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MSA Report

Economics of New Entry

28 April, 2004

MARKET SURVEILLANCE ADMINISTRATOR

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1 BACKGROUND

The Economics of New Entry project was initiated in order that the MSA might get a grasp of the attractiveness of the Alberta market to potential new generation. The idea was to simulate the typical cash flows of a number of new generators representing typical plant configurations that have been or will soon be added to the Alberta system in order to better understand the price signal that our current market is sending to prospective generators.

For the purposes of this project, three plant configurations have been chosen:

- Base load coal-fired unit (unit addition to an existing plant) – Central Alberta
- Peaking gas-fired combustion turbine – Northern Alberta
- Combined cycle plant – Southern Alberta

Specific locations of the three units had to be assumed in order to simulate transmission charges associated with the new generation. All other aspects of the costs and performance characteristics have been 'genericized' so that they represent a *typical* new project rather than a specific unit.

2 ANALYSIS

Cost and operational data was collected from a variety of sources for each of the three listed projects. Most of the data was obtained through conversations with industry participants and in publicly available documents from both Canada and the US. Where specific data could not be found, reasonable assumptions were made. The parameters assumed for the analysis are presented in **Table 1**. All assumptions made have been tested with several market participants with generation development experience. Note that the assumptions made are estimates of reasonable values at this time. Actual costs associated with the development of a new project will vary on a case by case basis.

Table 1 - Unit Characteristics

		Unit		
		Coal	**Gas**	**Combined Cycle**
MCR	(MW)	450	47	250
Availability	(%)	92.0%	94.0%	92.0%
Capital Cost	($)	$800,000,000	$35,000,000	$250,000,000
Cost per Installed MW	($/MW)	$1,777,778	$744,681	$1,00,000
Annual Fixed Cost		$30,000,000	$2,700,000	$11,000,000
Operational Constraints				
Minimum Output	(MW)	200	15	85
Minimum Up Time	(h)	4	0	4
Minimum Down Time	(h)	4	0	4
Ramp Rate	MW/min	8	1	5.8
Time to MCR from Min	(h)	0.52	0.53	0.47
Variable Cost				
Variable O&M	($/MWh)	$ 0.70	$ 0.50	$1.02
Fuel				
Fuel Cost	($/GJ)	$1.26	variable	variable
Heat Rate	(GJ/MWh)	9.35	9.65	7.86
Royalties	($/MWh)	$0.02	NA	NA
Emissions Charges	($/MWh)	$5.00	NA	NA
Transmission				
Losses (2002)				
JF	(%)	8.7%	-8.2%	-9.4%
MAM	(%)	9.9%	-6.1%	-4.6%
JJA	(%)	9.0%	-2.5%	-7.8%
SON	(%)	9.2%	15.9%	-5.0%
D	(%)	9.2%	-7.7%	-8.9%
Interconnection	($/MWh)	$2.44	$2.44	$2.44
STS	(%)	3.5%	3.5%	3.5%
Starts	($/start)	NA	$300	NA

Project cash flows were simulated hourly for a two year period using 2002 and 2003 hourly Pool prices and 2002 and 2003 daily AECO-C gas prices (where applicable). Note that this type of analysis ignores the effect of the potential new project had it been in service over the period of analysis. In other words, price data used is actual price data from the 2002-2003 period and has not been adjusted to reflect the addition of new capacity to the system.

Cash flows were calculated on a monthly basis as follows:

Monthly Revenue = ∑ (Generation x Pool Price)

Monthly Cost = Variable Cost + Fixed Cost

Variable Cost = Variable O&M + Fuel + Transmission
+ Emissions Charge (coal-fired unit)
+ Cost of Starts (gas-fired combustion turbine)

Monthly Net = Monthly Revenue – Monthly Cost

For the purposes of this exercise it was assumed that all of the monthly net was applied to the payback of the capital cost. No assumptions were made regarding financing for any of the units as these costs are felt to be unique to each new generation owner.

2.1 Coal-Fired Unit

It was assumed that the new coal-fired unit addition would be a 450 MW (net) unit addition to an existing plant. Because this unit is an addition to an existing facility as opposed to a new development, the capital cost is reduced. This was thought to be a suitable assumption for use in this analysis as the majority of new coal generation currently anticipated in the province will likely be at existing facilities.

As coal units are (for the most part) base-loaded units, it was assumed that the unit was run for the entire two year period with no interruption. Two offer blocks were assumed: minimum stable generation at a price of $0/MWh and the remainder of MCR at a variable cost price[1]. As such the unit was never switched off. However, we know that this is not realistic and that all units are required to shut down for maintenance from time to time. Rather than try to predict the timing of the outages of the unit, cash flows were calculated as if the unit were running at either MCR or minimum stable generation (depending on Pool price) for the entire period and subsequently scaled down to reflect the availability of the unit. (Costs and revenues were also scaled down accordingly.) No derates were simulated.

Table 2 summarizes the estimated monthly costs and revenues associated with running the theoretical new coal-fired unit. Note that based on the 2002 average Pool price, the variable cost of running this plant would be $25.30/MWh. Based on the 2003 average Pool price the variable cost of running this unit would increase to $27.63/MWh[2].

[1] For the purposes of this analysis, variable cost is calculated on an hourly basis as the true variable cost of operating the unit is a function of Pool price (due to the calculation of transmission losses).

[2] Average Pool prices were $43.93/MWh and $62.99/MWh for 2002 and 2003 respectively.

Table 2 - Estimated Monthly Cash Flows of New Coal-Fired Generation

Year	Month	Total Production	Average Hourly Production		Monthly Revenue	Monthly Costs			Monthly Net	% Capital Cost
						Variable	Fixed	Total		
		(MWh)	(MWh)	(%)						
2002	1	251,896	339	75%	$8,006,864	$5,999,895	$2,500,000	$8,499,895	-$493,032	-0.1%
	2	184,138	247	55%	$4,943,905	$4,275,052	$2,500,000	$6,775,052	-$1,831,147	-0.2%
	3	279,726	376	84%	$16,583,107	$7,800,153	$2,500,000	$10,300,153	$6,282,955	0.8%
	4	259,210	348	77%	$12,892,532	$6,896,506	$2,500,000	$9,396,506	$3,496,026	0.4%
	5	230,046	309	69%	$11,380,894	$6,112,387	$2,500,000	$8,612,387	$2,768,507	0.3%
	6	209,070	281	62%	$12,842,400	$5,774,365	$2,500,000	$8,274,365	$4,568,035	0.6%
	7	207,736	279	62%	$6,942,465	$5,010,272	$2,500,000	$7,510,272	-$567,806	-0.1%
	8	213,026	286	64%	$8,596,492	$5,322,513	$2,500,000	$7,822,513	$773,979	0.1%
	9	254,840	343	76%	$13,012,978	$6,734,413	$2,500,000	$9,234,413	$3,778,565	0.5%
	10	252,356	339	75%	$12,940,832	$6,675,717	$2,500,000	$9,175,717	$3,765,115	0.5%
	11	274,160	368	82%	$20,257,867	$8,039,774	$2,500,000	$10,539,774	$9,718,093	1.2%
	12	264,776	356	79%	$21,262,271	$7,980,207	$2,500,000	$10,480,207	$10,782,064	1.3%
Annual		**2,880,980**	**323**	**72%**	**$149,662,605**	**$76,621,252**	**$30,000,000**	**$106,621,252**	**$43,041,353**	**5.4%**
2003	1	282,256	379	84%	$24,456,858	$8,612,204	$2,500,000	$11,112,204	$13,344,654	1.7%
	2	262,108	352	78%	$22,332,017	$7,951,202	$2,500,000	$10,451,202	$11,880,815	1.5%
	3	288,006	387	86%	$27,385,016	$9,412,720	$2,500,000	$11,912,720	$15,472,296	1.9%
	4	258,750	348	77%	$14,863,939	$7,151,502	$2,500,000	$9,651,502	$5,212,437	0.7%
	5	261,326	351	78%	$16,775,347	$7,458,998	$2,500,000	$9,958,998	$6,816,349	0.9%
	6	222,640	299	66%	$12,395,631	$5,989,118	$2,500,000	$8,489,118	$3,906,513	0.5%
	7	296,976	399	89%	$26,934,768	$9,288,844	$2,500,000	$11,788,844	$15,145,923	1.9%
	8	289,156	389	86%	$16,869,741	$7,874,777	$2,500,000	$10,374,777	$6,494,964	0.8%
	9	245,640	330	73%	$12,360,477	$6,468,088	$2,500,000	$8,968,088	$3,392,390	0.4%
	10	281,520	378	84%	$20,433,690	$8,208,869	$2,500,000	$10,708,869	$9,724,821	1.2%
	11	282,670	380	84%	$15,422,640	$7,595,398	$2,500,000	$10,095,398	$5,327,243	0.7%
	12	269,422	362	80%	$13,082,505	$7,034,022	$2,500,000	$9,534,022	$3,548,483	0.4%
Annual		**3,240,470**	**363**	**81%**	**$223,312,628**	**$93,045,741**	**$30,000,000**	**$123,045,741**	**$100,266,887**	**12.5%**
Total		**6,121,450**			**$372,975,234**	**$169,666,994**	**$60,000,000**	**$229,666,994**	**$143,308,240**	**17.9%**
Average		**3,060,725**	**343**	**76%**	**$186,487,612**	**$84,833,497**	**$30,000,000**	**$114,843,497**	**$71,654,120**	**9.0%**

The calculation indicates that under 2002 price conditions and with the assumptions stated earlier, the Owner will have paid back 5.4% of the capital cost of the coal-fired generating unit. Prices were higher in 2003 and in that year the Owner would have been able to pay back as much as 12.5% of the capital cost. This would result in a 17.9% capital cost pay back in the first two years of operation.

Note that the calculations shown in **Table 2** assume an emissions charge of $5.00/MWh. Discussions with industry participants indicated that the emissions charge for such a plant could be as high as $15.00/MWh. If the higher emissions charge is used, capital cost payback bill be reduced to 1.9% for 2002 prices and 8.6% for 2003 prices for a total of 10.5% capital cost payback in two years. Average annual production would be reduced to 64% and 74% from 72% and 81% for 2002 and 2003 respectively.

2.2 Gas-Fired Combustion Turbine

A 47 MW single GE LM6000 gas turbine generator set was chosen to represent a typical gas-fired peaking unit addition to the Alberta system. The operation of a peaking unit is not as straightforward as the operation of a base-load unit. Peaking units do not typically run all of the time and are generally more opportunistic in their operation. They tend to offer their energy into the merit order at higher prices (usually based on the price of gas) than base-load units and are therefore more subject to dispatch risk. It is not uncommon for peaking units to be dispatched up and down several times a day.

Cash flows for the gas-fired combustion turbine unit were simulated based on full operation of the unit during hours when the Pool price was greater than the variable operating cost for at least two consecutive hours[3]. No outages or derates were considered but the monthly generation, revenue and costs were scaled accordingly to reflect the assumed availability of the unit. This is a conservative assumption as routine maintenance of an LM6000 unit can occur in the time frame of a weekend (maximum 72 hours)[4] and it is likely that a new unit of this type would not require any major maintenance in its first two years of operation.

Operational constraints of the unit were also considered in the application of this operational pattern. However, LM6000 units have minimum up and down times of zero hours and the ramp rate is fast enough such that the unit can ramp from zero to MCR in less than an hour. It is therefore reasonable to assume that generation from the unit could be zero in one hour and MCR in the next (or vice-versa).

Results of the monthly cash flow analysis for the gas-fired unit are presented in **Table 3**. Note that under 2002 average price conditions the variable cost of running this unit was $37.93/MWh and under the higher priced conditions of 2003, the variable cost of running the units increased to $60.87/MWh[5].

[3] This operational pattern assumes that the plant operators cannot react quickly enough to capture a single high priced hour but can react to longer higher priced events (i.e. there is no generation in the first hour that Pool price exceeds variable cost).

[4] Information presented to the MSA by GE Aero Energy Products (the manufacturer of the LM6000 gas turbine generator set) indicates that routine maintenance should be scheduled after 25,000 hours of operation and can be conducted over a weekend while turnaround maintenance should be scheduled after 50,000 hours of operation and would take a number of weeks. An increased number of stops and starts could accelerate this maintenance schedule to some degree.

[5] Average AECO-C gas prices were $3.84/GJ and $6.31/GJ for 2002 and 2003 respectively.

Table 3 – Estimated Monthly Cash Flows of New Gas-Fired Combustion Turbine Generation

Year	Month	Total Production (MWh)	Average Hourly Production (MWh)	Average Hourly Production (%)	Monthly Revenue	Monthly Costs: Variable (incl. starts)	Monthly Costs: Fixed	Monthly Costs: Total	Monthly Net	% Capital Cost
2002	1	12,989	17	37%	$524,079	$391,701	$225,000	$616,701	-$92,623	-0.3%
	2	4,506	6	13%	$192,998	$147,526	$225,000	$372,526	-$179,528	-0.5%
	3	20,986	28	60%	$1,489,885	$883,887	$225,000	$1,108,887	$380,998	1.1%
	4	15,640	21	45%	$994,877	$684,513	$225,000	$909,513	$85,365	0.2%
	5	9,675	13	28%	$764,930	$381,028	$225,000	$606,028	$158,902	0.5%
	6	10,780	14	31%	$1,128,184	$338,693	$225,000	$563,693	$564,492	1.6%
	7	11,929	16	34%	$576,447	$283,571	$225,000	$508,571	$67,875	0.2%
	8	9,189	12	26%	$594,609	$310,852	$225,000	$535,852	$58,758	0.2%
	9	5,832	8	17%	$486,005	$330,469	$225,000	$555,469	-$69,463	-0.2%
	10	2,121	3	6%	$246,985	$163,192	$225,000	$388,192	-$141,206	-0.4%
	11	5,655	8	16%	$787,938	$459,575	$225,000	$684,575	$103,363	0.3%
	12	11,575	16	33%	$1,573,939	$611,334	$225,000	$836,334	$737,605	2.1%
Annual		**120,876**	**14**	**29%**	**$9,360,877**	**$4,986,340**	**$2,700,000**	**$7,686,340**	**$1,674,537**	**4.8%**
2003	1	9,234	12	26%	$1,408,962	$594,137	$225,000	$819,137	$589,825	1.7%
	2	5,169	7	15%	$954,587	$428,068	$225,000	$653,068	$301,519	0.9%
	3	8,571	12	25%	$1,461,925	$657,930	$225,000	$882,930	$578,995	1.7%
	4	3,579	5	10%	$477,738	$228,113	$225,000	$453,113	$24,625	0.1%
	5	4,948	7	14%	$734,135	$319,660	$225,000	$544,660	$189,475	0.5%
	6	3,534	5	10%	$514,226	$231,613	$225,000	$456,613	$57,614	0.2%
	7	15,772	21	45%	$2,047,128	$919,239	$225,000	$1,144,239	$902,889	2.6%
	8	10,426	14	30%	$861,822	$627,369	$225,000	$852,369	$9,453	0.0%
	9	1,370	2	4%	$204,713	$121,218	$225,000	$346,218	-$141,504	-0.4%
	10	4,285	6	12%	$787,489	$385,771	$225,000	$610,771	$176,718	0.5%
	11	1,458	2	4%	$217,996	$121,021	$225,000	$346,021	-$128,026	-0.4%
	12	2,960	4	8%	$308,727	$177,246	$225,000	$402,246	-$93,518	-0.3%
Annual		**71,307**	**8**	**17%**	**$9,979,449**	**$4,811,385**	**$2,700,000**	**$7,511,385**	**$2,468,064**	**7.1%**
Total		**192,183**			**$19,340,326**	**$9,797,725**	**$5,400,000**	**$15,197,725**	**$4,142,601**	**11.8%**
Average		**96,092**	**11**	**23%**	**$9,670,163**	**$4,898,863**	**$2,700,000**	**$7,598,863**	**$2,071,301**	**6.9%**

The calculation indicates that under 2002 Pool price and gas price conditions and with the assumptions stated earlier, the Owner will have paid back 4.8% of the capital cost of the gas-fired generating unit in its first year of operation. Under 2003 pricing conditions the Owner could pay back as much as 7.1% of the capital cost in a year. This would result in a total of 11.9% capital cost payback in two years. Note that in a number of months the gas-fired combustion turbine actually loses money.

Under the assumed generating conditions, the unit would only be running 29% of the time in 2002 and 17% of the time in 2003. (Note that although the unit ran less often in 2003 than in 2002, 2003 was a more profitable year due to a higher price environment.) This is significantly lower than the assumed availability of this type of unit

2.3 Combined Cycle Unit

A typical 250-MW combined cycle unit was the third type of new generation analyzed. Although the economic operation of a combined cycle unit is highly dependent on the price of gas, its operating characteristics are actually more comparable to that of a coal-fired base-load unit than of a gas-fired peaking unit. For this reason a combination of the conditions applied to the simulation of the coal-fired unit and the gas fired combustion turbine was applied to the simulation of the operation of the combined cycle unit. It was assumed that (like the gas-fired combustion turbine) the unit was running at MCR when Pool price exceeded the variable cost for at least two consecutive hours (see footnote 3, page 5) and (like the coal-fired plant) was running at the minimum stable generation level for all other hours.

Operational characteristics of the combined cycle unit are such that the unit is constrained by minimum up and down times of 4 hours; however, since the unit is never shut off during the simulation, this is not a factor. The unit is able to ramp from minimum stable generation to MCR in less than an hour. Outages were treated similar to the simulation of the other units - cash flows were calculated as if the unit were running at either MCR or minimum stable generation for the entire period and subsequently scaled down to reflect the availability of the unit. No derates were simulated.

Results of the monthly cash flow analysis for the combined cycle unit are presented in **Table 4**. Note that the variable cost of operating the combined cycle units was $31.05/MWh under 2002 average price conditions and increased to $49.34/MWh under 2003 average price conditions.

Table 4 - Estimated Monthly Cash Flows of New Combined-Cycle Generation

Year	Month	Total Production (MWh)	Average Hourly Production (MWh)	Average Hourly Production (%)	Monthly Revenue	Monthly Costs: Variable	Monthly Costs: Fixed	Monthly Costs: Total	Monthly Net	% Capital Cost
2002	1	121,026	163	65%	$4,001,833	$2,960,688	$916,667	$3,877,354	$124,479	0.0%
	2	75,169	101	40%	$2,076,578	$1,927,658	$916,667	$2,844,325	-$767,747	-0.3%
	3	138,938	187	75%	$8,696,634	$4,917,851	$916,667	$5,834,517	$2,862,117	1.1%
	4	117,783	158	63%	$6,299,048	$4,290,033	$916,667	$5,206,700	$1,092,348	0.4%
	5	100,229	135	54%	$5,337,739	$3,373,957	$916,667	$4,290,624	$1,047,115	0.4%
	6	99,719	134	54%	$6,664,321	$2,232,461	$916,667	$3,149,128	$3,515,193	1.4%
	7	105,391	142	57%	$3,659,449	$1,872,109	$916,667	$2,788,776	$870,673	0.3%
	8	98,408	132	53%	$4,273,541	$2,455,821	$916,667	$3,372,487	$901,054	0.4%
	9	127,043	171	68%	$6,806,570	$4,334,298	$916,667	$5,250,965	$1,555,605	0.6%
	10	108,275	146	58%	$6,038,243	$4,619,803	$916,667	$5,536,470	$501,773	0.2%
	11	127,802	172	69%	$10,324,396	$5,463,787	$916,667	$6,380,454	$3,943,942	1.6%
	12	108,427	146	58%	$10,195,297	$4,718,467	$916,667	$5,635,134	$4,560,163	1.8%
Annual		**1,328,209**	**149**	**60%**	**$74,373,648**	**$43,166,934**	**$11,000,000**	**$54,166,934**	**$20,206,714**	**8.1%**
2003	1	103,114	139	55%	$10,546,803	$5,191,325	$916,667	$6,107,991	$4,438,811	1.8%
	2	84,580	114	45%	$8,789,165	$5,448,358	$916,667	$6,365,025	$2,424,140	1.0%
	3	96,738	130	52%	$11,207,823	$6,308,985	$916,667	$7,225,652	$3,982,171	1.6%
	4	75,886	102	41%	$5,191,751	$4,034,356	$916,667	$4,951,023	$240,728	0.1%
	5	84,594	114	45%	$6,542,884	$4,586,935	$916,667	$5,503,602	$1,039,282	0.4%
	6	76,493	103	41%	$4,845,243	$3,874,450	$916,667	$4,791,117	$54,126	0.0%
	7	134,688	181	72%	$13,569,753	$5,719,799	$916,667	$6,636,466	$6,933,287	2.8%
	8	113,436	152	61%	$7,416,135	$5,175,246	$916,667	$6,091,912	$1,324,223	0.5%
	9	88,030	118	47%	$4,931,092	$3,964,298	$916,667	$4,880,965	$50,128	0.0%
	10	118,068	159	63%	$9,706,843	$5,115,668	$916,667	$6,032,335	$3,674,508	1.5%
	11	108,979	146	59%	$6,646,301	$4,575,174	$916,667	$5,491,841	$1,154,460	0.5%
	12	79,203	106	43%	$4,329,913	$3,893,462	$916,667	$4,810,129	-$480,215	-0.2%
Annual		**1,163,809**	**130**	**52%**	**$93,723,706**	**$57,888,057**	**$11,000,000**	**$68,888,057**	**$24,835,649**	**9.9%**
2002-2003		**2,492,018**			**$168,097,354**	**$101,054,991**	**$22,000,000**	**$123,054,991**	**$45,042,363**	**18.0%**
Average		**1,246,009**	**140**	**56%**	**$84,048,677**	**$50,527,495**	**$11,000,000**	**$61,527,495**	**$22,521,182**	**9%**

The calculation shows that under 2002 price conditions, 8.1% of capital costs would be recovered and under 2003 price conditions approximately 9.9% of capital cost payback would be possible. This results in a total capital cost payback of 18.0% in two years.

The simulated operation of the combined cycle unit indicates the unit would only be operational 60% of the time in 2002 and 52% of the time in 2003–quite a bit less than the assumed availability of the unit. As the operation of a combined-cycle unit is more difficult to simulate than either a base-loaded coal-fired plant or a peaking gas-fired plant, there is likely more room for error in the assumed operational strategy. A number of operational strategies are available to combined-cycle generators that may differ from the strategy assumed in the analysis. For example, in our combined-cycle unit simulation, the unit actually lost money 49% of the time. It is not unreasonable to expect that the plant would be losing money for some portion of time, but it is likely that plant operators would actually cease to generate in extended periods of low prices. If the plant had been shut down during long periods of negative revenues, overall revenues would have been greater and the rate of capital cost payback would have increased.

2.4 Sensitivity Studies

The sensitivity of the rate of capital payback to a number of different parameters was analyzed to determine the impact of some of the assumptions made. It was assumed that the unit configurations are the same for each type of generation and therefore no operational parameters of the units were changed (i.e. MCR, heat rate, ramp rate, etc…) The capital and fixed costs associated with the units also remained the same[6]. Sensitivities of fuel cost and Pool price were considered but it was felt that these variables are highly dependent on too many other factors to be considered independently. Sensitivities were performed on the variable O&M cost and location[7]. Results of the sensitivity studies are captures in **Table 5**.

Table 5 - Sensitivity of Average Rate of Capital Payback

Sensitivity	2002-2003 Rate of Capital Payback		
	Coal-Fired	**Gas-Fired**	**Combined Cycle**
Base Case	**9.0%**	**6.0%**	**9.0%**
Variable O&M			
+ 50%	8.9% (↓)	5.9% (↓)	8.8% (↓)
- 50%	9.1% (↑)	6.0% (↑)	9.3% (↑)
Location			
Moved to Southern Alberta	10.0% (↑)	NA	NA
Moved to Central Alberta	NA	3.4% (↓)	NA
Moved to Northern Alberta	NA	NA	3.0% (↓)

(↑) indicates higher capital cost payback than the base case
(↓) indicates lower capital cost payback than the base case

While the variable O&M cost has a negligible impact on the annual rate of capital payback, the location of the new generation site has a surprisingly large effect. Locating new generation in areas with particularly high demand or weak transmission systems could be very lucrative based on current transmission tariff design. Conversely, siting new generation in the wrong place can have a large impact on revenues. For example, if the combined-cycle plant had been built in the oil-patch in the northern part of the province,

[6] This is a somewhat limiting assumption because the capital cost of installing new generation is also a function of the location of that generating capacity.

[7] Transmission losses are a function of the location of generation within the province. To determine the effect of generator location on revenues, new generation located in areas with high loss factors was moved to areas with low loss factors and vice-versa.

capital cost payback would have been reduced to approximately 3.0% from 9.0% in its assumed southern Alberta location. Based on the current transmission tariff design, selection of the right location for future generation projects could be crucial to the profitability of the project.

2.5 Limitations of the Analysis

Although the analysis is as complete as it could be while still remaining theoretical in nature, it does not consider a number of factors that impact the economics of generating electricity in Alberta. Such factors include:

- **Provision of Ancillary Services**
  While not all units in the Alberta market participate in the ancillary services market, most units (particularly the newer units) have the capability to provide some form of ancillary services. Provision of ancillary services may or may not be considered at the time the decision to embark on a new generation project is made, but ancillary service revenues have the potential to significantly increase net revenues of any project.

- **Transmission Must Run (TMR) Contracts**
  The AESO offers TMR contract to some generation that is located in areas of the province where the local demand is high or where the transmission system in the area is particularly weak. Under the terms of a TMR contract the generator is paid a negotiated price for energy that is dispatched under the TMR contract. TMR contract also have the potential to increase the net revenue of new generation in the province.

- **IBOC and LBC-SO Contracts**
  IBOC and LBC-SO contracts were offered by the AESO in order to incent new generation to locate in areas of the province which are in need of increased generation capacity. Units under these types of contracts are paid incentive payments if the units generate over a threshold number of MWh in a month. Similar to TMR contracts, these contracts also have the potential to increase net revenues and profits of the units.

Note that all three factors discussed above have the potential to increase net revenues of the units and as a result would likely increase the rates of capital payback. As such, results provided in this study may be somewhat conservative and should be considered directional in nature.

3 CONCLUSIONS

Annual capital cost repayment percentages for the three unit types for the two price years analyzed are presented in **Table 6**.

Table 6 - Annual Capital Cost Repayment Percentages, 2002-2003

Reference Year	Unit		
	Coal	**Gas**	**Combined Cycle**
2002	5.4%	4.8%	8.1%
2003	12.5%	7.1%	9.9%
Average	**9.0%**	**6.0%**	**9.0%**

Coal-fired and combined-cycle generation appear to be equally attractive options with average capital paybacks of 9.0%/year each. There is, however, more volatility in the annual rates of capital payback for the coal-fired generation option as the annual rates of payback range from 5.4% to 12.5%. Gas-fired generation achieved an average rate of capital payback of only 6%/year and appears to be the least attractive option.

These capital payback figures need to be placed in the context of the merchant generator. In today's difficult investment climate a weighted average cost of capital of about 15% seems reasonable (50%/50% debt/equity ratio, 10% borrowing rate for debt and 20% desired rate for equity). As such, an annual payback of less than 15% is clearly unattractive. This is the case for all three generation projects simulated. Clearly the prices in 2002 and 2003 are not sending a signal to "build" to would-be generators.