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Gasification-based Power Generation with CO_2 Production for Enhanced Oil Recovery

by

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SUMMARY

Expected economic and CO_2 emission performance of two fossil-based technologies for providing new electric generating capacity in the State of California in the time frame 2010-2030 are compared. The two technologies are state of art natural gas combined cycle (NGCC) and coal-based integrated gasification combined cycle (IGCC). In the case of IGCC, it is assumed that nominal 90% of the CO_2 emissions are captured, pressurized, and sold for use in conducting enhanced oil recovery (EOR) in the State. This version of IGCC that includes CO_2 sequestration is dubbed IGCC+S. The specific carbon emissions to the atmosphere (kg C/net kWh) of IGCC+S are only about 1/5 those of NGCC.

Previous analysis has shown that NGCC and IGCC+S are both more economic than a third approach, capturing CO_2 from NGCC power plants. The present paper uses improved data describing process performance and cost of IGCC+S technology. It also describes two bases on which income tax credits might be established that would further improve the economics of IGCC+S operation. One tax credit would support the extra capital and operating costs of performing CO_2 capture while generating electricity. The other tax credit would encourage management of CO_2 EOR in oil fields so as to maximize the net storage of CO_2 in underground formations at the termination of oil recovery operations. The two income tax credits together would be worth about 0.42 cents/kWh as described.

Predicted costs of coal and natural gas and selling prices of electricity and CO_2 are used to estimate economic return of NGCC and IGCC+S plants installed in 2010 and operating 20 years. Both types of plant are predicted to cover their expected returns on invested capital. Depending on the plant capacity factor (65% and 80% modeled), selling price of CO_2 ($0.65, $1.00, and $2.00/Mcf modeled), the predicted price of natural gas in California in any given year, and whether the suggested income tax credits are included, the economic return of one or the other technology is higher. In summary, NGCC and IGCC+S appear to be very competitive for new generating capacity in California.

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 18^{th} 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. The present analysis estimates their expected economic performance over their book life, to 2030. Expected prices for coal or natural gas fuels and the expected revenue to generators from sale of electricity are estimated using the National Energy Modeling System (NEMS) economic forecasting program with input values as used by the Energy Information Agency to prepare *Annual Energy Outlook 2002* (EIA, 2001a). Historic price data are used to compute standard deviations for fuel prices and electricity revenues. A Monte Carlo analysis is used to develop a probabilistic estimate of economic performances for power generators using both IGCC+S and NGCC.

A previous paper presented similar analysis that compared economic performance of IGCC+S, NGCC, and NGCC with CO_2 capture and use for EOR, dubbed NGCC+S (Ruether et al., 2002).

Both IGCC+S and NGCC+S plants were assumed to achieve nominal 90% capture of CO_2 per the engineering study from which cost and performance figures were taken (EPRI, 2000). It was shown that NGCC was expected to yield the highest economic return over the assumed 20 year plant life, with the second best being IGCC+S. The technology NGCC+S gave the poorest economic return because it embodied disadvantages from both the other two technologies with little offsetting benefit. Because the heat rate of NGCC+S is higher than NGCC, the former is at greater risk than the latter from increasing price of natural gas. The incremental capital cost to permit capture of CO_2 is greater for NGCC than for IGCC per net kW of capacity. For NGCC+S, the volume of captured and salable CO_2 was insufficiently large to balance the extra costs of capital and fuel. It is noteworthy that IGCC+S was predicted to be profitable with no special financial incentive for carbon emission avoidance. If IGCC+S is used instead of NGCC for new power generation facilities, it would contribute to fuel diversification, reducing demand for natural gas. Further, it would help address global warming concerns by reducing carbon emissions. The specific carbon emission (kg C/net kWh) of IGCC+S is about 1/5 that of state-of-art NGCC.

The present paper extends the earlier analysis in a number of ways. A different approach is used to estimate revenue from sales of CO_2. Also, updated figures are used for the capital and operating cost and heat rate of the IGCC+S plants. Also, two approaches are developed for possible income tax credits that could be made available to practitioners of power generation with CO_2 capture and CO_2 EOR for avoiding carbon emissions to the atmosphere. As was done in the earlier paper, the expected economic performance of the most profitable coal-based generation technology, IGCC+S, is compared to that of the most profitable gas-based technology, NGCC.

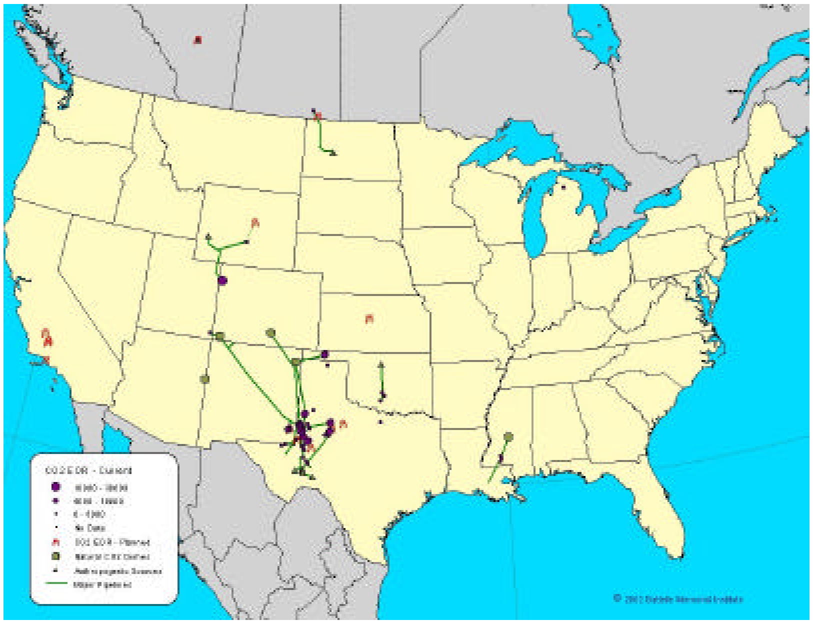
CO_2 EOR: OVERVIEW AND PROSPECTS

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. Several additional projects are in various stages of development.

Figure 1 shows the locations of active CO_2 EOR projects (small dots) along with several planned and pilot sites (oil derricks).

Figure 1
U.S. CO_2-EOR Landscape



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 (shown as the large dots in Fig. 1). 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.

Several other key areas are believed to be ripe for CO_2 injection as well, but have to this date lacked a dependable supply of economical CO_2. Where natural sources are not readily available, operators have been reluctant to risk large up-front capital on a CO_2 flood. However, several projects are underway that could lead to a vast expansion of this EOR technology. There are plans to extend a pipeline carrying waste CO_2 from the LaBarge natural gas plant in Wyoming further towards numerous fields in Central and Northern Wyoming (Moritis, 2001). In Central Kansas, a field demonstration sponsored in part by the U.S. Department of Energy (DOE) will examine the technical and economic feasibility of CO_2 flooding to recover residual oil from mature reservoirs in that region (Kansas Geological Survey, 2002). This will be the first time CO_2 has been used for EOR in Kansas, and if successful, could lead to the development of CO_2 supplies and the possible additional recovery of over 250 million barrels of incremental oil.

Yet, even with all of the action in Wyoming and Kansas, 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 tripling 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.

METHOD OF ANALYSIS

A probabilistic analysis was performed to determine the Required Selling Price for Electricity (RSPOE) for the period 2010-2030 for two technologies for electricity generation:

Natural Gas Combined Cycle (NGCC)

Integrated Gasification Combined Cycle with CO_2 capture and sequestration (IGCC+S)

For plants employing IGCC+S, nominal 90% of the CO_2 generated is captured and sold. As mentioned above, an earlier paper considered a third approach to power generation from fossil fuels, Natural Gas Combined Cycle with carbon capture and sequestration (NGCC+S). It was shown that NGCC+S is uneconomic compared to either of the above two generation approaches when captured CO_2 is marketable for practice of EOR. Therefore NGCC+S is not considered in the present paper.

A probabilistic analysis was also performed for the expected rate of return on common stock equity. For both analyses, equations were developed that employ price predictions that contain uncertainty. Monte Carlo simulation was used to estimate expected values of RSPOE and expected rate of return on common stock equity, as well as standard deviations for these estimates.

All historic prices were converted to year 2000 dollars by use of values for the Gross Domestic Product Implicit Price Deflator. Furthermore, price predictions are also stated in year 2000 dollars. Thus all prices in this paper refer to year 2000 dollars, and computed values for RSPOE and rate of return on common stock equity are expressed in constant dollars, before tax.

Data on both performance, e.g., heat rate or efficiency, and capital and operating costs for the NGCC technology studied in the present analysis were obtained from a report prepared by Parsons Energy and Chemicals Group under sponsorship of EPRI and USDOE (EPRI, 2000). In our earlier work, cost and efficiency data for the IGCC+S technology analyzed were taken from the same report. In this paper we use updated data for IGCC+S that have also been prepared by the Parsons group (Schoff et al.). The newer treatment includes a water wash step in syngas cleanup and improves treatment of equipment sparing compared to the earlier work. A summary of the data used in the present and earlier papers is given in Table 1. Also included is information for an IGCC plant that does not capture CO_2.

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, mill/kWh
NGCC	53.6	0.338	496	33.5
NGCC, nomin. 90% capture	43.3	0.040	943	54.1
IGCC	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.

Both Parsons studies computed capital costs for a plant sited in an East West region of the United States that exhibits a relative equipment/materials/labor cost factor of 1.0. In the present study we used these costs without adjustment. All technologies shown in Table 1 employ H class combustion turbines.

Table 1 shows that the updated treatment of IGCC+S lowers the thermal efficiency and the capital cost compared to the earlier Parsons study. The net result is a slightly lowered Levelized Cost of Electricity (LCOE) for IGCC+S in the updated analysis. Calculations for LCOE are presented in the Parsons reports for a number of power generation technologies at two average capacity factors, 65% and 80%. The figures for LCOE shown in Table 1 were computed by Parsons for natural gas and coal costs of \$2.70 and \$1.24 per million BTU (HHV), respectively. The figures for LCOE shown in Table 1 do not include revenue from the sale of CO_2. Table 1 shows that NGCC yields the lowest LCOE of all technologies considered and gives insight as to why this technology is currently the overwhelming choice for planned expansion of generating capacity.

Table 1 also shows that specific carbon emissions for power generated without capture via NGCC are less than half as large as those for IGCC without capture. With nominal 90% capture for both the gas- and coal-based technologies, specific carbon emissions for NGCC+S again is about half as large as IGCC+S. But notice also that specific carbon emissions for IGCC+S are only about one-fifth as large as for NGCC. Thus use of IGCC+S would represent a significant improvement in reducing carbon emissions compared to NGCC. Notice also that efficiency degradation is greater when capture is practiced with NGCC than with IGCC, and that the capital cost increment for providing capture is greater for NGCC than for IGCC. As explained in the first Parsons report, both observations are due to the different manner in which capture is accomplished in the two generating approaches, from the flue gas with NGCC and from syngas with IGCC (EPRI, 2000).

The size of plants for the NGCC and IGCC+S technologies studied here differed. Net power output is 310.8 MW for the NGCC plant and 386.8 MW for the IGCC+S plant. Some discussion is presented in the first Parsons report on the effect that scale would have on LCOE. No account is taken in the present work of the effect of scale on process economics.

Costs of electricity given in the Parsons reports include capture, drying, and pressurization of CO_2 to about 1222 psia (8.43 MPa) at which point it is ready for pipeline transport. In the present analysis an additional cost of $3.00/tonne of CO_2 (equivalent to $0.16/Mcf) has been added for transport from generating station to oil field (Wallace, 2000).

The Parsons reports show how LCOE was calculated for each of the technologies of interest in the present study for assumed constant values of fuel prices. The analysis follows the familiar approach developed by EPRI. LCOE calculations assumed a book life of 20 years. LCOE is determined by the annual revenue stream needed to cover operating expenses, repay capital and interest, and give agreed to return on preferred and common stock. Prices are assumed to be constant over the plant life, so the annual revenue stream is unchanging. RSPOE allows for changing price of fuel. The revenue stream needed to cover all expenses and returns on invested capital is computed on an annual basis.

The present work treats cost of fuels (natural gas and coal) and the value of CO_2 as variables over a nominal 20 year plant life starting in 2010. For each year the RSPOE is calculated in order to satisfy the expected rates of return for three classes of invested capital. These three investment classes and the expected returns are shown in Table 2 (EPRI, 2000).

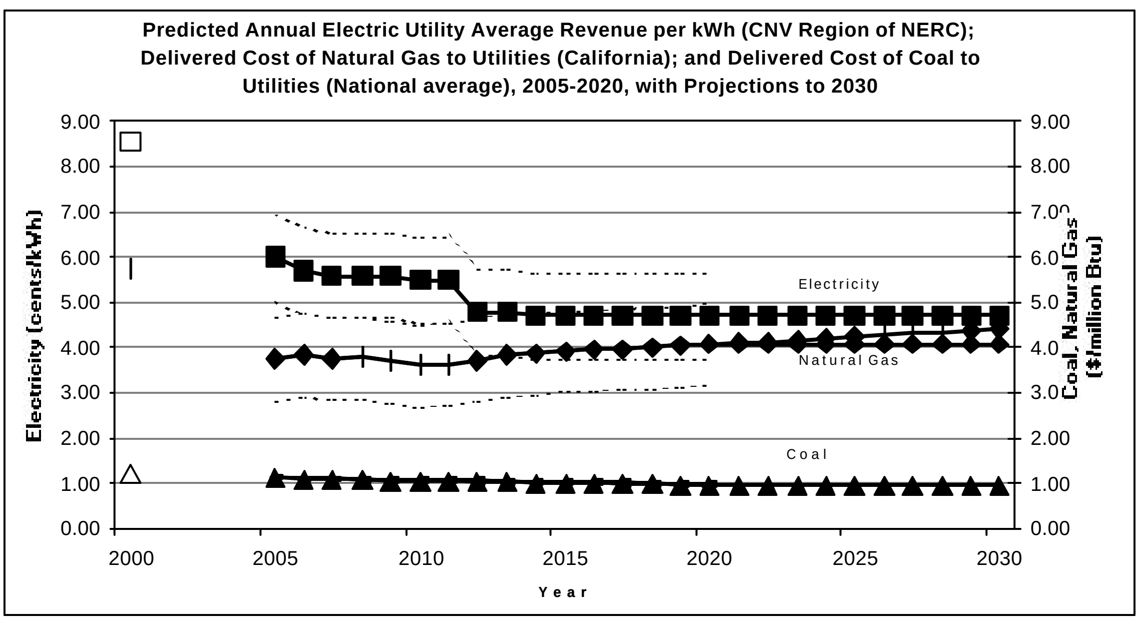
Table 2
Capital Structure of Plant Investment

	Percent of Total	**Rate of Return: Current $**	**Rate of Return: Constant $**
Debt	45	9.0	5.83
Pref. Stock	10	8.5	5.34
Common Stock	45	12.0	8.74
Total	100		

Of course in a deregulated electricity market the actual prices that a generator receives for electricity could be higher or lower than the RSPOE. If electricity revenue is higher than RSPOE, the financial return would be greater than that specified in the capital structure shown in Table 2. If electricity revenue is lower than RSPOE, the financial return is lower than that shown in Table 2; it is possible that a net loss would be realized. Rates of return on bonds and preferred stock are fixed, so all uncertainty in financial performance is borne by holders of common stock. We have computed the expected rate of return on common stock equity as follows. Rates of return on debt and preferred stock as specified in Table 2 are treated as fixed costs. The difference between expected electricity revenue and required selling price to cover debt and preferred stock interest and dividend payments is computed. This difference, which could be positive or negative, is divided by the amount of common stock equity. The result is the expected rate of return on common stock equity. The computation of expected rate of return on common stock equity includes uncertainty in the selling price of electricity as well as the uncertainty in RSPOE.

To compute RSPOE in California in 2010 and following years it is necessary to specify expected prices for natural gas and coal. Further, to compute expected rate of return on common stock it is necessary to have predictions of utility average revenue per kWh. Price predictions contained in *AEO2002* extend only to the year 2020, so it was necessary to otherwise specify expected prices from 2021-2030. The base case assumption we used is that there would be no price change over this 10 year period, that is, the price predicted for 2020 would remain constant for the rest of the study period. For natural gas we also created a sensitivity case in which the price trend predicted in the period 2015-2020 was assumed to continue in a linear fashion to 2030. The predicted prices with base case and sensitivity case extensions to 2030 are shown in Fig. 2. Note that actual prices for both fuels and electricity are shown for the year 2000 in the Figure.

Figure 2

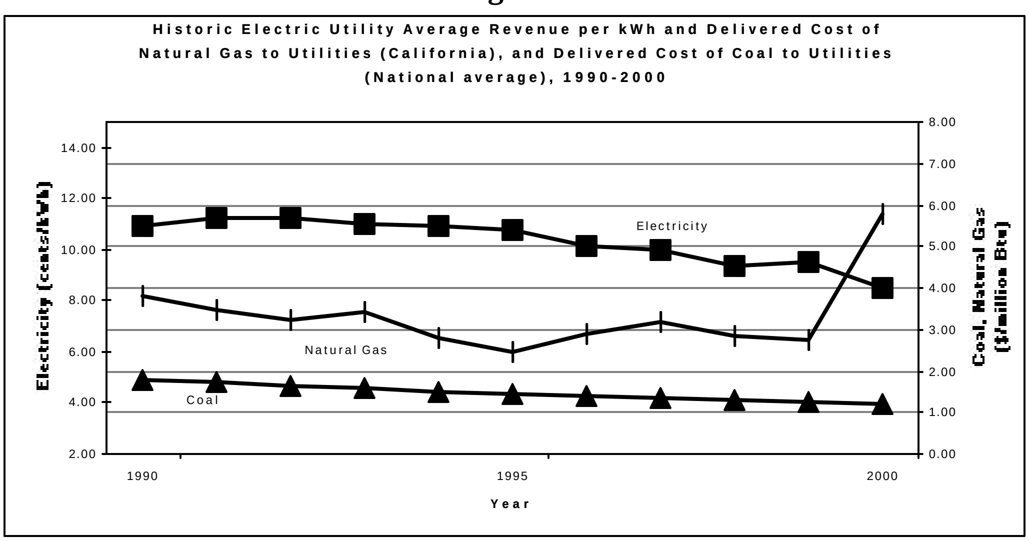


Ideally, the fuel prices used in our analysis would be authoritative predictions of delivered prices to California generators, and for electricity, revenues received by these generators. The NEMS model develops predicted prices for various commodities with varying geographic specificity. Thus, predicted revenues for electricity received by generators is broken out for the CNV region of the NERC (National Energy Reliability Council). The CNV region contains most of California and a small area of southern Nevada. The NEMS model predicts the cost of natural gas to electricity generators in the State of California, and the predicted values are used in the present paper. In our earlier paper these values were not available, so prediction for an aggregated region consisting of multiple Pacific coast states was used as the best information available at the time. Use of predictions specific to California should improve the analysis. For coal, national prices delivered to electricity generators are developed in NEMS, and these have been used in the present analysis. At present there is no significant use of coal for power generation in California so it is not possible to develop projected costs from historic trends in that State.

Over the period during which a plant is assumed to operate and NEMS predictions are available, 2010-2020, the national average delivered price of coal to utilities is expected to be in the range \$1.05-\$0.98/million Btu. Eastern coals, which figure in the computation of the national average, are expected to be more expensive than Western coals, which would be the type used in California. At the price of coal used in the Parsons calculation of LCOE (\$1.24/million Btu), the contribution of fuel cost to LCOE for IGCC+S plants at 65% capacity factor is just 12.0 of a total of 62.6 mills/kWh. Use of the predicted national price reduces the fuel cost by about 19% relative to the value computed by Parsons. If projected prices of Western coal were used, fuel costs for IGCC+S plants would be still smaller than used in the present analysis.

The dotted lines above and below the predicted prices shown in Fig. 2 represent one standard deviation. The standard deviations were computed by use of historic prices over the period 1990-2000. Details are given in the earlier paper (Ruether et al., 2002). Historic price data used to calculate standard deviations are shown in Fig. 3.

Figure 3



The standard deviation for coal is \$0.024/million BTU, too small a value to show on the graph in Fig. 2. Figure 2 shows that not only is the price of natural gas expected to be several times higher than that of coal, but so also is the uncertainty of the price.

For analysis of IGCC+S, in addition to prices and measures of uncertainty for those prices for fuel and electricity, similar data are needed for CO_2. In our earlier paper, we related future price of CO_2 to that of oil by use of a linear relation between the two that was developed for practice of CO_2 EOR in the Permian Basin. Expected variation in price of CO_2 was computed by use of predictions of world oil price. The present paper treats uncertainty in CO_2 value differently. In retrospect, we think the values for CO_2 used in the earlier paper were both too low and exhibited too small a variability, as expressed in the standard deviation of price used in the analysis. It is thought the price was too low because the linear expression used to link CO_2 and oil prices was particular to the Permian Basin and reflects the supply/demand situation there. As noted above, there are multiple relatively low cost sources of CO_2 available in the Permian Basin as well as an extensive network of pipelines to move it from source to oil fields. The situation contrasts with that in California where it was noted that no large sources of CO_2 exist that could sustain practice of EOR. This suggests that at least until some substantial capacity for CO_2 production is established for California, supply/demand will dictate a higher price for CO_2 there than in the Permian Basin.

Oil price in the period 2010-2020 is predicted by EIA to fall in the range \$23.36-24.68/bbl. In our earlier paper this yielded a maximum value of CO_2 of \$0.99/Mcf during the assumed plant life, a value close to the most probable value assumed in the current study, \$1.00/Mcf. Concerning variability in CO_2 price, the earlier analysis related it to historic fluctuations in world oil price via the linear relation mentioned for the Permian Basin. The standard deviation for CO_2 price was computed to be \$0.08/Mcf.

The present analysis defines a triangular probability distribution for price of CO_2 in California. The lower value is set at \$0.65/Mcf, a typical price for natural sources (Stevens et al, 1999; Moritis, 2002). The expected value is set at \$1.00/Mcf, a price at the high end for natural sources, a typical price when captured from natural gas processing, and a price suggested as the upper bound for economic practice of EOR in the Permian Basin (ibid.; Moritis, 2001). The upper value is set to \$2.00/Mcf, a value suggested as the clearing price that may be realized by advanced power plants such as the ones treated in the present analysis (Stevens et al., 1999). These values yield a computed standard deviation for price of CO_2 of \$0.29/Mcf. In the present paper the value of CO_2 is treated as a sensitivity parameter, and economic results are computed for values of \$0.65, \$1.00, and \$2.00/Mcf.

A further change from our earlier paper is to compute a value of CO_2 production per kWh that reflects the particular coal that would probably be used by any installation that would be sited in California. Computations in both Parsons studies have been based on use of Illinois #6 bituminous coal. Calculations indicate that with use of a lower rank coal from the Wyoming Powder River Basin, specific carbon emissions will be about 7% higher. In the present paper we have increased the carbon emissions given in the Parsons reports by this amount.

POSSIBLE INCOME TAX CREDITS FOR DEPLOYMENT OF IGCC+S

Income tax credits are sometimes fashioned to promote activity in the private sector that advances the public good. An example of a federal income tax credit in a business area related to the subject of this paper is that for EOR. The purpose of the credit is "..to boost levels of domestically produced oil and gas bypassed by conventional production." (EIA, 1999). Allowable expenses incurred in the practice of EOR, both capital and operating, are eligible for an income tax credit at the rate of 15% (IRS,2002).

Below we identify two practices involving the deployment of IGCC+S power plants and use of the captured CO_2 for EOR and describe how they could be the basis of income tax credits. Both ideas for income tax credits would help accelerate the commercialization of IGCC+S technology and storage of the collected CO_2 in depleted oil fields, resulting in reduced atmospheric emissions of CO_2. For each of the two approaches to be described, we identify the additional capital and operating costs that would be incurred if the beneficial action is taken. Similarly to the EOR tax credit and to make our ideas concrete, we suggest here that 15% of this differential cost be offered as a federal income tax credit. We admit that the basis for choosing 15% is arbitrary. The treatment of tax credits in the present paper is meant to be conceptual, however, not prescriptive. Both tax credits are computed per kg or metric ton of CO_2 emissions avoided. Because the CO_2 captured via IGCC+S plants per kWh of electricity generation is known, the tax credit is easily expressed also on the basis of net kWh generated.

The first tax credit is for practicing CO_2 capture in the process of generating electricity from fossil fuels. Additional capital and operating costs are incurred by practicing capture. The extra cost of capture, ECC, is computed as follows. Capital costs are depreciated over the tax life of the generating plant, 20 years. In the equations below "Δ" refers to the difference in cost between a power plant that practices capture less an otherwise equivalent plant that does not. Equations 1 and 2 yield ECC in units of $/kg CO_2 captured.

1. ECC= [Δ(total capital requirement)/net kW) * (1/tax life, hr) + Δ(operating cost, $/kWh) +Δ(consumable operating cost, $/kWh) +Δ(fuel cost, $/kWh)] * (1/specific CO_2 capture rate, kWh/kg CO_2 captured)]

2. Δ(operating cost, $/kWh)= Δ(fixed operating cost, $/kW-y) * (y/8760 h) * (avg. lifetime capacity factor) + Δ(variable operating cost, $/kWh)

Values needed to evaluate Equations 1 and 2 for the IGCC+S plant analyzed are taken from the two Parsons reports and shown in Table 3. Use of these values yields

3. ECC= $0.0191/kg CO_2 captured, equivalent to $1.01/Mcf CO_2 captured.

The value in Equation 3 ($19.1/tonne CO_2) compares to a figure of $20.6/tonne CO_2 avoided given in the first Parsons report (EPRI, 2000).

Table 3
Capital and Operating Costs of IGCC Plants With and Without CO_2 Capture

	IGCC	IGCC+S
Nameplate capacity, MW	424.5	386.8
Total capital requirement, $/kW	1419.9	1698.6
Tax life @ 20y, h	175320	175320
CO_2 capture rate, kg/kWh	0	0.801
Fixed operating cost, $/kW-y	33.0	51.4
Avg. lifetime capacity factor	0.65	0.65
Variable operating cost, $/kWh	0.0027	0.0032
Consumable operating cost less fuel, $/kWh	0.0008	0.0009
Fuel cost @$1.20/mm Btu, $/kWh	0.0098	0.0120

The cost in Equation 3 is very nearly equal to $1.00/Mcf, the most likely value in the triangular probability distribution used in this study. At an assumed rate of 15%, this income tax credit would be worth $0.0030/kg CO_2 captured.

The second proposed income tax credit is to discourage the practice of "blowing down" an oil field at the termination of EOR operations to recover CO_2 for reuse. In this process, the pressure in the field is reduced, resulting in some of the CO_2 that was left in porous underground formations being collected. In the absence of any value attributed to leaving the CO_2 in the depleted oil reservoir, the economic incentive for blowing down is straightforward. The cost of collecting and recompressing CO_2 recovered from an oil field is about $0.20/Mcf (Stevens et al., 1999). This represents a considerable saving compared to purchase of new CO_2.

The basis of the second tax credit is to maximize the amount of CO_2 left in an oil field at the end of EOR operations. It has been pointed out that this would involve changing the way EOR operations would be conducted as well as avoiding blowdown at the end of operations (ibid.). Compared to current practice for CO_2 EOR a higher ratio of CO_2 to water injection would be used, and CO_2 injection would begin earlier in the management of the oil field.

Some rules of thumb have been used to estimate the magnitude of the difference in how much CO_2 would be left in an oil field at the end of EOR operations if current practice including terminal blowdown is used, or if maximum final sequestration in the field is the object. Three cases are considered as shown below.

Table 4

Summary of CO2 EOR Mass Balances (Rules of Thumb)

(All figures are in units of Mcf per bbl of additional oil recovered via CO_2 EOR)

Net CO_2 purchased	**Recycled CO_2**	**CO_2 losses**	**CO_2 sequestered**
I. Conventional EOR practice during continuous operation phase			
6.0	4.0	0.1	5.9
II. Conventional EOR practice including post operation field blowdown			
2.1	4.0	0.1	2.0
III. High CO_2 usage practice including leaving field at pressure			
9.0	6.0	0.1	8.9

At any time in the operation of CO_2 EOR, the sum of (CO_2 losses) plus (CO_2 sequestered) must equal (Net CO_2 purchased). However, (Net CO_2 purchased) can change depending on whether the field is still being operated or if operation has ceased and blowdown has occurred. This difference is shown in lines I. and II. above. About 3.9 Mcf/bbl is recovered by blowdown. The extra cost incurred in operating so as to maximize final storage of CO_2 in the reservoir is estimated as follows using values from lines II. and III. of Table 4. An extra 6.9 Mcf/bbl of CO_2 must be purchased at an assumed cost of \$1.00/Mcf. Also, an extra 2.0 Mcf/bbl must be recycled at an assumed cost of \$0.20/Mcf. This gives a combined additional cost to the field operator (who will seek reimbursement) of \$7.30/bbl.

All costs above are per bbl additional oil recovered. The additional cost of operating so as to maximize permanent storage of CO_2 can now be expressed per net Mcf or kg of CO_2 purchased. This is \$7.30/9.0, or \$0.81/Mcf, or equivalently \$0.0154/kg CO_2. At an assumed rate of 15%, this income tax credit is worth \$0.0023/kg CO_2 purchased, which is the same as \$0.0023/kg CO_2 captured.

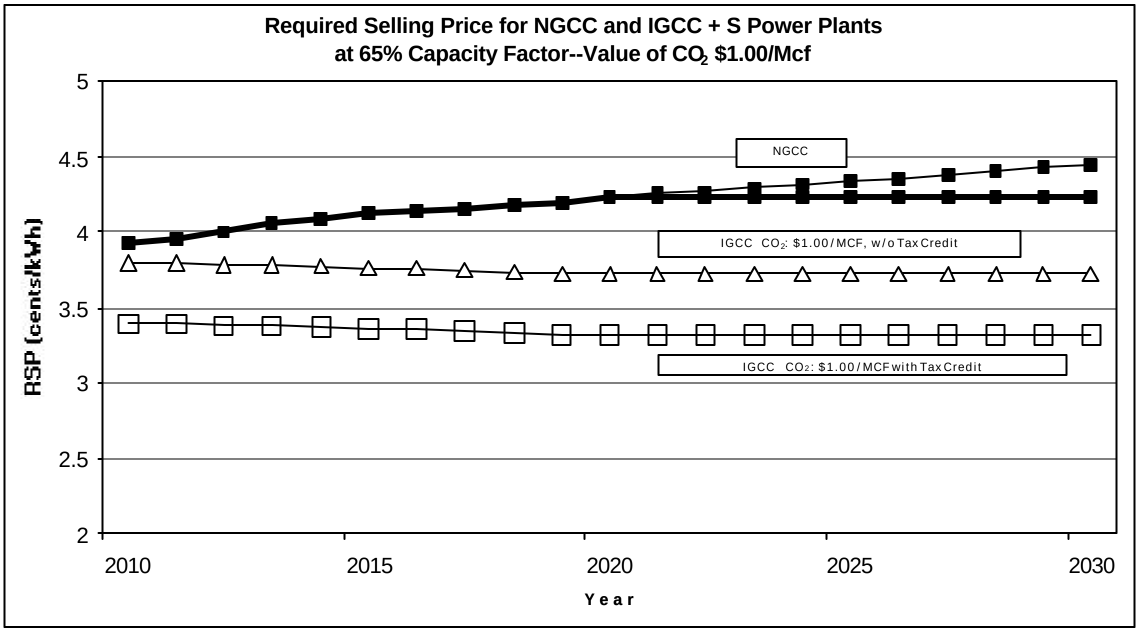
If the government were to endeavor to maximize storage of CO_2 in the conduct of EOR it would cost it more than the tax credit computed above. The oil field operator has incurred real costs relative to present day EOR operation to maximize sequestration. To a first approximation he has produced no extra oil, although more careful analysis may show that he has (Stevens et al., 1999). To change the way CO_2 EOR is conducted to maximize final CO_2 storage would require the government to assume all incremental operating costs as well as the cost for the suggested tax credit. Thus the total cost to the government would be 115% of the extra operating cost.

In the present analysis we imagine that substantially all the tax credit for maximizing sequestration flows back to the IGCC+S plant operator to add extra incentive to build this kind of plant. Implemented as a climate change mitigation strategy, this tax credit would only be offered if the source of CO_2 used for EOR was anthropogenically produced.

RESULTS OF MONTE CARLO SIMULATIONS

Results of Monte Carlo simulations for required selling price of electricity for both NGCC and IGCC+S plants at 65% capacity factor are shown in Fig. 4. The assumed value of CO_2 is \$1.00/Mcf. For IGCC+S, plots are shown with and without an assumed income tax credit for CO_2 management. The income tax credit is the sum of the two credits described above, together worth \$0.0053/kg CO_2 captured. At the capture rate shown in Table 3, this is equivalent to 0.42 cents/kWh. Standard deviations of RSPOE for the two technologies are 0.57 and 0.68 cents/kWh for NGCC and IGCC+S, respectively. The figure shows that RSPOE for NGCC is slightly less than 4 cents/kWh in the first two years of operation, then increases above 4 cents/kWh in later years under the influence of higher natural gas prices. Recall that the sensitivity case for NGCC assumes that the price trend for expected increasing natural gas prices in 2015-2020 extends through the period 2021-2030. For this case the RSPOE approaches 4.5 cents/kWh in 2030.

Figure 4



The RSPOE for IGCC+S technology is less than that for NGCC over the entire study period for both cases considered. The RSPOE declines slightly in the period 2010-2020 due to the small decrease in coal price that is predicted. RSPOE is unchanging after 2020 because the price of coal is assumed to be constant.

In our earlier analysis, the RSPOE for NGCC was lower than that for IGCC+S over the entire plant life (Ruether et al., 2002). The values for NGCC have changed little between the two studies. As mentioned above, this study uses projections of the price of natural gas in the CNV region of NERC, while the earlier study used projections for the larger Pacific region of NEMS. The two gas price projections differed by only a few cents per Mcf in any year, however, so this change in methodology had little effect on the results.

Most of the difference in results of the two studies is due to treatment of the IGCC+S technology. In the earlier work, the RSPOE for IGCC+S at 65% capacity factor was close to 5 cents/kWh for the entire plant life, while Fig. 4 shows that the comparable value is 3.7-3.8 cents/kWh in the present study. A higher value for CO_2 assumed in the present work accounts for part of the difference between the two studies. Other differences are the higher heat rate (lower efficiency) for IGCC+S and lower capital cost assumed in the present study as shown in Table 1, and the higher carbon emissions per BTU computed for use of Western coal. All these differences tend to lower the RSPOE for IGCC+S in the present study relative to those computed previously.

A second difference in results between the two studies is the relative sizes of the standard deviations for RSPOE for the two technologies. In the present study they are of comparable size. In the earlier work the standard deviation for IGCC+S was smaller than that computed here, just 0.21

cents/kWh. The increase in standard deviation is due principally to the larger variability in CO_2 price that is assumed in the present work.

The effect of CO_2 value on RSPOE for IGCC+S plants is shown in Fig. 5. Plots are shown for assumed values of \$0.65, \$1.00, and \$2.00 per Mcf, without income tax credits. At the lowest value of CO_2 considered in this study, the RSPOE for IGCC+S is higher than that for NGCC, by comparison with Fig. 4. At the highest value of CO_2 considered, the RSPOE has a value of just 1.3 cents/kWh. Figure 5 shows the importance of CO_2 revenue on the economics of operating an IGCC+S plant.

Similar plots for the cases of 80% capacity factor are shown in Figs. 6 and 7. Comparison of Figs. 4 and 6 shows that the economic advantage of the coal-based technology increases with capacity factor, as is well known, due to the higher capital costs of IGCC compared to NGCC. At 80% capacity factor, the RSPOE for IGCC+S at CO_2 value of \$2.00/Mcf is 0.4-0.5 cents/kWh. If the 0.42 cent/kWh income tax credit were included for this case, the RSPOE would approach zero. That is, under these conditions, the assumed return on investment would be satisfied by sale of CO_2 alone.

Figure 5

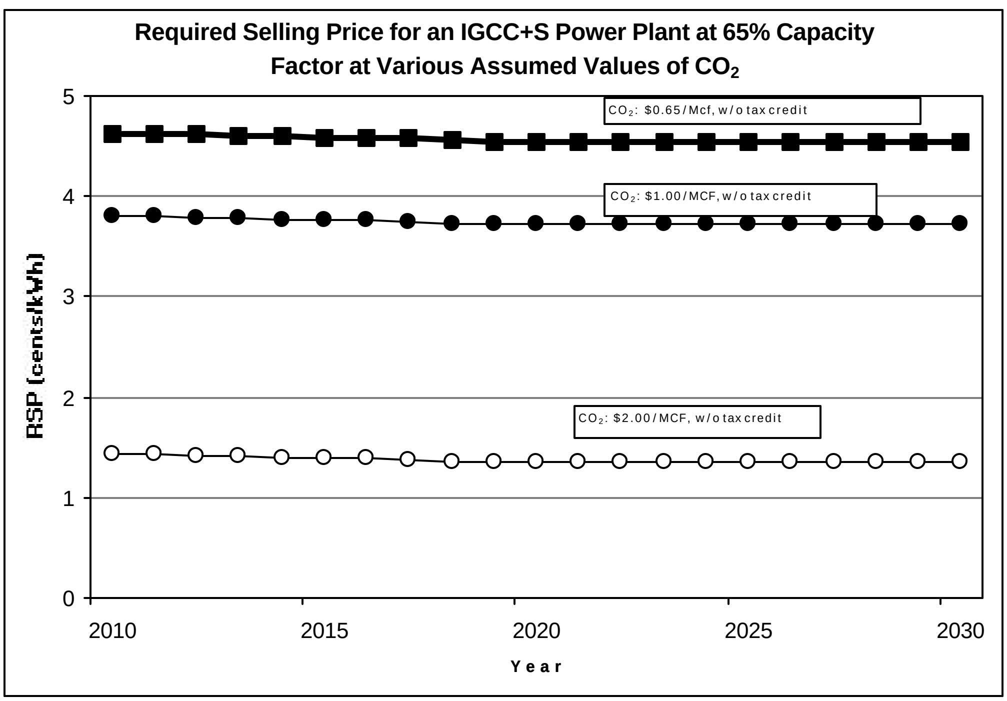


Figure 6

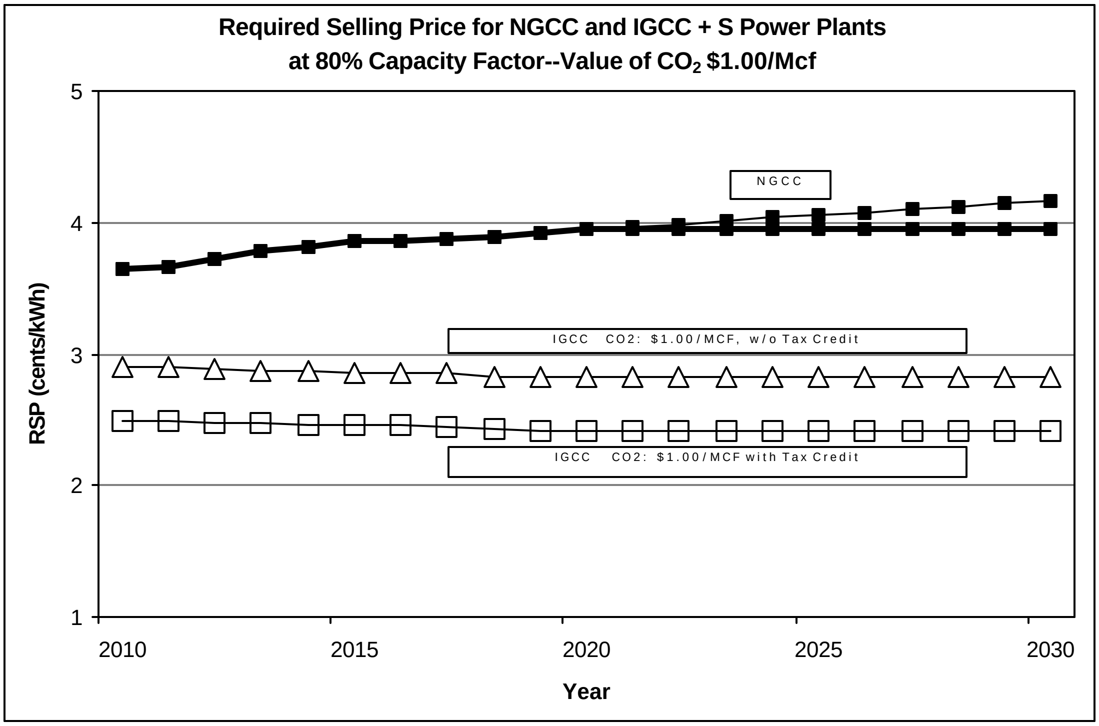
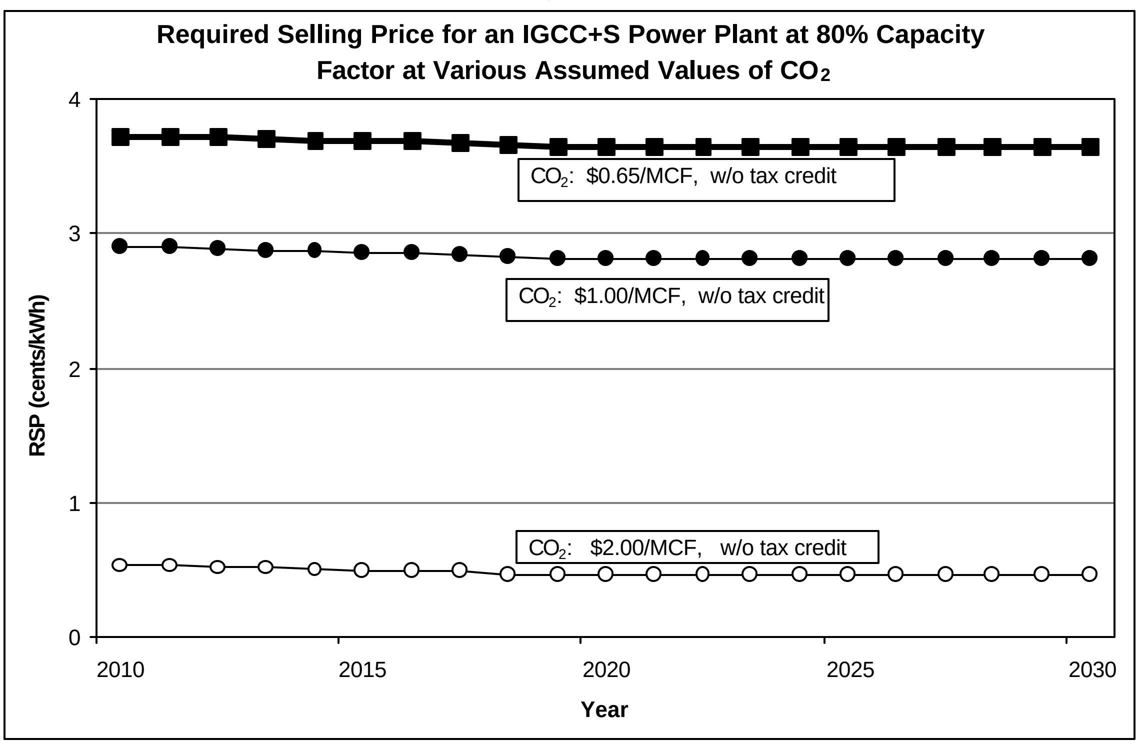


Figure 7



Expected pretax rates of return on common stock equity for both types of technology are shown in Figs. 8 and 9 for capacity factors of 65% and 80%, respectively. The value of CO_2 is assumed to be $1.00/Mcf in both figures, and results for IGCC+S with and without the assumed income tax credit are shown. Recall that these simulation results incorporate uncertainty in selling price of electricity as well as price of fuel. At both capacity factors the rate of return for NGCC is higher than for IGCC+S for the first four years of operation. The rate of return for NGCC declines rapidly, however, and after the fourth year is less than that for IGCC+S for the rest of the assumed plant life. The decline in rate of return is due to expected reduced selling price of electricity and increasing price of natural gas with time as shown in Fig. 2.

Figure 8

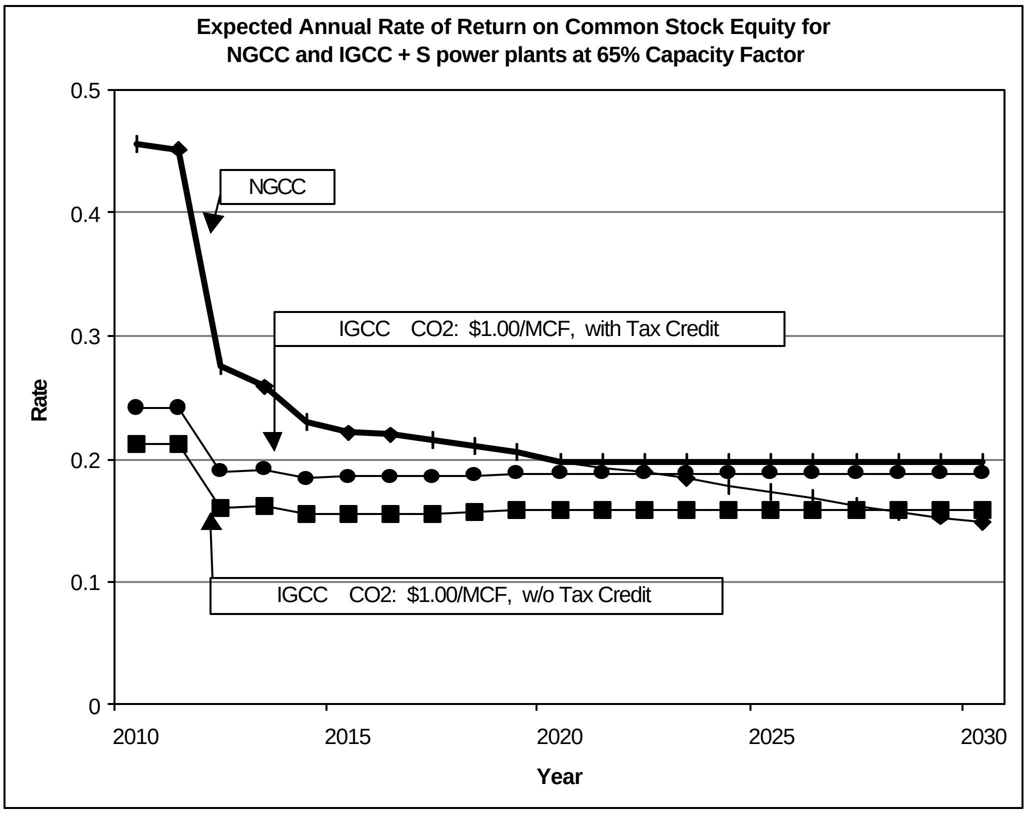
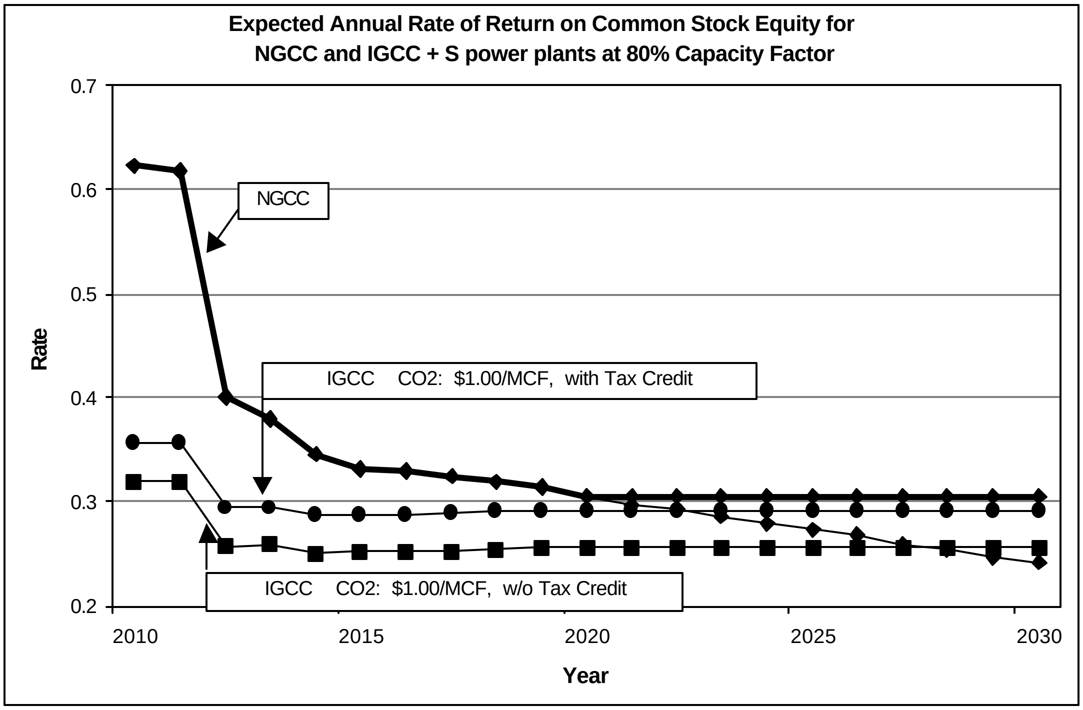


Figure 9



Rate of return on common stock equity for IGCC+S plants also declines in the first five years of operation due to declining electricity selling price. The decline is less steep than for NGCC because CO_2 revenues moderate the decline and because coal prices actually decline a small amount. The effect of the income tax credit of 0.42 cents/kWh is to increase pretax rate of return on common stock by about 3% for both capacity factors considered.

The standard deviation for rate of return on common stock equity for NGCC plants is 0.15 at 65% capacity factor and 0.19 at 80% cf. That is, it is of comparable magnitude to the expected returns themselves. For IGCC+S, standard deviations are 0.049 for 65% cf and 0.061 for 80% cf, only about one-third as large as for NGCC technology. The explanation, of course, is the large uncertainty in the price of natural gas used in NGCC plants. Uncertainty in the value of CO_2 is the largest contribution to uncertainty for IGCC+S plants, and this is considerably smaller than the uncertainty of natural gas cost for NGCC plants.

COST EFFECTIVENESS OF NOTIONAL INCOME TAX CREDITS

Would income tax credits such as are described here represent good value to the government relative to other possible approaches to reducing carbon dioxide or other greenhouse gas emissions? We can answer for each of the two tax credit approaches. In the case of the first credit, for the extra cost of capture, we imagine that the CO_2 would be used in the current manner of operating EOR fields, following line II. of Table 4. The public good consists of capturing CO_2 that would otherwise have entered the atmosphere and instead storing it (except for small losses that will be considered) permanently underground in the conduct of EOR. Per barrel of incremental oil recovered the cost to the government for the suggested tax credit is

4. 0.15* 2.1 Mcf/bbl * \$1.00/Mcf = \$0.315

where \$1.00/Mcf is taken as the basis for the 15% tax credit, and 2.1 Mcf/bbl net purchase of CO_2 is needed.

How much CO_2 emission is avoided? From Table 4, 2.0 Mcf/bbl are permanently sequestered. In addition, the CO_2 losses, 0.1 Mcf/bbl, do not originate from CO_2 that was initially underground. This assumes that if power plant CO_2 had not been used, the EOR operation would have been conducted with CO_2 of geologic origin, i.e., from wells. Total avoided emission is then 2.1 Mcf/bbl additional oil recovered. Therefore the cost for carbon emission avoidance is \$0.315/2.1 Mcf, or \$0.15/Mcf, or \$2.85/tonne CO_2, or \$10/tonne C.

Now consider the tax credit for maximizing sequestration of CO_2 in the conduct of EOR. As shown above, the additional cost for operating in this mode is 1.15* \$7.30/bbl, or \$8.40/bbl. From lines II. and III. of Table 4, this results in an extra 6.9 Mcf/bbl sequestered. Thus the cost for emission avoidance here is \$8.40/6.9 Mcf, or \$1.22/Mcf, or \$23/tonne CO_2, or \$85/tonne C.

Hayhoe et al. (1999) developed cost curves for various approaches for reducing emissions of methane and CO_2. They present a cost curve for annual reduction of CO_2 emissions in the year 2010 covering the range 0-725 million metric tonnes carbon (MtC). (As a point of reference, total CO_2 emissions from fossil fuel combustion in the U.S. in the year 2000 were 1534 MtC (USEPA, 2002.)) Costs are given in year 1992 dollars by Hayhoe et al., which we convert here to year 2000 dollars. Costs per tonne of carbon (as CO_2) emission avoided start at zero for the first increment of reduction and range to about \$510 per tonne carbon (tC) for a reduction of 725 MtC.

We here use the abatement curve of Hayhoe et al. to estimate what fraction of the CO_2 emission reductions they identified are less expensive than those given by the two income tax credits described above. Using their curve we estimate that about 34 MtC can be abated for \$10/tC or less. Thus the income tax credit for CO_2 collection in IGCC plants is more cost effective than 95% of the measures identified to reduce emissions by 725 MtC.

We estimate that about 270 MtC can be abated for \$85/tC or less. Thus the income tax credit for retention of CO_2 in depleted oil fields at the completion of CO_2 EOR is more cost effective than 63% of the measures identified to reduce emissions by 725 MtC.

In the above calculations it has been assumed that the proposed income tax credits were solely responsible for the avoided CO_2 emissions. It could be argued that this assumption is invalid. Concerning carbon capture at IGCC plants, our analysis indicates that the technology is cost competitive even without an income tax credit. The case could be made that avoided CO_2 emissions would occur due to market forces alone. The authors do not express an opinion on this issue. It is not our purpose to advocate either of the tax credits described, rather to widen the discussion of possible approaches to reducing greenhouse gas emissions to include consideration of income tax credits.

The situation is different for the proposed income tax credit for oil field management at the end of CO_2 EOR operation. In this case it is clear that in the absence of some economic incentive not to blow down the oil field, current practice of minimizing permanent storage of CO_2 in the field will continue. Real money must be spent to purchase the extra CO_2 that is stored in the depleted field. As shown above, the cost for the purchase of the extra CO_2 has been included in the calculation of the $85/tC figure derived as the total cost for emission avoidance. While the proposed tax credit for oil field management yields the higher cost for avoided emissions, $85/tC vs $10/tC, it has the advantage of clarity of what is being paid for. It is likely that if an income tax credit and assumption of incremental operating costs for oil field management at termination of CO_2 EOR along the lines described here were made available, oil field operators would employ it, and CO_2 emissions would be reduced.

Finally, attention should be drawn to some issues that could incur additional costs that have not been considered in this analysis. If blowdown of oil fields at the end of CO_2 EOR operations is avoided as has been discussed, the final field pressure would be higher than in current practice. This would increase the likelihood of leakage of CO_2 out of the field. It will be necessary to demonstrate that such leakage can be avoided or acceptably limited. In addition, as will be true for any approach for reducing CO_2 emissions by underground storage, some additional costs for long term monitoring and verification will be incurred. It is thought that these costs will be small compared to the direct costs that have been identified here, but at this time they are unknown.

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