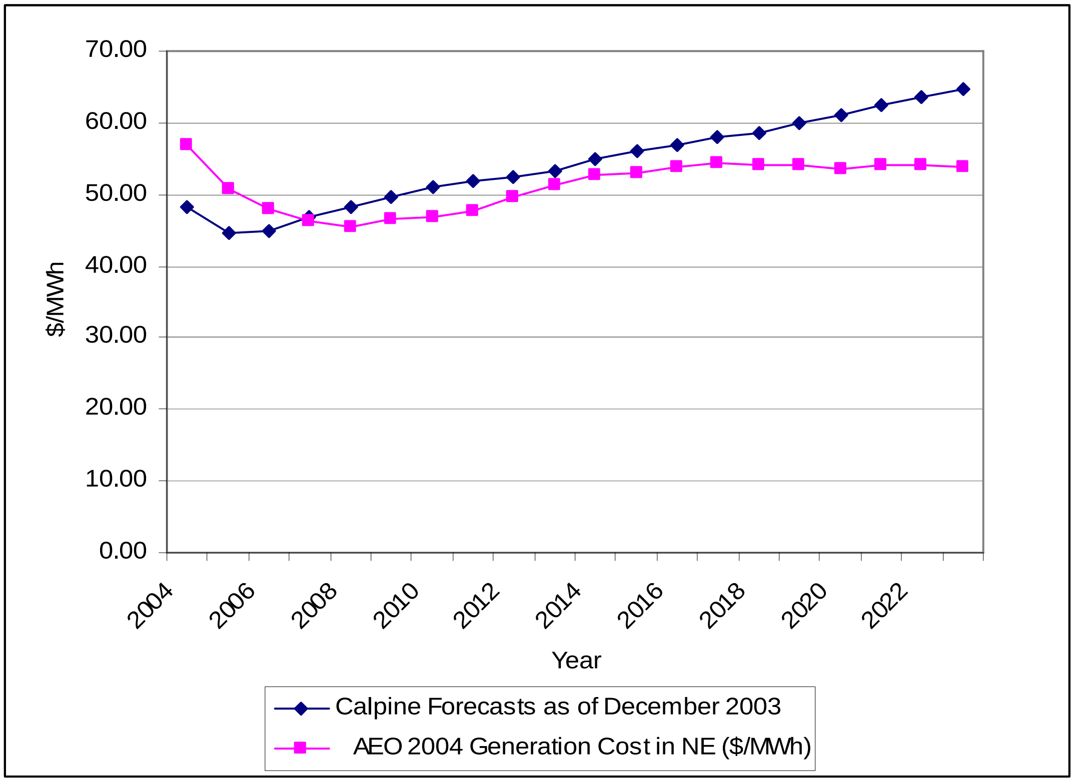
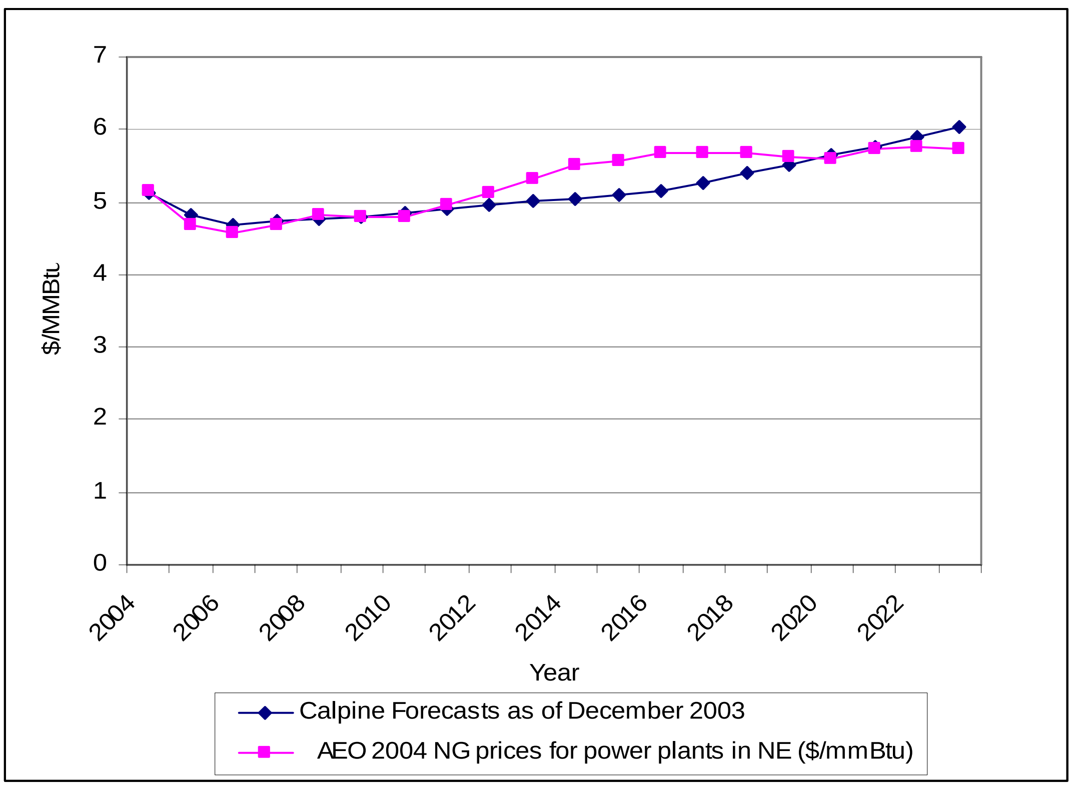


Figure 3. Natural gas price projections circa April 2004



4 Long-Term Expectations regarding Project Revenues and Costs - April 2005

The major difference in outlook for the Project between April 2004 and April 2005 was the termination of the ESA and AELLC's bankruptcy filing. Despite those two events, the Project still had many positive attributes, which are identified in the *Technical Summary* of February 2005 prepared by Calpine Northbrook Corporation of Maine. Therefore, as of April 2005, one could assess the long-term viability of the Project under at least two broad options. One option would be to negotiate a revised steam sales contract with IP and continue operating as a cogeneration plant. The second option would be to change its primary product from steam to electric energy and capacity by improving its generating efficiency and thereby converting to a combined cycle plant.

4.1.1 Scenarios

Synapse prepared a set of expectations regarding the Project's long-term annual revenues and costs for those options using three scenarios. The scenarios are prepared from the perspective of the Project, regardless of whether it is owned by AELLC or a new buyer.

Each scenario assumes that the Project would not operate in 2005 while AELLC made the necessary changes – either negotiations with IP, sale of the Project, or investment in a back pressure turbine to reconfigure the plant. The key assumptions underlying each scenario are described below.

- **Scenario 1**. In this scenario we assume that the long-term fixed price gas supply contracts and associated firm transportation on Nova and TCPL are terminated effective January 1, 2005. AELLC, or a new buyer, renegotiate a new steam contract with IP. Effective January 2006 the Project resumes production of steam as its primary product. It acquires all of its gas supply at market based prices delivered into PNGTS. This scenario is consistent with AELLC's long-term projections of December 2003 except the fixed price gas supply contracts and associated upstream firm transportation contracts are terminated effective January 1 2005 rather than expiring in 2009.

- **Scenario 2.** In this scenario we assume that the long-term fixed price gas supply and associated firm transportation contracts continue for their full term through 2009. Thus, during the 2005 shutdown the Project resells the gas under long-term fixed contracts. Either AELLC, or a new buyer, spend 2005 installing some combination of HRSG's and turbines in order to change its configuration to a combined cycle operation with a lower heat rate, i.e., 8 MMBtu/MWh or less. The installed cost of the HRSG and turbine would be in the order of $10 million or more. We did not include that capital cost in our projections. Starting January 2006 AELLC no longer produces steam for IP. Instead it begins producing electric energy and capacity as its primary products. In this scenario, the net capacity is increased from 156 MW to 216 MW due to installation of the back pressure turbine. All three units are dispatched economically. This scenario is consistent with a mill closure scenario analyzed in an independent engineer's report prepared in June 1998 in connection with the financing of the Project.

- **Scenario 3.** This Scenario rests on the same assumptions as Scenario 2 except the long-term fixed price gas supply contracts and associated firm transportation are terminated January 1, 2005. Effective January 2006 the Project acquires its gas supply at market based prices delivered into PNGTS.

Our analyses of these scenarios are presented in Appendices 1 to 3. We prepared our projections using the same basic methodology as that used by AELLC in its *Long-Term Projections*. For each scenario we prepared a set of forecasts and calculations consisting of three main sections – energy prices, plant performance and Project revenues and costs. The prices section presents our forecast of energy prices. The performance section presents our forecast of Project operating levels and production efficiencies. The operating revenues section presents our calculation of revenues and costs.

4.1.2 Prices

This section presents the projections we used for prices of natural gas, electric energy, electric capacity and steam.

The price projections for electric capacity are based upon expectations as of April 2005 as described earlier on page 7.

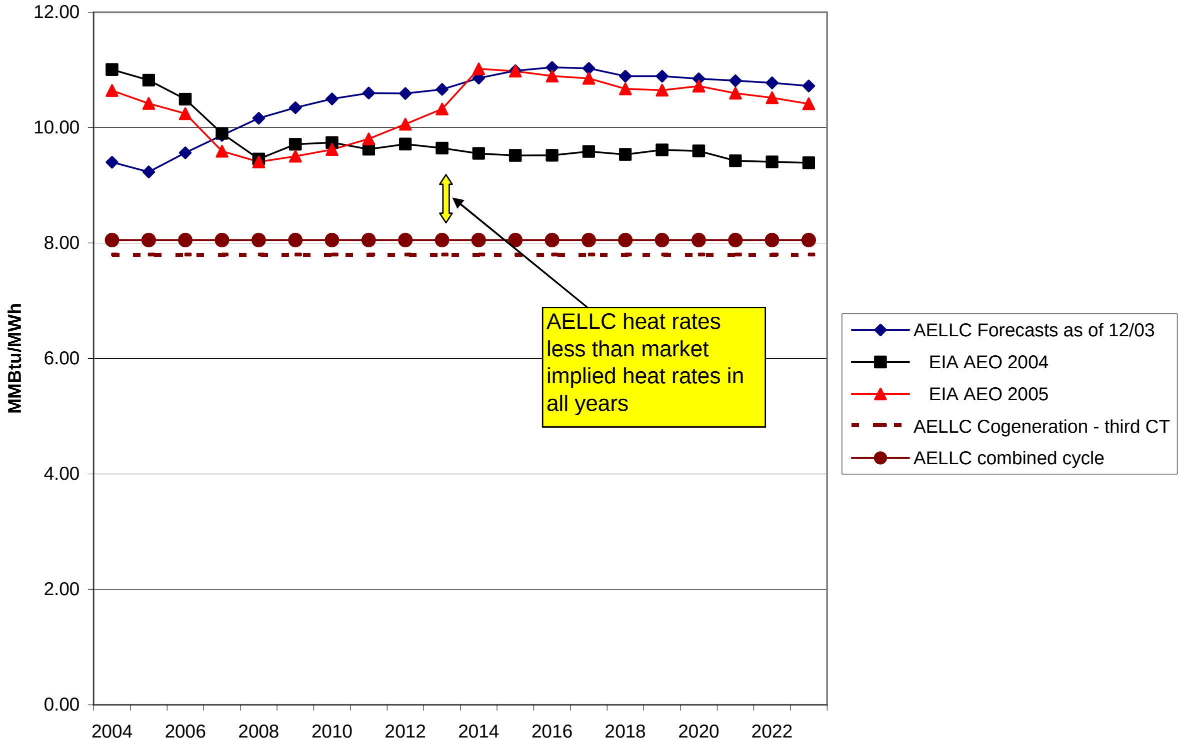
The projected steam prices are derived from the delivered price of natural gas in the same manner as derived under the ESA, i.e., average delivered variable price of natural gas divided by 84.1%.

The projected prices for natural gas and electric energy in New England markets are drawn from the EIA Annual Energy Outlook 2005.[6] As noted earlier, AELLC's internal price forecasts as of April 2004 were consistent with the EIA AEO 2004, therefore we believe that it is reasonable to use EIA projections from AEO 2005.

It is also important to note that the ratio of electric market prices to natural gas market prices from AEO 2005, sometimes referred to as the "market implied heat rate" is comparable to that in the AELLC projections of December 2003 and the AEO 2004 forecasts. This is illustrated in Figure 4. AELLC in December 2003, EIA in AEO 2004 and EIA in AEO 2005 all expected the implied heat rate to range between 10 to 11 MMBtu/MWh range over the forecast period.

[6] Annual Energy Outlook 2005, February 2005. U.S. Energy Information Administration. http://www.eia.doe.gov/oiaf/archive/aeo05/index.html.

Figure 4
Market implied heat rate vs AELLC heat rates



4.1.3 Project Revenues and Costs

The projected operating revenues and costs under each scenario are the result of the projected quantities and projected prices.

Results. The results of our analyses, summarized earlier in Figure 1, indicate that the Project's operating cashflow would be positive in most years between 2006 and 2024.

Line #		Assumption / Calculation	Source	Years Ending December 31 2005	2006	2007	2008	2009
							Red = Key inputs	
	Androscoggin Energy Project						Blue = Calculated values	
	Projected Operating Results (constant 2005$)							
	Scenario 1							
	Sell steam based on market price of gas beginning Jan. 1, 2006; terminate fixed price gas supply contracts							
	A. PRICES							
1	General Inflation (%)	0.00%	1	0.00%	0.00%	0.00%	0.00%	0.00%
2	Natural Gas commodity prices							
3	Average Market Price New England ($/MMBtu) (2005$)		2	$ 6.25	$ 5.52	$ 5.17	$ 4.92	$ 4.78
3a	Average Market Price East Hereford PQ ($/MMBtu) (2005 $)	(Line 3 - 0.20 $/MMBtu)	1	$ 6.05	$ 5.32	$ 4.97	$ 4.72	$ 4.58
4	Average Purchase Price under Contracts ($/MMBtu)							
5	Electricity							
6	Steam Injection Capacity Price ($/KW/yr)							
7	Market Wholesale Capacity Price ($/kW/yr) (2005$)	$ 4.40	3	10.8	10.8	52.8	52.8	52.8
7a	Market Wholesale Capacity Price ($/kW/yr) (Nominal $)	(Line 7) * (Line 1)^t		$ 10.80	$ 10.80	$ 52.80	$ 52.80	$ 52.80
8	Market Wholesale Energy Price ($/MWh) (2005$)		2	$ 65.17	$ 56.58	$ 49.57	$ 46.24	$ 45.45
8a	Market Wholesale Energy Price ($/MWh) (Nominal $)	(Line 8) * (Line 1)^t		$ 65.17	$ 56.58	$ 49.57	$ 46.24	$ 45.45
9	Transmission & Distribution Charge ($/MWh)							
10	Stranded Cost Charge ($/MWh)							
11	Steam ($/MMBtu)	Line 3 / 84.1%	4	n/a	$ 6.33	$ 5.91	$ 5.61	$ 5.45
12								
13	**B. PERFORMANCE and ECONOMIC DISPATCH**							
14	Net Capacity (kW)	156,000	4	156,000	156,000	156,000	156,000	156,000
15	Availability	95%	4	95%	95%	95%	95%	95%
16a	Units 1 and 2 Net Equivalent Heat Rate (Btu/kWh)	6,100	1	12,000	6,100	6,100	6,100	6,100
16b	Unit 3 Net Equivalent Heat Rate (Btu/kWh)	7,800	1	12,000	7,800	7,800	7,800	7,800
17	Non-Fuel VOM electricity production costs for dispatch ($/Mwh)	$ 3.00	6	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
18	Electricity variable production cost ($/MWh)	Line 17 + (Line 3 * Line 16 / 100)		$ 78.06	$ 46.08	$ 43.31	$ 41.35	$ 40.30
19	Dispatch or Resell	Dispatch if L18<=L8		No	Dispatch	Dispatch	Dispatch	Dispatch
20	Annual Capacity and Energy Sales (kW)							
21	Steam Injection Capacity Sales (kW)							
22	Capacity Sales to IP (kW)			0	0	0	0	0
23	Energy Sales to IP (MWh)			0	0	0	0	0
24	Market Capacity Sales (MW)	Line 14 / 1000 if Dispatch		0	156	156	156	156
25a	Market Energy Sales (MWh) unit 3	51 MW * Line 15 * 8760	4	0	424422	424422	424422	424422
25b	Market Energy Sales (MWh) unit 1 and 2	817,117	1		817,117	817,117	817,117	817,117
26	Process Steam Sales (MMBtu x 1000)	5,912	1	0	5,912	5,912	5,912	5,912
					0			
27	Capacity Factor (%)	Line 25(a + b) / (Line 24 * 8760)		0.0%	90.9%	90.9%	90.9%	90.9%
28								
29	Maximum Supply of Contract Gas (MMBTU * 1000)		5	0	0	0	0	0
30	Fuel Consumption (MMBtu x 1000)			0	14,352	14,352	14,352	14,352
31	Supply from contracts (MMBTu*1000)	Line 29		0	0	0	0	0
32	Supply from spot purchases (MMBtu*1000)	Line 30 - Line 31		0	14,352	14,352	14,352	14,352
33	Excess Contract Gas available for resale (MMBTU*1000)	Line 29 - Line 31		0	0	0	0	0
34								
35	**C. OPERATING REVENUES and EXPENSES (000 of $2005)**							
36	Electricity Revenues							
37	Steam Injection Capacity Sales	0		0	0	0	0	0
38	Electric Sales to IP							
39	Market Electric Capacity Sales	Line 24 * Line 7		$ -	$ 1,685	$ 8,237	$ 8,237	$ 8,237
40a	Market Electric Energy Sales - Unit 3	(Line 25a * Line 8) / 1000		$ -	$ 24,014	$ 21,039	$ 19,627	$ 19,289
40b	Market Electric Energy Sales - Unit 1 and 2	(Line 25b * Line 8) / 1000		$ -	$ 46,234	$ 40,506	$ 37,787	$ 37,137
41	Steam Revenues	Line 26 * Line 11			$ 37,424	$ 34,925	$ 33,157	$ 32,209
42	Resale of Contract Gas	Line 33 * (Line 3 - Line 4)		$ -	$ -	$ -	$ -	$ -
43	Interest Income	0		0	0	0	0	0
44	**Total Operating Revenues**			$ -	**$ 109,357**	**$ 104,707**	**$ 98,808**	**$ 96,872**
45								
46	**Fuel Operating Expenses ($000)**							
47	Fuel - Supply from Contracts	Line 31 * Line 4		$ -	$ -	$ -	$ -	$ -
48	Fuel - Supply from Spot Market	Line 32 * Line 3		$ -	$ 76,404	$ 71,301	$ 67,692	$ 65,757
49	Fuel - Transportation	$ 9,000	1	$ 9,000	$ 9,000	$ 9,000	$ 9,000	$ 9,000
49a	Revenues from release of pipeline capacity							
50	Sub-Total			**$ 9,000**	**$ 85,404**	**$ 80,301**	**$ 76,692**	**$ 74,757**
51								
52	**Non-fuel Operating Expense ($000)**							
53	Variable Operating Expenses	**$ 181.0**	1	$ -	$ 181	$ 181	$ 181	$ 181
54	O&M - Fixed (excl Major Maint)	**$ 682.0**	1	$ 682	$ 682	$ 682	$ 682	$ 682
55	Major Maintenance	**$ 1,447.0**	1	$ -	$ 1,447	$ 1,447	$ 1,447	$ 1,447
56	Labor	**$ 2,028.0**	1	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028
57	EH&S	**$ 118.0**	1	$ 118	$ 118	$ 118	$ 118	$ 118
58	Plant Administration	**$ 93.0**	1	$ 93	$ 93	$ 93	$ 93	$ 93
59	Property Tax/Gas Tax	**$ 996.0**	1	$ 996	$ 996	$ 996	$ 996	$ 996
60	Insurance	**$ 646.0**	1	$ 646	$ 646	$ 646	$ 646	$ 646
61	Legal Fees	**$ 513.0**	1	$ 513	$ 513	$ 513	$ 513	$ 513
62	Plant Maintenance	**$ 671.0**	1	$ 671	$ 671	$ 671	$ 671	$ 671
63	Managers Operating Expenses	**$ 300.0**	1	$ -	$ 300	$ 300	$ 300	$ 300
64	Management Fees	**$ 55.0**	1	$ -	$ 55	$ 55	$ 55	$ 55
65	Sub- Total Non-fuel Operating Expenses			**$ 5,747**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**
66								
67	**Operating Cash flow**	Line 44 - Line 50 - Line 64		**$ (14,747)**	**$ 16,223**	**$ 16,676**	**$ 14,385**	**$ 14,385**

Data Sources

1	AELLC Long-Term Projections December 2003
2	AEO 2005
3	Synapse assumption re expectations re LICAP as of April 2005
4	AELLC 2004 Operating Plan
5	AELLC Technical Summary, Calpine Northbrook Corp., 2005
6	Synapse generating unit database

Line #		Assumption / Calculation	Source	2010	2011	2012	2013	2014	2015	2016
	Androscoggin Energy Project									
	Projected Operating Results (constant 2005$)									
	Scenario 1									
	Sell steam based on market price of gas beginning Jan. 1, 2006; terminate fixed price gas supply contracts									`
	A. PRICES									
1	General Inflation (%)	0.00%	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	Natural Gas commodity prices									
3	Average Market Price New England ($/MMBtu) (2005$)		2	$ 4.67	$ 4.70	$ 4.76	$ 4.86	$ 5.00	$ 5.05	$ 5.11
3a	Average Market Price East Hereford PQ ($/MMBtu) (2005 $)	(Line 3 - 0.20 $/MMBtu)	1	$ 4.47	$ 4.50	$ 4.56	$ 4.66	$ 4.80	$ 4.85	$ 4.91
4	Average Purchase Price under Contracts ($/MMBtu)									
5	Electricity									
6	Steam Injection Capacity Price ($/KW/yr)									
7	Market Wholesale Capacity Price ($/kW/yr) (2005$)	$ 4.40	3	52.8	52.8	52.8	52.8	52.8	52.8	52.8
7a	Market Wholesale Capacity Price ($/kW/yr) (Nominal $)	(Line 7) * (Line 1)^t		$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80
8	Market Wholesale Energy Price ($/MWh) (2005$)		2	$ 44.88	$ 46.11	$ 47.85	$ 50.17	$ 55.14	$ 55.44	$ 55.64
8a	Market Wholesale Energy Price ($/MWh) (Nominal $)	(Line 8) * (Line 1)^t		$ 44.88	$ 46.11	$ 47.85	$ 50.17	$ 55.14	$ 55.44	$ 55.64
9	Transmission & Distribution Charge ($/MWh)									
10	Stranded Cost Charge ($/MWh)									
11	Steam ($/MMBtu)	Line 3 / 84.1%	4	$ 5.31	$ 5.35	$ 5.42	$ 5.54	$ 5.71	$ 5.77	$ 5.84
12										
13	**B. PERFORMANCE and ECONOMIC DISPATCH**									
14	Net Capacity (kW)	156,000	4	156,000	156,000	156,000	156,000	156,000	156,000	156,000
15	Availability	95%	4	95%	95%	95%	95%	95%	95%	95%
16a	Units 1 and 2 Net Equivalent Heat Rate (Btu/kWh)	6,100	1	6,100	6,100	6,100	6,100	6,100	6,100	6,100
16b	Unit 3 Net Equivalent Heat Rate (Btu/kWh)	7,800	1	7,800	7,800	7,800	7,800	7,800	7,800	7,800
17	Non-Fuel VOM electricity production costs for dispatch ($/Mwh)	$ 3.00	6	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
18	Electricity variable production cost ($/MWh)	Line 17 + (Line 3 * Line 16 / 100)		$ 39.39	$ 39.68	$ 40.11	$ 40.91	$ 42.04	$ 42.40	$ 42.84
19	Dispatch or Resell	Dispatch if L18<=L8		Dispatch	Dispatch	Dispatch	Dispatch	Dispatch	Dispatch	Dispatch
20	Annual Capacity and Energy Sales (kW)									
21	Steam Injection Capacity Sales (kW)									
22	Capacity Sales to IP (kW)			0	0	0	0	0		
23	Energy Sales to IP (MWh)			0	0	0	0	0		
24	Market Capacity Sales (MW)	Line 14 / 1000 if Dispatch		156	156	156	156	156	156	156
25a	Market Energy Sales (MWh) unit 3	51 MW * Line 15 * 8760	4	424422	424422	424422	424422	424422	424422	424422
25b	Market Energy Sales (MWh) unit 1 and 2	817,117	1	817,117	817,117	817,117	817,117	817,117	817,117	817,117
26	Process Steam Sales (MMBtu x 1000)	5,912	1	5,912	5,912	5,912	5,912	5,912	5,912	5,912
27	Capacity Factor (%)	Line 25(a + b) / (Line 24 * 8760)		90.9%	90.9%	90.9%	90.9%	90.9%	90.9%	90.9%
28										
29	Maximum Supply of Contract Gas (MMBTU * 1000)		5							
30	Fuel Consumption (MMBtu x 1000)			14,352	14,352	14,352	14,352	14,352	14,352	14,352
31	Supply from contracts (MMBTu*1000)	Line 29		0	0	0	0	0	0	0
32	Supply from spot purchases (MMBtu*1000)	Line 30 - Line 31		14,352	14,352	14,352	14,352	14,352	14,352	14,352
33	Excess Contract Gas available for resale (MMBTU*1000)	Line 29 - Line 31		0	0	0	0	0	0	0
34										
35	**C. OPERATING REVENUES and EXPENSES (000 of $2005)**									
36	Electricity Revenues									
37	Steam Injection Capacity Sales	0		0	0	0	0	0	0	0
38	Electric Sales to IP									
39	Market Electric Capacity Sales	Line 24 * Line 7		$ 8,237	$ 8,237	$ 8,237	$ 8,237	$ 8,237	$ 8,237	$ 8,237
40a	Market Electric Energy Sales - Unit 3	(Line 25a * Line 8) / 1000		$ 19,050	$ 19,569	$ 20,308	$ 21,293	$ 23,404	$ 23,532	$ 23,616
40b	Market Electric Energy Sales - Unit 1 and 2	(Line 25b * Line 8) / 1000		$ 36,675	$ 37,675	$ 39,097	$ 40,995	$ 45,058	$ 45,305	$ 45,467
41	Steam Revenues	Line 26 * Line 11		$ 31,391	$ 31,653	$ 32,035	$ 32,757	$ 33,776	$ 34,100	$ 34,504
42	Resale of Contract Gas	Line 33 * (Line 3 - Line 4)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interest Income	0		0	0	0	0	0	0	0
44	**Total Operating Revenues**			**$ 95,353**	**$ 97,134**	**$ 99,677**	**$ 103,282**	**$ 110,474**	**$ 111,174**	**$ 111,824**
45										
46	**Fuel Operating Expenses ($000)**									
47	Fuel - Supply from Contracts	Line 31 * Line 4		$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	Fuel - Supply from Spot Market	Line 32 * Line 3		$ 64,087	$ 64,622	$ 65,402	$ 66,876	$ 68,955	$ 69,617	$ 70,443
49	Fuel - Transportation	$ 9,000	1	$ 9,260	$ 9,375	$ 9,492	$ 9,610	$ 9,728	$ 9,847	$ 9,966
49a	Revenues from release of pipeline capacity									
50	Sub-Total			**$ 73,347**	**$ 73,997**	**$ 74,894**	**$ 76,486**	**$ 78,683**	**$ 79,464**	**$ 80,409**
51										
52	**Non-fuel Operating Expense ($000)**									
53	Variable Operating Expenses	**$ 181.0**	1	$ 181	$ 181	$ 181	$ 181	$ 181	$ 181	$ 181
54	O&M - Fixed (excl Major Maint)	**$ 682.0**	1	$ 682	$ 682	$ 682	$ 682	$ 682	$ 682	$ 682
55	Major Maintenance	**$ 1,447.0**	1	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447
56	Labor	**$ 2,028.0**	1	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028
57	EH&S	**$ 118.0**	1	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118
58	Plant Administration	**$ 93.0**	1	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93
59	Property Tax/Gas Tax	**$ 996.0**	1	$ 996	$ 996	$ 996	$ 996	$ 996	$ 996	$ 996
60	Insurance	**$ 646.0**	1	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646
61	Legal Fees	**$ 513.0**	1	$ 513	$ 513	$ 513	$ 513	$ 513	$ 513	$ 513
62	Plant Maintenance	**$ 671.0**	1	$ 671	$ 671	$ 671	$ 671	$ 671	$ 671	$ 671
63	Managers Operating Expenses	**$ 300.0**	1	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300
64	Management Fees	**$ 55.0**	1	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55
65	Sub- Total Non-fuel Operating Expenses			**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**
66										
67	**Operating Cash flow**	Line 44 - Line 50 - Line 64		**$ 14,276**	**$ 15,407**	**$ 17,053**	**$ 19,066**	**$ 24,060**	**$ 23,979**	**$ 23,685**

Data Sources

1	AELLC Long-Term Projections December 2003
2	AEO 2005
3	Synapse assumption re expectations re LICAP as of April 2005
4	AELLC 2004 Operating Plan
5	AELLC Technical Summary, Calpine Northbrook Corp., 2005
6	Synapse generating unit database

Androscoggin Energy Project
Projected Operating Results (constant 2005$)
Scenario 1
Sell steam based on market price of gas beginning Jan. 1, 2006; terminate fixed price gas supply contracts

Line #		Assumption / Calculation	Source	2017	2018	2019	2020	2021	2022	2023
	A. PRICES									
1	General Inflation (%)	0.00%	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	Natural Gas commodity prices									
3	Average Market Price New England ($/MMBtu) (2005$)		2	$ 5.15	$ 5.32	$ 5.48	$ 5.49	$ 5.61	$ 5.72	$ 5.73
3a	Average Market Price East Hereford PQ ($/MMBtu) (2005 $)	(Line 3 - 0.20 $/MMBtu)	1	$ 4.95	$ 5.12	$ 5.28	$ 5.29	$ 5.41	$ 5.52	$ 5.53
4	Average Purchase Price under Contracts ($/MMBtu)									
5	Electricity									
6	Steam Injection Capacity Price ($/KW/yr)									
7	Market Wholesale Capacity Price ($/kW/yr) (2005$)	$ 4.40	3	52.8	52.8	52.8	52.8	52.8	52.8	52.8
7a	Market Wholesale Capacity Price ($/kW/yr) (Nominal $)	(Line 7) * (Line 1)^t		$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80
8	Market Wholesale Energy Price ($/MWh) (2005$)		2	$ 55.91	$ 56.76	$ 58.37	$ 58.85	$ 59.49	$ 60.14	$ 59.68
8a	Market Wholesale Energy Price ($/MWh) (Nominal $)	(Line 8) * (Line 1)^t		$ 55.91	$ 56.76	$ 58.37	$ 58.85	$ 59.49	$ 60.14	$ 59.68
9	Transmission & Distribution Charge ($/MWh)									
10	Stranded Cost Charge ($/MWh)									
11	Steam ($/MMBtu)	Line 3 / 84.1%	4	$ 5.89	$ 6.09	$ 6.28	$ 6.29	$ 6.44	$ 6.56	$ 6.58
12										
13	**B. PERFORMANCE and ECONOMIC DISPATCH**									
14	Net Capacity (kW)	156,000	4	156,000	156,000	156,000	156,000	156,000	156,000	156,000
15	Availability	95%	4	95%	95%	95%	95%	95%	95%	95%
16a	Units 1 and 2 Net Equivalent Heat Rate (Btu/kWh)	6,100	1	6,100	6,100	6,100	6,100	6,100	6,100	6,100
16b	Unit 3 Net Equivalent Heat Rate (Btu/kWh)	7,800	1	7,800	7,800	7,800	7,800	7,800	7,800	7,800
17	Non-Fuel VOM electricity production costs for dispatch ($/Mwh)	$ 3.00	6	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
18	Electricity variable production cost ($/MWh)	Line 17 + (Line 3 * Line 16 / 100)		$ 43.18	$ 44.49	$ 45.76	$ 45.83	$ 46.80	$ 47.60	$ 47.71
19	Dispatch or Resell	Dispatch if L18<=L8		Dispatch	Dispatch	Dispatch	Dispatch	Dispatch	Dispatch	Dispatch
20	Annual Capacity and Energy Sales (kW)									
21	Steam Injection Capacity Sales (kW)									
22	Capacity Sales to IP (kW)									
23	Energy Sales to IP (MWh)									
24	Market Capacity Sales (MW)	Line 14 / 1000 if Dispatch		156	156	156	156	156	156	156
25a	Market Energy Sales (MWh) unit 3	51 MW * Line 15 * 8760	4	424422	424422	424422	424422	424422	424422	424422
25b	Market Energy Sales (MWh) unit 1 and 2	817,117	1	817,117	817,117	817,117	817,117	817,117	817,117	817,117
26	Process Steam Sales (MMBtu x 1000)	5,912	1	5,912	5,912	5,912	5,912	5,912	5,912	5,912
27	Capacity Factor (%)	Line 25(a + b) / (Line 24 * 8760)		90.9%	90.9%	90.9%	90.9%	90.9%	90.9%	90.9%
28										
29	Maximum Supply of Contract Gas (MMBTU * 1000)		5							
30	Fuel Consumption (MMBtu x 1000)			14,352	14,352	14,352	14,352	14,352	14,352	14,352
31	Supply from contracts (MMBTu*1000)	Line 29		0	0	0	0	0	0	0
32	Supply from spot purchases (MMBtu*1000)	Line 30 - Line 31		14,352	14,352	14,352	14,352	14,352	14,352	14,352
33	Excess Contract Gas available for resale (MMBTU*1000)	Line 29 - Line 31		0	0	0	0	0	0	0
34										
35	**C. OPERATING REVENUES and EXPENSES (000 of $2005)**									
36	Electricity Revenues									
37	Steam Injection Capacity Sales	0		0	0	0	0	0	0	0
38	Electric Sales to IP									
39	Market Electric Capacity Sales	Line 24 * Line 7		$ 8,237	$ 8,237	$ 8,237	$ 8,237	$ 8,237	$ 8,237	$ 8,237
40a	Market Electric Energy Sales - Unit 3	(Line 25a * Line 8) / 1000		$ 23,728	$ 24,091	$ 24,773	$ 24,979	$ 25,250	$ 25,525	$ 25,331
40b	Market Electric Energy Sales - Unit 1 and 2	(Line 25b * Line 8) / 1000		$ 45,681	$ 46,380	$ 47,694	$ 48,091	$ 48,613	$ 49,141	$ 48,768
41	Steam Revenues	Line 26 * Line 11		$ 34,803	$ 35,988	$ 37,130	$ 37,193	$ 38,065	$ 38,789	$ 38,886
42	Resale of Contract Gas	Line 33 * (Line 3 - Line 4)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interest Income	0		0	0	0	0	0	0	0
44	**Total Operating Revenues**			**$ 112,449**	**$ 114,696**	**$ 117,834**	**$ 118,499**	**$ 120,166**	**$ 121,691**	**$ 121,222**
45										
46	**Fuel Operating Expenses ($000)**									
47	Fuel - Supply from Contracts	Line 31 * Line 4		$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	Fuel - Supply from Spot Market	Line 32 * Line 3		$ 71,053	$ 73,472	$ 75,803	$ 75,931	$ 77,713	$ 79,190	$ 79,389
49	Fuel - Transportation	$ 9,000	1	$ 10,081	$ 10,196	$ 10,322	$ 10,453	$ 10,582	$ 10,710	$ 10,842
49a	Revenues from release of pipeline capacity									
50	Sub-Total			**$ 81,134**	**$ 83,668**	**$ 86,125**	**$ 86,384**	**$ 88,295**	**$ 89,900**	**$ 90,231**
51										
52	**Non-fuel Operating Expense ($000)**									
53	Variable Operating Expenses	**$ 181.0**	1	$ 181	$ 181	$ 181	$ 181	$ 181	$ 181	$ 181
54	O&M - Fixed (excl Major Maint)	**$ 682.0**	1	$ 682	$ 682	$ 682	$ 682	$ 682	$ 682	$ 682
55	Major Maintenance	**$ 1,447.0**	1	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447
56	Labor	**$ 2,028.0**	1	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028
57	EH&S	**$ 118.0**	1	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118
58	Plant Administration	**$ 93.0**	1	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93
59	Property Tax/Gas Tax	**$ 996.0**	1	$ 996	$ 996	$ 996	$ 996	$ 996	$ 996	$ 996
60	Insurance	**$ 646.0**	1	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646
61	Legal Fees	**$ 513.0**	1	$ 513	$ 513	$ 513	$ 513	$ 513	$ 513	$ 513
62	Plant Maintenance	**$ 671.0**	1	$ 671	$ 671	$ 671	$ 671	$ 671	$ 671	$ 671
63	Managers Operating Expenses	**$ 300.0**	1	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300
64	Management Fees	**$ 55.0**	1	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55
65	Sub- Total Non-fuel Operating Expenses			**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**
66										
67	**Operating Cash flow**	Line 44 - Line 50 - Line 64		**$ 23,585**	**$ 23,298**	**$ 23,979**	**$ 24,385**	**$ 24,141**	**$ 24,061**	**$ 23,260**

Data Sources

1	AELLC Long-Term Projections December 2003
2	AEO 2005
3	Synapse assumption re expectations re LICAP as of April 2005
4	AELLC 2004 Operating Plan
5	AELLC Technical Summary, Calpine Northbrook Corp., 2005
6	Synapse generating unit database

Red = Key inputs
Blue = Calculated values

Androscoggin Energy Project
Projected Operating Results (constant 2005$)
Scenario 2
No steam load, buy turbine, sell electricity, keep fixed price gas supply contracts until expiration

Line #		Assumption / Calculation	Source	Years Ending December 31 2005	2006	2007	2008	2009
	A. PRICES							
1	General Inflation (%)	0.00%	1	0.00%	0.00%	0.00%	0.00%	0.00%
2	Natural Gas commodity prices							
3	Average Market Price New England ($/MMBtu) (2005$)		2	$ 6.25	$ 5.52	$ 5.17	$ 4.92	$ 4.78
3a	Average Market Price East Hereford PQ ($/MMBtu) (2005 $)	(Line 3 - 0.20 $/MMBtu)	1	$ 6.05	$ 5.32	$ 4.97	$ 4.72	$ 4.58
4	Average Purchase Price under Contracts ($/MMBtu)			$ 2.07	$ 2.12	$ 2.17	2.23	$ 2.27
5	Electricity							
6	Steam Injection Capacity Price ($/KW/yr)							
7	Market Wholesale Capacity Price ($/kW/yr) (2005$)	$ 4.40	3	10.8	10.8	52.8	52.8	52.8
7a	Market Wholesale Capacity Price ($/kW/yr) (Nominal $)	(Line 7) * (Line 1)^t		$ 10.80	$ 10.80	$ 52.80	$ 52.80	$ 52.80
8	Market Wholesale Energy Price ($/MWh) (2005$)		2	$ 65.17	$ 56.58	$ 49.57	$ 46.24	$ 45.45
8a	Market Wholesale Energy Price ($/MWh) (Nominal $)	(Line 8) * (Line 1)^t		$ 65.17	$ 56.58	$ 49.57	$ 46.24	$ 45.45
9	Transmission & Distribution Charge ($/MWh)							
10	Stranded Cost Charge ($/MWh)							
11	Steam ($/MMBtu)	Line 3 / 84.1%	4	n/a	$ 6.33	$ 5.91	$ 5.61	$ 5.45
12								
13	**B. PERFORMANCE and ECONOMIC DISPATCH**							
14	Net Capacity (kW)	216,664	7	216,664	216,664	216,664	216,664	216,664
15	Availability	95%	4	95%	95%	95%	95%	95%
16	Net Equivalent Heat Rate (Btu/kWh)	8,050	7	12,000	8,050	8,050	8,050	8,050
17	Non-Fuel VOM electricity production costs for dispatch ($/Mwh)	$ 3.00	6	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
18	Electricity variable production cost ($/MWh)	Line 17 + (Line 3 * Line 16 / 100)		$ 78.06	$ 47.47	$ 44.60	$ 42.58	$ 41.49
19	Dispatch or Resell	Dispatch if L18<=L8		No	Dispatch	Dispatch	Dispatch	Dispatch
20	Annual Capacity and Energy Sales (kW)							
21	Steam Injection Capacity Sales (kW)							
22	Capacity Sales to IP (kW)			0	0	0	0	0
23	Energy Sales to IP (MWh)			0	0	0	0	0
24	Market Capacity Sales (MW)	Line 14 / 1000 if Dispatch		0	217	217	217	217
25	Market Energy Sales (MWh) unit 1 and 2	Line 24 * Line 15 * 8760	1		1,803,078	1,803,078	1,803,078	1,803,078
26	Process Steam Sales (MMBtu x 1000)	0	1	0	0	0	0	0
					0			
27	Capacity Factor (%)	Line 25 / (Line 24 * 8760)		0.0%	95.0%	95.0%	95.0%	95.0%
28								
29	Maximum Supply of Contract Gas (MMBTU * 1000)	7650	5	7,650	7,650	7,650	7,650	7,650
30	Fuel Consumption (MMBtu x 1000)	Line 25 * Line 16		0	14,515	14,515	14,515	14,515
31	Supply from contracts (MMBTu*1000)	Line 29		7,650	7,650	7,650	7,650	7,650
32	Supply from spot purchases (MMBtu*1000)	Line 30 - Line 31		0	6,865	6,865	6,865	6,865
33	Excess Contract Gas available for resale (MMBTU*1000)	Line 29 - Line 31		7,650	0	0	0	0
34								
35	**C. OPERATING REVENUES and EXPENSES (000 of $2005)**							
36	Electricity Revenues							
37	Steam Injection Capacity Sales	0		0	0	0	0	0
38	Electric Sales to IP							
39	Market Electric Capacity Sales	Line 24 * Line 7		$ -	$ 2,340	$ 11,440	$ 11,440	$ 11,440
40	Market Electric Energy Sales	(Line 25 * Line 8) / 1000		$ -	$ 102,021	$ 89,382	$ 83,382	$ 81,947
41	Steam Revenues	Line 26 * Line 11			$ -	$ -	$ -	$ -
42	Resale of Contract Gas	Line 33 * (Line 3 - Line 4)		$ 32,015	$ -	$ -	$ -	$ -
43	Interest Income	0		0	0	0	0	0
44	**Total Operating Revenues**			$ 32,015	**$ 104,361**	**$ 100,822**	**$ 94,822**	**$ 93,387**
45								
46	**Fuel Operating Expenses ($000)**							
47	Fuel - Supply from Contracts	Line 31 * Line 4		$ 15,836	$ 15,836	$ 16,218	$ 16,601	$ 17,366
48	Fuel - Supply from Spot Market	Line 32 * Line 3		$ -	$ 36,546	$ 34,105	$ 32,379	$ 31,453
49	Fuel - Transportation	$ 23,093	1	$ 23,093	$ 23,093	$ 23,093	$ 23,093	$ 16,477
49a	Revenues from release of pipeline capacity							
50	Sub-Total			**$ 38,929**	**$ 75,474**	**$ 73,416**	**$ 72,072**	**$ 65,296**
51								
52	**Non-fuel Operating Expense ($000)**							
53	Variable Operating Expenses	**$ 181.0**	1	$ -	$ 181	$ 181	$ 181	$ 181
54	O&M - Fixed (excl Major Maint)	**$ 682.0**	1	$ 682	$ 682	$ 682	$ 682	$ 682
55	Major Maintenance	**$ 1,447.0**	1	$ -	$ 1,447	$ 1,447	$ 1,447	$ 1,447
56	Labor	**$ 2,028.0**	1	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028
57	EH&S	**$ 118.0**	1	$ 118	$ 118	$ 118	$ 118	$ 118
58	Plant Administration	**$ 93.0**	1	$ 93	$ 93	$ 93	$ 93	$ 93
59	Property Tax/Gas Tax	**$ 996.0**	1	$ 996	$ 996	$ 996	$ 996	$ 996
60	Insurance	**$ 646.0**	1	$ 646	$ 646	$ 646	$ 646	$ 646
61	Legal Fees	**$ 513.0**	1	$ 513	$ 513	$ 513	$ 513	$ 513
62	Plant Maintenance	**$ 671.0**	1	$ 671	$ 671	$ 671	$ 671	$ 671
63	Managers Operating Expenses	**$ 300.0**	1	$ -	$ 300	$ 300	$ 300	$ 300
64	Management Fees	**$ 55.0**	1	$ -	$ 55	$ 55	$ 55	$ 55
65	Sub- Total Non-fuel Operating Expenses			**$ 5,747**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**
66								
67	**Operating Cash flow**	Line 44 - Line 50 - Line 64		**$ (12,661)**	**$ 21,156**	**$ 19,676**	**$ 15,019**	**$ 20,361**

Data Sources

1	AELLC Long-Term Projections December 2003
2	AEO 2005
3	Synapse assumption re expectations re LICAP as of April 2005
4	AELLC 2004 Operating Plan
5	AELLC Technical Summary, Calpine Northbrook Corp., 2005
6	Synapse generating unit database
7	R.W. Beck Independent Engineer's Report;

Androscoggin Energy Project
Projected Operating Results (constant 2005$)
Scenario 2
No steam load, buy turbine, sell electricity, keep fixed price gas supply contracts until expiration

Line #		Assumption / Calculation	Source	2010	2011	2012	2013	2014	2015	2016
	A. PRICES									
1	General Inflation (%)	0.00%	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	Natural Gas commodity prices									
3	Average Market Price New England ($/MMBtu) (2005$)		2	$ 4.67	$ 4.70	$ 4.76	$ 4.86	$ 5.00	$ 5.05	$ 5.11
3a	Average Market Price East Hereford PQ ($/MMBtu) (2005 $)	(Line 3 - 0.20 $/MMBtu)	1	$ 4.47	$ 4.50	$ 4.56	$ 4.66	$ 4.80	$ 4.85	$ 4.91
4	Average Purchase Price under Contracts ($/MMBtu)									
5	Electricity									
6	Steam Injection Capacity Price ($/KW/yr)									
7	Market Wholesale Capacity Price ($/kW/yr) (2005$)	$ 4.40	3	52.8	52.8	52.8	52.8	52.8	52.8	52.8
7a	Market Wholesale Capacity Price ($/kW/yr) (Nominal $)	(Line 7) * (Line 1)^t		$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80
8	Market Wholesale Energy Price ($/MWh) (2005$)		2	$ 44.88	$ 46.11	$ 47.85	$ 50.17	$ 55.14	$ 55.44	$ 55.64
8a	Market Wholesale Energy Price ($/MWh) (Nominal $)	(Line 8) * (Line 1)^t		$ 44.88	$ 46.11	$ 47.85	$ 50.17	$ 55.14	$ 55.44	$ 55.64
9	Transmission & Distribution Charge ($/MWh)									
10	Stranded Cost Charge ($/MWh)									
11	Steam ($/MMBtu)	Line 3 / 84.1%	4	$ 5.31	$ 5.35	$ 5.42	$ 5.54	$ 5.71	$ 5.77	$ 5.84
12										
13	**B. PERFORMANCE and ECONOMIC DISPATCH**									
14	Net Capacity (kW)	216,664	7	216,664	216,664	216,664	216,664	216,664	216,664	216,664
15	Availability	95%	4	95%	95%	95%	95%	95%	95%	95%
16	Net Equivalent Heat Rate (Btu/kWh)	8,050	7	8,050	8,050	8,050	8,050	8,050	8,050	8,050
17	Non-Fuel VOM electricity production costs for dispatch ($/Mwh)	$ 3.00	6	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
18	Electricity variable production cost ($/MWh)	Line 17 + (Line 3 * Line 16 / 100)		$ 40.56	$ 40.86	$ 41.29	$ 42.12	$ 43.29	$ 43.66	$ 44.12
19	Dispatch or Resell	Dispatch if L18<=L8		Dispatch	Dispatch	Dispatch	Dispatch	Dispatch	Dispatch	Dispatch
20	Annual Capacity and Energy Sales (kW)									
21	Steam Injection Capacity Sales (kW)									
22	Capacity Sales to IP (kW)			0	0	0	0	0		
23	Energy Sales to IP (MWh)			0	0	0	0	0		
24	Market Capacity Sales (MW)	Line 14 / 1000 if Dispatch		217	217	217	217	217	217	217
25	Market Energy Sales (MWh) unit 1 and 2	Line 24 * Line 15 * 8760	1	1,803,078	1,803,078	1,803,078	1,803,078	1,803,078	1,803,078	1,803,078
26	Process Steam Sales (MMBtu x 1000)	0	1	0	0	0	0	0	0	0
27	Capacity Factor (%)	Line 25 / (Line 24 * 8760)		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
28										
29	Maximum Supply of Contract Gas (MMBTU * 1000)	7650	5							
30	Fuel Consumption (MMBtu x 1000)	Line 25 * Line 16		14,515	14,515	14,515	14,515	14,515	14,515	14,515
31	Supply from contracts (MMBTu*1000)	Line 29		0	0	0	0	0	0	0
32	Supply from spot purchases (MMBtu*1000)	Line 30 - Line 31		14,515	14,515	14,515	14,515	14,515	14,515	14,515
33	Excess Contract Gas available for resale (MMBTU*1000)	Line 29 - Line 31		0	0	0	0	0	0	0
34										
35	**C. OPERATING REVENUES and EXPENSES (000 of $2005)**									
36	Electricity Revenues									
37	Steam Injection Capacity Sales	0		0	0	0	0	0	0	0
38	Electric Sales to IP									
39	Market Electric Capacity Sales	Line 24 * Line 7		$ 11,440	$ 11,440	$ 11,440	$ 11,440	$ 11,440	$ 11,440	$ 11,440
40	Market Electric Energy Sales	(Line 25 * Line 8) / 1000		$ 80,929	$ 83,136	$ 86,273	$ 90,461	$ 99,426	$ 99,971	$ 100,329
41	Steam Revenues	Line 26 * Line 11		$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	Resale of Contract Gas	Line 33 * (Line 3 - Line 4)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interest Income	0		0	0	0	0	0	0	0
44	**Total Operating Revenues**			**$ 92,369**	**$ 94,576**	**$ 97,713**	**$ 101,901**	**$ 110,866**	**$ 111,411**	**$ 111,768**
45										
46	**Fuel Operating Expenses ($000)**									
47	Fuel - Supply from Contracts	Line 31 * Line 4		$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	Fuel - Supply from Spot Market	Line 32 * Line 3		$ 64,816	$ 65,356	$ 66,146	$ 67,636	$ 69,739	$ 70,409	$ 71,243
49	Fuel - Transportation	$ 23,093	1	$ 9,260	$ 9,375	$ 9,492	$ 9,610	$ 9,728	$ 9,847	$ 9,966
49a	Revenues from release of pipeline capacity									
50	Sub-Total			**$ 74,076**	**$ 74,731**	**$ 75,638**	**$ 77,246**	**$ 79,467**	**$ 80,256**	**$ 81,209**
51										
52	**Non-fuel Operating Expense ($000)**									
53	Variable Operating Expenses	**$ 181.0**	1	$ 181	$ 181	$ 181	$ 181	$ 181	$ 181	$ 181
54	O&M - Fixed (excl Major Maint)	**$ 682.0**	1	$ 682	$ 682	$ 682	$ 682	$ 682	$ 682	$ 682
55	Major Maintenance	**$ 1,447.0**	1	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447
56	Labor	**$ 2,028.0**	1	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028
57	EH&S	**$ 118.0**	1	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118
58	Plant Administration	**$ 93.0**	1	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93
59	Property Tax/Gas Tax	**$ 996.0**	1	$ 996	$ 996	$ 996	$ 996	$ 996	$ 996	$ 996
60	Insurance	**$ 646.0**	1	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646
61	Legal Fees	**$ 513.0**	1	$ 513	$ 513	$ 513	$ 513	$ 513	$ 513	$ 513
62	Plant Maintenance	**$ 671.0**	1	$ 671	$ 671	$ 671	$ 671	$ 671	$ 671	$ 671
63	Managers Operating Expenses	**$ 300.0**	1	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300
64	Management Fees	**$ 55.0**	1	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55
65	Sub- Total Non-fuel Operating Expenses			**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**
66										
67	**Operating Cash flow**	Line 44 - Line 50 - Line 64		**$ 10,563**	**$ 12,114**	**$ 14,346**	**$ 16,925**	**$ 23,669**	**$ 23,425**	**$ 22,829**

Data Sources

1 AELLC Long-Term Projections December 2003
2 AEO 2005
3 Synapse assumption re expectations re LICAP as of April 2005
4 AELLC 2004 Operating Plan
5 AELLC Technical Summary, Calpine Northbrook Corp., 2005
6 Synapse generating unit database
7 R.W. Beck Independent Engineer's Report;

Androscoggin Energy Project
Projected Operating Results (constant 2005$)
Scenario 2
No steam load, buy turbine, sell electricity, keep fixed price gas supply contracts until expiration

Line #		Assumption / Calculation	Source	2017	2018	2019	2020	2021	2022	2023
	A. PRICES									
1	General Inflation (%)	0.00%	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	Natural Gas commodity prices									
3	Average Market Price New England ($/MMBtu) (2005$)		2	$ 5.15	$ 5.32	$ 5.48	$ 5.49	$ 5.61	$ 5.72	$ 5.73
3a	Average Market Price East Hereford PQ ($/MMBtu) (2005 $)	(Line 3 - 0.20 $/MMBtu)	1	$ 4.95	$ 5.12	$ 5.28	$ 5.29	$ 5.41	$ 5.52	$ 5.53
4	Average Purchase Price under Contracts ($/MMBtu)									
5	Electricity									
6	Steam Injection Capacity Price ($/KW/yr)									
7	Market Wholesale Capacity Price ($/kW/yr) (2005$)	$ 4.40	3	52.8	52.8	52.8	52.8	52.8	52.8	52.8
7a	Market Wholesale Capacity Price ($/kW/yr) (Nominal $)	(Line 7) * (Line 1)^t		$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80
8	Market Wholesale Energy Price ($/MWh) (2005$)		2	$ 55.91	$ 56.76	$ 58.37	$ 58.85	$ 59.49	$ 60.14	$ 59.68
8a	Market Wholesale Energy Price ($/MWh) (Nominal $)	(Line 8) * (Line 1)^t		$ 55.91	$ 56.76	$ 58.37	$ 58.85	$ 59.49	$ 60.14	$ 59.68
9	Transmission & Distribution Charge ($/MWh)									
10	Stranded Cost Charge ($/MWh)									
11	Steam ($/MMBtu)	Line 3 / 84.1%	4	$ 5.89	$ 6.09	$ 6.28	$ 6.29	$ 6.44	$ 6.56	$ 6.58
12										
13	**B. PERFORMANCE and ECONOMIC DISPATCH**									
14	Net Capacity (kW)	216,664	7	216,664	216,664	216,664	216,664	216,664	216,664	216,664
15	Availability	95%	4	95%	95%	95%	95%	95%	95%	95%
16	Net Equivalent Heat Rate (Btu/kWh)	8,050	7	8,050	8,050	8,050	8,050	8,050	8,050	8,050
17	Non-Fuel VOM electricity production costs for dispatch ($/Mwh)	$ 3.00	6	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
18	Electricity variable production cost ($/MWh)	Line 17 + (Line 3 * Line 16 / 100)		$ 44.46	$ 45.82	$ 47.13	$ 47.20	$ 48.20	$ 49.03	$ 49.14
19	Dispatch or Resell	Dispatch if L18<=L8		Dispatch	Dispatch	Dispatch	Dispatch	Dispatch	Dispatch	Dispatch
20	Annual Capacity and Energy Sales (kW)									
21	Steam Injection Capacity Sales (kW)									
22	Capacity Sales to IP (kW)									
23	Energy Sales to IP (MWh)									
24	Market Capacity Sales (MW)	Line 14 / 1000 if Dispatch		217	217	217	217	217	217	217
25	Market Energy Sales (MWh) unit 1 and 2	Line 24 * Line 15 * 8760	1	1,803,078	1,803,078	1,803,078	1,803,078	1,803,078	1,803,078	1,803,078
26	Process Steam Sales (MMBtu x 1000)	0	1	0	0	0	0	0	0	0
27	Capacity Factor (%)	Line 25 / (Line 24 * 8760)		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
28										
29	Maximum Supply of Contract Gas (MMBTU * 1000)	7650	5							
30	Fuel Consumption (MMBtu x 1000)	Line 25 * Line 16		14,515	14,515	14,515	14,515	14,515	14,515	14,515
31	Supply from contracts (MMBTu*1000)	Line 29		0	0	0	0	0	0	0
32	Supply from spot purchases (MMBtu*1000)	Line 30 - Line 31		14,515	14,515	14,515	14,515	14,515	14,515	14,515
33	Excess Contract Gas available for resale (MMBTU*1000)	Line 29 - Line 31		0	0	0	0	0	0	0
34										
35	**C. OPERATING REVENUES and EXPENSES (000 of $2005)**									
36	Electricity Revenues									
37	Steam Injection Capacity Sales	0		0	0	0	0	0	0	0
38	Electric Sales to IP									
39	Market Electric Capacity Sales	Line 24 * Line 7		$ 11,440	$ 11,440	$ 11,440	$ 11,440	$ 11,440	$ 11,440	$ 11,440
40	Market Electric Energy Sales	(Line 25 * Line 8) / 1000		$ 100,802	$ 102,344	$ 105,244	$ 106,118	$ 107,272	$ 108,436	$ 107,613
41	Steam Revenues	Line 26 * Line 11		$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	Resale of Contract Gas	Line 33 * (Line 3 - Line 4)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interest Income	0		0	0	0	0	0	0	0
44	**Total Operating Revenues**			**$ 112,242**	**$ 113,784**	**$ 116,684**	**$ 117,558**	**$ 118,712**	**$ 119,876**	**$ 119,052**
45										
46	**Fuel Operating Expenses ($000)**									
47	Fuel - Supply from Contracts	Line 31 * Line 4		$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	Fuel - Supply from Spot Market	Line 32 * Line 3		$ 71,861	$ 74,307	$ 76,665	$ 76,794	$ 78,596	$ 80,090	$ 80,292
49	Fuel - Transportation	$ 23,093	1	$ 10,081	$ 10,196	$ 10,322	$ 10,453	$ 10,582	$ 10,710	$ 10,842
49a	Revenues from release of pipeline capacity									
50	Sub-Total			**$ 81,942**	**$ 84,503**	**$ 86,987**	**$ 87,247**	**$ 89,178**	**$ 90,800**	**$ 91,134**
51										
52	**Non-fuel Operating Expense ($000)**									
53	Variable Operating Expenses	**$ 181.0**	1	$ 181	$ 181	$ 181	$ 181	$ 181	$ 181	$ 181
54	O&M - Fixed (excl Major Maint)	**$ 682.0**	1	$ 682	$ 682	$ 682	$ 682	$ 682	$ 682	$ 682
55	Major Maintenance	**$ 1,447.0**	1	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447
56	Labor	**$ 2,028.0**	1	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028
57	EH&S	**$ 118.0**	1	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118
58	Plant Administration	**$ 93.0**	1	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93
59	Property Tax/Gas Tax	**$ 996.0**	1	$ 996	$ 996	$ 996	$ 996	$ 996	$ 996	$ 996
60	Insurance	**$ 646.0**	1	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646
61	Legal Fees	**$ 513.0**	1	$ 513	$ 513	$ 513	$ 513	$ 513	$ 513	$ 513
62	Plant Maintenance	**$ 671.0**	1	$ 671	$ 671	$ 671	$ 671	$ 671	$ 671	$ 671
63	Managers Operating Expenses	**$ 300.0**	1	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300
64	Management Fees	**$ 55.0**	1	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55
65	Sub- Total Non-fuel Operating Expenses			**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**
66										
67	**Operating Cash flow**	Line 44 - Line 50 - Line 64		**$ 22,570**	**$ 21,551**	**$ 21,967**	**$ 22,581**	**$ 21,803**	**$ 21,346**	**$ 20,189**

Data Sources

1	AELLC Long-Term Projections December 2003
2	AEO 2005
3	Synapse assumption re expectations re LICAP as of April 2005
4	AELLC 2004 Operating Plan
5	AELLC Technical Summary, Calpine Northbrook Corp., 2005
6	Synapse generating unit database
7	R.W. Beck Independent Engineer's Report;

Red = Key inputs
Blue = Calculated values

Androscoggin Energy Project
Projected Operating Results (constant 2005$)
Scenario 3
No steam load, buy turbine, sell electricity, keep fixed price gas supply contracts until expiration

Line #		Assumption / Calculation	Source	Years Ending December 31 2005	2006	2007	2008	2009
	A. PRICES							
1	General Inflation (%)	0.00%	1	0.00%	0.00%	0.00%	0.00%	0.00%
2	Natural Gas commodity prices							
3	Average Market Price New England ($/MMBtu) (2005$)		2	$ 6.25	$ 5.52	$ 5.17	$ 4.92	$ 4.78
3a	Average Market Price East Hereford PQ ($/MMBtu) (2005 $)	(Line 3 - 0.20 $/MMBtu)	1	$ 6.05	$ 5.32	$ 4.97	$ 4.72	$ 4.58
4	Average Purchase Price under Contracts ($/MMBtu)			$ 2.07	$ 2.12	$ 2.17	2.23	$ 2.27
5	Electricity							
6	Steam Injection Capacity Price ($/KW/yr)							
7	Market Wholesale Capacity Price ($/kW/yr) (2005$)	$ 4.40	3	10.8	10.8	52.8	52.8	52.8
7a	Market Wholesale Capacity Price ($/kW/yr) (Nominal $)	(Line 7) * (Line 1)^t		$ 10.80	$ 10.80	$ 52.80	$ 52.80	$ 52.80
8	Market Wholesale Energy Price ($/MWh) (2005$)		2	$ 65.17	$ 56.58	$ 49.57	$ 46.24	$ 45.45
8a	Market Wholesale Energy Price ($/MWh) (Nominal $)	(Line 8) * (Line 1)^t		$ 65.17	$ 56.58	$ 49.57	$ 46.24	$ 45.45
9	Transmission & Distribution Charge ($/MWh)							
10	Stranded Cost Charge ($/MWh)							
11	Steam ($/MMBtu)	Line 3 / 84.1%	4	n/a	$ 6.33	$ 5.91	$ 5.61	$ 5.45
12								
13	**B. PERFORMANCE and ECONOMIC DISPATCH**							
14	Net Capacity (kW)	216,664	7	216,664	216,664	216,664	216,664	216,664
15	Availability	95%	4	95%	95%	95%	95%	95%
16	Net Equivalent Heat Rate (Btu/kWh)	8,050	7	12,000	8,050	8,050	8,050	8,050
17	Non-Fuel VOM electricity production costs for dispatch ($/Mwh)	$ 3.00	6	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
18	Electricity variable production cost ($/MWh)	Line 17 + (Line 3 * Line 16 / 100)		$ 78.06	$ 47.47	$ 44.60	$ 42.58	$ 41.49
19	Dispatch or Resell	Dispatch if L18<=L8		No	Dispatch	Dispatch	Dispatch	Dispatch
20	Annual Capacity and Energy Sales (kW)							
21	Steam Injection Capacity Sales (kW)							
22	Capacity Sales to IP (kW)			0	0	0	0	0
23	Energy Sales to IP (MWh)			0	0	0	0	0
24	Market Capacity Sales (MW)	Line 14 / 1000 if Dispatch		0	217	217	217	217
25	Market Energy Sales (MWh) unit 1 and 2	Line 24 * Line 15 * 8760	1		1,803,078	1,803,078	1,803,078	1,803,078
26	Process Steam Sales (MMBtu x 1000)	0	1	0	0	0	0	0
					0			
27	Capacity Factor (%)	Line 25 / (Line 24 * 8760)		0.0%	95.0%	95.0%	95.0%	95.0%
28								
29	Maximum Supply of Contract Gas (MMBTU * 1000)	0	5	0	0	0	0	0
30	Fuel Consumption (MMBtu x 1000)	Line 25 * Line 16		0	14,515	14,515	14,515	14,515
31	Supply from contracts (MMBTu*1000)	Line 29		0	0	0	0	0
32	Supply from spot purchases (MMBtu*1000)	Line 30 - Line 31		0	14,515	14,515	14,515	14,515
33	Excess Contract Gas available for resale (MMBTU*1000)	Line 29 - Line 31		0	0	0	0	0
34								
35	**C. OPERATING REVENUES and EXPENSES (000 of $2005)**							
36	Electricity Revenues							
37	Steam Injection Capacity Sales	0		0	0	0	0	0
38	Electric Sales to IP							
39	Market Electric Capacity Sales	Line 24 * Line 7		$ -	$ 2,340	$ 11,440	$ 11,440	$ 11,440
40	Market Electric Energy Sales	(Line 25 * Line 8) / 1000		$ -	$ 102,021	$ 89,382	$ 83,382	$ 81,947
41	Steam Revenues	Line 26 * Line 11			$ -	$ -	$ -	$ -
42	Resale of Contract Gas	Line 33 * (Line 3 - Line 4)		$ -	$ -	$ -	$ -	$ -
43	Interest Income	0		0	0	0	0	0
44	**Total Operating Revenues**			$ -	**$ 104,361**	**$ 100,822**	**$ 94,822**	**$ 93,387**
45								
46	**Fuel Operating Expenses ($000)**							
47	Fuel - Supply from Contracts	Line 31 * Line 4		$ -	$ -	$ -	$ -	$ -
48	Fuel - Supply from Spot Market	Line 32 * Line 3		$ -	$ 77,272	$ 72,111	$ 68,462	$ 66,504
49	Fuel - Transportation	$ 9,000	1	$ 9,000	$ 9,000	$ 9,000	$ 9,000	$ 9,000
49a	Revenues from release of pipeline capacity							
50	Sub-Total			**$ 9,000**	**$ 86,272**	**$ 81,111**	**$ 77,462**	**$ 75,504**
51								
52	**Non-fuel Operating Expense ($000)**							
53	Variable Operating Expenses	**$ 181.0**	1	$ -	$ 181	$ 181	$ 181	$ 181
54	O&M - Fixed (excl Major Maint)	**$ 682.0**	1	$ 682	$ 682	$ 682	$ 682	$ 682
55	Major Maintenance	**$ 1,447.0**	1	$ -	$ 1,447	$ 1,447	$ 1,447	$ 1,447
56	Labor	**$ 2,028.0**	1	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028
57	EH&S	**$ 118.0**	1	$ 118	$ 118	$ 118	$ 118	$ 118
58	Plant Administration	**$ 93.0**	1	$ 93	$ 93	$ 93	$ 93	$ 93
59	Property Tax/Gas Tax	**$ 996.0**	1	$ 996	$ 996	$ 996	$ 996	$ 996
60	Insurance	**$ 646.0**	1	$ 646	$ 646	$ 646	$ 646	$ 646
61	Legal Fees	**$ 513.0**	1	$ 513	$ 513	$ 513	$ 513	$ 513
62	Plant Maintenance	**$ 671.0**	1	$ 671	$ 671	$ 671	$ 671	$ 671
63	Managers Operating Expenses	**$ 300.0**	1	$ -	$ 300	$ 300	$ 300	$ 300
64	Management Fees	**$ 55.0**	1	$ -	$ 55	$ 55	$ 55	$ 55
65	Sub- Total Non-fuel Operating Expenses			**$ 5,747**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**
66								
67	**Operating Cash flow**	Line 44 - Line 50 - Line 64		**$ (14,747)**	**$ 10,359**	**$ 11,981**	**$ 9,630**	**$ 10,153**

Data Sources

1. AELLC Long-Term Projections December 2003
2. AEO 2005
3. Synapse assumption re expectations re LICAP as of April 2005
4. AELLC 2004 Operating Plan
5. AELLC Technical Summary, Calpine Northbrook Corp., 2005
6. Synapse generating unit database
7. R.W. Beck Independent Engineer's Report;

Androscoggin Energy Project
Projected Operating Results (constant 2005$)
Scenario 3
No steam load, buy turbine, sell electricity, keep fixed price gas supply contracts until expiration

Line #		Assumption / Calculation	Source	2010	2011	2012	2013	2014	2015	2016
	A. PRICES									
1	General Inflation (%)	0.00%	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	Natural Gas commodity prices									
3	Average Market Price New England ($/MMBtu) (2005$)		2	$ 4.67	$ 4.70	$ 4.76	$ 4.86	$ 5.00	$ 5.05	$ 5.11
3a	Average Market Price East Hereford PQ ($/MMBtu) (2005 $)	(Line 3 - 0.20 $/MMBtu)	1	$ 4.47	$ 4.50	$ 4.56	$ 4.66	$ 4.80	$ 4.85	$ 4.91
4	Average Purchase Price under Contracts ($/MMBtu)									
5	Electricity									
6	Steam Injection Capacity Price ($/KW/yr)									
7	Market Wholesale Capacity Price ($/kW/yr) (2005$)	$ 4.40	3	52.8	52.8	52.8	52.8	52.8	52.8	52.8
7a	Market Wholesale Capacity Price ($/kW/yr) (Nominal $)	(Line 7) * (Line 1)^t		$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80
8	Market Wholesale Energy Price ($/MWh) (2005$)		2	$ 44.88	$ 46.11	$ 47.85	$ 50.17	$ 55.14	$ 55.44	$ 55.64
8a	Market Wholesale Energy Price ($/MWh) (Nominal $)	(Line 8) * (Line 1)^t		$ 44.88	$ 46.11	$ 47.85	$ 50.17	$ 55.14	$ 55.44	$ 55.64
9	Transmission & Distribution Charge ($/MWh)									
10	Stranded Cost Charge ($/MWh)									
11	Steam ($/MMBtu)	Line 3 / 84.1%	4	$ 5.31	$ 5.35	$ 5.42	$ 5.54	$ 5.71	$ 5.77	$ 5.84
12										
13	**B. PERFORMANCE and ECONOMIC DISPATCH**									
14	Net Capacity (kW)	216,664	7	216,664	216,664	216,664	216,664	216,664	216,664	216,664
15	Availability	95%	4	95%	95%	95%	95%	95%	95%	95%
16	Net Equivalent Heat Rate (Btu/kWh)	8,050	7	8,050	8,050	8,050	8,050	8,050	8,050	8,050
17	Non-Fuel VOM electricity production costs for dispatch ($/Mwh)	$ 3.00	6	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
18	Electricity variable production cost ($/MWh)	Line 17 + (Line 3 * Line 16 / 100)		$ 40.56	$ 40.86	$ 41.29	$ 42.12	$ 43.29	$ 43.66	$ 44.12
19	Dispatch or Resell	Dispatch if L18<=L8		Dispatch	Dispatch	Dispatch	Dispatch	Dispatch	Dispatch	Dispatch
20	Annual Capacity and Energy Sales (kW)									
21	Steam Injection Capacity Sales (kW)									
22	Capacity Sales to IP (kW)			0	0	0	0	0		
23	Energy Sales to IP (MWh)			0	0	0	0	0		
24	Market Capacity Sales (MW)	Line 14 / 1000 if Dispatch		217	217	217	217	217	217	217
25	Market Energy Sales (MWh) unit 1 and 2	Line 24 * Line 15 * 8760	1	1,803,078	1,803,078	1,803,078	1,803,078	1,803,078	1,803,078	1,803,078
26	Process Steam Sales (MMBtu x 1000)	0	1	0	0	0	0	0	0	0
27	Capacity Factor (%)	Line 25 / (Line 24 * 8760)		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
28										
29	Maximum Supply of Contract Gas (MMBTU * 1000)	0	5							
30	Fuel Consumption (MMBtu x 1000)	Line 25 * Line 16		14,515	14,515	14,515	14,515	14,515	14,515	14,515
31	Supply from contracts (MMBTu*1000)	Line 29		0	0	0	0	0	0	0
32	Supply from spot purchases (MMBtu*1000)	Line 30 - Line 31		14,515	14,515	14,515	14,515	14,515	14,515	14,515
33	Excess Contract Gas available for resale (MMBTU*1000)	Line 29 - Line 31		0	0	0	0	0	0	0
34										
35	**C. OPERATING REVENUES and EXPENSES (000 of $2005)**									
36	Electricity Revenues									
37	Steam Injection Capacity Sales	0		0	0	0	0	0	0	0
38	Electric Sales to IP									
39	Market Electric Capacity Sales	Line 24 * Line 7		$ 11,440	$ 11,440	$ 11,440	$ 11,440	$ 11,440	$ 11,440	$ 11,440
40	Market Electric Energy Sales	(Line 25 * Line 8) / 1000		$ 80,929	$ 83,136	$ 86,273	$ 90,461	$ 99,426	$ 99,971	$ 100,329
41	Steam Revenues	Line 26 * Line 11		$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	Resale of Contract Gas	Line 33 * (Line 3 - Line 4)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interest Income	0		0	0	0	0	0	0	0
44	**Total Operating Revenues**			**$ 92,369**	**$ 94,576**	**$ 97,713**	**$ 101,901**	**$ 110,866**	**$ 111,411**	**$ 111,768**
45										
46	**Fuel Operating Expenses ($000)**									
47	Fuel - Supply from Contracts	Line 31 * Line 4		$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	Fuel - Supply from Spot Market	Line 32 * Line 3		$ 64,816	$ 65,356	$ 66,146	$ 67,636	$ 69,739	$ 70,409	$ 71,243
49	Fuel - Transportation	$ 9,000	1	$ 9,260	$ 9,375	$ 9,492	$ 9,610	$ 9,728	$ 9,847	$ 9,966
49a	Revenues from release of pipeline capacity									
50	Sub-Total			**$ 74,076**	**$ 74,731**	**$ 75,638**	**$ 77,246**	**$ 79,467**	**$ 80,256**	**$ 81,209**
51										
52	**Non-fuel Operating Expense ($000)**									
53	Variable Operating Expenses	**$ 181.0**	1	$ 181	$ 181	$ 181	$ 181	$ 181	$ 181	$ 181
54	O&M - Fixed (excl Major Maint)	**$ 682.0**	1	$ 682	$ 682	$ 682	$ 682	$ 682	$ 682	$ 682
55	Major Maintenance	**$ 1,447.0**	1	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447
56	Labor	**$ 2,028.0**	1	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028
57	EH&S	**$ 118.0**	1	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118
58	Plant Administration	**$ 93.0**	1	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93
59	Property Tax/Gas Tax	**$ 996.0**	1	$ 996	$ 996	$ 996	$ 996	$ 996	$ 996	$ 996
60	Insurance	**$ 646.0**	1	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646
61	Legal Fees	**$ 513.0**	1	$ 513	$ 513	$ 513	$ 513	$ 513	$ 513	$ 513
62	Plant Maintenance	**$ 671.0**	1	$ 671	$ 671	$ 671	$ 671	$ 671	$ 671	$ 671
63	Managers Operating Expenses	**$ 300.0**	1	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300
64	Management Fees	**$ 55.0**	1	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55
65	Sub- Total Non-fuel Operating Expenses			**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**
66										
67	**Operating Cash flow**	Line 44 - Line 50 - Line 64		**$ 10,563**	**$ 12,114**	**$ 14,346**	**$ 16,925**	**$ 23,669**	**$ 23,425**	**$ 22,829**

Data Sources

1	AELLC Long-Term Projections December 2003
2	AEO 2005
3	Synapse assumption re expectations re LICAP as of April 2005
4	AELLC 2004 Operating Plan
5	AELLC Technical Summary, Calpine Northbrook Corp., 2005
6	Synapse generating unit database
7	R.W. Beck Independent Engineer's Report;

Androscoggin Energy Project
Projected Operating Results (constant 2005$)
Scenario 3
No steam load, buy turbine, sell electricity, keep fixed price gas supply contracts until expiration

Line #		Assumption / Calculation	Source	2017	2018	2019	2020	2021	2022	2023
	A. PRICES									
1	General Inflation (%)	0.00%	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2	Natural Gas commodity prices									
3	Average Market Price New England ($/MMBtu) (2005$)		2	$ 5.15	$ 5.32	$ 5.48	$ 5.49	$ 5.61	$ 5.72	$ 5.73
3a	Average Market Price East Hereford PQ ($/MMBtu) (2005 $)	(Line 3 - 0.20 $/MMBtu)	1	$ 4.95	$ 5.12	$ 5.28	$ 5.29	$ 5.41	$ 5.52	$ 5.53
4	Average Purchase Price under Contracts ($/MMBtu)									
5	Electricity									
6	Steam Injection Capacity Price ($/KW/yr)									
7	Market Wholesale Capacity Price ($/kW/yr) (2005$)	$ 4.40	3	52.8	52.8	52.8	52.8	52.8	52.8	52.8
7a	Market Wholesale Capacity Price ($/kW/yr) (Nominal $)	(Line 7) * (Line 1)^t		$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80	$ 52.80
8	Market Wholesale Energy Price ($/MWh) (2005$)		2	$ 55.91	$ 56.76	$ 58.37	$ 58.85	$ 59.49	$ 60.14	$ 59.68
8a	Market Wholesale Energy Price ($/MWh) (Nominal $)	(Line 8) * (Line 1)^t		$ 55.91	$ 56.76	$ 58.37	$ 58.85	$ 59.49	$ 60.14	$ 59.68
9	Transmission & Distribution Charge ($/MWh)									
10	Stranded Cost Charge ($/MWh)									
11	Steam ($/MMBtu)	Line 3 / 84.1%	4	$ 5.89	$ 6.09	$ 6.28	$ 6.29	$ 6.44	$ 6.56	$ 6.58
12										
13	**B. PERFORMANCE and ECONOMIC DISPATCH**									
14	Net Capacity (kW)	216,664	7	216,664	216,664	216,664	216,664	216,664	216,664	216,664
15	Availability	95%	4	95%	95%	95%	95%	95%	95%	95%
16	Net Equivalent Heat Rate (Btu/kWh)	8,050	7	8,050	8,050	8,050	8,050	8,050	8,050	8,050
17	Non-Fuel VOM electricity production costs for dispatch ($/Mwh)	$ 3.00	6	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
18	Electricity variable production cost ($/MWh)	Line 17 + (Line 3 * Line 16 / 100)		$ 44.46	$ 45.82	$ 47.13	$ 47.20	$ 48.20	$ 49.03	$ 49.14
19	Dispatch or Resell	Dispatch if L18<=L8		Dispatch	Dispatch	Dispatch	Dispatch	Dispatch	Dispatch	Dispatch
20	Annual Capacity and Energy Sales (kW)									
21	Steam Injection Capacity Sales (kW)									
22	Capacity Sales to IP (kW)									
23	Energy Sales to IP (MWh)									
24	Market Capacity Sales (MW)	Line 14 / 1000 if Dispatch		217	217	217	217	217	217	217
25	Market Energy Sales (MWh) unit 1 and 2	Line 24 * Line 15 * 8760	1	1,803,078	1,803,078	1,803,078	1,803,078	1,803,078	1,803,078	1,803,078
26	Process Steam Sales (MMBtu x 1000)	0	1	0	0	0	0	0	0	0
27	Capacity Factor (%)	Line 25 / (Line 24 * 8760)		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
28										
29	Maximum Supply of Contract Gas (MMBTU * 1000)	0	5							
30	Fuel Consumption (MMBtu x 1000)	Line 25 * Line 16		14,515	14,515	14,515	14,515	14,515	14,515	14,515
31	Supply from contracts (MMBTu*1000)	Line 29		0	0	0	0	0	0	0
32	Supply from spot purchases (MMBtu*1000)	Line 30 - Line 31		14,515	14,515	14,515	14,515	14,515	14,515	14,515
33	Excess Contract Gas available for resale (MMBTU*1000)	Line 29 - Line 31		0	0	0	0	0	0	0
34										
35	**C. OPERATING REVENUES and EXPENSES (000 of $2005)**									
36	Electricity Revenues									
37	Steam Injection Capacity Sales	0		0	0	0	0	0	0	0
38	Electric Sales to IP									
39	Market Electric Capacity Sales	Line 24 * Line 7		$ 11,440	$ 11,440	$ 11,440	$ 11,440	$ 11,440	$ 11,440	$ 11,440
40	Market Electric Energy Sales	(Line 25 * Line 8) / 1000		$ 100,802	$ 102,344	$ 105,244	$ 106,118	$ 107,272	$ 108,436	$ 107,613
41	Steam Revenues	Line 26 * Line 11		$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	Resale of Contract Gas	Line 33 * (Line 3 - Line 4)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	Interest Income	0		0	0	0	0	0	0	0
44	**Total Operating Revenues**			**$ 112,242**	**$ 113,784**	**$ 116,684**	**$ 117,558**	**$ 118,712**	**$ 119,876**	**$ 119,052**
45										
46	**Fuel Operating Expenses ($000)**									
47	Fuel - Supply from Contracts	Line 31 * Line 4		$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	Fuel - Supply from Spot Market	Line 32 * Line 3		$ 71,861	$ 74,307	$ 76,665	$ 76,794	$ 78,596	$ 80,090	$ 80,292
49	Fuel - Transportation	$ 9,000	1	$ 10,081	$ 10,196	$ 10,322	$ 10,453	$ 10,582	$ 10,710	$ 10,842
49a	Revenues from release of pipeline capacity									
50	Sub-Total			**$ 81,942**	**$ 84,503**	**$ 86,987**	**$ 87,247**	**$ 89,178**	**$ 90,800**	**$ 91,134**
51										
52	**Non-fuel Operating Expense ($000)**									
53	Variable Operating Expenses	**$ 181.0**	1	$ 181	$ 181	$ 181	$ 181	$ 181	$ 181	$ 181
54	O&M - Fixed (excl Major Maint)	**$ 682.0**	1	$ 682	$ 682	$ 682	$ 682	$ 682	$ 682	$ 682
55	Major Maintenance	**$ 1,447.0**	1	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447	$ 1,447
56	Labor	**$ 2,028.0**	1	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028	$ 2,028
57	EH&S	**$ 118.0**	1	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118	$ 118
58	Plant Administration	**$ 93.0**	1	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93
59	Property Tax/Gas Tax	**$ 996.0**	1	$ 996	$ 996	$ 996	$ 996	$ 996	$ 996	$ 996
60	Insurance	**$ 646.0**	1	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646
61	Legal Fees	**$ 513.0**	1	$ 513	$ 513	$ 513	$ 513	$ 513	$ 513	$ 513
62	Plant Maintenance	**$ 671.0**	1	$ 671	$ 671	$ 671	$ 671	$ 671	$ 671	$ 671
63	Managers Operating Expenses	**$ 300.0**	1	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300	$ 300
64	Management Fees	**$ 55.0**	1	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55	$ 55
65	Sub- Total Non-fuel Operating Expenses			**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**	**$ 7,730**
66										
67	**Operating Cash flow**	Line 44 - Line 50 - Line 64		**$ 22,570**	**$ 21,551**	**$ 21,967**	**$ 22,581**	**$ 21,803**	**$ 21,346**	**$ 20,189**

Data Sources

1. AELLC Long-Term Projections December 2003
2. AEO 2005
3. Synapse assumption re expectations re LICAP as of April 2005
4. AELLC 2004 Operating Plan
5. AELLC Technical Summary, Calpine Northbrook Corp., 2005
6. Synapse generating unit database
7. R.W. Beck Independent Engineer's Report;

Gas & Electricity Price Forecasts (2005$)									
	2004	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Forecasts as as of April 2005									
EIA AEO 2005									
AEO 2005 Gas Pices for Generators in NE ($/mmBtu)	6.36	6.25	5.52	5.17	4.92	4.78	4.67	4.70	4.76
AEO 2005 Generation Cost in NE ($/MWh)	67.68	65.17	56.58	49.57	46.24	45.45	44.88	46.11	47.85
Market implied heat rate	10.64	10.42	10.24	9.59	9.41	9.50	9.62	9.80	10.06
Forecasts as as of April 2004									
EIA AEO 2004									
AEO 2004 NG prices for power plants in NE ($/mmBtu)	5.16	4.69	4.58	4.68	4.81	4.78	4.81	4.96	5.12
AEO 2004 Generation Cost in NE ($/MWh)	56.79	50.74	48.03	46.32	45.52	46.46	46.81	47.69	49.71
Market implied heat rate	11.00	10.82	10.49	9.90	9.46	9.71	9.74	9.62	9.71
AELLC Long Term Projections December 2003									
Baseload Energy Price ($/MWh)	48.25	44.60	44.87	46.77	48.38	49.67	50.93	51.95	52.45
Spot Market Purchase (PNGTS)	5.133	4.831	4.692	4.741	4.761	4.802	4.852	4.902	4.952
Market implied heat rate	9.40	9.23	9.56	9.87	10.16	10.34	10.50	10.60	10.59

SOURCES

AEO 2005 - Energy Information Administration. Annual Energy Outlook 2005, February 2005

AEO 2004 - Energy Information Administration. Annual Energy Outlook 2004, February 2004

Gas & Electricity Price Forecasts (2005$)												
												AVERAGE
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2005 - 2023**
Forecasts as as of April 2005												
EIA AEO 2005												
AEO 2005 Gas Pices for Generators in NE ($/mmBtu)	4.86	5.00	5.05	5.11	5.15	5.32	5.48	5.49	5.61	5.72	5.73	**5.28**
AEO 2005 Generation Cost in NE ($/MWh)	50.17	55.14	55.44	55.64	55.91	56.76	58.37	58.85	59.49	60.14	59.68	**54.76**
Market implied heat rate	10.32	11.02	10.98	10.89	10.85	10.67	10.65	10.72	10.60	10.52	10.41	**10.36**
Forecasts as as of April 2004												
EIA AEO 2004												
AEO 2004 NG prices for power plants in NE ($/mmBtu)	5.32	5.52	5.58	5.66	5.67	5.68	5.62	5.58	5.74	5.76	5.74	**5.27**
AEO 2004 Generation Cost in NE ($/MWh)	51.31	52.73	53.06	53.91	54.33	54.12	53.99	53.55	54.13	54.14	53.88	**51.36**
Market implied heat rate	9.64	9.55	9.52	9.52	9.59	9.53	9.61	9.59	9.42	9.41	9.39	9.74
AELLC Long Term Projections December 2003												
Baseload Energy Price ($/MWh)	53.33	54.85	56.05	56.89	58.09	58.70	60.03	61.17	62.39	63.60	64.74	**54.39**
Spot Market Purchase (PNGTS)	5.002	5.052	5.102	5.152	5.269	5.39	5.513	5.64	5.77	5.903	6.039	**5.17**
Market implied heat rate	10.66	10.86	10.99	11.04	11.02	10.89	10.89	10.85	10.81	10.77	10.72	**10.51**
SOURCES												
AEO 2005 - Energy Information Administration. Annual Energ												
AEO 2004 - Energy Information Administration. Annual Energ												