# Natural Gas Generation with Low GHG Emissions

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## 1. Introduction:

This study evaluated several ways to produce power from natural gas with a greenhouse gas (GHG) emission intensity of about .2 t $CO_2$/MWh. Only the first three carbon capture and storage (CCS) options listed below can be retrofitted onto existing natural gas combined cycle (NGCC) power plant. All of the technologies can be used however on greenfield projects.

The technologies evaluated in this study were:

<u>Reference NGCC</u>: This NGCC is a 2-on-1 configuration using GE-7F.05 gas turbines without carbon capture.

<u>NGCC</u>: The base case is an NGCC power plant fitted with Advanced Solvent Post Combustion Capture (AS-PCC). This technology lends itself to both existing plant retrofits and new builds.

- One option used a steam boiler with a backpressure turbine to provide the power and steam required by the CCS system.
- The second option extracted steam from the NGCC heat recovery steam generator (HRSG) or steam turbines to supply the steam required by the CCS system. Power required by the CCS system is taken from the NGCC.

<u>Molten Carbonate Fuel Cells</u>: This is a NGCC fitted with Combined Electric Power and Carbon Dioxide Separation (CEPACS) PCC system using molten carbonate fuel cells. This technology lends itself to both existing plant retrofits and new builds. No commercial plants have been built, but demonstration plants are being built.

- One case captured about 60 to 70% of the $CO_2$ given the lower concentration of $CO_2$ in the fuel gas.
- In the second case, in order to increase the partial pressure of the $CO_2$ across the membranes and increase the capture rate, $CO_2$ was recycled back to the gas turbines.
- A third case was considered based on a high $CO_2$ capture rate, but this limited the mass of flue gas which could be treated by a fuel cell stack. This case was not evaluated in detail.

<u>NGCC with Low Carbon Fuel</u>: Hydrogen fuel is generated from natural gas (NG) using an autothermal reformer (ATR), syngas shift, precombustion $CO_2$ removal providing a $H_2$ rich stream to the GT. Steam produced by the ATR is fed to the steam turbines. This technology lends itself to both existing plant

retrofits and new builds; however, the gas turbine must be suitable for firing a high proportion of hydrogen fuel. No commercial plants have been built, but the technologies involved are commercially available.

- One case used amine scrubbing to remove $CO_2$ from the syngas produced by the ATR.
- A second case used a Pressure Swing Absorber (PSA) to remove $CO_2$ from the syngas produced.

<u>NGCC with Chemical Looping Combustion (CLC):</u> This plant captured $CO_2$ from the NGCC flue gas using CaO. The $CaCO_2$ produced was heated with natural gas in a second bed to drive off and capture the $CO_2$. This technology is applicable to new build only. No commercial plants have been built and CLC is not commercially available but is being demonstrated.

<u>Direct-fired Supercritical $sCO_2$ Open Brayton Cycle:</u> Natural gas diluted with supercritical $CO_2$ is combusted with oxygen at high temperature and pressure in a turbine. Some of the $CO_2$ existing in the turbine is purified and sent to storage and the remainder is recycled back to the inlet of the gas turbine. This technology is applicable to new build only as it does not employ an NGCC based cycle. A demonstration plant is being built.

Each case was designed to have an emission intensity of .2 t $CO_2$/MWh; however, the open Brayton cycle is inherently designed to have very low $CO_2$ emissions. The plant location was assumed to be Alberta. The economics for all of the cases was compared to the reference NGCC case. This study was carried out by Jacobs Engineering with the support of the Electric Power Research Institute (EPRI), CanmetENERGY, and a molten carbonate fuel cell developer. The Open Brayton cycle estimates were based on earlier work completed on the CCPC greenfield coal project. Net Power declined to participate in the development of the Open Brayton cycle cost for this study. The cost estimates presented are expected to have an accuracy of +/- 40%. Costs are shown on an n-th of-a-kind basis.

This study builds on earlier work earlier work completed on the Evaluation of Repowering Options, Molten Carbon Fuel Cells, Advanced Cycles, and other CCPC studies.

## 2. <u>Key Results:</u>

The net output for all the cases was designed be close to 600 MW net except for the Open Brayton Cycle case. The Open Brayton Cycle was based on expected commercial design considerations. The heat rates of all the cases were slightly more than for an NGCC. A capacity factor of 85% was assumed for all cases along with a 30-year design life. 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 weighted average cost of capital (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 by the energy produced and the carbon tax in $/t to determine the total tax paid. If this value is negative then it is assumed a credit is generated.

Table 1: Physical Characteristics of Cases

| | NGCC - AB | Amine w/Boiler | Amine no Boiler | CEPACS | CEPACS w 40% Recirc |
|---|---|---|---|---|---|
| Net Output (MW) | 624 | 625 | 575 | 673 | 664 |
| NG HR (GJ/MWh) | 6.3 | 7.1 | 6.8 | 6.7 | 6.7 |
| Efficiency | 57% | 51% | 53% | 54% | 54% |
| CF First Year | 85% | 85% | 85% | 85% | 85% |
| Design Life (Years) | 30 | 30 | 30 | 30 | 30 |

| | ATR w/ Amine | ATR w/PSA | Ca Looping | Open Brayton Cycle |
|---|---|---|---|---|
| Net Output (MW) | 607 | 640 | 705 | 456 |
| NG HR (GJ/MWh) | 7.8 | 7.7 | 7.4 | 7.6 |
| Efficiency | 46% | 47% | 49% | 47% |
| CF First Year | 85% | 85% | 85% | 85% |
| Design Life (Years) | 30 | 30 | 30 | 30 |

Table 2 shows the capital cost for each case. In addition, it shows the capex in $/kW. The Amine PCC cases have the lowest capex on a $/kW basis of the cases with $CO_2$ reductions. 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 allow for possible changes in capital cost as the performance of the process become more apparent.

Table 2: Capital Costs

| | NGCC - AB | Amine w/Boiler | Amine no Boiler | CEPACS | CEPACS w 40% Recirc |
|---|---|---|---|---|---|
| Net Output (MW) | 624 | 625 | 575 | 673 | 664 |
| Direct Field Costs | 596 | 783 | 702 | 894 | 921 |
| Indirect Field Costs | 116 | 156 | 141 | 174 | 179 |
| Head Office Costs | 50 | 82 | 73 | 86 | 91 |
| Contingency | 76 | 167 | 138 | 196 | 203 |
| Owners Costs | 73 | 99 | 90 | 110 | 113 |
| Initial Cat. and Chem. | 2 | 6 | 5 | 3 | 3 |
| Capital Cost ($ millions) | 913 | 1,291 | 1,149 | 1,462 | 1,510 |
| Capex ($/kW) | 1,464 | 2,066 | 2,000 | 2,170 | 2,274 |
| Contingency | 10% | 16% | 15% | 17% | 17% |

| | ATR w/ Amine | ATR w/PSA | Ca Looping | Open Brayton Cycle |
|---|---|---|---|---|
| Net Output (MW) | 607 | 640 | 705 | 456 |
| Direct Field Costs | 1,022 | 1,018 | 1,052 | 1,102 |
| Indirect Field Costs | 221 | 218 | 222 | 235 |
| Head Office Costs | 137 | 131 | 136 | 261 |

| | | | | |
|---|---|---|---|---|
| Contingency | 280 | 275 | 320 | 349 |
| Owners Costs | 135 | 132 | 142 | 157 |
| Initial Cat. and Chem. | 14 | 10 | 4 | 1 |
| Capital Cost ($ millions) | 1,809 | 1,787 | 1,877 | 2,105 |
| Capex ($/kW) | 2,982 | 2,792 | 2,662 | 4,615 |
| Contingency | 20% | 20% | 23% | 22% |

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 emitted. The percentage of $CO_2$ captured is designed to yield an emission intensity of about .2 t $CO_2$/MWh. The Open Brayton Cycle has a very high capture rate of 99% which leads to a very low emission intensity. The capture rate for the other cases is about 50%. The mass of $CO_2$ avoided is defined as the difference between the GHG emission intensity of the NGCC reference case and the CCS case multiplied by the energy produced by the NGCC reference 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 | Amine w/Boiler | Amine no Boiler | CEPACS | CEPACS w 40% Recirc |
|---|---|---|---|---|---|
| GHG Intensity (t/MWh) | 0.35 | 0.20 | 0.20 | 0.19 | 0.20 |
| GHG Produced (Mt/yr) | 1.63 | 1.84 | 1.63 | 1.87 | 1.83 |
| $CO_2$ Captured (Mt/yr) | 0.00 | 0.91 | 0.77 | 0.89 | 0.86 |
| GHG Emissions (Mt/yr) | 1.63 | 0.93 | 0.86 | 0.98 | 0.97 |
| % Captured | 0% | 50% | 47% | 48% | 47% |
| $CO_2$ Avoided (Mt/yr) | 0.00 | 0.71 | 0.64 | 0.79 | 0.77 |

| | ATR w/ Amine | ATR w/PSA | Ca Looping | Open Brayton Cycle |
|---|---|---|---|---|
| GHG Intensity (t/MWh) | 0.22 | 0.22 | 0.21 | 0.01 |
| GHG Produced (Mt/yr) | 1.94 | 2.04 | 2.24 | 1.43 |
| $CO_2$ Captured (Mt/yr) | 0.94 | 1.01 | 1.15 | 1.41 |
| GHG Emissions (Mt/yr) | 1.00 | 1.03 | 1.09 | 0.02 |
| % Captured | 49% | 49% | 51% | 99% |
| $CO_2$ Avoided (Mt/yr) | 0.59 | 0.65 | 0.75 | 1.17 |

Table 4 shows the first-year 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 or compliance costs.

The marginal cost for all the cases, except the open Brayton cycle case is estimated to be lower than for a NGCC. The reason for this is that the increase in fuel cost is offset by the additional $CO_2$ credits sold. The Open Brayton cycle case has the highest estimated first-year cost of power and marginal cost. The

Amine and CEPACS cases have the lowest first year costs and marginal costs. It appears as well that adding recirculation to the CEPACS system does not improve its first year cost of power.

Table 4: Cost of Electricity in $/MWh

| | NGCC - AB | Amine w/Boiler | Amine no Boiler | CEPACS | CEPACS w 40% Recirc |
|---|---|---|---|---|---|
| 1st Yr Cost | 55.8 | 68.4 | 65.9 | 66.5 | 68.5 |
| Fuel Cost | 23.4 | 26.4 | 25.4 | 24.9 | 24.8 |
| Transmission | 3.9 | 3.9 | 3.9 | 3.9 | 3.9 |
| $CO_2$ Credit Sales | 0.0 | -7.5 | -7.5 | -7.7 | -7.7 |
| Marginal Cost | 27.3 | 22.8 | 21.9 | 21.1 | 21.0 |

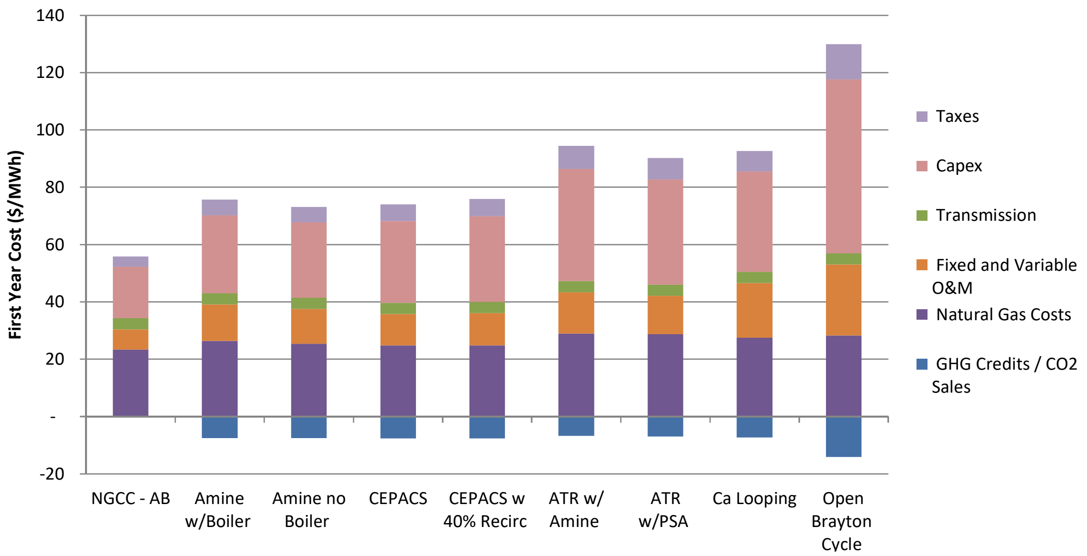
| | ATR w/ Amine | ATR w/PSA | Ca Looping | Open Brayton Cycle |
|---|---|---|---|---|
| 1st Yr Cost | 88 | 83 | 86 | 116 |
| Fuel Cost | 27.8 | 26.3 | 26.2 | 37.6 |
| Transmission | 3.9 | 3.9 | 3.9 | 3.9 |
| $CO_2$ Credit Sales | -6.8 | -7.0 | -7.2 | -14.1 |
| Marginal Cost | 24.9 | 23.2 | 22.9 | 27.4 |

Figure *1* below shows the cost components which make up the first-year cost of power. The fuel cost for the CCS cases are a bit higher than the reference NGCC case accounting for their lower efficiency. The capital cost for the CCS cases are significantly greater than for the reference NGCC case.

There are other ways to produce syngas with a high hydrogen content where the $CO_2$ can be captured. The capital cost of the ATR systems would have to decrease by 40% before they have a similar first-year cost as the post combustion capture systems on NGCC. This means that other competing technologies to produce low carbon fuels will need to be substantially cheaper than using commercially available ATR.

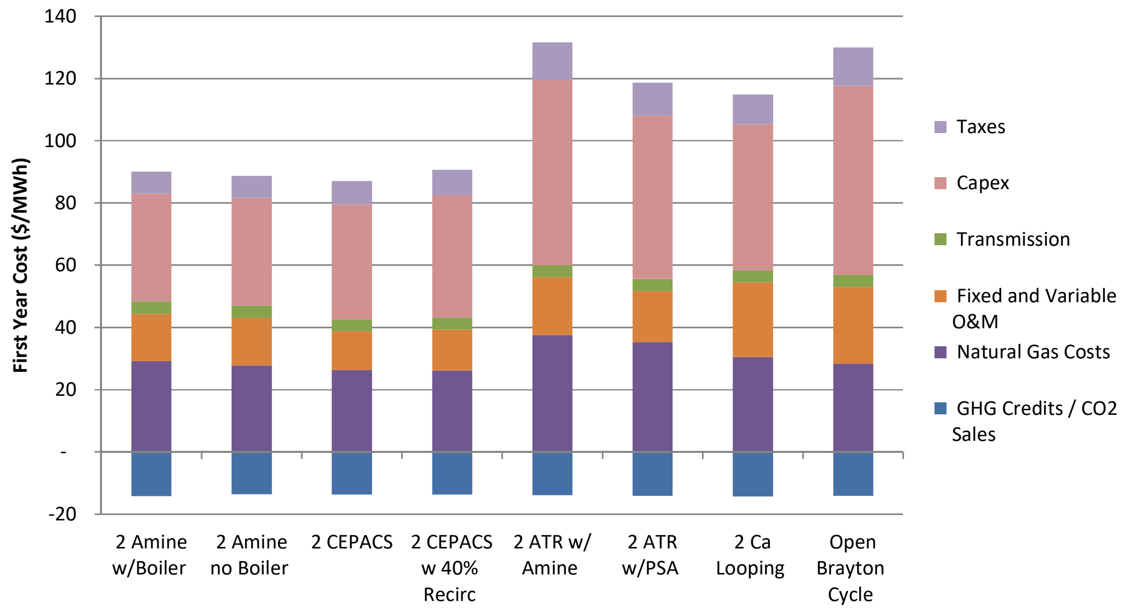
It should be noted that the Open Brayton Cycle case has a much higher capture rate. If the capture rate for the other cases was just as high, the first year cost of power for these cases would be substantially higher.

Figure 1: First Year Cost of Power Components




An attempt was made to factor up the costs for the other CCS cases, except the Open Brayton Cycle, to approximate what the costs might be for 95% $CO_2$ capture, as depicted in Figure 2. All cases in Figure 2 have a very high capture rate. The incremental mass of natural gas required was doubled. The incremental use of power for CCS was doubled. The value of $CO_2$ credits generated was doubled. The incremental capital cost for each case, compared to the NGCC was also doubled. The amine and CEPACS cases still had the lowest first year cost; however, the ATR and chemical looping cases had first-year costs of power similar to the open Brayton cycle.

Figure 2: First Cost Components Adjusted to 95% Capture




The avoided cost calculation requires a reference case without CCS to complete. The reference case for this analysis is a new NGCC 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.

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:

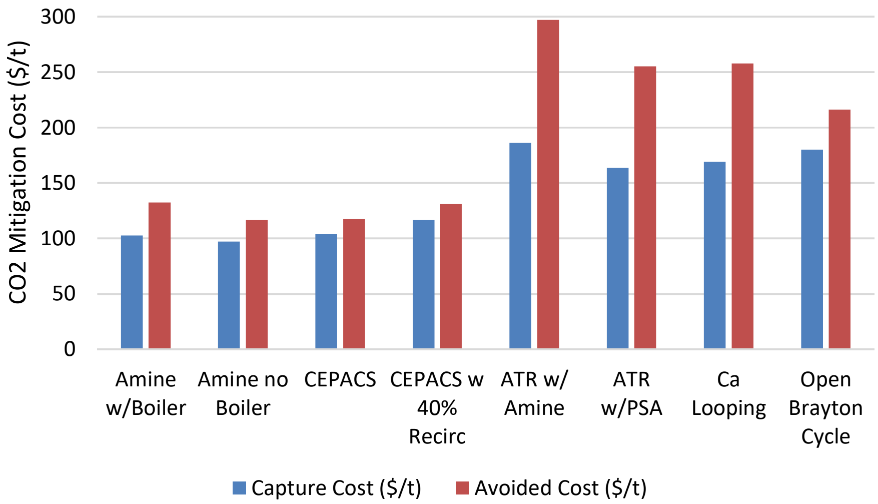
COE NGCC = COE CCS + (GHG Intensity NGCC - GHG Intensity CCS) X Price of $CO_2$ Credits

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 avoided costs in Figure 3 are the breakeven price of $CO_2$ credits required to make the first-year cost of power from the CCS cases equal that of a new NGCC without CCS. Part of the reason the avoided costs are so high for the final four cases (except the Open Brayton Cycle) is that the proportion of $CO_2$ avoided compared to the mass of $CO_2$ generated is much lower than the other cases. In addition, the first-year cost of power for these case is higher than the other cases.

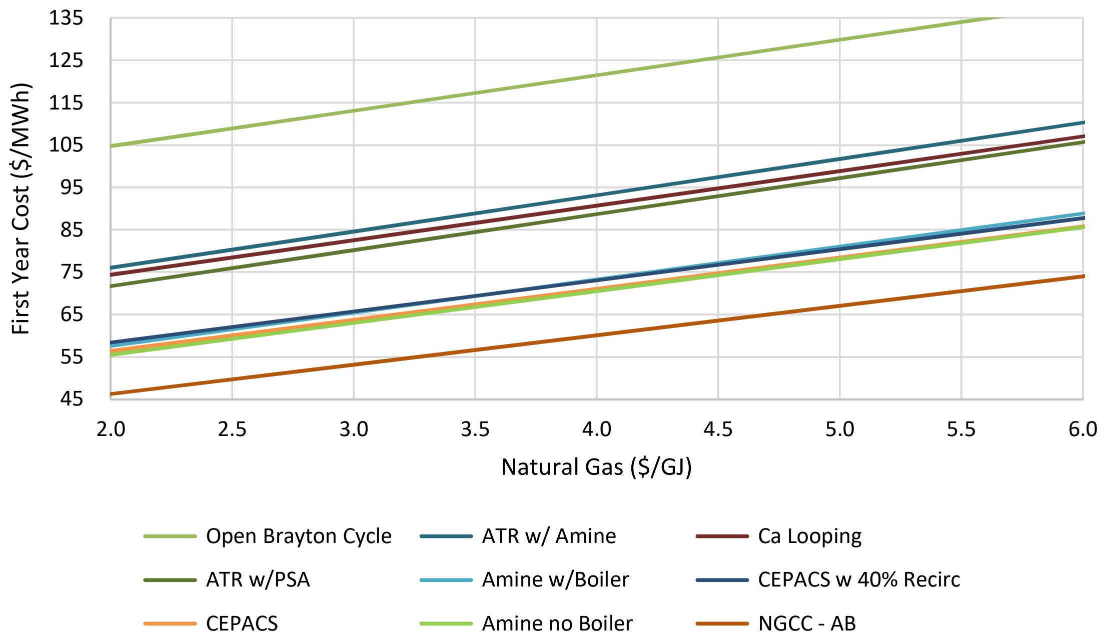
Figure 3: Capture and Avoided Costs




3. Sensitivities:

Figure 4 shows how the natural gas price impacts the first-year cost of power. Because a single fuel is used and the heat rates of the cases do not change, the first year costs increase at the same rate as the natural gas price increases.

Figure 4: First Year Cost as Gas Prices Change




Gas-fired generation has a relatively high marginal cost compared to other forms of generation. For this reason, it may not be dispatched on with a high capacity factor. Figure 5 shows how the first-year cost of power increases as the capacity factor decreases.

Figure 5: Impact of Capacity Factor on First Year Cost

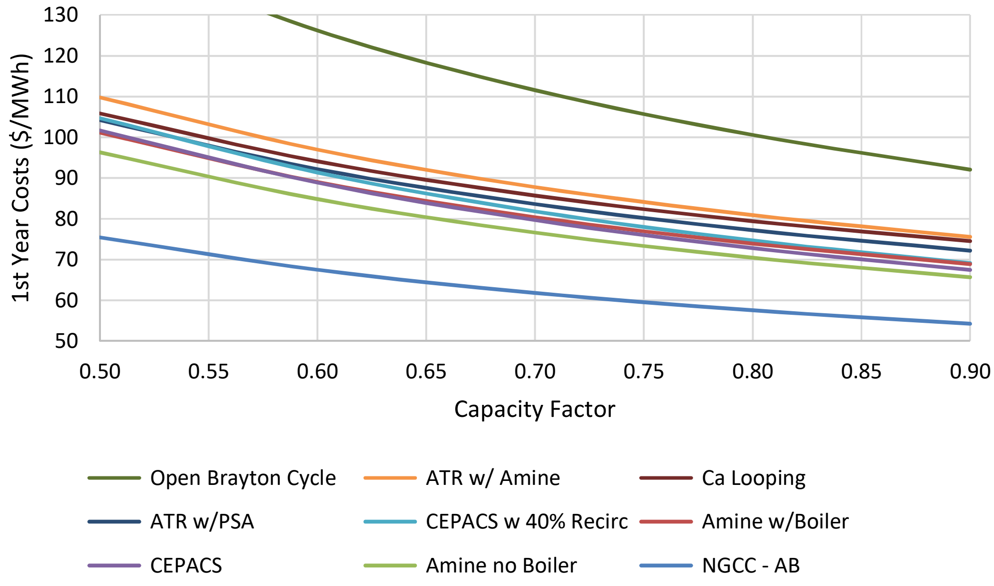



Figure 6 shows how the first-year cost of power changes as the capital cost of the cases change. The values at -20% in the graph below are 80% of the base case values (X 1/1.25 = .80). The following graph shows how changes in capex impact the first-year cost of power.

Figure 6: Impact of Change in Capex on the First Year Cost of Power

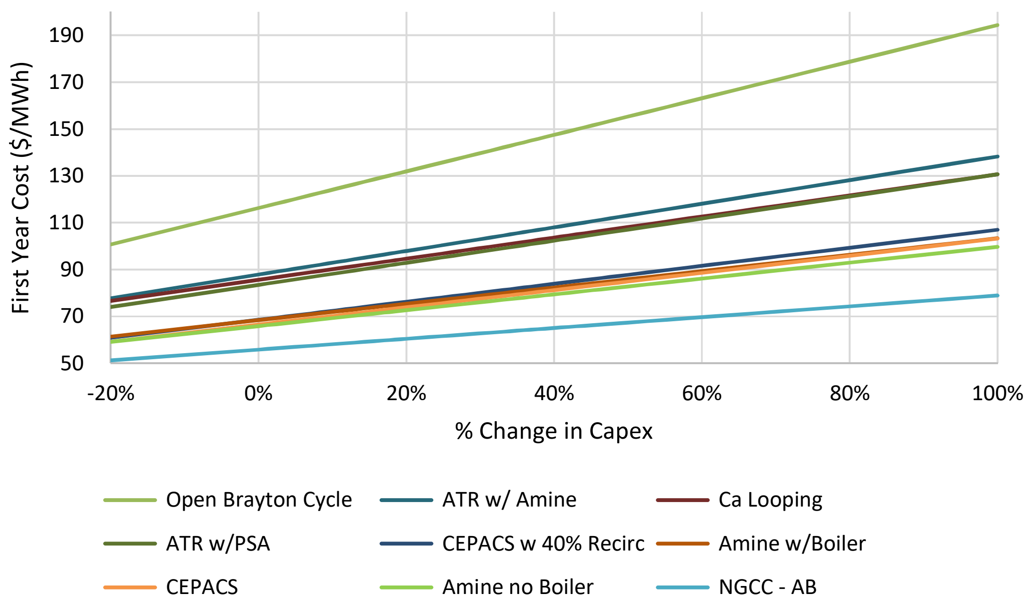
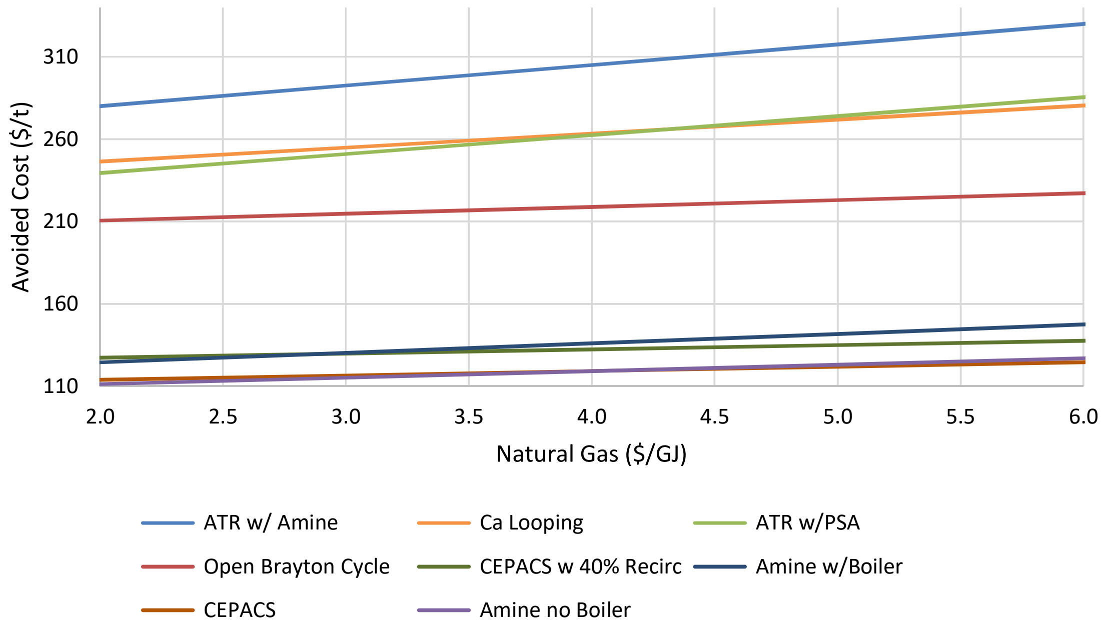


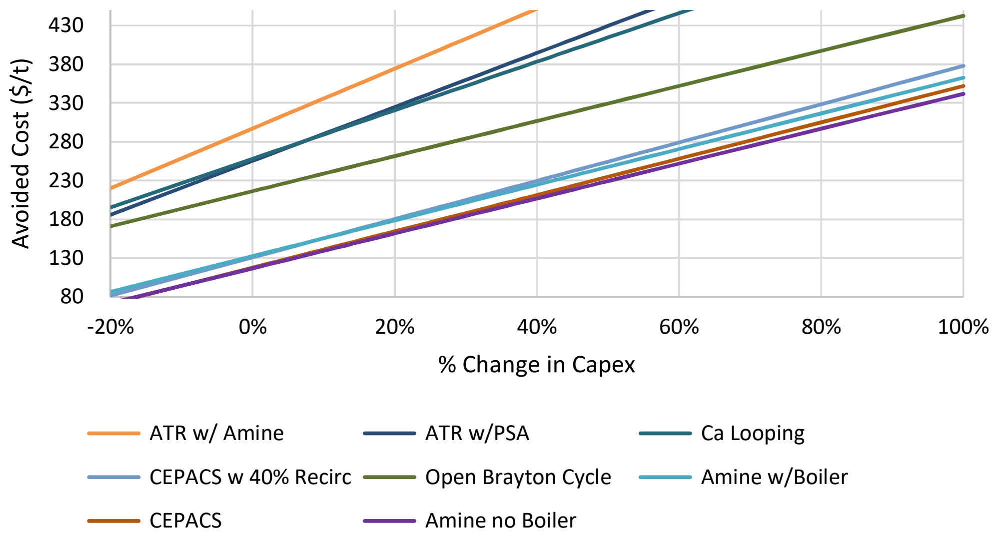
Figure 7 shows how the avoided cost changes as the natural gas price changes. Gas price has little relative impact on the avoided cost except for the ATR case which uses proportionally more natural gas than the other cases.

Figure 7: Avoided Cost as Natural Gas Price Changes



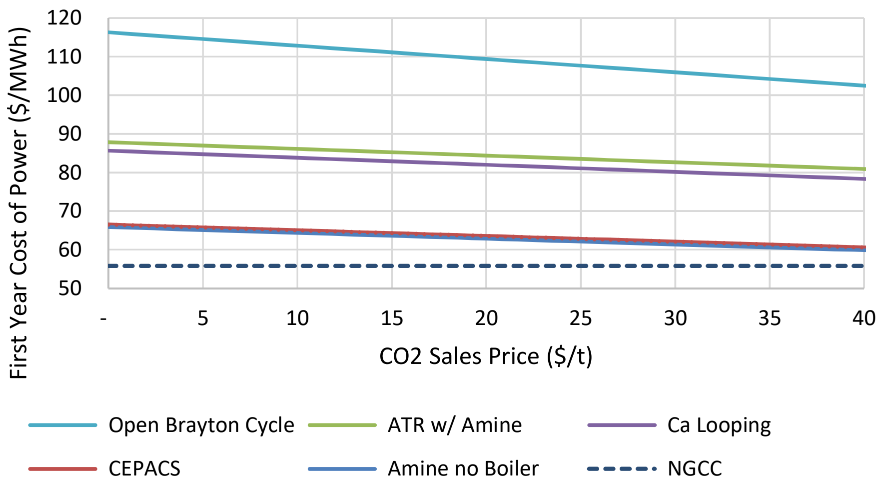

Changes in capital cost have a significant impact on the avoided cost of the technologies a shown below in Figure 8.

Figure 8: Impact of Changes in Capex on Avoided Cost



It may be possible in the future to sell $CO_2$ for enhanced oil recovery (EOR) purposes. Figure 9 shows the impact of adding value associated with selling $CO_2$ for EOR. Given that for all cases, except the Open Brayton Cycle, about half of the $CO_2$ is captured, selling this $CO_2$ has a modest impact on the first-year cost of power.

Figure 9: $CO_2$ Sales Price Impact on First Year Cost of Power




4. <u>Conclusion</u>:

Based on this study, amine scrubbing of NGCC flue gas and the molten carbon fuel cell cases had the most attractive first-year costs of power and $CO_2$ capture costs. The open Brayton cycle and chemical looping $CO_2$ capture technologies are in the early stage of development. Advances in these areas are likely and the costs for these technologies may decrease over time.