Economics and Policies for Carbon Capture and Sequestration in the Western United States: A Marginal Cost Analysis of Potential Power Plant Deployment

by

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ABSTRACT

Carbon capture and sequestration (CCS) is a technology that can significantly reduce power sector greenhouse gas (GHG) emissions from coal-fired power plants. CCS technology is currently in development and requires higher construction and operating costs than is currently competitive in the private market. A question that policymakers and investors have is whether a CCS plant will operate economically and be able to sell their power output once built. One way of measuring this utilization rate is to calculate capacity factors of possible CCS power plants. To investigate the economics of CCS generation, a marginal cost dispatch model was developed to simulate the power grid in the Western Interconnection. Hypothetical generic advanced coal power plants with CCS were inserted into the power grid and annual capacity factor values were calculated for a variety of scenarios, including a carbon emission pricing policy.

I demonstrate that CCS power plants, despite higher marginal costs due to the operating costs of the additional capture equipment, are competitive on a marginal cost basis with other generation on the power grid at modest carbon emissions prices. CCS power plants were able to achieve baseload level capacity factors with \$10 to \$30 per ton-CO_2 prices. However, for investment in CCS power plants to be economically competitive requires that the higher capital costs be recovered over the plant lifetime, which only occurs at much higher carbon prices. To cover the capital costs of first-of-the-kind CCS power plants in the Western Interconnection, carbon emissions prices have been calculated to be much higher, in the range of \$130 to \$145 per ton-CO_2 for most sites in the initial scenario. Two sites require carbon prices of \$65 per ton-CO_2 or less to cover capital costs. Capacity factors and the impact of carbon prices vary considerably by plant location because of differences in spare transmission capacity and local generation mix.

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LIST OF ACRONYMS

AC	Alternating Current
ACES	American Clean Energy and Security Act
BPA	Bonneville Power Authority
BTU	British thermal units
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CCS	Carbon capture and sequestration
CGE	Computable general equilibrium
CO_2	Carbon dioxide
DC	Direct Current
DOE	United States Department of Energy
ED	Economic dispatch
eGRID	Emissions and generation resource integrated database
EIA	United States Energy Information Administration
EOR	Enhanced oil recovery
EPA	United States Environmental Protection Agency
EPPA	Emissions Prediction and Policy Analysis model
ETS	European Union Emission Trading Scheme
FERC	United States Federal Energy Regulatory Commission
FOAK	First-of-a-kind
GHG	Greenhouse gas
HHV	High heating value
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IPM	Integrated Planning Model
ISO	Independent system operator
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatt-electrical

kWh	Kilowatt-hour
LMP	Locational marginal price
MARKAL	Market Allocation model
MIT	Massachusetts Institute of Technology
MMBTU	Million British thermal units
MW	Megawatt
MWe	Megawatt-electrical
MWh	Megawatt-hour
NEMS	National Energy Modeling System
NOAK	Nth-of-a-kind
NO_x	Nitrogen oxide
OPF	Optimized power flow
PC	Pulverized coal
PRB	Powder River Basin
PTC	Production tax credit
PUC	Public utility commission
RGGI	Regional Greenhouse Gas Initiative
RTO	Regional Transmission Operator
SCOPF	Security constrained optimized power flow
SCPC	Supercritical pulverized coal
SO_x	Sulfur oxide
Ton-CO_2	Short ton of carbon dioxide
WECC	Western Electricity Coordinating Council
WESTCARB	West Coast Carbon Sequestration Partnership

1. INTRODUCTION

1.1. Motivation: Climate Change

Climate change from carbon dioxide emissions and other greenhouse gases is altering the planet's environment and atmosphere. Possible direct climate impacts include extreme weather changes, rising sea levels and the increase in catastrophic weather events. The indirect impacts include drought and flooding on land, severe alterations in local ecosystems and the destruction of infrastructure.

Potential reductions in the likelihood of catastrophic environmental damage from anthropogenic climate change requires a decrease in carbon dioxide (CO_2) emission to the atmosphere and the stabilization of CO_2 and other greenhouse gases (GHG) concentrations. This would entail a dramatic reduction in CO_2 emissions from current levels. There are numerous proposals for large reductions in emissions up to 80% below current levels by midcentury. (EIA 2008; Stern 2006; Alley et al. 2007)

GHG emissions are produced in many different sectors of the human economy and society; however, the energy sector in particular provides a large contribution to greenhouse gas emissions and to possible climate change. The combustion of fossil fuels like coal and natural gas in electrical generators are a significant source of carbon dioxide emitted into the atmosphere as a result of human activity. Mitigation of climate change will necessarily include reduction in CO_2 from the electricity sector.

In the United States, the power sector is responsible for over 40% of all energy-related CO_2 emissions, with emissions from coal-fired power plants accounting for 80% of electricity-related emissions. Using coal for electricity thus accounts for nearly a third of the United States' CO_2 emission alone. (EIA 2008) If United States, along with other countries, is to decrease its emissions by 80%, carbon emissions from coal-fired power plants must be reduced.

Carbon capture and sequestration (CCS) has been identified as a promising set of technologies with the potential for reducing carbon emissions from coal-fired power plants. (IPCC Special

Report on CCS 2005) CCS captures CO_2 from a power plant's flue gas and pumps concentrated CO_2 into geological storage reservoirs, preventing its release into the atmosphere. (IPCC Special Report on CCS 2005; MITEI 2007) The widespread adoption and deployment of CCS would allow the continued use of coal, an abundant and inexpensive fossil fuel resource, with a much smaller carbon footprint.

Electricity generation with CCS would have much higher costs than current generation options and is not sufficiently mature to compete with other types of electrical generation. (Hamilton et al. 2008) CCS also requires sequestration sites in which carbon dioxide would be stored, necessitating additional infrastructure costs and siting constraints. Coal-fired power plants with CCS require large capital expenditures and initial outlays making it difficult for rapid and widescale deployment.

In the future, regulation may be imposed on the emission of carbon dioxide and other greenhouse gases. A price on carbon, either through a tax or through the market of a cap-and-trade permit market, will impact the cost of electricity generated by fossil fuels proportionate to their CO_2 emissions rates. Given that coal emits approximately twice as much carbon dioxide per kilowatt-hour as natural gas does, a government policy to price greenhouse gas emissions will favor natural gas power plants and coal-fired power plants with greenhouse gas control technology like CCS. (Freese & Clemmer 2006)

The determination of which power plants operates is made through a dispatch calculation by the transmission operator. Regions as small as a single utility's balancing area or as big as the operating area of a Regional Transmission Operator (RTO) use dispatch. In a dispatch calculation, power plants in an area are turned on and off in order to minimize the cost of serving electricity demand within operational constraints like transmission congestion. With little to no transmission congestion, the cheapest power plants get turned on the most.

The imposition of a carbon price will cause a dispatch calculation to favor less carbon-intensive fuel sources. Because CCS power plants are more expensive to operate, CCS power plants would be disadvantaged in a dispatch calculation in the absence of supporting policies like a carbon emissions price. Even if policies exist that favor a CCS power plant to dispatch, transmission constraints can make it physically infeasible to generate electricity from a given source. These constraints vary by location and, for a given location, depend on the state of the entire interconnected system which is constantly changing at each point in time.

Over an entire year, the percentage of time that a generator will operate, its "capacity factor", is a critically important input to financial calculations that investors use to determine the profitability of a given project. A generator must profitably run for enough hours of the year to recover both the initial capital costs of a construction and its marginal operating costs while still providing a profit to its owner.

Most studies of CCS technology and specific projects assume a set capacity factor. However, given the nonlinear physical constraints of the electric power system, it is important to determine whether a CCS power plant would dispatch *even if* it is cheaper than other generation in pure economic terms, and to explore how constraints like transmission capacity depend on the specific siting within the power system.

In order to deploy CCS technology successfully, it is important to understand how it operates and dispatches within the electric transmission grid.

1.2. Objectives and Scope

The purpose of this study is to understand the operation and utilization of CCS power plants in a realistic electric transmission grid. This includes how CCS power plants respond to varying operating conditions like lower efficiencies and capture rates, varying market conditions like different fuel price scenarios, and varying government policies regarding carbon emissions pricing. I will model CCS power plants in different locations to investigate how siting affects operation through transmission congestion and regional competition.

Our analysis will perform a transmission-constrained generation dispatch simulation using an optimization method employed by transmission organizations called optimized power flow (OPF) to calculate the economics and utilization of potential CCS power plants. By exploring how the transmission network affects the economics of CCS power plants under various scenarios, I consider a deployment strategy that prioritizes effective policies and locations for power plants with CCS technology can be considered.

The area of study is the Western Interconnection of North America, encompassing a vast region of the Western United States, two Canadian provinces, and a small section of Baja Mexico. This region, overseen by the Western Electricity Coordinating Council (WECC) represents an extremely broad area with diverse regional energy mixes. Transmission is a concern in this region because the major load centers in California import substantial amounts of electricity. The WECC is also an area where active CCS projects are currently planned or underway, and the study of siting strategies is important and can have an impact.

I will examine alternative scenarios will be explored to determine the conditions, political and economic, that would support the development of CCS projects. Scenarios include market fuel prices since these affect the costs of electricity produced by other power plants on the grid that would compete with any CCS plant. By treating natural gas and coal as substitutable fuels in the production of electricity, shifting the prices of these fuels will lead to corresponding adjustments in the generation mix used to meet electricity demand. Because of the lower CO_2 emissions rates from gas-fired generation, for CCS to be economic for wide-scale commercial use, the electricity generated by a coal-fired power plant with CCS will need to be cost-competitive with the electricity generated from natural gas.

Transmission limitations are also crucial in the siting and locations of power plants. As electricity is supplied to the transmission grid, transmission constraints can limit the ability to transfer power from generation to load. The demand for electricity is generally concentrated in large metropolitan urban areas like Las Vegas, Phoenix, and Southern California in the west. However, land-use zoning, permitting and real-estate costs in these dense urban areas generally require power plants to be built far away from population centers, especially larger power plants that produce electricity at lower cost. Utilities may need to build large, expensive transmission lines may need to be built to allow electricity from these power plants to be delivered to urban load. In the absence of new transmission, plants at some locations may not dispatch even if they are competitive on a purely marginal cost basis. In this analysis, I explore the sensitivity of results to location by testing 14 different sites.

Calculated capacity factors for different locations and conditions will then be used as an input to a financial investment decision analysis, determining the conditions (e.g. carbon prices, fuel prices, etc.) and the locations where it is economical to build a CCS power plant. The results provide insight into policies that are likely to encourage such investments.

The remaining chapters are organized as follows. Introduction and background into CCS technology, policy tools, and the electric grid are provided in Chapter 2. Chapter 3 offers detailed discussion into assumptions, data, methodology and construction of the marginal cost dispatch model. In Chapter 3, specific attributes and history of the CCS sites chosen to be modeled are described. Chapter 4 contains a comprehensive analysis of the simulation results, and individual scenarios and their consequences are explained. A discussion of the implications for policy and business strategy is provided in Chapter 5. Finally, Chapter 6 presents my conclusions and possible future work.

2. BACKGROUND

2.1. *Prior Research and Studies*

The energy economics literature contains numerous studies and analyses of advancing the deployment of carbon capture and sequestration in the electricity sector. These studies often offer perspectives from an economic or technological analysis in order to inform policymakers, businesses, governments, and organizations on potential pathways or barriers to CCS adoption. A brief review of major studies and methodologies follows in order to provide context and motivation for the novel approach and analytical results regarding plant capacity factors and investment cash flow decisions this thesis offers.

The highest abstracted level of studies regarding CCS analyzes the technology's attributes to compare CCS against alternatives in the economic, political and policy environments in order to produce next-step recommendations to advance the state of the art. For instance, the World Resource Institute (WRI) offers recommendations for disparate areas like risk assessment, site selection, injection operation. (WRI 2008) The International Energy Agency (IEA) gives suggestions on techniques to incentivize CCS deployment in the international sphere. (Philibert et al. 2007) The MIT Future of Coal Report recommends a special emphasis on ensuring that CCS demonstration projects are rapidly developed worldwide. (MITEI 2007).

These policy studies offer actionable recommendations using aggregated information in order to identify legal, economic, and policy barriers that may need attention. However, analyses of novel technologies like CCS require projections of future use. Such projections are made using models that can take a variety of forms, including economy-wide, energy sector, electric capacity planning, unit commitment, and generator dispatch model. Each type of model is designed and used to answer specific questions that can provide insight from a different perspective into how best to deploy a technology like CCS.

One of the most important questions that economic models answer is what the impact of a technology or a technology portfolio will be on supply, demand and prices. In order to answer such questions, partial equilibrium or computable general equilibrium (CGE) models are applied to simulate a sector or region's economy. One example is the US DOE EIA National Energy Modeling System (NEMS) used in the EIA's Annual Energy Outlook, which splits the United States into nine Census regions which, due to variations in weather and fuel supply accessibility, contain their own characteristic demand and prices for certain types of energy as well as separate electricity markets. (US Energy Information Administration 2009) The International Energy Agency (IEA) uses a similar structure for the modeling behind its influential annual World Energy Outlook report. (International Energy Agency 2009) The MIT Emissions Prediction and Policy Analysis (EPPA) model is a CGE model of the global economy, consisting of 16 geopolitical regions with trade among them, and each made up of economic sectors with greatest resolution in energy fuels, technology, and consumption. (Sergey Paltsev et al. 2005)

Economic models can identify how large, economy-wide impacts; for example, how the additional coal input into CCS power plants will affect coal and related markets and not just the impact of coal-fired power plants with CCS in the electric power sector. However, since these kinds of top-down models must necessarily account for large sectors of economic activity, analysts often omit details regarding certain sectors and technologies - like the power sector and coal thermal generation with CCS - or aggregate them into phenomenological variables due to complexity and computational concerns. One particularly important technological attribute I attempt to determine is the nonlinearity of the electricity transmission system and how it affects the usage rate, the "capacity factor", of a coal-fired power plant with CCS.

One alternative is a more detailed technological model. These models include greater resolution of technological options, each with many associated technology-specific attributes in order to compare technologies against one another. The usage and potential revenues of an electricity power plant are determined by the technologies that are chosen by the model. MARKAL (MARKet ALlocation) is well-known example of a technology optimization model. The advantage of such an approach is that the model can choose from a comprehensive suite of technologies according to cost and performance characteristics. However, a major disadvantage in these models is the lack of feedbacks, like changes in market prices with large technology usage shifts.

A significant attribute of the power sector that many of these types of models often lack is detail regarding the transmission system. Transmission constraints caused by congestion can limit the ability for even the cheapest and environmentally-friendly electric generation technology to deliver energy, a crucial detail. More aggregated models often lack even a rudimentary transmission system and often require exogenous penetration rates that limit the level of technology adoption to the realm of feasibility.

One example of a model that incorporates transmission detail is one that the US EPA and the FERC sometimes use from an external contractor, ICF International, who provides technical modeling expertise using their own economic model, the Integrated Planning Model (IPM). This model contains detailed network information on the national transmission grid as well as the location, type, and costs of individual power plants.

Utilities and transmission agencies often use more detailed transmission and generation computer models to run the power grid. Capacity expansion planning models optimize long-term additions to the power grid using cost and technological attributes of possible new generation using cost and reliability as primary factors. (Hobbs 1995; Kagiannas et al. 2004) Unit commitment models look at how generation utilization must be planned ahead of time in order to optimize scheduled maintenance outages and to work around technological attributes such as ramp rates and start-up costs for thermal power plants. (Sen & Kothari 1998) These more detailed models still do not explicitly take into account the cost of electricity at a particular location nor do these models identify constraints in the ability to deliver energy over transmission lines. Both are crucial factors in determining the utilization and capacity factor rates in an electric power generator.

An optimal power flow (OPF) dispatch model can explicitly calculate the cost-effectiveness of a power plant while considering transmission and other physical constraints and the existing cost of electric power on the grid. For new technologies such as CCS, understanding the conditions in which a potential generator is cost-competitive is crucial to developing that technology at minimal cost. Because it also requires siting power plants in particular locations on the power grid network, OPF models can also reveal location-specific effects of generation. CCS, with its need to sequester CO_2 in specific geologic formations, is also very location-dependant and a dispatch model can explore the interactions between transmission and sequestration siting.

The OPF dispatch model has previously been applied to examine various aspects of integrating advanced coal-fired power plants into electricity systems. Studies have represented dispatch through simplified assumptions in plant-level cost analysis as well as CGE models. (Rubin et al. 2007; McFarland & Herzog 2006; Geisbrecht & Dipietro 2009) Others have used a dispatch calculation to look at how coal-fired power plants with CCS would fare under conditions such as GHG caps and other policies. (Johnson & Keith 2004; Wise & Dooley 2009) Studies have also specifically examined the dispatch characteristics for technology penetration in the Western Interconnection. (Ford 2008)

I will expand on previous studies in this thesis by using a marginal cost dispatch model to capture detail regarding the existing transmission grid and specific locations in the Western United States for advanced coal power plants. Using this model, I will explicitly calculate the availability and cost-effectiveness of a hypothetical coal-fired power plant with CCS. In this way, important transmission constraints will be captured that can determine much of the usage and revenue of a power generator which can cause significant variations across transmission grid locations. The impact of policies, future scenarios, and technology characteristics will thus incorporate a spatial component according to a hypothetical plant's location in the simulated transmission grid.

2.2. Carbon Capture and Sequestration

While CCS technology can be used in natural gas power plants, refineries, cement manufacturing and chemical processing plants, the application of CCS in coal-fired power plants represents some of the greatest carbon mitigation potential. The current state of CCS in coal-fired power plants uses two predominant designs: pre-combustion and post-combustion capture.

The technology that is most compatible with the existing fleet of coal-fired power plants (i.e., pulverized coal (PC)) is post-combustion CCS which removes CO_2 from a power plant’s flue gas. Post-combustion systems afford the ability to fit CCS systems onto existing coal-fired power plants, allowing retrofits into the existing fleet but typically at a heavy energy penalty.

Pre-combustion systems can be used where coal is first gasified, like Integrated Coal Gasification Combined Cycle (IGCC) power plants. Since the CO_2 in gasified coal is under pressure and not diluted by combustion air, the cost of capturing CO_2 can be substantially less. However, IGCC power plants have not yet proven to be commercially viable on a large-scale. IGCC technology is also highly integrated; a failure in a component of the system will likely lead to the unavailability of the entire plant.[1]

The cost of CCS technology when compared to reference plants can be substantial. N^{th}-of-a-kind (NOAK) supercritical pulverized coal (SCPC) power plants have been found to have costs of over $3,000 per kWe, representing an additional cost of about 50% over plants without CCS equipment. (Hamilton et al. 2008) Studies into the implementation of post-combustion retrofit CCS system on existing PC power plants has found that the capital cost by itself would be half a billion dollars. (MITEI 2009, p.21) The MIT Energy Initiative retrofit workshop report found that for N^{th}-of-a-kind (NOAK) PC power plants with CCS, CO_2 avoidance costs would be in the range of $50 to $ 90 per ton-CO_2. (MITEI 2009) Costs for first-of-a-kind (FOAK) PC CCS power plants would be greater than $100 per ton-$CO_2$. (Al-Juaied & Whitmore 2009)

Costs for IGCC and oxy-fuel combustion are highly tentative and subject to large amounts of uncertainty. Nevertheless, other recent studies have calculated that, in the case of a first-of-a-kind (FOAK) IGCC power plant, capital costs are in the range of $6,000 to $7,000 per kWe. (Al-Juaied & Whitmore 2009) The reported costs of DOE's FutureGen experimental CCS power plant fall within this range at $6,545 per kWe.[2] (GAO 2009) While CCS has been determined to be a necessary technology to reducing overall CO_2 emissions, its high costs necessitate careful planning and understanding of its effects in order to maximize its impact with minimal cost.

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[1] For more information on CO_2 capture technology, see the MIT Coal Study. (MITEI 2007)
[2] The original structure of FutureGen in 2008 was planned to be a 275 MWe whose reported costs were $1.8B.

In order to avoid releasing the CO_2 into the atmosphere, CO_2 must be stored. The most promising method of CO_2 storage is to pump pressurized CO_2 into geological sinks. This is currently being done for the benefit of enhanced oil recovery (EOR) in declining oil fields for financial benefit. However, the use of CO_2 for EOR is limited to areas accessible to oil fields. More common are saline aquifers that can be found in many regions of the United States and other countries.

Other costs involved in CCS include transportation of CO_2 and the potential infrastructure cost of building CO_2 pipelines to connect CCS power plants with CO_2 sinks. In order to minimize such transportation infrastructure for FOAK CCS power plants, siting of power plants will probably be as close as possible to storage locations.

2.3. Policies

Governments have at their command a set of policy instruments to diminish CO_2 emissions from the power sector in general and in CCS in particular. Each has their advantages and disadvantages and particular implementation issues that greatly impact their effectiveness as a policy tool.[3]

2.3.1. Regulation

One method of ensuring that CCS power plants are used for coal-fired power plants is to simply mandate that all newly built coal-fired power plants include the technology. Such moratoriums on traditional coal-fired power plants have advanced in fits and starts but have not gained widespread traction. Advocates for such a moratorium famously include former Vice President Al Gore and former NASA atmospheric scientist James Hansen, who has claimed that adding even one additional coal-fired power plant to the world's national grid can be the tipping point in the climate system. (Hansen 2008) To date, no national government has issued such a moratorium on traditional coal-fired power plants and required the use of full capture CCS.

A method of regulating emissions is to set emissions performance standards on a per energy unit basis. California passed legislation (SB 1368) in 2007 setting a maximum emissions limit of

[3] For further discussion on policy instruments, please see (Hamilton 2009).

1100 lbs-CO_2/MWh for any new power plant that provides power to the state. This emissions rate is similar to that of lower-efficiency natural gas-fired power plants, about half of a typical coal-fired power plant, thus precluding the construction of future coal generation. The state of Washington passed similar legislation with SSB 6001.

Such regulations can be effective in ensuring that high CO_2 emissions power plants will not be built. However, they do not offer much financial incentive or support in building low-carbon sources nor do they ensure that new technology will be developed or used in future instances. One critique of such a policy tool is that power developers will merely shift heavily toward natural gas-fired power plants. They also deny the use of coal as a fuel in new conventional power plants no matter how cheap or convenient it may be. Other policy instruments may be more flexible in how they incentivize new technologies.

2.3.2. Carbon Tax

A carbon tax puts a cost on every ton of CO_2 emitted. By placing a value on CO_2 emission, sources with higher emissions will have a higher cost than lower emissions sources. This will allow initially expensive low-carbon electricity generation to be more competitive against cheaper carbon-intensive sources of electricity like coal-fired power plants. Utilities and developers will be incentivized to use to power plants that emit less CO_2 like renewables, nuclear and – relative to coal – natural gas.

How a carbon tax impacts the power sector can vary depending on how the tax is imposed but theoretically its effect should be the same. If the burden of paying the tax is imposed upstream in the energy process, such as the coal minemouth or the gas well, the cost of the carbon emissions is encapsulated in the price that power plants pay for fuel. If a carbon tax is imposed instead on the power plants generating electricity and emitting the CO_2 then the utility will have to pay directly for its emissions. Although the overhead for administering the tax may be very different because of the large difference in sources covered, in both cases, costs will be passed through to electricity consumers and electricity prices will be proportionately impacted by the additional cost of CO_2, in theory.

The advantage of a carbon tax lies in its transparency, certainty and ease of government monitoring and enforcement. A carbon tax allows businesses and the markets to respond to the price on emissions and reallocate resources to minimize CO_2 emissions as cheaply as possible. Unlike other market-based regulations that rely on trading and exchanges, a carbon tax will provide a firm price for carbon emissions that is less alterable. A carbon tax also requires less overhead to administer for the government. (Babiker et al. 2003) Governments do not have to ensure that required equipment such as emission control technology are installed or manage permits. The supervising agency simply counts emissions and issues a bill.

The primary disadvantage of a carbon tax in the United States is a political one. According to one poll by GlobeScan, a majority of those polled in the United States are against carbon taxes. (Globescan 2007) The political realities make it difficult for politicians and legislators to back a carbon tax without significant public backlash. Carbon taxes as such are a non-starter in the United States as a carbon emissions regulation mechanism.

2.3.3. Cap-and-Trade Program

Cap-and-trade schemes have been proposed based on the experience of their application in SO_x and NO_x emissions markets. In a cap-and-trade program, the total amount of some emissions is set at a maximum level and allowances to emit are administered through government-monitored permits. The value of emissions permits can be determined by requiring some or all emissions permits to be distributed through a government-run auction and allowing the remained to be bought and sold on an exchange (the "trade" part of cap-and-trade), allowing a market to set the price of emissions.

CO_2 cap-and-trade programs have been used to limit carbon emissions. The European Union Emissions Trading Scheme (ETS) has been in operation since 2005, the largest such cap-and-trade program in the world, covering power and industrial sectors. The price that the ETS has put on a metric ton of carbon emission has varied considerably from €30 at its peak to a low of fractions of €1.[4] In the United States, the Regional Greenhouse Gas Initiative (RGGI) recently started in 2009 in the Northeast between ten states to limit the emissions of the power sector.

[4] Source: Carbon Point

The value of RGGI's permits have varied from a high of $3.51 per (short) ton of CO_2 to a low of $1.87 per ton of CO_2..

Major legislation is currently under consideration by the United States Congress to establish a nationwide cap-and-trade program. In Congress, H.R. 2545, the American Clean Energy and Security Act of 2009 (ACES, also nicknamed Waxman-Markey) has passed the House of Representatives and would establish a cap-and-trade program for CO_2. At the beginning of 2010, S. 1733 the Clean Energy Jobs and American Power Act is being considered in the Senate. The major component of both of these programs is an economy-wide cap-and-trade program, including the electric power sector.

According to economic theory, a cap-and-trade program would have impacts similar to a carbon tax. For cap-and-trade, a CO_2 emissions target is set and the market determines the carbon price. For a carbon tax, a carbon price is administratively set and the market determines the level of CO_2 emissions. Another difference is that in a cap-and-trade program, policymakers decide how to allocate emissions permits while in a carbon tax policymakers decide how to allocate revenue from the emissions tax.

The ability to distribute emissions allowances through a political process can provide significant cost relief to emissions sources. In this way, the implementation of a cap-and-trade program – a major new regulation that would affect entire economies – can be made politically palatable. In the United States, for instance, the allocation of emissions permits to coal interests has allowed moderates from coal-dependant regions to be more inclined to back the cap-and-trade program. (Lerer 2009)

One of the major disadvantages of a cap-and-trade system is that a lax cap can create leakages in emissions and price volatility. For instance, the ETS program provided too many permits in its first phase which, when discovered, caused the value of permits to bottom out. RGGI has experienced similar problems as its auction results have produced lower prices. Volatility in the value of emissions allowances creates an uncertain investment environment for the deployment of new technologies. One remedy for this is a "price collar" that sets a floor and ceiling on the value of emissions permits, a solution currently being discussed in conjunction with the Kerry-Boxer Senate bill. (Energy Washington Week 2009)

2.3.4. Subsidies and Demonstration Projects

Governments can use public funds to provide subsidies or to support demonstration projects for large unproven technologies like CCS or new nuclear power plants. Programs like the DOE's Loan Guarantee Program provide large, low-cost loans to developers of power projects. Grants are also provided through offices like the Advanced Research Projects Agency – Energy (ARPA-E) to perform research and development and to support the commercialization of energy technologies.

The initial risk of multi-billion dollar projects for early technology demonstrations could warrant such use of public money. The rationale is that private businesses and banks may be unwilling to support immature technologies with highly risky financial returns. But a larger public benefit may exist in advancing the state of the technology in cost and knowledge to the point that the private sector can use and deploy the technology. To that end, governments may take on risk through financing, insurance or the backing of debt.

Governments and industrial groups have been putting together FOAK demonstration plants for IGCC with CCS. FutureGen is a consortium of government and businesses to create the first commercial scale IGCC power plant with sequestration in the United States. The project has had a troubled history having hit roadblocks and funding droughts along with some project restructuring. The United States government along with American Electric Power is also supporting the Mountaineer experimental project in West Virginia. In China, GreenGen is a project that started construction in the summer of 2009 and is expected to be operational sometime during 2010 or 2011. Up and running in Germany is Schwarze Pumpe, a experimental project by utility company Vattenfall.

Subsidies can accelerate technology development and deployment by getting FOAK plants built quicker. The rationale for using public funding for technology development are the widespread benefits that private developers may have difficulty capturing. For instance, an industry as a whole could benefit from the technical and operating learning furnished by the first set of technology demonstrations. Businesses, like the finance and insurance industries, may become more comfortable with supporting large, yet-unproven technology investments. Finally, the public will gain some familiarity and understanding of the benefits that a technology like CCS may have, and lend community and political support.

The primary disadvantage of subsidies is that they are often directed at specific technologies where success is not guaranteed. In these cases, not only are the subsidy funds lost, but there is also the opportunity cost of not using that money to support other technologies and other public investments. Subsidies can be viewed as calculated risks to support specific technologies in which the payoff of further technology development is uncertain.

2.4. Electricity Grid

The electricity grid is a large network of transmission lines connecting disparate power generation stations with load areas and the distribution network. In order for CCS or any new electricity technology to operate economically and profitably, it must compete against other generation types on the power grid: plants using natural gas, existing coal, diesel, geothermal, wind, solar and hydropower. Fossil fuel burning power plants also have a set of differing technologies that produce varying operating characteristics even though the plants are burning the same fuel.

Different regions will utilize different portfolios of technologies and fuels to produce electricity according to their resource endowment and proximity to fuel supplies. Other factors that may affect capacity expansion decisions include regional weather variations, transmission capacity, level of load, expected growth and environmental regulations, to name a few.

Capacity planners are also cognizant of the diurnal and seasonal cycles that require generation that can serve constantly varying demand. Power generation is categorized as baseload, intermediate, and peaking depending on which part of the load curve it serves. This categorization is determined by ramp rates and ability to dispatch but mostly by cost of generation. Baseload generation runs nearly all of the time with greater than 80% capacity factors and peaking power plants can run as little as a few percent of the hours of the year. Intermediate or shoulder power plants run between peaking and baseload.

In order to serve growing electricity demand in the United States and the world while at the same time minimizing GHG emissions, there is a significant need for low-carbon baseload generation, like hydropower, nuclear and coal-fired power with CCS. Renewable sources, like solar and wind, suffer from intermittent generation and the inability to store and dispatch energy to meet periods of peak load.

2.5. Electricity Markets

2.5.1. Regulation

Electricity is often the classic example of the natural monopoly. Electricity cannot be stored and requires nearly instantaneous production and consumption after conducting across transmission wires. As such, a transmission network must be built and regulated to accommodate the delivery of electrical power to households and businesses. The power industry requires government regulation in order to fully realize the externalities of the network effects in building the power grid.

Historically, governments have allowed for the existence of local monopolies that are vertically integrated. In the power sector, this vertical integration takes the form of a single utility company that owns and operates nearly all levels of electricity production and delivery – the utility owns the generation that produce electric power, the high-voltage transmission lines that deliver power to the distribution grid, which provides lower-voltage power to commercial and residential customers and whose billing and service is also managed by the same utility.

Utilities are required to submit their costs of operations and rationale for investments to regulators each year through rate cases, an annual ritual of give-and-take and negotiation. In the United States these regulatory boards, often called public utility commissions (PUCs) sit at the state level. These regulatory boards decide on a case-by-case basis for each utility what customer usage charges to allow the distribution portion of the energy delivery system. In regulated regions, these rates, or tariffs, are often based on a “cost-plus” or “CPI – X” formula which allow utilities to recover their costs and make a slight return while possibly providing for limited incentives. Other than the sale of power exports from their area, the primary source of revenue for utilities is through these tariffs.

Regulated utilities make investments based on anticipated future power needs and the ability to demonstrate to PUCs that building a generator serves the reliability and affordability of the utility’s customers. An entire suite of factors are considered – environmental impact, fuel diversity and security, and social equity – but the primary criterion is often cost. Traditional regulation has encouraged utilities to be risk-averse and conservative; regulated utilities have traditionally not been promoters or early adopters of new power generation technology. Under regulation, utilities can only receive a set rate of return, so risky projects are discouraged when safer, but more expensive, projects exist where costs are guaranteed to be recovered.

2.5.2. Restructuring and Competitive Markets

In the last three decades in certain markets, the power sector has undergone significant market reform away from the traditional regulated vertical monopoly. These reforms often blend some set of liberalization and deregulation measures to form wholly restructured markets. Traditional utilities in these regions are split between companies that sell power from their own generation and distribution companies that purchase power and deliver it to end-users. Transmission infrastructure is owned privately, but control and responsibility of operating the grid is handed over to regional transmission operators (RTOs) or independent system operators (ISOs).

Multiple rationales exist for restructuring the power sector. By liberalizing the power sector and allowing many different companies to enter the electricity business rather than a single monopoly, private capital from more companies can be used for power investments. Private investment also allows private firms to take on the risk of doing business in the power sector rather than having captive ratepayers shoulder risk, as regulated tariffs and cost recovery required. The introduction of additional firms should also allow for competition in the power sector, putting pressure to drive down costs and to make the sector more efficient. Finally, restructuring the market also can entail the introduction of local pricing through locational marginal prices (LMPs) that provide price signals for investors. Higher LMPs provide incentives for building new generation or transmission in a particular region.

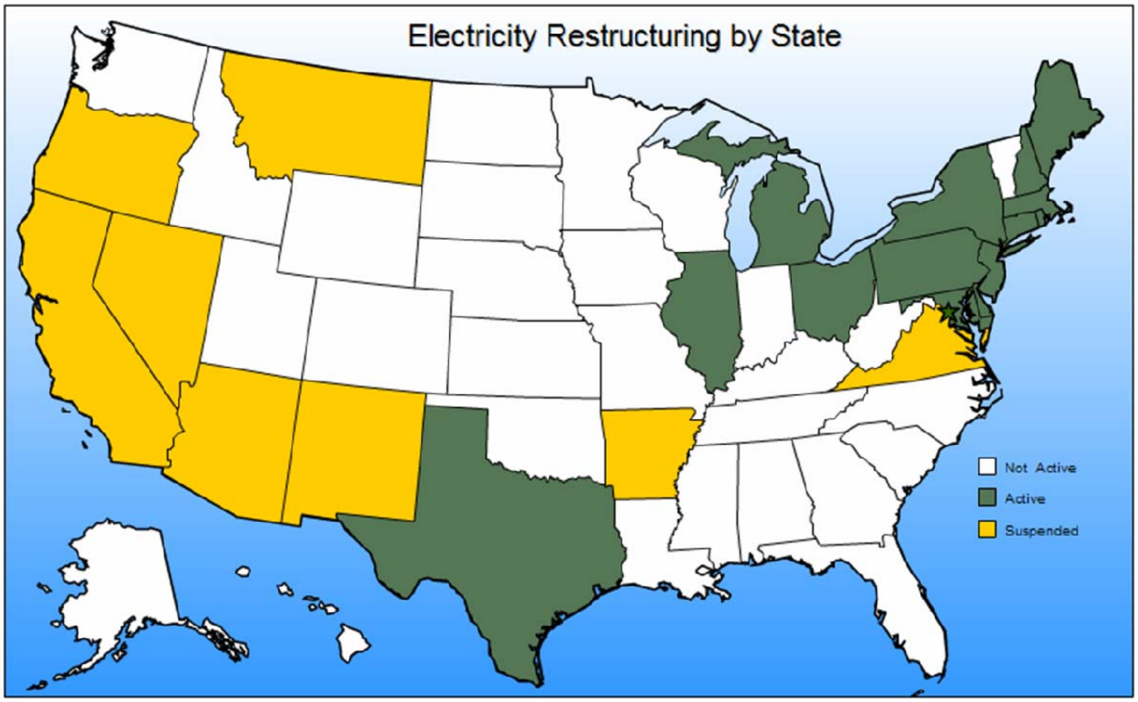

Figure 2-1 Status of Electricity Restructuring by State, September 2009[5]

In areas where an ISO handles regional dispatching of generation, the prices within the market are determined by calculating an optimization problem for the system area for the lowest overall cost considering transmission and reliability constraints. The LMP in a particular zone is considered the market clearing price and all electricity generation is paid at that price, even if their marginal costs are lower.

Merchant operators, as generation-only companies are often called, base their investment decision on whether they can profitably sell the electricity through a bilateral contract to a distribution utility or on the market. Captive electricity consumers are not exposed to the risk of poor investment decisions or pricey generation options as they were in regulated markets. However, in the absence of a guaranteed return, firms will only make investments that will be profitable.

[5] US Energy Information Administration

2.5.3. Electricity Costs

The cost of electricity to consumers and producers are determined by many different factors, from the retail to the wholesale level. The price of wholesale electricity, or the electricity being traded and delivered on the transmission grid, can be established through long-term bilateral contracts where a supplier guarantees a fixed price to a customer. Prices for wholesale electricity can also be established through a marginal cost dispatch calculation, discussed in further detail in Section 3.2.

A large portion of the electricity cost in a fossil fuel power plant derives from the cost of fuel like oil, natural gas or coal. Fuel costs are passed onto the cost of electricity according to how efficient the power plant is, often expressed in heat rate (the amount of energy input versus the electrical energy output). Other variable costs for a power plant include the operating and maintenance cost and, for power plants operating under a carbon emissions price, the cost of emitting CO_2. Fixed costs also include some set operating and maintenance but the largest portion of fixed costs is in construction and capital costs, which are carried for the book life of the power plant.

Delivering electrical power entails transmission costs which can involve payments to transmission infrastructure owners. Power lost to resistance in the transmission lines is minimal – generally only a few percent – but the generation company is responsible for making up the shortfall. The distribution network contains even more resistance losses than the transmission system and requires more maintenance and administration to bill customers and provide service.

2.6. Area of Interest – Western Interconnection

The study area is the Western Interconnection of the United States. The Western Interconnection is one of three electrical interconnections in the United States, along with the Eastern Interconnection and the Texas Interconnection. Interconnections are isolated electric networks that contain special transmission connections in order to ensure synchronization within each region.

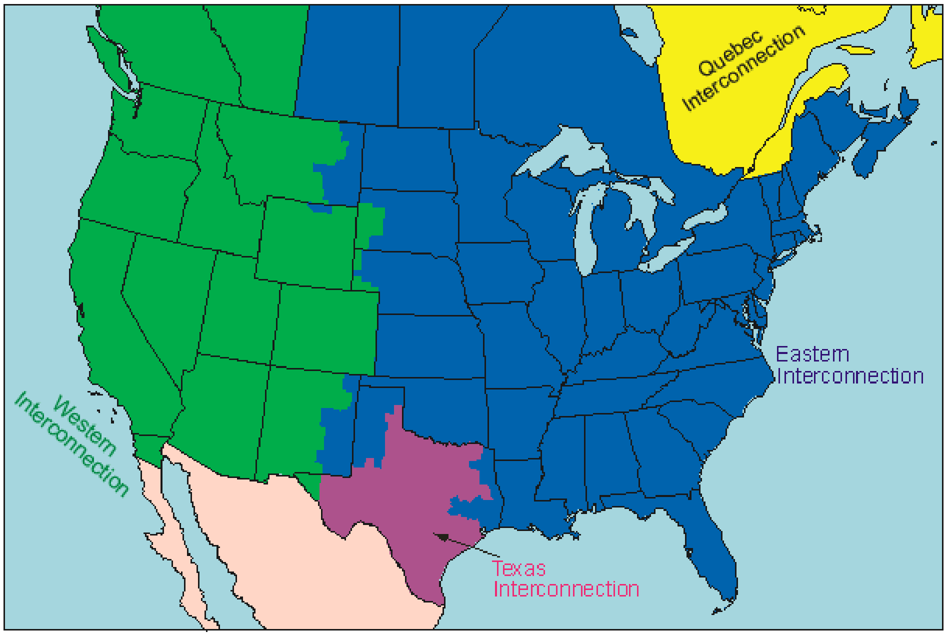

Figure 2-2 Electrical Interconnections in the United States and Canada[6]

Electricity reliability and coordination is managed by the Western Electricity Coordinating Council (WECC). The area under their authority contains the western US states of Washington, Oregon, California, Nevada, Idaho, Utah, Colorado, Arizona, and parts of Montana, Wyoming, South Dakota, Nebraska, New Mexico, and Texas. The Canadian provinces of Alberta and British Columbia are also under WECC's purview as well as northern Baja California, Mexico.

Other organizations and areas that the Western Interconnection contains include the West Coast Regional Carbon Sequestration Partnership (WESTCARB), one of the DOE's regional sequestration initiatives to advance the state of the art in CCS. The Western Interconnection is largely a regulated area with California ISO (CAISO) as the only deregulated market. The Bonneville Power Authority (BPA) controls a large portion of the hydroelectricity capacity in the northwest.

The Western Interconnection features important regional differences among its thirty-seven balancing authorities. The northwestern region is dominated by inexpensive hydropower, a resource highly dependant on seasonal weather for filling water reservoirs. The mountain states

[6] US Energy Information Administration

along the Rockies utilize the cheap, abundant resources from Montana and Wyoming: coal. As such, in Arizona, New Mexico, Utah and Nevada many of the power plants are coal-fired and also relatively polluting in their emissions. In California, due to stricter environmental regulations and higher population densities, utilities have emphasized natural gas in order to fulfill demand.

3. METHODOLOGY

The methodology used in this thesis is outlined below and further explained in this chapter:

1) Choose a model for the simulation calculations. (Section 3.1: Dispatch Model)
2) Establish performance and economic metrics like capacity factors to be measured from dispatch simulations. (Section 3.2: Dispatch and Capacity Factor Calculation)
3) Estimate individual marginal costs for all existing power plants. (Section 3.3: Marginal Costs)
4) Determine attributes of individual hypothetical coal-fired CCS power plants. (Section 3.4: CCS Power Plants)
5) Decide locations for hypothetical CCS power plants to be inserted in the simulated electric power grid based on transmission, sequestration potential and other contextual factors. (Section 3.5: Discussion of Hypothetical Power Plant Sites)
6) Pick portfolio of sensitivity and market scenarios to use to explore CCS power plant dispatch. (Section 3.6: Simulation Scenarios Summary)

3.1. Dispatch Model

The model we have chosen to explore transmission constraints is an optimized power flow (OPF) model. The commercial software PowerWorld Simulator version 13 was selected with a software add-on that also calculates OPF solutions. The data used to characterize the WECC study region will be described in detail below.

Several methods for calculating the dispatch of power system exist. The simplest is economic dispatch (ED). In ED, a system operator would line up generation by marginal cost, cheapest to most expensive, in *merit order*. The price on the electricity grid is set by the cost of the marginal unit of electricity. In order to serve load under ED, the system operator would use the set of cheapest power necessary to meet the demand. Given each generator's capacity and marginal costs, ED is computationally simple. However, ED does not account for transmission constraints or redispatch due to congestion.

Optimized Power Flow (OPF) solves the power and circuit engineering problems to determine the level of current flow and voltages at all buses, the nodes of the electricity network, in the power grid given transmission connections ,power injections and withdrawals. OPF will observe transmission line capacities so that lines will not be overloaded. The OPF algorithm will then look for the next cheapest available generation that will not violate transmission constraints and dispatch power plants "out-of-merit" order. The result is a dispatch that will serve load with the cheapest system cost given the constraints imposed by the transmission network.

Another more stringent type of dispatch is Security-Constrained Optimized Power Flow (SCOPF). SCOPF uses OPF calculations to dispatch in the presence of transmission constraints but also is aware of *security constraints*. Security constraints concern the reliability of the electricity grid and contingency violations, such as an unexpected transmission line failure or generator outage. A SCOPF solution must also allow for these contingencies so that, for instance, a failed transmission line will not overload other lines with rerouted power and cause a cascade that will take down the entire system. Security constraints thus ensure that *n-1* or even *n-2* generators (situations with the sudden unplanned loss of one or two generators) will operate reliably. We were unable to obtain definitions of security constraints in the WECC and thus relied on OPF calculations for capacity factor calculations.

Calculating a dispatch solution requires numerically solving a system of nonlinear equations. Given a system, an initial state and a set of constraints, there is no guarantee that a solution within tolerances can be found that does not violate a system of constraints. This is especially true given the large system that is used for our study area.

The WECC provided network data for the Western Interconnection. This data was a solved load flow case for the Western Interconnect on August 25, 2005, approximating an annual peak load. It represents the generation, transmission flow, and load for a moment during that date. The data include transmission connections, electricity generators and their capacities. The network data represent 58,000 miles of transmission, 190,000 MW of generating capacity, and 2,886 generators within the Western Interconnection. The power plants represented in the dispatch model network after cross-referencing are shown in Figure 3-1.

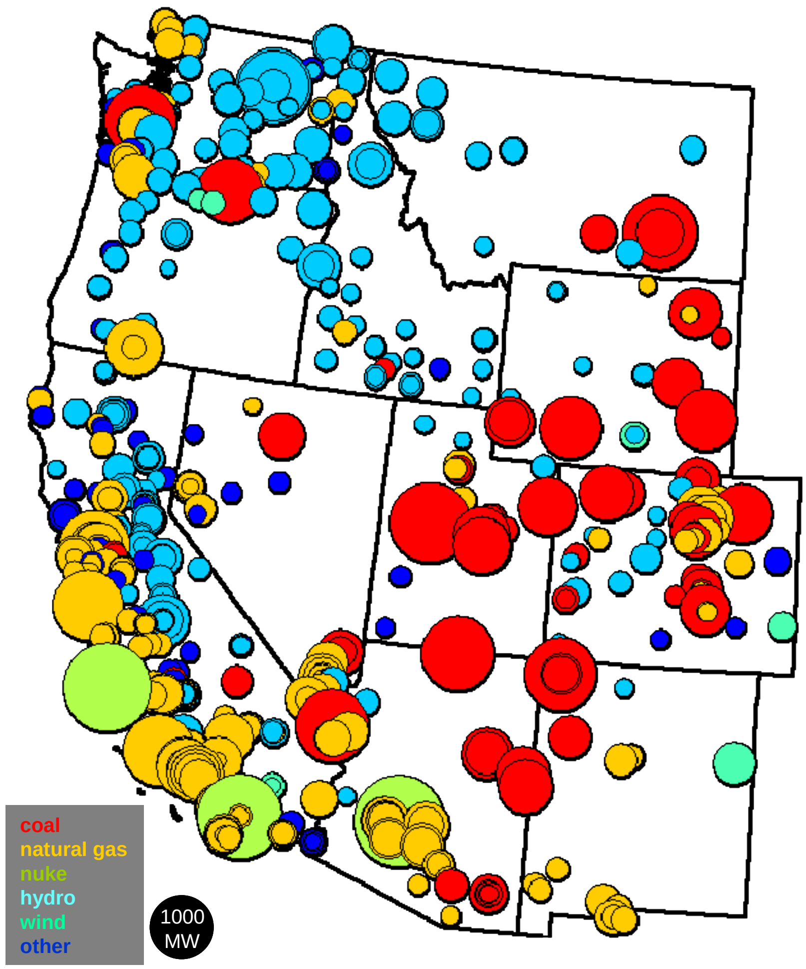

Figure 3-1 WECC Power Plants Represented in the Dispatch Model.
Color indicates power plant type (by fuel) and size corresponds to the size of the generator unit.

The network data can be considered a single solution in a moment of time, or a "snapshot" of the power grid at a particular instant. One consideration is that the load and generation distribution may be different for a hot summer afternoon than for an off-peak time during the shoulder months of spring and autumn. Also, updates to the transmission grid, such as additions in generation and transmission lines since 2005, will not have been modeled in the network data. However, the 2005 model data is a good approximation as the amount of additions in the past years have not been significant. (WECC Staff 2006)

In actual electricity operations, dispatch calculations like OPF are undertaken by the grid operator of a balancing authority. A regulated utility will act as their own balancing authority and will undertake their own economic dispatch and OPF calculation within their area to provide load to the demand. In the Western United States, of the thirty-seven balancing authorities in the region, only one is a deregulated market which uses OPF to determine the power for a large group of distribution companies: CAISO. Our modeling effort is used to calculate the optimal generation for the entire Western Interconnection, in effect, pooling the power generation for the entire interconnection.

The assumption that the entire interconnection is one large dispatchable area is used for several reasons. First, the power from other balancing authorities outside of a hypothetical power plant's is crucially important. Power is transmitted over long distances in the interconnection to reach load, possibly causing congestion for other generation. Some of the scenarios modeled, most notably the carbon pricing scenario, will drastically affect the dispatch of many power plants in other balancing authorities, requiring all power plants to be redispatched. Second, due to data limitations, it is unclear what power plants are under which balancing authorities' control. Certain power plants within other areas may be owned and operated by other entities. Finally, an OPF dispatch calculation will calculate the most economical method to distribute power generation, representing a floor for overall cost.

It is important to keep in mind what marginal cost dispatch represents. A marginal cost dispatch calculation uses only the variable costs to determine whether a power plant should operate. It does not take into account the capital costs of building a power plant, a factor that can be considerable for earlyCCS power plants. The dispatch calculation is equivalent to making a short-run economic decision on whether to operate. It does not represent shutdown or startup decisions, which take into account longer run calculations, and can be considered as the case where a power plant has already been built and a utility merely wants to determine whether it will be worthwhile to operate. For the long-term investment decision, the financing calculation is determined from the simulations calculating revenue value.

In actual operation, a transmission grid operator in a deregulated market, like CAISO, only receives bids from power plants. That is, the inputs into dispatch calculation are values given by market participants, but the grid operator has no way of knowing whether the bids actually represent the short-run marginal costs as economic theory indicates participants should bid, or whether they represent poor decision-making or even gaming of the system. Because the model used here uses estimated costs, actual operation may still produce different results.

3.2. Dispatch and Capacity Factor Calculation

A capacity factor is a metric of how much a generator's capacity is used. If a power plant is running for every hour of the year at maximum capacity, that power plant would have a capacity factor of 100%. A 50% capacity factor may represent a power plant running for half of the hours at maximum capacity or at all of the hours at half capacity.

To run a full OPF calculation for each of the 8,760 hours in a non-leap year is computationally intensive and could take several days to calculate on a desktop computer. In order to run simulations for each individual site and for many different policy and price scenarios, a stratified sampling approach was applied in which the annual hourly load was sampled at percentiles of the load duration curve, as well as the annual minimum and maximum load, for a total of 102 samples.

A dispatch calculation was made at each of these system load levels, and capacity factors were calculated from these dispatch calculations. This procedure ensured that that capacity factors are taken from a sample that takes into account the daily, weekly and seasonal variations in the load that occurs in regular electricity usage. For each new carbon price, fuel price, CCS plant location, and CCS plant characteristic, a capacity factor was calculated by running 102 samples for each of these scenarios. An example of a capacity factor calculation can be found in Appendix A: Dispatch and Capacity Factor Calculation Example.

There is an important caveat in understanding what capacity factor calculations represent. A calculated 100% capacity factor would not realistically result in a power plant running at full capacity for the entire year as there since any power plant is not fully 100% available and requires outages for critical maintenance. A 100% power plant capacity factor then would represent that the power plant could profitably run for all hours of the year at maximum capacity.

For a full and comprehensive capacity factor calculation, hourly load for the year would have to be known for each bus. Data and computational limitations are prohibitive for a complete calculation. It is difficult to obtain and aggregate hourly load data for the entire interconnection from each of the 37 balancing areas in the Western Interconnection. During the data collection, load was taken from the hourly demand data of the CAISO system (shown in Figure 3-2) and the data was scaled to the load of the Western Interconnection. In using this approximation, regional variations in demand must be considered. For instance, regions with heavy industry will have a different demand profile from largely residential areas. Also, the weather in California will be significantly different from areas such as Arizona or Montana, a major factor in electricity usage.

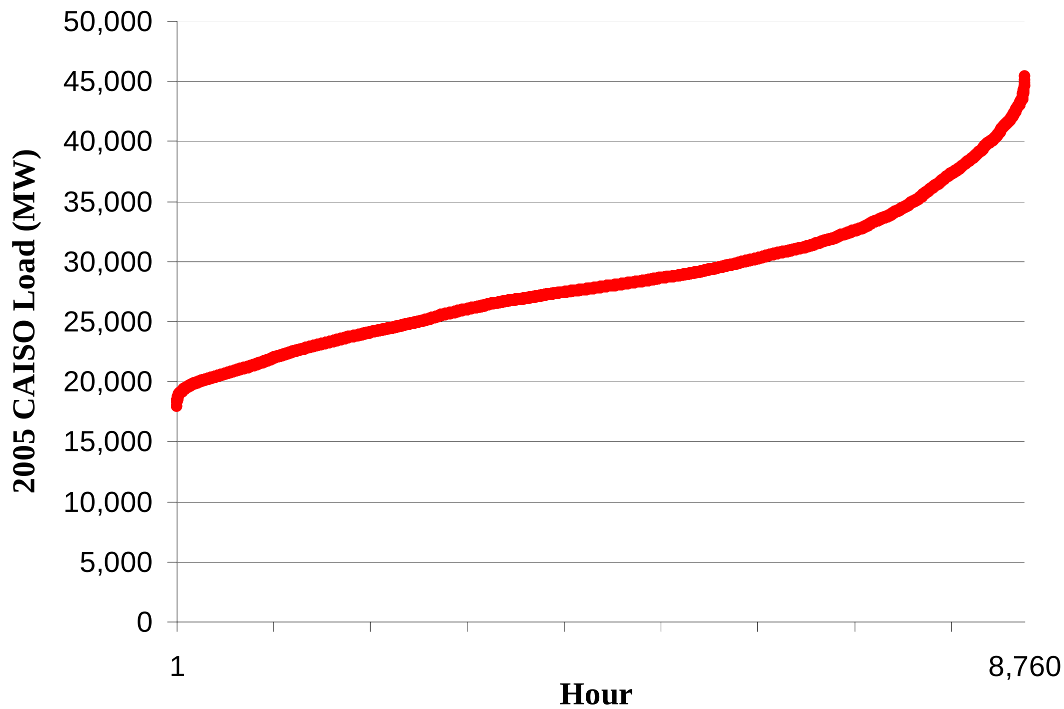

Figure 3-2 Load Duration Curve for 2005 CAISO System Area[7]

FERC Form 714 is also available with a several year delay that includes data reported by balancing authorities. This information contains hour-by-hour load for reported dates for each balancing authority. However, there is no guarantee that the data in PowerWorld corresponds with the information in Form 714. PowerWorld also will simply scale all buses up and down to fit the total aggregated demand; in other words, the model keeps load proportions fixed between

[7] CAISO OASIS

buses. Given these approximations, the accuracy of CAISO data for use in PowerWorld was considered reasonable.

3.3. Marginal Costs

Economic dispatch and optimized power flow require marginal costs for individual generators in order to minimize the overall system cost function. However plant costs are closely guarded proprietary information and not available to the public. The solved load flow case from the WECC does not contain such information. Therefore these plant costs must be approximated.

3.3.1. Data Sources

In order to construct plant costs for the model, several sources were needed to compile the necessary data to produce a marginal cost dispatch analysis of the Western Interconnection.

The US Energy Information Administration (EIA) collects data from utilities and generation companies through Form 860. These data contain information on all power plants in the United States, including location, the prime mover or the generation type, and nameplate capacity. Historical fuel prices for input commodities were also retrieved from EIA reports, forms, and databases. For coal and natural gas, delivered prices were available by region and sector i.e. utilities in states in the Mountain region. Where available, the most detailed data was used.

The US Environmental Protection Agency (EPA) collects data on all domestic power generation as a part of its air-quality monitoring. This information is collected in the Emissions and Generation Resource Integrated Database (eGRID) and contains statistics on input fuels, total generation and fuel, effective heat rates, emissions rates of pollutants like CO_2, and geographical location data. In order to chronologically match data sets to the PowerWorld solved load flow case, the eGRID2007 data was used since it contained 2005 calendar year information.

3.3.2. Calculation

Marginal costs were assumed to be the sum of fuel and emissions costs. Power plants were individually cross-referenced and matched between the PowerWorld, EPA eGRID and EIA Form 860 databases. Nominal heat rates for individually-matched generators were used from eGRID and multiplied by respective fuel prices to produce individual power plant fuel costs for electricity. Additionally, the nominal emissions rates for pollutants such as NO_x, SO_x, and CO_2 from eGRID enabled the calculation of the costs of emissions for individual power plants. As the network data set was obtained for 2005 in Western Interconnection, fuel prices from 2005 were used. The prices of emissions were directly inputed into the marginal cost of modeled power plants. This was done by proportionally increasing the fuel price so that the plant's marginal cost is proportionately impacted.

A full example of the calculation for marginal costs can be found in Appendix B: Marginal Cost Calculation Example.

The cost of carbon emissions must be carefully considered in the modeling. In cap-and-trade programs, acquiring and possessing emissions permits may be treated differently from a carbon tax. Because cap-and-trade emissions permits may be obtained before a generation or dispatch decision through auction or through allocation (as the 2009 Waxman-Markey climate bill does) there is some question as to whether generation companies consider the value of emissions permits when selling electricity or bidding into dispatch. Permit prices might not be perfectly passed through to wholesale electricity costs.

Carbon emissions costs under a cap-and-trade program or a carbon tax should be equivalent in theory. The effect on the price of permits should be equal to a carbon tax on emissions. Utilities would properly price their costs beforehand with permits or taxes. The approach taken in the model is agnostic with this respect: the cost of carbon emissions will fully and directly impact the cost of electricity regardless of how that cost is imposed. In practice, utilities may act differently but there is evidence that pass-through of permit costs is a good approximation. For example, experience with electricity prices and the carbon market in the European Union, the Emission Trading Scheme (ETS) has been mixed but ultimately it appears that freely allocated permit values were passed on as costs. (McGuinness & Ellerman 2008; Reguant & Ellerman 2008) Studies have indicated that the 60% to 100% of the value of freely allocated carbon emissions permits were passed through to the cost of electricity and dispatch bids. (Sijm et al. 2006) Passing-through the entire value of carbon emissions costs to generator bids is thus an acceptable approximation.

3.4. CCS Power Plants

IGCC power plants with precombustion CCS were modeled as this technology represents one of the best options for the mitigation of CO_2 emissions for coal-fired power plants. However, the results of this study are generally applicable to uses of CCS technology in other types of coal-fired power plants. The method used for simulating CCS power plants allows for the limited application of the results to other types of technology. Any power plant with the same fuel input prices (coal for IGCC) and similar heat rates and carbon capture rates would experience similar marginal costs for electricity and therefore similar dispatch characteristics. For instance, a future PC power plant with highly efficient capture technology or an oxy-fired power plant with similar heat rate, fuel cost, and carbon capture rate would feature similar marginal costs and thus dispatch and capacity factors. Economic dispatch thus does not distinguish between technologies, only economics.

The power plants modeled for the OPF calculation in PowerWorld only require marginal cost information. Estimations regarding the heat rate are uncertain and a range of values are available in the literature. The value used for the model is 11,500 BTU per kWh. The heat rate includes the impact of increased parasitic load required for additional carbon capture equipment in a CCS power plant.

The CCS power plants simulated in our dispatch model could approximately represent NOAK SCPC power plant or a NOAK IGCC power plant. The heat rate of a NOAK IGCC power plant has been estimated to be 10,942 BTU per kWh. (MITEI 2007) In this situation, there is administrative and operational optimization as well as technical learning left to develop for IGCC with CCS power plants which can lower the heat rate as deployment reaches NOAK levels of construction. It should be noted that the heat rate of an NOAK SCPC power plant has been estimated as 11,652 BTU per kWh. (Hamilton et al. 2008)

Significant discussion on the strategy of CCS deployment has focused on the capture rate of potential CCS power plants. There is significant variation in costs depending on the capture rate of a power plant. (Hildebrand 2009) Higher capture rates will incur greater costs through greater parasitic load and higher heat rates as well as the requirement larger, more expensive capture equipment. The maximum capture rate that is currently being built for FOAK CCS power plants given the state of the technology is between 85-90%. Capture rates for NOAK power plants are not significantly different.

The coal-fired CCS power plants modeled also use 100% capture rates, a rate that is considered not technologically feasible without extremely high cost. The rationale for this approximation is to simplify and isolate the impact of carbon prices and capture rates in the electricity system with a carbon-free power plant. The impact on electricity cost of emitting 10-15% of the carbon dioxide is also relatively small. Nevertheless, the capture rates were varied in scenarios to determine the sensitivity of dispatch and capacity factor to other types of realistic CCS power plants.

3.5. Discussion of Hypothetical Power Plant Sites

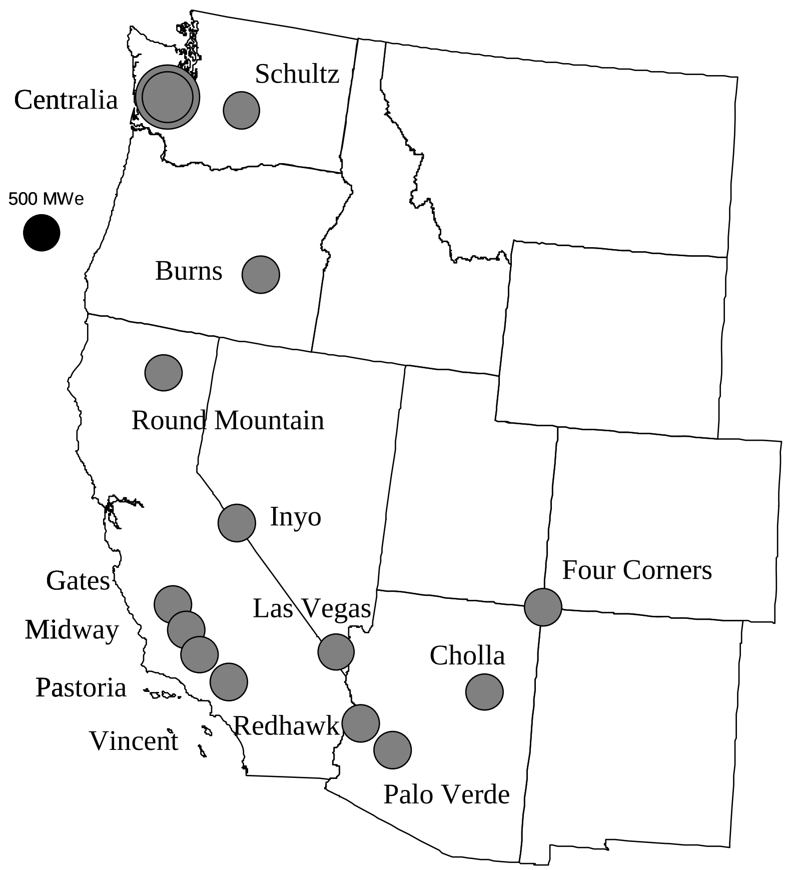

Figure 3-3 Hypothetical CCS Power Plants Modeled in the Western Interconnection. Size corresponds to size of CCS generation.

The sites of hypothetical plants were chosen to represent reasonable and likely locations of future FOAK CCS power plants. The primary criteria for these sites were:

- sequestration potential
- sufficient transmission to load

The following describes in the detail the regions, potential sequestration sites, electrical properties and locations that hypothetical IGGC power plants with CCS were simulated in the model. Sites of hypothetical power plants and their transmission substations are discussed generally since details of the Western Interconnection grid are considered confidential information. A map of sites is shown in Figure 3-3 and a summary table is provided in Table 3-1.

Table 3-1 Hypothetical CCS Power Plant Site Summary

Hypothetical Plant Name	Area	Plant Type	Nearby Planned or Existing CCS Demonstrations
Burns	Oregon	500 MWe CCS	
Centralia	Washington State	1.528 MWe "retrofit"	Centralia Geologic Formation CO_2 Storage Investigation
Centralia	Washington State	1,000 MWe CCS	Centralia Geologic Formation CO2 Storage Investigation
Cholla	Northeast Arizona	500 MWe CCS	Arizona Utilities CO2 Storage Pilot Project
Four Corners	Northeast Arizona	500 MWe CCS	
Gates	Central California	500 MWe CCS	
Inyo	California-Nevada Border	500 MWe CCS	Rosetta-Calpine Saline Formation CO_2 Storage Pilot; Rosetta-Calpine Gas Reservoir CO_2 Storage Pilot
Las Vegas	California-Nevada Border	500 MWe CCS	
Midway	Central California	500 MWe CCS	Hydrogen Energy plant; Kimberlina oxyfuel demonstration plant
Palo Verde	California-Arizona Border	500 MWe CCS	
Pastoria	Central California	500 MWe CCS	
Redhawk	California-Arizona Border	500 MWe CCS	
Round Mountain	Northern California	500 MWe CCS	Shell Northern California CO2 Reduction Project
Schultz	Washington State	500 MWe CCS	
Vincent	Central California	500 MWe CCS	

3.5.1. Central California

The Central Valley region of California contains numerous potential saline sequestration sites in the Central Valley aquifer system. The aquifers begin in northern California with the Redding basin then pass through the Sacramento Valley through the San Joaquin Valley to reach the Tulare Basin, ending just south of Bakersfield. Researchers have estimated the sequestrations potential of the central California basins at approximately 90 to 330 billion tons of CO_2. (NETL 2008)

The transmission grid in California's Central Valley is well-connected to the large load centers in the Bay Area and southern California by 500 kV high-voltage AC transmission lines, facilitating energy delivery and preventing transmission constraints. California experiences large amounts of transmission congestion due to their need to import energy to serve their demand. Power plants sited within the California power grid would experience higher locational marginal prices due to their location within a congested region. (CAISO 2009)

Clean Energy Systems operates the Kimberlina natural gas-fired oxyfuel capture demonstration power plant located approximately 18 miles north of Bakersfield in Kern County. If Kimberlina were a full-scale power plant connected to a high-voltage node in the transmission network, the closest high-voltage substation would be the Midway substation. (Pronske et al. 2006) Hydrogen Energy, a joint venture between BP and Rio Tinto, has also announced plans to build a 250-MWe demonstration IGCC-CCS power plant. The company has stated its intention to connect the plant to the Midway substation. (URS 2009, pp.1-2)

Gates, Midway and Pastoria are substations in the Central Valley located along a 500 kV AC transmission line following the Pacific Coast Mountain Range in the western section of the valley. These substations are connected closely in distance and electrically in the grid. A hypothetical CCS power plant sited at these locations would serve load throughout California while being capable of sequestrating the capture carbon dioxide in the Central Valley. Vincent is a major substation just outside the southern California region with access to the Central Valley aquifer for sequestration.

The rationale for simulating power plants so close together is to highlight differences that the transmission system can create. By simulating identical hypothetical power plants in nearly electrically adjacent substations, any variation can be attributed to the highly nonlinear effects of local transmission constraints.

3.5.2. Bordering California

A set of sites for simulating hypothetical CCS power plants was chosen for possible importing of power. California has a large concentration of the load in the Western Interconnection but due to stringent environmental regulations and policies, California also has had difficulty siting power plants within the state. (Batten & Manlove 2008; Sweet 2009) Approximately a third of the average state load is served by imports, a particularly heavy dependence on out-of-state generation. (CAISO 2009, pp.5-6) Regulations produce an in-state generation fuel mix that skews towards natural gas-fired power plants, a fuel generally more expensive than coal and nuclear as a baseload option. Utilities seeking to provide competitive, large baseload often look to site their generation in nearby states Nevada, Arizona, Utah or New Mexico. Permitting and siting are generally easier in these regions and power is deliverable through existing large transmission lines like the high-voltage DC line from the Intermountain coal-fired power plant.

Plants exporting power will need more infrastructure than in-state sources. Our transmission network mode, however, does not take into account additional transmission or site-specific CO_2 transportation infrastructure required due to the relatively small additional marginal costs. (See Section 3.4) Transmission lines may need to be built or upgraded to connect the generators to load. Siting power plants in convenient locations may mean that coal-fired generators with CCS will need transportation infrastructure for the captured CO_2.

When utilities site power plants, transmission is often connected to ensure that the generator can deliver the energy. This infrastructure can sometimes be substantial. In order to minimize the additional transmission lines required, the approach taken in the model was to find the largest electrical substations to connect to and to link them to hypothetical power plants with oversized transmission. This was done for the hypothetical power plant at the Palo Verde substation.

In other cases, if the hypothetical power plant was equidistant from approximately equivalent substations (similar connectivity and capacity), then the power plant was tied to both substations. The Las Vegas and Redhawk hypothetical CCS power plants took this approach in connecting to the Victorville and McCullough and the Redhawk and Serrano substations respectively. While this may assume a higher initial capital cost for the construction of additional transmission lines, we assume that utilities would not ignore the ability to deliver their power to other load centers like Las Vegas and Phoenix in an improved manner. Using this approach will ensure that generator output will not be transmission-limited and disproportionately affect a dispatch calculation.

One site bordering California, the Inyo substation, did not attempt to maximize transmission capacity. This was done in order to study the impact that limited transmission capacity would create on optimal power flow dispatch. The hypothetical power plant was connected to the Inyo substation along the Sierra Nevada range, the site of numerous small hydropower stations.

3.5.3. Northern California

A site for simulating a hypothetical CCS power plant was chosen in northern California. The closest major load center for such a power plant would be the Bay Area. Such a generator would also be in closer proximity to the large amount of cheap, plentiful hydropower from dams in Oregon and Washington. Siting a CCS power plant allows the model to uncover the effects of these unique characteristics.

The site chosen was approximately 30 miles east of Redding, California and connected to the one of the largest local electricity substations, Round Mountain. While this power plant is relatively distant from the Central Valley aquifer system, a reasonably modest pipeline infrastructure could be built to deliver CO_2 to sequestration sites. For modeling variation, connecting the hypothetical power plant to a large, ideal substation was of more interest than potential questions regarding the feasibility of sequestration.

Northern California is already an area of interest for sequestration and future power plants with CCS. WESTCARB in collaboration with Shell Oil Company is moving ahead on the Northern

California CO_2 Reduction Project, a small-scale sequestration project to demonstrate the potential and possibility of sequestration in the area. A site in the Montezuma Hills of Solano County near Sacramento has been considered for the sequestration site. (NETL 2008)

3.5.4. Northwest

The Northwest states of Washington and Oregon contain abundant hydropower resources. As a result, only a handful of coal-fired power plants are in the region. The utilization of hydropower resource is driven not by the marginal cost as it is in coal and natural gas generation, but more often limited by the availability and level of reservoirs. As such, dispatch decisions regarding hydroelectric power plants do not use the economic dispatch calculations of optimal power flow and are generally treated as existing power flows by a transmission operator. A simulated power plant in the region will also be in closer proximity to the Seattle-Tacoma metropolis and Portland as load centers, areas that experience significantly lower load than the high population areas of California. The dispatch dynamics of a CCS power plant could be significantly different from that of generation that delivers energy mainly to California.

Oregon and Washington contain ten coastal basins for CO_2 sequestration the largest of which is the Puget Trough, located in northwest Washington. (NETL 2008) The Pacific Northwest basin also covers a large portion of the state of Oregon. Altogether, the abundance of carbon sequestration sinks in the Northwest ensure that the siting of power plants with CCS is not limited by sequestration potential.

Identifying sites that contain both sufficient transmission and local access to sequestration is more difficult. For instance, one hypothetical CCS power plant was modeled in eastern Oregon, connected to the Burns substation. Although the substation is connected by high-voltage 500 kV transmission lines, its location is relatively isolated on the transmission network by only two connections, unlike many of the connected substations simulated. This results in a transmission constraint similar to that of the power plant connected to Inyo in central California with lower expect dispatch and capacity factor values.

Another power plant partially tested was located at the site of the Centralia substation and a 1,528 MW coal-fired power plant, a major electricity generation station in Seattle-Tacoma area. Two power plants were modeled independently there:

- a retrofit case of equal size which lacked an energy penalty in total capacity but with a retrofit's expected heat rate of 15,000 BTU per kWh, and
- a 1,000 MW power plant with costs and heat rates similar to that of the standard 500 MW CCS power plants modeled elsewhere.

These alternative simulations were done because of the size of the current Centralia power plant and the relatively small load for the area. Additional hypothetical CCS power plants may not dispatch due to price or transmission constrained but instead the lack of adequate load to take up the generation of another very large coal-fired power plant. By replacing the existing Centralia power plant, these concerns are alleviated.

The other power plant modeled in the area was connected to the Schultz substation in Central Washington. Although concerns over load adequacy are not alleviated by this modeling decision, simulating a potential CCS power plant in this location will provide a data point in the transmission characteristics of the region. The Schultz substation is well-connected, with six high-voltage 500 kV transmission lines. Centralia's transmission, on the other hand, is designed to deliver its power more exclusively toward the local load.

3.5.5. Four Corners

The Four Corners region – located at the sparsely populated intersection of Utah, Colorado, Arizona, and New Mexico – is the location of several large coal-fired power plants like Navajo, San Juan, and the aptly-named Four Corners. These generators are well-connected by numerous large transmission lines that allow for the delivery of power from the Four Corners region and the greater Rocky Mountain states to the load centers of Las Vegas, Phoenix and further on to southern California. The power provided by these plants thus serves more than their local region due to the ample transmission network infrastructure and are important sources of energy for the greater regional population. For instance, two units of the Four Corners power plant are 48% owned by Southern California Edison, over 500 miles to the west of the generator. (SCE 2009)

The Four Corners region also contains several large possible sequestration sinks. The northeast region and northern border of Arizona are part of the Colorado Plateau. This area contains the Naco and Martin formations which represent attractive and convenient opportunities for CO_2 sequestration. Previous surveys have pointed out that such sinks are extensive in area and have geologically sturdy seal rock structures. (NETL 2008)

As such, sequestration demonstration projects have already been conducted in the area by WESTCARB. The Arizona Utilities CO_2 Storage Pilot Project is such a project conducted at the site of the Cholla coal-fired power plant, connected to the Cholla substation. Cholla is also the location of a simulated CCS power plant in order to represent the transmission and hypothetical dispatch characteristics of a potential future demonstration CCS power plant.

The other hypothetical power plant was modeled at the Four Corners substation, next to the Four Corners power plant. This and the Cholla sites are excellent sites for potential demonstration CCS power plants. Because they already contain coal-fired power plants, rail infrastructure for freight delivery of coal is in place. The sites also contain large local potential sequestration sources and abundant transmission capacity for the delivery of electric power to distant load.

3.6. *Simulation Scenarios Summary*

Scenarios have been chosen to demonstrate the sensitivity of CCS power plant dispatch and capacity to multiple parameters. Table 3-2 summarizes the scenarios and the parameters used.

Table 3-2 Summary of Dispatch Model Scenarios

Scenario	**Carbon Prices**	**CCS Plants**	**Capture Rate**	**Heat Rate** (BTU per kWh)	**Fuel Prices** (per ton-carbon dioxide)	**Section Described**
Carbon Prices (no CCS plants)	$0 and $100	none	not applicable	not applicable	base case (see Appendix B)	4.1.1
Carbon Prices with CCS Power Plants	$0 to $100, increments of $5	15	100%	11,500	“ ”	4.1.2
Alternative Fuel Prices	“ ”	“ ”	“ ”	“ ”	see Appendix C	4.1.3
CCS Power Plant Efficiency	“ ”	13	“ ”	11,500, 13,500 and 17,000	base case (see Appendix B)	4.1.4
CCS Capture Rate Sensitivity	“ ”	“ ”	0%, 50% and 100%	11,500	“ ”	4.1.5
Partial Capture	“ ”	“ ”	See Appendix D		“ ”	4.1.6

4. RESULTS AND ANALYSIS

In Section 4.1: Dispatch Model Simulation Results, dispatch simulations were performed and results are presented for six scenarios.

- Section 4.1.1: Carbon Price Scenarios – a case with no hypothetical CCS power plants. The purpose of this scenario is to illuminate how carbon emissions prices create redispatch throughout the electric grid network.
- Section 4.1.2: Carbon Prices with CCS Power Plants Scenarios – a scenario where hypothetical CCS plants are individually simulated. The purpose of this scenario is to explore how CCS power plants in a variety of locations respond to carbon emissions prices. This case is considered the *base case scenario*.
- Section 4.1.3: Alternative Fuel Price Scenarios – a scenario with varying fuel prices. The purpose of this scenario is to explore how fuel prices will cause redispatch and changes in capacity factor in hypothetical CCS power plants.
- Section 4.1.4: CCS Power Plant Efficiency – a scenario where efficiencies of hypothetical CCS power plants are varied. This scenario explores heat rate and operational efficiency sensitivities of hypothetical CCS plants.
- Section 4.1.5: CCS Capture Rate Sensitivity – a scenario where capture rates of hypothetical CCS power plants are varied. This scenario explores capture rate sensitivities of hypothetical CCS power plants. Note: heat rates are not varied.
- Section 4.1.6: Partial Capture CCS Power Plants – a case where hypothetical CCS power plants with partial capture are modeled with their associated heat rates. This scenario simulates realistic partial capture CCS power plants and can be considered a combination of the scenarios in 4.1.5 and 4.1.6.

In Section 4.2: Financial Analysis of the Investment Decision, financial analysis of a FOAK CCS plant construction and investment decision were performed in two scenarios to determine the level of carbon emissions prices necessary to build CCS generation profitably.

- Section 4.2.1: Base Case Financial Analysis – performs the financial analysis calculation for the base case scenario.
- Section 4.2.2: High Natural Gas Price Financial Analysis – performs the financial analysis for a higher natural gas price of $5 per MMBTU.

4.1. *Dispatch Model Simulation Results*

4.1.1. Carbon Price Scenarios

A marginal dispatch simulation of the grid was performed without hypothetical CCS power plants using the verified base case of fuel prices. (See Appendix C: Base Case Scenario Inputs for details.) Capacity factors were calculated for all power plants without carbon emissions prices and at $100 per ton-$CO_2$. By itself, the imposition of a carbon price absent a hypothetical CCS power plant will create a significant redispatch in the power system, as shown in Figure 4-1 (a) and Figure 4-2 (b).

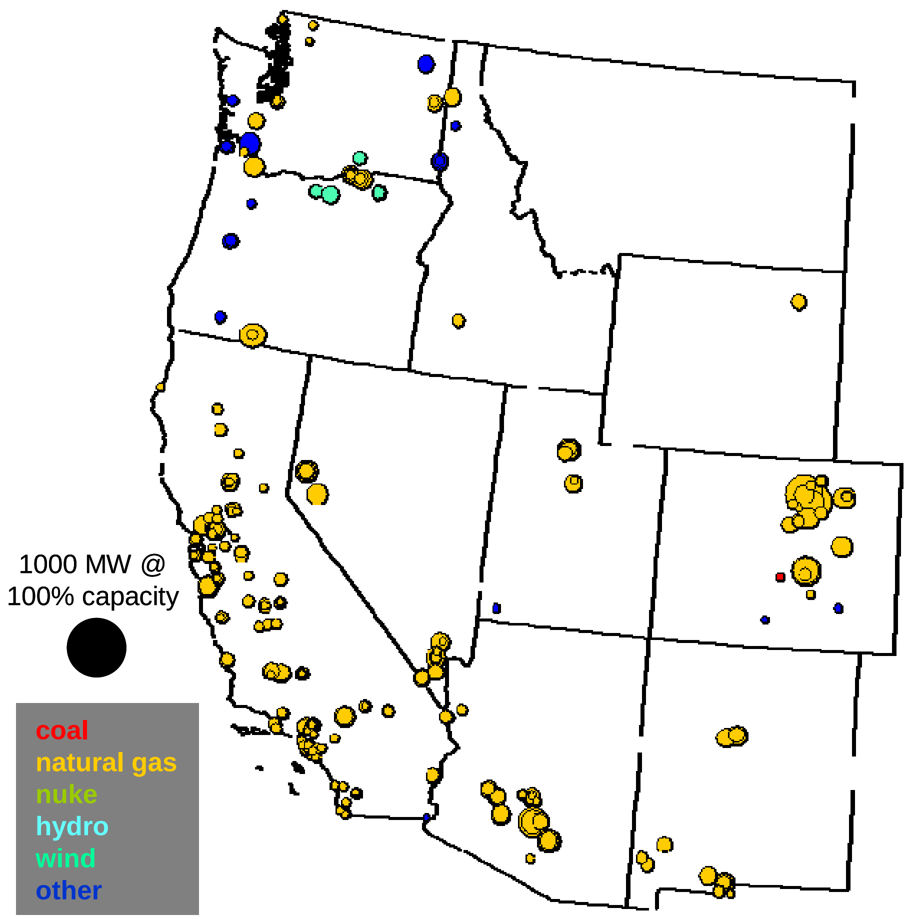

Figure 4-1 (a) Capacity Factor Increase Weighted by Maximum Capacity due to a $100 per ton-$CO_2$ Carbon Policy Relative to No Policy
Color indicates power plant type (by fuel) and size corresponds to the size of the generator unit.

In Figure 4-1 (a), only power plants that increase their capacity factor under a change from a no policy (\$0 per ton-CO_2) case to a \$100 per ton-CO_2 case are shown. The size of the bubble indicates the level of capacity factor change weighted by the size of the power plant. A larger bubble indicates a greater change in electricity generation over the course of the simulated year. Color corresponds to power plant fuel type, as indicated in the legend. Decreases in capacity factor between the no policy case to the \$100 per ton-CO_2 case are shown in Figure 4-2 (b).

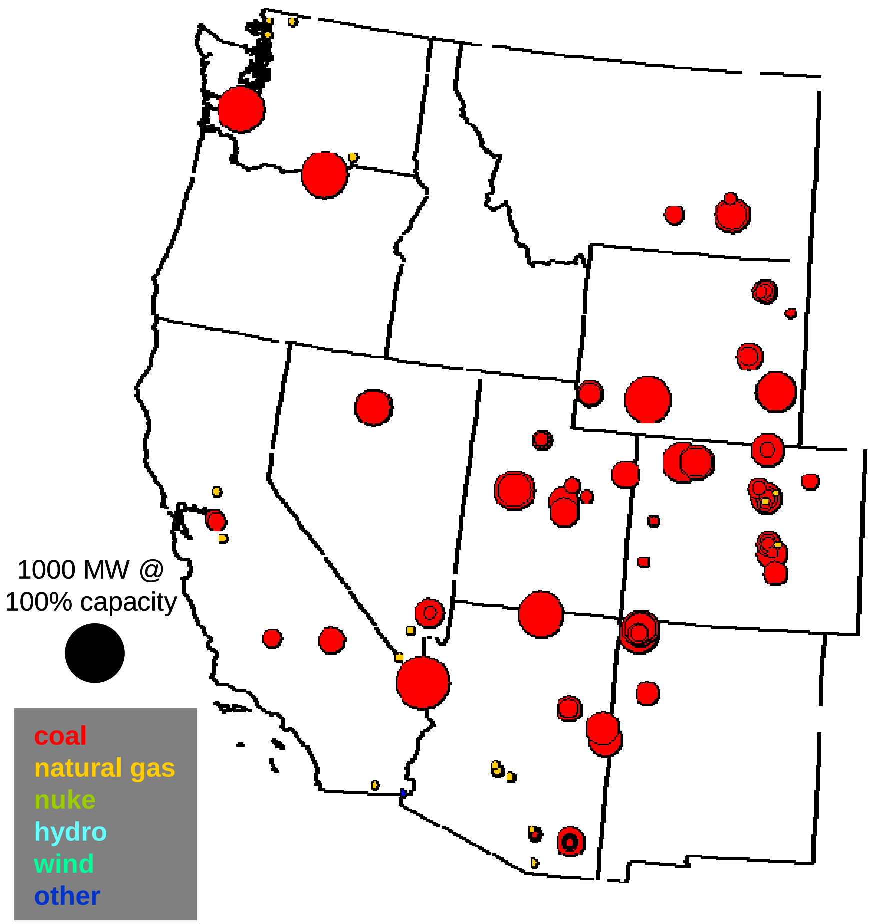

Figure 4-2 (b) Capacity Factor Decrease Weighted by Maximum Capacity due to a \$100 per ton-CO_2 Carbon Policy Relative to No Policy
Color indicates power plant type (by fuel) and size corresponds to the size of the generator unit.

As shown by redispatched power plants in Figure 4-1 (a) and Figure 4-2 (b), large amounts of coal-fired power plants will become less economic due to the additional cost burden of pricing the carbon emissions necessary to generate each megawatt-hour. To compensate, the dispatch calculation chooses natural gas-fired power plants that emit less carbon dioxide emissions per MWh. This redispatch under a carbon pricing policy is not the result of singling out of specific generator fuels (e.g. turn up natural gas, turn down coal) but solely the effect of introducing a significant carbon emissions cost given the sizeable difference in carbon emissions rates between natural gas-fired plants and coal-fired power plants.

A carbon price policy exhibits several significant distributive results as well. The location of the power plants that increase their capacity factor in a dispatch calculation throughout a simulated year are concentrated around the load centers throughout the American West – the San Francisco Bay Area, southern California, Las Vegas, the Phoenix metro area and Denver. Again, these power plants are mostly natural gas. On the one hand, the power plants that mostly suffer reduced capacity factor values are located in the mountain states like Utah, Colorado, and Wyoming. The power plants with capacity factor increases are more widely distributed, demonstrating that the benefits of a carbon price are less concentrated than the losses. On the other hand, the decreases in capacity factor in the mostly coal-fired power plants are concentrated in fewer power plants with larger capacity factor decreases. Therefore, a carbon pricing policy would impact utilities differently based on their generation mix and location.

4.1.2. Carbon Prices with CCS Power Plants Scenarios

CCS power plants were individually modeled in dispatch simulations in this “base case” scenario, detailed in Appendix C: Base Case Scenario Inputs. Carbon prices from \$0 to \$100 per ton-CO_2 in \$5 increments. Only one CCS power plant was online during each simulation. The results of this set of simulation runs are shown in Figure 4-3.

Simulations demonstrate the NOAK CCS power plants, assuming the cost and performance characteristics discussed in Section 2.6, have reasonable capacity factors of between 60% and 80% across all sites for carbon prices between \$0 to \$100 per ton-CO_2. While the financing and build decisions of existing large coal-fired power plants assume very high power plant capacity factors such as 85% or higher, the economic dispatch calculation in this scenario results in capacity factor levels approaching baseload values. This demonstrates the potential viability of such an investment for capital intensive power plants absent a carbon price.

As carbon prices increase, the costs for all non-capture fossil fuel plants will increase due to their carbon emissions. The exceptions are the hypothetical CCS plants that are modeled using equipment that captures 100% of the carbon emissions and other low-carbon generation, most of which is non-dispatchable like wind or hydropower. The result is that many of the fossil fuel power plants surrounding and competing with the hypothetical CCS plants become less competitive compared to less carbon-intensive generation like renewable sources and the CCS power plants.

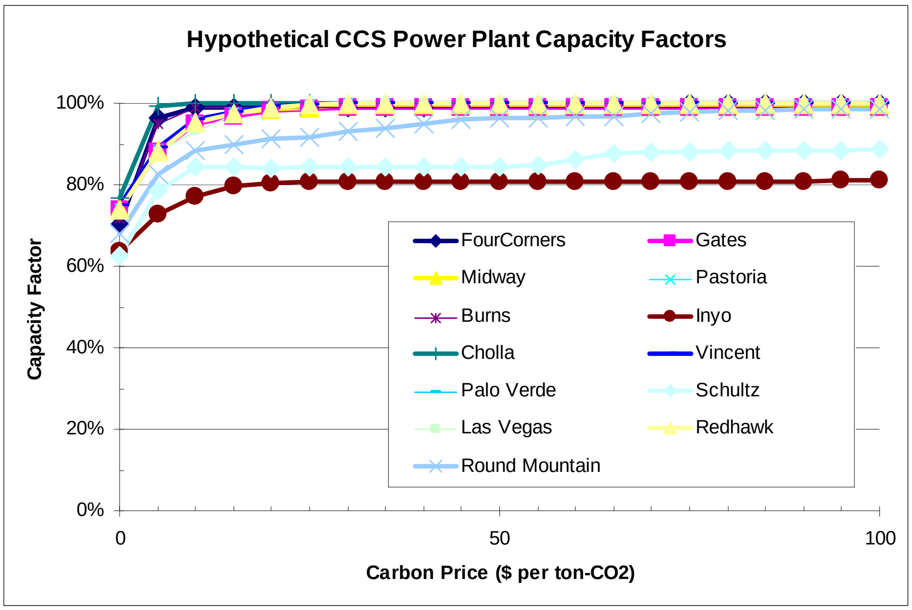

Figure 4-3 Capacity Factor vs Carbon Price for Individual Hypothetical CCS Power Plants

As Figure 4-3 demonstrates, as the carbon prices increases, the resulting CCS capacity factors increase for nearly all locations. The level of the carbon price required to make one of the identical, hypothetical CCS power plant economical for a baseload capacity factor varies according to geographic distribution and transmission connections. There are generally two trends among the hypothetical CCS power plants in the results.

The capacity factors of one set of hypothetical CCS power plants, located at the Inyo and Schultz substations, level off at the 80% mark. This phenomenon can be explained by the limited amount of transmission connections that these power plants have at their connected substation. The transmission limits the amount of power that can be delivered from these plants to the load centers further away. It should be understood that even though their capacity factors are lower, at a high carbon price these power plants *generate at maximum capacity* for the hours that they are dispatched. It is the aggregation of these dispatch values calculated as capacity factor that is unable to achieve as high a capacity factor value as many of the other hypothetical CCS power plants. At lower demand hours, these CCS power plants are dispatched at lower levels and less frequently than other hypothetical power plants.

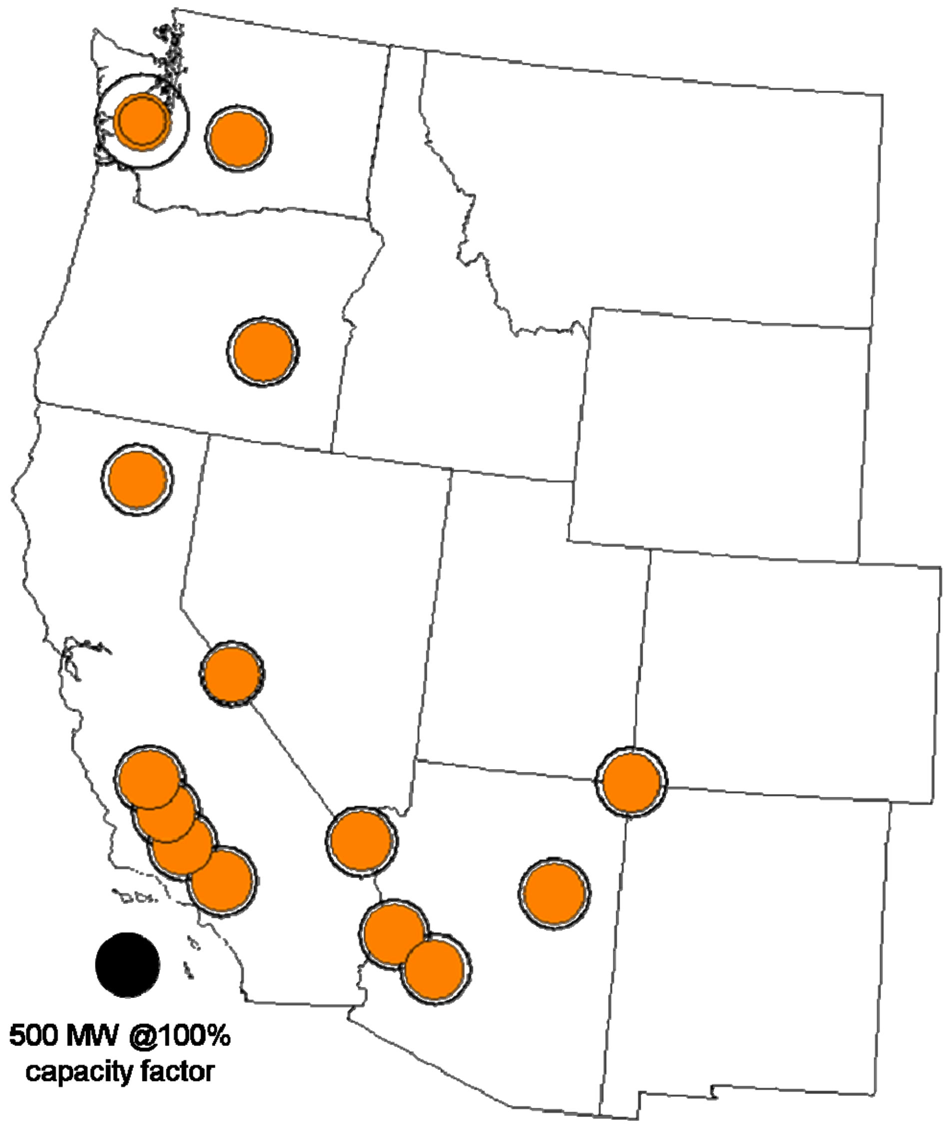

Figure 4-4 Capacity Factor for Individual Hypothetical CCS Power Plants.
Black outline represents capacity factor at \$100 per ton-CO_2. Orange fill represents capacity factor at \$0 per ton-CO_2.

The hypothetical CCS power plant at Centralia in Washington state demonstrates lower capacity factors due to two factors. The lower efficiency (higher heat rate) of the retrofit case causes the hypothetical CCS power plant to be less competitive in a dispatch calculation. Also, the load and transmission in the area is relatively small compared to the demand requirements and connectivity of many of the other locations.

The remaining set of locations – connected to the Four Corners, Cholla, Burns, Round Mountain, Las Vegas, Redhawk, Palo Verde, Vincent, Pastoria, Midway and Gates substations – exhibit similar values of capacity factors at any carbon price. Except for the hypothetical CCS power plant connected to the Round Mountain substation which required a $15 per ton carbon dioxide, all of these hypothetical power plants reach a 90% capacity factor at modest carbon emissions prices of $5-10 per ton-$CO_2$.

4.1.3. Alternative Fuel Price Scenarios

Individual CCS plants were modeled using varying natural gas and coal fuel prices. Fuel prices were a combination of $3 and $5 per MMBTU for natural gas and $25 and $40 per ton of coal, detailed in Appendix D: Alternative Fuel Price Scenario.

A small set of fuel price scenarios were calculated using the marginal cost spreadsheet model and served as inputs into the dispatch model. An examination of the response to differing fuel prices is important to understanding how volatile prices for fuel commodities like natural gas and coal affect dispatch order and capacity factor calculations for not just coal-fired power plants with carbon capture and sequestration equipment but for the electric power system as a whole.

Fuel prices have recently demonstrated significant volatility in their prices. For example, natural gas prices peaked in June 2008 at $10.82 per thousand cubic feet and have since hit a low of $3.43 per thousand cubic feet in July 2009. (U.S Energy Information Administration 2009) These significant price fluctuations have severely affected the dispatch and thus the price of wholesale power. (Smith 2009)

Because coal- and natural gas-fired generation most directly compete with one another in dispatch for the rights to generate the marginal unit of electricity, not only are the actual fuel costs for coal and natural gas important but the ratio of cost of electricity produced by these fuels. To explore this relationship, other values of coal and natural gas prices were used besides the verified 2005 fuel prices of $25 per ton of coal and $3 per MMBTU for natural gas. $40 per ton of coal and $5 per MMBTU of natural gas were simulated, both representing about 60% increases in the value of these commodities. Three additional scenarios from these values were used to provide alternative fuel-price assumptions:

- "Low coal price - low natural gas price" with $25 per ton of coal, $3 per MMBTU natural gas, the *base case* scenario already modeled in Section 4.1.2: Carbon Prices with CCS Power Plants Scenarios
- "Low coal price-high natural gas price" with $25 per ton of coal, $5 per MMBTU natural gas,
- "High coal price-low natural gas price" with $40 per ton of coal, $3 per MMBTU natural gas, and
- "High coal price-high natural gas price" with $40 per ton coal, $5 per MMBTU natural gas.

A summary table of these fuel price inputs can be found in Table A-5 in the Appendices.

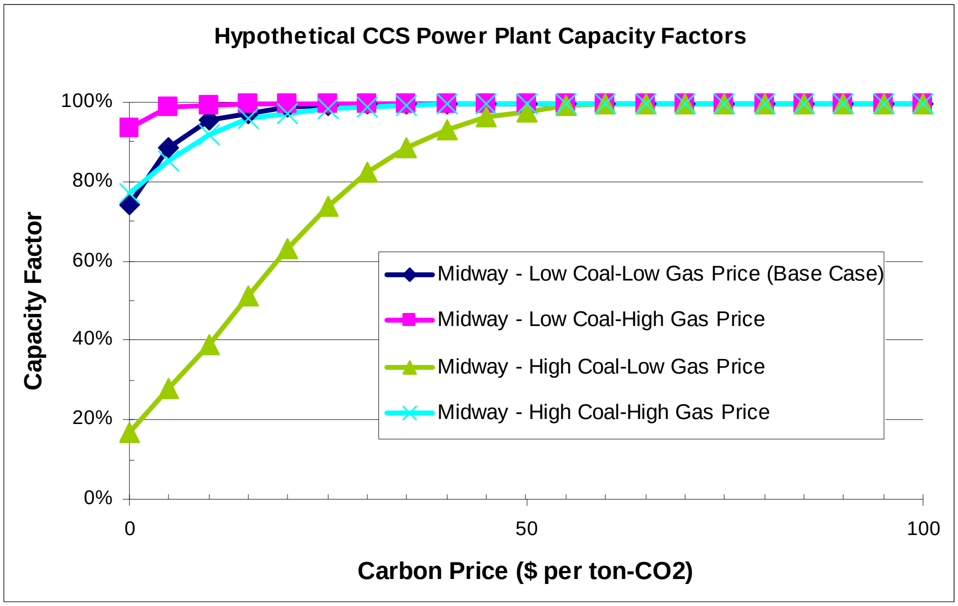

Figure 4-5 Capacity Factor vs Carbon Price for CCS Power Plant at Midway Site for Fuel Price Scenarios

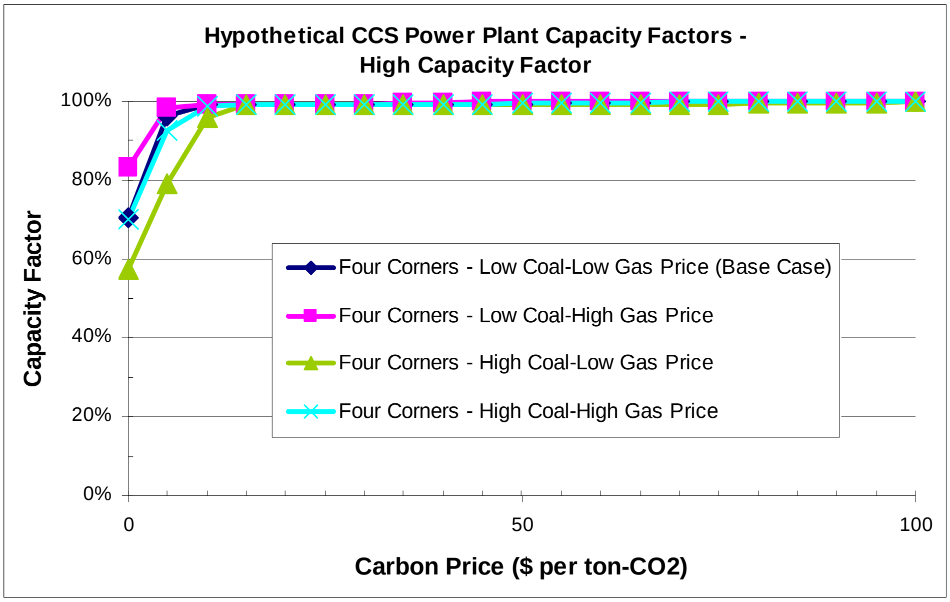

Figure 4-6 Capacity Factor vs Carbon Price for CCS Power Plant at Four Corners Site for Fuel Price Scenarios

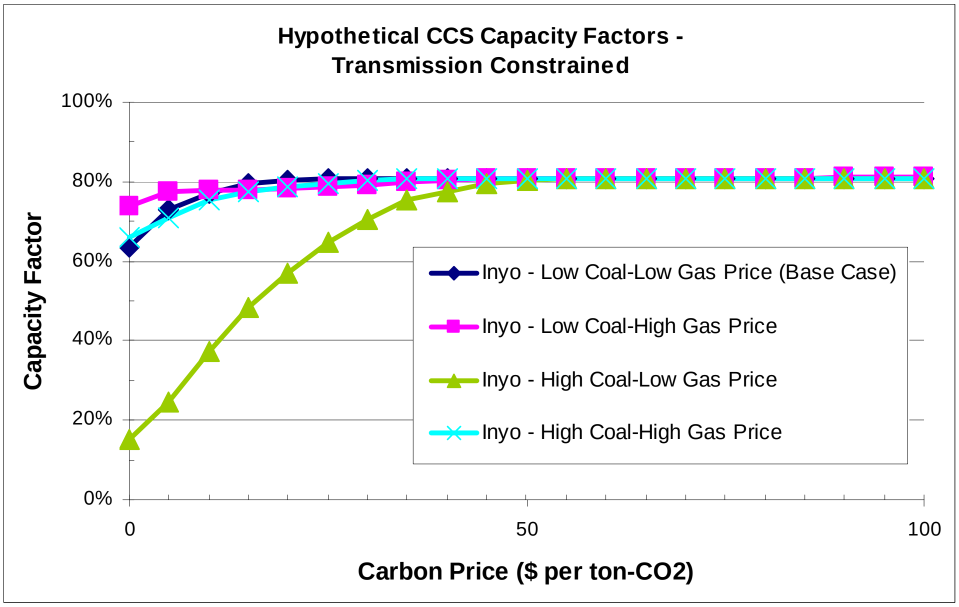

Figure 4-7 Capacity Factor vs Carbon Price for CCS Power Plant at Inyo Site for Fuel Price Scenarios

The calculated capacity factors of hypothetical CCS power plants for the various fuel price scenarios are represented in Figure 4-5, Figure 4-6 and Figure 4-7. These are representative examples of power plant behavior. Results for all locations for the three new fuel price scenarios are shown in Appendix D: Alternative Fuel Price Scenario.

In general, for all fuel scenarios except the "high coal price-low natural gas price" case, the capacity factors for all locations in the absence of a carbon pricing policy (i.e. \$0 per ton-CO_2) exceeds 60 percent. Such a capacity factor would nearly represent the lower end of baseload power. As the carbon price increases in each of these three scenarios, these capacity factors all monotonically increase. For each of these three scenarios, the majority of the locations that are not transmission-constrained reach 90 percent capacity factors with carbon prices of \$5 to \$10 per ton-CO_2, like the base case fuel scenario of \$25 per ton coal and \$3 per MMBTU natural gas, the "low coal price-low natural gas price". The "high coal price-low natural gas price" scenario has qualitatively different results. Coal-fired power plants compete principally with natural-gas plants and as the costs of coal increases and natural gas decreases, coal-fired power plants become less competitive.

The capacity factors in these fuel price scenarios can be divided into three trends:

- The first group of locations has capacity factors around 20 percent without a carbon pricing policy, much lower than the other fuel scenarios. Capacity factor calculations for a representative CCS power plant in this group at Midway are shown in Figure 4-5.
- The second group of CCS power plants is located in Burns, Four Corners and Cholla has higher capacity factors. Capacity factor calculations for a representative CCS power plant in this group at Four Corners are shown in Figure 4-6.
- The last group of power plants is transmission-constrained and is unable to achieve 100% capacity factor at carbon prices of up to \$100 per ton-CO_2. Capacity factor calculations for a representative CCS power plant in this group at Inyo are shown in Figure 4-7.

For power plants in the first group, a 20 percent capacity factor as found in the first group is a significant decrease from the 60 to 80 percent levels in other scenarios, moving such power plants from baseload to intermediate or peaking plants in the dispatch order. An increasing carbon price would increase the marginal costs for all power plants with significant carbon emissions and make low-carbon emissions power plants like the hypothetical CCS plants more competitive since their costs do not change with 100 percent carbon capture equipment. The carbon price required for most of the CCS power plants to reach baseload capacity factors of 80 percent is approximately $35 per ton carbon dioxide, roughly three times higher than the other fuel price scenarios. Although this is a significant difference, this per ton carbon dioxide value is reasonable when compared to carbon permit values in the European Trading System which reached peak prices for emissions permit futures in the same range. (Ellerman & Joskow 2008)

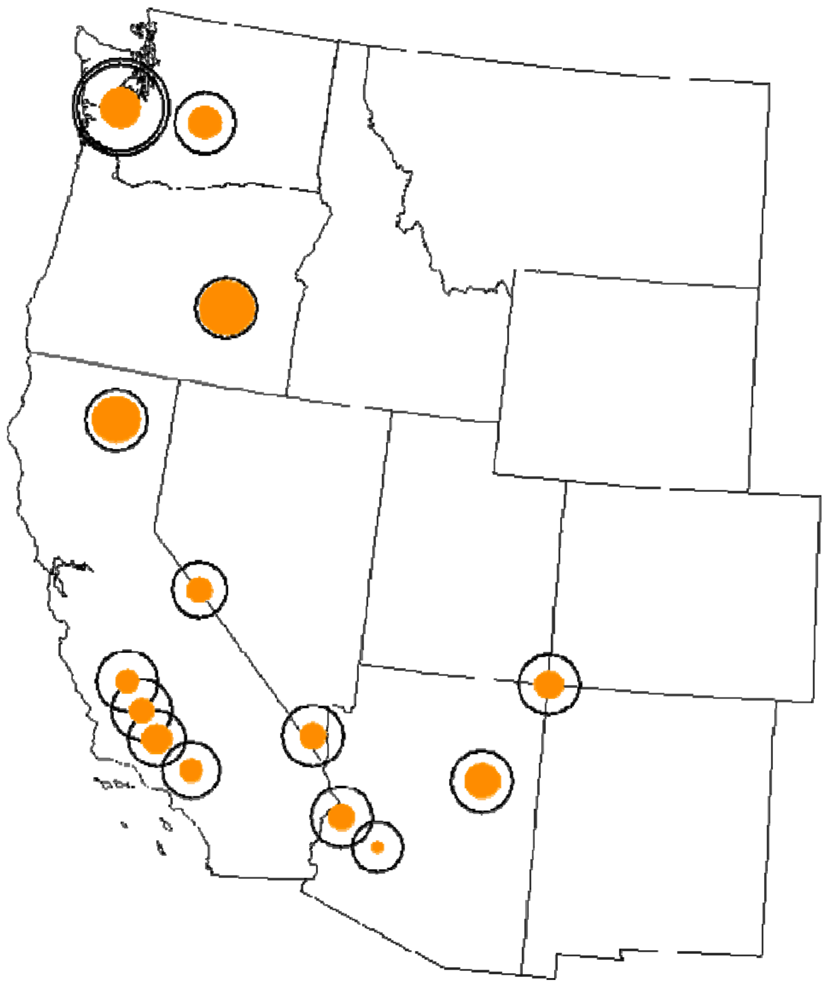

Figure 4-8 Capacity Factor for Individual Hypothetical CCS Power Plants in High Coal Price, Low Natural Gas Price Scenario.
Black outline represents capacity factor at $100 per ton-$CO_2$. Orange fill represents capacity factor at $0 per ton-$CO_2$.

The second set of hypothetical CCS power plants, located at the substations named Four Corners, Cholla and Burns achieve higher capacity factors at lower carbon prices and reach baseload-like capacity factors at much lower carbon prices. The locations of these power plants have several distinguishing characteristics that likely produce higher capacity factors from dispatch. Four Corners and Cholla are located in northeastern Arizona, an area close to the mountain regions where coal-fired power plants are abundant. The conventional coal-fired power plants in these regions transmit their power to the load centers in California and, to a lesser extent, Denver and Phoenix. Burns is located in Oregon where there is less coal and natural gas dispatchable generation to compete with when compared to California and the Arizona power plants. For generators seeking to reduce the fuel price risk of represented by the "high coal price-low natural gas price" scenario, siting a new CCS power plant in a location, like the Four Corners and Cholla, could be beneficial.

The third set of power plants are connected to the transmission-constrained substations of Inyo and Schultz. An interesting characteristic of their capacity factor curves is that they follow the trend of the bulk of transmission sites, but eventually become constrained so that they cannot attain a capacity factor significantly higher than 80%.

4.1.4. CCS Power Plant Efficiency Scenario

A range of heat rates was tested to determine the sensitivity of the analysis to the efficiency of the CCS power plants. The additional heat rate values simulated in addition to the base case of 11,500 BTU per kWh (roughly 30% low heating value efficiency) were heat rates of 13,500 and 17,000 BTU per kWh, representing high heating value (HHV) efficiencies of roughly 25% and 20% respectively. Details can be found in Appendix E: CCS Power Plant Efficiency Scenario.

A lower efficiency or higher heat rate CCS power plant could represent earlier generations of a CCS technology that has not yet matured. These units would have higher variable costs that would impact their dispatch order and thus their capacity factor. As heat rates increase and efficiency concomitantly decreases, more fuel inputs will be required to generate the same amount of electrical energy, raising the costs of each of these hypothetical power plants and pushing down the dispatch order of these types of CCS power plants. Figure 4-9 and Figure 4-10 show this effect, where capacity factors decrease as heat rates increase for lower carbon prices.

As the price for carbon emissions increases, the power plant efficiency scenarios show a divergence in the behavior of CCS sites. Similar to the groupings in the fuel price scenarios in Section 4.1.3, there are three trends among the CCS power plants:

- One set of locations require low carbon prices to dramatically increase their capacity factors in every efficiency scenario. Capacity factor calculations for a representative CCS power plant in this group at Four Corners is shown in Figure 4-9.
- The second set of locations gradually increase their capacity factors. Capacity factor calculations for a representative CCS power plant in this group at Vincent is shown in Figure 4-10.
- The last group of CCS power plants at the Schultz and Inyo substations is once again transmission-constrained and, despite very high carbon prices of $100 per ton of carbon dioxide, the CCS power plants never reach capacity factors higher than the 80 percent range.

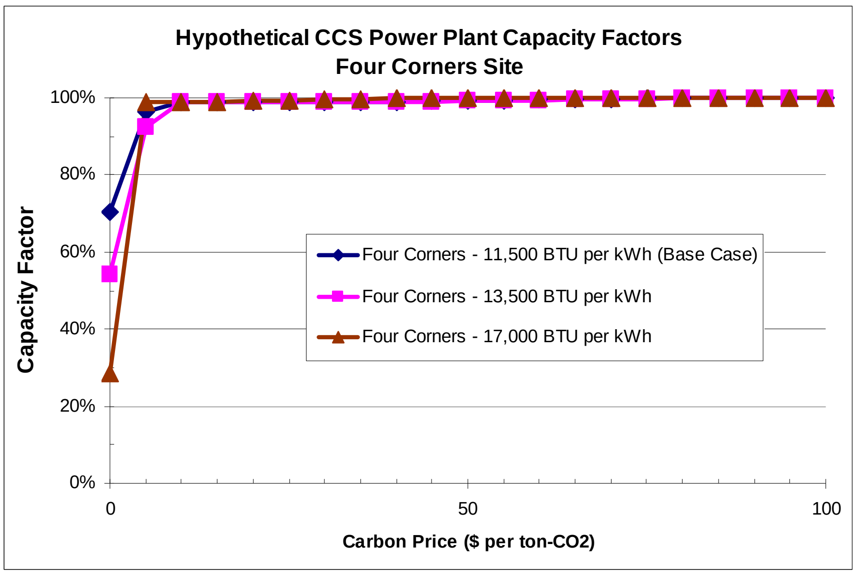

Figure 4-9 Capacity Factor vs Carbon Price for CCS Power Plant at Four Corners Site for Efficiency Sensitivity Scenarios

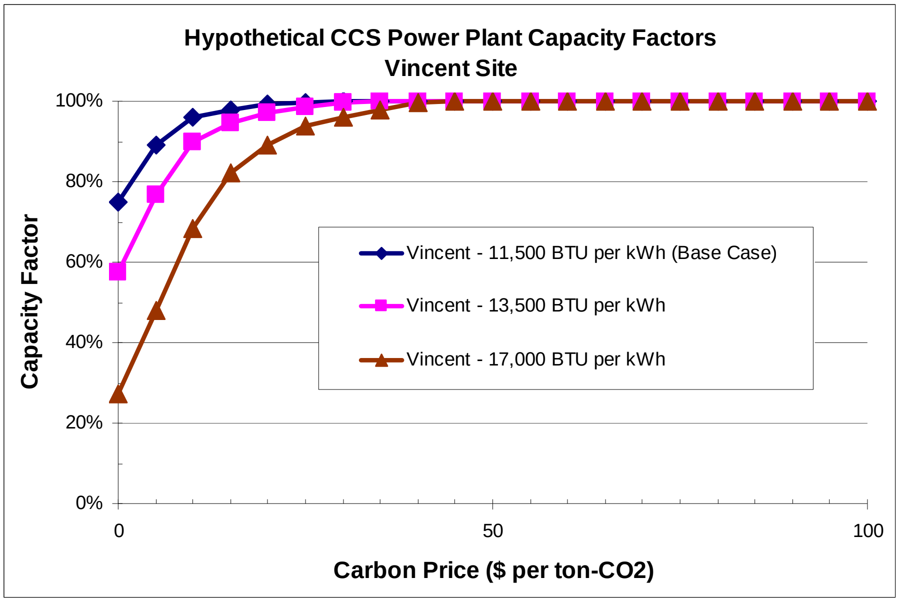

Figure 4-10 Capacity Factor vs Carbon Price for CCS Power Plant at Vincent Site for Efficiency Sensitivity Scenarios

In the 17,000 BTU per kWh scenario, capacity factors decrease to roughly 30% , as shown by the representative location Vincent in Figure 4-10. 17,000 BTU per kWh represents an efficiency decrease in relative percentage terms of roughly one-third from the 11,500 BTU per kWh base case scenario, and a halving of the capacity factor is not unreasonable nor unexpected.

A handful of CCS power plants require only a very modest carbon price in order to dramatically increase their capacity factors. When the carbon price goes from $0 per ton-$CO_2$ to just $5 per ton-$CO_2$, the capacity factors at the hypothetical CCS power plants connected to the Palo Verde, Cholla, Four Corners, Las Vegas, Burns and Midway power plants jump from roughly 30 percent to the high 90 percent. The map in Figure 4-11 shows the locations of these power plants.

Only rough generalizations about this set of hypothetical CCS plants can be made. Except for Midway, these power plants are generally located away from the natural gas-fired power plants and large load centers in southern California and the Bay Area. CCS plants connected to the Schultz and Inyo substations may require higher carbon prices due to their transmission constraints to deliver their power to load. The hypothetical power plant connected to the Redhawk substation is not as constrained in delivering power nor has this specific trend appeared in previous scenarios. A specific explanation for why a CCS power plant connected to the Redhawk substation does not achieve high capacity factors with modest carbon prices compared to other power plants may not be possible. The disparities demonstrate the large amount of nonlinearity involved in a highly complex system like the power grid.

The CCS power plants in the second group, and comprising most of the locations, require at least a \$25 per ton-CO_2 price before the capacity factor attains a level similar to that of baseload generators. \$25 per ton-CO_2 is a relatively modest value similar to that of the carbon permits in the European Trading Scheme. (Ellerman & Joskow 2008) Other power plants are mostly sited within California and compete on price with nearby natural gas power plants in the dispatch model.

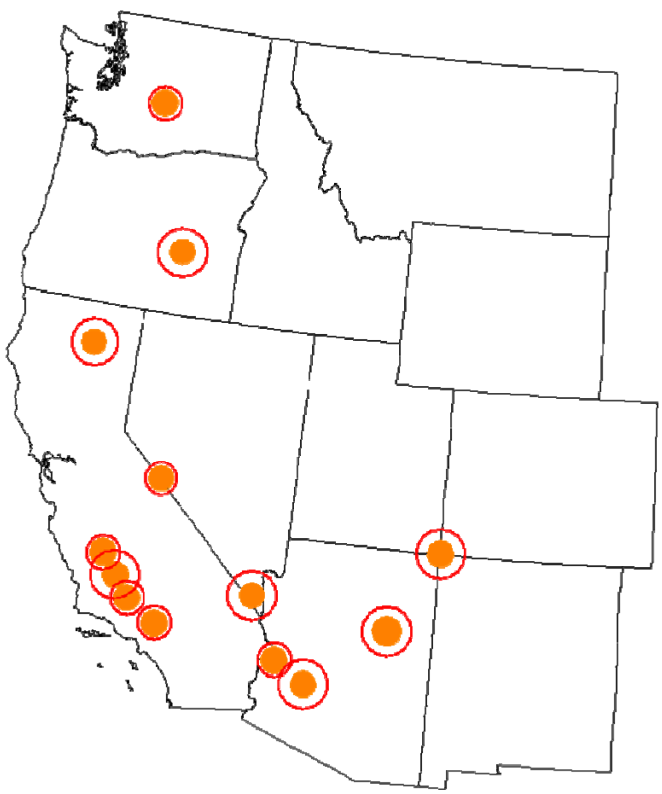

Figure 4-11 Capacity Factor for Individual CCS Power Plants with 17,000 BTU per kWh Heat Rate. Red outline represents capacity factor at \$5 per ton-CO_2. Orange fill represents capacity factor at \$0 per ton-CO_2.

4.1.5. CCS Capture Rate Sensitivity Scenario

Reduced capture rates of 50% and 0% were simulated for individual CCS power plants. The purpose of this scenario is to explore the sensitivity of dispatch and capacity factor to capture rate alone. It is important to note, the increase in efficiency that comes with reducing the capture rate of a CCS power plant is not modeled here. The scenario in Section 4.1.6: Partial Capture CCS Power Plants models reduced capture hypothetical power plants with their related efficiencies and heat rates.

As carbon capture rates decrease, a CCS power plant will be more impacted by carbon pricing policies that increase the costs bid into the dispatch calculation. These increased costs will decrease the capacity factor of reduced capture CCS power plants. Previous scenarios had disadvantages imposed upon hypothetical CCS power plants that could be compensated by increasing the carbon price so that all other fossil fuel plants' costs were higher. In a reduced capture CCS scenario, however, increasing the carbon emissions price might increase the cost differential between a CCS power plant and the generation on the grid. Figure 4-12 demonstrates this.

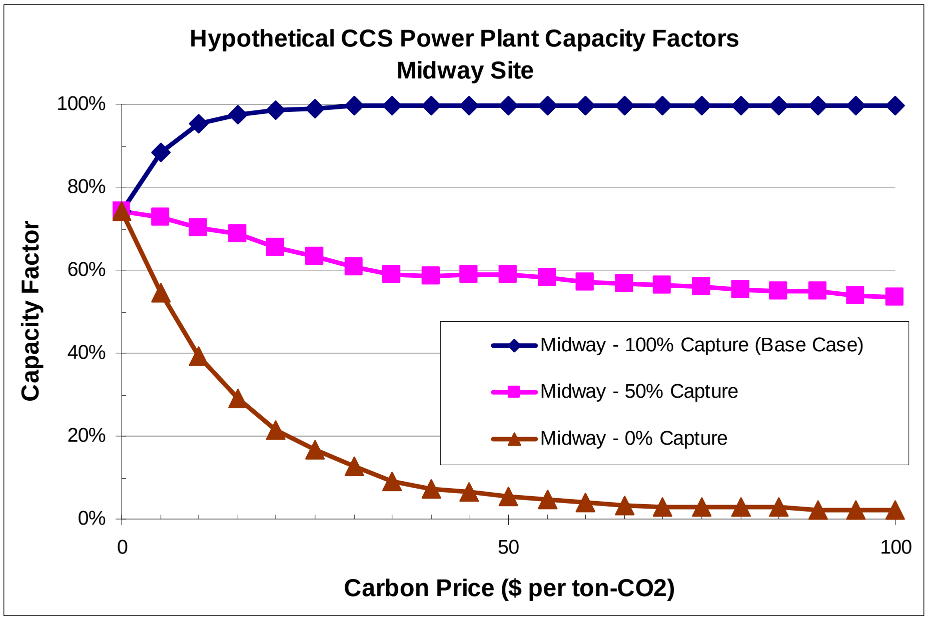

Figure 4-12 Capacity Factor vs Carbon Price for CCS Power Plant at Midway Site for Capture Rate Sensitivity Scenarios

Results for all locations are available in Appendix F: CCS Capture Rate Sensitivity Scenario.

Most of the hypothetical CCS power plants with 50% capture rates have their peak capacity factor at $0 per ton-$CO_2$. When carbon prices are imposed, capacity factors for nearly all of the hypothetical CCS power plants begin to steadily decline, reaching the 50 percent levels with $100 per ton-$CO_2$ prices. The costs imposed by half of the carbon dioxide emissions from the CCS generators thus impact these hypothetical power plants' costs enough to negatively affect their capacity factor and dispatch order.

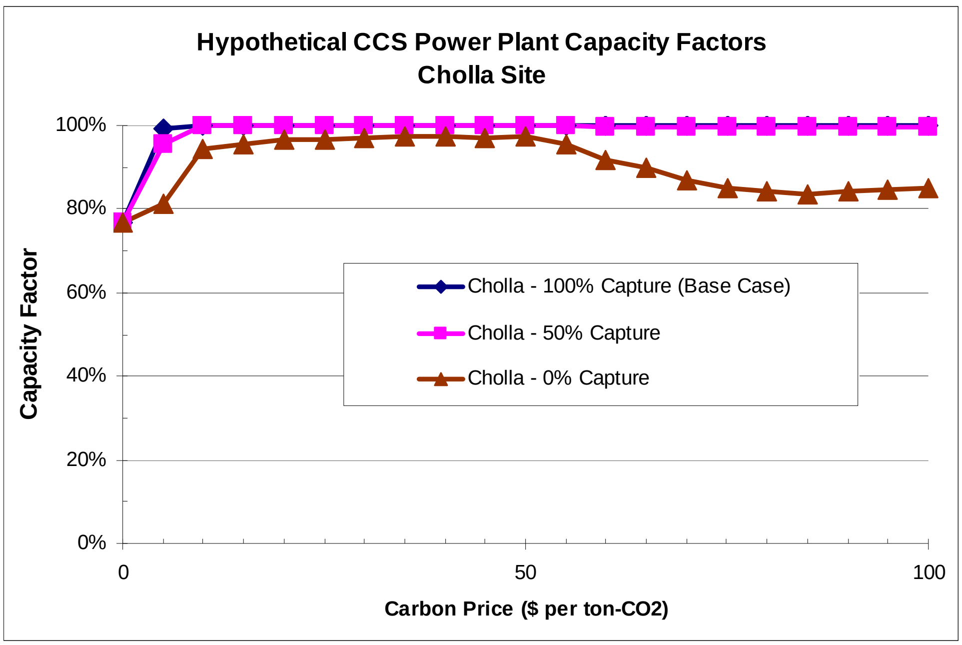

Figure 4-13 Capacity Factor vs Carbon Price for CCS Power Plant at Cholla Site for Capture Rate Sensitivity Scenarios

There are three exceptions – Cholla, Four Corners and Burns – to the trend of continuously reduced capacity factors from increasing carbon price. As demonstrated by a representative power plant at Cholla shown in Figure 4-13, hypothetical power plants located at Cholla and Four Corners increase their capacity factors to almost 100% as the carbon price increases from $0 to $10, and the capacity factors stay in high 90 percentage range. As previously discussed, these test CCS power plants are sited in northeastern Arizona closer to the large numbers of coal-fired generators in the mountain states. When Cholla and Four Corners CCS power plants are dispatched in the presence of the regional transmission constraints, the generation that is displaced is the most carbon-intensive generation in the power grid, the coal-fired power plants in New Mexico, Colorado and Arizona. The generation that is displaced by hypothetical CCS power plants in California is more typically natural gas generation, which has fewer carbon emissions and feels less of a price impact as carbon pricing increases.

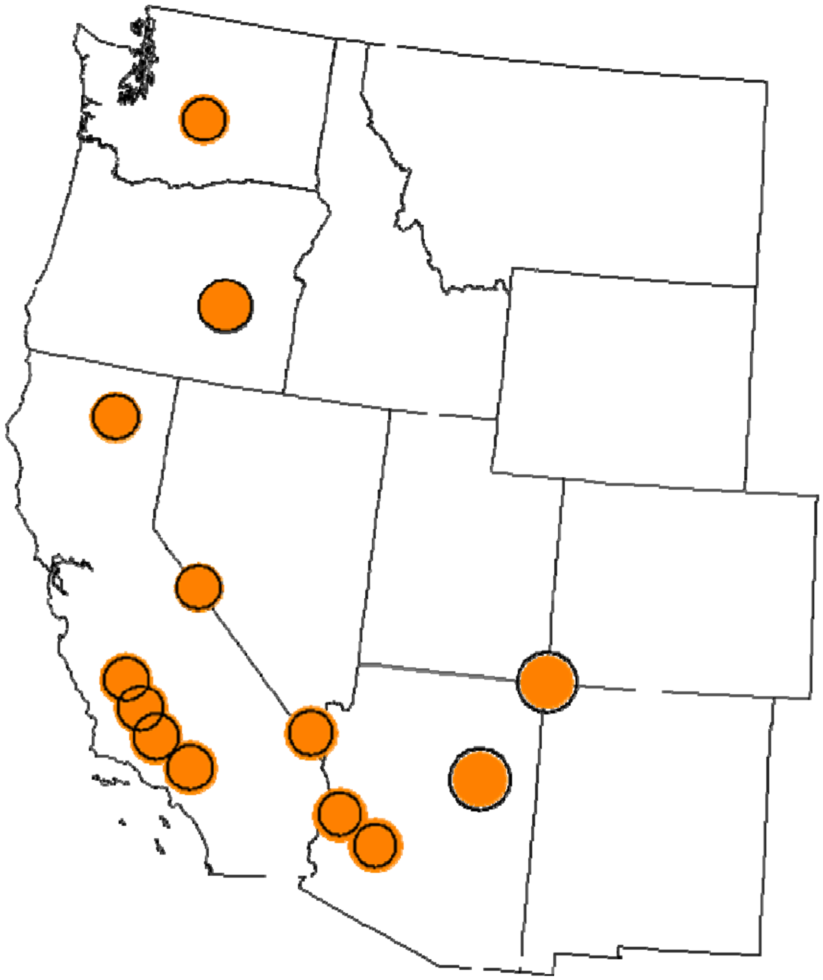

Figure 4-14 Capacity Factor for Individual CCS Power Plants with 50% Capture Rate. Black outline represents capacity factor at \$100 per ton-CO_2. Orange fill represents capacity factor at \$0 per ton-CO_2.

The CCS power plant connected to the Burns substation in Oregon exhibits behavior somewhere between the hypothetical CCS generators in California and those hooked up to the Cholla and Four Corners substations as is shown in Figure 4-15. The capacity factor initially increases with increasing carbon emissions prices. The capacity factor tops out around 90 percent when the carbon price reaches approximately \$40 per ton-CO_2 but then steadily drops. The generation around the Burns substation is very different from the area around northeast Arizona, however.

The Burns substation is located in a region with substantial hydroelectric generation. Another explanation is possible.

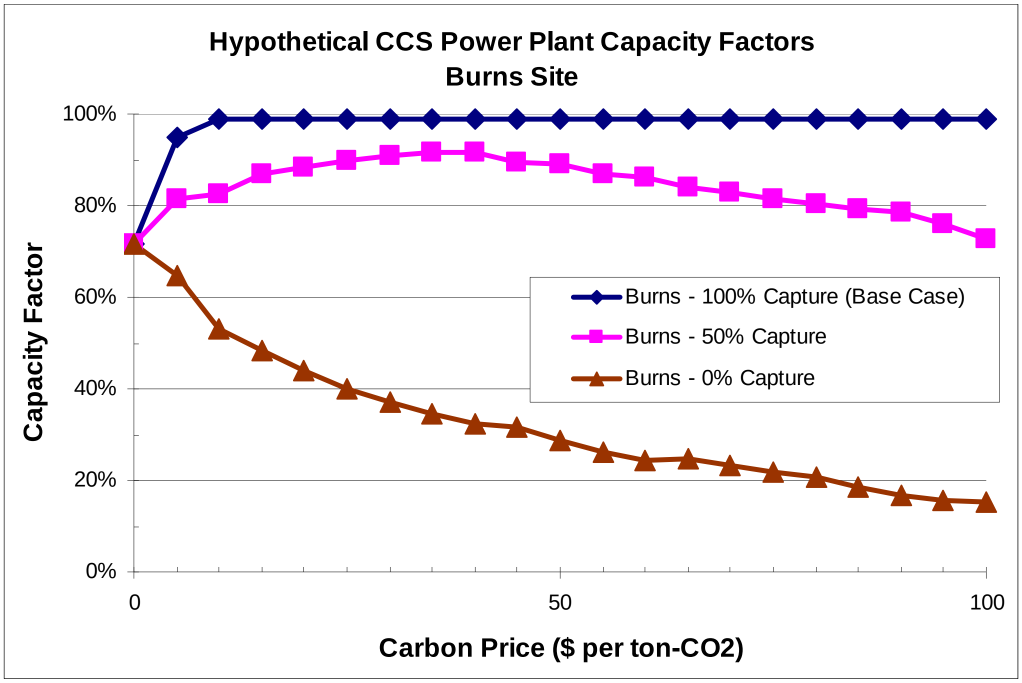

Figure 4-15 Capacity Factor vs Carbon Price for CCS Power Plant at Burns Site for Capture Rate Sensitivity Scenarios

As discussed in previous scenarios, the Burns hypothetical power plant also exhibited transmission constraints, where the capacity factor never reached levels as high as that of other CCS power plants. These transmission constraints, which limited the capacity factor in other scenarios, may instead aid a CCS power plant connected at the Burns substation. A power plant with plentiful transmission capacity close to, but not within, California would be able to deliver power to the load centers within the state. However, this also means that this hypothetical plant will compete with the natural gas-fired power plants in the state, a disadvantage when carbon price policies impact their costs. In addition, the smaller number of power plants that a transmission-constrained power plant will compete with can mean that more substantial changes in the generator costs that are used in a dispatch calculation will impact the capacity factor less. This is because there are a fewer number of generators that can replace the change in costs.

CCS power plants with no capture equipment and thus 0% capture rates might represent so-called "capture-ready" CCS coal-fired power plants. These generators would represent the deployment of CCS power plant technology and have the possibility for the installation of carbon capture equipment with the onset of a climate policy that places a cost on carbon emissions.

No-capture CCS power plants are even more impacted by rising carbon emissions prices and experience greater declines in dispatch and capacity factor compared to 50 percent capture power plants. Like the 50 percent capture scenarios however, CCS power plants lacking capture equipment but connected to the Four Corners and Cholla power plants still are calculated to have significant capacity factors. A Four Corners CCS power plant would have greater than 90 percent capacity factor from relatively large carbon prices of $10 to $60 per ton carbon dioxide while still staying over the 80 percent values. A Cholla CCS power plant maintains greater than 50 percent capacity factor for the range of carbon prices simulated. In contrast, all other identical CCS power plants steadily decrease their capacity factors until the $50 per ton-$CO_2$ level where all power plants have capacity factors less than 10 percent.

The underlying explanation for the difference in capacity factors between identical power plants remains the same. The power plants at the Four Corners and Cholla substations are large coal-fired power plants like the currently existing Four Corners, Cholla, San Juan and Coronado coal-fired power plants that have slightly more efficient nominal heat rates as the test CCS power plants at 9,850 BTU per kWh. (US Environmental Protection Agency 2008) As the other hypothetical CCS power plants modeled throughout the system dispatch less due to rising carbon emissions prices, CCS power plants connected to the Four Corners and Cholla substation remain competitive as coal-fired power plants. New CCS power plants will also have slightly less carbon emissions at roughly 1,850 lb. per MWh (MITEI 2007, p.30) simulated in the dispatch model versus the 2,170 lb. per MWh (US Environmental Protection Agency 2008) of the aforementioned coal-fired power plants. The difference in carbon emissions rates will create a difference between the hypothetical CCS generators and the existing coal-fired power plants that will be exacerbated as carbon emissions costs increase, causing the CCS power plants to be more competitive.

4.1.6. Partial Capture CCS Power Plants Scenario

Partial capture CCS plants are modeled with their related capture rates and efficiencies/heat rates. (See Appendix G: Partial Capture CCS Power Plant Scenario for details.) This scenario explores how realistic partial capture CCS power plants will behave in the presence of carbon emissions prices.

CCS power plants with partial capture equipment represent a compromise between capturing carbon dioxide emissions and improvements in efficiency. Higher carbon dioxide capture rates require larger equipment that introduces parasitic loads, reducing the overall efficiency of a power plant. (Hildebrand 2009, p.95) However higher capture rates mitigate the impact of carbon pricing, especially at larger carbon price values. The effects on cost of increasing efficiency (through lower heat rates due to small carbon capture equipment) and increasing carbon emissions costs (through lower capture rates and greater carbon emissions) will compete with each other through a dispatch cost evaluation. CCS power plants with capture equipment also more realistically reach maximum capture rates of approximately 90 percent, rather than the 100 percent capture modeled in the base case.

Results for all locations and all partial capture scenarios are presented in Appendix G: Partial Capture CCS Power Plant Scenario.

For the no-capture rate scenario, the capacity factor curves of partial capture CCS power plants looks more similar to those of the reduced capture CCS power plant scenarios than of a higher efficiency power plant that has reduced heat rates. The costs of the increased carbon emissions due to a reduced capture rate are greater than the efficiency benefits that come from reducing the capture equipment and attendant parasitic load. Capacity factors do not bottom out at 0% capacity factors for many of the hypothetical CCS generators as they did in the reduced capture scenarios.

Figure 4-16 demonstrates CCS power plant dispatch at Midway, which is representative of most locations. The initial capacity factor in a no-carbon price scenario steadily increases with decreasing capture rates due to the improvement in heat rate and efficiency that comes with lower carbon capture rates. As the carbon price increases however, a high capture rate offsets this initial efficiency benefit because for cost reductions, the value of carbon emissions outweighs the value of the efficiency gain from a partial capture case.

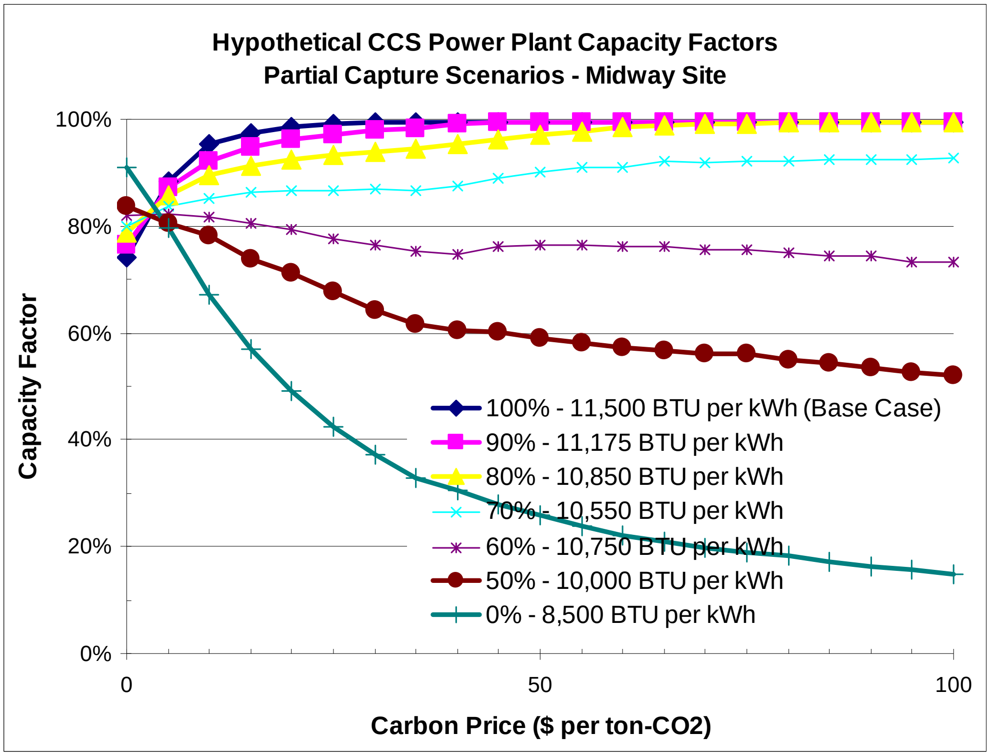

Figure 4-16 Capacity Factor vs Carbon Price for CCS Power Plant at Midway Site for Partial Capture Scenarios

Once again the hypothetical CCS power plants with the highest capacity factors that act as exceptions to this rule remain the generators connected to the Four Corners and Cholla substations, as shown by the Cholla power plant case in Figure 4-16. As discussed, the surrounding large coal-fired power plants at Four Corners, Cholla, San Juan and Coronado are older and less-efficient with an average heat rate of 9,850 BTU per kWh. The hypothetical power plant connected to the Four Corners and Cholla substations is more efficient at 8,500 BTU per kWh as well as less carbon dioxide polluting and will remain competitive at higher carbon emissions rates. For hypothetical CCS power plants in the rest of the Western Interconnection, as carbon emissions prices rise nearby natural gas power plants will begin to displace the more carbon-emitting no-capture CCS power plants.

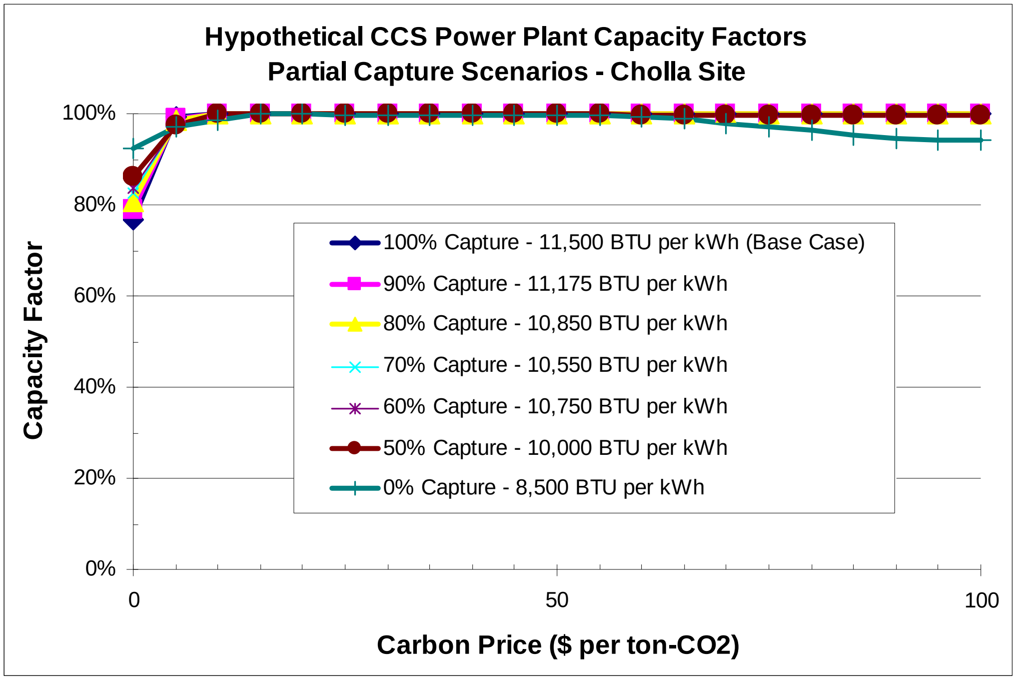

Figure 4-17 Capacity Factor vs Carbon Price for CCS Power Plant at Cholla Site for Partial Capture Scenarios

The partial capture rate scenario where the benefit of the associated efficiency improvement is balanced by the increased partial carbon emission costs is at roughly 60 percent capture rate. Except for the CCS plants sited at the Four Corners, Cholla and Burns substations, as carbon emissions prices increase, the additional costs that impact the hypothetical CCS power plants are roughly equal to the additional costs of the generators that the CCS plants are competing with. Building future CCS power plants with these characteristics would represent a compromise in initial equipment costs and a hedge against rising carbon dioxide prices.

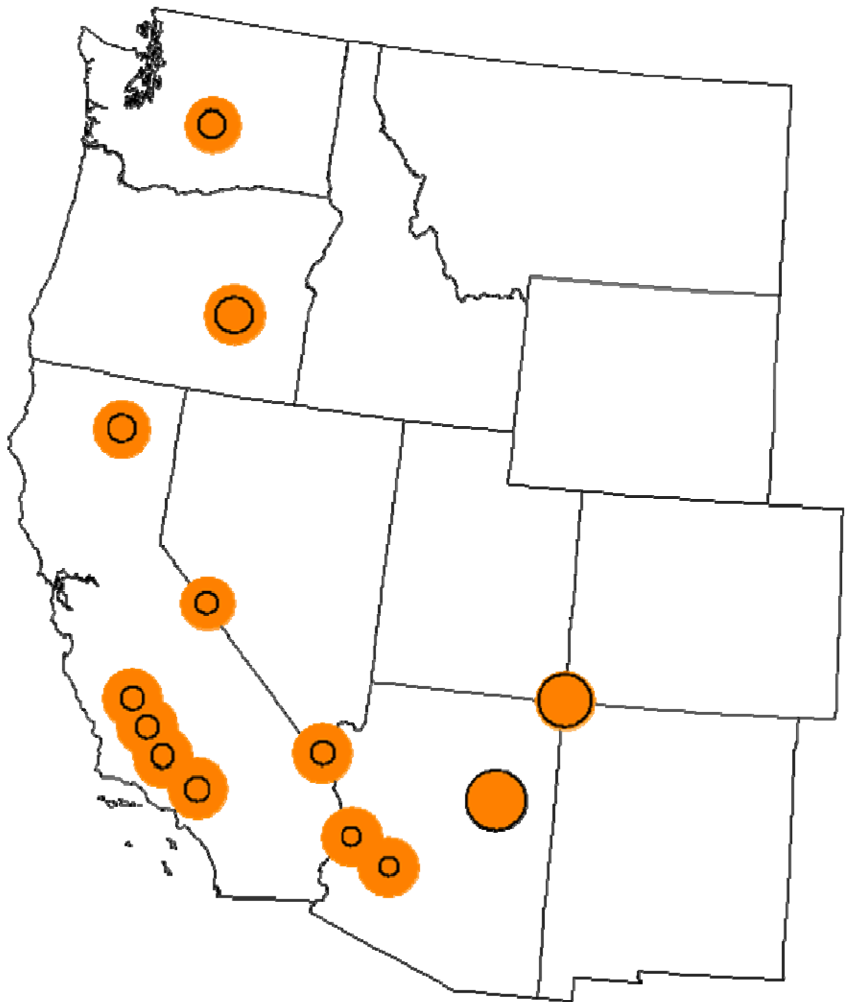

Figure 4-18 Capacity Factor for Individual CCS Power Plants with 0% Capture and 8,500 Heat Rate. Black outline represents capacity factor at \$100 per ton-CO_2. Orange fill represents capacity factor at \$0 per ton-CO_2.

4.2. Financial Analysis of the Investment Decision

A financial analysis from dispatched power revenue was used to calculate a cashflow for a typical FOAK CCS power plant at each site. These results are detailed in

- Section 4.2.1: Base Case Financial Analysis, with inputs detailed in Appendix C: Base Case Scenario Inputs, and
- Section 4.2.2: High Natural Gas Price Financial Analysis – a case with \$5 per MMBTU natural gas prices.

The dispatch model was used to calculate revenue values for each hypothetical CCS power plant for every dispatch. By scaling these values consistent with the capacity factor calculations, annual plant revenues can be calculated for each plant. Annual plant revenues can then be compared to a simple power plant financing analysis in order to determine the level of carbon emissions prices necessary to break-even on a CCS power plant and induce private sector investment.

In a dispatch model, all power plants receive revenue according to the locational marginal price (LMP) calculated for that specific power plant. The LMP is calculated based on transmission capacity and the cost of the marginal unit of generation which depends on the costs of other local power plants. In order for a plant to dispatch, the LMP must be higher than the marginal costs of the power plant in order for the power plant not to lose money. While the LMP may cover marginal costs for a CCS power plant, it may not cover the capital costs of construction.

The financing assumptions are shown in Table 4-1.

Table 4-1 Key Financial Assumptions Applied in Capital Cost Evaluation

Plant Size	500	MWe
All-In Capital Cost	6,000	$ per kWe
Heat Rate	11,500	BTU per kWh
Debt Fraction	55%	
Equity Fraction	45%	
Debt Interest Rate	6.5%	
Equity Required Return	12.0%	
Tax Rate	39.2%	
Book Life	20	years

These values are the same as the ones used in the MIT Future of Coal Study. (MITEI 2007) Assuming a cost for NOAK plants roughly half of FOAK costs, these values are in line with previous studies of the costs of CCS power plants. (Hamilton 2009; Al-Juaied & Whitmore 2009) These capital costs are also in agreement with reported construction costs for the 275-MWe IGCC-CCS FutureGen power plant at $1.8B. (GAO 2009)

4.2.1. Base Case Financial Analysis

The minimum carbon price at which the investment is profitable is shown for all locations in Table 4-2. For most locations, a carbon price in the range of \$130 to \$145 per ton-CO_2 is necessary to have a profitable investment to build, construct and operate a CCS power plant. A CCS power plant at Inyo never became profitable under the conditions of the analysis. Three other sites require less than \$130 per ton-CO_2 for profitability: Burns at \$115 per ton-CO_2, Four Corners at \$65 per ton-CO_2 and Cholla at \$30 per ton-CO_2.

Table 4-2 Carbon Prices for Profitable CCS Power Plant Investment at Each Site: Base Case

(per ton-carbon dioxide)

Site	Carbon Price for Profitable Investment
Burns	$115
Cholla	$30
Four Corners	$65
Gates	$140
Inyo	>$300
Las Vegas	$135
Midway	$135
Palo Verde	$145
Pastoria	$140
Redhawk	$145
Round Mountain	$130
Schultz	$145
Vincent	$135

Burns, Cholla and Four Corners coincide with the power plants that operate with the highest capacity factors demonstrated in various scenarios in Section 4.1: Dispatch Model Simulation Results. Such a result is not unexpected since the higher the capacity factor, the greater the operational time of the power plant and the more revenue the power plant is receiving.

However, a high capacity factor by itself does not guarantee a profitable investment. While capacity factors for a hypothetical Four Corners CCS power plant shown in Figure 4-19 are nearly 100% with only \$10 per ton-CO_2, the revenue received for the energy sold increases as carbon price increases. Even though the capacity factor does not significantly change from near 100% from a low carbon price, it is not until the carbon price reaches \$65 per ton-CO_2 when is the revenue received sufficient to also cover capital costs.

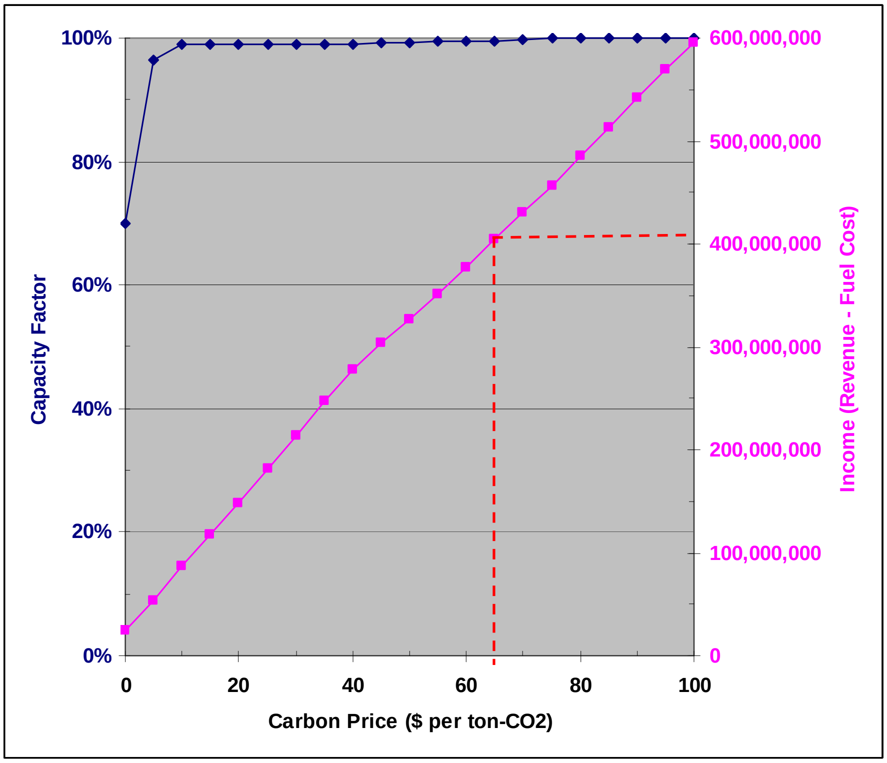

Figure 4-19 Capacity Factor and Income vs. Carbon Price at a Four Corners CCS Power Plant
The red dotted line represents the calculated capital and marginal cost break even value for the carbon price.

When the income vs. carbon price graph at a Four Corners CCS power plant is compared to a similar graph at another site, several points of comparison can be made. As shown in Figure 4-19 and Figure 4-20, approximately \$400M in annual revenue is required to cover capital costs and full-capacity fuel costs. The value graphed is the amount of money leftover after variable and marginal costs like fuel are paid. This is indicated by the very high capacity factors: marginal costs are being covered.

The increases in revenue that come with increases in carbon price strongly determine the level of carbon price necessary for investment. Revenue increases for Four Corners are about double that of the increases at Midway. As a result, the carbon price necessary for a profitable CCS investment at Four Corners (\$60 per ton-CO_2) is roughly half that of the necessary carbon price at Midway ($135 per ton-$CO_2$). How carbon prices affect the revenue determined by dispatch is crucial to understanding this relationship.

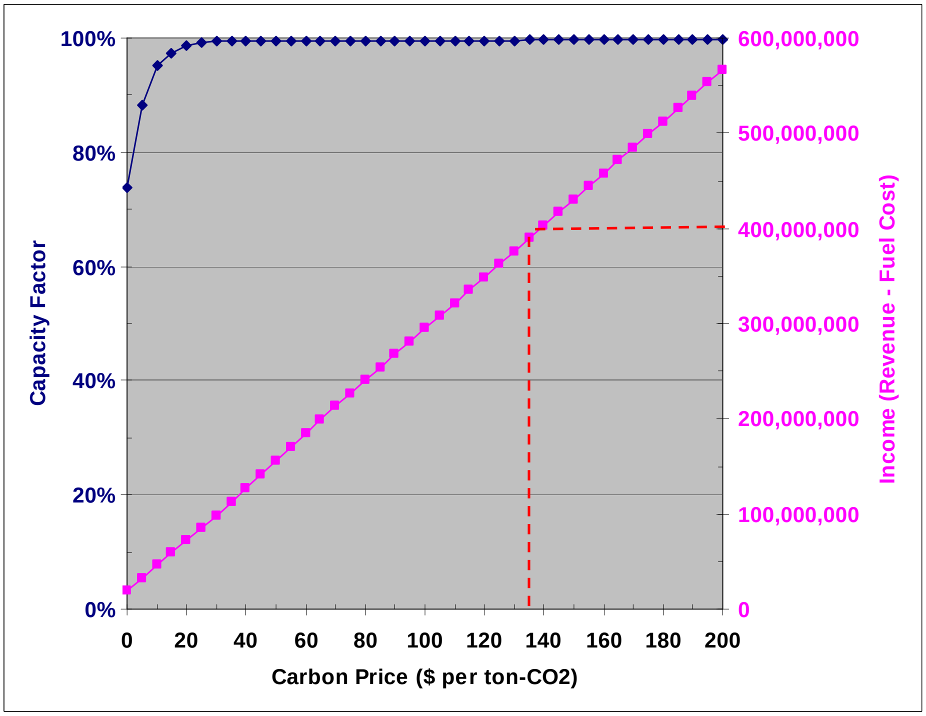

Figure 4-20 Capacity Factor and Income vs. Carbon Price at a Midway CCS Power Plant
The red dotted line represents the calculated capital and marginal cost break even value for the carbon price.

As discussed, the cost of the marginal unit of electricity sets the price of electricity. For CCS power plants at Four Corners and Cholla, which are in close electric proximity to a concentration of coal-fired power plants, the price of electricity will be largely determined by coal-fired power plants. For CCS power plants in California like Midway, the price of electricity will determined by the abundant natural gas power plants in the region running at the margin.

As the carbon price increases, the impact of the increased CO_2 emissions cost will impact coal-fired power plants twice as much as natural gas-fired power plants. Power plants whose electricity price and revenue are set by coal-fired power plants, like Four Corners and Cholla, will thus experience greater revenue increases as carbon price increases. Natural gas-fired power plants emit half as much as coal-fired power plants. Power plants whose electricity prices are set by natural gas-fired generation will thus experience less revenue increases due to the lower carbon emissions costs imposed on a marginal natural gas power plant.

4.2.2. High Natural Gas Price Financial Analysis

The revenue and financing calculation was performed for a natural gas price 67% higher than the base case at $5 per MMBTU and 167% higher at $8 per MMBTU. The carbon price necessary for profitably CCS power plant investment in this scenario are shown in Table 4-3.

Table 4-3 Carbon Prices for Profitable CCS Power Plant Investment at Each Site: Base Case and High Natural Gas Price Scenarios

Site	**Carbon Price for Profitable Investment $3 per MMBTU Gas Price (Base Case)** (per ton-carbon dioxide)	**Carbon Price for Profitable Investment $5 per MMBTU Gas Price** (per ton-carbon dioxide)	**Carbon Price for Profitable Investment $8 per MMBTU Gas Price** (per ton-carbon dioxide)
Burns	$115	$75	$55
Cholla	$30	$30	$25
Four Corners	$65	$55	$50
Gates	$140	$105	$70
Inyo	>$300	>$300	>$300
Las Vegas	$135	$105	$70
Midway	$135	$105	$70
Palo Verde	$145	$110	$70
Pastoria	$140	$105	$70
Redhawk	$145	$110	$70
Round Mountain	$130	$100	$70
Schultz	$145	$115	$80
Vincent	$135	$100	$65

For a natural gas price of $5 per MMBTU, the carbon prices necessary for CCS investment are still in the $100 to $115 per ton-$CO_2$ range for most locations, a value higher than the current market supports. The exceptions remain Inyo (which never becomes a profitable investment in this analysis), Burns ($75 per ton-$CO_2$), Four Corners ($55 per ton-CO_2) and Cholla ($30 per ton-$CO_2$).

For a natural gas price of $8 per MMBTU, the carbon prices necessary for CCS investment are in the range of $65 to 80 per ton-$CO_2$ for most locations, a high carbon value but more reasonable.

For power plants at Burns ($55 per ton-$CO_2$), Four Corners ($50 per ton-CO_2) and Cholla ($25 per ton-$CO_2$), CCS power plants could be worthy of investment in the near future with a carbon policy and a high natural gas price.

With higher natural gas prices, coal-fired power plants become more competitive on the grid and in the dispatch calculation. This results in a higher capacity factor and more opportunity to recover capital costs, so the carbon prices necessary for investment are lower than in the lower natural gas price in the base case. Higher natural gas prices will impact hypothetical CCS power plants located in region dominated by natural gas-fired generation, which turns out to be the majority of the sites modeled.

While the decrease in necessary carbon price (approximately $30 per ton-$CO_2$ for $5 per MMBTU natural gas, and $65 per ton-$CO_2$ for $8 per MMBTU natural gas) for the majority of the power plants is greater due to the greater influence of natural gas prices, these carbon prices are still high and difficult to sustain in the current political and business environment. The price of natural gas, however, can significantly alter the investment decision calculus for CCS power plants.

5. DISCUSSION AND POLICY IMPLICATIONS

This analysis of coal-fired power plants with CCS equipment offers useful insights to government policy-makers and to business decision-makers regarding the ability to economically dispatch CCS power plants and the policies necessary to make CCS competitive in the electricity marketplace.

5.1. Carbon Emissions Price

As a policy tool, putting prices on carbon emissions would significantly impact the dispatch order of the electricity grid which will have implications for regions, states, and individual electricity companies as well as new carbon-mitigation technologies such as CCS. For potential CCS electricity plants, a substantial carbon price will allow CCS generation to be more competitive by making the generation technology cheaper relative to other fossil fuel generation due to the capture equipment and reduced carbon emissions costs.

Given the high fixed capital costs to construct coal-fired generation (with or without CCS equipment), coal-fired power plants are not a viable investment unless they provide baseload generation, with capacity factors of 80 percent or better, in order to recover capital costs over time. The carbon price necessary for CCS generation to achieve this level of capacity factor is relatively modest – in the range of \$10 to \$30 per ton-CO_2 across all locations for a full capture plant in our base case. Carbon prices in this range exist today in the European Union's ETS and is a level that is considered politically achievable in the United States. The Congressional climate bill passed in the House of Representatives (H.R. 2454) and is awaiting for passage in the Senate at the time of this writing also allow for carbon prices in this range. This level of carbon price is realistic and would allow for significant dispatch of CCS generation.

It might be surprising that a modest \$10 per ton-CO_2 price would result in CCS plants with high capacity factors. This occurs because the heat rate of advanced coal generation technologies with the energy penalty of the CCS equipment is not appreciably worse than the heat rate of existing coal-fired power plants, an already competitive power generation technology. Coal-fired power plants on the grid currently have an average heat rate of 10,164 MMBTU per kWh. (EIA 2006) The latest CCS technology power plants, which the hypothetical power plants represent, generally have plant efficiencies of about 40%, or about 8,500 BTU per kWh, without capture equipment. With capture equipment, these power plants become slightly worse than the average existing coal-fired power plant. Compared against natural gas-fired power plants with their higher fuel costs, CCS power plants can be considered competitive in many scenarios.

However, there is a critical difference between whether a CCS plant, once built, will dispatch and whether such an investment would be made in the first place. Understanding the type and stringency of policies required to support and encourage the deployment of CCS must not be limited to a marginal cost dispatch analysis. A marginal cost analysis only looks at a policy that will cover the marginal cost of generating electricity from a CCS plant, but any full consideration must also take into account the significant capital costs involved in building a coal-fired power plant with CCS equipment. In a standard financial analysis of a CCS power plant investment, the level of carbon price necessary to break-even is significantly higher and varies depending on the location of the power plant. This is because a plant will dispatch to cover its marginal costs but not necessarily its capital costs which will require additional revenue. Existing plants may sometimes operate often but operate at a loss when taking long-term fixed capital costs into account.

The results are sensitive to assumptions about electric power regulation in the Western Interconnection with carbon pricing. The dispatch model used here simulates the entire Western Interconnection as a dispatchable area because multiple features of a realistic electricity market – ramping rates for unit commitment, ancillary services like reserves, opaque bilateral contracts – are not public information and are extremely data intensive for large numbers of simulations for such a large area. Only recently has California become a completely nodal pricing market using a full dispatch model as this thesis does.

By modeling pure marginal cost economic dispatch, the simulation represents a lowest system cost case. That is, the deviations of actual power grid operation produce efficiency losses and create higher overall system costs in order to generate the same amount of electricity. A least-cost optimization calculation for the power grid will produce the most competitive power environment. Computations of capacity factors in such a scenario describe a system's operation under an overall least cost computation, but individual power plants' capacity factors may vary.

5.2. Siting and Transmission

The results also indicate disparities between locations of identical CCS power plants due to local generation and transmission constraints. Two of the sites modeled – Inyo and Schultz –were constrained by transmission capacity and would never reach 100 percent capacity factors without major new transmission investment. Under the base case scenario of $25 per ton of coal and $3 per MMBTU of natural gas however, even these sites were able to dispatch and achieve an 80% capacity factor with a carbon price of $25 per ton-$CO_2$. Only approximately $10 per ton-$CO_2$ is required for all the other modeled power plants to achieve 95% capacity factors. Sufficient transmission is thus necessary to maximize the potential of any single power plant.

One reason that the minimum carbon price is so low for many of these plants is their siting in congested areas. California is a significant importer of electricity and there is sizeable intra-state congestion. Power plants sited along the Central Valley transmission corridor in California can provide power to the large load areas of the Bay Area and Southern California while at the same time experiencing high locational prices due to transmission congestion and natural gas-fired plants as its primary competition. CCS power plants located here may ease congestion along transmission lines that import and deliver power across long distances.

The dynamic between transmission, plant siting and carbon prices is even more evident in a high coal price ($40 per ton-coal) and a low natural gas price ($3 per MMBTU) scenario. Locations that are transmission-constrained continue to be prevented from higher capacity factors while the remaining power plants require higher carbon prices of approximately $30 per ton-$CO_2$ for >80% capacity factors. Higher carbon prices are required for a coal CCS power plant to be competitive with natural gas generation when gas-fired generation prices are lower relative to coal-fired generation prices.

However, another set of locations require much lower carbon prices of $5 to $10 per ton-$CO_2$ for baseload-like capacity factors. This lower carbon price is required for CCS power plants primarily due to their location. A hypothetical new power plants sited in northwest Arizona, in the transmission corridor between the coal generation of the Rockies and the load centers in Phoenix, Las Vegas, and Southern California would already be competitive cost-wise against existing coal generation and would gain an edge with the imposition of even the slightest carbon emissions price. Other locations for hypothetical CCS power plants compete less successfully against natural gas generation in the presence of a carbon emissions price.

Partial capture CCS power plants modeled reinforce this view. Most CCS plants become less competitive as measured by capacity factor values with declining capture rates due to increased exposure to carbon emissions prices. However, the site-specific exceptions remain the northeastern Arizona power plants with their grid-competitive proximity to coal-fired power plants.

In terms of siting power plants, one lesson is that in regions which use marginal cost dispatch to determine power plant operation and where carbon emissions prices are fully passed-through to a plant's incremental costs, the best locations for nascent CCS power plants may not be where prices are at present relatively high, like California. Instead, as carbon prices increases, they will disproportionately impact the costs of coal-fired power plants. A CCS power plant will experience greater price differentials under increasing carbon emissions prices when competing against currently cheap coal-fired power plant regions rather than currently expensive natural gas-fired generation. This price differential is sensitive to the price of natural gas as well, since natural gas can compete again a CCS power plant and set price of electricity with the marginal unit.

5.3. Technology Support Policies

There is a significant gap between the carbon price necessary to have a CCS plant dispatch and the carbon price needed to induce investment, and this gap highlights the need for additional government policy to advance the state of CCS technology. In conjunction with a carbon pricing policy, subsidies for construction of CCS plants may be appropriate to support the technology as well as other capital cost recovery policies like a production tax credit (PTC) or loan guarantees.

Supporting the capital costs of first-of-the-kind CCS generation and its initial deployment will support learning and maturity of CCS. This early construction will support the growth of this nascent industry by producing technical and operational knowledge. Demonstration and early deployment also promotes the acceptance of CCS technology in financial, political and public spheres, moving CCS from an unproven technology to available option. Finally, these early projects would likely result in lower costs at an earlier point in time.

Subsidies, in the form of loan guarantees or tax credits, may be especially compatible with a carbon pricing policy since our analysis has shown that a built and operating CCS power plant requires only a modest and politically-acceptable carbon price in order to cover fuel costs, the majority of operating costs. A subsidy would help build out the initial fleet of CCS generation to encourage the development of the CCS industry while a moderate carbon price sustains business operations. The increasing maturity of CCS industry and technology would follow long-term and increasing carbon prices which would allow falling CCS construction costs to be taken on by the private sector.

Initial, sustained high prices for carbon emissions greater than $100 per ton-$CO_2$ would produce a business environment for profitable CCS investments and preclude the need for capital cost support. These carbon price values, however, are currently politically untenable and would create large shifts throughout a fossil fuel-based economy. In order deploy CCS technology with lower carbon prices (about $30 per ton-$CO_2$), another policy instrument is needed to recover capital costs.

6. CONCLUSIONS AND FUTURE WORK

This thesis has provided a method for calculating the capacity factor for future CCS power plants based on a marginal cost dispatch of electricity generation under a variety of scenarios. The ability to explicitly calculate capacity factors for different CCS plant locations has revealed the dynamics of regional and local features in the electric grid. The capacity factors can then be used in financial analysis of CCS investments, rather than simply assumed as in previous studies. This dispatch analysis has provided insight into the deployment and strategies for crafting effective technology policy for CCS coal-fired power plants.

6.1. Transmission Constraints and the Regional Fuel Mix Matter

The level of dispatch, competitiveness and capacity factor of a particular power plant will depend on the location of the power plant. This is due to the availability of transmission to deliver power from that generator to load centers as well as competition with the other generators in the immediate vicinity. Both of these factors are key determinants in a marginal cost dispatch. The analysis has shown that for hypothetical CCS power plants with identical operating characteristics, this can still result in large differences in capacity factor and dispatch behavior under the same scenarios and carbon pricing policies. A discussion of how CCS can best be deployed in initial stages needs to take into consideration these diverging local results. Considering a generation technology and power plant without the context of transmission and the power grid will not fully recognize these effects.

6.2. CCS Power Plants Will Dispatch With Modest Carbon Prices

To induce the dispatch of higher cost CCS power plants, a policy of placing a price on carbon emissions (either a cap-and-trade emissions program or a carbon tax) will require relatively modest CO_2 prices in the range of \$10 to \$30 per ton-CO_2. The higher marginal operating costs of CCS power plants will require a policy to fully dispatch such generation so as to provide the maximum opportunity to recover costs. The levels of carbon price necessary to dispatch CCS power plants at a high capacity factor are generally lower than \$50 per ton-CO_2 price. The calculated level for a carbon price in this analysis is lower than expected when compared to the avoided costs calculated from previous studies. These studies focused on the impact that levelized cost will have on power plant investment decisions by assuming capacity factors for new technologies rather than the effect marginal costs will have on dispatch.

6.3. Investment for First-of-a-Kind CCS Generation Require High Carbon Prices

While high capacity factors for CCS power plants require relatively modest carbon prices, higher carbon prices are needed to make an investment in a FOAK power plant with CCS profitable. Capacity factors calculated using dispatch simulations represent the amount of time that power plants can cover marginal costs but not the fixed costs necessary to cover initial capital investments, a crucial and significant portion of power plant costs. In the base case scenario, with two exceptions, all of the sites required at carbon prices of at least \$115 per ton-CO_2 with half of the sites requiring a range of emissions costs of between \$130 to \$145 per ton-CO_2. In a higher natural gas price scenario, carbon prices still needed to be \$100 per ton-CO_2 or higher in the majority of the locations. These values can be considered as the carbon emissions costs necessary to cover a levelized cost of electricity for CCS.

6.4. CCS Technology Deployment Policy and Siting Strategies: Policies to Recover Capital Costs and Coal Regions

A policy to recover capital costs in conjunction with a carbon pricing policy would be helpful in deploying CCS technology. Subsidies for the initial construction of CCS power plants would be an effective policy for supporting CCS deployment as well as a production tax credit (PTC). CCS technology is expected to be able to be grid-competitive on a marginal cost basis with modest and anticipated carbon emissions prices, but not on the basis of levelized cost comparison. Construction or production subsidies for CCS power plants could be effective policies to meet this gap between marginal cost and levelized cost competitiveness. Government support in building of the first set of CCS generation could generate technical learning in industry and broader acceptance of CCS in business and the public while a modest carbon emissions price to cover marginal operational costs of these power plants.

When siting these initial CCS power plants, one counterintuitive strategy that has emerged from the marginal cost dispatch analysis is to place these coal-fired power plants with capture equipment close to other coal plants. CCS power plants are already fairly competitive on a marginal cost basis with existing coal-fired power plants. As long as locational marginal prices are determined by the marginal cost of the local fuel mix, CCS power plants will become more competitive as carbon emissions prices rise. Existing coal-fired power without CCS equipment will be the most exposed and impacted by rising emissions costs and these rising values will set the price of electricity of a CCS power plant high. The revenue margin would be higher for these plant locations than CCS power plants located in mostly natural gas-fired generation regions due to their lower emissions and thus lower carbon price exposure, a counterintuitive result as these regions currently have higher electricity costs. The level of natural gas prices will affect these regional differences but the differential is probably large enough for this strategy to hold true for a large range of natural gas prices.

6.5. Future Work

This study has demonstrated that understanding and analyzing power plant capacity factors can affect policy prescriptions for the development and deployment of new electricity generation technologies. Immediate future work could include additional scenarios regarding fuel costs, carbon prices, and the ever-changing state of the electricity grid with the updates and planned additions to generation and transmission. Integrating such scenarios – a specific fuel cost scenario with various levels of future generation and transmission build-out – with an explicit analysis of new transmission required for specific power plant locations and their costs would represent a comprehensive effort to understand all build-out possibilities.

Other work could explore the sensitivity of dispatch and capacity factor of CCS power plants to intermittent resources like solar, wind, hydropower and other renewable generation. The availability of hydroelectric resources would be of interest in simulations of the Western Interconnection due to the large amount of hydropower in northwestern region.

By linking potential power plant locations with possible CO_2 sequestration sinks, CCS power plants could also be modeled with variable CO_2 storage and transportation costs with a dependence on location. In addition, other coal-fired power plants with CCS equipment, like oxy-fired generation or retrofit scenarios should be modeled.

Model improvements could take into account the nature of regulated regions and the impact of bilateral contracts. Ancillary services, like reserves, would also contribute to a more accurate capacity factor calculation. Ramp-up and ramp-down times could be accounted for by integrating a marginal cost dispatch model with a unit commitment analysis and accounting for necessary maintenance downtime and the inability for plants to be instantly on or off. NO_x and SO_x emissions markets prices could be explicitly calculated for power plants and used in dispatch calculations.

Finally, modeling the various stages of CCS penetration in the power grid would provide a list of candidate sites for building CCS power plants. Not only would this provide a sense of priority and sequencing for CCS deployment, but such an analysis would optimize and minimize the cost of deploying CCS technology.

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APPENDICES

Appendix A: Dispatch and Capacity Factor Calculation Example

Table A-1 Capacity Factor Calculation Example for Hypothetical CCS Power Plant from Sampled Dispatch

Carbon Price (ton-carbon dioxide)	WECC System Load	Percentile Load	Bus Number	Bus Name	Dispatched Generation (MW)
$ 5	64,278	1	99998	IGCCGATES	0
$ 5	69,501	2	99998	IGCCGATES	200
$ 5	70,923	3	99998	IGCCGATES	200
$ 5	71,861	4	99998	IGCCGATES	200
$ 5	72,606	5	99998	IGCCGATES	200
$ 5	73,370	6	99998	IGCCGATES	200
$ 5	74,129	7	99998	IGCCGATES	200
$ 5	74,860	8	99998	IGCCGATES	300
$ 5	75,598	9	99998	IGCCGATES	300
$ 5	76,354	10	99998	IGCCGATES	300
$ 5	77,170	11	99998	IGCCGATES	300
$ 5	78,091	12	99998	IGCCGATES	300
$ 5	79,076	13	99998	IGCCGATES	300
$ 5	79,832	14	99998	IGCCGATES	300
$ 5	80,652	15	99998	IGCCGATES	300
$ 5	81,301	16	99998	IGCCGATES	300
$ 5	82,032	17	99998	IGCCGATES	300
$ 5	82,673	18	99998	IGCCGATES	400
$ 5	83,264	19	99998	IGCCGATES	400
$ 5	83,909	20	99998	IGCCGATES	400
$ 5	84,525	21	99998	IGCCGATES	400
$ 5	85,116	22	99998	IGCCGATES	400
$ 5	85,682	23	99998	IGCCGATES	400
$ 5	86,273	24	99998	IGCCGATES	400
⋮	⋮	⋮	⋮	⋮	⋮
$ 5	147,165	99	99998	IGCCGATES	500
$ 5	149,669	100	99998	IGCCGATES	500
$ 5	154,058	101	99998	IGCCGATES	500
$ 5	162,566	102	99998	IGCCGATES	500
				Capacity Factor	**88.0%**

Appendix B: Marginal Cost Calculation Example

Table A-2 Example of Marginal Cost Calculation with Sources

Unit			Source
	Name	PERSONG1	PowerWorld
	Area Name	NEW MEXICO	PowerWorld
	Number	10,246	PowerWorld
	ID	1	PowerWorld
	Name	Delta Person LLC	EIA
	Number	55,039	EIA
	Fuel Type	Natural Gas	EIA
	Prime Mover	Gas Turbine	EIA
	Heat Rate for Generic Plant by Fuel & Prime Mover Type	11,664	EIA
	Latitude	35.026	eGRID
	Longitude	-106.644	eGRID
(Btu/kWh)	**Heat Rate (2005)**	7,161	eGRID
(tCO2/yr)	**CO2 Emissions (2005)**	4,492	eGRID
(MWh/yr)	**Plant Generation (2005)**	10,293	eGRID
	Plant Capacity Factor	0.78%	eGRID
	Plant Number of Generators	1	eGRID
(MMBtu)	**2005 Heat Input**	73,706	eGRID
(lb.-CO2/MWh)	**CO2 Emissions Rate**	872.77	eGRID
(ton-CO2/Btu)	**CO2 Emissions Rate**	0.0609404	(calculated)
($/MMBtu)	**Add. CO2 Cost**	18.2821	(calculated, input)
($/MMBtu)	**Fuel Only Cost**	3.00	(input)
($/MMBtu)	**Total Fuel Cost**	21.2821	(calculated)
($/MWh)	**Fuel O&M Costs**	0	(input)
($/MWh)	**Other O&M Costs**	0	(input)
	Dispatchable?	YES	(input)
(MBTU/MWh)	**Heat Rate**	7.1609	(calculated)
($/MWh)	**Marginal MWh Cost**	**$152.40**	(calculated)

Appendix C: Base Case Scenario Inputs

Table A-3 Base Case Fuel and Generation Inputs

	(units)	Cost	Dispatch?
CO2	**($/tCO2)**	$ -	
Coal	**($/ton)**	$ 25.00	**ON**
	($/MMBtu)	$ 1.42	
Oil	**($/gal)**	$ 2.00	**ON**
	($/MMBtu)	$ 14.39	
Gas	**($/MMBtu)**	$ 3.00	**ON**
Wind	($/MWh)	$ 30.00	**off**
Hydro	($/MWh)	$ 30.00	**off**
Geothermal	($/MWh)	$ 50.00	**off**
Solar	($/MWh)	$ 100.00	**off**
Nuclear	($/MWh)	$ 30.00	**off**
Biomass	($/MWh)	$ 50.00	**off**
Other	($/MWh)	$ 1.00	**off**
Unknown	($/MWh)	$ 1.00	**off**

Table A-4 Base Case CCS Power Plant Inputs

heat rate	11,500	(BTU per kWh)
efficiency	29.7%	
capture rate	100%	

Appendix D: Alternative Fuel Price Scenario

Table A-5 Alternate Fuel Price Scenario Inputs

		Coal Prices (per ton-coal)	
		$25	**$40**
Natural Gas Price (per MMBTU)	**$3**	Low Coal Price-Low Natural Gas Scenario	High Coal Price-Low Natural Gas Scenario
	$5	Low Coal Price-High Natural Gas Scenario	High Coal Price-High Natural Gas Scenario

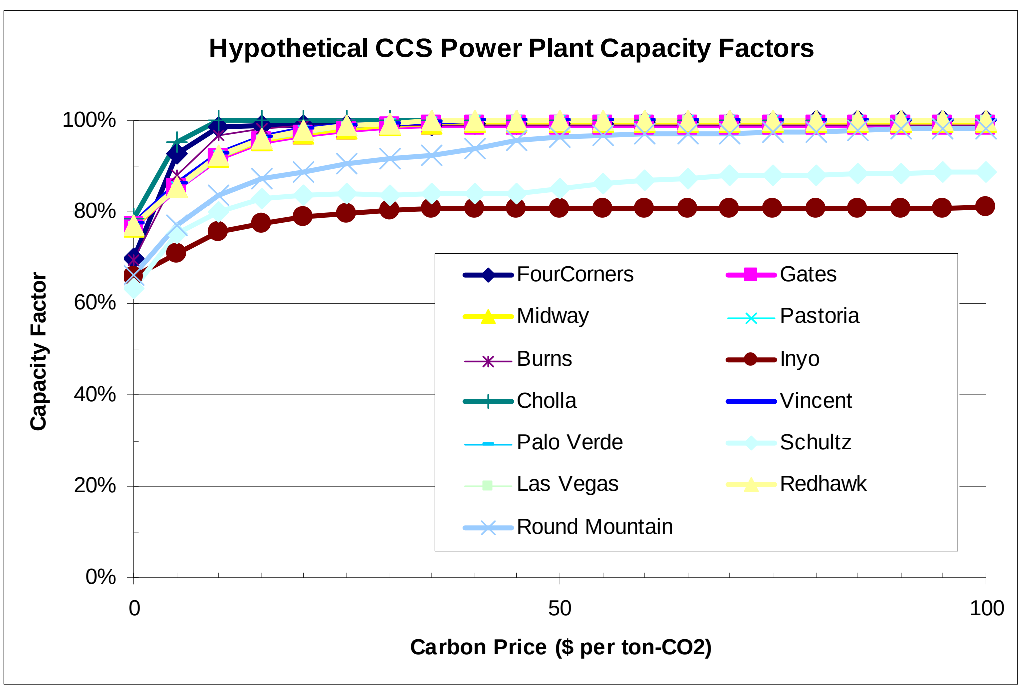

Figure A-1 Capacity Factor vs Carbon Price for Individual Hypothetical CCS Power Plants – High Coal-High Natural Gas Fuel Price Scenario

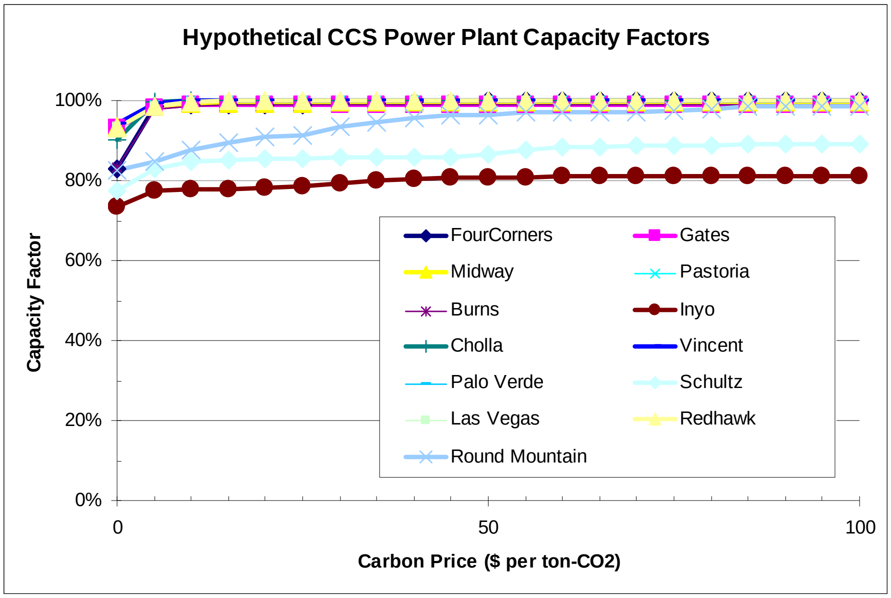

Figure A-2 Capacity Factor vs Carbon Price for Individual Hypothetical IGGC Power Plants – Low Coal-High Natural Gas Fuel Price Scenario

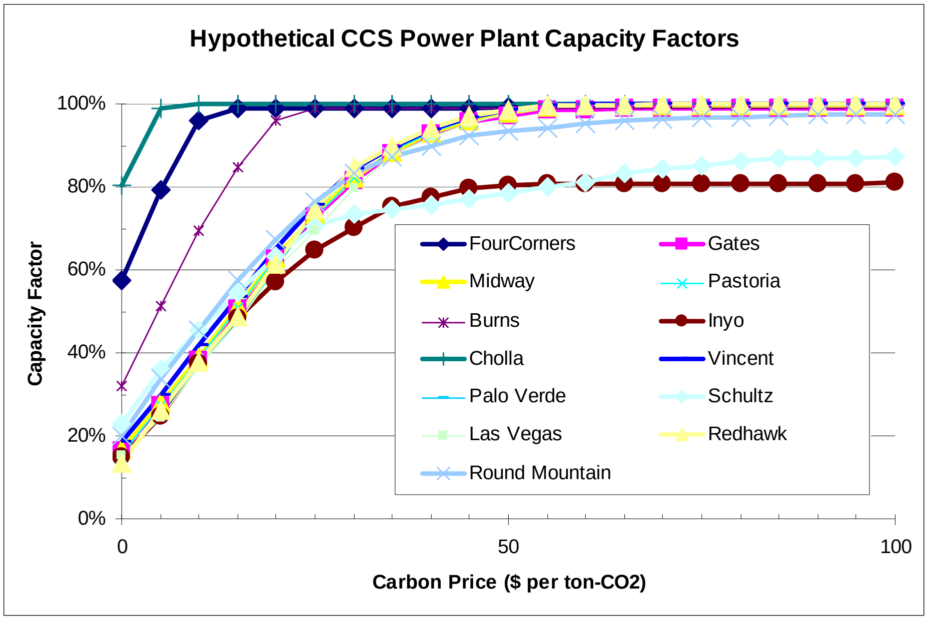

Figure A-3 Capacity Factor vs Carbon Price for Individual Hypothetical IGGC Power Plants – High Coal-Low Natural Gas Fuel Price Scenario

Appendix E: CCS Power Plant Efficiency Scenario

Table A-6 CCS Power Plant Efficiency Scenario Inputs

(BTU per kWh)

Heat Rate	Efficiency
11,500	29.7%
13,500	25.3%
17,000	20.1%

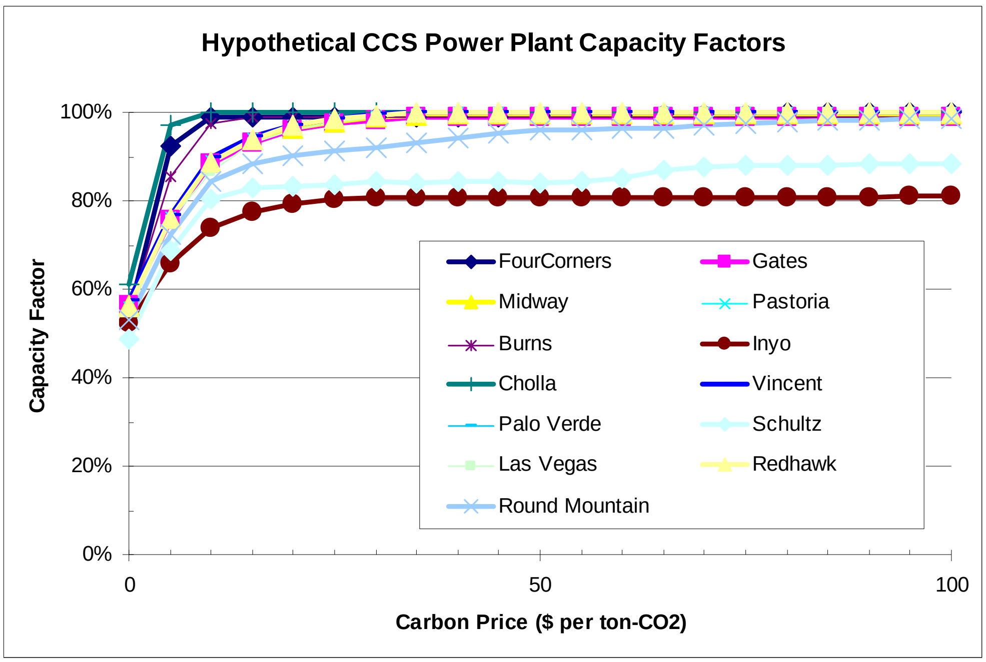

Figure A-4 Capacity Factor vs Carbon Price for Individual CCS Power Plants with 13,500 BTU per kWh Heat Rate.

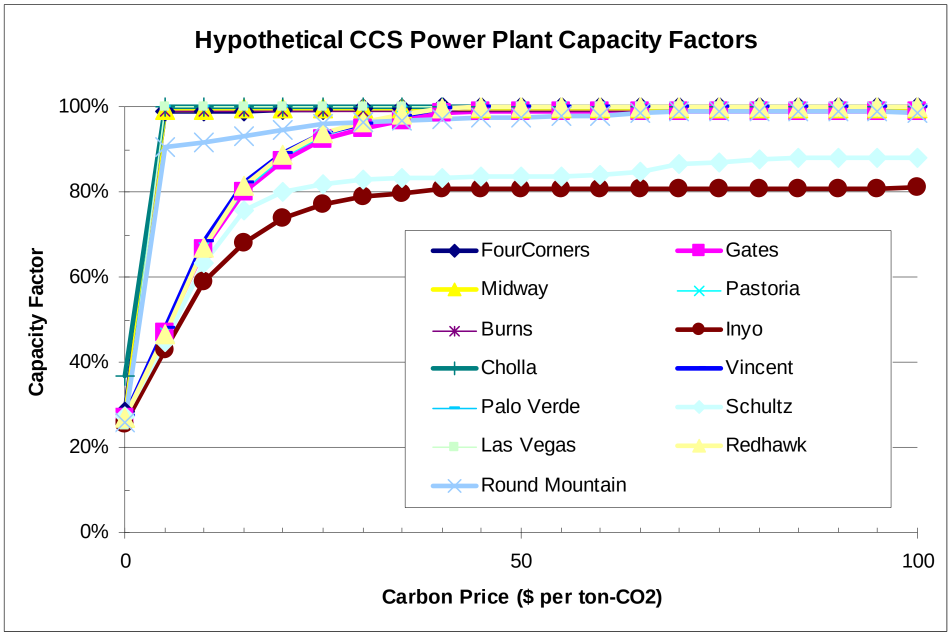

Figure A-5 Capacity Factor vs Carbon Price for Individual CCS Power Plants with 17,000 BTU per kWh Heat Rate.

Appendix F: CCS Capture Rate Sensitivity Scenario

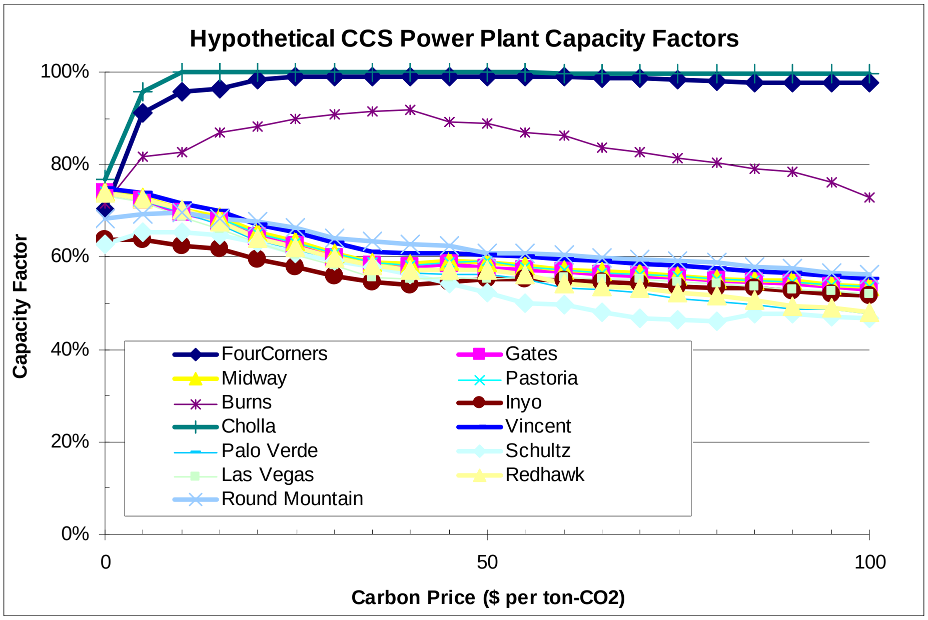

Figure A-6 Capacity Factor vs Carbon Price for Individual CCS Power Plants with 50% Capture Rate.

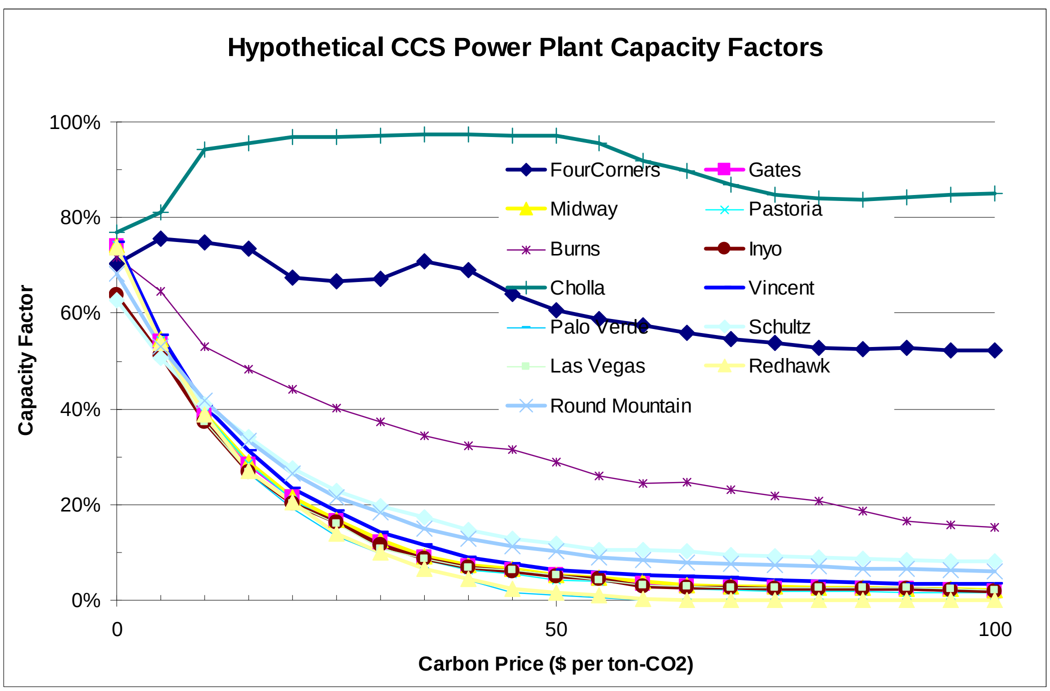

Figure A-7 Capacity Factor vs Carbon Price for Individual CCS Power Plants with 0% Capture Rate.

Appendix G: Partial Capture CCS Power Plant Scenario

[Refer to Figure A-1 through Figure A-7 for location legend in subsequent figures.]

Table A-7 Partial Capture CCS Power Plant Scenario Inputs

Capture Rate	Heat Rate (BTU per kWh)	Efficiency
100%	11,500	29.7%
90%	11,175	30.5%
80%	10,850	31.4%
70%	10,550	32.3%
60%	10,275	33.2%
50%	10,000	34.1%
0%	8,500	40.1%

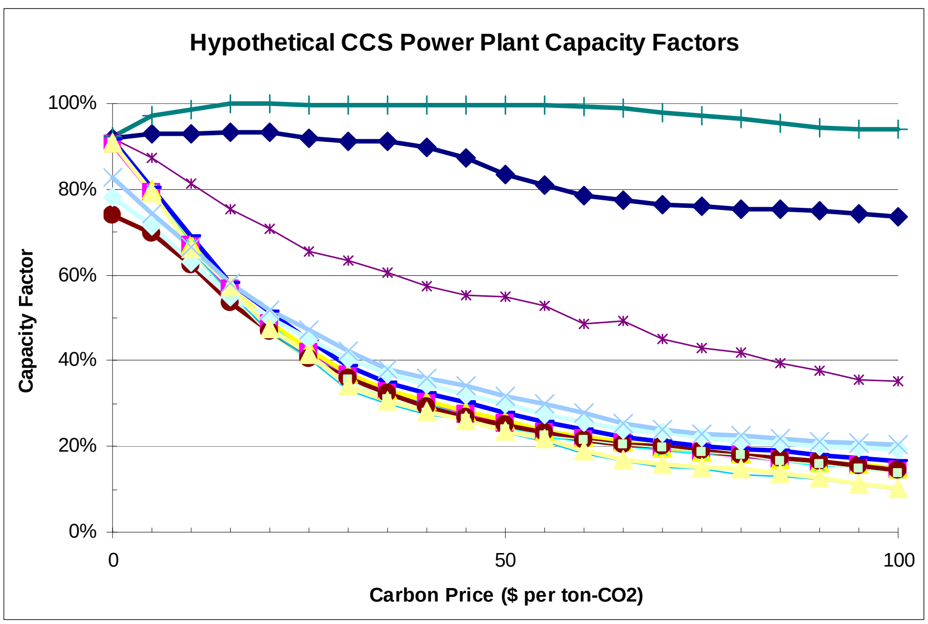

Figure A-8 Capacity Factor vs Carbon Price for Individual CCS Power Plants with 0% Capture Rate and 8,500 BTU per kWh Heat Rate.

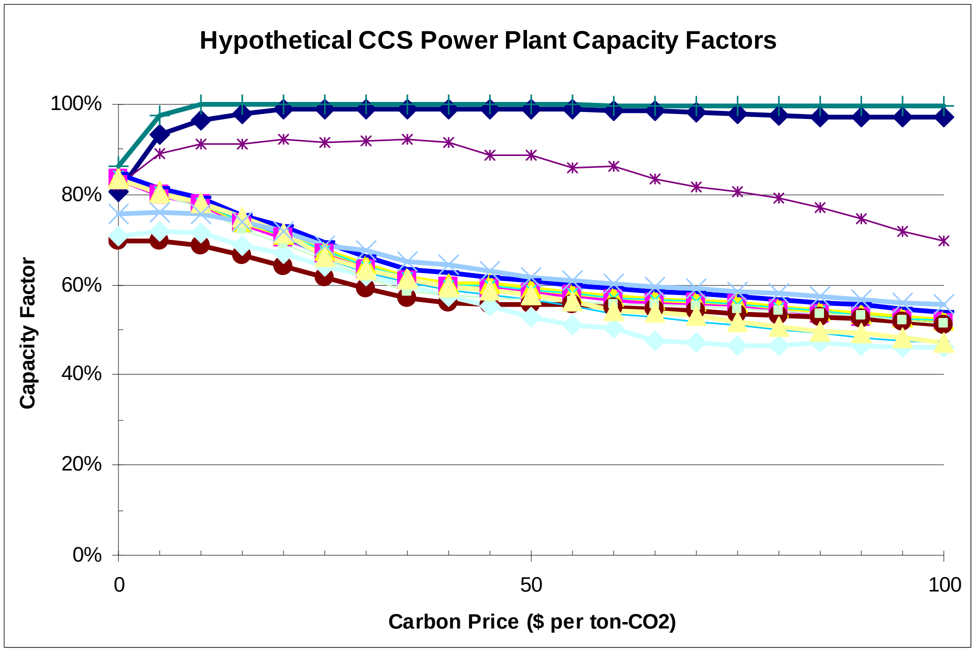

Figure A-9 Capacity Factor vs Carbon Price for Individual CCS Power Plants with 50% Capture Rate and 10,000 BTU per kWh Heat Rate.

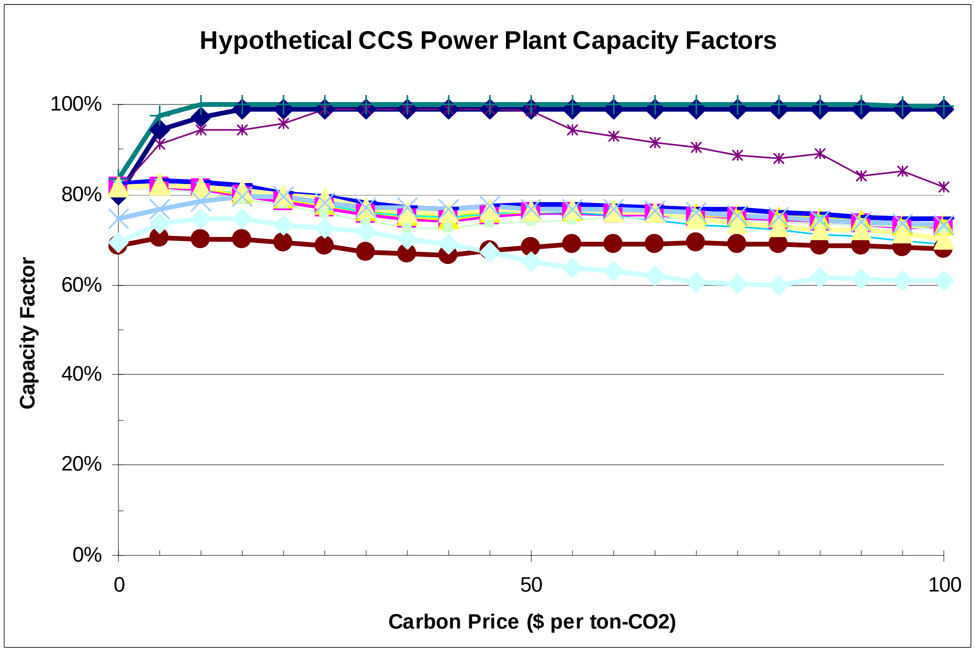

Figure A-10 Capacity Factor vs Carbon Price for Individual CCS Power Plants with 60% Capture Rate and 8,500 BTU per kWh Heat Rate.

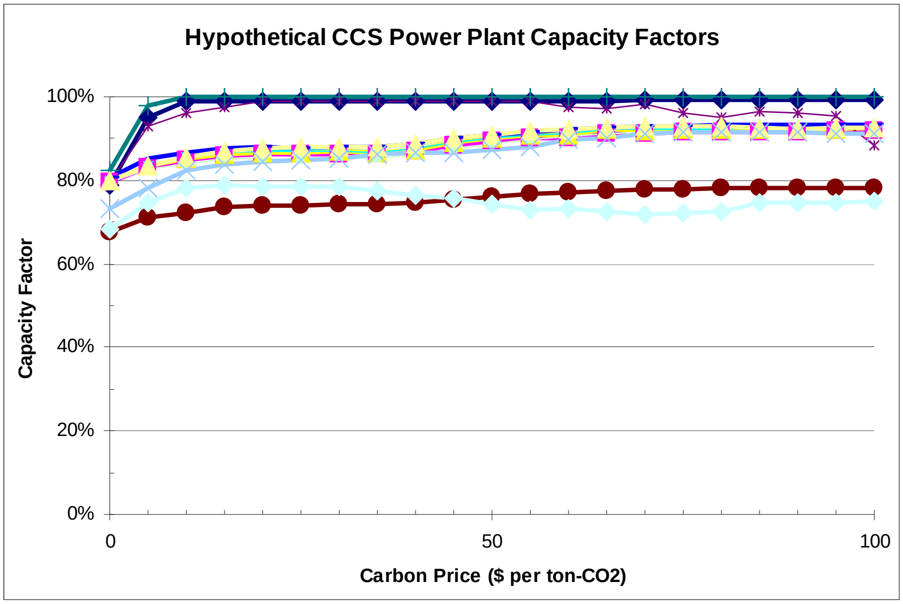

Figure A-11 Capacity Factor vs Carbon Price for Individual CCS Power Plants with 70% Capture Rate and 10,550 BTU per kWh Heat Rate.

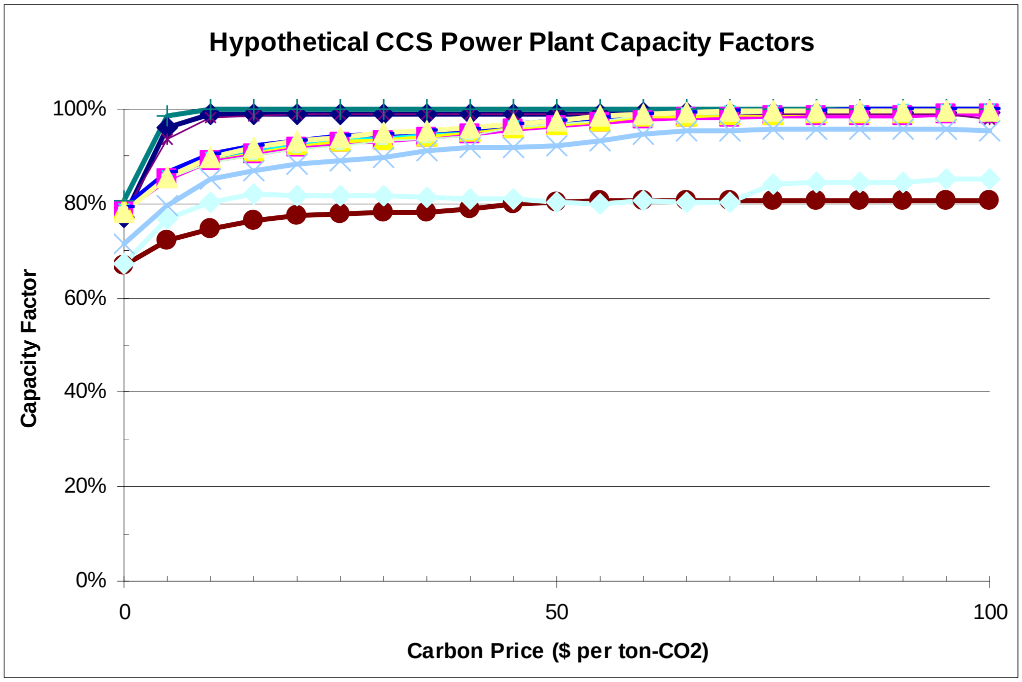

Figure A-12 Capacity Factor vs Carbon Price for Individual CCS Power Plants with 80% Capture Rate and 10,850 BTU per kWh Heat Rate.

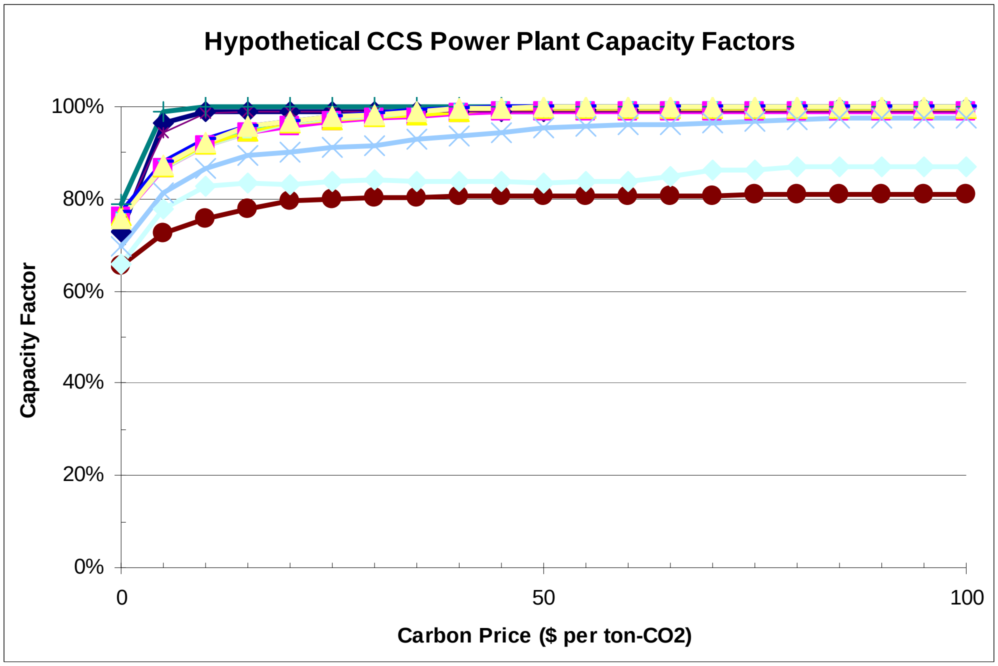

Figure A-13 Capacity Factor vs Carbon Price for Individual CCS Power Plants with 90% Capture Rate and 11,175 BTU per kWh Heat Rate.