NATIONAL ENERGY TECHNOLOGY LABORATORY

Techno-Economic Analysis of CO_2 Capture-Ready Coal-Fired Power Plants

August 1, 2012

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OFFICE OF FOSSIL ENERGY

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1. EXECUTIVE SUMMARY

The objective of this study is to evaluate options for new, CO_2 capture-ready supercritical pulverized coal-fired power plants to achieve an average 30-year CO_2 emission rate of 1,000 Lb CO_2/MWh. A CO_2 capture-ready unit is one that does not initially capture carbon dioxide emissions, but fully intends to at some future date. Such a unit can minimize the future retrofit burden by incorporating certain design considerations into the initial plant construction, which will take into account the installation of future CO_2 capture equipment, and minimizing the retrofit burden later on (by allowing for additional space in pipe racks and cable trays, access to utilities like water and instrument air, and pouring foundations where future capital equipment will be installed). See APPENDIX A for further details and discussion on the definition of capture ready.

It is assumed in this study that CO_2 capture will not begin until the start of the 11th year of full operation. There is another option evaluated that includes a reduced amount of CO_2 capture beginning in the 9th year of full operation, and steadily ramping up until meeting full capture in year 11. The advantage would be that by starting slightly early, some of the inevitable operational problems could be worked out in advance of the 11th year.

Two design strategies are explored in the analysis:

- Building a CO_2 capture-ready plant, but taking extra steps to minimize the heat rate penalty during retrofit, by incorporating additional capital equipment such as a steam letdown turbine, and clutched low pressure steam turbine (see Exhibit B-1). This will result in a higher up-front capital expense, but will help maintain a higher net power output. These cases are referred to by "Min Heat Rate Penalty" in this study.
- Building a CO_2 capture-ready plant, but adding only the minimum capital equipment to accommodate future CO_2 capture (see Exhibit B-2). This approach results in the minimum capital cost, but will have the greatest heat rate penalty amongst the given scenarios when CO_2 capture occurs. These cases are referred to by "Min CapEx" in this study.

This analysis finds that the most cost-effective way for new supercritical units to achieve the goal emission rate is to build CO_2 capture-ready plants that seek to minimize the heat rate penalty, post-retrofit. Although the capital cost of this configuration is slightly higher, the benefit of maintaining a higher net power output far outweighs the increased capital expenditure. If 2nd generation CO_2 capture is assumed, there could be a 20% capital cost savings realized over a non capture-ready plant using today's post combustion amine scrubber (see Exhibit 2). Compared to nuclear generation, the capital cost savings of the CO_2 capture-ready plant could be substantial: when compared to several recent nuclear estimates[i,ii], a 50-60% capital cost savings is possible.

The analysis also highlights the benefits of continued development of carbon capture, utilization, and storage (CCUS). A capture-ready coal-fired unit using 2nd

generation CO_2 capture technology, as well as earning additional revenue from CO_2 sales for enhanced oil recovery (EOR), could achieve parity with natural gas combined cycle (NGCC) at gas prices as low as $8/mmBtu (see Exhibit 5).

Development of CO_2 capture-ready coal-fired power plants is critical to ensuring a diversified domestic energy portfolio that provides reliable power. Although recent low natural gas prices have improved NGCC's economic competitiveness, there is reason to believe that gas prices may not remain this low (see Exhibit 6). In the event that natural gas prices do increase beyond recent low levels, retaining the ability to use coal through CO_2 capture-ready systems will be essential for our nation's continued economic prosperity by using a proven domestic resource. Retaining this ability is made possible by continued support for, and development of, our nation's coal resources

2. INTRODUCTION

This study evaluates the performance of four supercritical pulverized coal (PC) CO_2 capture-ready plants. All four cases were modeled using Aspen Plus process simulations to determine key performance parameters critical to the analysis of each configuration.

All electric generating units in this analysis are designed to achieve an emission rate of 1,000 Lb CO_2/MWh (gross) over a 30-year period. One way for a unit to achieve this would be to begin capturing CO_2 emissions on the first day of operation, continuing for the entire 30 years. A second option is to capture CO_2 emissions only for some portion of the time, such that the 30-year average is 1,000 Lb CO_2/MWh (gross). This latter option allows for the construction of CO_2 capture-ready power plants, and is the focus of this analysis.

A CO_2 capture-ready unit is one that does not initially capture carbon dioxide emissions, but fully intends to at some date in the future. These units can minimize the future retrofit burden by incorporating certain design considerations into the initial plant construction. This is the subject of the present study. See APPENDIX A for further details and discussion on the definition of capture ready.

The goal of the CO_2 capture-ready unit should be to comply with the desired CO_2 emission limit at the lowest possible cost by minimizing the future retrofit burden. This means identifying plant areas where future modifications and construction will occur, and doing as much of that work as possible during initial plant construction. This will minimize disruption and plant downtime when the retrofit takes place, ultimately helping to keep costs low. Examples include building foundations for CO_2 compressors, oversizing selected pipe racks and cable trays, and designing the steam turbine system to allow for future integration of CO_2 capture. A detailed list of modifications is further discussed in APPENDIX B.

The retrofit in this study is assumed to occur in either the 9^{th}, or 11^{th}, year of operation, and the future state-of-the-art post-combustion CO_2 capture technology is unknown. However, in the interest of designing an integrated coal-fired power plant, a CO_2 capture technology selection must be made. Therefore the eventual

CO_2 removal system is assumed to be a post-combustion based process, similar to today's amine scrubber. The system is comprised of the flue gas supply, SO_2 polishing, CO_2 absorption, solvent stripping and reclaiming, and CO_2 compression and drying. If there are technology advances in the ensuing 5 to 7 years before final implementation of the carbon capture solution, the plant may incur additional costs caused by the removal and replacement or retrofitting of the early selected systems. This is a fairly normal risk with early investment, but the risk needs to be emphasized.

The cost of electricity (COE) is significantly affected by two key components that are explored in this study: capital cost and net power generation. The COE can be minimized by either decreasing the retrofit capital cost, or maintaining the highest net power generation after retrofit. These two approaches are mutually exclusive. Maintaining high power generation can only be accomplished by adding capital equipment and cost. Likewise, taking a minimum capital cost approach (adding only the capital equipment that is essential to capturing CO_2, and nothing more) will result in a high heat rate penalty after retrofit. Either approach will ultimately result in an increased COE after retrofit.

This analysis investigates a minimum capital cost approach (at the expense of a high heat rate penalty), and a minimum heat rate penalty approach (resulting in high capital cost) to determine which method results in a lower COE. The timing of the retrofit is also investigated: it is assumed that CO_2 capture does not begin until the start of the 11^{th} year. However, it may be prudent for coal units to start capturing CO_2 early, in order to resolve inevitable operational issues that will arise from incorporating a post-combustion capture process. The CO_2 capture that occurs prior to the 11^{th} year would also count as a credit toward the 30-year average, therefore reducing the degree of capture required in later years to meet 1,000 Lb CO_2/MWh.

This analysis investigates cases that begin to capture CO_2 in the 11^{th} year, and also cases that start with a reduced degree of removal in the 9^{th} year, but slowly ramp up to full capture by year 11. A summary of the cases is presented in Exhibit 1. Cases labeled "1" are the minimum capital cost cases, and Cases labeled "2" are the minimum heat rate penalty cases. An "A" indicates that the initial plant construction was not CO_2 capture-ready, and all of the necessary components were installed when the plant was retrofitted to capture CO_2 at the start of the 11^{th} year. A "B" indicates that the initial plant was CO_2 capture-ready, with some of the required components (foundations, pipe racks, cable trays, throttling valves) installed during initial plant construction, and the balance of the carbon capture components installed at the time of the retrofit. The "9" or "11" corresponds to the year of retrofit.

As explained above, there are two cases in this analysis (1B-9 and 2B-9) that begin to capture CO_2 slightly earlier than the start of the 11^{th} year. It is assumed for these cases that at the start of the 9^{th} year, the unit will capture 20% of CO_2 emissions, and 40% in the 10^{th} year. By the 11^{th} year, the degree of capture can be increased to the level required to achieve the 1,000 Lb CO_2/MWh 30-year average. Although the initial retrofit for these cases takes place in the 9^{th} year, the performance summary for the 10^{th} and 11^{th} years is also shown (in italics) in Exhibit 1.

Exhibit 1 CO_2 Capture-Ready Case Summary

Name	Retrofit Year	Design Approach	Percent Carbon Capture[1]	30-Year Average Emission Rate (Lb CO_2/MWh)[2]	Net Power Produced, MW
1A-11	11	Non-Capture Ready, No Ramp-Up	70%	1,000	365.7[3]
1B-9	9	Capture ready, Min. Capital Cost, 2 Year Ramp-Up (Year 9)	20%	1,000	443.8
1B-9	*9*	*Capture ready, Min. Capital Cost, 2 Year Ramp-Up (Year 10)*	*40%*	*1,000*	*412.5*
1B-9	*9*	*Capture ready, Min. Capital Cost, 2 Year Ramp-Up (Year 11)*	*69%*	*1,000*	*367.6*[3]
1B-11	11	Capture ready, Min. Capital Cost, No Ramp-Up	70%	1,000	365.7[3]
2B-9	9	Capture Ready, Min. Heat Rate Penalty, 2 Year Ramp-Up (Year 9)	20%	1,000	514.4
2B-9	*9*	*Capture Ready, Min. Heat Rate Penalty, 2 Year Ramp-Up (Year 10)*	*40%*	*1,000*	*480.5*
2B-9	*9*	*Capture Ready, Min. Heat Rate Penalty, 2 Year Ramp-Up (Year 11)*	*63%*	*1,000*	*441.5*[3]
2B-11	11	Capture Ready, Min. Heat Rate Penalty, No Ramp-Up	65%	1,000	438.0[3]

[1] Reflects the degree of CO_2 capture, starting in the retrofit year. It is assumed that no capture will occur until the specified retrofit year.
[2] CO_2 emissions are calculated on a gross power basis, and do not consider auxiliary loads
[3] Given power produced is the amount produced for the remaining life of the plant after CO_2 capture retrofit

3. RESULTS

A discounted cash flow analysis was used to generate the cost of electricity for each case analyzed in this study. The assumptions that formed the basis of these calculations are discussed further in APPENDIX C.

3.1 CAPITAL COST RESULTS

The capital cost summary (total overnight cost, expressed in \$/kW) for all cases is shown in Exhibit 2. All cases are compared to a supercritical unit that is not CO_2 capture-ready, but retrofits and begins to capture at the start of the 11th year of operation (Case 1A-11). The cost of constructing the base CO_2 capture-ready plant (prior to CO_2 capture) is shown in blue, which would include allowances for extra pipe racks and cable trays, as well as other items such as concrete foundations to accommodate future retrofit. The incremental capital cost resulting from actually installing the equipment located in the CO_2 capture plant is shown in green. This would include the post-combustion CO_2 scrubber, CO_2 compressors, and other associated items such as the letdown turbine or throttling valve.

As shown above in Exhibit 1, one of the strategies was to minimize capital cost impact by adding only the equipment that was absolutely necessary to building a CO_2 capture-ready plant (Case 1B-9 and 1B-11). Besides foundations, cable trays, pipe racks, and other minor costs, the major piece of equipment is a throttling valve at the intermediate pressure (IP)/low pressure (LP) crossover pipe of the steam turbine section. In nominal/absolute dollars, Case 1B-9 and 1B-11 were the least expensive CO_2 capture-ready plants (\$1.940 billion and \$1.942 billion, respectively after retrofit). However since the heat rate penalty for these two cases was so significant, the power produced post-retrofit dropped significantly. Therefore on a \$/kW basis, the minimum capital cost retrofit cases (1B-9 and 1B-11) were more expensive than the other configurations that added significant capital equipment to minimize heat rate penalty (Case 2B-9 and 2B-11).

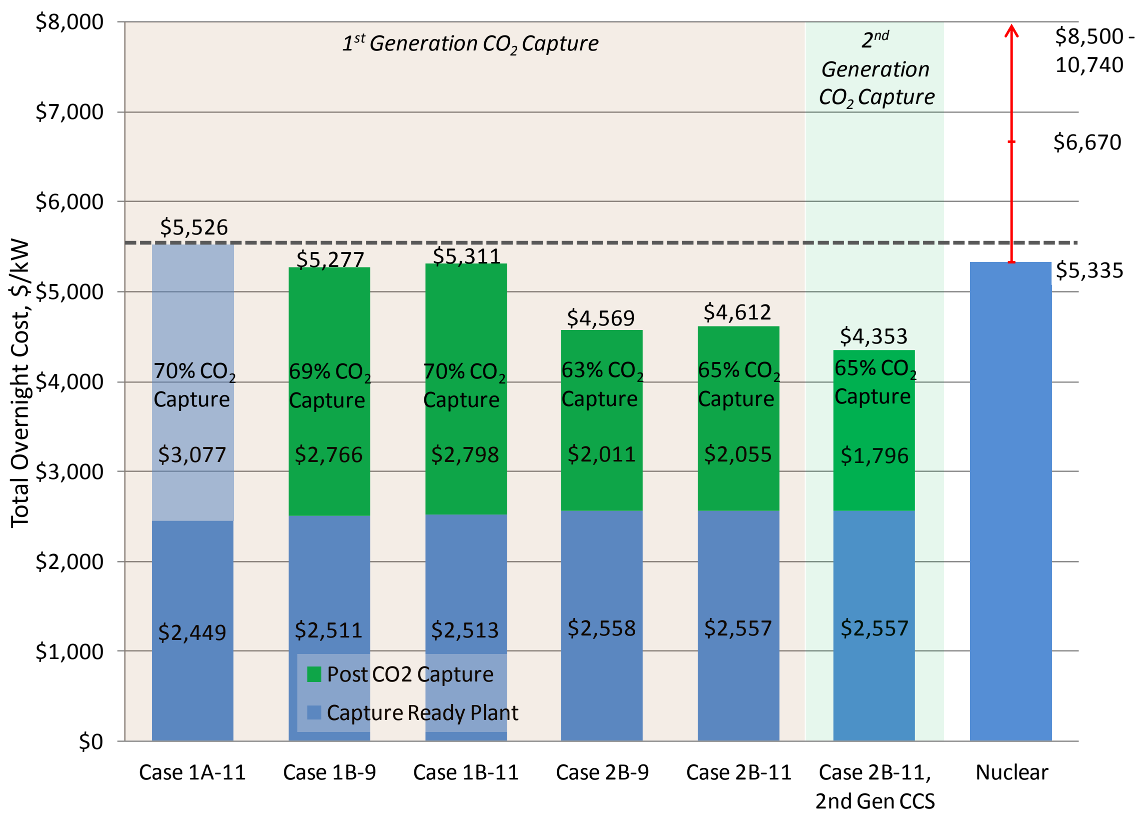
Cases 2B-9 and 2B-11 included a clutched LP turbine and letdown steam turbine to minimize the heat rate penalty after CO_2 retrofit occurred, which added capital cost in absolute dollars (total overnight cost for Case 2B-9 and 2B-11 was \$2.01 billion and \$2.02 billion, respectively after retrofit). Even though total overnight cost for these two cases is highest, they are the most attractive on a \$/kW basis. Although the cost is greater in absolute dollars, the benefit is significant when compared to the minimum capital cost approach (Cases 1B-9 and 1B-11).

Exhibit 2 includes a capture-ready case that assumes the use of 2nd generation CO_2 capture technology. The advances assumed over today's post-combustion amine CO_2 scrubber include:

- 25% reduction in auxiliary power load (reduced solvent circulation rate)
- 20% reduction in extraction steam quality (advanced solvent chemistry requiring lower quality steam for solvent regeneration)
- 30% reduction in capital cost

Exhibit 2 also shows the capital cost benefit associated with construction of coal-fired CO_2 capture-ready units, compared to nuclear generation. A wide variation in capital cost estimates exists for nuclear power: the lower end nuclear estimate ($5,335/kW)[iii] is roughly comparable to the capture-ready, minimum capital cost approach (1B-9 and 1B-11). Other estimates associated with construction of actual nuclear facilities are much higher (ranging from $6,670/kW, to as high as $10,740/kW)[i,ii]. Compared to these estimates, the CO_2 capture-ready coal units analyzed in this study appear economically attractive.

Exhibit 2 - Capital Cost Summary



3.2 COST OF ELECTRICITY RESULTS

The annual cost of electricity summary, in nominal dollars, is shown in Exhibit 3. The COE for all cases increases sharply after the year of the retrofit. This is a result of the capital expenditure associated with CO_2 capture and compression equipment, as well as the reduction in power output. For all cases, the COE is continually increasing due to an assumed 3% annual escalation factor.

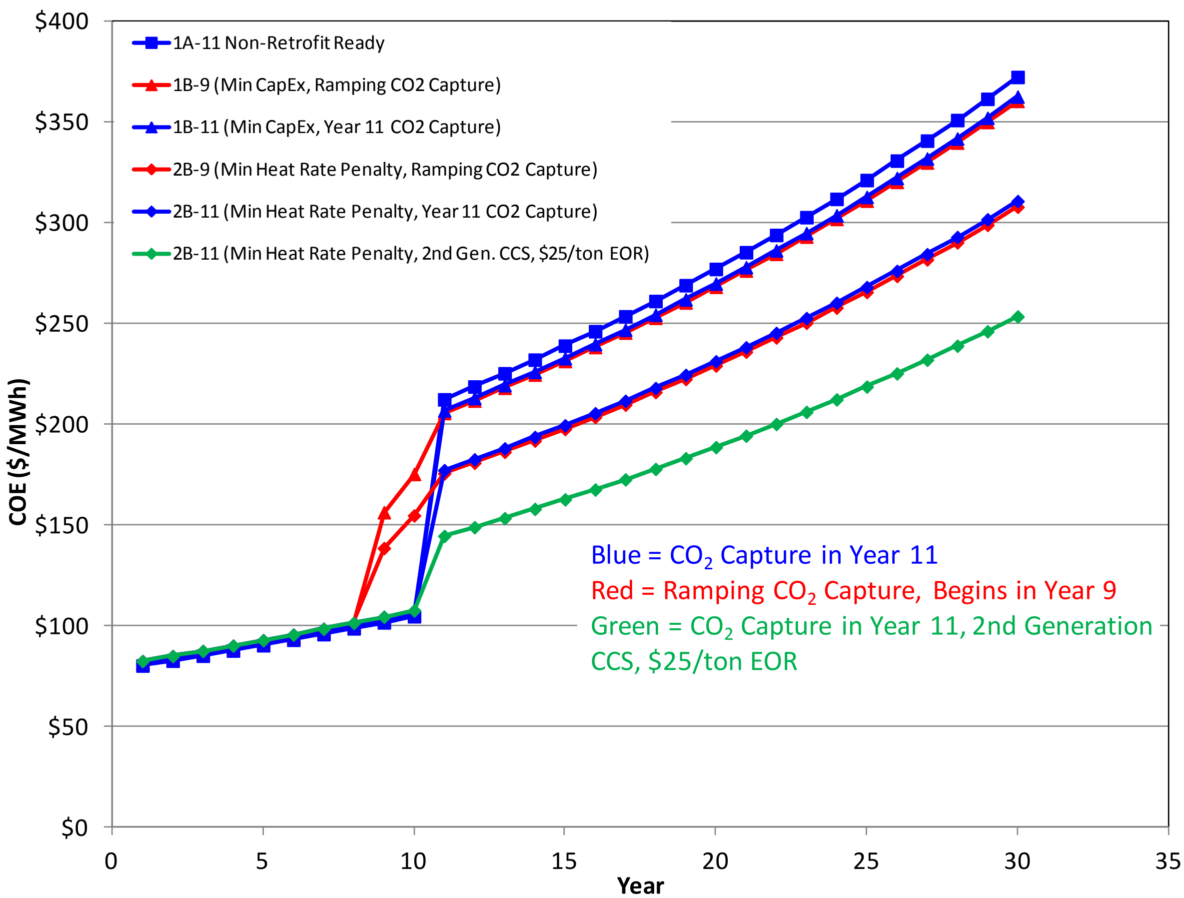
The COE trend shown in Exhibit 3 is very similar to the capital cost trend in Exhibit 2. The CO_2 capture-ready options with lowest COE are the cases which strive to minimize the heat rate penalty, post-retrofit. These results confirm that there is a strong incentive to add the extra capital equipment (letdown turbine, clutched LP steam turbine) which will maintain the highest possible net power generation after the retrofit occurs.

The cases that begin to capture CO_2 slightly early, and slowly ramp up the capture rate (Cases 1B-9 and 2B-9), do not have a long-term COE advantage over the corresponding cases that wait to implement carbon capture until the 11th year. However, there may be other, more practical reasons to implement such a strategy, such as resolving inevitable operational issues that will arise, prior to the 11th year.

Exhibit 3 also shows the benefits of an additional revenue stream from CO_2 sales for enhanced oil recovery. At a selling price of $25/ton CO_2, the cost of electricity is approximately a third less than the minimum capital cost cases (1B-9 and 1B-11)[4].

[4] This is based on the minimum heat rate penalty design that retrofits at the beginning of the 11th year (Case 2B-11), and assumes 2nd generation CO_2 capture.

Exhibit 3 - Annual Cost of Electricity Summary



The 30-year levelized cost of electricity (LCOE) summary is shown in Exhibit 4. Unlike the cost of electricity, which increases annually according to the escalation rate, the LCOE is a representation of the average price a coal unit would require to earn a specified rate of return over a 30-year period. Therefore the LCOE is represented by a single weighted average for both the pre- and post-retrofit period.

On this basis, the minimum LCOE case is the 11th-year retrofit that seeks to minimize heat rate penalty through the inclusion of additional capital equipment (Case 2B-11). The reasons this case represents the minimum LCOE are twofold:

1. Since the retrofit does not occur until the 11th year, the plant de-rating (resulting from adding CO_2 capture) is delayed, compared to the same unit that starts to capture in the 9th year. Adding a CO_2 capture process to the coal unit decreases the net power produced, and this represents a significant lost revenue stream. The coal unit's ability to maintain this revenue for an additional 2 years reduces the average

electricity selling price needed to generate the required rate of return. This is reflected in Exhibit 4, where the 11th-year retrofit cases generally result in the lowest 30-year LCOE (when compared to the 9th-year retrofit cases).

2. Including a letdown turbine and clutched LP steam turbine in Cases 2B-9 and 2B-11 minimizes the heat rate penalty after retrofit. Therefore, for the same coal throughput, more net power is generated (compared to the minimum capital expenditure cases). LCOE is an average measure of the required electricity selling price needed to generate a specified rate of return. A process that can generate more power with the same coal throughput will have a lower LCOE than an identical configuration, with the same capital expenditure, but a lower power production. This is the trend shown in Exhibit 4. Cases 1B-9 and 2B-9 have total overnight costs that are only approximately 3% different ($1.94 billion and $2.01 billion, respectively). However, the power produced by Case 2B-9 is almost 74 MW greater than 1B-9 (for the same coal throughput). As a result, the LCOE of Case 2B-9 is noticeably lower.

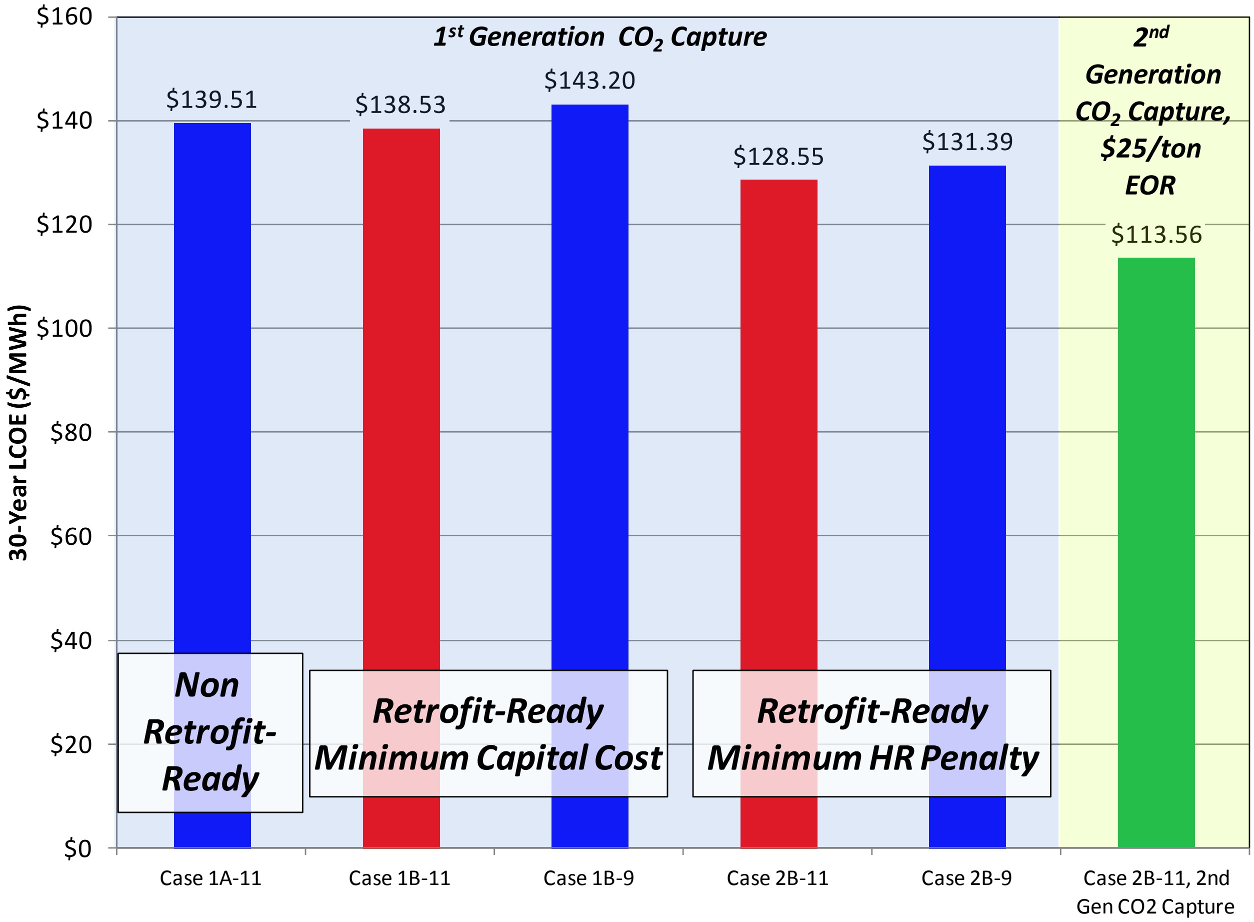
Exhibit 4 also shows the economic benefit of EOR revenue (at $25/ton CO_2), as well as 2nd generation CCUS: a 19% reduction is realized over the non capture-ready case (1A-11).

Although the LCOE favors delaying CO_2 capture until the 11th year, there are other non-economic reasons that favor starting early, and steadily increasing the capture rate. The risk of adding a CO_2 capture process can be mitigated by slowly incorporating it over time, and steadily increasing the capture rate as experience grows.

Finally, it is emphasized that construction of a new CO_2 capture-ready coal-fired power plant carries with it a tremendous amount of project risk. For example, who accepts the liability if CO_2 capture technology is not commercially available at large scale at the end of the tenth year (possibly the plant owner, equipment vendors, or the engineering and construction company)? Who is liable if critical pieces of process equipment (such as the steam turbines) are adversely impacted by the incorporation of CO_2 capture, in ways that were not anticipated? Will the turbine vendor be willing to accept this risk, knowing that the turbine operation could possibly be affected by future addition of the CO_2 capture island?

Each element of risk must be assumed by someone within the group of participants, or the project likely will not be financed, and hence will not be built. Design and financing of CO_2 capture-ready power plants will introduce new aspects of risk that need to be addressed during project negotiations.

Exhibit 4 - Thirty-Year Levelized Cost of Electicity Summary



The 30-year LCOE for three CO_2 capture-ready cases are shown in Exhibit 5, and are compared to NGCC LCOE[iv] over a range of natural gas prices and capacity factors. A CO_2 capture-ready unit that assumes 1st generation CCUS (Case 2B-11) does not achieve parity with NGCC until natural gas prices reach $12/mmBtu. This is the natural gas price at which NGCC and Case 2B-11 have equal 30-year LCOE's. However if 2nd generation CCUS is assumed, along with additional revenue due to CO_2 sales (for EOR) at a price of $25/ton, the equilibrium natural gas price falls to approximately $10/mmBtu.

The selling price of CO_2 for enhanced oil recovery will likely be site specific. Exhibit 5 includes a case that assumes $25/ton CO_2. The actual figure will likely be a function of the market price of oil: as oil prices climb, the CO_2 has more value, and therefore can sell at a higher price. A recent study[v] has calculated the CO_2 price (for enhanced oil recovery) as a function of market oil price, and finds that when oil sells for $100 per barrel, the CO_2 has a maximum value in the range of $81 to $113 per ton (depending on the cost of oil production). Using this as a basis, Exhibit 5 also includes a case that assumes 2nd generation CCUS, and a CO_2 price of $75/ton. This case achieves parity with NGCC at a natural gas price of approximately $8/mmBtu. It is worth noting that the CO_2 price of $75/ton was based on oil reaching $100/barrel. However, the average annual oil price during 2020 – 2030 (the period during which a capture-ready plant would most likely retrofit) is expected to be well in excess of $100 per barrel according to recent figures[iii], therefore $75/ton CO_2 may be a plausible estimate.

The decrease in natural gas price needed for capture-ready coal units to achieve parity with NGCC could be interpreted as the return on a continued investment in CCUS research, development and demonstration: without the continued development needed to achieve 2nd generation CCUS, natural gas prices could be as high as $12/mmBtu before another generation option (capture-ready coal) penetrates the market, according to Exhibit 5. With 2nd generation CCUS, and a CO_2 price of $75/ton (which could be justified given world oil price estimates[iii,v]), a capture-ready coal unit would penetrate when natural gas exceeds approximately $8/mmBtu, according to Exhibit 5. This 33% decrease in the natural gas price shown in Exhibit 5 (from $12 to $8/mmBtu) could be characterized as one of the benefits of continued investment in CCUS research, development, and demonstration.

Although recent low natural gas prices have improved the economic competitiveness of NGCC power generation, there is reason to believe that gas prices may not remain this low. Exhibit 6 shows natural gas spot price at the Henry Hub since 2000 and compares it to the Japanese LNG import price (around $16/mmBtu in 2012), as well as German and UK spot prices (approximately $11 and $9/mmBtu, respectively). Given the large difference when compared to recent Henry Hub prices, a strong argument could be made for the global commoditization of natural gas, causing the U.S. spot price to increase to more closely reflect global prices. This would significantly increase the cost of gas-fired power generation, which is mostly dominated by fuel price. Development of a full suite of generation options, including CO_2 capture-ready coal, is therefore critical to ensuring reliable electricity supply at the lowest possible cost.

Exhibit 5 – CO_2 Capture-Ready Coal and NGCC 30-Year LCOE Comparison

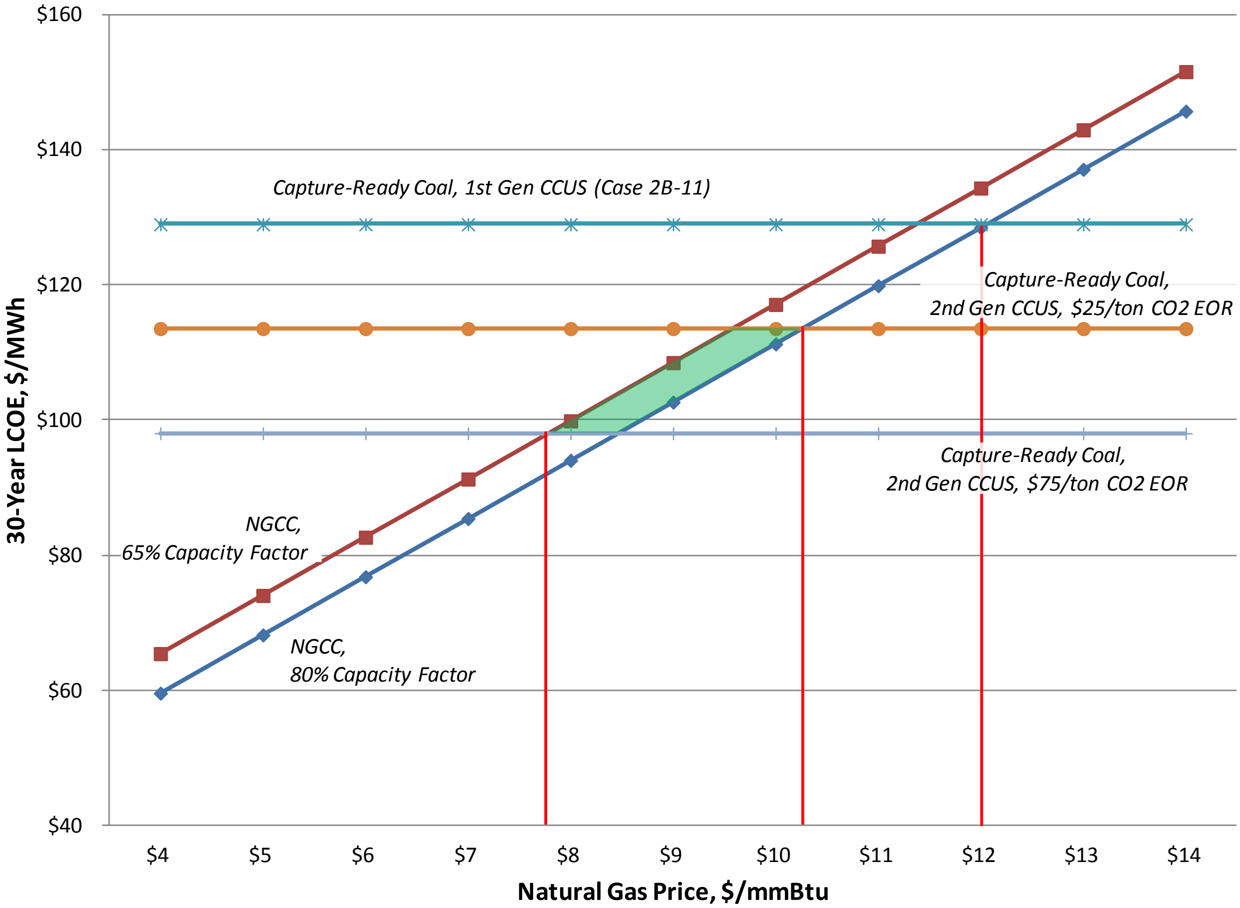
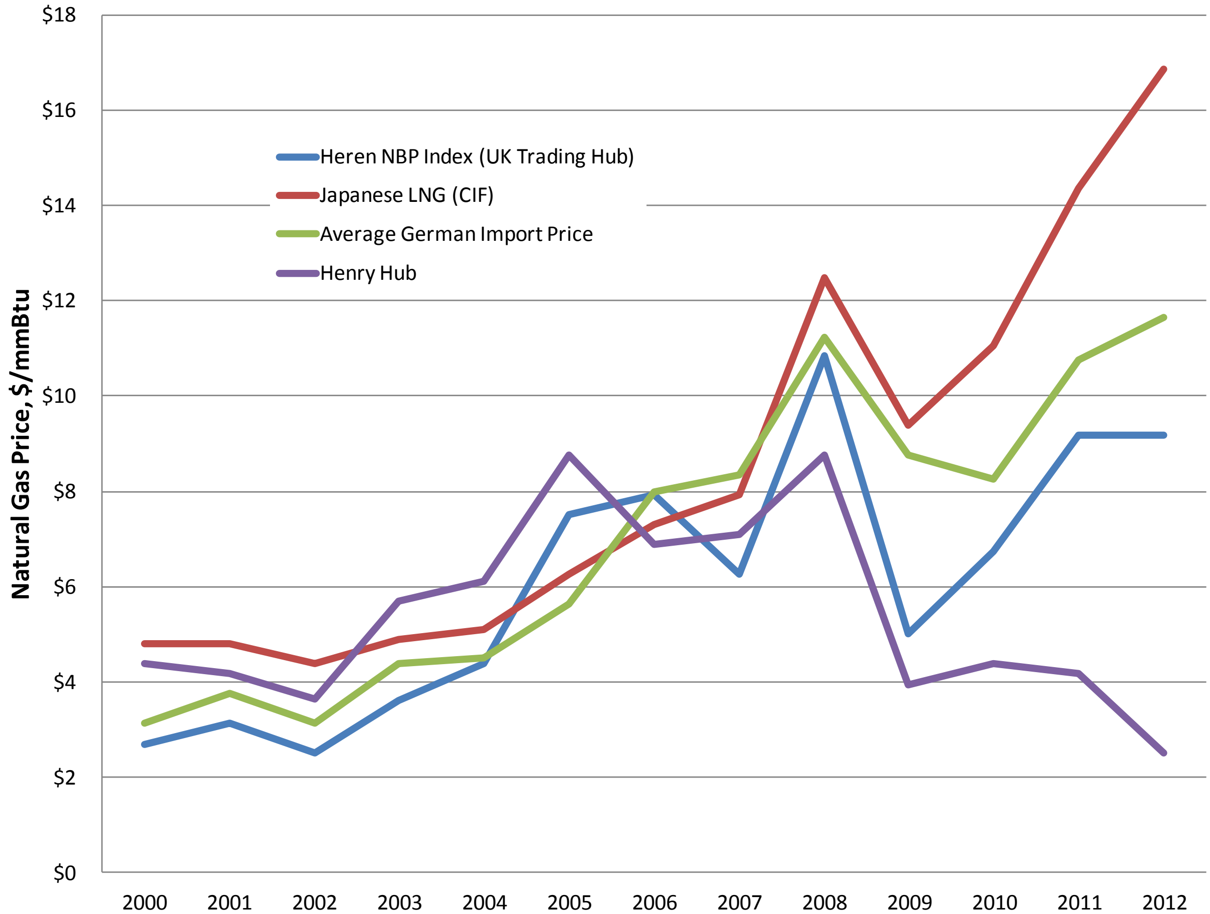


Exhibit 6 – Global Natural Gas Price Summary[vi]



4. Supercritical CO_2 Capture-Ready Pulverized Coal Performance and Cost

This study evaluates the cost and performance of four supercritical PC CO_2 capture-ready plants. All four cases were modeled using Aspen Plus process simulations to determine key performance parameters critical to the analysis of each configuration. This section provides details of each configuration and the results of process modeling. Although the retrofit approach and timing of CO_2 capture differs across cases, the goal of each case is to achieve a CO_2 emission rate of 1,000 Lb CO_2/MWh (gross basis) over a 30-year period.

The coal used in all cases is Illinois #6, shown in Exhibit 7. The delivered coal price is assumed to be $63.58/short ton[5].

Exhibit 7 - Coal Properties

Ultimate Analysis (weight %)		
	As Received	Dry
Moisture	11.12	0
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen	6.88	7.75
HHV, Btu/lb	11,666	13,126

[5] Typical delivered fuel price for east-coast, bituminous coal units (Mountaineer and Longview), as reported by Velocity Suite, accessed March 21, 2012.

All cases in this analysis are based on supercritical steam conditions of 3,500 psig/1,100 ºF/1,100 ºF. The emissions control systems include a fabric filter, activated carbon injection, SCR, and wet FGD.

The eventual CO_2 removal system is assumed to be a post-combustion based process, similar to today's amine scrubber (as technology develops, this selection is subject to change – as noted above, this is a fairly common development risk with projects of this type). It is expected that LP steam extraction will be needed for CO_2-rich solvent regeneration. However since the exact nature of the solvent is subject to change, it is not possible to design the LP turbine with extraction points at the appropriate steam pressure. Therefore, extraction steam is taken off at the IP/LP crossover pipe. The steam pressure at the crossover pipe is approximately double what will be needed at the reboiler, therefore there are two different approaches taken to bring steam pressure down to reboiler conditions: a letdown turbine (Cases 2B-9 and 2B-11), and a throttling valve (Cases 1B-9 and 1B-11).

There are two general design philosophies adopted for this study:

- <u>*The first approach attempts to minimize the heat rate penalty associated with retrofitting for CO_2 capture, by allowing for certain design considerations during the construction of the plant.*</u> For example, when the plant is built, extra foundations, piping, wiring and other utilities are accounted for to allow for future addition of a steam letdown turbine. When CO_2 capture is added, it is a certainty that low pressure steam extraction will be required for CO_2-rich solvent regeneration. What is unknown is what steam quality will be required; therefore it is impossible to design the LP steam turbine with the appropriate extraction ports. Instead, all process steam needs will be taken from the IP/LP crossover pipe. The steam pressure at the crossover pipe for this analysis is 170 psia, which is far greater than the 75 – 80 psia currently required by conventional amine scrubbing. This pressure difference (between the extraction pressure and steam pressure at the amine reboiler) represents a significant loss of energy that could otherwise be converted into power. Therefore, <u>*Cases 2B-9 and 2B-11 include a steam letdown turbine*</u>, which attempts to recover some of the energy that would otherwise be lost between extraction and solvent regeneration. The other factor that is considered in Cases 2B-9 and 2B-11 is the decrease in LP steam turbine efficiency after CO_2 capture retrofit. The LP turbines are designed for a certain mass flow, however upon CO_2 capture retrofit, a significant flow of LP steam will be extracted from the crossover pipe for solvent regeneration. This will drastically reduce the amount of steam flow through the LP turbine (some sources estimate up to half of the steam will be extracted), and the LP turbine efficiency will suffer drastically. Therefore, <u>*Cases 2B-9 and 2B-11 also include the addition of a clutched LP steam turbine*</u>. When retrofit occurs the clutch can be disengaged, and although the LP steam flow will be greatly reduced, the remaining LP turbine can continue to operate with no loss in efficiency (since steam flow through the remaining turbine will be roughly the same). The clutched LP steam turbine is explored in greater detail in Section B.1.1. Although these design allowances (letdown turbine and clutched LP steam turbine) are expected to minimize the heat rate penalty, there will be a significant increase in capital cost for these cases.

- *The second approach attempts to minimize capital cost associated with retrofit; however this will result in a high heat rate penalty when the retrofit occurs*. In Cases 1B-9 and 1B-11, the only additional design allowance (during initial plant construction) is a throttling valve between the steam extraction at the IP/LP crossover pipe, and the solvent regeneration reboiler. This is required to decrease the steam pressure to the conditions that will be needed at the solvent reboiler. In addition to the minimum CO_2 capture-ready requirements such as extra foundations, piping, wiring and access to utilities, the only extra capital equipment required in Cases 1B-9 and 1B-11 is the throttling valve. However, there will be a significant loss of energy due to the difference between steam pressure at the extraction point and solvent reboiler, as well as a drop in LP steam turbine efficiency due to reduced flow.

Both design philosophies are based on a given CO_2 capture system. In practice, there is risk involved with selecting a technology in the Front End Engineering and Design (FEED) study, however, for this study it is assumed that once a plant initially chooses a technology for CO_2 capture, it does not deviate. Therefore, additional "retrofit ready" costs due to removal and replacement of an original CO_2 capture technology for a new technology are not considered here.

It is also assumed that after the retrofit occurs, there is no additional generation to make up for lost power due to the new parasitic loads.

4.1 CO_2 CAPTURE-READY – RETROFIT IN YEAR 11

The cases in this section assume that the retrofit occurs over a 3 year period and will be completed at the start of the 11th year. The goal of all cases is to achieve a 30-year average CO_2 emission rate of 1,000 Lb CO_2/MWh (gross basis).

4.1.1 Case 2B-11 (Minimum Heat Rate Penalty, Retrofit in Year 11)

Case 2B-11 includes a steam letdown turbine (which recovers a portion of the energy in the steam extracted from the IP/LP crossover pipe) and clutched LP steam turbine (which helps to maintain high conversion efficiency in the LP turbine). These are shown in the block flow diagram (Exhibit 10) and accompanying stream table (Exhibit 11). Exhibit 12 and Exhibit 13 provide the capital and O&M costs for this case.

All cases in this analysis are required to maintain an average 30-year CO_2 emission rate of 1,000 Lb CO_2/MWh (gross basis). Since CO_2 capture will not begin until the start of the 11th year, a capture rate of

65% is required to satisfy the long-term average of 1,000 Lb CO_2/MWh. This is also shown graphically in Exhibit 9.

Exhibit 8 - Case 2B-11 Performance Summary

Plant Output		
Steam Turbine Power	486,500	kW
Letdown Steam Turbine	22,900	kW
Gross Power	**509,400**	**kW**
Auxiliary Load		
Coal Handling and Conveying	440	kW
Pulverizers	2,790	kW
Sorbent Handling & Reagent Prep	890	kW
Ash Handling	530	kW
Primary Air Fans	1,310	kW
Forced Draft Fans	1,670	kW
Induced Draft Fans	7,050	kW
SCR	50	kW
Baghouse	70	kW
Wet FGD	2,980	kW
CO_2 Scrubber Auxiliaries	10,800	kW
CO_2 Compression	28,280	kW
Miscellaneous Balance of Plant	2,000	kW
Steam Turbine Auxiliaries	400	kW
Condensate Pumps	530	kW
Circulating Water Pumps	6,130	kW
Ground Water Pumps	620	kW
Cooling Tower Fans	3,170	kW
Transformer Losses	1,650	kW
Total	**71,360**	kW
Net Power	438,040	kW
Net Plant Efficiency (HHV)	31.2%	
Net Plant Heat Rate (HHV)	10,919	Btu/kWh
Coal Feedrate	410,000	Lb/hr
Percent CO_2 Capture	65%	
CO_2 Emission Rate	669	Lb CO_2/MWh

Exhibit 9 - Case 2B-11 30-Year Average CO_2 Emission Rate

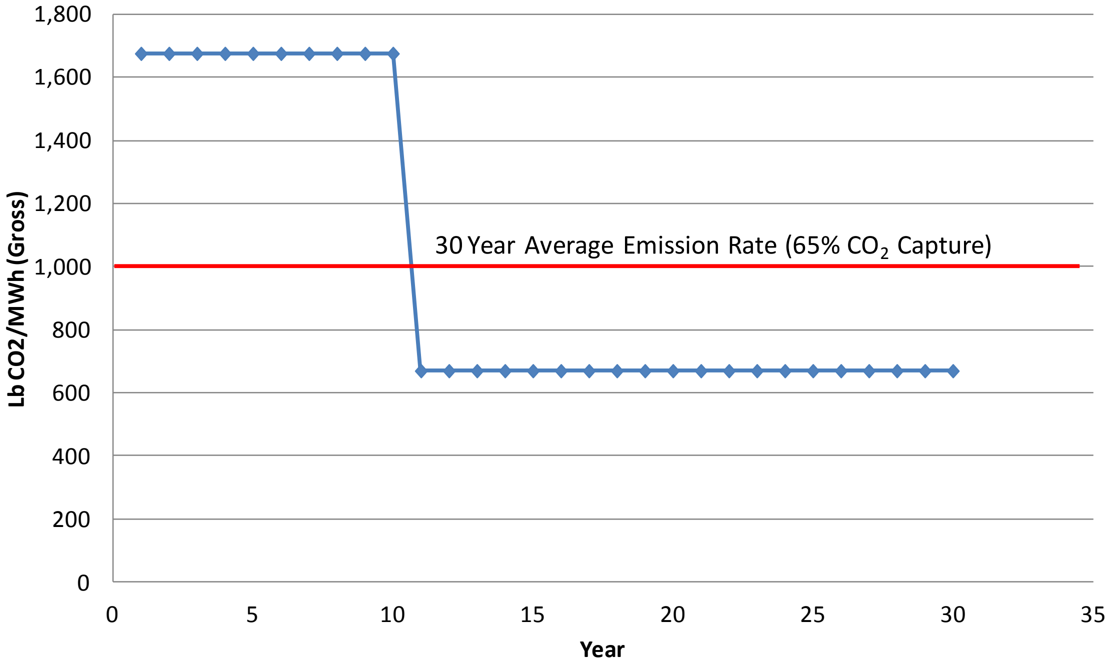
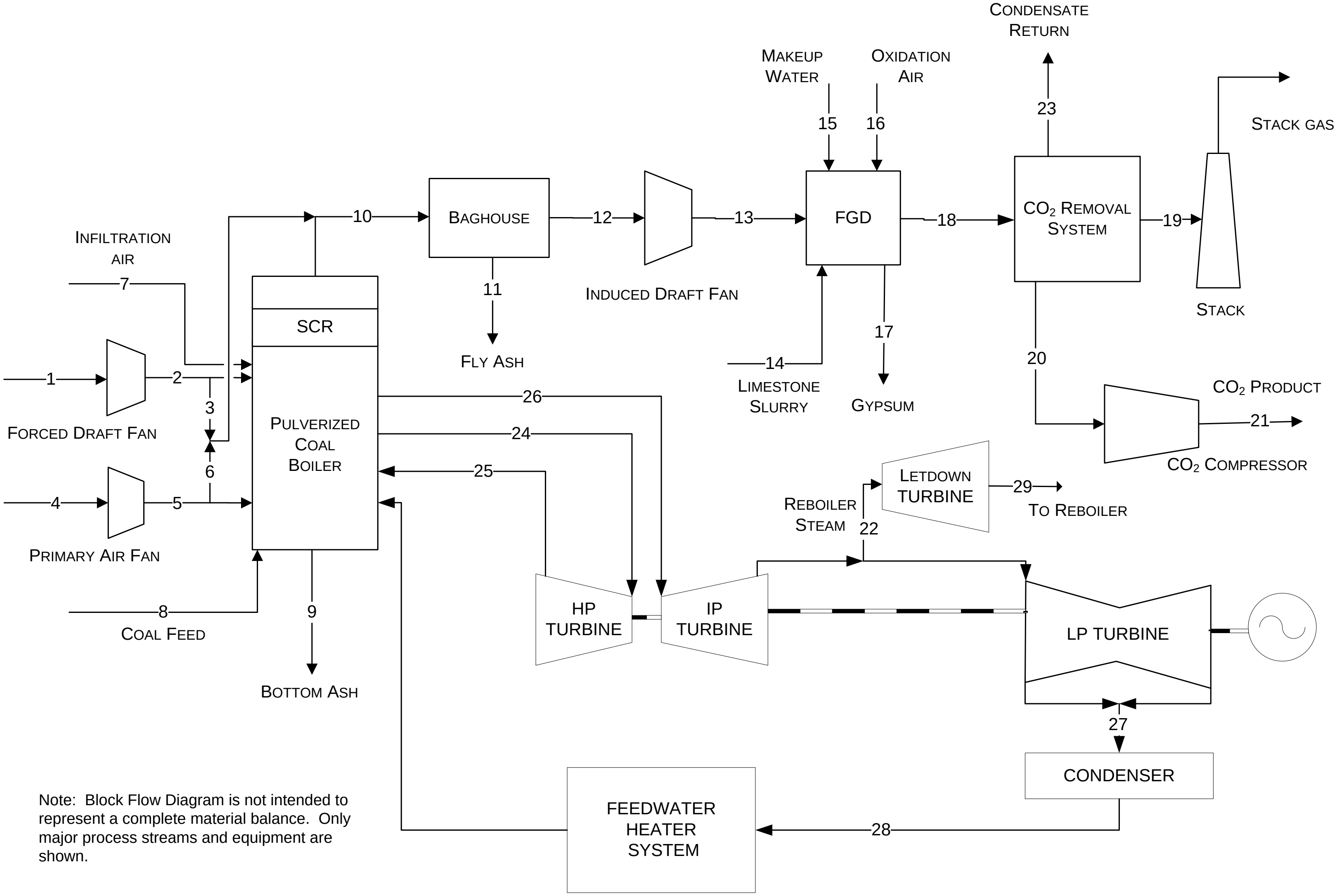


Exhibit 10 - Case 2B-11 Block Flow Diagram



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 11 - Case 2B-11 Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870	1.0000	1.0000
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324	0.0000	0.0000
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	106,836	106,836	3,162	32,819	32,819	4,516	2,469	0	0	150,337	0	150,337	150,337	5,073	54,788
V-L Flowrate (lb/hr)	3,082,950	3,082,950	91,255	947,050	947,050	130,314	71,257	0	0	4,471,500	0	4,471,500	4,471,500	91,399	987,024
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	410,000	7,951	31,806	31,806	0	0	40,693	0
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337	357	59	59
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2	15.3	15.0	14.7
Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.8	---	132.8	138.0	---	-20.1
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049	0.052	---	62.622

A - Reference conditions are 32.02 F & 0.089 PSIA

	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V-L Mole Fraction														
Ar	0.0128	0.0000	0.0082	0.0090	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0005	0.0004	0.1353	0.0519	1.0000	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0062	0.9995	0.1517	0.1664	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7506	0.0000	0.6808	0.7465	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2300	0.0000	0.0240	0.0263	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	1,602	388	163,500	149,115	14,378	14,378	51,102	51,102	204,618	166,412	166,412	103,499	103,499	51,102
V-L Flowrate (lb/hr)	46,519	6,993	4,717,795	4,084,593	632,792	632,792	920,614	920,614	3,686,253	2,997,953	2,997,953	1,864,570	1,864,570	920,614
Solids Flowrate (lb/hr)	0	63,332	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	333	135	135	135	198	80	737	300	1,100	669	1,100	101	103	554
Pressure (psia)	45.0	14.8	14.8	14.8	70.4	2,214.5	170.0	150.0	3,514.7	710.8	655.8	1.0	245.0	75.0
Enthalpy (Btu/lb)[A]	76.4	---	128.0	132.6	33.0	-100.7	1,394.0	269.5	1,494.7	1,325.4	1,570.2	860.1	71.8	1,307.7
Density (lb/ft^3)	0.154	---	0.067	0.065	0.445	43.314	0.243	57.318	4.319	1.164	0.722	0.004	62.001	0.126

Exhibit 12 – Case 2B-11 Capital Cost Summary

	Case:	2B-11 SuperCritical PC with Clutch Turbine and LDT - Capture Ready Retrofitted for 65% Capture Design										
	Plant Size:	438.0 MW,net		Estimate Type: Conceptual				Cost Base (Jun) 2011		($x1000)		
Acct No.	**Item/Description**	**Equipment Cost**	**Material Cost**	**Labor Direct**	**Labor Indirect**	**Sales Tax**	**Bare Erected Cost $**	**Eng'g CM H.O.& Fee**	**Contingencies Process**	**Contingencies Project**	**TOTAL PLANT COST $**	**TOTAL PLANT COST $/kW**
1	COAL & SORBENT HANDLING	$19,885	$5,077	$11,756	$0	$0	**$36,718**	$3,221	$0	$5,991	**$45,929**	$105
2	COAL & SORBENT PREP & FEED	$13,363	$742	$3,344	$0	$0	**$17,448**	$1,483	$0	$2,840	**$21,772**	$50
3	FEEDWATER & MISC. BOP SYSTEMS	$51,619	$0	$23,897	$0	$0	**$75,516**	$6,705	$0	$13,361	**$95,581**	$218
4	PC BOILER											
4.1	PC Boiler & Accessories	$185,402	$0	$105,641	$0	$0	**$291,043**	$28,011	$0	$31,905	**$350,959**	$801
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$185,402**	**$0**	**$105,641**	**$0**	**$0**	**$291,043**	**$28,011**	**$0**	**$31,905**	**$350,959**	**$801**
5	FLUE GAS CLEANUP	$96,010	$0	$32,384	$0	$0	**$128,395**	$11,972	$0	$14,037	**$154,404**	$352
5B	CO2 REMOVAL & COMPRESSION	$223,816	$0	$70,322	$0	$0	**$294,138**	$27,408	$51,536	$74,616	**$447,698**	$1,022
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Accessories	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$23,575	$1,378	$15,646	$0	$0	**$40,599**	$3,620	$0	$5,842	**$50,060**	$114
	SUBTOTAL 7	**$23,575**	**$1,378**	**$15,646**	**$0**	**$0**	**$40,599**	**$3,620**	**$0**	**$5,842**	**$50,060**	**$114**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$68,306	$0	$8,426	$0	$0	**$76,732**	$6,737	$0	$8,347	**$91,816**	$210
8.5	Let Down Turbine	$37,134	$0	$4,581	$0	$0	**$41,715**	$3,662	$0	$4,538	**$49,915**	$114
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$33,287	$1,310	$16,835	$0	$0	**$51,432**	$4,209	$0	$7,869	**$63,510**	$145
	SUBTOTAL 8	**$138,727**	**$1,310**	**$29,842**	**$0**	**$0**	**$169,879**	**$14,608**	**$0**	**$20,753**	**$205,240**	**$469**
9	COOLING WATER SYSTEM	$16,134	$8,342	$14,525	$0	$0	**$39,000**	$3,570	$0	$5,759	**$48,329**	$110
10	ASH/SPENT SORBENT HANDLING SYS	$5,436	$161	$7,058	$0	$0	**$12,654**	$1,177	$0	$1,422	**$15,254**	$35
11	ACCESSORY ELECTRIC PLANT	$27,429	$11,386	$30,760	$0	$0	**$69,574**	$5,993	$0	$9,442	**$85,009**	$194
12	INSTRUMENTATION & CONTROL	$11,679	$0	$11,713	$0	$0	**$23,393**	$2,066	$0	$3,138	**$28,597**	$65
13	IMPROVEMENTS TO SITE	$3,857	$2,217	$8,269	$0	$0	**$14,344**	$1,423	$0	$3,153	**$18,921**	$43
14	BUILDINGS & STRUCTURES	$0	$28,325	$26,832	$0	$0	**$55,156**	$4,871	$0	$9,004	**$69,031**	$158
	TOTAL COST	**$816,931**	**$58,937**	**$391,989**	**$0**	**$0**	**$1,267,857**	**$116,127**	**$51,536**	**$201,264**	**$1,636,783**	**$3,737**
	Total Overnight Costs (TOC)										**$2,020,478**	**$4,613**

Exhibit 13 – Case 2B-11 O&M Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2011
2B-11 SuperCritical PC with Clutch Turbine and LDT - Capture Ready Retrofitted for 65% Capture De:					Heat Rate-net (Btu/kWh):	10,919
Retrofitted CO2 Removal 65%					MWe-net:	438
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	39.70	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Total Plant			
Skilled Operator	2.0		2.0			
Operator	11.3		11.3			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	16.3		16.3			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$7,384,208	$16.857
Maintenance Labor Cost					$10,658,218	$24.332
Administrative & Support Labor					$4,510,607	$10.297
Property Taxes and Insurance					$32,735,665	$74.732
TOTAL FIXED OPERATING COSTS					**$55,288,698**	**$126.218**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$15,987,328**	**$0.00521**
Consumables	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Fill Cost		
Water (/1000 gallons)	0	4,938	1.67	**$0**	**$2,413,960**	**$0.00079**
Chemicals						
MU & WT Chem.(lbs)	0	23,905	0.27	$0	$1,869,618	$0.00061
Limestone (ton)	0	488	33.48	$0	$4,768,288	$0.00155
Carbon (Mercury Removal) (lb)	0	0.00	1.63	$0	$0	$0.00000
MEA Solvent (ton)	537	1	3,481.91	$1,869,754	$774,107	$0.00025
NaOH (tons)	38	4	671.16	$25,458	$743,380	$0.00024
H2SO4 (tons)	36	4	214.78	$7,774	$227,015	$0.00007
Corrosion Inhibitor	0	0	0.00	$74,276	**$3,537**	$0.00000
Activated Carbon (lb)	0	910	1.63	$0	**$431,622**	$0.00014
Ammonia (19% NH3) ton	0	73.52	330.00	$0	$7,084,773	$0.00231
Subtotal Chemicals				**$1,977,263**	**$15,902,339**	**$0.00518**
Other						
Supplemental Fuel (MBtu)	0	0.00	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.31	8,938.80	$0	$806,639	$0.00026
Emission Penalties	0	0.00	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$806,639**	**$0.00026**
Waste Disposal						
Fly Ash (ton)	0	381	25.11	$0	$2,795,191	$0.00091
Bottom Ash (ton)	0	95	25.11	$0	$698,798	$0.00023
Subtotal-Waste Disposal				**$0**	**$3,493,989**	**$0.00114**
By-products & Emissions						
Gypsum (tons)	0	759	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$1,977,263**	**$38,604,255**	**$0.01258**
Fuel (ton)	0	4,920	63.58	**$0**	**$91,341,571**	**$0.02976**

4.1.2 Case 1B-11 (Minimum Capital Cost, Retrofit in Year 11)

Case 1B-11 includes a throttling valve to decrease the pressure from the conditions at the IP/LP crossover pipe (170 psia) to what is required for the steam reboiler (75 psia). These are shown in the block flow diagram (Exhibit 16) and accompanying stream table (Exhibit 17). Exhibit 18 and Exhibit 19 provide the Capital and O&M costs for this case.

All cases in this analysis are required to maintain an average 30-year CO_2 emission rate of 1,000 Lb CO_2/MWh (gross basis). Since CO_2 capture will not begin until the start of the 11th year, a capture rate of 70% is required to satisfy the long-term average of 1,000 Lb CO_2/MWh. This is also shown graphically in Exhibit 15.

Exhibit 14 - Case 1B-11 Performance Summary

Plant Output		
Steam Turbine Power	440,050	kW
Gross Power	**440,050**	**kW**
Auxiliary Load		
Coal Handling and Conveying	440	kW
Pulverizers	2,790	kW
Sorbent Handling & Reagent Prep	890	kW
Ash Handling	530	kW
Primary Air Fans	1,310	kW
Forced Draft Fans	1,670	kW
Induced Draft Fans	7,050	kW
SCR	50	kW
Baghouse	70	kW
Wet FGD	2,980	kW
CO_2 Scrubber Auxiliaries	11,600	kW
CO_2 Compression	30,450	kW
Miscellaneous Balance of Plant	2,000	kW
Steam Turbine Auxiliaries	400	kW
Condensate Pumps	540	kW
Circulating Water Pumps	6,490	kW
Ground Water Pumps	650	kW
Cooling Tower Fans	3,360	kW
Transformer Losses	1,520	kW
Total	**74,790**	kW
Net Power	365,710	kW
Net Plant Efficiency (HHV)	26.1%	

Net Plant Heat Rate (HHV)	13,079	Btu/kWh
Coal Feedrate	410,000	Lb/hr
Percent CO_2 Capture	70%	
CO_2 Emission Rate	663	Lb CO_2/MWh

Exhibit 15 - Case 1B-11 30-Year Average CO_2 Emission Rate

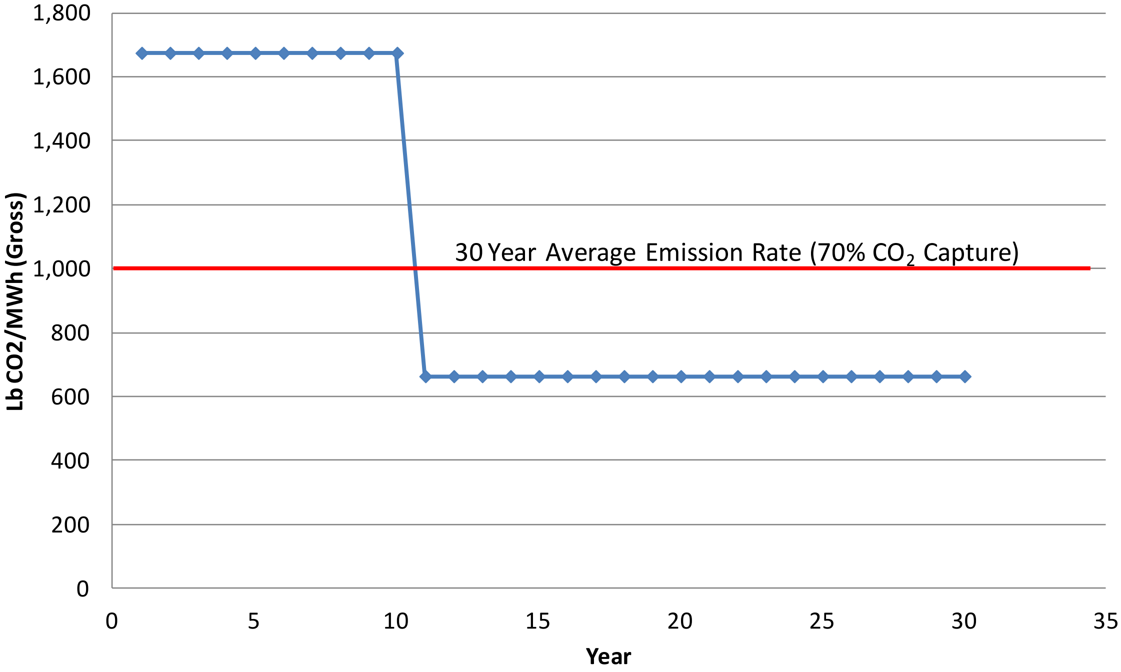
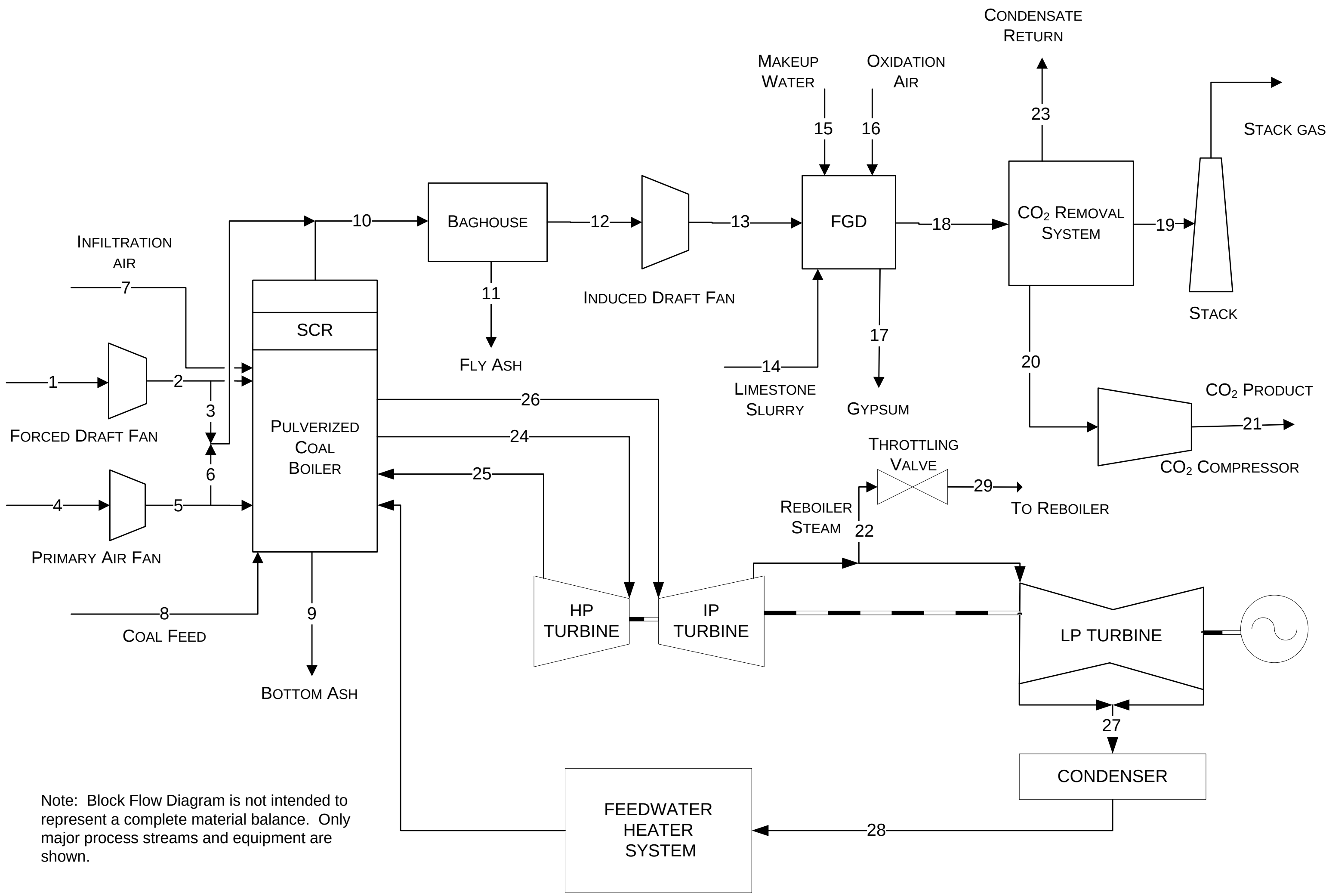


Exhibit 16 - Case 1B-11 Block Flow Diagram



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 17 - Case 1B-11 Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870	1.0000	1.0000
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324	0.0000	0.0000
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	106,836	106,836	3,162	32,819	32,819	4,516	2,469	0	0	150,337	0	150,337	150,337	5,073	54,788
V-L Flowrate (lb/hr)	3,082,950	3,082,950	91,255	947,050	947,050	130,314	71,257	0	0	4,471,500	0	4,471,500	4,471,500	91,399	987,024
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	410,000	7,951	31,806	31,806	0	0	40,693	0
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337	357	59	59
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2	15.3	15.0	14.7
Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.8	---	132.8	138.0	---	-20.1
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049	0.052	---	62.622

A - Reference conditions are 32.02 F & 0.089 PSIA

	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V-L Mole Fraction														
Ar	0.0128	0.0000	0.0082	0.0090	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0005	0.0004	0.1353	0.0448	1.0000	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0062	0.9995	0.1517	0.1676	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7506	0.0000	0.6808	0.7521	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2300	0.0000	0.0240	0.0265	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	1,602	388	163,500	148,009	15,484	15,484	50,785	50,785	204,618	166,412	166,412	103,841	103,841	50,785
V-L Flowrate (lb/hr)	46,519	6,993	4,717,795	4,035,916	681,468	681,468	914,902	914,902	3,686,253	2,997,953	2,997,953	1,870,723	1,870,723	914,902
Solids Flowrate (lb/hr)	0	63,332	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	333	135	135	135	198	80	737	300	1,100	669	1,100	101	103	728
Pressure (psia)	45.0	14.8	14.8	14.8	70.4	2,214.5	170.0	150.0	3,514.7	710.8	655.8	1.0	245.0	75.0
Enthalpy (Btu/lb)[A]	76.4	---	128.0	133.0	33.0	-100.7	1,394.0	269.5	1,494.7	1,325.4	1,570.2	946.8	71.8	1,394.0
Density (lb/ft^3)	0.154	---	0.067	0.064	0.445	43.314	0.243	57.318	4.319	1.164	0.722	0.003	62.001	0.107

Exhibit 18 – Case 1B-11 Capital Cost Summary

Case: 1B-11 SuperCritical PC with Throttling Valve - Capture Ready Retrofitted for 70% Capture Design
Plant Size: 365.7 MW,net Estimate Type: Conceptual **Cost Base (Jun)** 2011 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$19,885	$5,077	$11,756	$0	$0	**$36,718**	$3,221	$0	$5,991	**$45,929**	$126
2	COAL & SORBENT PREP & FEED	$13,363	$742	$3,344	$0	$0	**$17,448**	$1,483	$0	$2,840	**$21,772**	$60
3	FEEDWATER & MISC. BOP SYSTEMS	$51,664	$0	$23,917	$0	$0	**$75,582**	$6,711	$0	$13,375	**$95,668**	$262
4	PC BOILER											
4.1	PC Boiler & Accessories	$185,402	$0	$105,641	$0	$0	**$291,043**	$28,011	$0	$31,905	**$350,959**	$960
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$185,402**	**$0**	**$105,641**	**$0**	**$0**	**$291,043**	**$28,011**	**$0**	**$31,905**	**$350,959**	**$960**
5	FLUE GAS CLEANUP	$96,010	$0	$32,384	$0	$0	**$128,395**	$11,972	$0	$14,037	**$154,404**	$422
5B	CO2 REMOVAL & COMPRESSION	$226,464	$0	$71,308	$0	$0	**$297,773**	$27,747	$51,827	$75,469	**$452,816**	$1,238
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Accessories	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$21,621	$1,264	$14,349	$0	$0	**$37,234**	$3,320	$0	$5,358	**$45,912**	$126
	SUBTOTAL 7	**$21,621**	**$1,264**	**$14,349**	**$0**	**$0**	**$37,234**	**$3,320**	**$0**	**$5,358**	**$45,912**	**$126**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$66,640	$0	$8,221	$0	$0	**$74,861**	$6,572	$0	$8,143	**$89,576**	$245
8.5	Let Down Turbine	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$30,566	$1,248	$15,488	$0	$0	**$47,302**	$3,888	$0	$7,196	**$58,386**	$160
	SUBTOTAL 8	**$97,206**	**$1,248**	**$23,709**	**$0**	**$0**	**$122,162**	**$10,460**	**$0**	**$15,339**	**$147,962**	**$405**
9	COOLING WATER SYSTEM	$16,969	$8,779	$15,273	$0	$0	**$41,022**	$3,755	$0	$6,057	**$50,834**	$139
10	ASH/SPENT SORBENT HANDLING SYS	$5,436	$161	$7,058	$0	$0	**$12,654**	$1,177	$0	$1,422	**$15,254**	$42
11	ACCESSORY ELECTRIC PLANT	$25,515	$10,591	$28,614	$0	$0	**$64,720**	$5,575	$0	$8,783	**$79,078**	$216
12	INSTRUMENTATION & CONTROL	$10,865	$0	$10,896	$0	$0	**$21,761**	$1,922	$0	$2,919	**$26,602**	$73
13	IMPROVEMENTS TO SITE	$3,674	$2,112	$7,876	$0	$0	**$13,661**	$1,355	$0	$3,003	**$18,020**	$49
14	BUILDINGS & STRUCTURES	$0	$27,262	$25,842	$0	$0	**$53,104**	$4,690	$0	$8,669	**$66,462**	$182
	TOTAL COST	**$774,074**	**$57,235**	**$381,968**	**$0**	**$0**	**$1,213,277**	**$111,400**	**$51,827**	**$195,168**	**$1,571,671**	**$4,298**
	Total Overnight Costs (TOC)										**$1,942,132**	**$5,311**

Exhibit 19 – Case 1B-11 O&M Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2011
1B-11 SuperCritical PC with Throttling Valve - Capture Ready Retrofitted for 70% Capture Desigı					Heat Rate-net (Btu/kWh):	13,079
Retrofitted CO2 Remo 70%					MWe-net:	365.71
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	39.70	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Total Plant			
Skilled Operator	2.0		2.0			
Operator	11.3		11.3			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	16.3		16.3			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$7,384,208	$20.191
Maintenance Labor Cost					$10,234,230	$27.985
Administrative & Support Labor					$4,404,610	$12.044
Property Taxes and Insurance					$31,433,428	$85.952
TOTAL FIXED OPERATING COSTS					**$53,456,476**	**$146.172**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$15,351,346**	**$0.00599**
Consumables	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Fill Cost		
Water (/1000 gallons)	0	5,209	1.67	**$0**	**$2,546,290**	**$0.00099**
Chemicals						
MU & WT Chem.(lbs)	0	25,216	0.27	$0	$1,972,108	$0.00077
Limestone (ton)	0	488	33.48	$0	$4,768,288	$0.00186
Carbon (Mercury Removal) (lb)	0	0.00	1.63	$0	$0	$0.00000
MEA Solvent (ton)	578	1	3,481.91	$2,013,581	$833,654	$0.00033
NaOH (tons)	41	4	671.16	$27,417	$800,563	$0.00031
H2SO4 (tons)	39	4	214.78	$8,373	$244,477	$0.00010
Corrosion Inhibitor	0	0	0.00	$79,990	**$3,809**	$0.00000
Activated Carbon (lb)	0	979	1.63	$0	**$464,823**	$0.00018
Ammonia (19% NH3) ton	0	73.52	330.00	$0	$7,084,773	$0.00276
Subtotal Chemicals				**$2,129,360**	**$16,172,495**	**$0.00631**
Other						
Supplemental Fuel (MBtu)	0	0.00	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.31	8,938.80	$0	$806,639	$0.00031
Emission Penalties	0	0.00	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$806,639**	**$0.00031**
Waste Disposal						
Fly Ash (ton)	0	381	25.11	$0	$2,795,191	$0.00109
Bottom Ash (ton)	0	95	25.11	$0	$698,798	$0.00027
Subtotal-Waste Disposal				**$0**	**$3,493,989**	**$0.00136**
By-products & Emissions						
Gypsum (tons)	0	759	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$2,129,360**	**$38,370,759**	**$0.01497**
Fuel (ton)	0	4,920	63.58	**$0**	**$91,341,571**	**$0.03564**

4.2 CO_2 CAPTURE-READY – RETROFIT IN YEAR 9

The cases in this section assume that the retrofit will occur over a 3 year period with CO_2 capture beginning in the 9th year of plant operation. This analysis assumes that the initial CO_2 capture rate will be 20% during the 9th year, and 40% during the 10th. At the start of the 11th year, the capture rate will be the level required to achieve a 30-year average CO_2 emission rate of 1,000 Lb CO_2/MWh (gross basis).

4.2.1 Case 2B-9 (Minimum Heat Rate Penalty, Retrofit in Year 9)

Case 2B-9 includes a steam letdown turbine (which recovers a portion of the energy in the steam extracted from the IP/LP crossover pipe) and clutched LP steam turbine (which helps to maintain high conversion efficiency in the LP turbine). These are shown in the block flow diagram (Exhibit 22) and accompanying stream table (Exhibit 23). Exhibit 24 and Exhibit 25 provide the capital and O&M costs for this case.

Since the CO_2 capture rate slowly increases between the 9th and 11th year, the plant performance is continuously changing during this period. By the 11th year, the CO_2 capture rate, and therefore plant performance, reaches the level that it will hold for the remainder of the 30-year period. The performance summary during years 9, 10, and 11 is shown in Exhibit 20.

The 30-year average emission rate for Case 2B-9 is 1,000 Lb CO_2/MWh (gross basis). This includes the reduced degree of capture that takes place in the 9th and 10th years. This is also shown graphically in Exhibit 21.

Exhibit 20 - Case 2B-9 Performance Summary

Plant Output				
Year	9	10	11	
Steam Turbine Power	550,400	522,000	489,300	kW
Letdown Steam Turbine	7,100	14,100	22,200	kW
Gross Power	**557,500**	**536,100**	**511,500**	**kW**
Auxiliary Load				
Coal Handling and Conveying	440	440	440	kW
Pulverizers	2,790	2,790	2,790	kW
Sorbent Handling & Reagent Prep	890	890	890	kW
Ash Handling	530	530	530	kW
Primary Air Fans	1,310	1,310	1,310	kW
Forced Draft Fans	1,670	1,670	1,670	kW
Induced Draft Fans	7,050	7,050	7,050	kW
SCR	50	50	50	kW
Baghouse	70	70	70	kW
Wet FGD	2,980	2,980	2,980	kW
CO_2 Scrubber Auxiliaries	3,300	6,600	10,400	kW
CO_2 Compression	8,750	17,400	27,410	kW
Miscellaneous Balance of Plant	2,000	2,000	2,000	kW
Steam Turbine Auxiliaries	400	400	400	kW
Condensate Pumps	720	640	540	kW
Circulating Water Pumps	5,170	5,600	6,090	kW
Ground Water Pumps	530	570	620	kW
Cooling Tower Fans	2,680	2,900	3,150	kW
Transformer Losses	1,760	1,710	1,660	kW
Total	**43,090**	**55,600**	**70,050**	kW
Net Power	514,410	480,500	441,450	kW
Net Plant Efficiency (HHV)	36.7%	34.3%	31.5%	
Net Plant Heat Rate (HHV)	9,298	9,954	10,835	Btu/kWh
Coal Feedrate	410,000	410,000	410,000	Lb/hr
Percent CO_2 Capture	20%	40%	63%	
CO_2 Emission Rate	1,397	1,089	704	Lb CO_2/MWh

Exhibit 21 - Case 2B-9 30-Year Average CO_2 Emission Rate

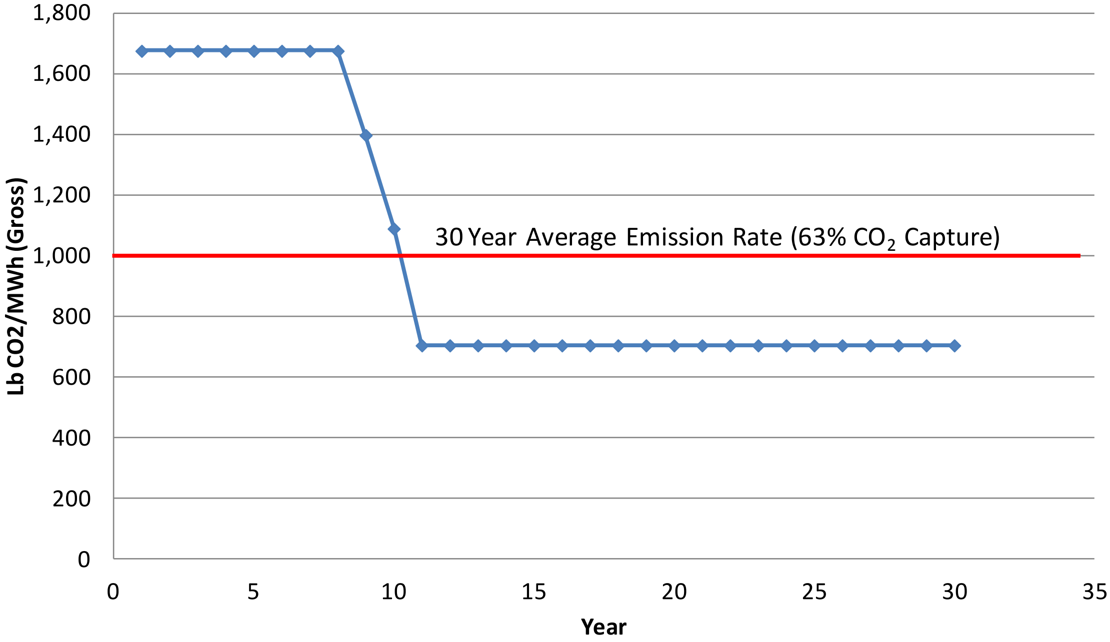
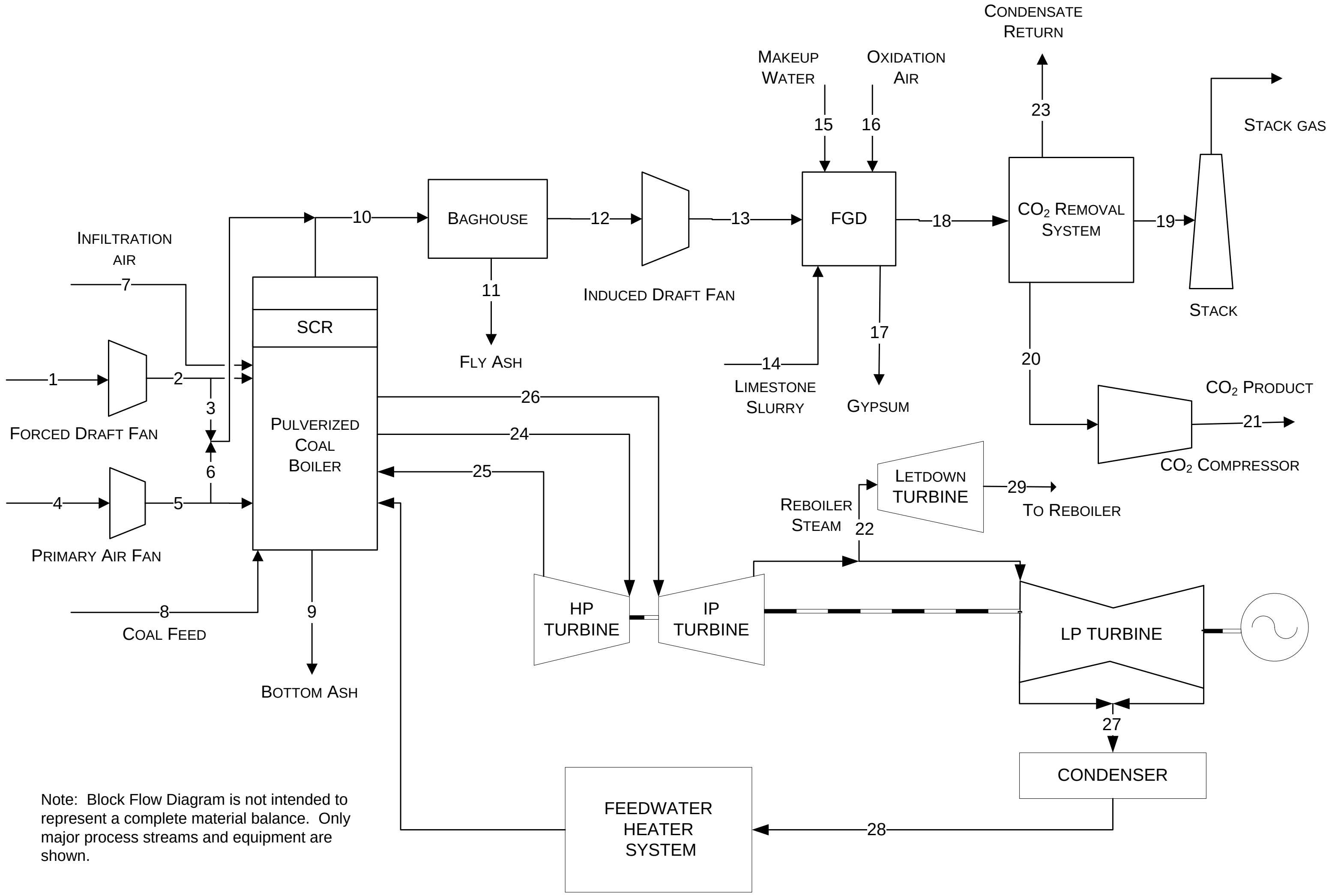


Exhibit 22 - Case 2B-9 Block Flow Diagram



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 23 Case 2B-9 Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870	1.0000	1.0000
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324	0.0000	0.0000
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	106,836	106,836	3,162	32,819	32,819	4,516	2,469	0	0	150,337	0	150,337	150,337	5,073	54,788
V-L Flowrate (lb/hr)	3,082,950	3,082,950	91,255	947,050	947,050	130,314	71,257	0	0	4,471,500	0	4,471,500	4,471,500	91,399	987,024
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	410,000	7,951	31,806	31,806	0	0	40,693	0
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337	357	59	59
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2	15.3	15.0	14.7
Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.8	---	132.8	138.0	---	-20.1
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049	0.052	---	62.622

A - Reference conditions are 32.02 F & 0.089 PSIA

	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V-L Mole Fraction														
Ar	0.0128	0.0000	0.0082	0.0089	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0005	0.0004	0.1353	0.0547	1.0000	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0062	0.9995	0.1517	0.1659	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7506	0.0000	0.6808	0.7443	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2300	0.0000	0.0240	0.0262	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	1,602	388	163,500	149,558	13,936	13,936	49,530	49,530	204,618	166,412	166,412	105,072	105,072	49,530
V-L Flowrate (lb/hr)	46,519	6,993	4,717,795	4,104,063	613,321	613,321	892,288	892,288	3,686,253	2,997,953	2,997,953	1,892,896	1,892,896	892,288
Solids Flowrate (lb/hr)	0	63,332	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	333	135	135	135	198	80	737	300	1,100	669	1,100	101	103	554
Pressure (psia)	45.0	14.8	14.8	14.8	70.4	2,214.5	170.0	150.0	3,514.7	710.8	655.8	1.0	245.0	75.0
Enthalpy (Btu/lb)[A]	76.4	---	128.0	132.4	33.0	-100.7	1,394.0	269.5	1,494.7	1,325.4	1,570.2	859.9	71.8	1,307.7
Density (lb/ft^3)	0.154	---	0.067	0.065	0.445	43.314	0.243	57.318	4.319	1.164	0.722	0.004	62.001	0.126

Exhibit 24 – Case 2B-9 Capital Cost Summary

	Case:	2B-9 SuperCritical PC with Clutch Turbine and LDT - Capture Ready Retrofitted for 63% Capture Design										
	Plant Size:	441.5 MW,net		Estimate Type: Conceptual				Cost Base (Jun) 2011		($x1000)		
Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL & SORBENT HANDLING	$19,885	$5,077	$11,756	$0	$0	**$36,718**	$3,221	$0	$5,991	**$45,929**	$104
2	COAL & SORBENT PREP & FEED	$13,363	$742	$3,344	$0	$0	**$17,448**	$1,483	$0	$2,840	**$21,772**	$49
3	FEEDWATER & MISC. BOP SYSTEMS	$51,619	$0	$23,897	$0	$0	**$75,516**	$6,705	$0	$13,361	**$95,581**	$217
4	PC BOILER											
4.1	PC Boiler & Accessories	$185,402	$0	$105,641	$0	$0	**$291,043**	$28,011	$0	$31,905	**$350,959**	$795
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$185,402**	**$0**	**$105,641**	**$0**	**$0**	**$291,043**	**$28,011**	**$0**	**$31,905**	**$350,959**	**$795**
5	FLUE GAS CLEANUP	$96,010	$0	$32,384	$0	$0	**$128,395**	$11,972	$0	$14,037	**$154,404**	$350
5B	CO2 REMOVAL & COMPRESSION	$222,773	$0	$69,932	$0	$0	**$292,704**	$27,274	$51,425	$74,281	**$445,684**	$1,010
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Accessories	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$23,767	$1,389	$15,751	$0	$0	**$40,907**	$3,648	$0	$5,884	**$50,439**	$114
	SUBTOTAL 7	**$23,767**	**$1,389**	**$15,751**	**$0**	**$0**	**$40,907**	**$3,648**	**$0**	**$5,884**	**$50,439**	**$114**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$68,306	$0	$8,426	$0	$0	**$76,732**	$6,737	$0	$8,347	**$91,816**	$208
8.5	Let Down Turbine	$36,111	$0	$4,455	$0	$0	**$40,565**	$3,561	$0	$4,413	**$48,539**	$110
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$33,557	$1,310	$16,955	$0	$0	**$51,823**	$4,239	$0	$7,932	**$63,994**	$145
	SUBTOTAL 8	**$137,974**	**$1,310**	**$29,836**	**$0**	**$0**	**$169,120**	**$14,537**	**$0**	**$20,692**	**$204,349**	**$463**
9	COOLING WATER SYSTEM	$16,075	$8,311	$14,472	$0	$0	**$38,858**	$3,557	$0	$5,738	**$48,152**	$109
10	ASH/SPENT SORBENT HANDLING SYS	$5,436	$161	$7,058	$0	$0	**$12,654**	$1,177	$0	$1,422	**$15,254**	$35
11	ACCESSORY ELECTRIC PLANT	$27,392	$11,349	$30,663	$0	$0	**$69,404**	$5,978	$0	$9,417	**$84,799**	$192
12	INSTRUMENTATION & CONTROL	$11,658	$0	$11,692	$0	$0	**$23,349**	$2,062	$0	$3,132	**$28,544**	$65
13	IMPROVEMENTS TO SITE	$3,857	$2,217	$8,269	$0	$0	**$14,344**	$1,423	$0	$3,153	**$18,921**	$43
14	BUILDINGS & STRUCTURES	$0	$28,324	$26,831	$0	$0	**$55,156**	$4,871	$0	$9,004	**$69,030**	$156
	TOTAL COST	**$815,210**	**$58,879**	**$391,526**	**$0**	**$0**	**$1,265,616**	**$115,918**	**$51,425**	**$200,857**	**$1,633,816**	**$3,701**
	Total Overnight Costs (TOC)										**$2,016,809**	**$4,569**

Exhibit 25 – Case 2B-9 O&M Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2011
2B-9 SuperCritical PC with Clutch Turbine and LDT - Capture Ready Retrofitted for 63% Capture Des					Heat Rate-net (Btu/kWh):	10,835
Retrofitted CO2 Removal 63%					MWe-net:	441
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	39.70	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Plant			
Skilled Operator	2.0		2.0			
Operator	11.3		11.3			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	16.3		16.3			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost					$7,384,208	$16.727
Maintenance Labor Cost					$10,638,899	$24.100
Administrative & Support Labor					$4,505,777	$10.207
Property Taxes and Insurance					$32,676,327	$74.020
TOTAL FIXED OPERATING COSTS					**$55,205,210**	**$125.054**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$15,958,348**	**$0.00516**
Consumables	Consumption		Unit	Initial Fill		
	Initial Fill	/Day	Cost	Cost		
Water (/1000 gallons)	0	4,907	1.67	**$0**	**$2,398,475**	**$0.00078**
Chemicals						
MU & WT Chem.(lbs)	0	23,752	0.27	$0	$1,857,624	$0.00060
Limestone (ton)	0	488	33.48	$0	$4,768,288	$0.00154
Carbon (Mercury Removal) (lb)	0	0.00	1.63	$0	$0	$0.00000
MEA Solvent (ton)	520	1	3,481.91	$1,812,223	$750,289	$0.00024
NaOH (tons)	37	4	671.16	$24,675	$720,507	$0.00023
H2SO4 (tons)	35	4	214.78	$7,535	$220,029	$0.00007
Corrosion Inhibitor	0	0	0.00	$71,991	**$3,428**	$0.00000
Activated Carbon (lb)	0	882	1.63	$0	**$418,341**	$0.00014
Ammonia (19% NH3) ton	0	73.52	330.00	$0	$7,084,773	$0.00229
Subtotal Chemicals				**$1,916,424**	**$15,823,279**	**$0.00511**
Other						
Supplemental Fuel (MBtu)	0	0.00	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.31	8,938.80	$0	$806,639	$0.00026
Emission Penalties	0	0.00	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$806,639**	**$0.00026**
Waste Disposal						
Fly Ash (ton)	0	381	25.11	$0	$2,795,191	$0.00090
Bottom Ash (ton)	0	95	25.11	$0	$698,798	$0.00023
Subtotal-Waste Disposal				**$0**	**$3,493,989**	**$0.00113**
By-products & Emissions						
Gypsum (tons)	0	759	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$1,916,424**	**$38,480,730**	**$0.01244**
Fuel (ton)	0	4,920	63.58	**$0**	**$91,341,571**	**$0.02953**

4.2.2 Case 1B-9 (Minimum Capital Cost, Retrofit in Year 9)

Case 1B-9 includes a throttling valve to decrease the pressure from the conditions at the IP/LP crossover pipe (170 psia) to what is required for the steam reboiler (75 psia). These are shown in the block flow diagram (Exhibit 28) and accompanying stream table (Exhibit 29). Exhibit 30 and Exhibit 31 provide the capital and O&M costs for this case.

Since the CO_2 capture rate slowly increases between the 9th and 11th year, the plant performance is continuously changing during this period. By the 11th year, the CO_2 capture rate, and therefore plant performance, reaches the level that it will hold for the remainder of the 30-year period. The performance summary during years 9, 10, and 11 is shown in Exhibit 26.

The 30-year average emission rate for Case 1B-9 is 1,000 Lb CO_2/MWh (gross basis). This includes the reduced degree of capture that takes place in the 9th and 10th years. This is also shown graphically in Exhibit 27.

Exhibit 26 Case 1B-9 Performance Summary

Plant Output				
Year	9	10	11	
Steam Turbine Power	487,400	468,600	441,600	kW
Gross Power	**487,400**	**468,600**	**441,600**	**kW**
Auxiliary Load				
Coal Handling and Conveying	440	440	440	kW
Pulverizers	2,790	2,790	2,790	kW
Sorbent Handling & Reagent Prep	890	890	890	kW
Ash Handling	530	530	530	kW
Primary Air Fans	1,310	1,310	1,310	kW
Forced Draft Fans	1,670	1,670	1,670	kW
Induced Draft Fans	7,050	7,050	7,050	kW
SCR	50	50	50	kW
Baghouse	70	70	70	kW
Wet FGD	2,980	2,980	2,980	kW
CO_2 Scrubber Auxiliaries	3,300	6,600	11,400	kW
CO_2 Compression	8,750	17,400	29,910	kW
Miscellaneous Balance of Plant	2,000	2,000	2,000	kW
Steam Turbine Auxiliaries	400	400	400	kW
Condensate Pumps	720	650	540	kW
Circulating Water Pumps	5,620	5,970	6,470	kW
Ground Water Pumps	570	610	650	kW
Cooling Tower Fans	2,910	3,090	3,350	kW
Transformer Losses	1,580	1,560	1,520	kW
Total	**43,630**	**56,060**	**74,020**	kW
Net Power	443,770	412,540	367,580	kW
Net Plant Efficiency (HHV)	31.7%	29.4%	26.2%	
Net Plant Heat Rate (HHV)	10,778	11,594	13,012	Btu/kWh
Coal Feedrate	410,000	410,000	410,000	Lb/hr
Percent CO_2 Capture	20%	40%	69%	
CO_2 Emission Rate	1,598	1,246	689	Lb CO_2/MWh

Exhibit 27 - Case 1B-9 30-Year Average CO_2 Emission Rate

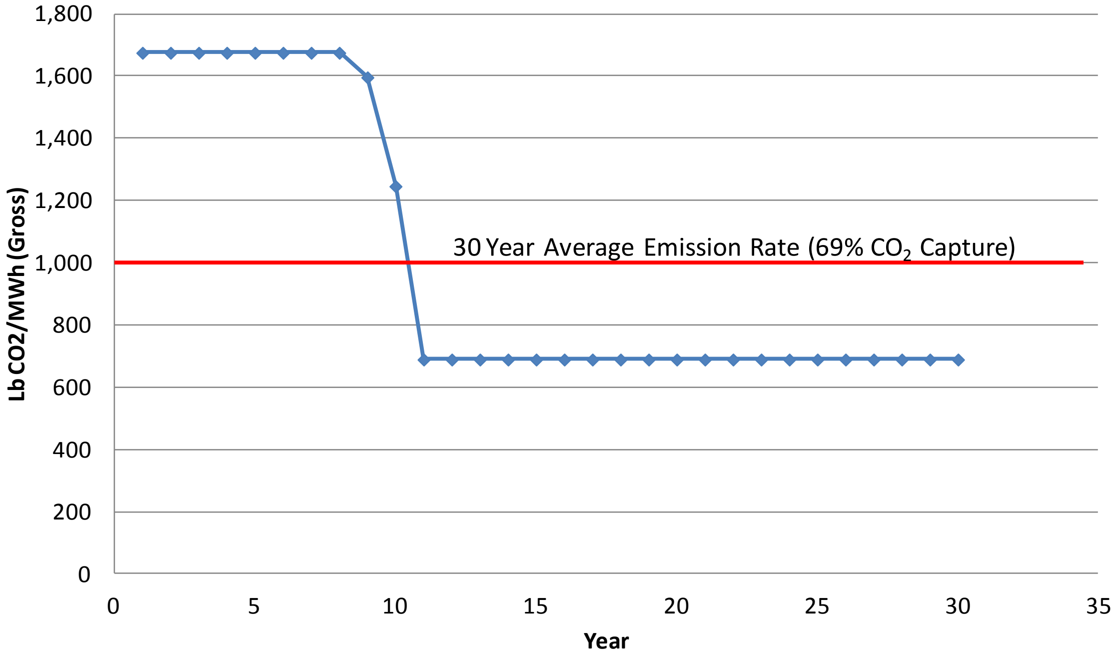


Exhibit 28 - Case 1B-9 Block Flow Diagram

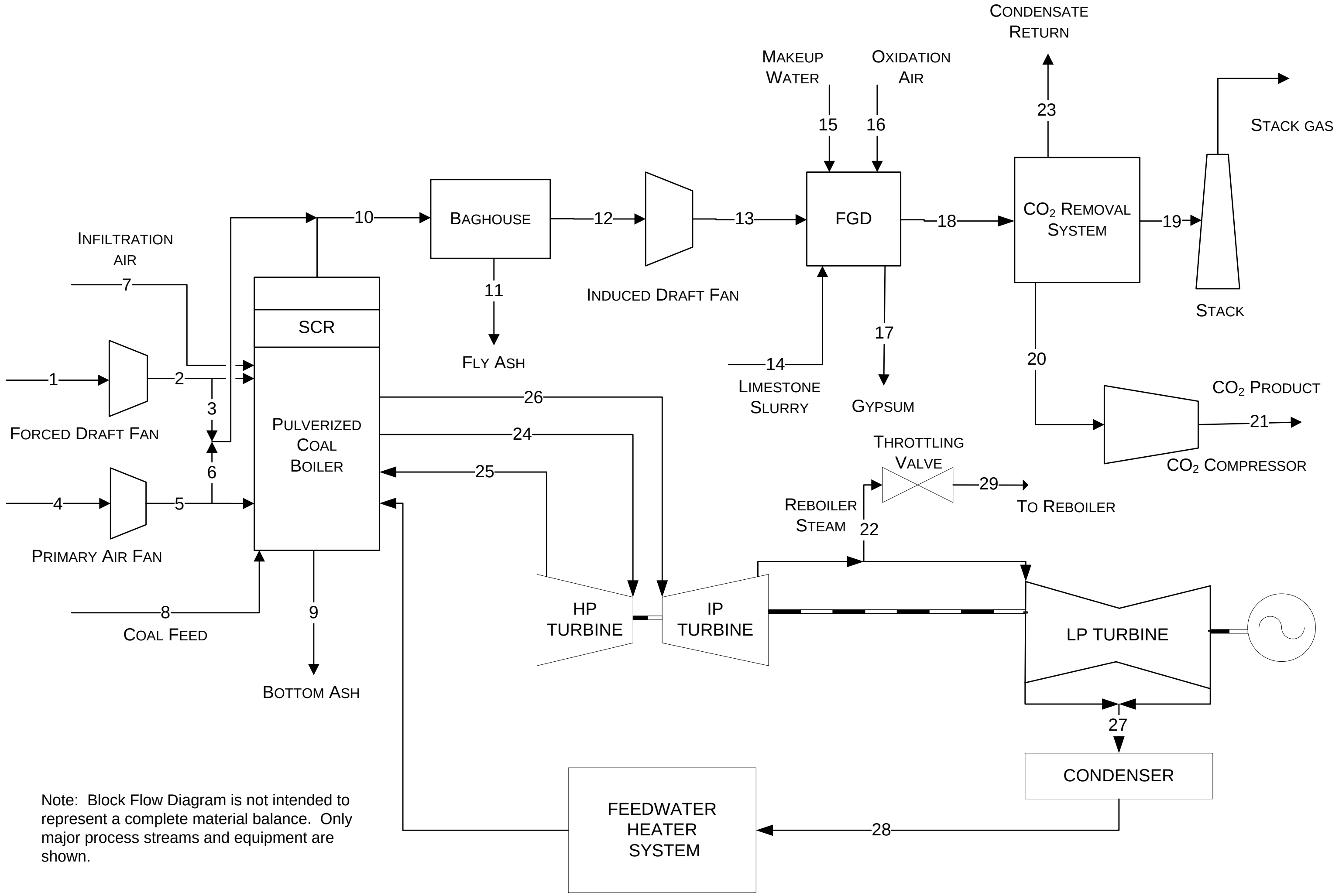


Exhibit 29 - Case 1B-9 Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870	1.0000	1.0000
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324	0.0000	0.0000
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	106,836	106,836	3,162	32,819	32,819	4,516	2,469	0	0	150,337	0	150,337	150,337	5,073	54,788
V-L Flowrate (lb/hr)	3,082,950	3,082,950	91,255	947,050	947,050	130,314	71,257	0	0	4,471,500	0	4,471,500	4,471,500	91,399	987,024
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	410,000	7,951	31,806	31,806	0	0	40,693	0
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337	357	59	59
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2	15.3	15.0	14.7
Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.8	---	132.8	138.0	---	-20.1
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049	0.052	---	62.622

A - Reference conditions are 32.02 F & 0.089 PSIA

	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V-L Mole Fraction														
Ar	0.0128	0.0000	0.0082	0.0090	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0005	0.0004	0.1353	0.0466	1.0000	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0062	0.9995	0.1517	0.1673	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7506	0.0000	0.6808	0.7507	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2300	0.0000	0.0240	0.0264	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	1,602	388	163,500	148,286	15,208	15,208	49,878	49,878	204,618	166,412	166,412	104,748	104,748	49,878
V-L Flowrate (lb/hr)	46,519	6,993	4,717,795	4,048,085	669,299	669,299	898,565	898,565	3,686,253	2,997,953	2,997,953	1,887,060	1,887,060	898,565
Solids Flowrate (lb/hr)	0	63,332	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	333	135	135	135	198	80	737	300	1,100	669	1,100	101	103	728
Pressure (psia)	45.0	14.8	14.8	14.8	70.4	2,214.5	170.0	150.0	3,514.7	710.8	655.8	1.0	245.0	75.0
Enthalpy (Btu/lb)[A]	76.4	---	128.0	132.9	33.0	-100.7	1,394.0	269.5	1,494.7	1,325.4	1,570.2	946.8	71.8	1,394.0
Density (lb/ft^3)	0.154	---	0.067	0.064	0.445	43.314	0.243	57.318	4.319	1.164	0.722	0.003	62.001	0.107

Exhibit 30 – Case 1B-9 Capital Cost Summary

	Case:	1B-9 SuperCritical PC with Throttling Valve - Capture Ready Retrofitted for 69% Capture Design										
	Plant Size:	367.6 MW,net		Estimate Type: Conceptual				Cost Base (Jun)		2011	($x1000)	
Acct		**Equipment**	**Material**	**Labor**		**Sales**	**Bare Erected**	**Eng'g CM**	**Contingencies**		**TOTAL PLANT COST**	
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
1	COAL & SORBENT HANDLING	$19,885	$5,077	$11,756	$0	$0	**$36,718**	$3,221	$0	$5,991	**$45,929**	$125
2	COAL & SORBENT PREP & FEED	$13,363	$742	$3,344	$0	$0	**$17,448**	$1,483	$0	$2,840	**$21,772**	$59
3	FEEDWATER & MISC. BOP SYSTEMS	$51,664	$0	$23,917	$0	$0	**$75,581**	$6,711	$0	$13,375	**$95,667**	$260
4	PC BOILER											
4.1	PC Boiler & Accessories	$185,402	$0	$105,641	$0	$0	**$291,043**	$28,011	$0	$31,905	**$350,959**	$955
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$185,402**	**$0**	**$105,641**	**$0**	**$0**	**$291,043**	**$28,011**	**$0**	**$31,905**	**$350,959**	**$955**
5	FLUE GAS CLEANUP	$96,010	$0	$32,384	$0	$0	**$128,395**	$11,972	$0	$14,037	**$154,404**	$420
5B	CO2 REMOVAL & COMPRESSION	$225,851	$0	$71,077	$0	$0	**$296,928**	$27,668	$51,767	$75,273	**$451,636**	$1,229
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Accessories	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$21,540	$1,259	$14,274	$0	$0	**$37,073**	$3,306	$0	$5,333	**$45,712**	$124
	SUBTOTAL 7	**$21,540**	**$1,259**	**$14,274**	**$0**	**$0**	**$37,073**	**$3,306**	**$0**	**$5,333**	**$45,712**	**$124**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$66,640	$0	$8,221	$0	$0	**$74,861**	$6,572	$0	$8,143	**$89,576**	$244
8.5	Let Down Turbine	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$30,543	$1,248	$15,478	$0	$0	**$47,269**	$3,885	$0	$7,190	**$58,344**	$159
	SUBTOTAL 8	**$97,183**	**$1,248**	**$23,699**	**$0**	**$0**	**$122,129**	**$10,458**	**$0**	**$15,334**	**$147,921**	**$402**
9	COOLING WATER SYSTEM	$16,957	$8,772	$15,262	$0	$0	**$40,992**	$3,752	$0	$6,052	**$50,796**	$138
10	ASH/SPENT SORBENT HANDLING SYS	$5,436	$161	$7,058	$0	$0	**$12,654**	$1,177	$0	$1,422	**$15,254**	$41
11	ACCESSORY ELECTRIC PLANT	$25,481	$10,557	$28,524	$0	$0	**$64,562**	$5,561	$0	$8,760	**$78,883**	$215
12	INSTRUMENTATION & CONTROL	$10,844	$0	$10,876	$0	$0	**$21,720**	$1,918	$0	$2,914	**$26,552**	$72
13	IMPROVEMENTS TO SITE	$3,674	$2,112	$7,876	$0	$0	**$13,661**	$1,355	$0	$3,003	**$18,020**	$49
14	BUILDINGS & STRUCTURES	$0	$27,262	$25,841	$0	$0	**$53,103**	$4,690	$0	$8,669	**$66,462**	$181
	TOTAL COST	**$773,289**	**$57,188**	**$381,529**	**$0**	**$0**	**$1,212,007**	**$111,284**	**$51,767**	**$194,908**	**$1,569,964**	**$4,271**
	Total Overnight Costs (TOC)										**$1,940,018**	**$5,278**

Exhibit 31 – Case 1B-9 O&M Cost Summary

INITIAL & ANNUAL O&M EXPENSES	Cost Base (Jun):	2011
1B-9 SuperCritical PC with Throttling Valve - Capture Ready Retrofitted for 69% Capture Design yea	Heat Rate-net (Btu/kWh):	13,012
Retrofitted CO2 Removal 69%	MWe-net:	367.58
	Capacity Factor (%):	80

OPERATING & MAINTENANCE LABOR

Operating Labor

Operating Labor Rate (base):	39.70	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant
Skilled Operator	2.0	2.0
Operator	11.3	11.3
Foreman	1.0	1.0
Lab Tech's, etc.	2.0	2.0
TOTAL-O.J.'s	16.3	16.3

	Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost	$7,384,208	$20.089
Maintenance Labor Cost	$10,223,116	$27.812
Administrative & Support Labor	$4,401,831	$11.975
Property Taxes and Insurance	$31,399,289	$85.422
TOTAL FIXED OPERATING COSTS	**$53,408,444**	**$145.297**

VARIABLE OPERATING COSTS

	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Fill Cost	Annual Cost $	$/kWh-net
Maintenance Material Cost					**$15,334,673**	**$0.00595**
Consumables						
Water (/1000 gallons)	0	5,193	1.67	**$0**	**$2,538,195**	**$0.00099**
Chemicals						
MU & WT Chem.(lbs)	0	25,136	0.27	$0	$1,965,838	$0.00076
Limestone (ton)	0	488	33.48	$0	$4,768,288	$0.00185
Carbon (Mercury Removal) (lb)	0	0.00	1.63	$0	$0	$0.00000
MEA Solvent (ton)	568	1	3,481.91	$1,977,625	$818,767	$0.00032
NaOH (tons)	40	4	671.16	$26,927	$786,267	$0.00031
H2SO4 (tons)	38	4	214.78	$8,223	$240,111	$0.00009
Corrosion Inhibitor	0	0	0.00	$78,561	**$3,741**	$0.00000
Activated Carbon (lb)	0	962	1.63	$0	**$456,523**	$0.00018
Ammonia (19% NH3) ton	0	73.52	330.00	$0	$7,084,773	$0.00275
Subtotal Chemicals				**$2,091,336**	**$16,124,309**	**$0.00626**
Other						
Supplemental Fuel (MBtu)	0	0.00	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.31	8,938.80	$0	$806,639	$0.00031
Emission Penalties	0	0.00	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$806,639**	**$0.00031**
Waste Disposal						
Fly Ash (ton)	0	381	25.11	$0	$2,795,191	$0.00109
Bottom Ash (ton)	0	95	25.11	$0	$698,798	$0.00027
Subtotal-Waste Disposal				**$0**	**$3,493,989**	**$0.00136**
By-products & Emissions						
Gypsum (tons)	0	759	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$2,091,336**	**$38,297,806**	**$0.01487**
Fuel (ton)	0	4,920	63.58	**$0**	**$91,341,571**	**$0.03546**

4.3 NON CO_2 CAPTURE-READY – RETROFIT IN YEAR 11

The case in this section is not a CO_2 capture-ready plant – the supercritical PC unit was not initially constructed to accommodate CO_2 capture at a future date. However, CO_2 capture will still begin in the 11th year of operation. None of the capture-ready design elements that were incorporated into the other cases in this study (such as extra room in pipe racks or cable trays, foundations, condenser and cooling tower modifications, and other balance of plant considerations) were included, therefore there is a capital cost premium associated with this case.

Since this is not a capture-ready plant, the design will not preserve a high heat rate after the retrofit. It is assumed that this approach can only be accommodated with a capture-ready design. Therefore, the process configuration for Case 1A-11 is identical to the CO_2 capture-ready designs that include the throttling valve (with the exception of including the items included during initial plant construction, such as pipe racks or cable trays, foundations, condenser and cooling tower modifications, and other balance of plant considerations).

Like the retrofit-ready cases, there is an inherent risk when making major retrofits and additions to an existing plant.

This case assumes that the capture rate will be the level required to achieve a 30-year average CO_2 emission rate of 1,000 Lb CO_2/MWh (gross basis).

4.3.1 Case 1A-11 (Non CO_2 Capture-Ready, Retrofit in Year 11)

Case 1A-11 includes a throttling valve to decrease the pressure from the conditions at the IP/LP crossover pipe (170 psia) to what is required for the steam reboiler (75 psia). These are shown in the block flow diagram (Exhibit 34) and accompanying stream table (Exhibit 35). Exhibit 36 and Exhibit 37 provide the capital and O&M costs for this case.

All cases in this analysis are required to maintain an average 30-year CO_2 emission rate of 1,000 Lb CO_2/MWh (gross basis). Since CO_2 capture will not begin until the start of the 11th year, a capture rate of 70% is required to satisfy the long-term average of 1,000 Lb CO_2/MWh. This is also shown graphically in Exhibit 33.

Exhibit 32 - Case 1A-11 Performance Summary

Plant Output		
Steam Turbine Power	440,050	kW
Gross Power	**440,050**	**kW**
Auxiliary Load		
Coal Handling and Conveying	440	kW
Pulverizers	2,790	kW
Sorbent Handling & Reagent Prep	890	kW
Ash Handling	530	kW
Primary Air Fans	1,310	kW
Forced Draft Fans	1,670	kW
Induced Draft Fans	7,050	kW
SCR	50	kW
Baghouse	70	kW
Wet FGD	2,980	kW
CO_2 Scrubber Auxiliaries	11,600	kW
CO_2 Compression	30,450	kW
Miscellaneous Balance of Plant	2,000	kW
Steam Turbine Auxiliaries	400	kW
Condensate Pumps	540	kW
Circulating Water Pumps	6,490	kW
Ground Water Pumps	650	kW
Cooling Tower Fans	3,360	kW
Transformer Losses	1,520	kW
Total	**74,790**	kW
Net Power	365,710	kW
Net Plant Efficiency (HHV)	26.1%	
Net Plant Heat Rate (HHV)	13,079	Btu/kWh
Coal Feedrate	410,000	Lb/hr
Percent CO_2 Capture	70%	
CO_2 Emission Rate	663	Lb CO_2/MWh

Exhibit 33 - Case 1A-11 30-Year Average CO_2 Emission Rate

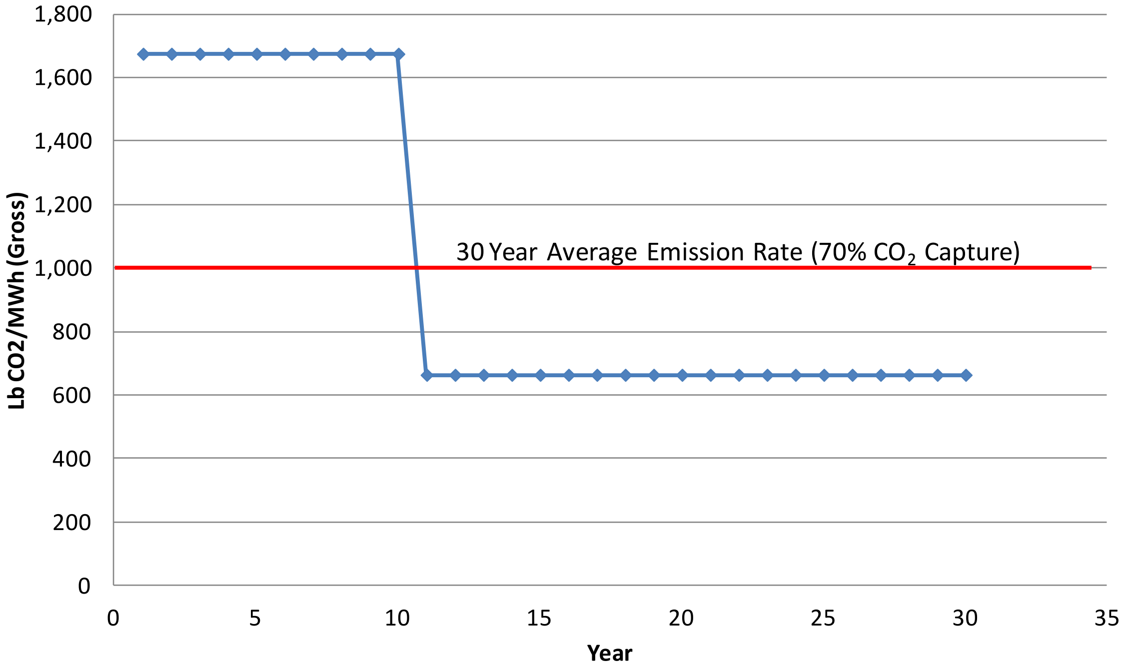


Exhibit 34 - Case 1A-11 Block Flow Diagram

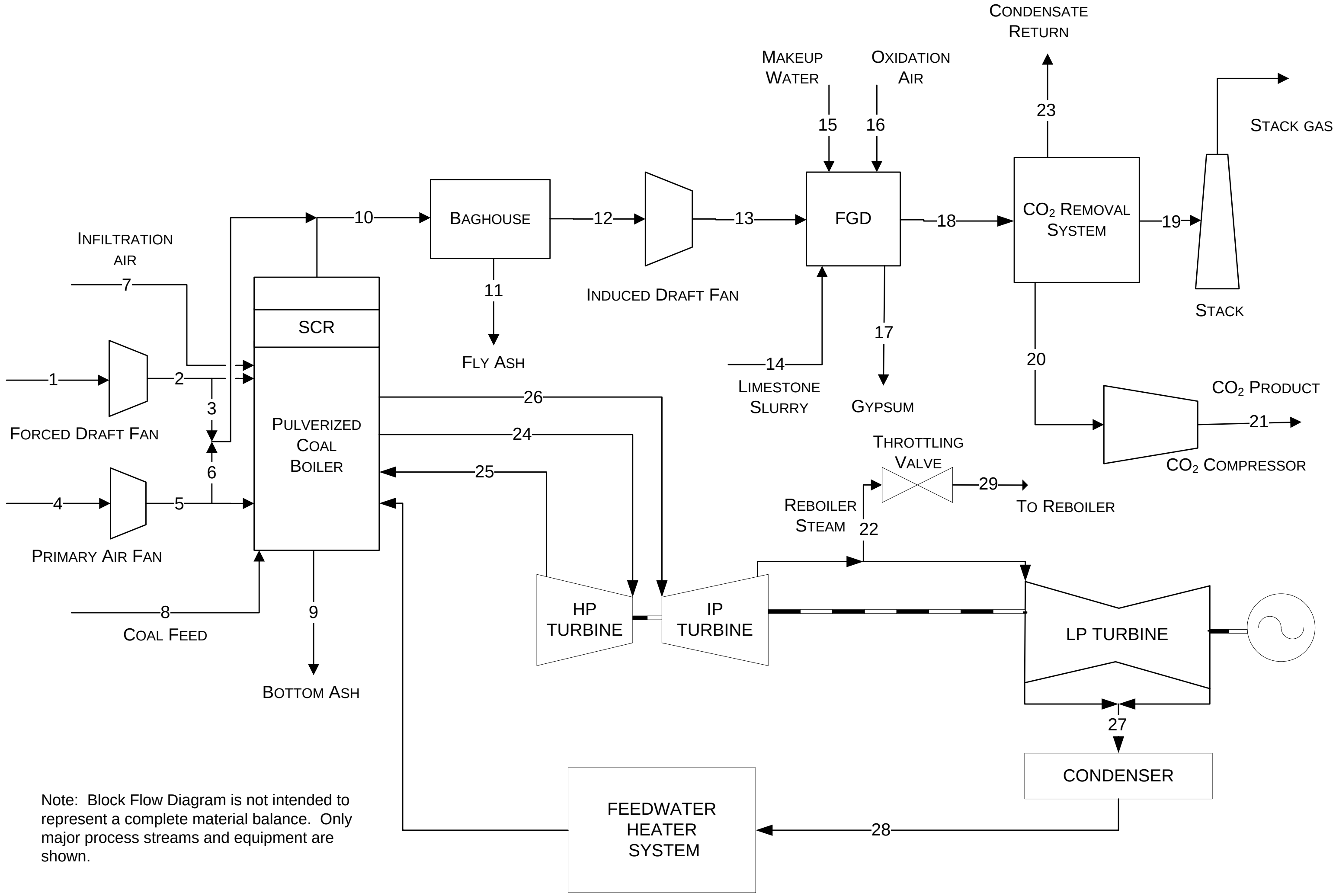


Exhibit 35 - Case 1A-11 Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870	1.0000	1.0000
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324	0.0000	0.0000
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	106,836	106,836	3,162	32,819	32,819	4,516	2,469	0	0	150,337	0	150,337	150,337	5,073	54,788
V-L Flowrate (lb/hr)	3,082,950	3,082,950	91,255	947,050	947,050	130,314	71,257	0	0	4,471,500	0	4,471,500	4,471,500	91,399	987,024
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	410,000	7,951	31,806	31,806	0	0	40,693	0
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337	357	59	59
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2	15.3	15.0	14.7
Enthalpy (Btu/lb)^A	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.8	---	132.8	138.0	---	-20.1
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049	0.052	---	62.622

A - Reference conditions are 32.02 F & 0.089 PSIA

	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V-L Mole Fraction														
Ar	0.0128	0.0000	0.0082	0.0090	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0005	0.0004	0.1353	0.0448	1.0000	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0062	0.9995	0.1517	0.1676	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7506	0.0000	0.6808	0.7521	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2300	0.0000	0.0240	0.0265	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	1,602	388	163,500	148,009	15,484	15,484	50,785	50,785	204,618	166,412	166,412	103,841	103,841	50,785
V-L Flowrate (lb/hr)	46,519	6,993	4,717,795	4,035,916	681,468	681,468	914,902	914,902	3,686,253	2,997,953	2,997,953	1,870,723	1,870,723	914,902
Solids Flowrate (lb/hr)	0	63,332	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	333	135	135	135	198	80	737	300	1,100	669	1,100	101	103	728
Pressure (psia)	45.0	14.8	14.8	14.8	70.4	2,214.5	170.0	150.0	3,514.7	710.8	655.8	1.0	245.0	75.0
Enthalpy (Btu/lb)^A	76.4	---	128.0	133.0	33.0	-100.7	1,394.0	269.5	1,494.7	1,325.4	1,570.2	946.8	71.8	1,394.0
Density (lb/ft^3)	0.154	---	0.067	0.064	0.445	43.314	0.243	57.318	4.319	1.164	0.722	0.003	62.001	0.107

Exhibit 36 – Case 1A-11 Capital Cost Summary

	Case:	1A-11 SuperCritical PC with Throttling Valve Retrofitted 70% Capture Design										
	Plant Size:	**365.7**	MW,net	Estimate Type:		Conceptual		**Cost Base (Jun)**		2011	($x1000)	
Acct		**Equipment**	**Material**	**Labor**		**Sales**	**Bare Erected**	**Eng'g CM**	**Contingencies**		**TOTAL PLANT COST**	
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
1	COAL & SORBENT HANDLING	$19,885	$5,077	$11,756	$0	$0	**$36,718**	$3,221	$0	$5,991	**$45,929**	$126
2	COAL & SORBENT PREP & FEED	$13,363	$742	$3,344	$0	$0	**$17,448**	$1,483	$0	$2,840	**$21,772**	$60
3	FEEDWATER & MISC. BOP SYSTEMS	$52,511	$0	$24,206	$0	$0	**$76,717**	$6,818	$0	$13,624	**$97,159**	$266
4	PC BOILER											
4.1	PC Boiler & Accessories	$185,402	$0	$105,641	$0	$0	**$291,043**	$28,011	$0	$31,905	**$350,959**	$960
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$185,402**	**$0**	**$105,641**	**$0**	**$0**	**$291,043**	**$28,011**	**$0**	**$31,905**	**$350,959**	**$960**
5	FLUE GAS CLEANUP	$96,010	$0	$32,384	$0	$0	**$128,395**	$11,972	$0	$14,037	**$154,404**	$422
5B	CO2 REMOVAL & COMPRESSION	$229,056	$0	$72,444	$0	$0	**$301,500**	$28,094	$52,573	$76,433	**$458,600**	$1,254
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Accessories	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$27,633	$1,527	$21,529	$0	$0	**$50,689**	$4,501	$0	$7,402	**$62,593**	$171
	SUBTOTAL 7	**$27,633**	**$1,527**	**$21,529**	**$0**	**$0**	**$50,689**	**$4,501**	**$0**	**$7,402**	**$62,593**	**$171**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$66,640	$0	$8,221	$0	$0	**$74,861**	$6,572	$0	$8,143	**$89,576**	$245
8.5	Let Down Turbine	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$31,113	$1,248	$15,709	$0	$0	**$48,070**	$3,947	$0	$7,320	**$59,337**	$162
	SUBTOTAL 8	**$97,753**	**$1,248**	**$23,930**	**$0**	**$0**	**$122,931**	**$10,519**	**$0**	**$15,463**	**$148,913**	**$407**
9	COOLING WATER SYSTEM	$20,422	$11,156	$19,191	$0	$0	**$50,769**	$4,646	$0	$7,553	**$62,968**	$172
10	ASH/SPENT SORBENT HANDLING SYS	$5,436	$161	$7,058	$0	$0	**$12,654**	$1,177	$0	$1,422	**$15,254**	$42
11	ACCESSORY ELECTRIC PLANT	$29,740	$13,471	$36,195	$0	$0	**$79,406**	$6,854	$0	$10,861	**$97,121**	$266
12	INSTRUMENTATION & CONTROL	$13,868	$0	$13,908	$0	$0	**$27,776**	$2,453	$0	$3,726	**$33,955**	$93
13	IMPROVEMENTS TO SITE	$4,177	$2,401	$8,955	$0	$0	**$15,532**	$1,541	$0	$3,415	**$20,488**	$56
14	BUILDINGS & STRUCTURES	$0	$27,419	$25,995	$0	$0	**$53,414**	$4,717	$0	$8,720	**$66,851**	$183
	TOTAL COST	**$795,256**	**$63,200**	**$406,537**	**$0**	**$0**	**$1,264,993**	**$116,009**	**$52,573**	**$203,392**	**$1,636,966**	**$4,476**
	Total Overnight Costs (TOC)										**$2,020,958**	**$5,526**

Exhibit 37 – Case 1A-11 O&M Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2011
1A-11 SuperCritical PC with Throttling Valve Retrofitted 70% Capture Design					Heat Rate-net (Btu/kWh):	13,079
Retrofitted CO2 Removal 70%					MWe-net:	365.71
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	39.70	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Plant			
Skilled Operator	2.0		2.0			
Operator	11.3		11.3			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	16.3		16.3			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost					$7,384,208	$20.191
Maintenance Labor Cost					$10,659,410	$29.147
Administrative & Support Labor					$4,510,905	$12.335
Property Taxes and Insurance					$32,739,326	$89.523
TOTAL FIXED OPERATING COSTS					**$55,293,849**	**$151.196**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$15,989,115**	**$0.00624**
Consumables	Consumption		Unit	Initial Fill		
	Initial Fill	/Day	Cost	Cost		
Water (/1000 gallons)	0	5,209	1.67	**$0**	**$2,546,290**	**$0.00099**
Chemicals						
MU & WT Chem.(lbs)	0	25,216	0.27	$0	$1,972,108	$0.00077
Limestone (ton)	0	488	33.48	$0	$4,768,288	$0.00186
Carbon (Mercury Removal) (lb)	0	0.00	1.63	$0	$0	$0.00000
MEA Solvent (ton)	578	1	3,481.91	$2,013,581	$833,654	$0.00033
NaOH (tons)	41	4	671.16	$27,417	$800,563	$0.00031
H2SO4 (tons)	39	4	214.78	$8,373	$244,477	$0.00010
Corrosion Inhibitor	0	0	0.00	$79,990	**$3,809**	$0.00000
Activated Carbon (lb)	0	979	1.63	$0	**$493,875**	$0.00019
Ammonia (19% NH3) ton	0	73.52	330.00	$0	$7,084,773	$0.00276
Subtotal Chemicals				**$2,129,360**	**$16,201,546**	**$0.00632**
Other						
Supplemental Fuel (MBtu)	0	0.00	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.31	8,938.80	$0	$806,639	$0.00031
Emission Penalties	0	0.00	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$806,639**	**$0.00031**
Waste Disposal						
Fly Ash (ton)	0	381	25.11	$0	$2,795,191	$0.00109
Bottom Ash (ton)	0	95	25.11	$0	$698,798	$0.00027
Subtotal-Waste Disposal				**$0**	**$3,493,989**	**$0.00136**
By-products & Emissions						
Gypsum (tons)	0	759	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$2,129,360**	**$39,037,580**	**$0.01523**
Fuel (ton)	0	4,920	63.58	**$0**	**$91,341,571**	**$0.03564**

APPENDIX A CO_2 Capture-Ready Definition

A.1 CO_2 Capture-Ready definitions found in literature

CO_2 capture-ready has multiple definitions depending on the source. International Energy Agency Greenhouse Gas Research and Development Program (IEA GHG) set the definition of CO_2 capture-ready as *"a plant which can include CO_2 capture when the necessary regulatory or economic drivers are in place. The aim of building plants that are capture ready is to reduce the risk of stranded assets and 'carbon lock-in'*[vii]*."*

Other studies defined CO_2 capture-ready as having three requirements[viii]:

- Plant site should have access to CO_2 storage.
- Additional space for expansion for the Carbon Capture Utilization and Storage (CO_2 capture) system
- In making the plant "ready", it should not contribute to an increase in emission rates compared to the non-CO_2 capture-ready configuration.

The European Power Plant Suppliers Association (EPPSA) in 2006 published a four-page recommendation on defining CO_2 capture-ready to suppliers of this technology[ix]. This included, in addition to the regular space and CO_2 capture location requirements, plant outage time, special control systems to transfer from normal operation to CO_2 capture, plant safety, and more. Siemens provides a carbon capture ready assessment based loosely on these requirements. Some recommendations suggested requesting 1 – 25 MW pilot plants demonstrating that CO_2 capture is possible before determining readiness status[x].

A.2 CO_2 Capture-Ready definition for this study:

For the purposes of this study, the CO_2 capture-ready requirements generally include:

- CO_2 storage should be either locally available or have established routing to a storage location
- The plant layout design should include additional areas for installation of CO_2 capture equipment, additional ancillary equipment such as pumps, fans, compressors, etc. The design should also include sufficient area for the planned construction activities including equipment storage and lay down areas
- The installation of the CO_2 capture system should not increase the emission rate of the plant after installation
- The plant would be designed to minimize the additional parasitic load resulting from installation of the capture system
- Design for piping, duct banks, underground utilities, and control system routing as needed to minimize disruptions during CO_2 capture installation
- Turbine steam extraction provisions should be identified and designed to provide access
- Steam piping tie-ins should be provided and piping routing designed for minimum lengths

- Any required condenser design modifications for CO_2 capture operation be included in initial plant design
- Design for additional fan requirements due to increased pressure drop in the flue gas pathway
- Any FGD enhancements should be provided, designed, or retrofitted for additional SO_2 control, if needed
- Feedwater systems, including makeup, pretreating, and waste treatment, sized appropriately for CO_2 capture
- Ductwork and stack tie-ins provided
- Cooling water tie-ins provided, piping layout designed for minimum lengths, towers sized for extra duty, use of multiple pumps or VFDs to meet required flow rates

APPENDIX B Equipment and System Evaluation for CO_2 Capture Ready Coal-Fired Power Plants

B.1 Steam Turbine

Steam turbine modification will be required when CO_2 capture is implemented. Through multiple literature sources, there are four CO_2 capture-ready options that were investigated. The options are detailed below and include:

1. Clutched LP Turbine
2. Throttled LP Turbine Retrofit
3. Floating IP/LP crossover pressure
4. Backpressure Turbine

B.1.1 Option A: Clutched LP Turbine

At the 9th International Conference on GHG Control Technologies (GHGT-9), Mathieu Lucquaid described Option A as[xi]:

> *This option is the most efficient, but also the least flexible and the most expensive, as it requires extensive modification of the turbine hall compared to a non capture-ready design. The clutch between the two turbines will add cost and complexity, with no immediate benefit when the plant is operated before a retrofit. The clutched LP turbine cylinder will be taken out of service for capture operation without affecting the steam cycle temperatures and pressures. The IP/LP crossover pressure would be set at the desired value for solvent regeneration. The remaining LP turbine cylinder still operates at its design conditions after capture is retrofitted, avoiding any additional losses.*

B.1.2 Option B: Throttled LP Turbine Retrofit

At GHGT-9, Mathieu Lucquaid described Option B as[xi]:

> *The crossover pressure remains constant in this option too due to a throttling valve downstream of the steam extraction point. Significant throttling losses occur when operating with capture, however, and this option is the least efficient of the three. Up -front capital costs are minimal though, with the principle additional items being a flange for a suitably-sized steam off take to be connected at the IP/LP crossover and a spool piece for the throttling valve.*

This option has a lower up-front capital investment compared to the other three options. Flexibility with a throttling valve allows adjustment to the steam requirements needed not only during installation and first use of the CO_2 capture system, but for future amine steam requirements. Downtime would be relatively short and retrofit would be simple to install and control.

The location of the throttling valve is determined by the cross-over pressure compared to the pressure required for the CO_2 capture system. If the crossover pressure is higher than the pressure required at the CO_2 capture interface, the throttling valve will be in the piping to the CO_2 capture unit. If the pressure is lower than the pressure required at the CO_2 capture connection, the throttling valve will be in the cross-over piping between the IP and LP turbines. If the pressure range covers both, installation may require valves in both steam lines to maintain control.

B.1.3 **Option C: IP/LP Crossover pressure**

At GHGT-9, Mathieu Lucquaid described Option C as[xi]:

> *In this option the pressure at the IP/LP crossover pipe is originally higher than in the two other options. When the capture unit is connected the pressure falls to the value that is required for operation with the MEA-based capture unit. The turbines suffer a small efficiency penalty since they are operating away from their original design point, although this is likely to be within acceptable variations. There are no throttling losses and the performance is intermediate between the two other options. The last stage blades of the IP turbine and the first stage blades of the LP turbine need to be reinforced because of increased stage loadings, i.e. axial thrust changes, increased blade bending moment and possible flow restrictions. A flange for a suitably-sized steam offtake and spool piece for an optional throttling valve will also be required. But additional costs for these modifications are expected to be relatively low.*

This option has higher upfront costs than Option B but lower than Option A. There are some questions regarding the statement "The turbines suffer a small efficiency penalty since they are operating away from their original design point, although this is likely to be within acceptable variations." The efficiency should be better than Option B, but there could be a chance that the CO_2 capture system would cause the turbine to operate outside the "acceptable variations" with the inability to control the system because of the lack of a throttling valve. An additional major concern would be the lack of balancing control between the steam turbine and the CO_2 capture system. Load following would also be more difficult here than with the other two options. One advantage would be that modifications would be relatively easy and downtime for conversion would be relatively short.

B.1.4 **Option D: Backpressure Turbine**

Because the pressure and temperature in the crossover pipe between the IP and LP turbines will be too high for the amine system, a backpressure turbine can be used in place of a pressure reducing valve. This will capture the energy for generation of additional electrical power instead of being lost. Bechtel claims in an article published by Power Magazine[xii] that this is the most efficient means of CO_2 capture retrofit out of the other four options as it re-introduces power; however the capital and installation costs of an additional turbine, generator, transformer, valving, and emergency bypass may be too high to justify the increase in efficiency.

The additional power could be used for the compressors or other CO_2 capture parasitic loads[xiii]. However, this could reduce flexibility if steam requirements change.

B.1.5 Steam Turbine Outcome

After reviewing the options presented in this study, the options used for the cases in this analysis are given below:

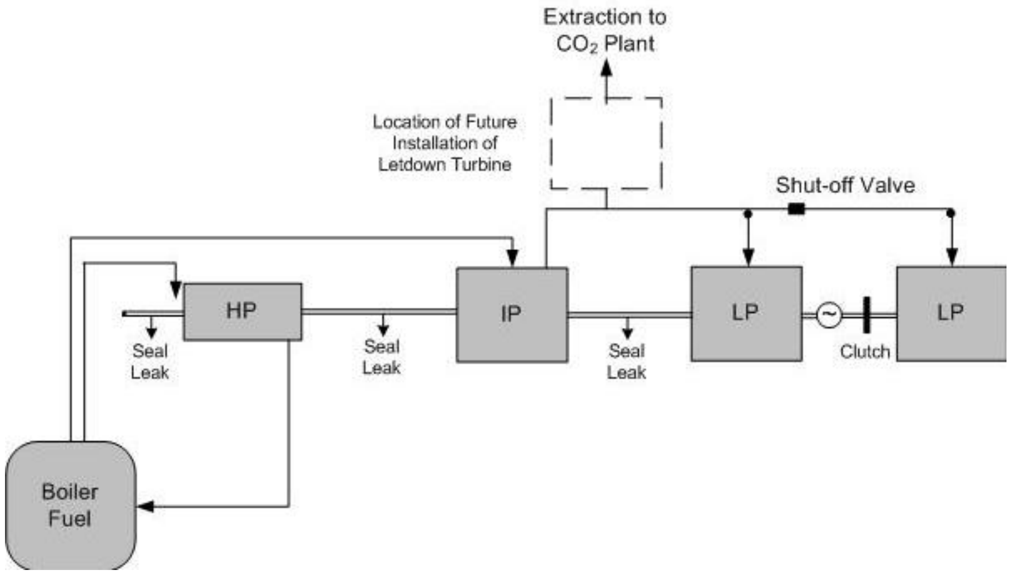
B.1.5.1 Minimum Heat Rate Penalty – Clutched LP Turbine with Letdown Turbine

The clutched LP turbine configuration is shown in Exhibit B-1 (used for Cases 2B-9 and 2B-11). This option features a low pressure steam turbine with two sections whose shafts are connected by a clutch. Disengaging the clutch makes isolation of only one LP turbine section possible.

After the CO_2 retrofit occurs, a large amount (some estimates claim up to half) of the low pressure steam will be required for CO_2-rich solvent regeneration. This reduction in steam flow would result in a significant decrease in LP turbine efficiency. However, by disengaging the clutch and keeping only one of the two turbine sections in service, the steam flow through the remaining turbine section would remain roughly the same, thereby maintaining the same LP turbine efficiency as before the retrofit.

By maintaining high conversion efficiency in the LP turbine, as well as the addition of a steam letdown turbine, heat rate penalty is minimized after retrofit. However, this comes at the expense of high capital cost.

Exhibit B-1 - Clutched Turbine Configuration



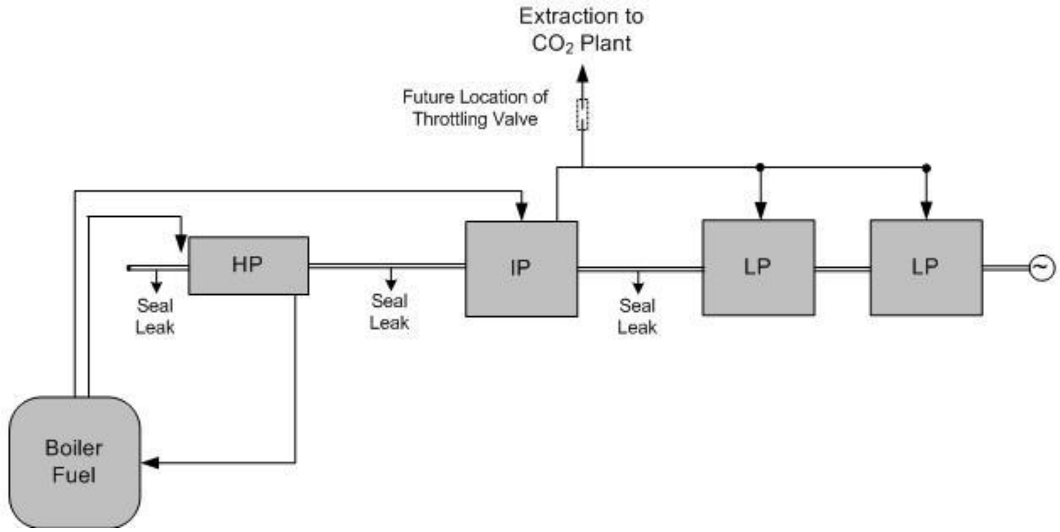
B.1.5.2 Minimum Capital Cost – Throttled Low Pressure Steam Turbine

The configuration in Exhibit B-2was the design selected for Case 1B-9 and 1B-11. Since the pressure in the IP/LP crossover pipe is approximately double what is required at the CO_2-rich solvent regenerator, it is necessary to decrease the pressure mechanically. This is attained with a throttling valve in the steam line.

The location of the throttling valve is determined by the cross-over pressure compared to the pressure required for the CO_2 capture system. With the pressure requirement for the CO_2-rich solvent regenerator being lower than the pressure drop across the LP turbines, the steam will naturally flow into the reboiler. That means the throttling valve will have to be located in the steam line going to the solvent regenerator.

This configuration is the least capital intensive, and therefore may be the most attractive from a project finance perspective. However the heat-rate penalty after the retrofit will be significant, potentially negating the benefit of low capital cost.

Exhibit B-2 - Throttled LP Turbine Configuration



B.2 Condenser

Condenser modification could be a potential requirement for a CO_2 capture-ready plant. Depending on the integration with the plant cooling system, the condenser duty may decrease when LP steam is extracted for CO_2-rich solvent regeneration. Therefore, units may consider purchasing a sectional condenser with the ability to isolate portions when not needed. This would help balance the heat transfer required for the reduced steam flow.

Discussions with SPX Heat Transfer/Ecolaire indicated that certain problems would have to be worked out with full time condenser isolation including the increase in oxygen levels in the condensate and emergency bypass discharge in the condenser[xiv].

B.3 Condensate System

Carbon dioxide capture will present an opportunity to recover heat from the CO_2 compression train and the solvent scrubbing system. A CO_2 capture-ready plant should have the ability to recover this energy through condensate heat exchangers or exhaust a cooling loop into the condenser for additional heat to the feedwater heaters[vii].

B.4 Deaerator / Feedwater Heaters

The deaerator is where the condensate from the CO_2 capture system is placed back into the steam cycle of the plant. Additional nozzle connections should be added to ease future integration. Additional energy could be obtained with additional feedwater heaters or other measures depending on the level of the integration desired for efficiency gains[xiii].

B.5 Cooling Tower

The heat loads from the CO_2 solvent scrubber, fuel gas cooler, and CO_2 compressors can be captured in the heat cycle through feedwater heaters. However, additional cooling will be required of the cooling tower. EPPSA's recommendation includes a 30% increase in cooling tower space requirement for this additional heat load[ix]. Having the room to expand the cooling towers will be required. If modular cooling tower cells can be utilized, expansion will be less difficult[vii].

B.6 Air Heaters

Depending on the level of integration, low grade heat could be employed with heat exchangers to heat combustion air entering the boiler[xv].

B.7 Flue Gas Desulfurization (FGD)

It is almost certain that any new coal unit built will require FGD. The FGD should have built-in flexibility in the event higher purity is required by the CO_2 removal system of the future[vii].

B.8 NOx Control System

Like the FGD, the SCR will also need to address the purity requirements of the future CO_2 removal system. NOx controls (whether inside the furnace or with an SCR or SNCR) must be evaluated to confirm purity requirements can be met in the future.

B.9 Duct and Stack

Ductwork and stack should have space and tie-in locations for ducting into the CO_2 solvent stripper[xvi]. The area between the FGD and the stack would be the location for the tie-in. The pressure drop across the new equipment may also require duct enlargement if the flue gas fans do not have sufficient head. Though the flue gas fans would not be oversized in a CO_2 capture-ready design, space should be provided for additional fans and/or the fans have the ability to increase output if required[xv].

B.10 Compressed Air System

With the addition of new equipment comes the need to expand the compressed air system (both instrument and service air if they are differentiated). Room in the compressor area will be needed for additional equipment. Unlike other systems, the cost of pre-fit pipe would probably make it advantageous to oversize the compressed air headers around the plant for future additions due to the CO_2 capture system. Also, adding air receivers near locations where the additional piping will be added will also help keep the system air pressure balanced, as well as provided much needed storage when the CO_2 capture system is added.

B.11 Miscellaneous

Other additional miscellaneous items to consider include

- Electrical systems including additional duct banks and cable trays.
- Control systems
- Fire protection systems
- Safety barrier zones
- Additional piping and oversized pipe supports

- Utilities and tie-ins with the existing plant.
- Permits – e.g. with the additional heat loads, water consumption will increase. Water permit will have to be revisited and confirmed[xv].

B.12 Other Layout Considerations

The addition of space is a major requirement for CO_2 capture systems, therefore a plant defined as carbon capture ready must have that space available. Justin Zachary, senior principal engineer for Bechtel estimates an addition 500,000 sq feet will be required for the capture system[xvii] but that does not include additional space required for the plant itself. The following systems will require additional space and layout consideration:

- Backpressure Turbine (if elected)
- Compressed air system
- Cooling Tower
- Raw Water Treatment Plant
- Waste Water Treatment
- Auxiliary Transformer
- Temporary storage of CO_2 – There will more than likely be requirements for maintaining temporary storage of compressed CO_2 on site in the event the storage location or equipment to that location is offline[xviii].

APPENDIX C Economic Analysis Background

C.1 Finance Structure, Discounted Cash Flow Analysis, and COE

The global economic assumptions are listed in Exhibit C-1.

The finance structure was chosen based on assuming an investor-owned utility (IOU), and the capture technology to be retrofitted is mature and commercially available; therefore all cases were considered low risk.

Exhibit C-1 Global Economic Assumptions

TAXES	
Income Tax Rate	38% (Effective 34% Federal, 6% State)
Capital Depreciation	20 years, 150% declining balance
Investment Tax Credit	0%
Tax Holiday	0 years
CONTRACTING AND FINANCING TERMS	
Contracting Strategy	Engineering Procurement Construction Management (owner assumes project risks for performance, schedule and cost)
Type of Debt Financing	TBD
Repayment Term of Debt	15 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
Return on Equity	12%
ANALYSIS TIME PERIODS	
Capital Expenditure Period	Coal Plants: 5 Years
Operational Period	30 years
Economic Analysis Period (for IRROE)	35 Years (capital expenditure plus operational period)
TREATMENT OF CAPITAL COSTS	
Capital Cost Escalation During Capital Expenditure Period (nominal annual rate)	3.6%
Distribution of Total Overnight Capital over the Capital Expenditure Period (before escalation)	5-Year Period: 10%, 30%, 25%, 20%, 15%
Working Capital	zero for all parameters
% of Total Overnight Capital that is Depreciated	100% *(this assumption introduces a very small error even if a substantial amount of TOC is actually non-depreciable)*
ESCALATION OF OPERATING REVENUES AND COSTS	
Escalation of COE (revenue), O&M Costs, and Fuel Costs (nominal annual rate)	3.0%

C.2 DCF Analysis and Cost of Electricity

The retrofit installation costs are spread across 3 years prior to operation as outlined in this study. In reality, the retrofit installation could occur at any time during the life of the plant. The year the retrofit occurs determines the impact on the cost of electricity for the plant. Intuitively, the earlier the additional retrofitting costs and any associated derating occur, the higher the subsequent cost of electricity will be. But because of the varying value of money and commodities over time, the final impact of the additional costs and any associated derating may decrease depending on the specific type and magnitude of the costs. A simplified discounted cash flow (DCF) analysis using the levelized cost of electricity is one method of quantifying the time value of money and the impact of retrofitting in later years.

Estimating COE with Capital Charge Factors

For scenarios that adhere to the global economic assumptions listed in Exhibit C-1, the following simplified equation can be used to estimate COE as a function of total overnight cost (TOC)[6], fixed O&M, variable O&M (including fuel), capacity factor and net output. The equation requires the application of the capital charge factor (CCF) listed in Exhibit C-2.

Exhibit C-2 Capital Charge Factors for COE Equation

Finance Structure	Low Risk IOU
Capital Charge Factor (CCF)	0.116

All factors in the COE equation are expressed in base-year dollars (this study assumes 2011). As shown in Exhibit C-1, all factors (COE, O&M, and fuel) are assumed to escalate at a nominal annual inflation rate of 3.0 percent. Accordingly, all first-year costs (COE and O&M) are equivalent to base-year costs when expressed in base-year (2011) dollars.

$$COE = \frac{(CCF * TOC) + OC_{Fixed} + (CF * OC_{Variable})}{(CF * MWh)}$$

where:

COE = revenue required by the generator ($/MWh, equivalent to mills/kWh), expressed in first-year dollars, to secure the specified return on equity (assuming that the COE escalates at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant)

[6] Although TOC is used in the simplified COE equation, the CCF accounts for escalation during construction and interest during construction (along with other factors related to the recovery of capital costs).

CCF =	capital charge factor corresponding to the applicable finance structure and capital expenditure period
TOC =	total overnight cost, expressed in *base-year dollars*
OC_{Fixed} =	the sum of all fixed annual operating costs, *expressed in base-year dollars*
$OC_{Variable}$ =	the sum of all variable annual operating costs, including fuel at 100 percent capacity factor, *expressed in base-year dollars*
CF =	plant capacity factor, assumed to be constant over the operational period
MWh =	annual net megawatt-hours of power generated at 100 percent capacity factor

Use of the capital charge factor, and the equation above, assumes that the CO_2 capture technology is commercial at the time of retrofit and therefore considered as financially low risk. This CCF also includes a five year initial plant construction period and three year CO_2 capture retrofit construction period; this includes the interest during construction, debt term and interest rates, and other financial assumptions.

<u>Levelized Cost of Electricity</u>

To examine the overall impact of the retrofit year (additional costs and associated decrease in net power) on the average COE for the life of the plant, a simplified DCF analysis approach was used to estimate the LCOE. All assumptions made for this analysis are consistent with the quality guidelines for energy system studies (QGESS)[xix], and the power systems financial model (PSFM)[xx].

The cost of electricity for each year was multiplied by a discount factor (Discount Factor = $1/(1 + \text{Discount Rate})^{\text{Year}}$) using the discount rate recommended in the QGESS. The LCOE was calculated as a weighted average of those values over the initial 30 year operating period.

APPENDIX D Supercritical PC without CO_2 Capture

Exhibit D-1 Supercritical PC Performance Summary

Plant Output		
Steam Turbine Power	580,400	kW
Gross Power	**580,400**	**kW**
Auxiliary Load		
Coal Handling and Conveying	440	kW
Pulverizers	2,780	kW
Sorbent Handling & Reagent Prep	890	kW
Ash Handling	530	kW
Primary Air Fans	1,300	kW
Forced Draft Fans	1,660	kW
Induced Draft Fans	7,050	kW
SCR	50	kW
Baghouse	70	kW
Wet FGD	2,970	kW
Miscellaneous Balance of Plant	2,000	kW
Steam Turbine Auxiliaries	400	kW
Condensate Pumps	800	kW
Circulating Water Pumps	4,730	kW
Ground Water Pumps	490	kW
Cooling Tower Fans	2,440	kW
Transformer Losses	1,820	kW
Total	**30,420**	kW
Net Power	549,980	kW
Net Plant Efficiency (HHV)	39.3%	
Net Plant Heat Rate (HHV)	8,687	Btu/kWh
Coal Feedrate	409,528	Lb/hr
Percent CO_2 Capture	0%	
CO_2 Emission Rate	1,675	Lb CO_2/MWh

Exhibit D-2 Supercritical PC Block Flow Diagram

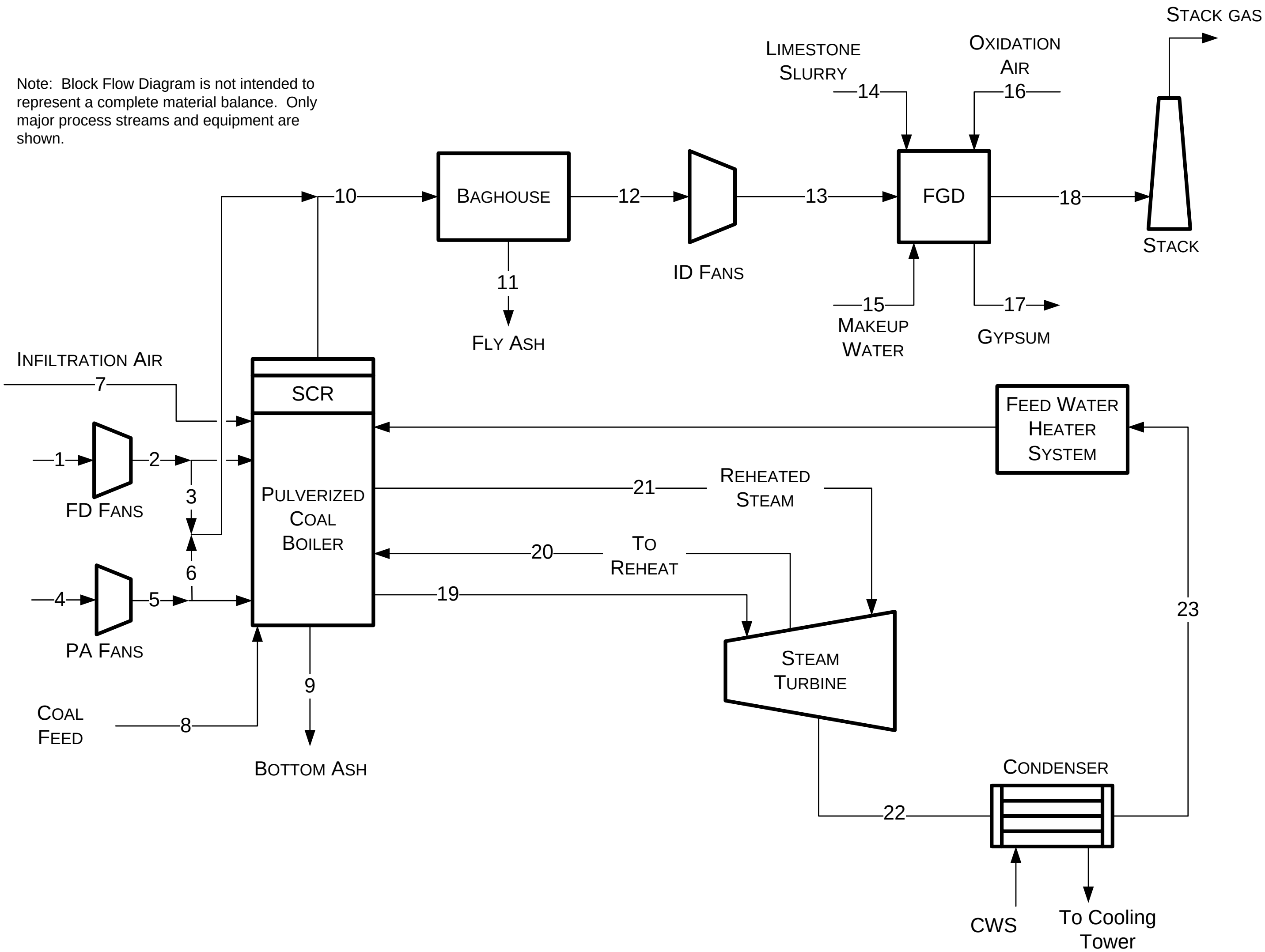


Exhibit D-3 Supercritical PC Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	106,734	106,734	3,161	32,787	32,787	4,512	2,466	0	0	150,191	0	150,191
V-L Flowrate (lb/hr)	3,080,006	3,080,006	91,224	946,145	946,145	130,215	71,175	0	0	4,467,142	0	4,467,142
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	409,528	7,942	31,769	31,769	0
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2
Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.7	---	132.8
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049

	13	14	15	16	17	18	19	20	21	22	23
V-L Mole Fraction											
Ar	0.0087	0.0000	0.0000	0.0128	0.0000	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1450	0.0000	0.0000	0.0005	0.0004	0.1353	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0870	1.0000	1.0000	0.0062	0.9995	0.1517	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7324	0.0000	0.0000	0.7506	0.0000	0.6808	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0247	0.0000	0.0000	0.2300	0.0000	0.0240	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	150,191	5,223	21,158	1,601	387	163,343	203,684	168,854	168,854	154,082	154,082
V-L Flowrate (lb/hr)	4,467,142	94,099	381,174	46,465	6,985	4,713,221	3,669,421	3,041,946	3,041,946	2,775,839	2,775,839
Solids Flowrate (lb/hr)	0	40,646	0	0	63,259	0	0	0	0	0	0
Temperature (°F)	357	59	59	333	135	135	1,100	669	1,100	101	103
Pressure (psia)	15.3	15.0	14.7	45.0	14.8	14.8	3,514.7	710.8	655.8	1.0	245.0
Enthalpy (Btu/lb)[A]	138.0	---	-20.1	76.4	---	128.0	1,494.7	1,325.4	1,570.2	853.8	71.2
Density (lb/ft^3)	0.052	---	62.622	0.154	---	0.067	4.319	1.165	0.722	0.004	62.009

Exhibit D-4 Supercritical PC Capital Cost Summary

Case: SuperCritical PC
Plant Size: 550.0 MW,net Estimate Type: Conceptual **Cost Base (Jun)** 2011 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$19,885	$5,077	$11,756	$0	$0	**$36,718**	$3,221	$0	$5,991	**$45,929**	$84
2	COAL & SORBENT PREP & FEED	$13,363	$742	$3,344	$0	$0	**$17,448**	$1,483	$0	$2,840	**$21,772**	$40
3	FEEDWATER & MISC. BOP SYSTEMS	$51,492	$0	$23,858	$0	$0	**$75,351**	$6,689	$0	$13,325	**$95,364**	$173
4	PC BOILER											
4.1	PC Boiler & Accessories	$185,402	$0	$105,641	$0	$0	**$291,043**	$28,011	$0	$31,905	**$350,959**	$638
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$185,402**	**$0**	**$105,641**	**$0**	**$0**	**$291,043**	**$28,011**	**$0**	**$31,905**	**$350,959**	**$638**
5	FLUE GAS CLEANUP	$96,010	$0	$32,384	$0	$0	**$128,395**	$11,972	$0	$14,037	**$154,404**	$281
5B	CO2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Accessories	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$21,086	$1,146	$14,144	$0	$0	**$36,376**	$3,252	$0	$5,172	**$44,799**	$81
	SUBTOTAL 7	**$21,086**	**$1,146**	**$14,144**	**$0**	**$0**	**$36,376**	**$3,252**	**$0**	**$5,172**	**$44,799**	**$81**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$66,640	$0	$8,221	$0	$0	**$74,861**	$6,572	$0	$8,143	**$89,576**	$163
8.5	Let Down Turbine	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$29,629	$1,248	$15,074	$0	$0	**$45,950**	$3,784	$0	$6,978	**$56,712**	$103
	SUBTOTAL 8	**$96,269**	**$1,248**	**$23,294**	**$0**	**$0**	**$120,811**	**$10,357**	**$0**	**$15,121**	**$146,289**	**$266**
9	COOLING WATER SYSTEM	$14,774	$7,749	$13,728	$0	$0	**$36,251**	$3,318	$0	$5,380	**$44,949**	$82
10	ASH/SPENT SORBENT HANDLING SYS	$5,436	$161	$7,058	$0	$0	**$12,654**	$1,177	$0	$1,422	**$15,254**	$28
11	ACCESSORY ELECTRIC PLANT	$20,761	$7,933	$21,603	$0	$0	**$50,297**	$4,327	$0	$6,770	**$61,394**	$112
12	INSTRUMENTATION & CONTROL	$10,579	$0	$10,610	$0	$0	**$21,190**	$1,871	$0	$2,842	**$25,903**	$47
13	IMPROVEMENTS TO SITE	$3,342	$1,921	$7,164	$0	$0	**$12,427**	$1,233	$0	$2,732	**$16,392**	$30
14	BUILDINGS & STRUCTURES	$0	$27,220	$25,804	$0	$0	**$53,024**	$4,683	$0	$8,656	**$66,363**	$121
	TOTAL COST	**$538,399**	**$53,196**	**$300,389**	**$0**	**$0**	**$891,984**	**$81,594**	**$0**	**$116,193**	**$1,089,771**	**$1,981**
	Total Overnight Costs (TOC)										**$1,346,847**	**$2,449**

Exhibit D-5 Supercritical PC O&M Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2011
SuperCritical PC					Heat Rate-net (Btu/kWh):	8,686
					MWe-net:	550
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	39.70	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Total Plant			
Skilled Operator	2.0		2.0			
Operator	9.0		9.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	14.0		14.0			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$6,329,450	$11.508
Maintenance Labor Cost					$7,297,262	$13.267
Administrative & Support Labor					$3,406,678	$6.194
Property Taxes and Insurance					$21,795,421	$39.627
TOTAL FIXED OPERATING COSTS					**$38,828,811**	**$70.595**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$10,945,892**	**$0.00284**
Consumables	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Fill Cost		
Water (/1000 gallons)	0	3,884	1.67	**$0**	**$1,898,367**	**$0.00049**
Chemicals						
MU & WT Chem.(lbs)	0	18,799	0.27	$0	$1,470,290	$0.00038
Limestone (ton)	0	488	33.48	$0	$4,768,288	$0.00124
Carbon (Mercury Removal) (lb)	0	0.00	1.63	$0	$0	$0.00000
MEA Solvent (ton)	0	0	3,481.91	$0	$0	$0.00000
NaOH (tons)	0	0	671.16	$0	$0	$0.00000
H2SO4 (tons)	0	0	214.78	$0	$0	$0.00000
Corrosion Inhibitor	0	0	0.00	$0	$0	$0.00000
Activated Carbon (lb)	0	0	1.63	$0	$0	$0.00000
Ammonia (19% NH3) ton	0	73.52	330.00	$0	$7,084,773	$0.00184
Subtotal Chemicals				**$0**	**$13,323,351**	**$0.00346**
Other						
Supplemental Fuel (MBtu)	0	0.00	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.31	8,938.80	$0	$806,639	$0.00021
Emission Penalties	0	0.00	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$806,639**	**$0.00021**
Waste Disposal						
Fly Ash (ton)	0	381	25.11	$0	$2,795,191	$0.00073
Bottom Ash (ton)	0	95	25.11	$0	$698,798	$0.00018
Subtotal-Waste Disposal				**$0**	**$3,493,989**	**$0.00091**
By-products & Emissions						
Gypsum (tons)	0	759	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$0**	**$30,468,238**	**$0.00790**
Fuel (ton)	0	4,920	63.58	**$0**	**$91,341,571**	**$0.02370**

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