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Scenario analysis of carbon capture and sequestration generation dispatch in the western U.S. electricity system

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Abstract

We present an analysis of the feasibility of dispatch of coal-fired generation with carbon capture and sequestration (CCS) as a function of location. Dispatches for locations are studied with regard to varying carbon dioxide (CO_2) prices, demand load levels, and natural gas prices. Using scenarios with a carbon price range of $0 to $100 per ton - CO_2, we show that a hypothetical CCS generator would be dispatched on a marginal cost basis given a high enough carbon price but that the minimum carbon price required for dispatch varies widely by location and system demand.

Keywords: Carbon capture; carbon sequestration; electricity; optimized power flow; generation dispatch;

1. Introduction

Climate change due to accumulating greenhouse gases such as carbon dioxide (CO_2) is a serious risk to the environment and the world economy. [IPCC 2007] The majority of CO_2 emissions are emitted into the atmosphere when hydrocarbon fuels are burned for energy, especially in the electricity sector. One emerging technology that has been proposed to mitigate future CO_2 emissions is carbon capture and sequestration (CCS) of electricity-generating coal power plants. Coal fuels much of the electricity generated throughout the world; for instance, coal-fired generators produce half of the electrical energy in the United States. [IPCC 2005]

CCS for coal-fired generators requires additional capital costs and equipment. These costs can substantially add to the cost of producing electricity for these power plants. In addition to the equipment needed to capture CO_2, the CO_2 will need an appropriate reservoir to be stored. Saline aquifers have been considered the best candidate for sequestering CO_2 but they are found in specific geological formations which may be distant from transmission lines and existing power plants. [IPCC 2005]

In order for energy planners and utilities to be able to effectively deploy CCS as a technology to mitigate CO_2 emissions and alleviate the risks of climate change, a thorough understanding of how the electricity grid interacts with this new technology will be required. The rate at which CCS is adopted will depend on the cost effectiveness

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and profitability of CCS which will in turn be affected by many locational parameters of electricity generation and transmission like losses, cost, price, and capacity factors. [Newcomer]

This study will look at the western United States and the potential for integrating CCS power plants into certain possible sequestration locations near the electrical grid by using an optimized power flow (OPF) model. An analysis of several potential CCS sites will attempt to look at the dispatch characteristics of these sites as well as to generalize features of a good CCS site in order to determine the trade-offs of different locations. Several scenarios are explored including a ramping of the price of CO_2 and varying fuel prices.

This paper is organized as follows. Section 2 presents the model structure and data sources along with a discussion of the limitations. Section 3 discusses the scenarios and assumptions that are used in simulation runs. Results are presented in Section 4 and conclusions are provided in Section 5.

2. Model and Data

Electricity in the western U.S. region is managed by the Western Electricity Coordinating Council (WECC) that includes the western states of the United States, the Canadian provinces of Alberta and British Columbia, and parts of northern Baja California, Mexico. [WECC (a)] Organizations and areas the WECC encompasses include the West Coast Regional Carbon Sequestration Partnership (WESTCARB) and the independent system operator of California (CAISO). Transmission line network data for this region was acquired from the WECC. The data was a single solved load flow case from August 25, 2005 and included transmission line capacities and generator locations and capacities. This included approximately 2,800 generators of all types, 58,000 miles of transmission lines, and 190,000 MW of generation capacity. Because the network data is a snapshot of the grid at a certain time, transmission and generation capacity that have been built since 2005 are not represented in our network. [WECC(b)]

The solved load flow case does not contain several important pieces of data. Dispatch models require the marginal costs of supplying electricity for each generator in order to determine the cheapest way of turning on the various power plants given the architecture of the transmission network. Marginal costs, however, are confidential pieces of information that power producers treat as corporate secrets. In order to create offer curves for each power plant, marginal costs are constructed from a variety of sources.

In our model, marginal costs are assumed to be the sum of emissions costs and fuel costs. Generator-specific emissions and heat rate data were taken from the 2004 EPA eGRID database. [US EPA] The eGRID database was matched with PowerWorld data for each generator to cross-reference emissions and heat rates to power plants in the network data. Fuel usage was approximated by multiplying heat rates with the cost of fuel for a type of plant. Emissions for NO_X, SO_X, and CO_2 were similarly calculated using emissions rates. Emissions costs are based on the costs of permits for each ton of emissions released. Costs for mercury emissions were not considered. When data was not available for a generator in the dispatch model, the plant either used generic emissions and heat rates forthe plant technology and fuel type if available. Otherwise, the generator was considered non-dispatchable if there was insufficientinformation.

The model uses the commercial software PowerWorld Simulator version 13 which uses an OPF add-on to calculate power flows from generators through transmission lines to demand load.

A few points should be made about the limitations of the model. Much of the discussion around CCS centers on the significant additional capital costs necessary to build a power plant with CCS equipment. [MIT] A dispatch calculation does not directly consider the impact of these fixed costs. Dispatch involves variable and marginal costs of the power plants. While a CCS plant may be dispatched in a certain situation in the electricity grid because the marginal cost of production is lower than the price of electricity, it still may not recoup the substantial fixed and startup costs required. A dispatch model is concerned with the short-run decision of whether to generate. The decision to build the plant requires a long-run calculation of the profitability of a possible CCS generator. [Ford]

A dispatch model also does not perfectly mimic the actual decisions made by the power producers. Certain technologies cannot be reliably dispatched because they are intermittent sources like wind and solar. These technologies have been modeled as non-dispatchable sources in our model. Plants in an electrical system will also require regular outages for scheduled maintenance and will not be available in the dispatch system. Dispatch is also not always used by utilities to determine the level of generation of their power plants. Power producers may enter into contracts with load serving entities so that even if a producer's plants are not the cheapest units, they will still turn on because a buy er for the power already exists. However, a dispatch model will reasonably approximate the long-term capacity factor and decisions made for plant operation if not the actual day-to-day operation.

Validations of the model were performed that demonstrate the reasonableness of the model using a hypothetical coal plant in the Four Corners region of New Mexico. Fuel prices from August 25, 2005 were used to dispatch such a plant as well as other utility areas to match aggregate output from the original solved load flow case.

3. Scenarios

Hypothetical CCS plants were sited near potential sequestration locations in the western United States. These plants are modeled using projections for an Nth-of-a-kind integrated gasification combined-cycle (IGCC) coal generator. Plants are assumed to source their fuel from the Powder River Basin (PRB) that provides the coal typically used in the western United States. Each plant, with one exception, was a net 500 MWe plant. The heat rate modeled for these hypothetical plants was 11,000 BTU/kWh. [MIT] Plants used 100% capture rates for CO_2 and thus their marginal costs were not directly impacted by prices for CO_2. Marginal costs of electricity for the hypothetical IGCC plants were thus strictly calculated on fuel costs because we assume emissions for pollutants like NO_X and SO_X are much lower for IGCC power plants and not represented.

Transmission lines for hypothetical CCS plants were connected to the largest and nearest substation on the transmission grid. These lines were modeled to be large so they were not a source of congestion for delivering power from hypothetical plants. Transmission lines are also assumed to be short and to have minimal losses. Transmission lines are connected using highest voltage available at the substation and not connected to lower voltages in order to minimize transformer equipment needed for voltage changes.

Parameters are modified in the dispatch simulations to investigate the effects of various market and policy environments surrounding CCS deployment. The price of carbon dioxide emissions were varied from \$0 to \$100 per tCO_2 in \$5 increments representing a reasonable near-term range of the price of CO_2. Fuel prices have been volatile in 2000s, and it should be noted that August 25, 2005 is only a few days before Hurricane Katrina hit the Gulf Coast and caused natural gas and oil prices to spike. [EIA] While coal prices have seen recent large and steady increases, they are still relatively cheap and stable compared to the wild swings in the natural gas markets. To that extent, when varying fuel costs, we have kept coal prices stable and varied natural gas prices from \$.50 to \$11 per MMBTU in \$3 increments except for the first value. Variations in the demand load are simulated by scaling the load distribution pattern in the obtained solved load flow case.

One hypothetical plant is considered dispatchable in each simulation. Other plants in the system are dispatched from the initial conditions in the solved load flow case and use our constructed marginal cost values as costs. In our simulations, only fossil fuel burning plants (oil, natural gas, and coal) are considered dispatchable.

4. Results

We present the dispatch levels of a hypothetical IGCC plant for five sites. These sites were chosen because they are considered good candidates for carbon sequestration due to their proximity to saline aquifers that would act as large sinks for carbon dioxide. [NETL] Figure 1 and Table 1 describes the sites of hypothetical IGCC generation in Central California and Oregon.

Figure 2 is a set of dispatch curves from a hypothetical IGCC plant at the Gates substation in the Central Valley of California. In this area of California, most plants competing for dispatch are natural gas power plants which emit about half the CO_2 as a coal plant but are still more polluting than the hypothetical plant with 100% capture. As the CO_2 price increases, surrounding plants become more expensive as the price to emit CO_2 impacts the cost of electricity. In the Gates simulations, this is readily apparent in the 55% load dispatch curves. The initial dip from \$0 to \$10 per tCO_2 demonstrates the nonlinear nature of dispatches and the electricity grid.

Dispatch curves for the Pastoria substation in the Central Valley of California are shown in Figure 3. There is a wider range of dispatch levels over a greater range of load values for this location. An interpretation of this is that an IGCC plant located at Pastoria is competing with more plants and is less able to deliver power due to congestion than an IGCC plant at Gates. The Central Valley transmission corridor is a large, high capacity set of transmission lines that delivers power to the Bay Area to the north and Southern California to south, both of which are very large load areas. As such, there are also many alternative and competing plants that can serve load rather than the hypothetical IGCC plant at Pastoria. More plants competing means that there are more situations where an IGCC plant would operate in between zero and full capacity since there is a greater likelihood that another plant would be able to fill in and supply enough generation so that an IGCC would not need to turn on.

Table 1. Hypothetical 500 MWe IGCC plants used in simulations.

Substation Name	Location	Carbon Sink	Highest Voltage
Gates	Fresno County, CA	San Joaquin Basin	500 kV
Pastoria	Kern County, CA	San Joaquin Basin	230 kV
Burns	Harney County, OR	Ochoco Basin	500 kV
Midway	Fresno County, CA	San Joaquin Basin	500 kV
Inyo	Inyo County, CA	San Joaquin Basin	230 KV

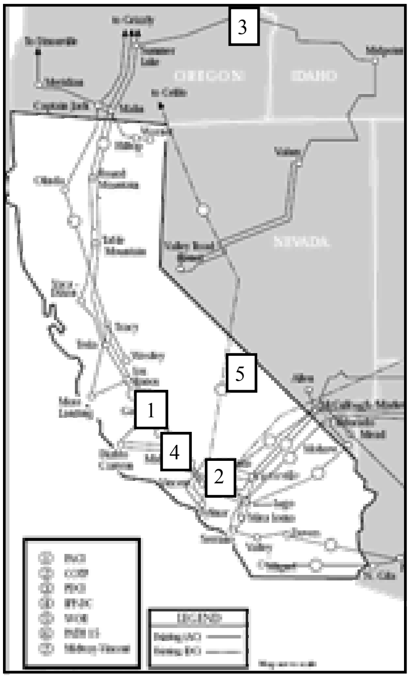

Figure 1. Locations of hypothetical 500 MWe IGCC plants used in scenarios.
Substations: 1) Gates, 2) Pastoria, 3) Burns, 4) Midway, 5) Inyo

As Figure 4 shows, a hypothetical IGCC plant at the Burns substation, located in central Oregon, would have an even more abrupt turn -on than a plant at the Gates substation. The interpretation of this is simi lar and more extreme. Burns has even fewer competing plants and there is less transmission capacity to deliver electricity to load in that portion of Oregon.

Figure 5 illustrates a plant at the Midway substation in the Central Valley. Midway is directly connected to the Gates substation via high voltage transmission lines but it still demonstrates important differences in dispatch behavior. The dispatch levels for the two identical IGCC plants occur at different levels of load even though both plants del iver power to very similar load areas. An interpretation is that a small difference in dispatch order can create opportunities for competing plants to fill in generation capacity and significantly affect the dispatch order and capacity factor of a plant. Demonstrating the difference in the relationship of a plant's dispatch and demand load level is the dispatch level of the Midway plant as CO_2 prices increases. The dispatch level is steady for a plant at Midway compared to nearby Gates and Pastoria plant s.

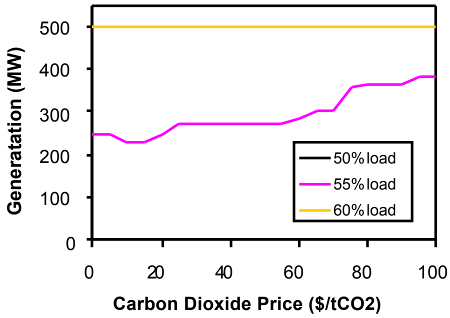

Figure 2. Dispatch curve of hypothetical 500 MWe IGCC plant at Gates substation.

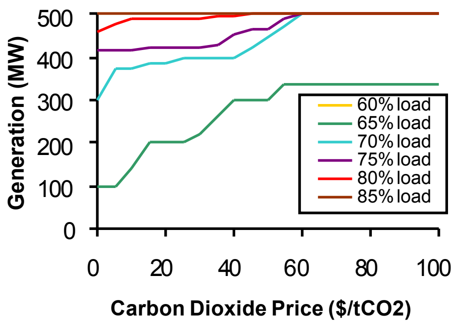

Figure 3. Dispatch curve of hypothetical 500 MWe IGCC plant at Pastoria substation.

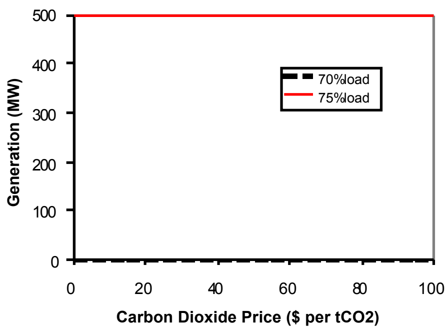

Figure 4. Dispatch curve of hypothetical 500 MWe IGCC plant at Burns substation.

The dispatch curves in Figure 6 is located at the Centralia coal plant in central Washington. Instead of the Nth-of-IGCC plants used in previous simulations, the simulated plant is considered a retrofit of the coal plant currently operating there. In the simulation, this means that the plant currently at Centralia is turned off and considered non-dispatchable while a hypothetical retrofit plant is inserted into the model at the same location with the same transmission connections. An equal net generation capacity of 1528 MWe is used and a heat rate of 15,000 BTU/kWh is employed to mimic the efficiency hit that a CCS retrofit would impose on the power plant.

The results of the simulation at the Centralia coal plant are shown in Figure 6. Absent a significant price on CO_2, the power plant does not operate at full capacity unless the demand load is at 100% of the solved load flow case, a situation that represents the peak demand of a hot summer day. For such a large coal plant, this represents a bump up the dispatch order from baseload to possibly a peaker level. This situation would cause the Centralia plant to lose much of its potential revenue. Even at high CO_2 prices, however, the dispatch level does not significantly change, demonstrating that transmission and load levels are more impactful than CO_2 prices at this location.

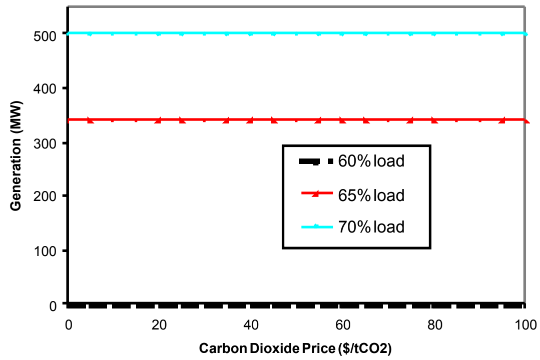

Figure 5. Dispatch curve of hypothetical 500 MWe IGCC plant at Midway substation.

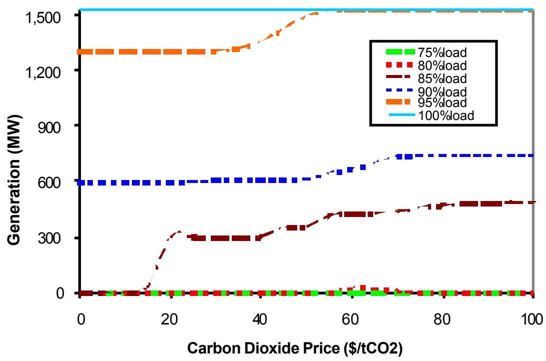

Figure 6. Dispatch curve of hypothetical 1528 MWe CCS Retrofit plant at the Centralia Generation Station in Washington State with a heat rate of 15,000 BTU/kWh

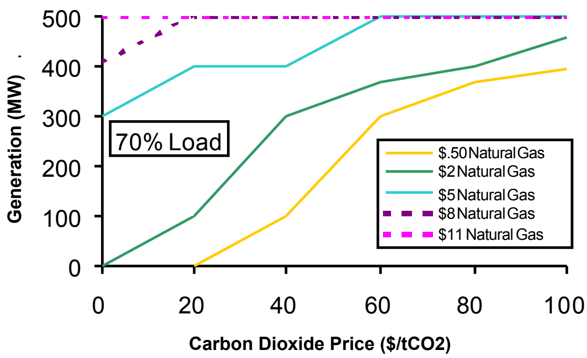

Figure 7. Dispatch curve of hypothetical 500 MWe IGCC plant at Pastoria substation with 70% demand load and varying natural gas prices

Varying natural gas prices cause dispatch curves to change as shown in Figure 7 for the Pastoria substation with a 70% load. These dispatches used $20 increments in carbon price. The original price of natural gas for all previous simulations was $5 per MMBTU. As natural gas prices decrease, the cost of electricity from competing natural gas plants decrease and they are increasingly dispatched more than the Pastoria IGCC plant.

Figure 8 summarizes the simulated plants all at a 65% demand load level. The graph demonstrates very different behavior that location imposes between plants that are identical, other than the Centralia retrofit.

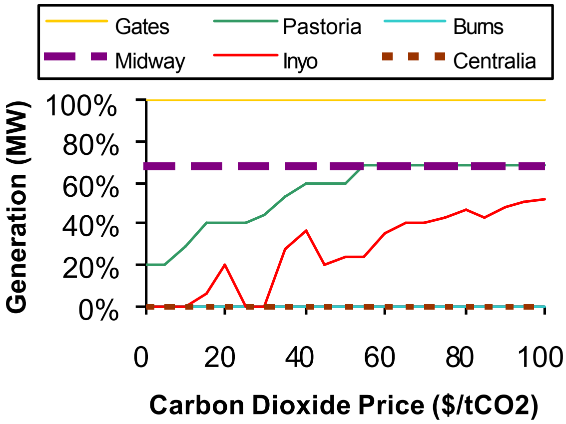

Figure 8. Dispatch curves for previous hypothetical CCS plants at 65% demand load

5. Conclusion

We have demonstrated the dispatch of hypothetical plants with CCS in the western United States. Our analysis has shown that CCS plants will dispatch under reasonable conditions in spite of the severe congestion in the California grid. Plant dispatch depends heavily on location and demand load. Identical generators that are physically close and adjacent to each other on the grid network will still exhibit dispatch behaviors with significant differences in response to carbon prices and demand load.

In our simulations, all plants will eventually fully dispatch given a sufficiently high demand load level and large enough carbon price. For the 500 MWe IGCC plants simulated, a demand load ranging between 60% to 85% of the solved load flow case was required in order for generation to fully dispatch without a carbon price. With a carbon price of $100 per t$CO_2$, this range was reduced to 60% to 75% for the IGCC plants simulated. In order for a retrofit plant to be dispatched in our simulation, 100% load was required without a carbon price in order for the plant to be fully dispatched, likely displacing a retrofit from baseload in the dispatch order. Fuel prices also affected the price for a hypothetical plant at the Pastoria substation. Natural gas prices shifted the IGGC generator from full dispatch at $11 per MMBTU to completely off at $2 per MMBTU.

Future research will involve a capacity factor calculation over diurnal and seasonal demand load patterns. Sensitivities to carbon price, demand load and fuel costs will again be tested throughout these different demand loads. Our analysis and future work should serve to inform state regulators and policy-makers as to relevant policies to make IGCC and CSS economic in the western electricity grid. Zoning and regulations may need to be modified in order to ease the siting and building and of the most cost-effective CCS plants. CO_2 prices that are necessary for CCS plants to dispatch can be determined and the appropriate policies can be enacted by regulators.

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