Greenfield Coal with Low GHG Emissions Study

3 December 2017

Disclaimer: *This document, and the opinions, analysis, evaluations, or recommendations contained herein are for comparison purposes only and Canadian Clean Power Coalition, CanmetENERGY, GTI, 8 Rivers Capital, EPRI and Jacobs Engineering Inc. shall have no liability whatsoever to third parties for any defect, deficiency, error, omission in any statement contained in or in any way related to this document. The results from one CCPC study should not be compared to other CCPC studies given the difference in assumptions and analysis used in the studies.*

1. Introduction:

This study evaluated several novel ways to produce power utilizing coal as a fuel in a new facility while significantly reducing GHG emissions.

The technologies evaluated in this study were:

- PCC: This base case is a new Supercritical Pulverised Coal (SCPC) power plant fitted with Flue Gas Desulphurisation (FGD) and Advanced Solvent Post Combustion Capture (AS-PCC);
- Closed Brayton: Supercritical CO_2 in a closed Brayton Cycle is indirectly heated in a standard air aspirated pulverised coal furnace fitted with AS-PCC. The high temperature supercritical CO_2 is used to produce power. Lower temperature heat exiting the furnace is used to raise steam used in the carbon capture plant and to make power;
- Oxy PFBC: Indirect fired supercritical CO_2 closed Brayton Cycle using Oxy-fired Pressurized Fluidized Bed Combustion (PFBC) being developed by the Gas Technology Institute (GTI). The supercritical CO_2 is used to produce power. Lower temperature heat is used to raise steam used to make power; and
- Open Brayton: Direct-fired gasification/oxy syngas fired supercritical CO_2 open Brayton cycle being developed by 8 Rivers Capital. Syngas from a gasifier is combusted with supercritical CO_2 and oxygen in a turbine and the heat in the turbine exhaust is provided to cooler CO_2 coming into the turbine. Some CO_2 is bled off for storage.

Two coals were considered, Alberta sub-bituminous and Saskatchewan lignite. The plant location is Genesee, Alberta. A factored cost estimate of these results was used to derive results for Saskatchewan. All cases are designed to produce a net capacity power output of about 450 MW to the grid. Carbon capture, when not inherently 100%, is designed to be approximately 90% which is the feasible limit for solvent based systems. All cases have emission intensities below the 2012 Federally mandated CO_2 emission intensity level of 420 kg/MWh net exported excluding the power of CO_2 compression to pipeline conditions and the Air Separation Unit (ASU) (where used). In addition, the economic results for the cases described above are compared to those for a new natural gas combined cycle (NGCC) plant.

The study was carried out by Jacobs Engineering with the support of the Electric Power Research Institute (EPRI), 8 Rivers Capital and the Gas Technology Institute (GTI), formerly Aerojet-Rocketdyne. EPRI developed the process design and performance of the coal fired boilers, PCC units and provided guidance for the design and performance of the closed Brayton cycle. 8 Rivers Capital developed the process design for the open Brayton cycle. GTI provided the design and performance for the pressurised oxy-fuel combustor and other components of the closed Brayton cycle. Jacobs developed the process design for the gasification units for the open Brayton cycle cases and the plant layouts and capital and operating cost estimates for all of the cases. The cost estimate presented here is expected to have an accuracy of +/- 40%.

This study builds on the work carried out by Jacobs in 2015 for the CCPC on the Evaluation of Repowering Options for Carbon Capture at the Lingan PGS and the previous phase 2, 3 and 4 studies evaluating coal gasification for power generation.

2. Results for Alberta:

2.1. Key Results

Table 1 shows the net output for the cases considered. The heat rates (HR) for coal and natural gas consumption are also listed. The Oxy PFBC case consumed a small amount of natural gas. The capacity factor (CF) for each case is assumed to be 85%. The design life for all cases is assumed to be 30 years. The cost of coal in 2016 is assumed to be \$1.41/GJ. The commercial operation date is assumed to be January 1, 2020 for all cases. An inflation rate of 2% was assumed in the analysis. The gas price used in this analysis is \$3.00/GJ in 2016 escalated by 3% per year. A WACC of 9% was used in this analysis. A carbon tax of \$30/t in 2020, \$40/t in 2021 and \$50/t in 2022 was assumed. A carbon tax is paid if the difference between the emission intensity of project and a performance standard of .42 t/MWh is positive. This difference is then multiplied the energy produced and the carbon tax in \$/t to determine the total tax paid. If this value is negative credit generation has been assumed.

Table 1: Physical Characteristics of Cases

	NGCC - AB	PCC - AB	Closed Brayton - AB	Oxy PFBC - AB	Open Brayton - AB
Net Output (MW)	320	467	428	400	422
Coal HR (GJ/MWh)		12.9	14.1	10.2	8.5
NG HR (GJ/MWh)	7.0	0.0	0.0	0.4	0.0
Efficiency		27.85%	25.51%	35.27%	42.55%
CF First Year	85%	85%	85%	85%	85%
Design Life (years)	30	30	30	30	30
Coal Cost (\$/GJ)		1.41	1.41	1.41	1.41

Table 2 shows the capital cost for each case. In addition, it shows the capex in \$/kW. The Open Brayton cycle case has the lowest capex on a \$/kW basis of the cases fueled with coal. The contingency rates at the bottom of Table 2 have been applied to the sum of the Field Costs and Head Office Costs. These rates account for un-estimated capital expenses and an allowance for possible changes in capital cost as the performance of the process become more apparent.

Table 2: Capital Cost

	NGCC - AB	PCC - AB	Closed Brayton - AB	Oxy PFBC - AB	Open Brayton - AB
Net Output (MW)	320	467	428	400	422
Direct Field Costs	315	1,801	2,073	1,752	1,319
Indirect Field Costs	101	411	472	399	291
Head Office Costs	22	285	322	262	294
Contingency	44	346	573	603	476
Owners Costs	46	212	255	231	195
Initial Cat. and Chem.	0	11	11	0	0
Capital Cost ($ millions)	529	3,065	3,707	3,247	2,575
Capex ($/kW)	1,651	6,566	8,660	8,125	6,078
Contingency	10%	14%	20%	25%	25%

Table 3 describes the GHG emission intensity of each case. This is followed by the GHG produced by each case and the amount of CO_2 captured. The difference is then the amount of GHG emissions released. All coal cases have a lower GHG emission intensity than an NGCC. The percentage of CO_2 captured is designed to be 90% for the first two coal cases. It is 96 and 97% respectively for the final two cases. The mass of CO_2 avoided is defined as the difference between the GHG emission intensity of the coal case and the NGCC case multiplied by the energy produced by the coal case. There are several other ways to define the mass of CO_2 avoided and they all provide the same values for each case.

Table 3: CO_2 Emissions

	NGCC - AB	PCC - AB	Closed Brayton - AB	Oxy PFBC - AB	Open Brayton - AB
GHG Intensity (t/MWh)	0.35	0.12	0.13	0.04	0.02
GHG Produced (Mt/yr)	0.85	4.25	4.25	2.81	2.47
CO_2 Captured (Mt/yr)	0.00	3.83	3.84	2.70	2.40
GHG Emissions (Mt/yr)	0.85	0.42	0.42	0.11	0.07
% Captured	0%	90%	90%	96%	97%
CO_2 Avoided (Mt/yr)	0.00	2.66	2.41	2.53	2.73

Table 4 shows the cost of power. The first year cost of power is the price power must be sold for in the first year, when escalated by inflation in all future years, which sets the NPV of a given case equal to zero. The marginal cost is defined as the cost to make one more MWh. Marginal cost is assumed to be the cost for fuel, transmission and CO_2 credits.

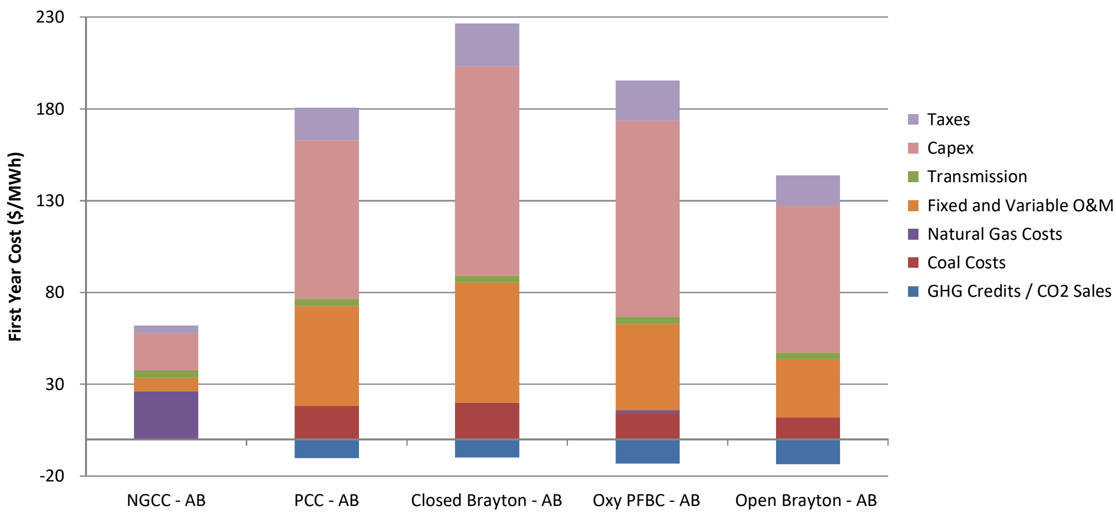
A carbon credit is assumed to be generated when the difference between the emission intensity of a case is less than that for the NGCC. Specifically, if the GHG emission intensity falls below .42 t/MWh for the coal case the mass of credits generated is: (.42 t/MWh - GHG Emission intensity CCS) X Energy CCS Case. The CO_2 price is assumed to be $30/t from 2016 to 2020 and then increases to $40/t in 2021 and $50/t in 2022. The marginal cost for all the coal cases is estimated to be lower than for a NGCC. Therefore, the coal cases should run more often than an NGCC. The Open Brayton cycle case has the lowest estimated first year cost of power and marginal cost of the coal cases.

Table 4: Cost of Electricity

	NGCC - AB	PCC - AB	Closed Brayton - AB	Oxy PFBC - AB	Open Brayton - AB
1st Yr Cost ($/MWh)	61.9	171.5	217.9	183.3	130.9
Fuel Cost ($/MWh)	26.3	18.2	19.9	14.4	12.0
Transmission ($/MWh)	3.9	3.9	3.9	3.9	3.9
CO_2 Credit Sales ($/MWh)	0.0	-10.2	-9.9	-13.1	-13.6
Marginal Cost ($/MWh)	30.2	11.9	13.9	5.2	2.3

Figure 1 below shows the cost components which make up the first-year cost of power. The capital cost alone for all the coal cases exceed the total first year cost of power for the NGCC case.

Figure 1: First Year Cost of Power Components



In order to calculate the cost of capture for a given case one must have the cost and performance data for that case without CCS. The cost and performance information for only the PCC case without CCS was estimated. Based on these values the cost of capture for the PCC case is estimated to be $71.3/t. The avoided cost calculations require a reference case without CCS. Avoided cost is generally estimated to be [(COE CCS - COE Ref) / (GHG Intensity Ref - GHG Intensity CCS)] where COE refers to the cost of electricity and GHG Intensity is the mass of CO_2 emitted per MWh. There are two possible candidates for the reference case. The reference case can be a new NGCC or a new super critical pulverized coal (SCPC) plant without CCS. The avoided costs detailed in Table 5 are based on a new NGCC. The results are so high because the GHG intensity of the NGCC is similar to that for the CCS cases, making the denominator of the avoided cost calculation rather small. The GHG intensity of a new SCPC plant is rather high making the denominator of the avoided cost calculation rather large.

In Alberta, the new carbon tax is likely to be applied on the mass of CO_2 emitted above a performance target assumed to be the GHG emission intensity for a new NGCC. Likewise, carbon credits are likely to be generated on the mass of CO_2 emitted below the NGCC performance target. The breakeven price of CO_2 credits which make the cost of electricity of a coal case with CCS equal to that for an NGCC can be calculated as follows:

COE NGCC = COE CCS + (GHG Intensity NGCC - GHG Intensity CCS) X Price of CO_2 Credits

This can be rearranged to yield:

(COE CCS - COE NGCC) / (GHG Intensity NGCC - GHG Intensity CCS) = Price of CO_2 Credits

This formula is the same as the avoided cost formula using an NGCC as the reference case; therefore, the values in the first row of Table 5 are the breakeven price of CO_2 credits required to make the first-year cost of power from the coal fired cases equal that of a new NGCC.

Table 5: Avoided Costs

	PCC - AB	Closed Brayton - AB	Oxy PFBC - AB	Open Brayton - AB
Avoided Cost - NGCC ($/t)	510	741	422	249
Avoided Cost - SCPC ($/t)	114	176	120	58

2.2. Sensitivities:

The following shows how gas price impacts the first year cost of power. Over the range of gas prices considered in Figure 2 the first-year cost of power for the NGCC case remains below all the coal fired cases.

Figure 2: First Year Cost of Power vs Natural Gas Price

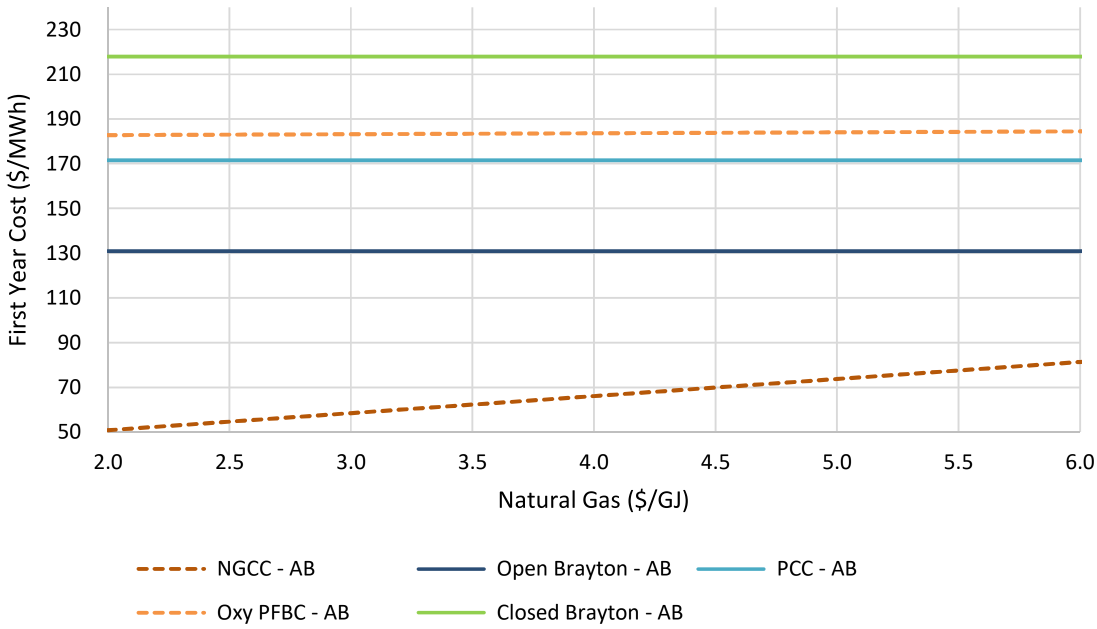


Figure 3 shows how the first-year cost of power changes as the cost of coal changes. Even if the cost of coal decreases by half, none of the coal cases have a first year cost of power less than an NGCC.

Figure 3: First Year Cost of Power vs Coal Cost

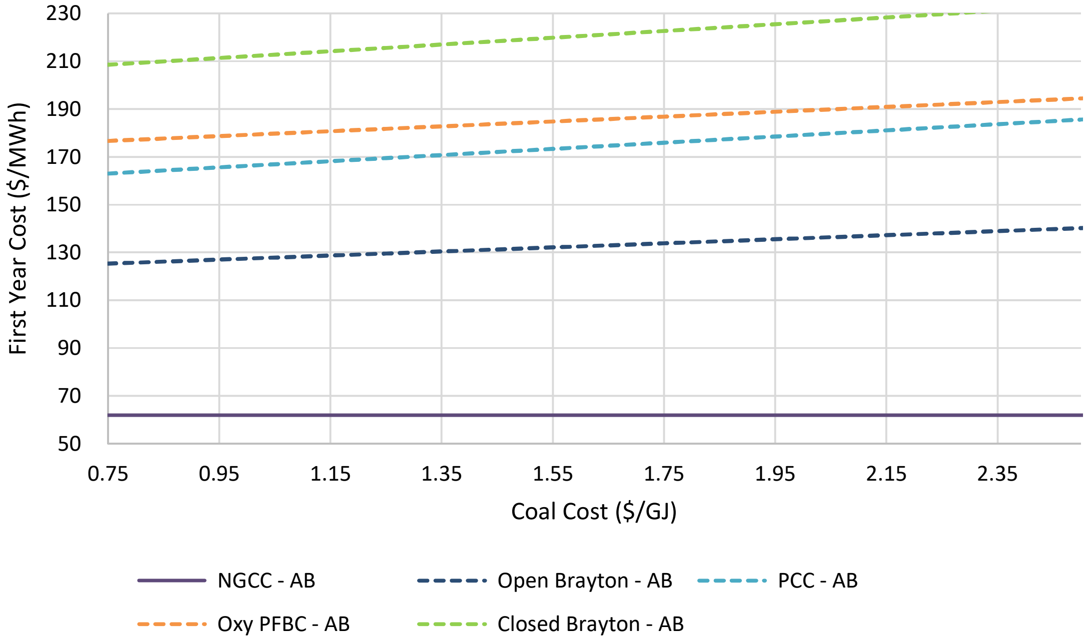
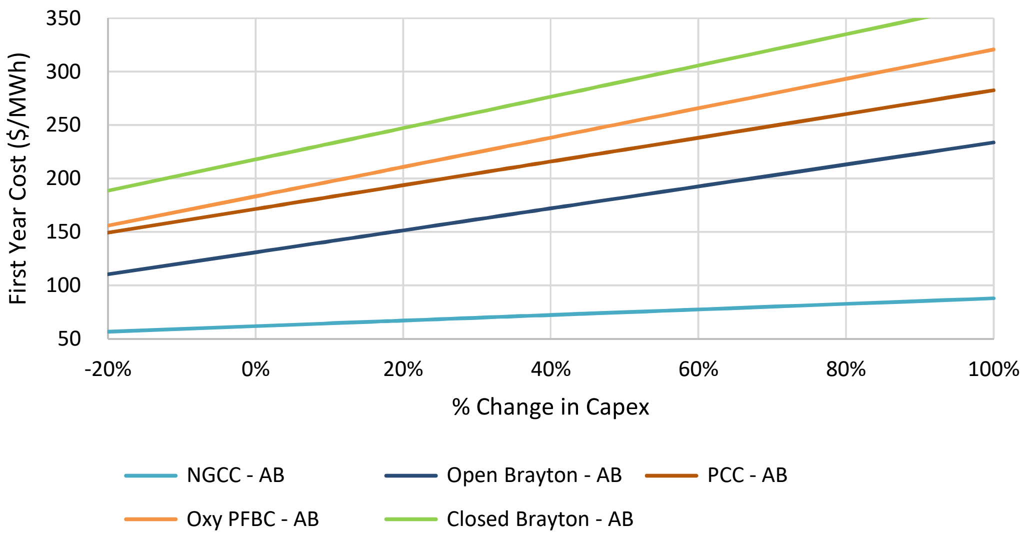


Figure 4 shows how the first year cost of power changes as the capital cost of the cases change. The values at -20% are 80% of the base values (X 1/1.25 = .80). These valuesshow the impact on the first year cost of power with the 25% contingency excluded. Over the range considered, the NGCC first-year cost of power does not exceed the first-year cost of power for any of the coal cases.

Figure 4: First Year Cost of Power vs Change in Capital Cost.



An attempt was made to target a net output of 450 MW for all the coal cases considered. The output of the Oxy-PFBC case was estimated to be 400 MW. A factored cost estimate was used to estimate the cost of an Oxy PFBC case which produces 465 MW similar to the PCC case. The capital cost increased from $3.247 million to $3.604 million. This amounts to an 11% increase in capital cost for a 16% increase in power output. The first-year cost of power for this case decreased from $183.3/MWh to $175.3/MWh or a 4% decrease.

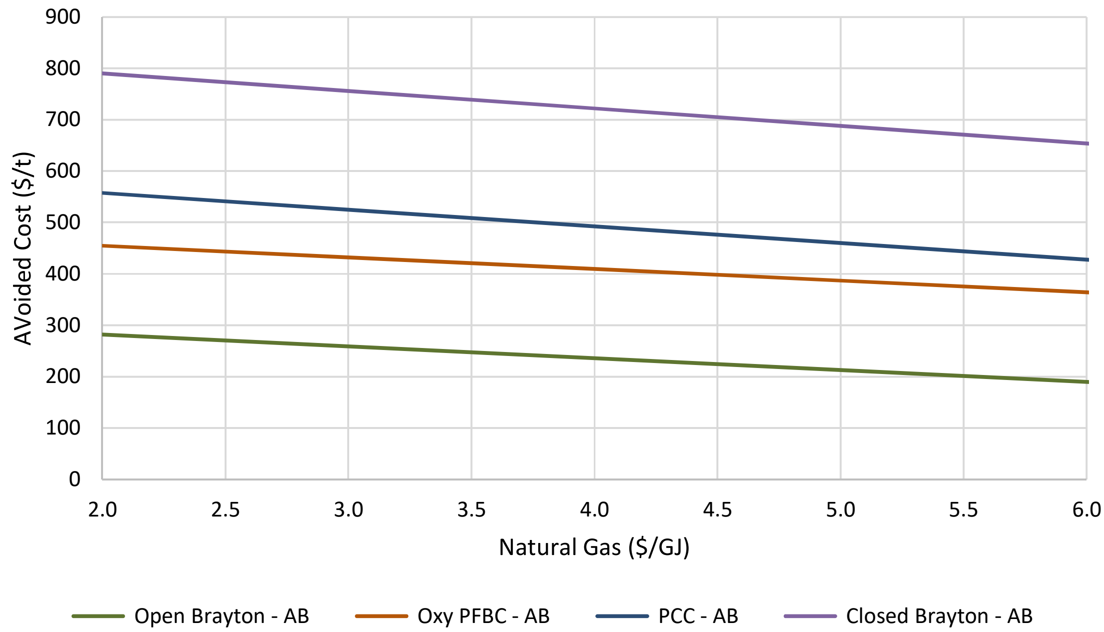
A contingency of 25% has been added to the ASU costs. Table 6 shows the impact on the first-year cost of power if this contingency is removed from the ASU costs. The values in yellow are slightly lower than the values above them which include the contingency on the ASU costs.

Table 6: First Year Cost for ASU Contingency Sensitivity

	NGCC - AB	PCC - AB	Closed Brayton - AB	Oxy PFBC - AB	Open Brayton - AB
ASU Contingency Included	62	172	218	183	131
ASU Contingency Not Included	62	172	218	183	131

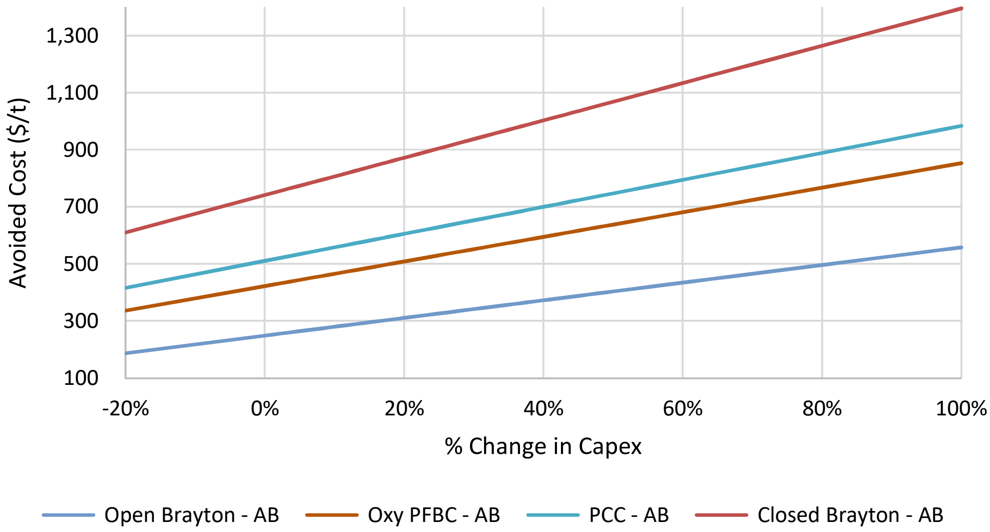
Figure 5 shows how the avoided cost for the coal fired cases changes as the gas price changes. Recall that the avoided cost is also the break-even price of CO_2 credits, using an NGCC as the reference case. Over the range of gas prices considered in Figure 5, none of the cases has a break-even price of CO_2 credits less than $50/t, the expected price in Canada by 2022 (for carbon tax jurisdictions and comparable emissions reduction goals within jurisdictions using a cap-and-trade pricing model).

Figure 5: Avoided Cost vs Natural Gas Price



Over the range of capital cost escalators considered in Figure 6, none of the cases has a break-even price of CO_2 credits, using an NGCC as the reference case, less than $50/t the expected price in the near future.

Figure 6: Avoided Cost vs Change in Capital Cost



3. Results for Saskatchewan

The results for Saskatchewan are based on factored cost adjustments made to the Alberta values to account for the combustion of lignite rather than sub-bituminous coal.

3.1. Key Results

The following table shows the net output for the cases considered. The heat rates (HR) for coal and natural gas consumption are also listed. The Oxy PFBC case consumes a small amount of natural gas. The capacity factor (CF) for each case is assumed to be 85%. The design life for all cases is assumed to be 30 years. The cost of coal in 2020 is assumed to be $2.25/GJ. The commercial operation date is assumed to be January 1, 2020 for all cases. Inflation was assumed to be 2% in the analysis. The gas price used in this analysis is $3.54/GJ in 2016 escalated by 3% per year. A WACC of 5.5% was used in this analysis.

Table 7: Physical Characteristics of Cases

	NGCC - SK	PCC - SK	Closed Brayton - SK	Oxy PFBC - SK	Open Brayton - SK
Net Output (MW)	320	460	424	394	377
Coal HR (GJ/MWh)	0.0	13.1	14.3	9.7	9.6
NG HR (GJ/MWh)	7.0	0.0	0.0	0.7	0.0
Efficiency		27.46%	25.24%	34.49%	38.22%

CF First Year	85%	85%	85%	85%	85%
Design Life (Years)	30	30	30	30	30
Coal Cost ($/GJ)		2.25	2.25	2.25	2.25

Table 8 displays the capital cost for each case. In addition, it shows the capex in $/kW. The Open Brayton cycle case has the lowest capex on a $/kW basis of the cases fueled with coal. The contingency rates at the bottom of Table 8 have been applied to the sum of the Field Costs and Head Office Costs. These rates account for un-estimated capital expenses and an allowance for possible changes in capital cost as the performance of the process become more apparent.

Table 8: Capital Cost

	NGCC - SK	PCC - SK	Closed Brayton - SK	Oxy PFBC - SK	Open Brayton - SK
Net Output (MW)	320	460	424	394	377
Direct Field Costs	315	1,902	2,183	181	1,424
Indirect Field Costs	101	436	478	412	318
Head Office Costs	22	300	336	269	312
Contingency	44	366	600	625	513
Owners Costs	46	223	266	238	208
Initial Cat. and Chem.	0	12	12	1	1
Capital Cost ($ millions)	529	3,237	3,874	3,363	2,775
Capex ($/kW)	1,787	7,032	9,148	8,526	7,210
Contingency	10%	14%	20%	25%	25%

Table 9 describes the GHG emission intensity of each case. This is followed by the GHG produced by each case and the amount of CO_2 captured. The resulting difference is the amount of GHG emissions released. All coal cases have a lower GHG emission intensity than an NGCC. The percentage of CO_2 captured is designed to be 90% for the first two coal cases. It is 95 and 96% respectively for the final two cases. The mass of CO_2 avoided is defined as the difference between the GHG intensity of the coal case and the NGCC multiplied by the energy produced by the coal case. There are several other ways to define the mass of CO_2 avoided and they all provide the same values for each case.

Table 9: CO_2 Emissions

	NGCC - SK	PCC - SK	Closed Brayton - SK	Oxy PFBC - SK	Open Brayton - SK
GHG Intensity (t/MWh)	0.35	0.12	0.13	0.05	0.03
GHG Produced (Mt/yr)	0.85	4.25	4.22	2.78	2.51
CO_2 Captured (Mt/yr)	0.00	3.83	3.81	2.63	2.41
GHG Emissions (Mt/yr)	0.85	0.42	0.41	0.15	0.10
% Captured	0%	90%	90%	95%	96%
CO_2 Avoided (Mt/yr)	0.00	2.62	2.38	2.45	2.44

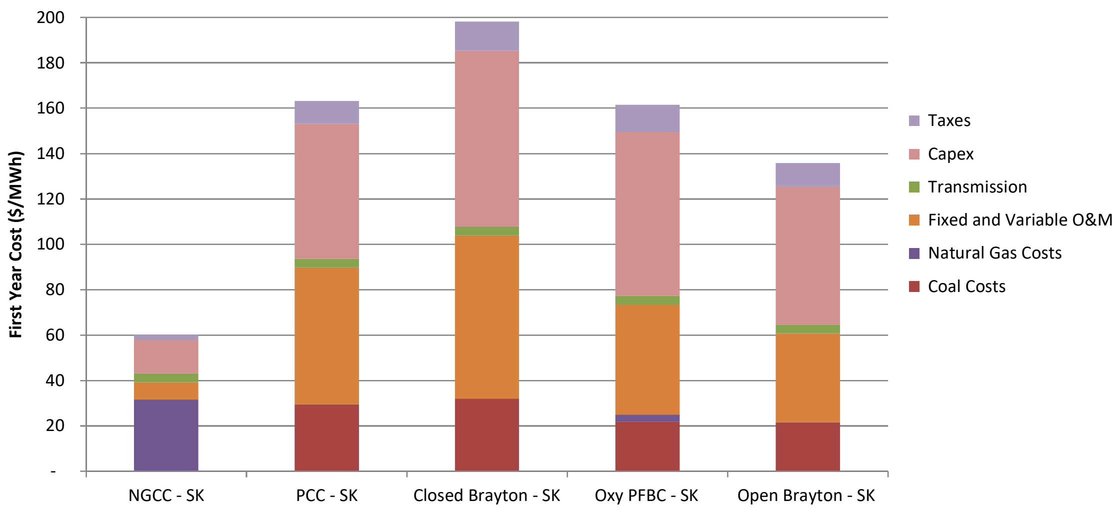
Table 10 displays the cost of power. The first-year cost of power is the price power must be sold for in the first year when escalated by inflation in all future years which sets the NPV of a given case equal to zero. The marginal cost is defined as the cost to make one more MWh. Marginal cost is assumed to be the cost for fuel, transmission and CO_2 credits. The marginal cost for all the coal cases except for the Closed Brayton case is lower than for a NGCC; therefore, the coal cases should generally run more often than an NGCC. The Open Brayton cycle case has the lowest estimated first-year cost of power and marginal cost.

Table 10: Cost of Electricity

	NGCC - SK	PCC - SK	Closed Brayton - SK	Oxy PFBC - SK	Open Brayton - SK
1st Yr Cost ($/MWh)	60	164	199	162	137
Fuel Cost ($/MWh)	31.7	29.5	32.1	21.9	21.6
Transmission ($/MWh)	3.9	3.9	3.9	3.9	3.9
CO_2 Credit Sales ($/MWh)	0.0	0.0	0.0	0.0	0.0
Marginal Cost ($/MWh)	35.6	33.4	36.0	25.8	25.5

Figure 7 shows the cost components which make up the first-year cost of power. The capital cost alone for all the coal cases exceeds or almost exceeds the first-year cost of power for the NGCC case.

Figure 7: First Year Cost of Power Components



Avoided cost is generally estimated to be (COE CCS – COE Ref) / (GHG Intensity Ref – GHG Intensity CCS) where COE refers to the cost of electricity and GHG Intensity is the mass of CO_2 emitted per MWh. There are two possible candidates for the reference case. The reference case can be a new NGCC. It can also be a new super critical pulverized coal (SCPC) plant without CCS. The avoided costs based on a new NGCC, detailed in Table 11, are so high because the GHG intensity of the NGCC is similar to that for the CCS cases making the denominator of the avoided cost calculation rather small. The GHG intensity of a new SCPC is rather high making the denominator of the avoided cost calculation rather large.

Table 11: Avoided Costs

	PCC - SK	Closed Brayton - SK	Oxy PFBC - SK	Open Brayton - SK
Avoided Cost - NGCC ($/t)	447	623	337	239
Avoided Cost - SCPC ($/t)	105	153	94	62

3.2. Sensitivities:

Figure 8 displays how gas price impacts the first-year cost of power. Over the range of gas prices considered in this analysis, the first-year cost of power for the NGCC case remains below all the coal fired cases.

Figure 8: First Year Cost of Power vs Natural Gas Price

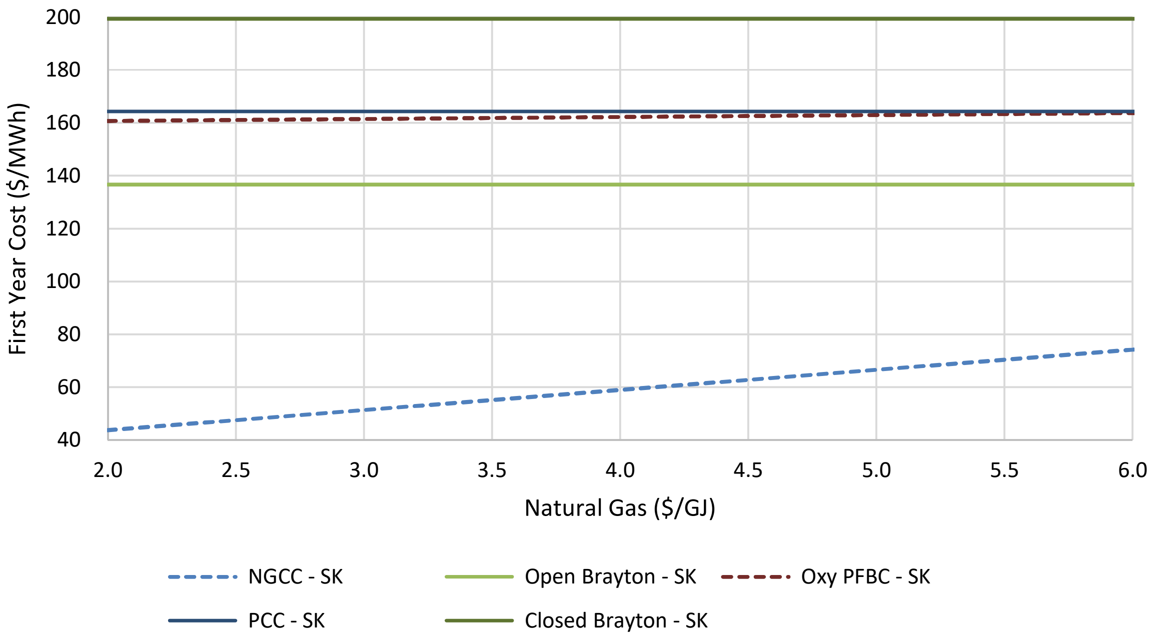


Figure 9 display the first-year cost of power changes as the cost of coal changes. Even if the cost of coal decreases by half, none of the coal cases have a first year cost of power less than an NGCC.

Figure 9: First Year Cost of Power vs Coal Cost

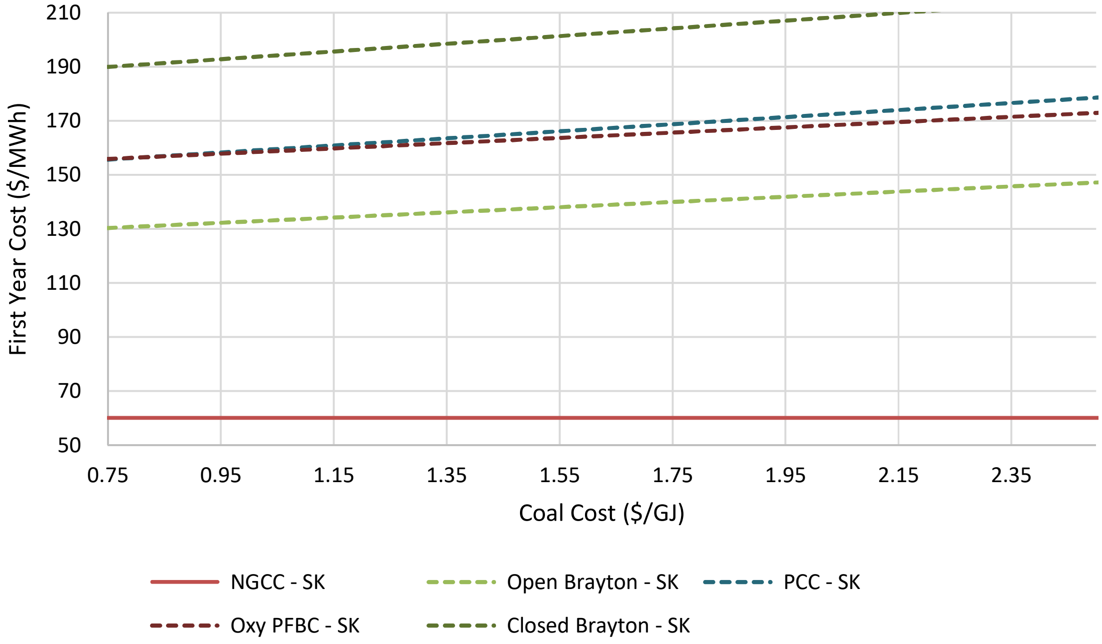
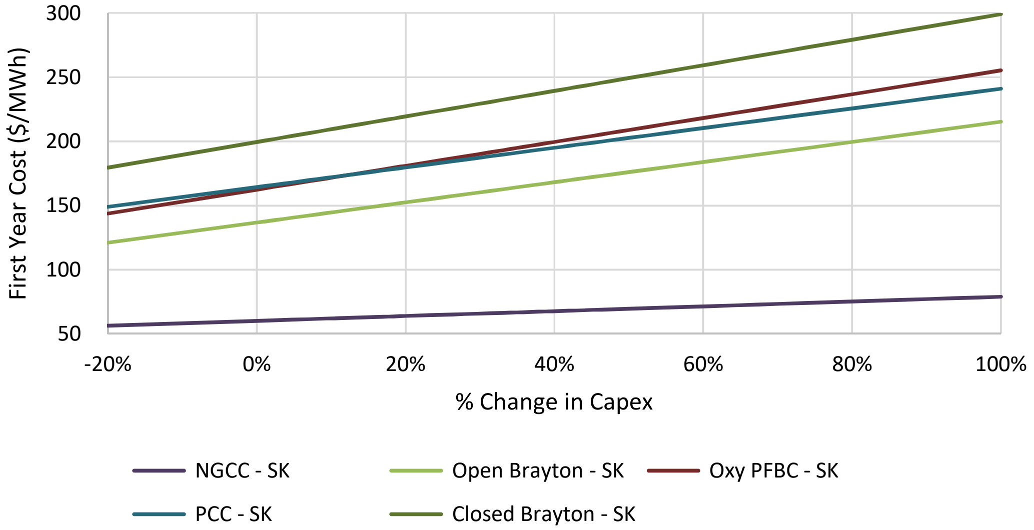


Figure 10 shows how the first-year cost of power changes as the capital cost of the cases change. The values at -20% are 80% of the base values (X 1/1.25 = .80). These value show the impact on the first-year cost of power with the 25% contingency excluded. Over the range considered, the NGCC first year cost of power does not exceed the first-year cost of power for any of the coal cases.

Figure 10: First Year Cost of Power vs Change in Capital Cost



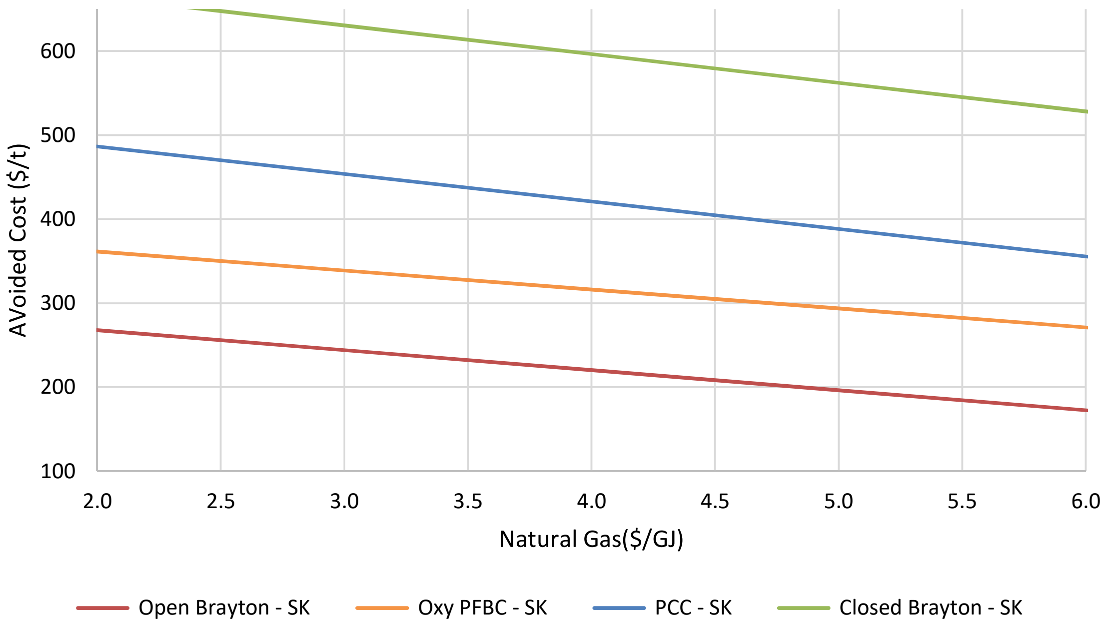
A contingency of 25% has been added to the air separation units (ASU) costs. Table 12 provides a summary of the impact on the first-year cost of power if this contingency is removed from the ASU costs. The values in yellow are slightly lower than the values above them which include the contingency on the ASU costs.

Table 12: First Year Cost for ASU Contingency Sensitivity

	NGCC - SK	PCC - SK	Closed Brayton - SK	Oxy PFBC - SK	Open Brayton - SK
ASU Contingency Included	60	158	189	149	126
ASU Contingency Not Included	60	164	199	162	137

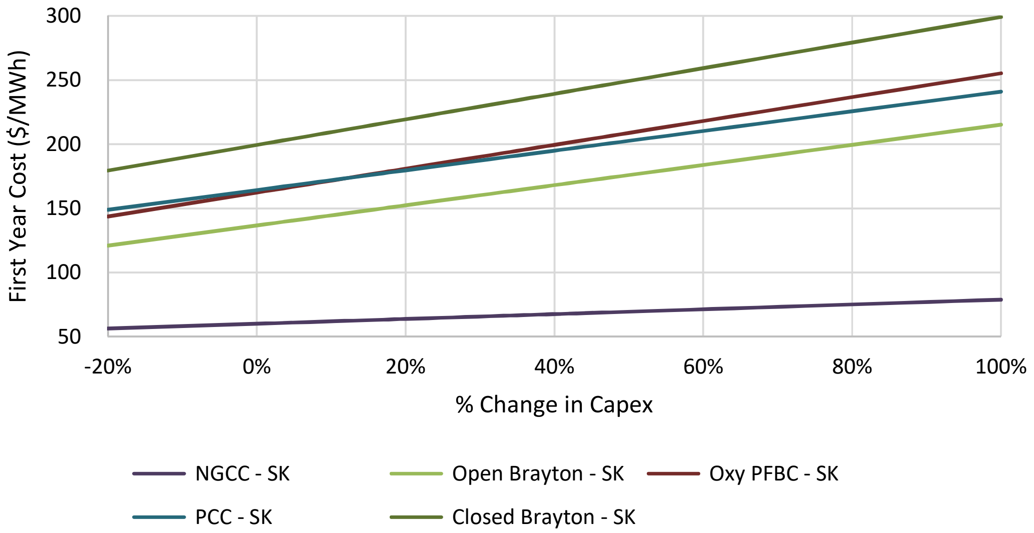
Figure 11 depicts how the avoided cost for the coal fired cases change as the gas price changes. Recall that the avoided cost is also the break-even price of CO_2 credits using an NGCC as the reference case. Over the range of gas prices considered in Figure 11, none of the cases has a break-even price of CO_2 credits less than \$50/t the expected price in the near future.

Figure 11: Avoided Cost vs Natural Gas Price



Over the range of capital costs escalators considered in Figure 12, none of the cases has a break-even price of CO_2 credits less than \$50/t the expected price in the near future.

Figure 12: Avoided Cost vs Change in Capital Cost



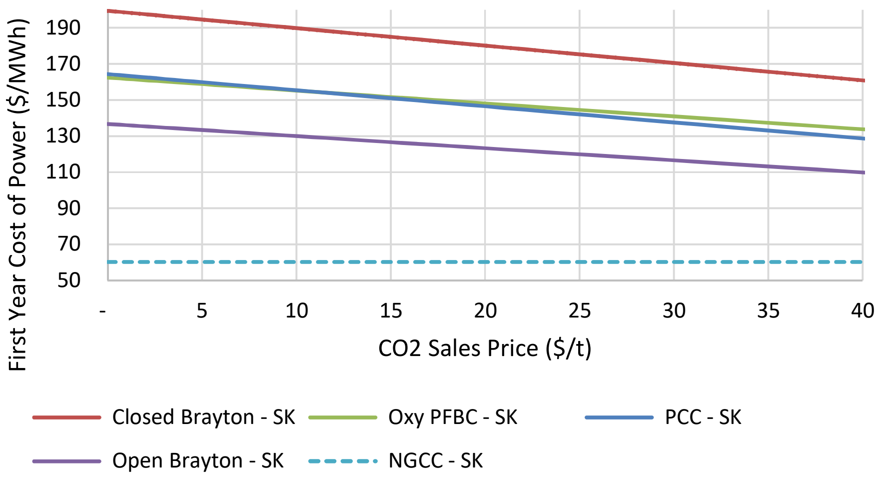
The Canadian government has proposed a carbon tax. It is assumed in the cases above that a carbon tax will not apply. For the purposes of running a sensitivity, a carbon tax of $30/t in 2020, $40/t in 2021 and $50/t in 2022 was assumed. The carbon tax is assumed to be paid on all GHG emissions for the Saskatchewan cases. All the cases with the carbon tax have higher first-year costs than those cases without a carbon tax because they all emit CO_2 and therefore pay a carbon tax.

Table 13: First Year Cost of Power Carbon Tax Sensitivity

	PCC - SK	Closed Brayton - SK	Oxy PFBC - SK	Open Brayton - SK	NGCC - SK
Without CO_2 Tax	164.3	199.4	162.3	136.7	60.1
With CO_2 Tax	168.5	203.9	164.1	137.8	72.3

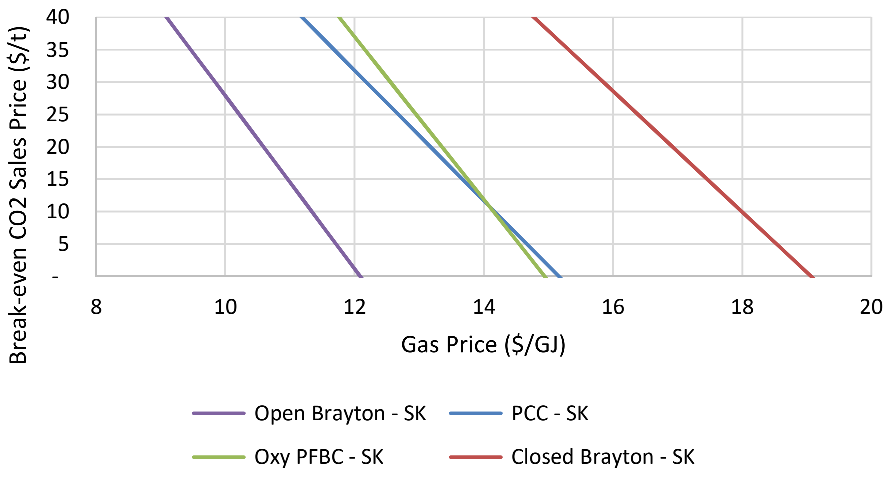
Saskatchewan also has the opportunity to sell CO_2 for enhanced oil recovery. The values above do not include the sale of CO_2 for enhanced oil recovery. Figure 13 shows how the first-year cost of power decreases as the price of CO_2 sold increases.

Figure 13: CO_2 Sales Price Impact on First Year Cost of Power



The price CO_2 must be sold for to reduce the first-year cost of power to that for a new NGCC is sensitive to the gas price assumed. Figure 14 show how the required selling price of CO_2 decreases as the price of natural gas increases. As the price of natural gas increases, the first-year cost of power from an NGCC increases, which reduces the price CO_2 must be sold for to allow the first-year cost of power for an NGCC and a coal case with CCS to be equal.

Figure 14: Gas Price impact on Required Selling Price of CO_2



4. Conclusions:

Based on this study none of the coal based carbon capture cases were more economical than a new NGCC. However, the coal based carbon capture cases evaluated are in the early stage of development. Further optimization and development of these cases may reduce their costs substantially.