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CO_2 MITIGATION ECONOMICS FOR EXISTING COAL-FIRED POWER PLANTS

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by

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ABSTRACT

Electric power generation represents one of the largest sources of CO_2 emissions in North America. A major issue in the analysis of CO_2 mitigation options is the fact that over 45% of total electric power generation in North America is from coal. These existing coal-based power plants have the highest CO_2 emissions of any power systems yet are the lowest cost electric generators. Retrofit CO_2 reduction or recovery of existing coal-based power plants has definite advantages—using the existing site infrastructure, having facilities that are mostly paid-off or amortized, and having high baseline CO_2 emissions. However, retrofits also have disadvantages—significant capacity and efficiency losses that require replacement capacity addition, and increased fuel use depending on the choice of CO_2 mitigation technology.

TransAlta is a major coal-based electric power generator in Canada and the United States. As discussed at www.transalta.com in the Sustainable Development section under "Our Actions," TransAlta has a goal of zero net greenhouse gas emission (including trading and offsets) for its Canadian operations by 2024. As part of this ambitious goal, TransAlta funded site-specific analysis by engineering vendors of two noteworthy PC retrofit CO_2 capture options: flue gas CO_2 scrubbing (amine) and oxygen combustion with flue gas recycle. SFA Pacific standardized and summarized these two analyses into single-page evaluation spreadsheets that include mass and energy balances, capital cost buildups, and economics. Additional options are developed in this simplified format for easy comparison on a consistent and transparent basis. This approach facilitates the objective identification of specific situations, innovative options, and R&D opportunities that could significantly improve CO_2 reduction, capture, separation, and utilization.

BACKGROUND

North America has over 320,000 MWe of existing coal-based power plants, or 35% of the total installed capacity. However, this coal capacity generates over 45% of the total annual power in North America. Assuming typical CO_2 emissions of 1.0 metric ton (mt) per net MWh of coal power plant generation and 79 % annual capacity factors, the existing coal-fired power plants in North America generate 2.2 billion metric tons per year (mt/yr) CO_2 emissions or 0.6 billion mt/yr carbon equivalent. Therefore, existing coal-fired power plants represents one third (33%) of the total North American CO_2 emissions which are estimated at 1.8 billion mt/yr carbon equivalent in 2000. SFA Pacific concluded that power plants will be required to meet a disproportionate share of any CO_2 reductions in the future [1]. This is because power generators cannot move to China, as many CO_2 intensive industries would be economically forced to do if faced with CO_2 reduction mandates or carbon taxes for only Annex 1 nations. In addition, power plants are the largest "point source" CO_2 emitters with large potential for CO_2 reductions and all electric consumers would share the resulting costs of CO_2 reductions.

Most of the existing coal-based power plant capacity is PC boilers that are 25-35 years old (1965-1975 start-up) and in the 200-600 MWe unit size range with subcritical single reheat steam cycles. Emission controls vary greatly depending on where and when the power plant was originally built and the sulfur content of the coal. Nevertheless, the "typical" existing PC power plant uses low sulfur subbituminous coal, low NO_x burners, and an electrostatic precipitator (ESP)—but with no flue gas desulfurization (FGD). The age of these "typical" existing PC power plants means the original capital costs are mostly paid-off or amortized.

This 320,000 MW of existing coal-based power plants in North America represents a major challenge and uncertainty in the economic analysis of CO_2 mitigation options since these plants have the highest CO_2 emissions, yet are the lowest cost electric generators. The high CO_2 emissions are due to the use of high carbon content fuel and the relatively low thermal efficiency of the older existing PC power plants. The low electric costs are due to the lower cost of coal relative to other generation types and the fact that these existing facilities are mostly paid-off.

It is possible to recover the CO_2 from an existing PC power plant. The most commonly considered CO_2 retrofit options are add-on PC flue gas CO_2 amine scrubbers or conversion of the PC boilers to oxygen combustion with flue gas recycle to match temperature and heat/mass flow rates of the original boiler design. TransAlta contracted engineering vendors to assess each of these options. Fluor Daniel analyzed the PC flue gas add-on CO_2 amine scrubber retrofit. ABB Combustion Engineering (now Alstom Power) and ABB Lummus analyzed oxygen combustion PC boiler retrofit with Air Liquide supplying the oxygen data. These engineering studies showed that both options are technically sound with minimal technical risk. However, the economic analysis was more complex due to the many options and assumptions in calculating the retrofit CO_2 emissions avoidance economics.

A way to compare these and other CO_2 mitigation options for existing PC power plants on a simple, consistent, and transparent basis would be a valuable tool. Such an approach has already been developed by SFA Pacific for new power plants [2,3]. The original TransAlta retrofit studies were reviewed and converted to single-page spreadsheets with standardized performance, capital cost, and economics. Other technologies and fuels were then added so a variety of options could be compared on a consistent and transparent basis for various economic input assumptions.

ECONOMIC BASIS FOR COMPARISON OF CO_2 EMISSIONS AVOIDANCE COST

Calculating the cost of CO_2 emissions avoidance options for an existing PC power plant first requires baseline CO_2 emissions and a baseline cost of electricity. **Figure 1** is the single-page spreadsheet developed for the existing PC power plant baseline. The technical performance is from ABB Combustion Engineering, the original PC boiler power plant vendor that was also utilized by TransAlta for the oxygen combustion retrofit analysis. SFA Pacific then developed capital and operating costs (current dollars). A key economic issue involves the remaining capital of the existing power plant yet to be amortized and how to treat this "old" capital in a way that is consistent with the "new" capital for CO_2 retrofits. We chose the approach of refinancing the old capital that is not yet amortized along with the new capital to keep it simple, consistent, and transparent. Therefore, the existing PC baseline economics in **Figure 1** include fuel, operating and maintenance (O&M), and only a fraction of the original power plant capital at current dollar value that is refinanced based on a simple annualized capital charge rate.

Figures 2 – 4 are examples of the single-page spreadsheet developed for several of the many CO_2 reduction options. **Figure 2** is for conversion of the existing PC baseline power plant to oxygen combustion with flue gas recycle and CO_2 recovery/compression. The performance is from the original TransAlta analysis. Capital costs were only slightly modified to reflect on-site oxygen manufacturing, power purchased during the retrofit tie-in shutdown time, and the remaining capital yet to be amortized for the original power plant. For effective CO_2 transport and utilization or disposal, all CO_2 recovery options include CO_2 drying and compression to 135 atmospheres pressure (2,000 psig). Non-condensable gases such as N_2, O_2, SO_2 and NOx are stripped from the liquid CO_2 during compression. Additional power generation capacity is added in all CO_2 recovery options to maintain the same net power output as the original PC power plant. This is quite important due to the large power requirements associated with oxygen manufacturing and CO_2 compression to high pressure. The additional power generation capacity is based on natural gas combined cycle (NGCC), as this is currently the option of choice for most new power plants. Furthermore, the capacity addition is too small for coal technology and the NGCC capital cost and emissions are much lower.

Figure 3 summarizes CO_2 recovery by a retrofit amine scrubber on the PC boiler flue gas. A small natural gas boiler with low-pressure extraction steam turbine generator is added to meet the additional power of CO_2 compression and large stripping steam needs of the CO_2 amine stripper. This avoids major retrofit costs to the existing PC boiler and steam turbine generator. A high efficiency FGD system is added to protect the amine from degradation by SO_2. High efficiency NOx removal was not required based on discussion with the Fluor Daniel, which has commercial experience with flue gas CO_2 amine scrubbers.

Figure 4 summarizes CO_2 recovery by conversion of the PC boiler to hydrogen fired coal gasification combined cycle (H_2-CGCC) power plant. This design assumes minimal reuse of the existing coal-based power plant facilities. The H_2-CGCC and NGCC options are based on the new state-of-the-art "H" class gas turbine, as was the basis for the original SFA Pacific analysis of CO_2 mitigation options for new power plants [2,3]. The CGCC designs are also based only on commercially well proven: coal gasification process, CO water gas shift, (to convert $CO + H_2O$ into $CO_2 + H_2$), and CO_2 recovery technologies. It is significant to note that the retrofit H_2-CGCC becomes larger net capacity and higher efficiency than the original PC power plant, even with the oxygen requirements, CO_2 recovery and CO_2 compression. High-pressure gasification reduces the CO_2 compression cost and power requirement, as the CO_2 is flashed from the CO_2 stripper at a lower but still significant pressure. It is also interesting to note that the oxygen requirement of H_2-CGCC is only one-forth that of the oxygen combustion option per net MW of electricity.

Table 1 is the summary spreadsheet, which contains economic inputs that links all the CO_2 mitigation options spreadsheets. This permits changing economic input at one location and observing the impact on all options. The retrofit economics for CO_2 reduction are presented in several ways in **Table 1.** Most important is the new electricity cost, which is shown in $/kWh and as a percent of the original existing PC baseline power cost. The electricity cost includes capital charges, fuel, O&M, and CO_2 disposal or credits.

Table 1 includes CO_2 avoidance in $ per metric ton ($/mt) CO_2 (avoided to the atmosphere, not recovery) which is also an important value due to potential for CO_2 emissions trading in the future. This is calculated for each option from the $/MWh net electricity cost increase (due to CO_2 reduction) divided by the net mt CO_2 per MWh emissions reduction. It should be noted that calculating $/mt CO_2 emissions <u>avoidance</u> at constant net MWh of electricity generation is much different and more important than calculating $/mt CO_2 <u>capture</u>, especially if the CO_2 capture significantly reduces capacity or efficiency.

Cost of CO_2 emissions avoided in this retrofit power plant analysis are significantly lower than the previous SFA Pacific analysis of new power plants [2,3]. This is principally due to the baseline CO_2 emission assumptions. The previous SFA Pacific analysis of CO_2 mitigation options for new power plants assumed a baseline CO_2 emission per MWh for a new "state-of–the-art" NGCC power plant, which is only one third that of an existing coal-fired power plant and about half that of new "state-of-the-art" coal power plants.

RESULTS

A number of additional single-page spreadsheet cases were added to the two modified TransAlta cases. This expanded model enables direct comparison of various fuel and technology options on a consistent economic basis. There are three general groupings of retrofit options presented in this analysis:

1. Conversions to lower CO_2 emission technologies <u>without</u> CO_2 recovery. This includes total coal replacement with: • 100% natural gas (via NGCC), • natural gas with coal (via gas turbine hot windbox repowering), • biomass with coal (via cofiring), • continued 100% coal use with replacement high efficiency coal technology (coal gasification combined cycle, CGCC).

2. Conversions <u>with</u> CO_2 recovery technologies. This includes new replacement H_2-fired CC power plants via NG and coal gasification plus the previously discussed retrofits of the existing PC power plant. In all cases the recovered CO_2 is purified and compressed to high pressure. The H_2-fired CGCC and amine CO_2 flue gas scrubber retrofit cases include second options of partial CO_2 reduction to the same CO_2 emission as a new NGCC power plant without CO_2 recovery.

3. Conversions to technologies with <u>no</u> net CO_2 emissions. This includes nuclear, 100% biomass (assuming the biomass is replanted), and wind turbines. However, all three are impractical for various reasons and are included only for reference. Nuclear is questionable until decommissioning, waste, and liability issues are resolved. Biomass is limited by high energy cost, supplies, land requirements, and transportation. The low energy content per hectare of land limits biomass to about a 50-mile radius and thereby only about 50 MW of power. Wind turbines are limited by inherently low annual capacity factors and requirement for back-up power when there is no wind.

It should be noted that no credits have been taken for the inherent reduction in NOx, SOx, Hg and fine particulate emissions (including sub-2.5 micron particles) for existing PC power plant conversion for CO_2 reduction. Most of the CO_2 recovery options reduce all of these emissions to very low levels. Finally, all options are compared on the same economic basis. No special subsidies have been given to any option, including renewables, to preserve a "level playing field" and objective analysis.

Table 1 is the summary sheet of various existing PC retrofit options for CO_2 reduction or capture. All the economic input variables are clearly shown by shading and placing in boxes. The economic input assumptions with the greatest impact on the results are the cost of capital (annual capital charge rate), original PC plant capital yet to be amortized, natural gas price, and CO_2 disposal cost or especially credits.

There are large beneficial applications for CO_2 sequestration such as enhanced oil recovery (EOR) or recovery of coal bed methane (CBM) once the CO_2 is available at high pressure. Therefore, a CO_2 credit assumption can be quite real in several areas of North America such as Alberta, Illinois, New Mexico, North Dakota, Oklahoma, Saskatchewan, Texas, and Wyoming. There are already commercial CO_2 utilization projects in these areas. Specifically, over 28 million mt/yr of CO_2 is currently being sequestered for EOR in the Permian Basin of West Texas and New Mexico [4]. This existing CO_2 sequestration is equivalent to the CO_2 generated by about 4,000 MWe of coal power plants or 9,000 MWe of NGCC power plants. Furthermore, there are already six process plants recovering anthropogenic CO_2 for use in EOR including 1.8 million mt/yr CO_2 from the large coal gasification plant in North Dakota. In fact, two CO_2 emission credit trades have been made for anthropogenic CO_2 recovery from process plants that is sequestered via EOR [5]. Finally, there are many potential CO_2 mitigation projects based on EOR and CBM in planning, driven by the recent rise in oil and gas prices. Any CO_2 avoidance value or trading credits would further improve the economics and environmental benefits. It is interesting to note that at 8,500 standard cubic feet (scf) of (or 0.45 mt) CO_2 per barrel (or 0.14 mt) of incremental oil recovery (EOR), the CO_2 from burning that oil is equal to the CO_2 sequestered in the EOR. There are currently CO_2 EOR projects operating at this rate and any value for CO_2 avoidance would increase the CO_2 use per barrel of oil recovered.

The results in **Table 1** can be varied significantly with the key economic input assumptions. Nevertheless, we found the following results of most use:

1. Only moderate CO_2 credits make the continued use of coal-based power with CO_2 recovery significantly more economic than renewables and even more economical than the conversion to NGCC when natural gas prices are greater than about $3 per million Btu. However, if there is a moderate ($10/mt) CO_2 disposal charge (added to the plant-gate high-pressure CO_2), natural gas conversion is more economical until natural gas prices reach about $6 per million Btu.
2. Co-firing natural gas or biomass with coal adds only moderately to costs but also provides only moderate CO_2 reductions. Coal with CO_2 capture or conversions to 100% natural gas or 100% renewables represent much larger CO_2 reductions.
3. Assuming continued coal use with CO_2 recovery for both cases, replacement or repowering with a new H_2-fired CGCC was more attractive than an existing PC retrofit with amine CO_2 flue gas scrubbing or oxygen combustion. This is due to the large capacity and efficiency losses of PC retrofits, whereas H_2-CGCC increases both capacity and efficiency relative to the original PC unit. In addition, the gasification option is essentially an all new power plant and the traditional emissions (SOx, NOx, Hg and fine particulates) are all reduced to near zero. The challenge of gasification is the larger "first costs" and fundamental suspicion of this complex chemical process by traditional coal boiler utilities. Nevertheless, we expect that more power generators will consider gasification repowering for existing coal power plant upgrades in the future, forced by the increased competition of deregulation. In addition, the dominant gasification vendor, Texaco, has already made equity investments in five of their last 12 commercial gasification projects [6].
4. Partial CO_2 reduction of an existing coal power plant to the same CO_2 emissions level as a new NGCC system (65% reduction) helps the retrofit fuel gas amine CO_2 scrubber option the most.

CONCLUSIONS AND DISCUSSION

The results of this analysis are useful in illuminating important characteristics of the various options and show that retrofits of existing coal power plants must be included in any objective analysis of CO_2 reduction options. The key economic issues appear to be the potential of CO_2 utilization producing a byproduct value as in the case of EOR or CBM. This opportunity already exists along the eastern slopes of the Rocky Mountains and the Great Plains of North America where large commercial CO_2 utilization projects already exist and new projects are being considered [4,5].

The foregoing conclusion is significant in view of the fact that only commercially available technologies were considered for this paper. Current development work by various organizations has the potential to improve both costs and performance. It is reasonable to assume that some of this development work can lead to capital cost and performance improvements of at least 10% over the next 5-10 years. Key organizations involved in this development work include: Alstom, ABB Lummus, Air Liquide, Air Products & Chemicals,

Alberta Innovation and Science, AOSTRA, American Electric Power, Argonne National Laboratory, BP Amoco, CANMET Energy Technology Center, Fluor Daniel, General Electric, U.S. National Energy Technology Laboratory, Praxair, Shell Oil, Texaco, TransAlta, and U.S. Department of Energy.

Key technologies that appear to have good opportunities for additional improvements include: CO_2 scrubbers (both low-pressure flue gas and especially high-pressure syngas from gasification), air separation (oxygen production), and gas turbines. There also appear to be potential improvements in technology integration. For example, small amounts of natural gas can be effectively used to consume all the residual oxygen in flue gas, thus reducing the costs of amine CO_2 scrubbing and oxygen-combustion flue gas compression. Furthermore, the new lower cost and simplified CGCC designs being developed by Texaco/General Electric/Praxair should also reduce CO_2 capture costs [7]. This design is based on higher pressure gasifiers with direct water quench cooling that will reduce the cost of water gas shifting of CO to H_2, CO_2 recovery and CO_2 compression.

The evaluation work addressed in this paper is ongoing. Cases are now being developed for various integration options and assumptions including advanced technology improvements. This approach is being taken not to promote, but to facilitate the objective identification of specific situations, innovative options, and R&D opportunities that could significantly improve CO_2 capture, separation, utilization, and applications.

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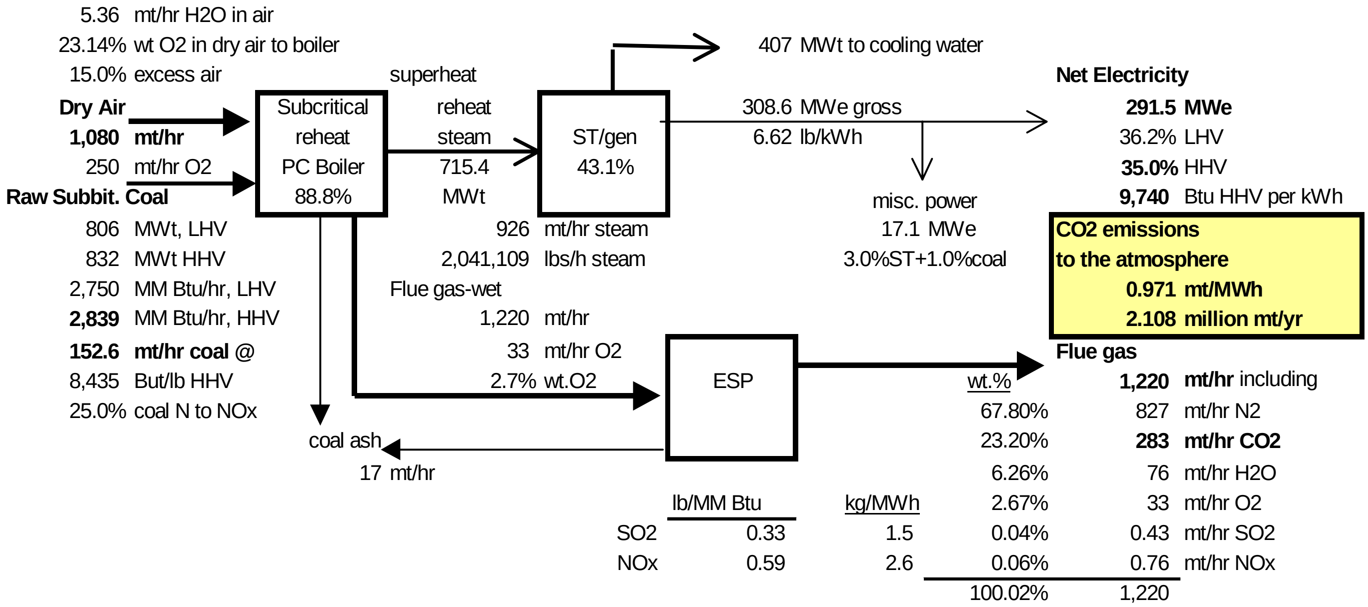
Figure 1

Baseline Existing Pulverized Coal (PC) Boiler

Basis: **Matching vendor's performance data**
Size, steam conditions & emission controls typical 25-35 year old PC units
Capital cost and electric cost estimates by SFA Pacific

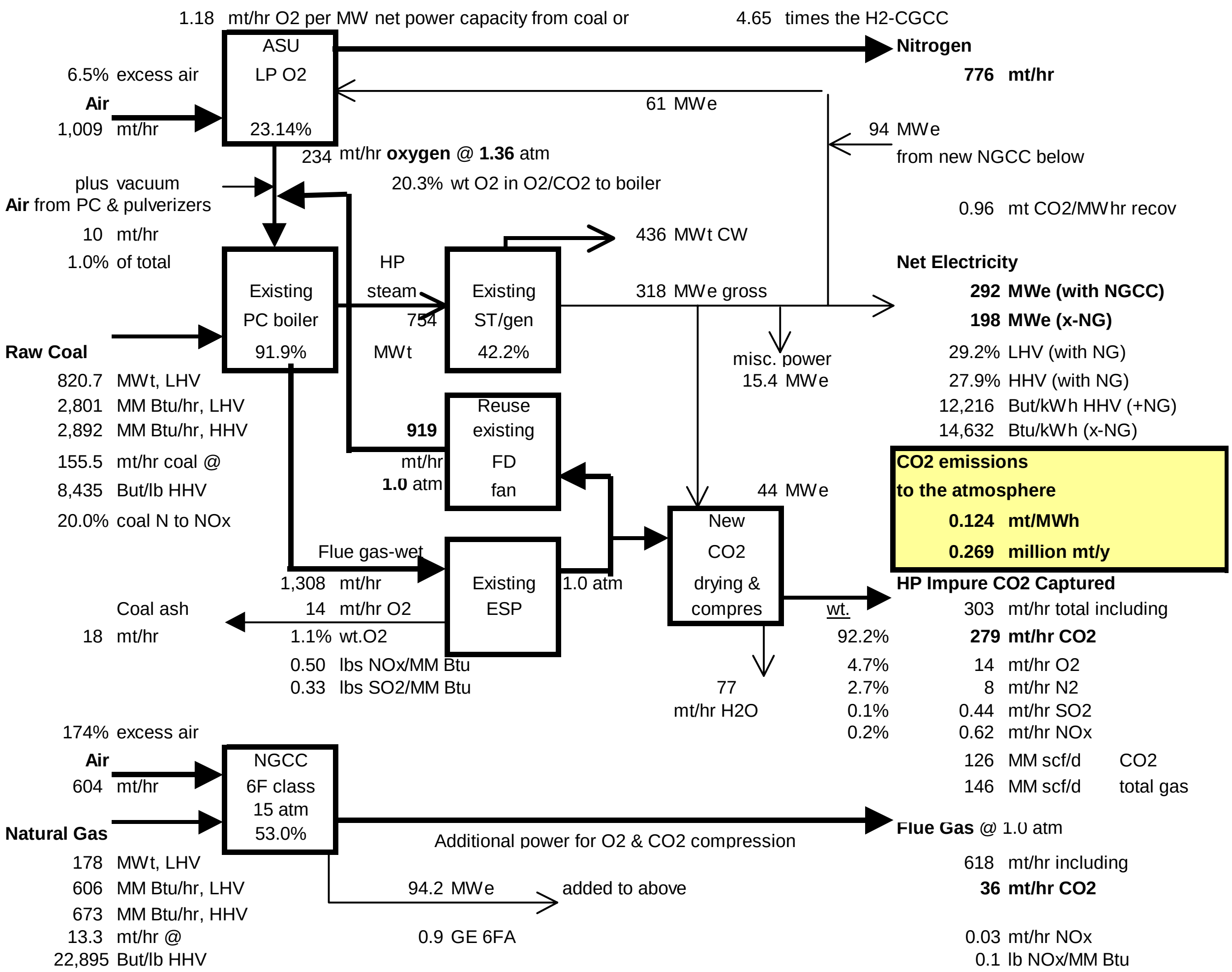


			US dollars		
Capital Costs if new	**key unit costs**		**$ MM**	**$/kW net**	**Notes**
Solids handling/prep	8,000	$/mt/d raw coal	29	101	
PC boiler	60	$/lb/hr reheat steam	122	420	
ST/gen & water sys	200	$/kWe gross	62	212	
ESP	4,000	$/mt/hr raw flue gas	5	17	
Subtotal of process units captial cost			218	749	
General facilities	20%	of process units capital	44	150	
Eng. fees & contingencies	10%	of process units capital	22	75	
Total capital cost of original new plant			**284**	**974**	
Partially paid-off existing PC	10%	of original capital remaining to be amortized	28	97	

	Inputs for summary			US dollars		
New PC Plant Electricity Cost		85%	ann. capacity factor	**$ MM/yr**	**$/MWh**	
Capital charges		15%	of capital per yr	43	19.6	
O&M		4%	of capital per yr	11	5.2	
CO2 emissions tax	$	-	per mt CO2	-	-	
Coal	$	0.52	per MM Btu LHV	11	4.9	
New PC Power Plant				**65**	**29.7**	**CO2 Emissions**
					Power Costs	**mt/MWh**
Partially paid-off PC costs		15%	/yr of remaining capital + fuel, O&M & CO2 costs	**26**	**12.1**	**0.971**
					Existing PC baseline	
Marginal load dispatch costs		50%	of O&M + fuel & CO2 costs		**7.5 $/MWh**	

Source: **SFA Pacific, Inc.**

Figure 2
Retrofit Existing PC Boiler with O2 and Recycle CO2

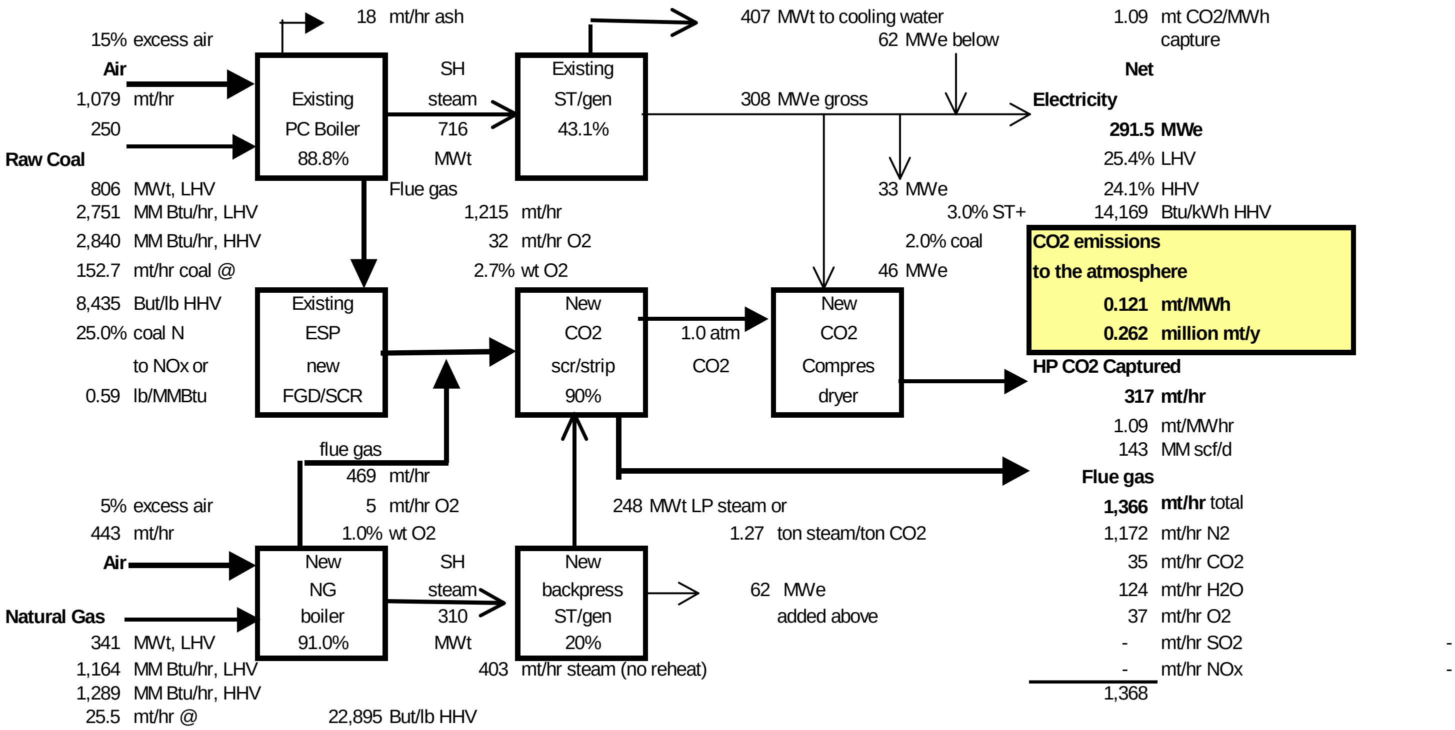


Capital Costs	key unit costs		$ MM	$/kW net	Notes
Existing solids handling	-	$/mt/d coal	-	-	
Existing PC modification	7%	of original boiler cost	9	29	modify fans, air heaters,
Existing ST/gen	-	$/kWe gross	-	-	economizer & pulverizers
Modified ESP?	-	$/mt/hr flue gas	-	-	
New ASU & LP O2 compre	19,000	$/mt/d oxygen	106	365	high purity to reduce N2 & Ar
New small NGCC	500	$/kW net CC	47	161	
New CO2 drying & compre	1,050	$/kWe power	47	160	trace O2, N2, SO2 & NOx
Subtotal of new & retrofit process units capital cost			209	715	increase compression costs
General facilities	20%	of process units capital	42	143	
Eng. fees & contingencies	10%	of process units capital	21	72	
New Capital			**271**	**930**	
Payoff existing PC	10%	of original capital	28	93	
Retrofit outage power	30	$/MWh for 0.10 year	7	22	
Total Capital			**306**	**1,049**	

Electricity Cost	Inputs for summary		US dollars $ MM/yr	$/MWh	
	85%	ann. capacity factor			
Capital charges	15%	of new capital per yr	41	18.7	
Payoff existing PC	15%	of PC capital per yr	4	2.0	
Retrofit outage power	15%	of power cost per yr	1	0.4	
O&M	4%	of capital per yr + PC	22	10.2	
CO2 emissions tax	$ -	per mt CO2	-	-	
CO2 disposal or use	$ (10)	per mt CO2	(21)	(9.6)	trace O2, N2, SO2 & NOx may
Natural gas	$ 4.43	per MM Btu LHV	20	9.2	impact value
Coal	$ 0.52	per MM Btu LHV	11	5.0	**CO2 Emissions**
O2 retrofit of existing PC			**78**	**36.0 $/MWh**	**0.124 mt/MWh**
Baseline existing PC reference				**12.1**	**0.971**
		net change		**23.9**	**-0.847**
O2 retrofit of existing PC		**relative to existing PC**		**298%**	**-87.2%**
					$ 28 /mt CO2 avoided or
					$ 103 /mt carbon avoided

Source: **SFA Pacific, Inc.**

Figure 3
Retrofit Existing PC Boiler with Amine Flue Gas CO2 Scrubber



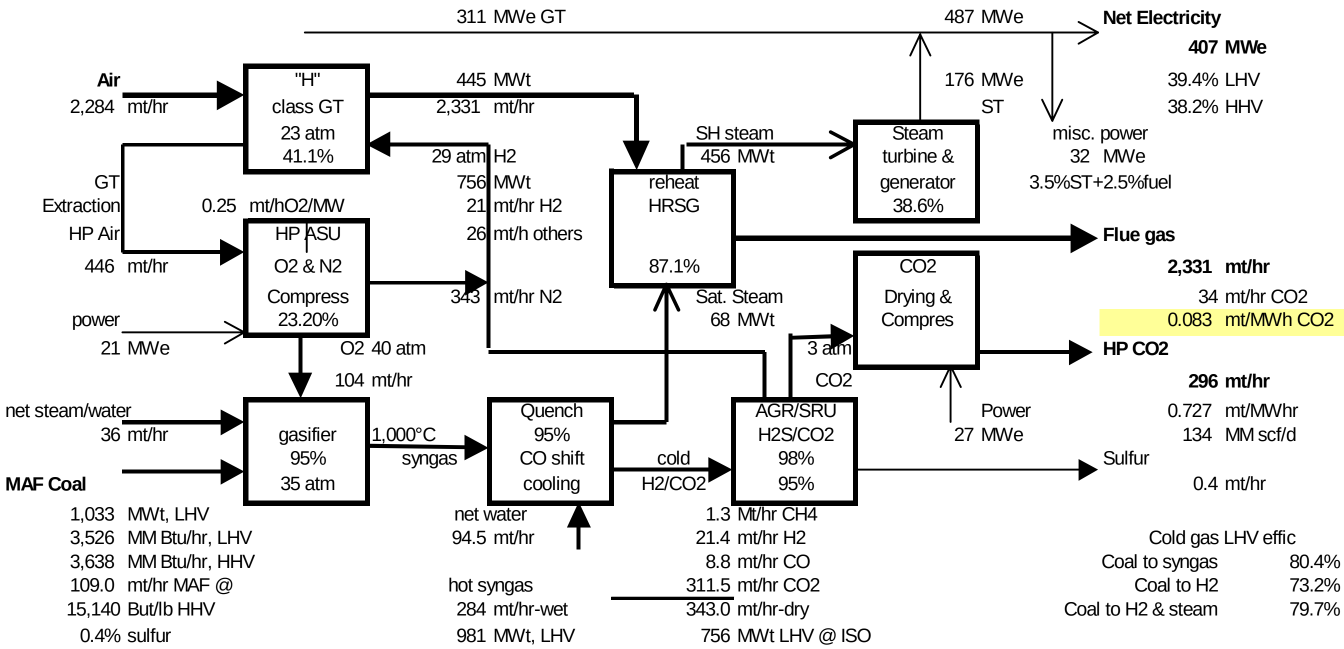
Capital Costs	key unit costs		$ MM	$/kW net
Existing solids handling	-	$/mt/d raw coal	-	-
Existing PC boiler	-	$/mt/hr flue gas	-	-
Existing ST/gen	-	$/kWe gross	-	-
New FGD-caustic wash	15,000	$/mt/hr PC flue gas	18	63
New SCR ?	-	$/mt/hr PC flue gas	-	-
Existing ESP	-	$/mt/hr PC flue gas	-	-
New NG boilers	15	$/lb/hr no RH steam boiler	13	46
New extraction ST/gen	300	$/kWe ST	19	64
New CO2 scrubber	25,000	$/mt/hr PC+NG flue gas	42	144
New CO2 stripper	130,000	$/mt/hr CO2	41	141
New CO2 drying & compress	1,000	$/kWe power	46	159
Subtotal of new & retrofit process units capital costs			180	617
General facilities	20%	of process units capital	36	123
Eng. fees & contingencies	10%	of process units capital	18	62
New Capital			**234**	**802**
Payoff existing PC	10%	of original capital	28	97
Retrofit outage power	30	$/MWhr for 0.10 year	7	22
Total Capital			**269**	**921**

		Inputs for summary		**US dollars**		
Electricity Cost		85%	ann. capacity factor	**$ MM/yr**	**$/MWh**	
Capital charges		15%	of capital per yr	35	16.2	
Payoff existing PC		15%	of PC capital per yr	4	2.0	
Retrofit outage power		15%	of power cost per yr	1	0.5	
O&M		4%	of capital per yr + PC	21	9.5	
CO2 emissions tax	$	-	per mt CO2	-	-	
CO2 disposal or use	$	(10)	per mt CO2	(24)	(10.9)	
Natural gas	$	4.43	per MM Btu LHV	38	17.7	**CO2 Emissions**
Coal	$	0.52	per MM Btu LHV	11	4.9	**mt/MWh**
CO2 retrofit of existing PC+ new NGB				**86**	**39.8**	**0.121**
Baseline existing PC reference					**12.1**	**0.971**
			net change		**27.7**	**-0.850**
CO2 retrofit of existing PC+ new NGB		**relative to existing PC**			**330%**	**-87.5%**
					$	**33 /mt CO2 avoided or**
Marginal load dispatch costs		50%	of O&M + fuel & CO2 costs		**$**	**120 /mt carbon avoided**
CO2 retrofit of existing PC+ new NGB					**16.5**	
Baseline existing PC reference					**7.5**	

Source: **SFA Pacific, Inc.**

Figure 4

H2-Fired CGCC with CO2 Recovery from Syngas



	key unit costs		US dollars $ MM	$/kW net	Notes
Capital Costs					
Solids handling/prep	10,000	$/mt/d coal	26	64	saving from existing coal systems
HP ASU & N2/O2 compressor:	22,000	$/mt/d O2	55	134	
Gasifier	220,000	$/mt/hr raw syngas	63	154	
Quench, shift & cooling	140,000	$/mt/hr product gas	48	118	
Acid gas scrubber	50,000	$/mt/hr syngas	17	42	
Acid gas stripper	60,000	$/mt/hr H2S&CO2	18	44	
Sulfur recovery units	900,000	$/mt/d sulfur	9	23	
Gas turbine	300	$/kW GT gross	93	229	air extraction
HRSG boiler	95	$/kWt SH steam	43	106	
ST/gen & water systems	220	$/kWe ST gross	39	95	
CO2 drying & compress	1,000	$/kW	27	65	
Subtotal of new & retrofit process units capital costs			437	1,074	
General facilities	20%	of process units capital	87	215	potential saving of existing GF
Eng. fees & contingencies	10%	of process units capital	44	107	
New Capital			**569**	**1,396**	
Payoff existing PC	10%	of original capital	28	70	
Total Capital			**597**	**1,466**	

	Inputs for summary			US dollars $ MM/yr	$/MWh		
Electricity Cost		85%	ann. capacity factor				
Capital charges		15%	of capital per yr	85	28.1		
Payoff existing PC		15%	of PC capital per yr	4	1.4		
O&M		4%	of capital per yr	23	7.5		
CO2 emissions tax	$	-	per mt CO2	-	-		
CO2 disposal or use	$	(10)	per mt CO2	(22)	(7.3)		
Fuel	$	0.52	per MM Btu LHV	14	4.5		**CO2 Emissions**
H2-CGCC with CO2 control				**104**	**34.2**	**$/MWh**	**0.083 mt/MWh**
Baseline existing PC reference					**12.1**		**0.971**
			net change		**22.2**		**-0.888**
H2-CGCC with CO2 control			**relative to existing PC**		**284%**		**-91.5%**
						$	**25 /mt CO2 avoided or**
						$	**91 /mt carbon avoided**
Marginal load dispatch costs		50%	of O&M + fuel & CO2 costs				
H2-CGCC with CO2 control					**1.0**		
Baseline existing PC reference					**7.5**		

Source: **SFA Pacific, Inc.**

Table 1

Summary Economic for CO2 Reduction from Existing Coal Power Plants

Technical basis is explained in detail on Existing PC worksheet

Recovered CO2 is dried and compressed to 135 atmospheres (2,000 psig)
Simple mass and energy balances based on mt/hr and MWt(**LHV**)/MWe

Capital cost basis is explained in detail on Existing PC worksheet

In summary, all costs are constant 1999 US dollars with no escalation or interest during construction
Assumed baseline is an existing PC unit that is partially paid-off & **refinanced** for CO2 modification
Therefore, **total capital includes** added capital for old PC payoff & power during shutdown

Consistent unit cost from mass and energy balances

Key economic input variables **shaded and located in black boxes** **plus linked to all worksheets**

Sub-Bituminus Coal		**Natural Gas**				
$ 0.50	/MM Btu **HHV**	$ 4.00	/MM Btu **HHV**	**Operating factor**	85%	Annual capacity factor
$ 0.52	/MM Btu LHV	$ 4.43	/MM Btu LHV	**Capital charges**	15%	of capital per yr
50.58%	**C by wt**	80.00%	**CH4 by wt**	**Yet to amortize**	10%	of original capital
2.89%	**H**	17.00%	**C2H6**	**Non-fuel O&M**	4%	of capital per yr
14.32%	**O**	1.00%	**N2**	**Variable O&M cost**	50%	of total O&M
0.61%	**N**	2.00%	**CO2**	**Replacement power**	30	$/MWh for retrofit shutdowns
0.14%	**S**	100.00%	total	**General facilities**	20%	of process units capital
11.46%	**ash**			**Engineering fees, contingencies & startup**	10%	of process units capital
20.00%	**moisture**			**CO2 emissions tax**	$ -	/mt CO2 or $ - /mt carbon
100.00%	total			**CO2 disposal costs or EOR (- credits)**	$ (10)	/mt CO2 or $ (36.67) /mt carbon
						$ (0.53) /1,000 scf

Worksheet Name	**Description/**comments	**Capital $/kW**	**Electric costs including any CO2 tax or credits relative to existing PC** $/MWh	% power of baseline	% CO2 of baseline	$/mt CO2 avoided
	If new (cost & performance reference)	974	**29.7**	**246%**		
Existing PC	**Baseline PC assuming partially paid-off**	**97**	**12.1**	**baseline**	**baseline**	**baseline**
	Subcritical steam cycle & no SO2 or NOx controls					
NGCC	**Replacement NGCC**	523	**38.2**	**316%**	-65%	$ 41
	State-of-the-art "H" class GT					
NG-Repower	**Retrofit hot windbox NG-GT repowering**	324	**25.2**	**209%**	-29%	$ 46
	Aero GT due to size, lower exhaust temp.					
Bio-cofire	**Biomass cofiring in existing PC**	188	**16.7**	**139%**	-8%	$ 62
	10% biomass energy mixed with coal feeding				if replanted	
CGCC	**Replacement CGCC with minimal reuse**	1,171	**33.2**	**275%**	-31%	$ 70
	Conventional gasifier, cleanup &" H"-GT					
H2-NGCC	**Replacement H2-CC with CO2 recovery**	931	**49.4**	**410%**	-96%	$ 40
	Conventional O2-ATR with H2/N2 fired H-GT					
H2-CGCC	**Replacement H2-CGCC with CO2 recovery**	1,466	**34.2**	**284%**	-91%	$ 25
	Conventional O2-gasifier, shift & N2/H2 fired H-GT					
H2-CGCC-65%	**H2-CGCC only to same CO2 as new NGCC**	1,374	**34.4**	**285%**	-67%	$ 35
	Conventional O2-gasifier, shift & N2/H2 fired H-GT					
O2-PC	**Retrofit PC with O2 & CO2 recycle**	1,049	**36.0**	**298%**	-87%	$ 28
	Add NGCC for O2 & CO2 power needs					
PC-CO2	**Retrofit PC with flue gas CO2 scrubber**	921	**39.8**	**330%**	-88%	$ 33
	Added NG boiler for CO2 power & steam needs					
PC-CO2-65%	**PC-CO2 only to same CO2 as new NGCC**	744	**34.2**	**284%**	-65%	$ 35
	Added NG boiler for CO2 power & steam needs					
Nuclear	**Replacement nuclear**	1,977	**59.2**	**490%**	-100%	$ 48
	uranium at $ 0.40 per MM Btu					
Wind Turbines	**Replacement wind turbine farm**	715	**62.0**	**514%**	-100%	$ 51
	25% annual capacity factor					
991	MW required for the same MWh/y as the original 292 MW PC					
Bio-GCC	**Replacement biomass GCC**	1,661	**63.4**	**525%**	-100%	$ 53
	Delivered biomass @ $ 50.00 /bone dry ton (BDT) or				if replanted	
	PCFBG $ 2.83 per MM LHV	based on below assumptions				
Based on:	$ 500 /hectare per yr	5 mt carbon/yr		50% wt. carbon	8,000 Btu/lb LHV	
gross revenues required for	land + O&M costs	per hectare		bone dry	bone dry	
thereby requires	340 hectares/MW or	1.31 sq. Miles per MW or		383 sq. Miles for 292 MW existing PC		

Source: **SFA Pacific, Inc.**