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CLIMATE CHANGE LEGISLATION AND ITS AFFECT ON BASE LOAD POWER GENERATION ECONOMICS

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Abstract

This thesis will evaluate the varying economic effects that climate change policy will have on near term base load power plant technologies. Specifically, it will look at how cap and trade regulations on carbon emissions will change the economics for new coal, gas and nuclear plants at varying carbon prices and will qualitatively evaluate other political, market, and technological risks involved with these technologies.

The ultimate goal of this thesis will be to provide a comprehensive picture of the strengths, weaknesses, and risks associated with new power generation technologies. The quantitative analysis shows significant uncertainty depending on how various factors come together, since the economic profiles of the different technologies are all so different and unique. The quantitative model will be balanced with a comprehensive qualitative analysis of the interplay between the social, political, and economic factors affecting the construction of new power plants. This study will provide a unique perspective that will inform individuals interested in the future makeup of the power generation landscape.

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I dedicate this thesis to my parents for their endless encouragement and support of my education.

Introduction

Problem Statement and Objectives

On June 26th, 2009, the US House of Representatives passed The American Clean Energy and Security Act, also known as the Waxman Markey climate change bill, signaling the beginning of climate change regulation in the United States. There is, at the time of this writing, another climate bill being debated in the US Senate. With electric power accounting for 40% of all energy consumption in the United States, and about half of that power being produced from coal, the most carbon intensive method, it stands to reason that this bill will have a significant effect on the power industry.

The goal of this thesis is to evaluate how varying price levels of carbon emissions would affect the project development economics of new power generation facilities, potentially changing the future mix of generation technologies employed by American utility companies.

In this thesis, I will discuss the history of cap and trade programs for reducing emissions, both in the United States to decrease emissions that cause acid rain, as well as in the European Union, where cap and trade has been used more recently as a market mechanism to decrease carbon dioxide emissions in an attempt to curb global warming. I will also discuss the current or near term, state of the art technologies for producing power from coal and natural gas, as well as some of the factors affecting power generation from new nuclear power plants.

Finally, using a financial model, I will evaluate the economic viability of new power plants producing electricity from coal, gas, or nuclear fuels at a variety of cost levels for fuels and carbon dioxide.

Literature Review

Cap and Trade Overview

The American Clean Energy and Security Act, H.R. 2452, requires an 83% reduction in greenhouse gas emissions from 2005 levels by 2050. The bill will create a cap and trade system that will cap annual emissions, distribute allowances equal to that cap, and allow those allowances to be traded on a climate exchange. In addition to these allowances, carbon offsets can also be traded. Offsets are certified reductions in greenhouse gas emissions from unregulated sources. Generally the cap and trade program does not cover these sources because they are produced outside its jurisdiction or are emitted by an industry that is not covered by the program.

Ideally, a cap and trade system provides the most efficient and economical mode of reducing emissions. Unlike a command and control method, it recognizes that emissions come from different processes and the cost incurred to cut emissions varies considerably from source to source. Instead of mandating reductions from each emitter, cap and trade sets an absolute emissions limit and, by monetizing and trading the right to pollute, it allows the market to set a clearing price equal to the lowest marginal abatement cost of that pollutant. Cap and trade is also more favorable politically than a carbon tax; one of the primary reasons it was chosen as the emissions reduction method in the Waxman Markey bill. However, there is some industry and academic support for a carbon tax, rather than cap and trade, notably from ExxonMobil, primarily because a tax sets a transparent price on emissions whereas a cap and trade program only sets the emissions limit and allows the market to determine price.

Cap and Trade in the United States: The Acid Rain Program

Historically cap and trade has been employed by the US Environmental Protection Agency (EPA) to reduce sulfur dioxide or SO_2 emissions, the primary cause of acid rain. However, there have been some smaller emissions trading systems for regional emissions of other pollutants as well, including the Emissions Reductions Market System to reduce volatile organic compounds around Chicago[1], oxides of nitrogen[2] and even carbon dioxide[3].

The first major cap and trade system for controlling pollution was put into law as part of the amended United States Clean Air Act of 1990. The goal of this legislation was to decrease sulfur dioxide emissions that were causing serious acid rain problems throughout the United States and Canada. The issue of regulating sulfur emissions and acid rain went back years, to the original Clean Air Act of 1970, which was passed into law under President Richard Nixon. This piece of landmark legislation set national air quality standards and compliance timelines, and led to the establishment of the Environmental Protection Agency (EPA) as the federal agency in charge of implementing the policies set forth by the Clean Air Act of 1970. The bill required the states to implement action plans for reducing six major air pollutants: Sulfur dioxide, lead, particulate matter, nitrogen oxides, carbon monoxide, and ozone[4]. The deadline for attaining reductions specified in the states' action plans was in 1975.

In 1977, Congress passed a modified clean air act, largely to extend the compliance deadlines, since few states had met the goals of original bill. The 1977 Clean Air Act also raised the limits for nitrogen oxides at the urging of American automakers and closed a loophole that allowed coal fired power plants to comply with clean air regulations by simply building taller smokestacks, which dispersed pollutants greater distances. The new law also required that all coal-fired power plants install industrial scrubbers to control sulfur and nitrogen oxide emissions, but grandfathered existing plants. The bill set a deadline of 1982 for compliance with air quality standards with no extensions allowed beyond 1987. Unsurprisingly, it became increasingly clear as the 1987 deadline approached that few states would be in compliance, as Regan had slashed the EPA's budget, replaced its leadership, and worked tirelessly to cut governmental regulation of business and industry.

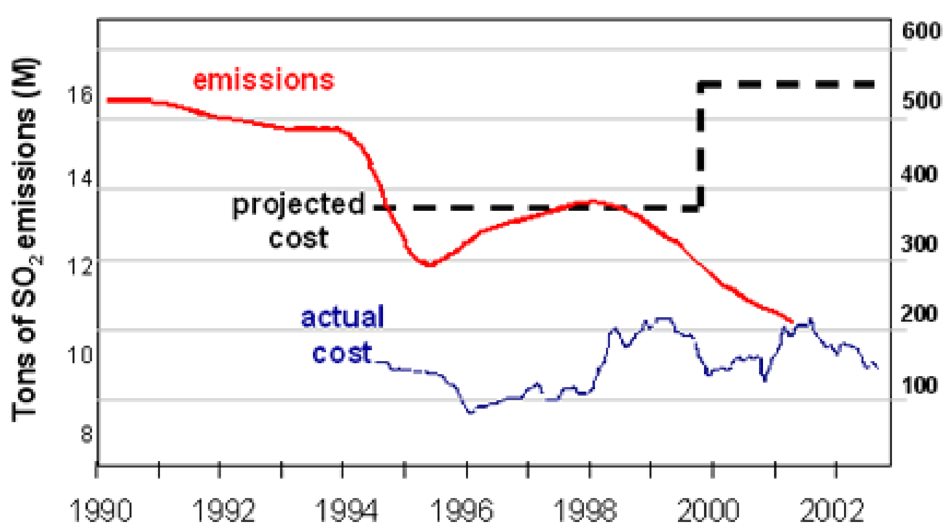
Canada repeatedly protested that pollution from American industry, primarily in the Ohio Valley, was traveling across the border, causing billions of dollars of damage to their environment and economy[5]. Environmental groups constantly battled Regan over his administration's inaction towards enforcement of clean air regulations, with some states eventually joining these groups in lawsuits against the federal government for failing to enforce the clean air act[4]. It was in this embattled atmosphere that the seeds of cap and trade emissions regulation were sown.

The concept was championed by an unusual combination of interest groups: A progressive environmental protection group called the Environmental Defense Fund, which was looking for a new, innovative plan to put on the table after more than a decade of stalemate over acid rain reductions by the old command and control method. A group of conservative republicans to whom the concept of a free market system of regulation appealed, and finally, congressional democrats who had been working for years to find a palatable plan for reducing acid rain.

Under the leadership of John Heinz, a republican senator from Pennsylvania, and Tim Wirth, a democratic representative from Colorado, cap and trade legislation was discussed in the House, Senate, and White House before ultimately being incorporated into the Clean Air Act of 1990 under the presidency of George H.W. Bush. The 1990 act set stringent emissions standards that required a 10 million ton reduction of sulfur dioxide emissions and put into place a monitoring system that allowed the EPA to track how much pollution was being emitted.

Ultimately, the program was a huge success with 100% compliance through Phase I from 1990 to 1995. In fact, power plants over-complied in the first phase and reduced SO2 emissions to 22% below mandated levels[6]. Moreover, compliance costs were low compared to expected costs, with allowance costs averaging between \$100 and \$200 rather than the \$650 to \$850 that were originally predicted[6].

Figure 1 - Sulfur Dioxide Emissions and Projected versus Actual Allowance Costs[6]



Carbon Dioxide Cap and Trade in the European Union

The largest trading system for greenhouse gas emissions to date has been the European Union Emissions Trading System, or EU ETS for short. The EU ETS began its initial trading phase in 2005 and is currently in Phase 2. Currently, all 27 EU nations, plus Iceland, Norway, and Liechtenstein participate in the program[7].

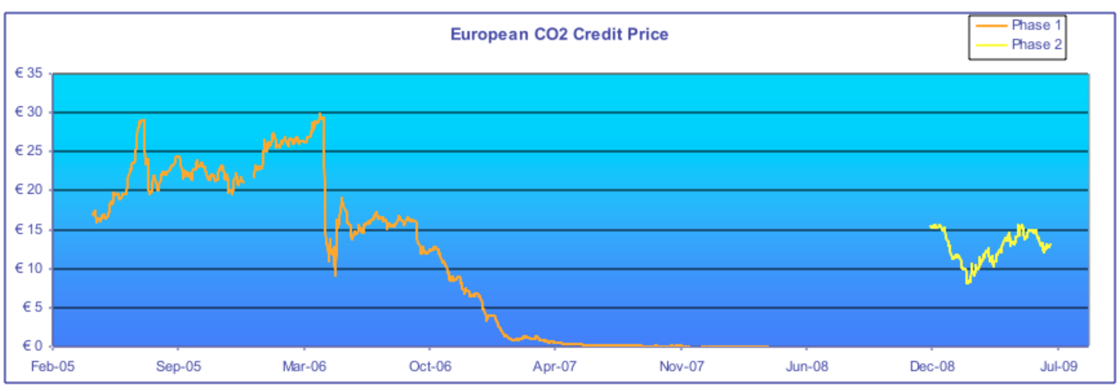
The initial trading phase was designed as a learning phase, so that the member states could better understand the market and how to optimize the cap and trade program for the second compliance phase. Because of this, the emissions caps were set relatively high and were almost all allocated for free to cushion consumers from increased energy costs[8]. These two choices led to some key lessons for implementing a new carbon trading system.

First, although the EU governments likely realized the cap on carbon dioxide emissions was not very stringent, they did not have strong enough data to reliably set a cap on emissions. Moreover, there was some significant lag time between when the emissions allowances began trading and when hard data on total emissions levels was released. Trading began on January 1, 2005. In late April of 2006, data was released showing that actual carbon dioxide emissions lagged far behind the allowances that had been distributed for that time period. Market participants realized that supply of emissions allowances exceeded demand, and responded by selling off allowances, causing prices to fall from €30 to €15 in one week[8]. See Figure 2. As more data was released showing that the allowances were over-allotted, their price continued their fall to essentially zero.

This demonstrates the need for the emissions governing body to have reliable data about historical emissions, as well as a robust system for reporting current emissions levels. Reliable historical data is necessary to implement a reasonable cap on greenhouse gas emissions, ensuring that the allowances will retain a market value. A robust reporting system is necessary to keep the market informed and cut down on speculation and volatility so that the market can put a fair price on emissions.

Another key question this raises is the issue of banking credits from phase to phase. Typically, emissions trading programs will be split into multi-year blocks, or phases, with the emissions cap tightening at the beginning of each new phase. In the implementation of the first phase of the EU ETS, there was no banking allowed between the initial phase and the second phase, rendering any unused allowances from the first phase worthless. Had they been allowed to carry over and be used in the next phase, they would have maintained some value. Generally, it is believed that banking is an important feature to smooth price volatility and maintain a value for the allowances

Figure 2 - European CO2 Credit Price by Date and Phase in Euros per Tonne



Finally, the EU ETS raised additional questions about whether it is more equitable to give allowances away for free, or whether they should be auctioned. In phase one of the EU ETS, 95% of the available allowances were distributed free of charge, the assumption being that by giving away the allowances, it would shield consumers from spikes in power prices. Retrospectively, however, Sijm et al found that between 60% and 100% of the allowance value was passed through in the power price, depending on market conditions and a complex mix of other factors[9]. Although this pass-through can be controlled in a regulated power market, it is only logical that it would occur in a deregulated power market, since the value of emissions enters into the marginal costs of producing power at the market price rather than the cost to the power producer.

Economists Kristen Sheeran and James Barrett made the following analogy in an op-ed piece they co-wrote for the Baltimore Sun:

> "Try buying World Series tickets from a scalper. Would he charge you any less if he found the tickets on the ground or got them free from a friend inside the ticket office? Of course he wouldn't. Like energy, the street price of World Series tickets is based on supply and demand. The supply and demand for tickets is the same no matter how much the scalper paid for them, and so the price he charges you will also be the same no matter how he got them.
>
> Of course, the scalper would much rather get his tickets for free - and that's precisely the point. Polluters are financially much better off if permits are given away instead of auctioned, but the cost of cutting emissions and the resulting effect on energy prices will be the same no matter how the permits are delivered[10]."

Base Load Fossil Fuel Power Generation Technologies Introduction

Project developers are currently considering both integrated gasification combined cycle (IGCC) coal plants and natural gas combined cycle (NGCC) plants, so these were the technologies chosen for an economic analysis. Although these technologies are both at the leading edge of fossil fuel power generation technology, they have different carbon footprints and economic development profiles.

Natural Gas Power Generation

Most power plants built in the last decade have been natural gas combined cycle power plants. These plants are the most efficient method currently available for producing electricity from natural gas. In a natural gas combined cycle power plant, the gas powers a combustion turbine, extracting energy through the high temperature Brayton thermodynamic cycle. The waste heat from this process is used to boil water into steam, which then runs through a steam turbine utilizing the Rankine thermodynamic cycle.

Natural gas plants produce practically no particulate or mercury emissions, extremely little sulfur, and very low NOx, so that in comparison with coal plants, natural gas plants need significantly less emissions scrubbing equipment. This is largely because, as a gas, it mixes well with air for combustion and has very few suspended impurities, unlike solid or liquid fossil fuels. Also, there have been major advances in natural gas drilling techniques in recent years, leading to massive discoveries of newly recoverable gas in unconventional geological formations like shale and tight sands. These discoveries have created a recent glut of supply and a significant price drop that could persist for some time.

Natural gas is primarily methane gas, which is a simple hydrocarbon composed of one carbon molecule bound to four hydrogen molecules. Like all hydrocarbons, the combustion products are primarily carbon dioxide and water. The former created from the carbon in the molecule, the latter from the hydrogen. Because methane has the highest ratio of hydrogen to carbon (4:1) of any hydrocarbon, burning methane gas produces the least carbon dioxide per unit of energy of any hydrocarbon.

Coal Fired Power Generation

Most coal fired generation units currently deployed are steam plants that burn coal to produce high-pressure steam. This steam runs through a single steam turbine, only utilizing one thermodynamic cycle, which limits the thermodynamic efficiency. However, this technology is not favored for new construction because of current emissions regulations, looming climate legislation, and the voting public's general distaste for coal fired power plants in their back yard.

IGCC technology partially offsets these limitations and is being touted as new "Clean Coal" technology due to its lower emissions, higher efficiency, and greater ability to remove carbon dioxide from the exhaust stream and potentially sequester it deep underground. "Clean Coal" implies the technology produces no pollution, which is not the case. Clean coal technology is cleaner than traditional coal plants, but not pollution-free. Rather than combusting the coal to produce heat, the coal undergoes a chemical reaction to form hydrogen gas and carbon monoxide. The carbon monoxide can then be further oxidized through a process called a water gas shift reaction to produce carbon dioxide and more hydrogen gas. The gasification process allows for significantly more control over the reaction products than simple combustion, which in turn allows IGCC plants to remove far more ash, sulfur dioxide, oxides of nitrogen, and mercury rather than venting them into the atmosphere.

Also, since the gas mixture coming off of the gasification unit is so much richer in CO_2 than the flue gas from a traditional coal plant (30% – 32% versus 9% – 14%), it is significantly easier to capture and potentially store in an underground geological formation such as depleted oil or gas wells, saline aquifers, salt caverns, or coal mines[11].

Geological Carbon Dioxide Sequestration

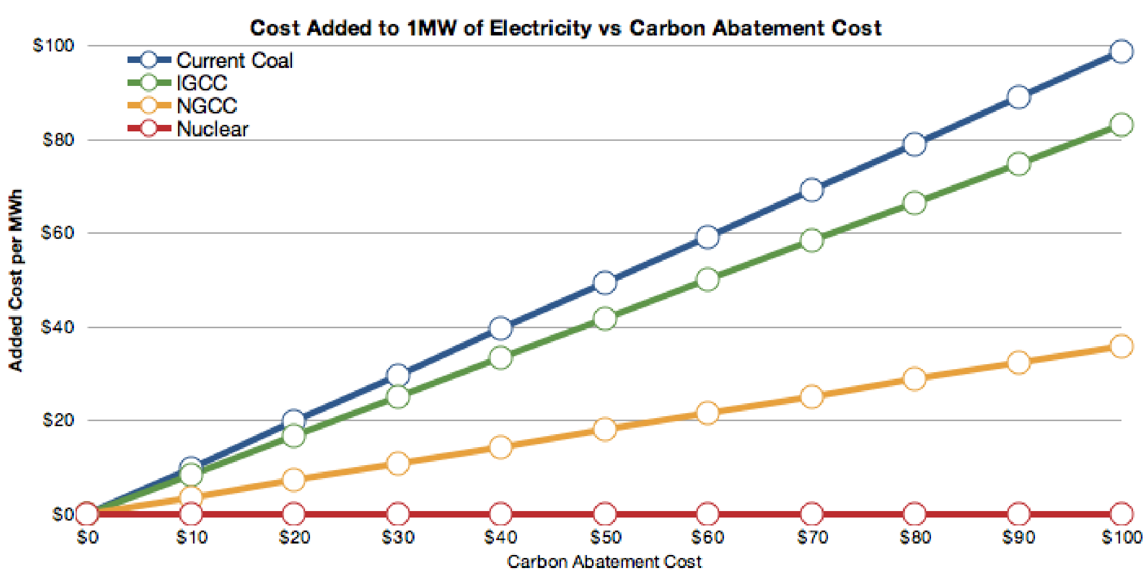
Unfortunately, geological carbon dioxide sequestration is still an unproven commercial process that complicates the design of power plants. It also places an enormous auxiliary load on the plant, thereby decreasing efficiency and increasing the total amount of carbon dioxide produced, reducing the impact of the CO_2 abatement. However, because IGCC produces a synthetic coal gas containing a relatively high concentration of CO_2, it would likely be less expensive to separate and sequester the carbon emissions from an IGCC plant than a natural gas power plant.

It remains to be seen, however, whether or not CO_2 sequestration will be a developed into a viable commercial technique for abating carbon emissions, and when, if ever, it would have a lower price tag than the significantly smaller amount of allowances that would need to be purchased for the same size natural gas combined cycle plant.

Economic Impacts of Climate Change

The real economic question in developing these two types of plants is mainly one of marginal versus fixed costs. For years, coal has been the primary source of base load generation thanks to the extremely low price of fuel, moderate plant cost, and the absence of any economic ramifications of its large carbon footprint. IGCC plants, however, are considerably more expensive to build than traditional coal fired steam plants. Moreover, since even a new, highly efficient coal-fired power plant produces approximately 2.3 times as much CO_2 as an advanced NGCC facility, any climate change legislation placing a cost on carbon emissions places a significantly larger burden on coal. Including the cost of the CO_2 emissions caused by combusting the fuel would narrow the marginal fuel cost between coal and natural for power generation. Since nuclear power does not produce carbon dioxide emissions, climate change legislation becomes a major incentive for its use in the place of fossil fuels as carbon allowances in cost. See figure below.

Figure 3 - Marginal Carbon Emissions Cost per MWh of Electric Power Generation



Admittedly, there is a great deal of uncertainty about the costs of fuels and carbon in the future, which has significant impact on the economics of any new power plant. It is, however, an unfortunate reality that utilities must make planning decisions about new plant investments with as much as a 50-year time horizon based on incomplete and unpredictable future conditions.

Nuclear Power

Setting a price for carbon dioxide emissions will likely encourage nuclear power generation by raising the marginal costs associated with producing power from fossil fuels, thus narrowing the economic gap between fossil fuel and nuclear power generation. Nuclear is the only carbon free source of base load power that is mature, reliable, and able to be expanded to meet new demand or displace current carbon intensive plants.

Although there have been no new orders of nuclear power plants in the United States since the Three Mile Island disaster in 1979, the nuclear industry has continued building new plants elsewhere and has made significant advances in safety, reliability, and nuclear waste concerns in advanced, so-called third generation nuclear reactor designs. According to worldnuclear.org, third generation nuclear reactors are an evolution of the second-generation reactors typified by the current US fleet of nuclear power reactors. They use fuel more efficiently, produce less long-lived radioactive waste, and are designed for much longer operational lives. They also feature more robust passive and inherent safety features that obviate the need for mechanical active safety systems and make a meltdown nearly impossible. They also claim that this new generation of plants can be built considerably faster and at a lower cost than was ever possible in the past, thanks to pre-engineered modular plant designs that streamline the engineering and construction processes.

According to the International Atomic Energy Agency's (IAEA) Power Reactor Information System, there are currently 53 nuclear power plants under construction worldwide, but only one project is underway in the United States. This reactor, Watts Bar 2 in Tennessee, began construction in 1972 but was halted midway through construction due to decreased electricity demand. Construction restarted in 2007 and the reactor is slated to go online in August of 2012[12].

Nuclear Incentives

A powerful combination of new incentives for advanced nuclear power and looming fears about climate change may signal an imminent nuclear renaissance in the United States. Although an absence of new construction has been the norm in the nuclear industry over the last three decades, it seems the tides have turned in favor of new nuclear construction. The Energy Policy Act of 2005 (EPAct) authorized a variety of incentives for innovative, carbon-free power generation facilities, primarily third generation nuclear power plants.

One of these incentives was a total of $18.5 Billion in federal loan guarantees for new advanced nuclear power technologies and, according to a 2008 press release by the US Department of Energy, they had received applications for loan guarantees on 21 new nuclear reactors at 17 different power plants. In total, electric power companies had requested $122 Billion in loan guarantees for new nuclear power plants.

The EPAct also included a number of other potentially valuable incentives to new nuclear power facilities, including a production tax credit of $18 per megawatt hour for the first eight years of power production from the first 6,000 MW of new nuclear capacity built before 2020. If more than 6,000 MW of new generation, or about five nuclear reactors, are installed before 2020, the production tax credit will be prorated and split evenly among the operating plants. For example, if 12,000 MW of new nuclear capacity were built, the production tax credit would drop to $9 per MWh generated. For reference, the weighted average wholesale price of electricity in the US in 2007 was $57.20 according to the EIA.

Additional incentives included in the EPAct included limited liability for a nuclear plant disaster, preferential tax treatment of money reserved for decommissioning the reactor, insurance against delays bringing plants online, and a 50/50 split of costs for licensing and design of the first of a kind unit of each approved reactor design.

Ultimately, these government incentives provided in the EPAct could be the deciding factor for new nuclear power plant construction in the United States.

Economic Concerns

In fact, it now looks like greatly increased reliance on nuclear power will be a necessity for satisfying the emissions reductions required by the Waxman Markey Climate Change bill. The Electric Power Research Institute (EPRI) estimates in its 2009 Prism/Merge study that 64 gigawatts of new nuclear capacity, likely more than 50 new reactors, would be required to meet the 2030 emissions goals of the Waxman Markey climate change bill. This is *including* a variety of optimistic assumptions including[13]:

- Total power consumption will decrease by 8% due to increased energy efficiency
- Transmission and distribution losses will decrease by 20%
- Renewable capacity will expand to 135 GW (Approx 29 GW nameplate capacity currently—EIA)
- Carbon capture and sequestration installed on all new coal and gas plants after 2020
- Extremely efficient new coal and gas plants
- Retrofits of 60GW of current fossil fuel capacity with CCS equipment

- 100 million plug in hybrids on the road
- Low carbon electric technologies (like heat pumps, induction melting, arc furnaces) displacing 4.5% of direct fossil fuel use

Ultimately, it looks like nuclear is, at least in the near term, the most technologically mature, scalable technology for meeting the demands of a low-carbon economy. This is not to say that new nuclear power is a sure thing. It has some enormous obstacles to overcome politically, including waste disposal, nuclear arms proliferation, and public perceptions about safety. Equally important, nuclear power must prove itself to be economically viable. Although the marginal costs of nuclear power generation are low compared to fossil fuel fired power plants, the capital costs of a new plant are much larger, and since no new nuclear plants have been built in the United States for decades, nobody knows how much it will ultimately cost to get a new plant operational.

Throughout the period from 1966 to 1977, the average actual cost of a nuclear power plant was more than three times the initial estimate[14]. Nuclear power advocates have argued that these kinds of excessive budget overruns are a thing of the past due to new Nuclear Regulatory Commission rules allowing significantly more design work to be finished before regulatory approval, cutting down on costly mid-construction modifications to the plant design. More standardized plant designs and partially pre-constructed modules allow for less individual engineering design work for different sites, thus spreading engineering cost across more units and simplifying construction.

According to a MIT working paper, overnight costs for five new nuclear power plants built in Japan and Korea between 2004 and 2006 ranged in price from $2,357 to

$3,357. Keep in mind that Japan and Korea have significantly more recent experience building new third generation nuclear power plants. Six other plants built in those countries between 1994 and 2002 had estimated inflation adjusted overnight costs of between $3,222 and $5,072, according to an MIT update on the cost of nuclear power[17].

While these figures provide a baseline for comparison, they must be interpreted carefully. These plants were built in countries that have had significantly more experience building nuclear power plants in the recent past than the United States and have different component and labor costs than would be found in the U.S. Although adjustments were made to the calculations using a purchasing power parity conversion, this allows only for a rough estimate of how these costs would translate into an American built plant.

Cost estimates submitted by utilities for proposed US nuclear power plants vary widely, from as little as $2,930 per kW to $4,745 per kW[17]. These estimates are exclusive of any cost overruns. In all likelihood, any new nuclear power builds in the United States will be difficult to complete on-time and on-budget, as the industry will need time to adapt and streamline their design and build processes. Much as has been the experience in Korea and Japan, overall plant costs will fall over time as the industry gets more experienced and knowledgeable in building new nuclear power reactors again for the first time in decades.

Design Needs

In building a model to evaluate the economics for various power plant designs, it is important to take into account a number of factors in order to produce a valid outcome. First, it must account for all major costs involved in building and operating a plant. These include overnight construction cost, fuel cost, fixed and variable plant operations and maintenance costs, carbon costs, decommissioning costs, taxes, depreciation of the plant's value as an asset. Second, in order to produce an accurate picture of the plant's financial worth, this model needs to take into account inflation as well as a time value of money, i.e. the monetary return an investor would expect in exchange for their capital investment.

The model should be able to show, based on these variables, the income or loss generated by these assets and produce a result that enables comparison between investments in the varying plant technologies in different price and cost scenarios. Ideally, the output of the model will produce a range of numbers that allows for a straightforward comparison between options.

Methodology

Description of Economic Model

I built a discounted cash flow model that takes into account a multitude of variables to analyze power plants. Discounted cash flow analysis is an economic model of future capital expenditure that discounts future income and expenditures so that cash flows in different periods are comparable. The model incorporates variables found in standard discounted cash flow models, like capital expenditure, time to build, discount rate, tax rate, tax depreciation schedule, et cetera, but it also includes features like the nameplate capacity, utilization factor, heat rate, carbon emissions, and other features unique to power plants.

From these inputs, it calculates how much it will cost annually to run the plant and how much money will be brought in assuming an estimated average cost of electricity. The model then uses a net present value calculation to determine whether the return on investment will meet the expected return in relation to a project's opportunity cost of capital. The model also evaluates the plants to find a levelized cost of electricity – the price that power must command to make the plant break even. The levelized cost of electricity is a good way to compare different technologies, as it provides a uniform basis of comparison[15].

Keep in mind, however, that the model is lacking some features that affect the economics of various power plants. First is the cost of capital to build these plants. This model assumes 100% equity investment, meaning that no money is borrowed for the construction of the plant. This is not normally the scenario for building new power plants. Generally, the utility will make a significant equity investment in building a plant, but will borrow at least some portion of the funds necessary for construction. Depending on a variety of factors, including the maturity of the technology and government incentives like loan guarantees and production tax credits that reduce the risk of newer, less mature technologies, the cost of capital can change significantly. The expected rate of return would also be higher for a riskier investment. These factors, however, are outside the scope of this project and would require significant additional research to address adequately.

Additionally, the LCOE calculated by the model is a gross, rather than net LCOE, meaning that it is before taxes. Although taxes factor into different types of plants differently, these have an affect on the relative economics of different plants. For example, since the marginal cost of producing power is much lower in a nuclear power plant than a gas power plant, once the capital costs of that plant have depreciated, profit margins would be much higher in a nuclear plant and it would thus incur a larger tax burden. Although this clearly has an effect on the plant, it makes the LCOE more difficult to calculate and is a relatively small affect when compared with volatility of operating and capital costs, which is essentially what this model is examining.

Model Variables

The capital expenditure or "overnight cost" of a new power plant is the total cost of building a power plant literally overnight. Because of this, these costs need to be adjusted when spread over multiple years (as is the case in the construction of a power plant) to account for inflation in the costs of commodities and labor. In this model, the overnight cost is spread linearly over the period of construction for simplicity's sake.

The values used for overnight cost are all from in the Electricity Market Module (EMM), part of the Energy Information Agency's (EIA) 2009 Annual Energy Outlook. The overnight costs used are as follows:

Table 1 - Overnight Cost of Power Plants in Dollars per kW Nameplate Capacity

Technology	**$/kW Nameplate Capacity**
Natural Gas CC	948
IGCC	2378
Advanced Nuclear	3318

The total overnight cost of a new power plant is equal to the nameplate capacity in kW multiplied by the cost per kW. The EIA's Electricity Module also supplies annual operations and maintenance costs, both fixed and variable for all three technologies.

Lead-time for construction is also sourced from the EMM and is an extremely important factor in determining the economics of a new power plant or any other type of large capital expenditure. The longer it takes before income is realized from a project, the higher the expected future revenue needs to be in order to offset the discount in the value of that revenue due to the passage of time. For example, if you are looking for a return of 10% on an investment, in order to make a $100 investment worthwhile, $110 would have to be returned one year later, $121 two years later, $161 six years later, etc. The required revenue needed to make the investment worthwhile increases exponentially with time.

The heat rates for each plant, also sourced from the EMM, are important in determining how much fuel is required to produce a unit of electricity – the lower the heat rate, the less fuel necessary to produce a kilowatt hour of electricity. The heat rate is the energy content of the fuel required to produce one unit of electric power. Natural gas combined cycle plants have the lowest heat rates, and are therefore the most efficient. Nuclear has the highest heat rate.

Using the heat rate of the plant, one can determine how many BTU's of that fuel are required to produce a year's worth of electricity. By multiplying required fuel energy in BTUs by the price per BTU provides the total annual fuel cost.

Equation 1 – Annual Fuel Cost

Total Fuel Cost = (Heat rate BTU/kW)*(Fuel Cost $/BTU)*

(Nameplate Capacity kW)*(Hours per Year)

The forecasted fuel prices are also from the EIA, which provides price outlooks for coal and natural gas out to the year 2030. In order to allow for 20 years of operation in each plant, these fuel prices are extrapolated out to the final year by increasing the 2030 price with inflation. Fuel price for nuclear is set at $0.67/mmBtu as described in the MIT update on nuclear power[17] and increases at the general inflation rate plus 0.5% per year. The cost of nuclear fuel is not readily available because it is different for every plant depending on a variety of factors beyond the scope of this paper, including raw material cost, processing and enrichment cost, and how much fissile material is burned up in the reactor. Overall, fuel cost for nuclear makes up a very small share of the total costs for the plant, and therefore a small share of the total levelized cost of electricity.

Carbon emissions for nuclear power plant operations are essentially zero; therefore there is no cost of carbon or any calculations associated with carbon emissions from nuclear plants. However, it should be noted that there are carbon emissions associated with nuclear power in mining and transporting the fuel, for example. For coal and natural gas fired power plants, this is not the case. For natural gas, the carbon intensity in tons per BTU is value sourced by the EIA[16]. Carbon intensity is defined as an amount of CO_2 produced through the combustion of a certain energy value of a fuel – Natural gas, for example has a carbon intensity of 117.080 pounds per million BTU. This is equivalent to 0.0531071 tonnes per million BTU, which is a more appropriate value because carbon allowances will likely be issued in units of metric tons rather than pounds.

Different sources of coal have different compositions and therefore different carbon intensities. Therefore, a weighted average was determined for the carbon intensities of the major varieties of coal used in power generation based on their consumption in 2008 and was approximately 0.0948199219813118 tonnes/MMBTU.

To Find the CO_2 emissions in metric tons per megawatt of electricity generated, the equation below is used:

Equation 2 - Metric Tons of CO_2 per MWh

$$(\text{Carbon Intensity MT } CO_2/\text{MWh}) = (\text{Carbon Intensity MT } CO_2/\text{MMBTU})* (\text{Heat Rate BTU/kWh})*1000$$

To determine the annual cost of all the emissions from a power plant, Equation 3, below, is used.

Equation 3 – Annual Emissions Cost

$$(\text{Carbon Intensity MT } CO_2/\text{MWh})*(\text{Nameplate Capacity})*(\text{Utilization Factor x\%})*$$

(8766 hr/year)*(Average Price of 1 MT of CO_2) = (Annual Emissions Cost)

Results

Data/Analysis

In general, coal plants have a high up-front cost, especially IGCC because it is a new technology and not widely used commercially. They also produce the most carbon dioxide, but have relatively low fuel costs and a fairly stable supply base. Natural gas power plants have very low capital costs, can be built quickly, but have relatively high and volatile fuel costs, although fuel prices have been depressed lately. Nuclear is very cheap to produce power from, but has the highest upfront costs by far, takes the longest to build, and has the most propensity for delays.

Quantitative Cost Estimates

Figure 4 and Table 2 below, show the relative contributions of the main cost components contributing to the cost of electricity, including carbon dioxide at the prices estimated by the EPA. Note that the nuclear case is excluding the potential production tax credit incentive, which would decrease the LCOE somewhat.

Figure 4 – Base Case Breakdown of LCOE by Cost Components in $/MWh

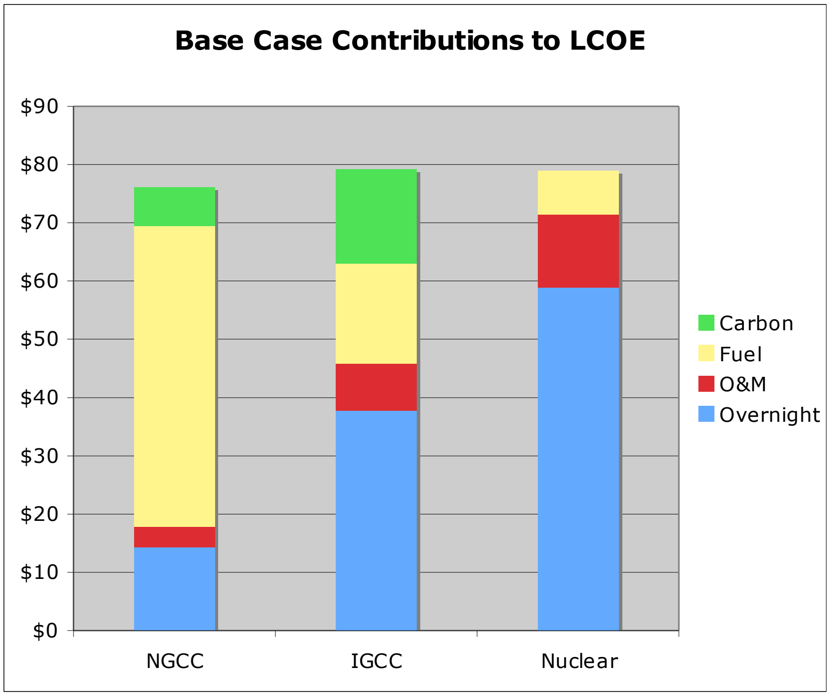


Table 2 - Base Case Breakdown of LCOE by Cost Components in $/MWh

	NGCC	IGCC	Nuclear
Overnight	$14.29	$37.74	$58.84
O&M	$3.57	$8.11	$12.57
Fuel	$51.51	$17.12	$7.51
Carbon	$6.73	$16.23	$0.00
Total LCOE	$76.10	$79.20	$78.92

Carbon pricing, fuel costs, and time to build were the primary factors analyzed for the three power plant technologies. Since coal and gas power plants are primarily affected by the cost of fuel and carbon dioxide, I evaluated the levelized cost of energy (LCOE) for each at three price levels: The baseline estimation of fuel and carbon costs by the EIA and EPA respectively, 67% of this cost, and 150% of this cost. The result is graphed on a three dimensional bar graph to show how the LCOE of each plant responds to these changing variables.

Figure 5 – Sensitivity of NGCC LCOE to Fuel and Carbon Prices

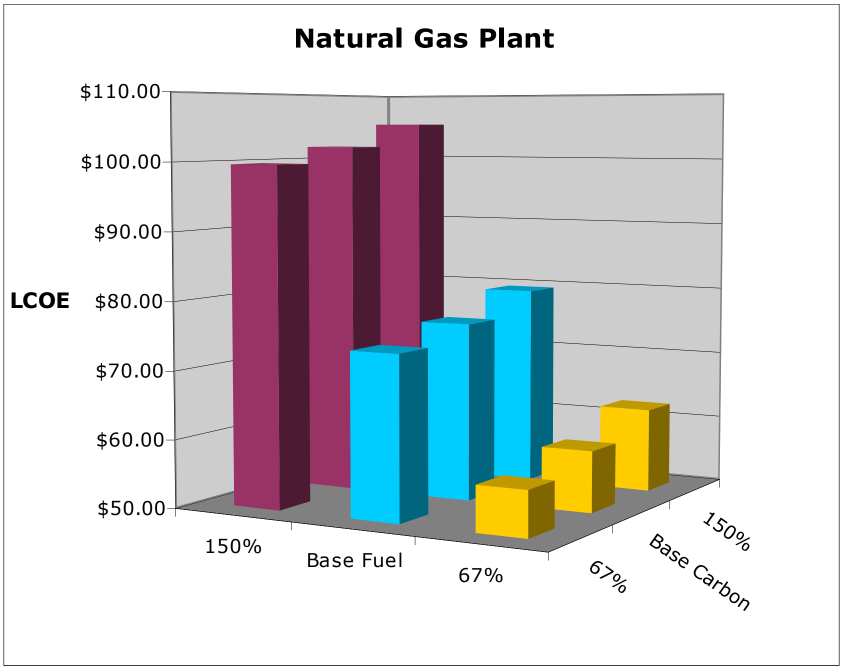
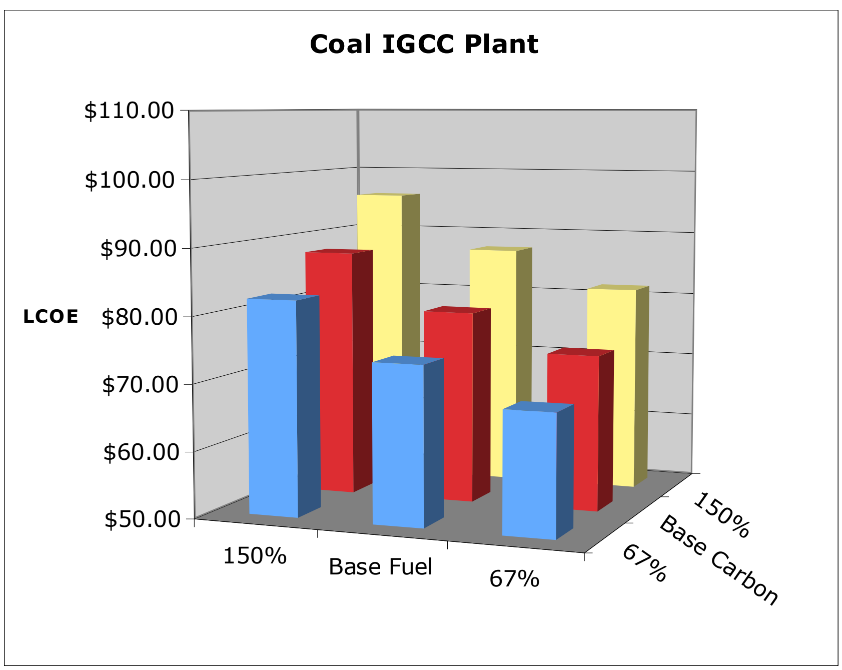
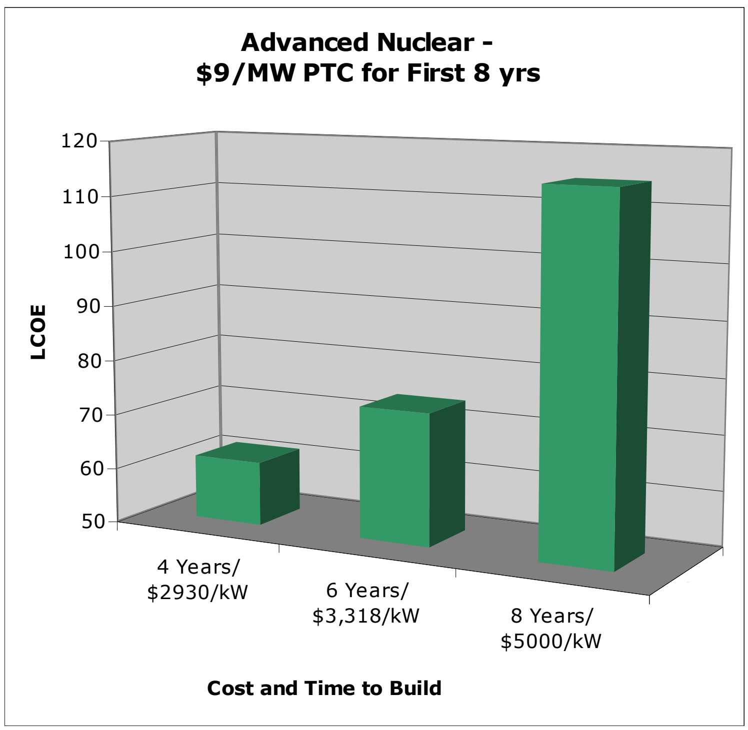


Figure 6 – Sensitivity of IGCC LCOE to Fuel and Carbon Prices



For nuclear, I only vary the cost and length of the project in order to represent best, expected, and worst case scenarios. This is because the marginal costs of running a nuclear power plant are relatively small in comparison to the upfront costs and time to build the plant. The best-case scenario is the lowest estimate of the cost for a new nuclear plant based on the MIT study on cost of nuclear power plant proposals in the US[17]. The worst-case scenario is based on the experience that the French nuclear power company Areva is having with cost and construction schedules on Olkiluoto nuclear power plant in Finland[18]. Clearly, the levelized cost of energy varies enormously based on construction time and cost.

Figure 7 – Sensitivity of Nuclear to Overnight Cost and Time to Build



In the base case, nuclear is cost competitive with coal and gas fueled power plants, however, as delays and added costs mount, the cost of energy from the reactor increases significantly. For example, with a $9/MWh production tax credit, the LCOE of nuclear using the EIA's estimates of time to build and overnight cost is $73.90 per MWh. Without this production tax credit, the LCOE climbs to $78.92 per MWh. One year of delay, with the same overnight cost, increases this by $3.51/MWh or about 4.5%. A two-year delay would add $7.32 to the LCOE, a 9.3% jump. These are likely conservative increases in comparison to real world delays, where delays are often accompanied by increases to the overnight cost of the project. The production tax credit could potentially be a very valuable incentive for the first couple reactors but the level of the incentive will depend on number and timing of reactors coming online.

Since fuel and carbon make similar contributions to the levelized cost of energy from IGCC, an increase or decrease to the price assumptions for fuel and carbon have a similar magnitude effect on the overall LCOE from these plants. For example, when the price of coal increases to 50% above the base assumption with no change to carbon, LCOE from an IGCC plant climbs from $79.20 to $87.31 – a 50% fuel price increase leads to a 10.2% increase in LCOE. When carbon costs climb 50% over the base case and coal prices stay constant, LCOE increases a similar amount, from $79.20 to $87.76, or about 10.8%.

This is in contrast to a natural gas power plant where carbon has a very small impact, but a variation in fuel costs from the original assumption makes a significant difference. In an example similar to the IGCC example above, when gas prices stay constant but carbon climbs to 50% higher than the base case, LCOE only rises by $3.37, or about 4.4%. When gas prices climb 50% higher than the base case, however, LCOE jumps by $25.76 – a 33.9% increase.

Although the cost of building a natural gas power plant is well known, the overnight cost of a nuclear or IGCC power plant is extremely difficult to quantify until there is more commercial experience building these plants in the United States. Since the overnight cost of the plants is a large contribution to the cost of electricity from both of these plants, this is significant (See Figure 4)

Fuel prices are also volatile. While fuel prices may be estimated, in the near term many factors affect energy prices so there is still a great deal of uncertainty. Predicting prices over a thirty year time horizon is futile. However, given the fact that future fuel prices are discounted, prices beyond the first few years of operations have a relatively small effect on the economic evaluation of the power plant.

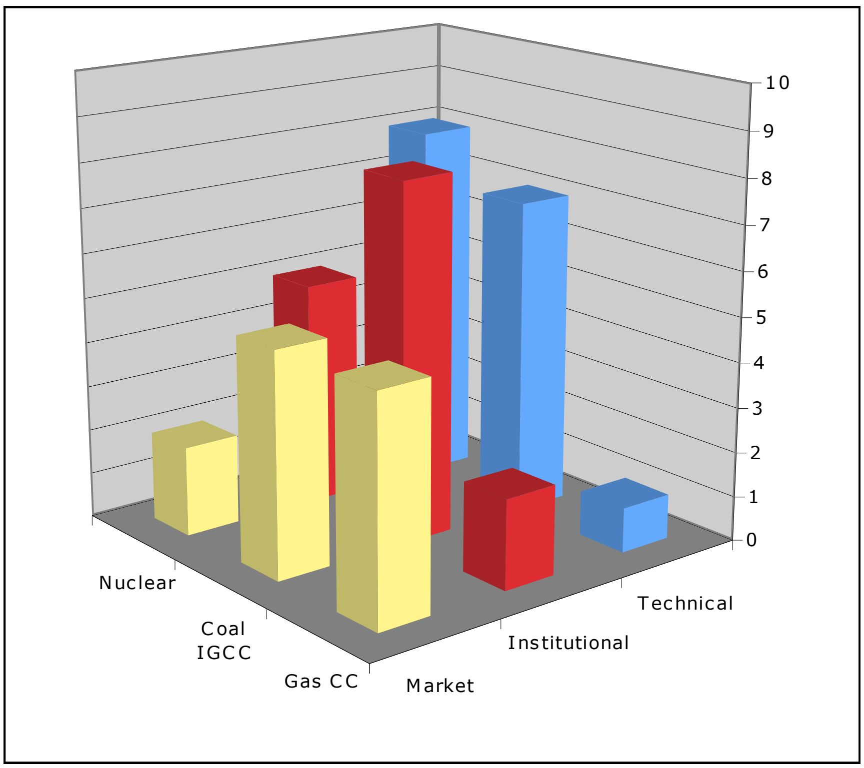
Finally, carbon prices for the United States are estimates from the U.S. Environmental Protection Agency (EPA) and are based on their evaluation of the effects of the Waxman Markey climate bill, however it is practically impossible to predict future U.S. carbon prices because climate change legislation has not been finalized. The EPA estimates of carbon costs seem conservative considering allowance prices in the European Union. The EPA estimate starts at $10.80 in 2012 and rises at a rate of 5% annually (in constant dollars). For reference, futures for 2012 EU emissions allowances traded at €16.11, or $23.95, on the European climate exchange as of 11/5/2009. This is more than double the EPA estimate and is significantly higher than the high cost assumption for carbon in this model. This may be a moot point, however, since Congress and the EPA will likely be able to manipulate allowance costs by adjusting the emissions caps if they feel the credits are placing undue stress on the economy.

Qualitative

Nuclear is most sensitive to construction time and cost overruns, but practically insensitive to fuel and carbon costs. Natural gas combined cycle plants are sensitive to fuel and, to a lesser extent, carbon costs. Of the three, coal is the most sensitive to the cost of carbon emissions, but is also sensitive to fuel and capital cost uncertainty.

For nuclear power plants, the economic risk is generated upfront and is concentrated in the first few years of the investment, as the plant is being built. Coal and gas fired power plants have longer term risks posed by fuel and carbon costs that will affect their operational profitability over the plant's life. Although the concept of upfront risks over a short period of time seems preferable, as of now, the magnitude of this upfront risk for nuclear is still unclear. It will not be until the next generation of plants has been built in the United States that there will be more certainty about the construction costs.

Figure 8 – Qualitative Evaluation of Risks to New Power Plants



In the figure 8, I have graphed qualitative risk values that I've assigned to each technology in each category based on criteria outlined by Lessard and Miller in their paper about project development risk evaluation[19]. This graph illustrates the varying market, institutional, and technological risks for IGCC, NGCC, and advanced nuclear power technologies.

Market risk is characterized by the possibility that the market electricity prices will be lower than the break-even electricity price to make a profit running the plant. Operations and maintenance costs (O&M) including fuel costs, are generally the marginal costs associated with running a plant. Since fuel costs are the most significant costs of power produced from natural gas plants, any market volatility in gas prices poses a significant risk to the economics of gas power. Fuel cost is less of a concern for coal plants since coal is much cheaper than gas per unit of energy, however, since it produces more carbon dioxide, it is more exposed to market risks stemming from a carbon dioxide cap and trade program, which would price carbon emissions. Nuclear, once it is built, has extremely low fuel costs and zero exposure to costs associated with greenhouse gas emissions from power plant operations.

Institutional risk is characterized by risks posed by governmental regulations and public perceptions. For nuclear, one risk is siting a plant, which requires regulatory approval from both the U.S. Nuclear Regulatory Commission as well the relevant state environmental and power authorities. These approvals in part are contingent upon the extent of opposition from local citizens in the area the plant is being built as well as opposition from others who have legal standing and may intervene in the regulatory proceedings. For example, this seems to be less of a problem in the Southeast United

States, since Georgia, Florida, and South Carolina are all pushing ahead with nuclear power projects. In Georgia both the legislature and the public utility commission will permit the utility that is building the new nuclear plant to recover from ratepayers construction costs for the plant while it is under construction before it produces any power[20]. It is unclear whether this model of ratepayers bearing the risk of construction cost would be followed in other parts of the United States.

Coal faces a similar problem with people opposing a new coal power plant being built near their back yards, but also faces risks from emissions regulations. Despite the low emissions of IGCC, it still produces higher levels of some regulated pollutants than natural gas combined cycle plants. These two factors may generate more institutional risk for coal than for nuclear.

Technological risk means that the technology may not perform as expected. For both advanced coal and nuclear, technological risk is generated from a lack of experience with a technology as well as uncertainty regarding aspects of the building process such as the reliability of the supply chain. For natural gas combined cycle power plants, technological risk is much lower, since all the parts are commonly available and these plants have accounted for most of the capacity additions over the last decade. Technological risk exists for nuclear power, since there is limited experience in the US building nuclear plants. It is also a problem for IGCC coal plants, since the technology is still new has not been widely implemented commercially.

Conclusion

Climate change legislation will be a powerful leveling factor in determining the economic viability of next generation base load power generation technology. Based on the quantitative analysis of the three technologies, the base case LCOE are within a $3.10 of each other, approximately a 4% range. However, as price levels for fuel, carbon, overnight cost, and government incentives vary, the resulting costs of energy diverge significantly.

Nuclear power, for example, is the cheapest source of power assuming a $9/MW production tax credit for the first eight year of operation, at $73.90. Without the production tax credit, it is almost exactly the same price as power from an IGCC power plant. With any delays in construction or increased overnight costs, both likely scenarios based on past experience, nuclear quickly becomes uncompetitive with any type of power plant at any level of fuel or CO_2 cost. Financing is a significant question with new nuclear power plants. Because these are multi-billion dollar projects, the financial risk to produce one of these power plants could threaten the financial security of even the largest electric utilities in the United States. Without government loan guarantees, the high risk of new nuclear plants could make project financing more difficult and expensive than for more established and well-understood power plant technologies.

Integrated gasification combined cycle coal power plants are cost competitive with natural gas in the base cases for fuel and CO_2 allowances. However, if the base case price of CO_2 allowances were closer to the current EU future prices, rather than EPA estimates, coal would no longer be competitive with natural gas. Moreover, there is still some uncertainty in the total overnight cost of an IGCC plant, so if it is higher than expected or the construction period is longer than expected, its LCOE would rise significantly.

With such uncertainty surrounding both nuclear and IGCC power plants, electric utilities will likely embrace the relatively more familiar risks involved in developing new natural gas combined cycle power plants. Natural gas power plants have a relatively small carbon footprint and are mature technology, so that the overnight cost and time to build may be more accurately estimated.

Natural gas plants do, however, carry significant risks. Between 1997 and 2009, the annual average price of natural gas delivered to electric utilities has ranged from as low as \$2.40 in 1998 to as high as \$9.35 in 2008[21]. With such volatility in prices, it is difficult to estimate future marginal cost of producing power. However, recent advances in natural gas extraction technology have allowed development of enormous, previously inaccessible domestic reserves trapped in shale and tight sand formations, causing natural gas prices to drop to their lowest levels in years and promising a steady supply for years to come.

In the near future, natural gas combined cycle plants seem to be the safest bet and will likely continue to make up the largest share of capacity additions among these technologies for some time. However, if mechanisms are developed to better allocate the risk of IGCC and nuclear, then there is a higher probability that those plants will be built, providing utilities with construction experience. Over time, this experience combined with greater regulatory certainty on climate change in the United States, will determine the competitiveness of advanced coal and nuclear with natural gas for base load power generation.

Appendix

Summary Of Inputs – Nuclear Base Case Example

Inputs

General	
Generator Type	Adv Nuclear
Model Start Year	2010
Days per Year	365.25

Macroeconomics	
Discount Rate	10%
Inflation Rate	0%

Prices	2010	2011	2012	2013	2014	2015	2016	2017
Natural Gas (per MMBtu)	$10.16	$10.40	$10.96	$11.13	$11.50	$12.00	$12.55	$13.18
Nuclear Fuel (per MMBtu)	$0.67	$0.67	$0.68	$0.68	$0.68	$0.69	$0.69	$0.69
Carbon (per Metric Tonne)	$0.00	$0.00	$11.46	$12.39	$13.40	$14.49	$15.68	$16.95

Plant Characteristics	Adv Nuclear
Heat Rate	10434
Carbon Emitted (Tons/MMBtu)	0
Carbon Emitted (Tons/MWh)	0
Nameplate Capacity (kW)	1,100,000
Utilization Factor	85%
Power Production (MW/Year)	8,196,210

Capital Expenditure	Adv Nuclear
CapEx Year	2010
Total Leadtime (Years)	6
Overnight Cost ($/kW)	$3,318
Total Overnight Cost ($)	$3,649,800,000

Operating Expenses	
Fixed O&M ($/kW)	$90.02
Total Fixed O&M	$99,022,000.00
Variable O&M ($/kWh)	$0.00049
Total Variable O&M	$4,016,142.90

Price Inputs Continued

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
$25.29	$26.36	$27.48	$28.64	$29.85	$31.11	$32.41	$33.76	$35.17	$36.62	$38.14	$39.71	$41.34	$43.04
$0.75	$0.75	$0.76	$0.76	$0.76	$0.77	$0.77	$0.77	$0.78	$0.78	$0.79	$0.79	$0.79	$0.80
$54.90	$59.37	$64.22	$69.45	$75.11	$81.23	$87.86	$95.02	$102.75	$111.13	$120.18	$129.99	$140.58	$152.03

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
$13.93	$14.62	$14.82	$14.86	$15.49	$16.11	$17.39	$18.58	$19.78	$21.00	$22.17	$23.16	$24.22	$24.25
$0.70	$0.70	$0.70	$0.71	$0.71	$0.71	$0.72	$0.72	$0.73	$0.73	$0.73	$0.74	$0.74	$0.74
$18.33	$19.82	$21.44	$23.19	$25.08	$27.12	$29.33	$31.72	$34.31	$37.11	$40.13	$43.40	$46.94	$50.77

Calculations Page Outputs – Base Case Nuclear Example

	Undisc. Total	Disc. Total	2010	2011	2012
MACROECONOMIC					
Discounting					
Discount factor - %			95%	87%	79%
Inflation					
Price inflation - %			0.0%	0.0%	0.0%
Cost inflation - %			0.0%	0.0%	0.0%
Inflators					
Price inflator - %			100.0%	100.0%	100.0%
Cost inflator - %			100.0%	100.0%	100.0%
Commodity Prices - Nominal Terms					
Natural gas price - $/MMBTU			10.16	10.40	10.96
Coal Prices ($/MMBtu)			0.67	0.67	0.68
Carbon Prices ($/Tonne)			0.00	0.00	11.46
PROJECT TIMING FLAGS					
Project Timing Flags					
Production flag	30	6	-	-	-
Capital flag	6	4	1	1	1
GROSS CASH FLOW					
Production					
Energy (MWh)	245,886,300	45,413,110	-	-	-
Revenue - Nominal Terms					
Power Revenue - $MM	-	-	-	-	-
Capital - Nominal Terms					
Total Overnight Cost ($MM)	3,650	2,672	608.3	608.3	608.3
Operating Expense - Nominal Terms					
Fixed O&M - $M	2,971	549	-	-	-
Variable O&M - $MM	120	22	-	-	-
Fuel - ($MM)	1,906	341	-	-	-
Total opex - $MM	4,997	912	-	-	-
Carbon Allowance Cost - Nominal Terms					
Carbon Allowances ($MM)	-	-	-	-	-
Gross Cash Flow - Nominal Terms					
Cash flow - $MM	(8,647)	(3,584)	(608.3)	(608.3)	(608.3)
Economic Metrics - Nominal Terms					
Negative cash flow - $MM	(4,627)	(3,082)	(608.3)	(608.3)	(608.3)
Positive cash flow - $MM	-	-	-	-	-
Cumulative cash flow - $MM	(199,009)	(37,332)	(608.3)	(1,216.6)	(1,824.9)
Project duration - years	666	99	1.0	2.0	3.0
Breakeven period - years	-	-	-	-	-
DISTRIBUTION OF CASH FLOW					
Cash Flow - Nominal Terms $MM					
Gross revenue	-	-	-	-	-
- Capex	(3,650)	(2,672)	(608.3)	(608.3)	(608.3)
- Opex	(4,997)	(912)	-	-	-
- Carbon	-	-	-	-	-
= Gross cash flow	(8,647)	(3,584)	(608.3)	(608.3)	(608.3)
Check = 0	-	-	-	-	-
Discounted Total Costs	**3,584**		608.3	608.3	608.3
LCOE	**$78.92**				

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
72%	66%	60%	55%	50%	45%	41%	38%	34%	31%	29%
0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
11.13	11.50	12.00	12.55	13.18	13.93	14.62	14.82	14.86	15.49	16.11
0.68	0.68	0.69	0.69	0.69	0.70	0.70	0.70	0.71	0.71	0.71
12.39	13.40	14.49	15.68	16.95	18.33	19.82	21.44	23.19	25.08	27.12
-	-	-	1	1	1	1	1	1	1	1
1	1	1	-	-	-	-	-	-	-	-
-	0	0	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210
-	-	-	-	-	-	-	-	-	-	-
608.3	608.3	608.3	-	-	-	-	-	-	-	-
-	-	-	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0
-	-	-	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
-	-	-	59.0	59.3	59.6	59.9	60.2	60.5	60.8	61.1
-	-	-	162.1	162.4	162.7	163.0	163.3	163.6	163.9	164.2
-	-	-	-	-	-	-	-	-	-	-
(608.3)	(608.3)	(608.3)	(162.1)	(162.4)	(162.7)	(163.0)	(163.3)	(163.6)	(163.9)	(164.2)
(608.3)	(608.3)	(608.3)	(162.1)	(162.4)	(162.7)	(163.0)	(163.3)	(163.6)		
-	-	-	-	-	-	-	-	-	-	-
(2,433.2)	(3,041.5)	(3,649.8)	(3,811.9)	(3,974.2)	(4,136.9)	(4,299.9)	(4,463.1)	(4,626.7)	(4,790.6)	(4,954.8)
4.0	5.0	6.0	7.0	8.0	9.0	10.0	11.0	12.0	13.0	14.0
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
(608.3)	(608.3)	(608.3)	-	-	-	-	-	-	-	-
-	-	-	(162.1)	(162.4)	(162.7)	(163.0)	(163.3)	(163.6)	(163.9)	(164.2)
-	-	-	-	-	-	-	-	-	-	-
(608.3)	(608.3)	(608.3)	(162.1)	(162.4)	(162.7)	(163.0)	(163.3)	(163.6)	(163.9)	(164.2)
-	-	-	-	-	-	-	-	-	-	-
608.3	608.3	608.3	162.1	162.4	162.7	163.0	163.3	163.6	163.9	164.2

2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
26%	24%	22%	20%	18%	16%	15%	14%	12%	11%	10%
0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
17.39	18.58	19.78	21.00	22.17	23.16	24.22	24.25	25.29	26.36	27.48
0.72	0.72	0.73	0.73	0.73	0.74	0.74	0.74	0.75	0.75	0.76
29.33	31.72	34.31	37.11	40.13	43.40	46.94	50.77	54.90	59.37	64.22
1	1	1	1	1	1	1	1	1	1	1
-	-	-	-	-	-	-	-	-	-	-
8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0
4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
61.4	61.7	62.1	62.4	62.7	63.0	63.3	63.6	63.9	64.3	64.6
164.5	164.8	165.1	165.4	165.7	166.0	166.3	166.7	167.0	167.3	167.6
-	-	-	-	-	-	-	-	-	-	-
(164.5)	(164.8)	(165.1)	(165.4)	(165.7)	(166.0)	(166.3)	(166.7)	(167.0)	(167.3)	(167.6)
-	-	-	-	-	-	-	-	-	-	-
(5,119.2)	(5,284.0)	(5,449.1)	(5,614.5)	(5,780.2)	(5,946.3)	(6,112.6)	(6,279.3)	(6,446.3)	(6,613.6)	(6,781.2)
15.0	16.0	17.0	18.0	19.0	20.0	21.0	22.0	23.0	24.0	25.0
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
(164.5)	(164.8)	(165.1)	(165.4)	(165.7)	(166.0)	(166.3)	(166.7)	(167.0)	(167.3)	(167.6)
-	-	-	-	-	-	-	-	-	-	-
(164.5)	(164.8)	(165.1)	(165.4)	(165.7)	(166.0)	(166.3)	(166.7)	(167.0)	(167.3)	(167.6)
-	-	-	-	-	-	-	-	-	-	-
164.5	164.8	165.1	165.4	165.7	166.0	166.3	166.7	167.0	167.3	167.6

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
9%	9%	8%	7%	6%	6%	5%	5%	4%	4%	4%
0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
28.64	29.85	31.11	32.41	33.76	35.17	36.62	38.14	39.71	41.34	43.04
0.76	0.76	0.77	0.77	0.77	0.78	0.78	0.79	0.79	0.79	0.80
69.45	75.11	81.23	87.86	95.02	102.75	111.13	120.18	129.99	140.58	152.03
1	1	1	1	1	1	1	1	1	1	1
-	-	-	-	-	-	-	-	-	-	-
8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210	8,196,210
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0
4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
64.9	65.2	65.6	65.9	66.2	66.5	66.9	67.2	67.5	67.9	68.2
167.9	168.3	168.6	168.9	169.3	169.6	169.9	170.3	170.6	170.9	171.3
-	-	-	-	-	-	-	-	-	-	-
(167.9)	(168.3)	(168.6)	(168.9)	(169.3)	(169.6)	(169.9)	(170.3)	(170.6)	(170.9)	(171.3)
-	-	-	-	-	-	-	-	-	-	-
(6,949.1)	(7,117.4)	(7,286.0)	(7,454.9)	(7,624.2)	(7,793.8)	(7,963.7)	(8,133.9)	(8,304.5)	(8,475.4)	(8,646.7)
26.0	27.0	28.0	29.0	30.0	31.0	32.0	33.0	34.0	35.0	36.0
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
(167.9)	(168.3)	(168.6)	(168.9)	(169.3)	(169.6)	(169.9)	(170.3)	(170.6)	(170.9)	(171.3)
-	-	-	-	-	-	-	-	-	-	-
(167.9)	(168.3)	(168.6)	(168.9)	(169.3)	(169.6)	(169.9)	(170.3)	(170.6)	(170.9)	(171.3)
-	-	-	-	-	-	-	-	-	-	-
167.9	168.3	168.6	168.9	169.3	169.6	169.9	170.3	170.6	170.9	171.3

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EDUCATION

The Pennsylvania State University, Schreyer Honors College — **University Park, PA**
Bachelor of Science in Engineering Science — *Expected Graduation: Dec. 2009*
Engineering Entrepreneurship Minor — GPA: 3.77/4.0

Relevant Coursework

Calculus I, II, III • Linear Algebra • Partial Differential Equations • Computer Math Methods • Quantum Mechanics
Electronic Circuits & Devices • Thermodynamics and Heat Transfer • Statics and Strengths of Materials • Dynamics
Tech Based Entrepreneurship • Entrepreneurial Leadership • Business Opportunities in Engineering • French III

National University of Singapore — **Singapore**
Summer Design Academy — *May – June 2008*
Learned about considerations in Engineering Design and worked in multinational teams to design an eco-friendly product.

EXPERIENCE

ConocoPhillips — **Houston, TX**
Intern, North American Gas and Power Trading — *June – August, 2009*

- Researched the impacts of proposed climate change legislation on future economic outlook for natural gas and power
- Analyzed project development economics of new gas and coal power facilities, accounting for sensitivities in fuel and CO_2 price levels to determine their comparative economic viability
- Studied relationships between coal and gas prices for current power generation facilities and analyzed likely future changes according to ConocoPhillips' long range price outlook for fuels and CO_2

General Motors — **Warren, MI**
Intern, North American Product Development — *May – August, 2007*

- Tested interior air quality of GM vehicles & evaluated their compatibility with pending Chinese import regulations
- Evaluated North American leather portfolio for stain resistance, worked with suppliers to test newly developed stain resistant leather finishes, and helped develop an upcoming stain resistance specification for new leathers
- Prepared internal report for circulation to GM's global engineering centers detailing performance of leather portfolio

The Pennsylvania State University — **University Park, PA**
Research Assistant, High Performance Materials Laboratory — *May – August, 2006*

- Researched high-performance glass and ceramic materials for use in the oil industry
- Produced samples according to procedure and prepared them for analysis by x-ray diffraction and electron microscopy
- Analyzed samples using a variety of methods, including helium pycnometry and diametral compression

The Wistar Institute — **Philadelphia, PA**
Research Assistant, Molecular Genetics Research Laboratory — *June – August, 2004 & 2005*

- Performed research on the effects of histone modifications on gene expression and replication in Dr. Shelly Berger's Lab
- Over two summers, I performed a variety of techniques for modification of genetic material including PCR, Purification of genomic DNA, immunoprecipitation, western blotting, and site-directed mutagenesis