Strategy to Accelerate Deployment of Gasification-based Power Generation with Carbon Capture and Sequestration[@]

by

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SUMMARY

Comparative economic analysis is performed on two fossil energy-based approaches for supplying new electricity generating capacity for the State of California. One approach is natural gas combined cycle (NGCC), the other is coal-based integrated gasification combined cycle in which nominally 90% of CO_2 emissions are captured and sold for use in enhanced oil recovery, thus sequestering the CO_2 (IGCC+S). NGCC and IGCC+S plants are described and costs developed for configurations that employ selective catalytic reduction (SCR) and other controls to reduce emission levels of four criteria pollutants (NOx, SO_2, CO, and particulate matter) plus Volatile Organic Carbons/Hydrocarbons to extremely low levels to conform to stringent emission requirements in California. Levelized cost of electricity (LCOE) is computed for NGCC+SCR as a function of natural gas price and for IGCC+S+SCR as a function of selling price of CO_2, both at prices expected in California over a 20 year plant life beginning in 2010. Zero net emissions of the five targeted pollutants are achieved by purchase of tradable emission "offsets" at prices prevailing in California in 2001. Total cost for all offsets required is \$1.72/MWh and \$6.81/MWh for NGCC+SCR and IGCC+S+SCR, respectively. The coal-based technology is cost competitive with NGCC+SCR when CO_2 commands a price of \$1.00/Mcf and natural gas sells in the range \$4.50-5.50/million BTU. Under these conditions the LCOE falls in the range \$47-57/MWh, depending on capacity factor. For the configurations evaluated, both gas- and coal-based plants yield electricity production with no net emissions of the five targeted pollutants, but the atmospheric emission of CO_2 for IGCC+S is only about 1/5 as large as for NGCC.

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INTRODUCTION

There is scientific consensus that radiative trapping, or forcing, by so-called "greenhouse gases" accumulating in the atmosphere is contributing to the current trend in global warming (Cicerone et al., 2001; IPCC, 2001). Carbon dioxide generated in the course of preparation and use of fossil fuels is the GHG responsible for the largest amount of radiative forcing, representing over 80% of U.S. greenhouse gas emissions in 2000 (USEPA, 2002). From the late 18th century to the present, the atmospheric concentration of CO_2 increased by about 30%. Climate modelers have estimated that current carbon emissions must be cut by about 60% from current levels over the course of this century and reduced further going forward, to stabilize atmospheric CO_2 levels at no more than twice the pre Industrial level (Wigley et al., 1996). This will be difficult to do during a period of increasing energy use. World energy use is expected to increase by 59% from 1999 to 2020, of which the great majority, about 86%, will be derived from fossil sources (EIA, 2001b). If global warming is to be arrested clearly there is much work to be done in avoiding CO_2 emissions.

Fossil energy power plants are one logical place to look for any program aimed at reducing carbon emissions due both to the large amounts of such emissions and their concentrated nature, i.e., large individual sources. While retaining the use of fossil fuels for power generation, emissions can be reduced by three different approaches. One is to switch to a fuel with lower carbon intensity, as for instance from coal to natural gas. Another is by practice of greater efficiency on both supply and demand sides. The third is to capture carbon emissions and store them permanently or quasi-permanently (e.g., underground or in deep oceans), called engineered sequestration. This paper describes a market based approach for developing the technology necessary to practice carbon capture from coal-based power plants and sequestration on a commercial scale. The approach is to use integrated gasification combined cycle (IGCC) for power generation, a technology that facilitates capture of CO_2 from synthesis gas prior to combustion. We develop the expected economic performance of IGCC plants employing CO_2 capture for new generating capacity in California where the CO_2 would be salable for practice of enhanced oil recovery (EOR). This approach, dubbed IGCC+S, is compared with state-of-art natural gas combined cycle, NGCC, currently the lowest cost technology for new base load power generation capacity.

Plants that practice IGCC+S are expected to be ready for commercial deployment by about the year 2010. As detailed below, we have used published data for power system performance and cost in which a plant life of 20 years was assumed for both IGCC+S and NGCC. In the case of IGCC+S, nominally 90% of the carbon emissions are captured and used for EOR. To address the particularly stringent air quality requirements of California, we have developed modified configurations of both types of power generators that include selective catalytic reduction (SCR) units and other measures to reduce emissions of criteria pollutants to extremely low levels.

Analysis is developed to estimate the cost of electricity with zero net emission of five targeted pollutants by use of purchased pollution credits, or "offsets," for both NGCC and IGCC+S. The environmental performances of the two approaches to power generation are thus equivalent with respect to emission of the targeted pollutants. The IGCC+S approach has much lower emissions of CO_2, however, only about 1/5 as much as NGCC.

PRACTICE OF CO_2 EOR IN THE U.S.A.

Carbon dioxide enhanced oil recovery is one of several methods to increase the production of oil from mature reservoirs whose output is declining under normal production processes. It has been the fastest growing EOR method, and currently accounts for about 25% of total U.S. EOR production. The most common CO_2 EOR method is miscible displacement, in which the injected CO_2 dissolves in the oil, increasing its volume and reducing its viscosity. This increases the mobility of the oil, resulting in the production of oil bypassed by primary and secondary recovery methods. Typical CO_2 floods, under the right conditions, can yield an additional 7 to 15 percent of original oil in place (OOIP), extending the life of a producing field by as much as 15-30 years (Moritis, 2001).

The United States is the world leader in the development and application of CO_2 EOR. In fact, commercial practice began in West Texas in 1972, and continues to flourish there today. According to a 2002 EOR survey, there are a total of 67 CO_2 projects in the U.S., 49 of these in the Permian Basin area of West Texas and southeast New Mexico (Moritis, 2002). Other areas with activity include the Rocky Mountain region, Oklahoma, and Mississippi. Collectively, these projects produce some 190,000 barrels of incremental oil per day (bbl/d), accounting for about 3% of total U.S. crude production.

The CO_2 used at these fields comes from several different sources. Most is supplied by large underground deposits of naturally occurring and high purity CO_2. Three such domes presently serve the fields of the Permian Basin with over 1 billion cubic feet per day (Bcf/d) of 97-99% pure CO_2, and have recoverable reserves estimated at over 12 trillion cubic feet (Tcf). This CO_2 is delivered to the fields via an extensive network of dedicated pipelines. A smaller number of projects utilize CO_2 waste streams from industrial sources including natural gas processing facilities and fertilizer plants.

Prospects for growth and expansion of CO_2 EOR look promising. Analyst estimates for the Permian Basin indicate that over 50 additional projects, adding 500 million to 1 billion barrels of oil reserves, are economically viable at recent prices and current technology. One operator in the Permian Basin is planning to initiate 4-5 new projects in the next five years, in addition to 10-12 expansions of existing projects (Moritis, 2001). Others likely have similar plans.

Many industry experts believe that the next largest opportunity for CO_2 flooding beyond the Permian Basin exists in California. The fourth largest oil-producing state in the U.S., California has many large mature fields that may respond well to CO_2 injection; one recent estimate of demand was on the order of 3-5 Tcf of CO_2 over the next 20 years (Hirl, 2002). While no large, stable supply of CO_2 is readily available, operators in the San Joaquin Basin are considering this EOR technique to boost production. In another DOE-sponsored project, Chevron Texaco is in the midst of conducting a pilot injection study at their Lost Hills field.

The field, discovered in 1910, has had a cumulative oil production of only 135 million barrels or 5% of OOIP, largely due to its low permeability. Under CO_2 injection, a rapid oil response has been observed and it is hoped that oil recovery can be increased to 20% of OOIP, effectively quadrupling overall production. If proven successful in this field, the technique could help recover billions of barrels of oil trapped in the siliceous shales and diatomite reservoirs of this rich petroleum province (Montgomery et al., 2000).

CO_2 for this California pilot project is being trucked over 120 miles to the injection site at a cost of $3.50/Mcf (Perri et al., 2000). This illustrates both the importance of the project to the oil resource base of this region as well as the need to secure a convenient CO_2 supply. In order to meet this anticipated need for CO_2, Ridgeway Petroleum is considering building a pipeline from its newly discovered deposits of highly concentrated CO_2 (plus helium) beneath the Arizona/New Mexico border region. The St. John's formation contains an estimated 14.8 Tcf of CO_2 in place, along with 64 Bcf of helium (Jarman, 2001). However, the pipeline would need to be some 600 miles in length and cross some very mountainous terrain, making it a costly and potentially risky endeavor. Ridgeway Petroleum is therefore carefully evaluating the California CO_2 market.

The economics of a CO_2 EOR project is heavily tied to the price of oil and availability of CO_2. CO_2 purchases constitute the single largest cost of a CO_2 EOR project (even at the low cost of natural CO_2). A reliable, nearby source of CO_2 is a key for oil field operators to consider CO_2 injection. Production response and effectiveness of enhancement is highly reservoir specific with net utilization rates typically in the range of 2.5 – 11 Mcf CO_2 injected per bbl incremental oil produced, averaging about 6 Mcf/bbl (Martin and Taber, 1992). Recent prices for CO_2 from various sources are roughly as follows: $0.65/Mcf from natural domes, and $1/Mcf from natural gas processing facilities.

As long as oil prices do not decline significantly, the next few years will likely see strong growth in CO_2 EOR. It has been estimated that if pure and inexpensive CO_2 were available to all U.S. oil fields, total demand would be on the order of 60 – >100 Tcf (Martin and Taber, 1992). Due to the disperse locations of the target fields and increasing urgency of reducing greenhouse gas emissions, utility plant CO_2 emissions may well become a growing part of the supply mix.

FOSSIL FUEL-BASED POWER GENERATION WITH CO_2 CAPTURE FOR USE IN EOR

Capital and operating costs for both natural gas- and coal-based generators were taken from a report prepared by the Parsons Group under the direction of EPRI and USDOE (EPRI, 2000). It was noted that coal gasification is a particularly favorable approach to power generation when CO_2 capture is practiced because it provides for CO_2 removal from the syngas following a water gas shift reaction. Since CO_2 is present in the shifted syngas at elevated pressure and high mole fraction, a physical solvent, such as Rectisol, can be used for its removal. Subsequent recovery of CO_2 from a physical solvent requires less energy than for a chemical solvent, such as an amine, which is needed to capture CO_2 from flue gas. The first

Parsons report (EPRI, 2000) provides flow sheets, capital and operating costs for a number of process approaches to power generation using natural gas and coal, with and without CO_2 capture. Processes configured to capture CO_2 do so at a nominal 90% capture rate.

For the special case of fossil fuel-based power generation where collected CO_2 can be used for EOR, collection of the CO_2 does not represent an unrecompensed extra capital and operating cost, rather a second revenue stream besides sale of power. An earlier paper considered the economics of power generation and of capturing CO_2 from natural gas- and coal-based power generators (Ruether et al., 2002a). It was shown that for prices of coal and natural gas, and revenues from sale of electricity and CO_2, that are expected to prevail in the U.S. through 2030, the lowest cost approach to generating electricity is NGCC. Where collected CO_2 could be sold for the practice of EOR, however, coal-based IGCC with capture, IGCC+S, was competitive with NGCC. It was also shown that NGCC with capture, abbreviated NGCC+S, was significantly more expensive than either NGCC or IGCC+S. This latter finding is due to the fact that the incremental capital cost to provide for capture is somewhat higher for NGCC than for IGCC, but the CO_2 captured per kWh is about twice as high for IGCC+S as for NGCC+S. Similarly, the heat rate for NGCC+S is higher than for NGCC, and with fuel being a large operating cost for generators using natural gas, the added fuel cost for NGCC+S was not balanced by sufficient additional revenue from sale of CO_2.

In a subsequent paper, an updated cost and performance analysis for IGCC+S prepared by the Parsons Group (Schoff et al., 2002) was used to redo the comparison of the profitability of NGCC and IGCC+S. Financial incentives in the form of income tax credits for avoiding CO_2 emissions to the atmosphere were described (Ruether et al., 2002b). The capital and operating costs of generating approaches analyzed in the two earlier papers are summarized in Table 1. Note that the capital cost is lower and the heat rate is higher for the IGCC+S plant described by Schoff et al. (2002) than for the IGCC+S plant described in the earlier report (EPRI, 2000). Both factors improve the profitability of IGCC+S when collected CO_2 is sold. The combination of more favorable process economics and tax incentives for IGCC+S resulted in its calculated profitability being as good as that of NGCC in the second analysis (Ruether et al., 2002b).

Table 1
Cost & Performance for Fossil Energy Generators

Technology	Thermal Eff., HHV, %	Carbon Emissions, kg CO_2/kWh[1]	Total Plant Cost, $/kW	LCOE @ 65% cap. factor, $/MWh
NGCC[2]	53.6	0.338	496	33.5
NGCC, nomin. 90% capture[2]	43.3	0.040	943	54.1
IGCC[2]	43.1	0.718	1263	52.4
IGCC, nomin. 90% capture[2]	37.0	0.073	1642	65.7
IGCC, nomin. 90 % capture[3]	35.4	0.073	1510	62.6

1 Feed coal: Illinois #6
2 “Evaluation of Fossil Fuel Power Plants with CO_2 Removal,” EPRI, 2000.
3 "Updated Estimate of Fossil Fuel Power Plants with CO_2 Removal,” Schoff et al., in press.

Note that the levelized cost of electricity (LCOE) given in Table 1 does not include revenue from the sale of CO_2.

In both of our previous papers we have not taken into account differences between NGCC and IGCC plants in emissions per kWh of pollutants associated with power generation from fossil fuels. In the present work we consider five such pollutants that are subject to control via the federal Clean Air Act and other regulations:

NOx
SO_2
CO
PM10 (particulate matter 10 micrometers and larger)
VOC/HC (volatile organic carbons/hydrocarbons)

The first four pollutants above are termed “criteria pollutants,” which are controlled by federal ambient air quality standards.

As detailed below, emission performance by IGCC is good when compared to federal New Source Performance Standards, which prescribe maximum allowable emissions of certain pollutants for new generators. This standard is not high enough to indicate that a technology will receive siting permits where there are preexisting air pollution problems, however. If an air quality district is already out of compliance with respect to ambient air concentrations of one or more criteria pollutants, or emission limits for VOC/HC, authorities will not permit any new stationary sources above a threshold size that would add to emissions (ENSR, 1988). The emission rate of the proposed new source for the pollutant that is out of compliance is noted, and project developers must arrange to purchase “offsets” of at least as much emissions as their proposed project would produce. Such offsets are offered for sale by existing permitted emission sources that are producing emissions below their permit level.

Our study focuses on California as a region that would be a good candidate for installation of IGCC+S generators because of its projected need for additional generating capacity and its unserved market for CO_2 for use in EOR. If IGCC+S generation is environmentally acceptable and economically competitive with NGCC, it will receive careful scrutiny from State energy planners and power project developers. There is broad agreement in the State that it would be beneficial to diversify sources of electricity away from those requiring natural gas.

Air quality problems throughout the State of California are well known, and differences between emissions of NGCC and IGCC+S generators that might be considered small or negligible elsewhere might be important in obtaining air emission permits anywhere in the State. For this reason, the present analysis develops comparative economics for super clean versions of NGCC and IGCC+S generators, so clean in fact that by purchase of offsets as needed, they produce zero net emissions of all five targeted pollutants. Levelized cost of electricity is computed for both NGCC and IGCC+S generators with inclusion of cost of offsets at prevailing market rates in California for the pollutants.

It is admitted that choice of zero net emissions of all five targeted pollutants is an arbitrary point on a continuum of allowable emission levels that energy project developers could expect to encounter within California. Not all areas are out of compliance for all pollutants, so in some air quality districts finite emission rates would be allowed. On the other hand, where an air quality district was out of compliance for a particular pollutant, the offset requirement could be a factor larger than unity times the actual proposed plant emission, as a means of moving towards compliance. Thus the choice of zero net emissions for all five pollutants in the present analysis has no special significance, but it will give some general information about the costs of generating electricity at an extremely high level of environmental performance for both NGCC and IGCC+S technologies. Other pollutants not considered here, such as lead or mercury, might also be of interest. The five pollutants treated in this study were chosen because they were the only ones for which data were available on costs of tradeable offset allowances in California (California Environmental Control Agency, 2002).

ENVIRONMENTAL PERFORMANCE WITH RESPECT TO FIVE POLLUTANTS BY NGCC AND IGCC POWER GENERATORS

As noted above, the State of California publishes data for costs of tradeable emission offsets for the five pollutants identified. In this section we describe some additional technical measures that can be taken to reduce emissions for some of these pollutants below the levels achieved by usual NGCC and IGCC plant configurations.

Gray et al. (2002) estimated the impact on the performance and cost of adding an SCR unit to a baseline IGCC plant. SCR technology uses ammonia injection to reduce NOx to nitrogen in the reductive catalyst bed. Ammonia added in excess of the stoichiometric amount is likely to form ammonium bisulfite by reaction with sulfur oxides in the coal-derived combustion turbine exit gas. This could then foul heat exchangers in the heat recovery steam generator (HRSG). To avoid this fouling problem sulfur oxide levels of 2 ppm maximum is allowable in the HRSG gas. Sulfur is not a problem for NGCC systems because of the absence of sulfur in natural gas. With coal-derived syngas, however, the problem could be significant if special measures were not taken to reduce sulfur content of flue gas feed to the SCR. A drawback to use of SCR is ammonia slip, which adds to airborne emissions. About 3 ppm ammonia in the exit flue gas is expected.

The capital cost for adding SCR technology and associated reduction in sulfur emissions for an IGCC system is about $137/kW (Gray et al., 2002). The cost of adding SCR technology for NOx reduction in NGCC systems is assumed to be about $80/kW (NESCAUM, 1998). For this study it is also estimated that SCR technology will increase the overall cycle heat rate by about 0.5% for both systems due to the slight additional pressure drop caused by the catalyst bed (estimated to be less than 1 psi).

Table 2 compares the capital cost and environmental performance of several NGCC and IGCC system configurations. As seen both NGCC+SCR and IGCC+S+SCR exhibit low emissions compared with the New Source Performance Standards (NSPS) for electric utility steam generating units.

The California Clean Air Act includes a New Source Review (NSR) Program that limits emissions of criteria pollutants and their precursors for air quality control districts that are out of compliance (California Environmental Control Agency, 2002). In such situations no net increase in emissions from new or modified stationary sources larger than a threshold size is permitted. As part of the NSR, stationary sources are required to apply Best Available Control Technology (BACT) to reduce emissions and, in some cases, to provide emission reduction offsets to mitigate the impact of emissions from the source remaining after the application of BACT. For the present study it is assumed that both the NGCC and IGCC+S plants are located in non attainment regions for all five targeted pollutants. It is further assumed that offsets for all pollutant emissions above zero are purchased at the average price that prevailed in California in 2001, as shown in Table 3.

Table 2
Cost and Environmental Performance (Criteria Pollutant Emissions)

Comparison of IGCC and NGCC Plant Configurations

Emissions	NGCC	NGCC+SCR	IGCC+S	IGCC+S+SCR	New Source Performance Standards
NOx (lb/MWh)	0.19 (3)	0.04 (3)	0.475 (2)	0.094 (2)	1.6
SO_2 (lb/MWh)	Trace	Trace	0.669 (2)	0.091 (2)	12.0*
CO (lb/MWh)	0.12 (3)	0.12 (4)	0.30 (1)	0.30 (1)	N/A
PM (lb/MWh)	Trace	Trace	0.088 (1)	0.088 (1)	0.3 **
VOCs (lb/MWh)	0.014 (3)	0.014 (4)	0.01635 (1)	0.01635 (1)	N/A
Total Plant Cost ($/kW)	496	576	1510	1647	N/A

* Based on actual 1.2 lb/million BTU for a power plant operating at 10,000 heat rate
** Based on actual 0.03 lb/million BTU for a power plant operating at 10,000 heat rate
1. USDOE, 2000.
2. Gray et al., 2002.
3. Pavri and Moore, 2001.
4. GE Power web site www.gepower.com

Table 3
2001 Offset Prices Paid in California ($/ton)[1]

	NOx	SOx	CO	PM	VOC-HC
Average (mean)	$27,074	$12,809	$19,447	$46,148	$12,684
Median	$22,000	$7,500	$10,026	$25,000	$10,959
High	$104,000	$82,192	$43,836	$126,027	$66,000
Low	$774	$15	$45	$400	$967

1. California Environmental Control Agency, 2002

COMPARISON OF NGCC AND IGCC+S GENERATORS

For each generating technology described, levelized cost of electricity over an assumed 20 year plant life was computed in the first Parsons study using the well known approach developed by EPRI (EPRI, 2000). Investment was assumed to be in three forms: common stock, preferred stock, and debt, and assumed rate of return for each was given. Weighted cost of capital (before tax) was 10.30% based on current dollars, and 7.09% based on constant (year 2000) dollars.

LCOE is computed in the first Parsons report for assumed constant values of fuel, natural gas or coal, over the 20 year plant life. In our previous two papers in this series, we have used predictions of fuel prices and electricity revenues to generators that have been developed by the Energy Information Agency of the USDOE, and estimates of the selling price of CO_2 for use in EOR to compute year by year estimates of required selling price of electricity, RSPOE, in the State of California (Ruether et al., 2002a,b). The calculation of RSPOE is similar to calculation of LCOE, but the former allows for changing fuel prices. In addition, for power generation with CO_2 collection and sale, such as IGCC+S, we credit the producer with the expected revenue from CO_2, which acts to lower the RSPOE. We showed that the principal source of variability in RSPOE for natural gas-based generation was the price of natural gas, while for IGCC+S it was the value of CO_2. The EIA predicts the price of coal to electricity generators will be stable while declining slightly over the next several decades.

Tables 4 and 5 summarize much of our results from the earlier papers, where we treated conventional NGCC and IGCC technologies. The Tables show LCOE for NGCC and IGCC+S plants at 65% and 80% capacity factor, respectively, as a function of natural gas price to generators (for NGCC plants) and selling price of CO_2 (for IGCC+S plants) for prices expected in California. All prices in the present paper are in constant year 2000 dollars. We showed earlier that the price range for CO_2 used in the Tables, \$0.65-2.00/Mcf, spans the expected range over the period 2010-2030, with the most likely price being \$1.00/Mcf, equivalent to about \$19/tonne CO_2 (Ruether et al., 2002b).

Using the energy economic modeling program NEMS, the EIA predicts natural gas prices to electricity generators in California will fall in the range \$3.59-3.99 per million BTU for the period 2010-2020 for their Base Case (EIA, 2002). The NEMS model is based on fundamental considerations such as available reserves and expected progress in drilling technology. It does not anticipate price spikes based on contingent events such as droughts leading to reduced availability of hydro power, or heat waves leading to demand surges. A more empirical approach to prediction of gas prices is used in the GEMSET model of an electric grid (Rawls et al., 2002). Starting with a base of EIA price projections, adjustments are made using historic price variability, NYMEX Henry Hub closings for the current year and NYMEX Henry Hub futures prices for natural gas extending to 2008. The GEMSET model predicts natural gas prices to electricity generators in California will fall in the range \$4.68-5.19 per million BTU in the period 2010-2020. These two sets of predictions of natural gas prices in California explain the range used in Tables 4 and 5. Calculated values of LCOE for IGCC+S generation were made with an assumed fuel cost for coal of \$1.02/million BTU, the average value predicted by EIA for electricity generators over the period 2010-2020.

Table 4
LCOE for Base Configurations without SCR,
65% Capacity Factor. In $/MWh
Key: NGCC/IGCC+S

		Value of CO_2, $/Mcf		
		0.65	1.00	2.00
Price of Natural Gas, $/Million BTU	3.50	38.6/50.8	38.6/45.1	38.6/28.8
	4.00	41.8/50.8	41.8/45.1	41.8/28.8
	4.50	44.9/50.8	44.9/45.1	44.9/28.8
	5.00	48.1/50.8	48.1/45.1	48.1/28.8
	5.50	51.3/50.8	51.3/45.1	51.3/28.8

Table 5
LCOE for Base Configurations without SCR,
80% Capacity Factor. In $/MWh
Key: NGCC/IGCC+S

		Value of CO_2, $/Mcf		
		0.65	1.00	2.00
Price of Natural Gas, $/Million BTU	3.50	35.7/41.8	35.7/36.1	35.7/19.8
	4.00	38.9/41.8	38.9/36.1	38.9/19.8
	4.50	42.0/41.8	42.0/36.1	42.0/19.8
	5.00	45.2/41.8	45.2/36.1	45.2/19.8
	5.50	48.4/41.8	48.4/36.1	48.4/19.8

For each entry in the Tables, the first figure is the LCOE for NGCC plants and the second is the figure for IGCC+S plants. Step-shaped lines in each table indicate where price advantage changes between the two technologies. NGCC is favored at prices to the left and above the lines, while IGCC+S is favored below and to the right of the lines. For a value of CO_2 of $1.00/Mcf, the break point for the technologies is between $4.50-5.00/million BTU natural gas price at 65% capacity factor, while for 80% capacity factor, the break point falls between $3.50-4.00/million BTU. Operation at higher capacity factor favors IGCC+S because it is more capital intensive than NGCC. Note that at the highest value for CO_2 considered in the Tables, $2.00/Mcf, IGCC+S exhibits lower LCOE for all gas prices, and by a wide margin. This is one indication of how significant CO_2 revenues are for IGCC+S plants.

Tables 6 and 7 present similar information for the super clean configurations of NGCC and IGCC+S plants described in the present work that yield zero net emissions of five targeted pollutants. Average costs of offsets as shown in Table 3 have been included in costs of electricity shown in Tables 6 and 7. As before, lines through the Tables indicate break points where economic advantage between the two technologies shifts. At a CO_2 value of $1.00/Mcf and a capacity factor of 65%, the break point falls between natural gas prices of $5.00-5.50/million BTU. At 80% capacity factor and the same value for CO_2, the break point occurs between natural gas prices of $4.50-5.00. Operation at high capacity factor still is relatively more advantageous for IGCC+S than for NGCC. The offset costs included in the electricity prices shown in Tables 6 and 7 are $1.72/MWh and $6.81/MWh for NGCC and IGCC+S systems, respectively, yielding a differential for offset costs of $5.09/MWh. A number of entries in Tables 6 and 7 where NGCC exhibits lower LCOE than IGCC+S show the difference in cost of the two technologies to be less than $5.09/MWh. This indicates the importance of offset costs to the comparison of the two technologies. It also shows how comparative results for the two technologies will depend on the assumptions made concerning allowable levels of emission of pollutants.

Table 6
LCOE for Configurations with SCR,
65% Capacity Factor, Includes Offset Costs.
In $/MWh
Key: NGCC/IGCC+S

		Value of CO_2, $/Mcf		
Price of Natural Gas, $/Million BTU		0.65	1.00	2.00
	3.50	43.9/62.4	43.9/56.7	43.9/40.4
	4.00	47.1/62.4	47.1/56.7	47.1/40.4
	4.50	50.3/62.4	50.3/56.7	50.3/40.4
	5.00	53.6/62.4	53.6/56.7	53.6/40.4
	5.50	56.8/62.4	56.8/56.7	56.8/40.4

The relative importance of components of the LCOE values appearing in Table 7 can be visualized by inspection of Figure 1. It shows data from the middle column of Table 7 broken out by major components. The category “all other” includes fixed and variable (non fuel) operating costs.

Table 7
LCOE for Configurations with SCR,
80% Capacity Factor, Includes Offset Costs.
In \$/MWh
Key: NGCC/IGCC+S

Price of Natural Gas, \$/Million BTU	Value of CO_2, \$/Mcf: 0.65	1.00	2.00
3.50	40.6/53.7	40.6/47.1	40.6/31.7
4.00	43.8/53.7	43.8/47.1	43.8/31.7
4.50	47.0/53.7	47.0/47.1	47.0/31.7
5.00	50.3/53.7	50.3/47.1	50.3/31.7
5.50	53.5/53.7	53.5/47.1	53.5/31.7

Coal-based IGCC technology is still in the process of achieving commercial status, but early indication is that it will exhibit high system availability, and as noted earlier, this will lead to high capacity factor due to its relatively low variable operating cost. Consider the data in Table 8 from Tampa Electric Company's Polk Power Station, a single-train IGCC system using a Texaco pressurized, oxygen-blown gasifier. The power plant began operation in 1997 and is one of the USDOE's Clean Coal Technology projects.

Table 8
On-Stream Factors for Polk Power Station[1]

Year	Gasifier	IGCC	Combined Cycle
1999	69.9	68.3	81.8
2000	80.1	78.0	84.0
2001	65.4	64.2	76.1

1. Tampa Electric Company, 2002

Values in Table 8 indicate the fraction of hours in the indicated year that the unit was in operation. The on-stream factor for Combined Cycle exceeded that for IGCC because the plant is equipped to operate with distillate fuel as well as syngas. As experience is gained and designs are standardized, the already impressive figures in Table 8 for a demonstration plant can be expected to increase further for subsequent plants. This encouraging operating experience for IGCC technology suggests that the capacity factor for an IGCC+S plant would likely be closer to 80% than to 65%.

Tables 6 and 7 show how much revenue from electricity sales would be needed to cover the assumed capital cost structure for the two kinds of plants. How do the values of LCOE shown in the two tables compare to current revenues received by generators in California and expected future revenues? These are important questions, but they are difficult to answer due to the state of flux of the electricity system in California. Following the crisis of unprecedented high prices for electricity in 2001, two large investor owned utilities in the State filed for bankruptcy. The State government then empowered the California Department of Water Resources to enter into long term contracts with private power generators as a way of moderating prices of electricity to consumers. The CDWR subsequently entered into multiple contracts for purchase of electricity worth over $45 billion. Electricity sales governed by these contracts currently account for the great majority of power use in California. Spot market sales represent less than 5% of the market.

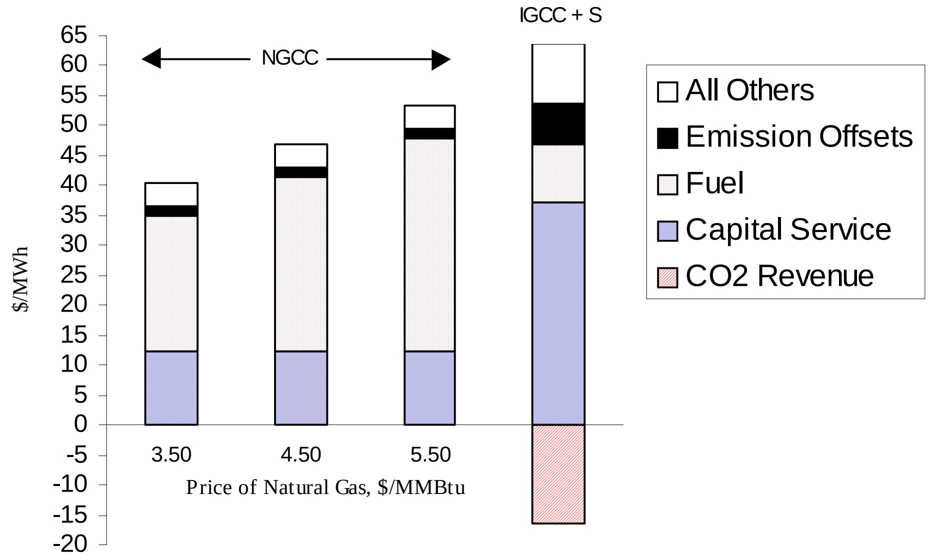
However, the California Public Utility Commission filed a legal brief with the Federal Energy Regulatory Commission in February, 2002, seeking to abrogate 44 transactions embodied in 32 contracts with 22 sellers entered into by the CDWR (CPUC, 2002). The CPUC argues in their brief that the contracts were entered into during a time when the State was under duress, that the sellers exercised unlawful market power, that the negotiated rates are "unjust and unreasonable," and that the contracts are therefore invalid. The brief charges that the challenged contracts exceed just and reasonable prices by some $14 billion on a net present value basis. The brief requests that the FERC rule that the contracts are no longer binding, or alternatively, that the agreed to rates for purchase of electricity be renegotiated. The FERC has not yet ruled on the petition of the CPUC.

Some anecdotal evidence is available to give some indication of what may come to be accepted as a reasonable range for electricity revenue to producers. At the high end is a price of $91.87/MWh, which is the maximum clearing price for all regions in the State currently posted on the web site operated by the California Independent System Operator (**http://oasis.caiso.com)**. This price is derived from a FERC Order posted on June 19, 2001. The price does not include a 10% uplift credit for uncertainty that was described in the FERC June 19 Order.

At the low end is a price of $45.80/MWh based on a calculation contained in the cited brief of the CPUC to the FERC. The CPUC quotes with apparent approval a calculation they claim was prepared by the private power producer Calpine of the price of electricity they required to realize a fair return on their investment. The calculation assumes a capital cost in the range $500-550/kW, a heat rate of 6800 BTU/kWh, a natural gas price of $3.50/million BTU, and a return on invested capital of 18%. From the capital cost and heat rate it appears that the generation plant described is a conventional NGCC. It should be mentioned that the nature of electricity offered for sale, e.g., whether it is base load or peaking, whether it is dispatchable, affects its value. The value of electricity claimed to have been prepared by Calpine appears to be for base load.

The lowest price energy among the transactions challenged in the CPUC brief is $58/MWh.

Figure 1
Components of LCOE for NGCC and IGCC + S
Plants with Zero Net Emissions of Criteria Pollutants[1]



[1] 80%capacity factor, CO_2 value $1.00/Mcf, Coal $1.02/MM Btu

It is clear that the calculation attributed to Calpine is an imperfect proxy for either of the super clean approaches for generation developed in the present paper, for NGCC or IGCC+S. The assumed cost of natural gas is at the low end of the range used in the present paper. The return on investment required by Calpine is higher than the weighted cost of capital used in the present work. It seems reasonable that power produced with substantially reduced emissions of pollutants would command a higher value than power that was not. Nevertheless, most of the values for LCOE appearing in Tables 6 and 7 are closer to $45.80/MWh than to $91.87/MWh, and all values are less than $91.87/MWh.

Thus, on an admittedly superficial level, it appears that power produced by configurations of NGCC and IGCC+S that employ SCR to reduce pollution emissions to very low levels could be economically competitive in California. Indeed, there are already some installations in California that employ NGCC+SCR. The new finding is that when CO_2 can be sold for use in EOR, a configuration of coal-based IGCC+S+SCR can be economically competitive with natural gas-based generators at the very highest levels of environmental performance.

The approach developed in this paper to commercializing IGCC with CO_2 capture, namely by selling the CO_2 for use in EOR, will be applicable to only a fraction of the locations where coal-based generators operate. To rein in greenhouse gas emissions as is required to stabilize climate while retaining use of fossil fuels for power generation will necessitate the large scale adoption of carbon capture and sequestration. Most of the facilities that capture and sequester will not likely be able to sell their CO_2. Still, the knowledge and experience that would be gained by building and operating IGCC+S generators for enabling CO_2 EOR would reduce technical risk and cost for other similar generators situated anywhere in the world, regardless of the type of repository for CO_2 that is employed.

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