Reducing US Greenhouse Gas Emissions through a Replacement of Coal with Natural Gas in Power Generation

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Abstract

Currently, coal provides about 50% of U.S. electricity supply and releases 80% of electricity sector carbon dioxide (Annual Energy Outlook Early Release Overview, 2009). A conceptual instantaneous switch to modern natural gas plants of the same capacity would reduce these carbon dioxide emissions by 74% or 1.5 annual gigatons (Gt) at the cost of $300 billion in construction capital and an increase in electricity rates of approximately 15%.

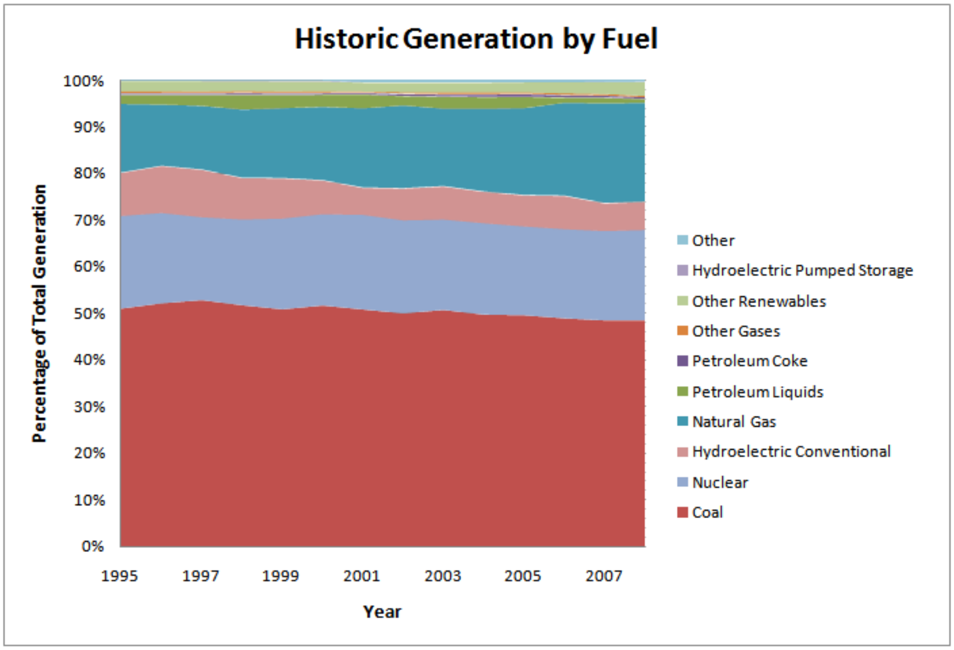
This analysis is accomplished primarily through a comparison of derived marginal cost functions for gas and coal generation under the assumption that fuel choice for baseload power is driven primarily by the lowest available cost of operation. The use of comparative supply curves clearly demonstrates the extent of the cost disadvantage of gas to coal and allows analysis of possible future scenarios through manipulation of model inputs of fuel and emissions permit costs.

In order for gas power to become less expensive than that from coal, either the price of gas must fall or the price of coal must rise. Two likely future developments might cause both of these changes to occur. Newly expected natural gas supply from unconventional sources and international trade of liquefied methane will put downward pressure on gas prices and ensure supply availability for an extended period. Perhaps at the same time, a U.S. federal climate law could introduce a price on carbon emissions which would disproportionately raise the price of coal power. This analysis shows that either situation will promote gas power if of great enough magnitude. The likelihood of a transition away from coal remains questionable but coal is no longer the obvious fuel choice in new baseload power plant construction.

Introduction

System planners choose a primary fuel for a new power plant based on many criteria. These criteria change depending on the operational role that the plant is intended to fill. These roles are diverse; ranging from hardly used non-spinning reserve generators to baseload plants designed to operate constantly at high levels of output. Ideally to utilities' profit margins, fuel choice would primarily be based upon operational costs. The cost of fuel is understandably a large part of a utility's operating expenses. For example, in 2008, fuel purchases represented about 42% of utility Duke Energy's operating expenses (2008 Statistical Supplement, 2009) and an even larger portion of variable costs as operating expenses include several fixed costs. However, under current technological and market conditions the least expensively operating plants such as coal, nuclear and large-scale hydroelectric (Electricity Market Module, 2009) are deficient in other criteria such as output ramp rates. If utilities decided to minimize operational costs and fulfill power demand through these sources alone, their combined level of output would be unable to vary to match load. This would result both in frequent outages and frequent periods of wasted over-generation. Federal standards require strict reliability (Reliability Standards for the Bulk Electric Systems of North America, 2010), forcing higher cost but more flexible power fuels such as natural gas on line.

Figure 1:



As shown in Figure 1, coal is by far the most widely used power fuel in America. In addition to nuclear and conventional large-scale hydroelectric plants, the three main baseload fuels provide three quarters of the nation's electricity. Natural gas already provides a large amount of power with growing market share; however, much of this power comes during times of peak and intermediate load.

Natural gas for electrical generation has several advantages over coal. Construction costs are lower on average and the aforementioned quick ramp rates allow for much more accurate load-following (Natural Gas Combined-cycle Turbine Power Plants, 2002; Electricity Market Module, 2009). Going forward, the most important criteria for which to choose natural gas over coal could be the former's reduced carbon intensity. A complete change from coal power to modern natural gas generation has the potential to reduce carbon dioxide emissions significantly. As greenhouse gas regulations cycle in and out popularity and probability of enaction, increased risk of disproportionately higher costs to coal generators rises and falls. Even without any actual charge for emissions, the possibility of this future cost is factored into a prudent integrated resource plan (IRP) by grid operators and capacity owners, thereby raising the expected price of coal generation over the life of the plant.

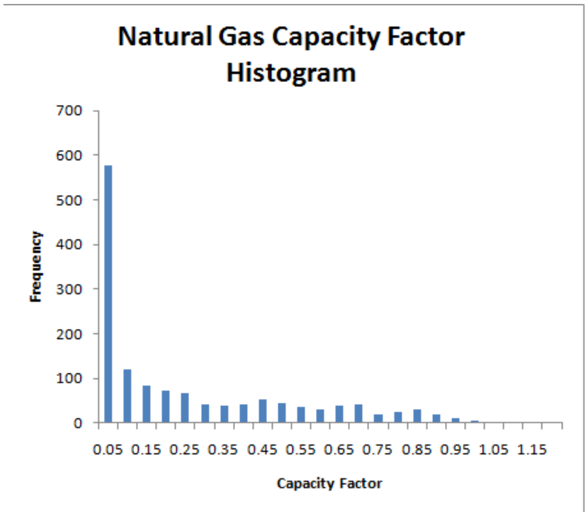
In this environment of new gas supply availability and potential legislative penalties to coal with unrestricted greenhouse gas emissions, study of the potential implementation of gas power in the baseload generation market is necessary. Coal has had a dominant market position in this power category for generations (Table 8.4b, 2009). Its advantages over other fuels are only shrinking to the point that its sole edge over natural gas is lower variable costs. This study attempts to quantify the extent of its cost advantage and suggest scenarios under which this barrier to gas expansion could be eliminated. The primary tool with which to analyze coal's marginal cost advantage over natural gas is with comparative supply curves. This relationship between output and marginal costs provides an intuitive framework with which to modify initial assumptions to predict the outcome in changes in the prices of inputs and the costs of emissions. While these curves are by necessity based upon past capacity, the addition of new capacity can be estimated through study of the available generation technologies allowing natural gas to rise in baseload market share. As technology continues to advance, natural gas will have the advantage over coal in the near term. This fuel will be the beneficiary of major advances in extraction, supply chain and generation developments. Until future use of carbon sequestration in coal brings it back to relevance in a time of greenhouse gas reductions, natural gas is narrowing its cost barrier to participation in baseload generation.

New sources of natural gas supply add another possible driver to the transition of fuel sources. Recently, domestic gas reserves have been revised upwards due to new extraction techniques allowing the possibility to extract vast amounts of gas from geologic shale deposits and tight formations. Extracting this gas requires the use of advanced techniques developed for oil extraction. In order to allow gas reserves to flow out of the reservoir rock more easily to allow for extraction, extremely high pressure fluids are pumped down the well. The pressure fractures the surrounding material, allowing gas to flow through the fractures to the collection well. Drilling rigs are also able to curve the well shape to near horizontal at the level of extraction allowing for a much longer well length within the reservoir and higher extraction rates. While the cost of extracting these reserves is higher than that of traditional extraction, the presence of increased reserves economically available above extraction costs will reduce the risk of supply constraints and reduce the volatility of gas prices. Estimates of market prices at which American unconventional reserves become economically available range from current prices to about $9 per thousand cubic feet (tcf) which is more than a 50% increase from current market rates (Natural Gas and Crude Oil Prices in AEO 2009, 2009; Nagarajan, 2009). Similarly, new investment in liquefied natural gas (LNG) capacity abroad allows widespread intercontinental trade in gas for the first time. Like shale gas, the added expense of liquefying, transporting and regasifying the hydrocarbons prices a large portion of this capacity outside of American spot prices. However, this presence of ample supply above a threshold price reduces the upside volatility in price expectations because increased supply drives prices down towards the cost of extraction. This reduction in risk is highly desirable to risk-averse utilities and further allows generation to shift away from coal.

Background on Existing Capacity

If new gas capacity is to replace coal power, developers will redispatch existing capacity to utilize more of the existing gas capacity as well as construct new capacity. Unused capacity exists because gas is used primarily during peak load hours.

Figure 2:



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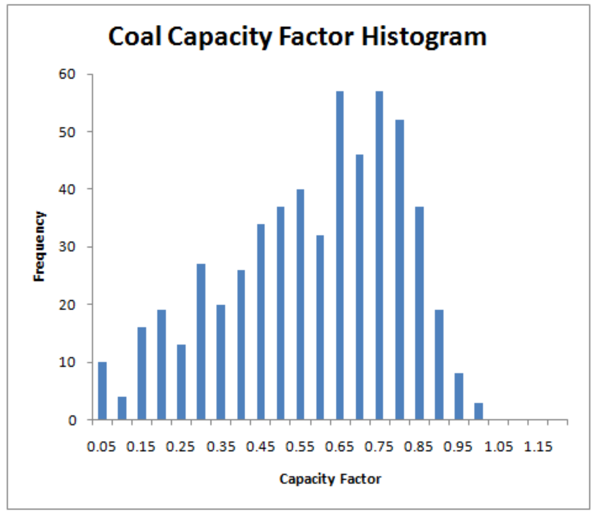


A look at the distribution of capacity factors across plants of both fuels shows this discrepancy between plant roles (Figures 2, 3). Capacity factor represents the actual amount of power output as a percentage of the total amount possible from the nameplate capacity of a given plant. The majority of gas plants have a capacity factor less than 5%, indicating that these plants are used only at times of highest peak demand or that they are used as reserve generators normally on standby ready to come on line during a contingency such as a plant or line outage. These plants will be able to operate more frequently if they can achieve a marginal cost of production lower than that of coal power, but only to a small extent as the plants are designed for infrequent use only. Conversely, coal plants tend to have a very high capacity factor, many with a figure over 60%, reinstating the fact that most are designed to run frequently to provide baseload power.

One significant advantage for natural gas power is the possibility for significantly improved efficiency over coal generators. While coal generators typically use simple steam turbines with efficiency levels of approximately 35% at best (eGRID, 2009), natural gas can more easily be used to drive a plant configured with a combined cycle system with thermal efficiency up to 60% (H System™ Turbine, 2009). With this design, the gas is first combusted to drive a steam or combustion turbine just as in a single-cycle system. The difference lies in the handling of waste heat which in a combined cycle mover drives a secondary steam turbine. (Natural Gas Combined-cycle Turbine Power Plants, 2002). This allows the design of gas plants to both counter some of the per heat content cost disadvantage of gas to coal as well as reduce the fuel's relative emissions per unit of output. However, many gas plants currently in operation use less efficient generation technologies.

Figure 4:

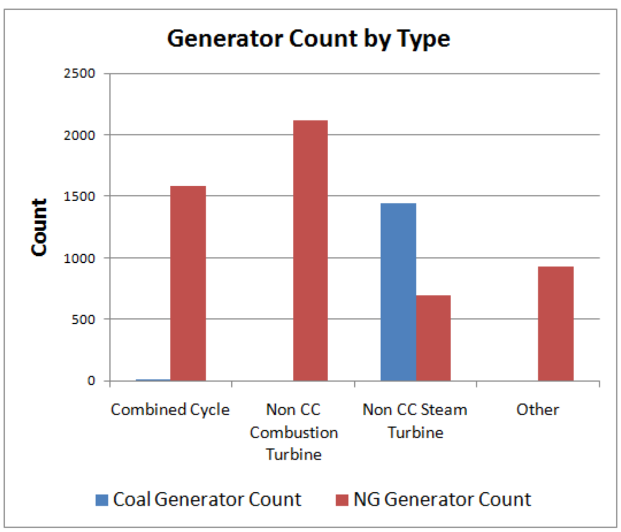
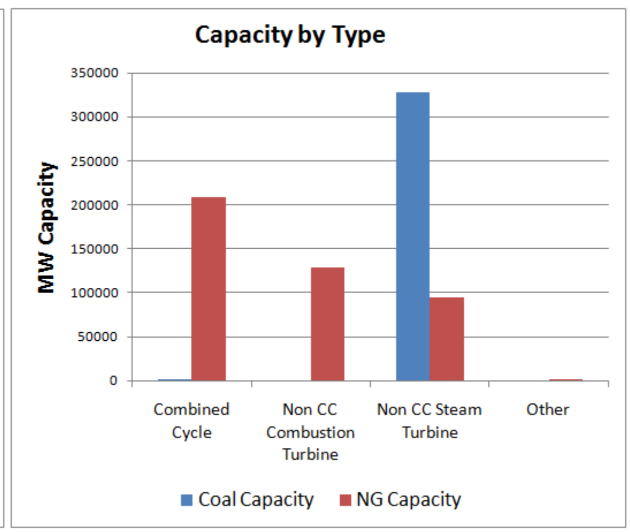


Figure 5:



Figures 4 and 5 show that while many current gas plants are combined cycle, a roughly equal proportion of the current fleet is single cycle. As older plants are retired or retrofitted, new plants should become more efficient over time as modern combined cycle plants replace retiring capacity.

In terms of efficiency, the current portfolio of gas generators is not using its technically possible advantage over coal plants.

Figure 6:

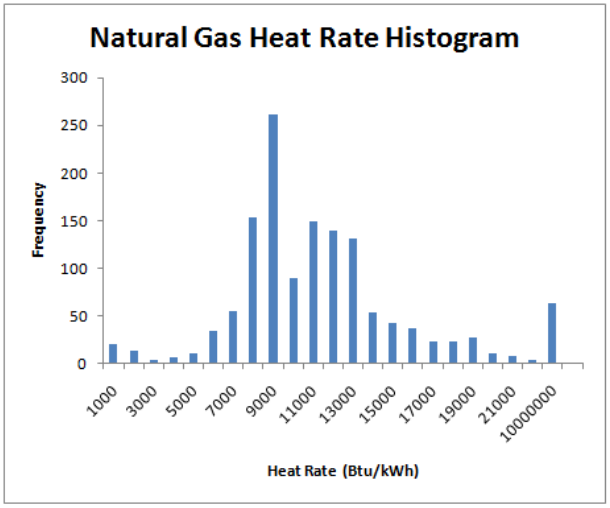
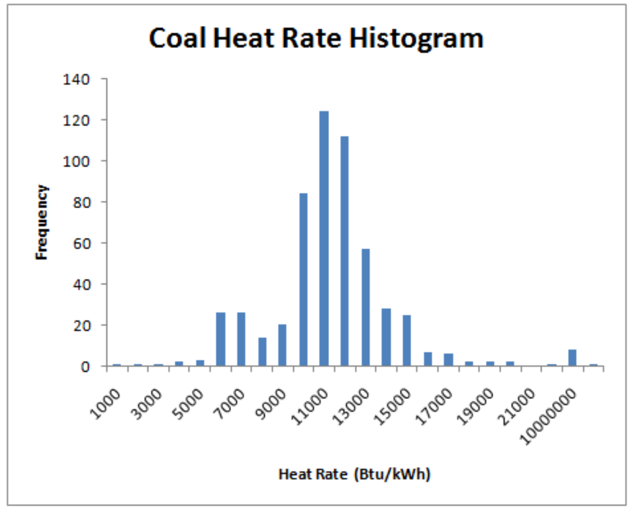


Figure 7:



A plant's heat rate is equal to the total heat input required to produce a unit of power output. A higher heat rate indicates a more inefficient plant as more heat is wasted without being converted into electricity. As shown in Figures 6 and 7, gas plants tend to be more distributed in efficiency than are coal plants which are clustered in a narrow band of operating efficiency. As a consequence of frequent output ramping due to their peaking function, some gas plants are very inefficient. Others are significantly less wasteful than the coal plant mean. This again indicates that there is possibility for improvement in the current natural gas generation fleet.

Methods

The core of this study consists of a derivation and analysis of supply curves for both fuels. This methodology is appropriate because plant operating marginal costs are the primary concern to capacity developers in the baseload power market. As power generation scheduling is fundamentally based on cost minimization before deferring to reliability management, plant marginal costs are critical to frequent operation and high capacity factors. Plant construction costs are of course fully considered in the new capacity planning process. If the developer can finance these high upfront costs on a plant with low operating costs, however, construction will likely move forward. The best example of this practice is the development of nuclear generators. Construction costs are extraordinarily high, but if the utility can afford this burden, the financial benefits of low future marginal costs are often enough to convince utilities to shoulder the risk. For this reason, the supply curve format presents the primary characteristics that drive plant fuel choice. As this study is limited to a comparison of coal and gas generation, these are the fuels selected for all analysis.

Marginal costs at a utility are largely dependent on fuel costs, however many other costs are invariably incurred. For the purposes of simplicity and reduced dependence on data availability, this analysis is limited to fuel costs, operation and maintenance costs, and potential carbon dioxide emissions costs. In reality, other costs such as taxes, permits for emissions of other pollutants, financing costs, transmission expenses and others represent potentially large portions of a utility's budget. As this analysis is a comparison between two types of generation, many of these costs would be similar and would not affect the conclusions. Future study should certainly account for any differences, but for the purposes of this exploratory exercise, the following marginal cost function is utilized.

$$MC = F + O + M + C$$

$$\begin{aligned}
&where: \\
&F = Fuel\ Cost \\
&O = Operation\ Cost \\
&M = Maintainance\ Cost \\
&C = Greenhouse\ Gas\ Emissions\ Cost \\
&(All\ components\ expressed\ in\ units\ of\ \left[\frac{\$}{MWh}\right])
\end{aligned}$$

$$F = \frac{(Q * P)}{AG}$$

$$\begin{aligned}
&where: \\
&Q = Heat\ Input\ [MMBtu] \\
&P = Fuel\ Price\ \left[\frac{\$}{MMBtu}\right] \\
&AG = Annual\ Generation\ [MWh] \\
&C = Emissions\ Price * [Carbon\ Dioxide\ Emissions + (21 * Methane\ Emissions) \\
&\qquad + (310 * Nitrous\ Oxide\ Emissions)]
\end{aligned}$$

This marginal cost statistic is paired with each plant's maximum annual capacity. This is calculated using a maximum 0.98 capacity factor for coal plants and a conservative 0.70 capacity factor for natural gas plants. These maximum capacity factors are reasonable approximations of the technical limits of each fuel technology as derived from 2007 data from operating generators (eGRID, 2009). As gas is not now used in a baseload role, these plants are not designed for full-time operation and will require substantial maintenance and down time resulting in a maximum capacity factor lower than that for coal. When all plants are ordered from lowest marginal cost to highest, the resulting plot of the relationship between marginal cost and capacity is known as the supply curve.

From the supply curve model, it is possible to alter input cost data to simulate alternative scenarios. This study is primarily concerned with the relative price difference between the two fuels and the possibility of a future price on greenhouse gas emissions. By altering the levels of these components, the supply curves shift based on marginal cost. Natural gas can be considered to compete with coal on a cost basis when the gas supply curve is even with that of coal on the marginal cost axis. For the purposes of this analysis, the breakeven price is that when a portion of natural gas capacity lies below a somewhat arbitrary "significant portion" of coal capacity in respect to marginal cost. This is judged as the standard of even competition because the objective of this study is to determine the price scenarios in which natural gas can largely increase its presence in the baseload power market. Ideally, the breakeven price should be that at which a specific threshold of coal capacity is more expensive than gas such as 50%, but the model currently lacks the ability to match this target precisely.

Looking forward to new capacity expansion, advances in generation technology present possibilities for greenhouse gas reduction. Refinement of the combined cycle configuration in natural gas generation raises efficiency levels significantly. In modeling the proposed expansion of natural gas power, a generator representing the most modern technology is used to provide an estimate of newly constructed natural gas capacity. General Electric's H System™ range of generators provides an appropriate proxy for the characteristics of new natural gas development in the coming years. Due to their large capacity (up to 400 MW) and high possible thermal efficiency (60%, compared to 35% for a typical coal steam generator), these turbines are capable of operating as baseload generation (H System™ Turbine, 2009; Heavy Duty Gas Turbine Products, 2009). Additionally, as they remain a natural gas turbine, they are flexible in output which could potentially displace some existing gas turbines that operate as intermediate or peak providers. These turbines are currently commercially available, and two generators have been installed in California which provides a realistic approximation of construction capital cost requirements (Inland Empire, No year published). Marginal costs for these turbines are derived from estimated fuel needs, greenhouse gas emissions and operating expenses and then plotted in the supply curve format using an unlimited supply of capacity as new capacity will be built as needed. Using the same methodology as the comparison between existing natural gas and coal generation, the point at which a significant portion of coal power becomes more expensive than that from these generators is used as the breakeven threshold.

In an effort to determine the theoretical emissions reductions possible from a switch from natural gas to coal power, a scenario is developed in which all coal capacity is immediately replaced by an equivalent capacity of H System™ turbines. While this is not possible, it provides an estimate of the target of greenhouse gas reduction as well as an estimate of the related costs.

Data

Most of the modeling in this analysis requires data to be aggregated at the plant level. This level of data is available for most of the marginal cost components except for operation and maintenance costs, for which this study uses estimates of average costs for plants using that fuel as feedstock as proxies. The majority of plant data is derived from the US EPA's eGRID database with 2005 data, the most recent year available (eGRID, 2009). Operation and maintenance costs are based on 2007 data from the EIA (Table 8.2, 2009). Table 1 includes initial base case assumptions on input prices.

Table 1:

Fuel	Source	Cost/ton(tcf)	$/MMBtu
Bituminous Coal	Central Appalachian 1/29/10	57.95	2.32
Subbituminous Coal	Powder River Basin 1/29/10	10.85	0.62
Lignite Coal	EIA Coal Prices and Outlook	16.50	1.27
Natural Gas	Henry Hub 1/29/10	5.59	5.42
CO2 Price		0	

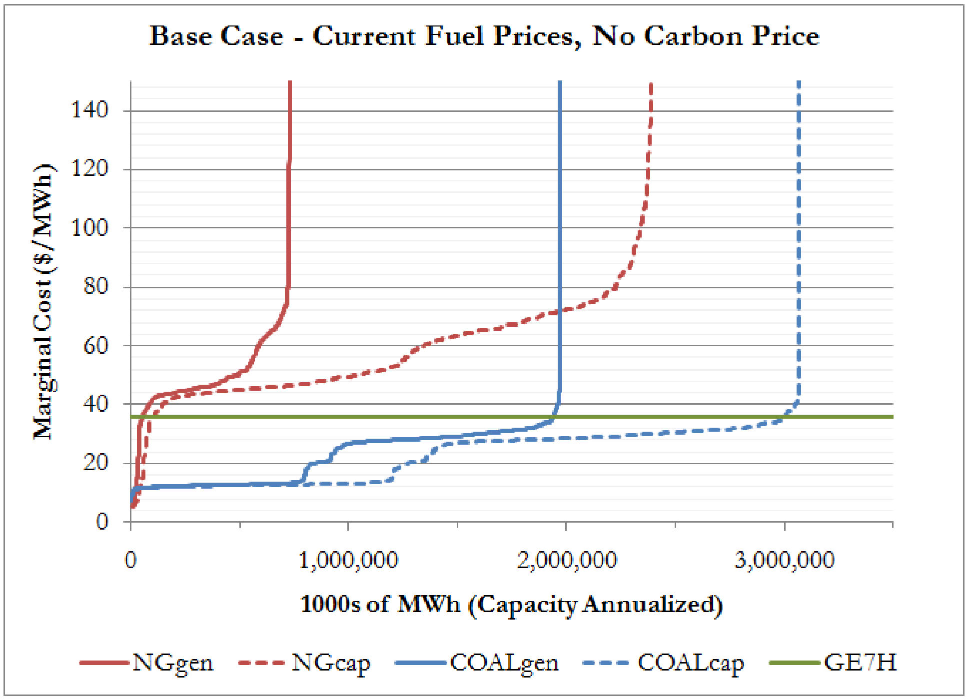
Prices are taken at the commodity exchange on January 29, 2010 (Coal News and Markets, 2010; Natural Gas Prices, 2010). In reality, there is a premium paid for transportation and intermediate handling before purchase by utilities, but for the purposes of this analysis the differences in these costs between fuel types should not affect fuel selection decisions. Background data on current generating capacity is available from the several Energy Information Administration sources (Annual Energy Outlook, 2009; CO2 History, 2007; Net Generation, 2010). Data concerning the H System™ turbine are found from publicly available GE documents (H System™ Turbine, 2009; Heavy Duty Gas Turbine Products, 2009) as well as news stories concerning plant construction (Inland Empire, No year published). Greenhouse gas global warming equivalence factors are from the EPA's TRACI tool (Tool for the Reduction and Assessment of Chemical and Other Environmental Impacts, 2009). Historical fuel prices are published by the EIA (US Natural Gas Wellhead Price, 2010; Table 7.8, 2008) with inflation adjustment data taken from the Bureau of Economic Analysis (Table 1.1.9, 2010).

Results

Baseline Results

The supply curves resulting from current price and operating conditions are represented in Figure 8.

Figure 8:



Primarily, the dashed capacity lines are the focus of this exercise as generation should be able to increase to these levels if the price and operating conditions are suitable. These supply curves can be read vertically with a lower line indicating lower marginal cost for a given amount of capacity. In the base case model with recent fuel prices and no price on carbon dioxide emissions, coal clearly enjoys a large operating cost advantage. There is hardly any natural gas capacity available at costs lower than those of competing coal generators. Even the most efficient H System™ turbine is unable to compete with coal on a cost basis, as its horizontal line lies above the majority of capacity in the coal market. Interestingly, natural gas generators possess nearly equal capacity as do coal, but most are operated at such low capacity factors that generation from coal so dominates the domestic fuel mix.

In these figures, both generation and available capacity are presented in order to show available idle capacity. The horizontal differences between the solid and dashed curves for each fuel represent capacity that is unused because of cost, technical and operational requirement constraints. Should the cost of natural gas power fall below that of coal, the gap between the natural gas generation and capacity should shrink as idle capacity is brought online to substitute for coal power. The figures indicate that there is enough natural gas capacity to replace coal generation, but not enough to maintain the current power output of natural gas and coal combined. If natural gas eventually enjoys a price advantage over coal power, new natural gas capacity additions will surely be necessary especially with consideration to the fact that most of these plants are not designed optimally for baseload operation.

Carbon Price Results

Increased price competitiveness between the two fuels becomes more likely in the future due to potential greenhouse gas legislation and new sources of gas supply. Without any mechanism to reduce carbon emissions from coal power plants, any price on carbon emissions increases the cost of generation at these plants disproportionately as compared to output from gas generators.

Figure 9:

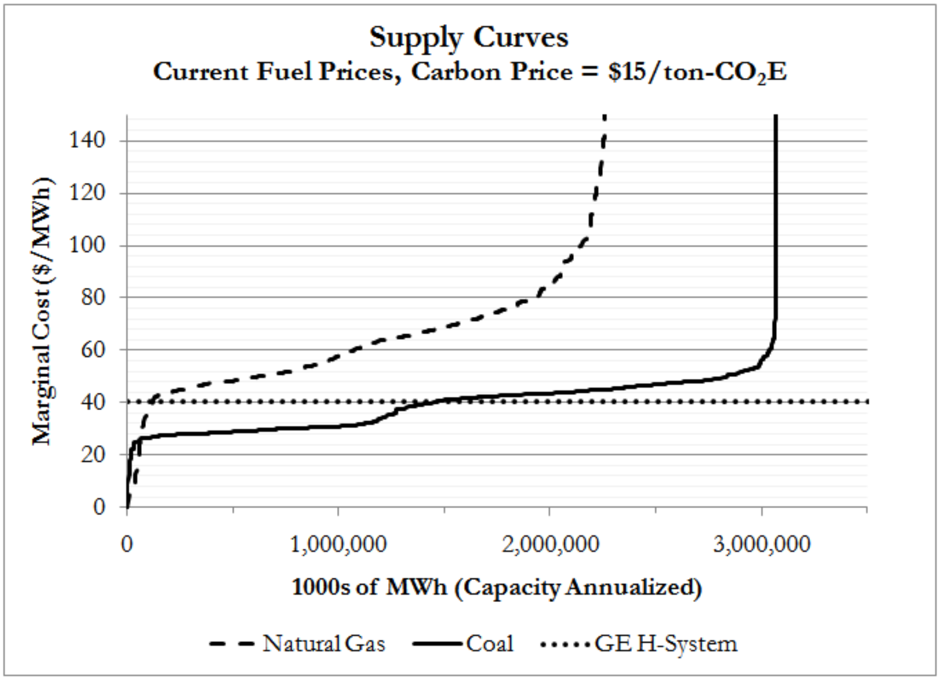
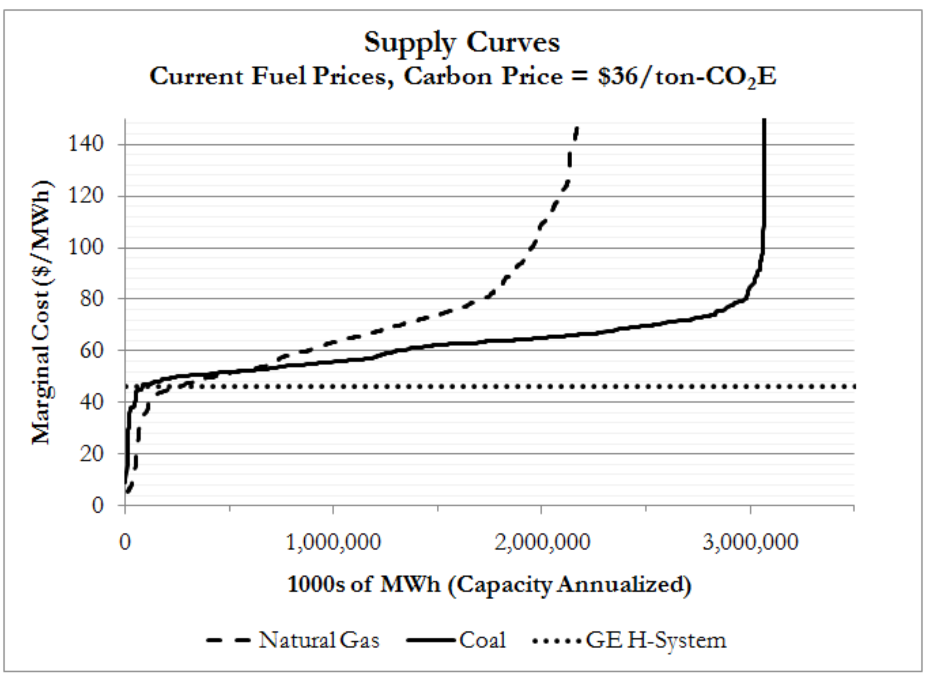


Figure 10:



Assuming current fuel prices do not shift, the implementation of a \$15/ton carbon dioxide-equivalent emissions permit price, a price likely shortly after the implementation of one proposed bill (H.R. 2454, 2009), does not seem to have much impact on the expansion of natural gas market share as shown in Figure 9. Even though this program would begin the costly process of internalizing the negative global effects of greenhouse gas emissions, the existing fleet of gas plants should be unable to compete with coal production. However, the most modern H System™ natural gas generators can but run less expensively than some coal plants. Operators of these plants should conduct a full analysis to determine if the financial benefit of slightly reduced operating costs justifies the investment in new generating units. Figure 10 shows that a higher carbon price of \$36/ton CO_2-e, a level likely after an emissions permit mechanism has time to mature (H.R. 2454, 2009), is likely to reduce the market share of coal by a partial replacement by gas and significantly reduce greenhouse gas emissions. As allowances approach this figure, the existing gas fleet outcompetes all but the cheapest operating coal plants. The modern H System™ generator is able to improve beyond this mark, indicating that using these generators would yield financial benefits to developers beyond those offered by coal fuel.

Increased Gas Supply Results

Developments in the gas supply will alter price characteristics of the natural gas market. New sources from shale gas reserves and international producers have the potential to reduce the relative price of gas to coal. The previous generation cost scenarios under varying carbon prices assume no change in the current price of gas and coal but the potential for a significant shift exists. With a given carbon price, it is possible to calculate a natural gas price that would allow gas to compete with coal in the power market. At this price, a significant portion of natural gas supply is available at lower cost than a portion of coal. This indicates that some existing gas capacity should be operated in baseload conditions and acquire market share from coal. This figure will be referred to as the "breakeven" price.

Figure 11:

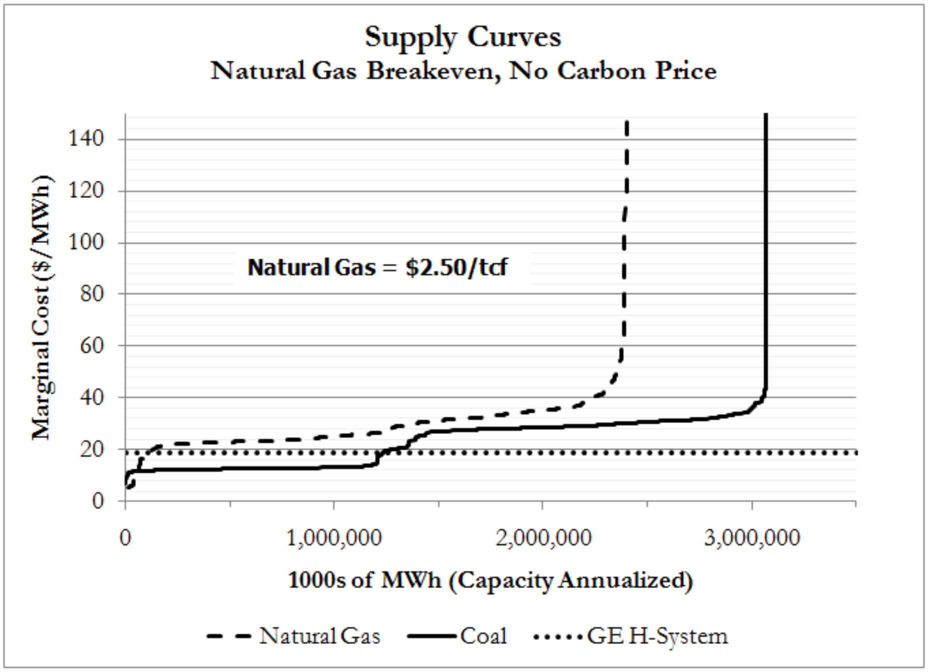
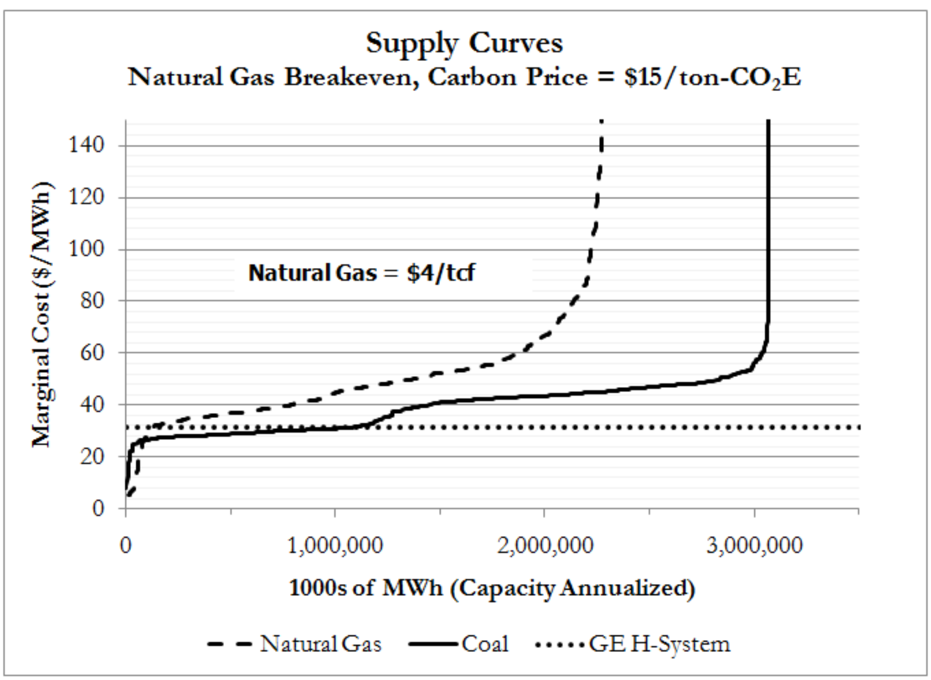


Figure 12:

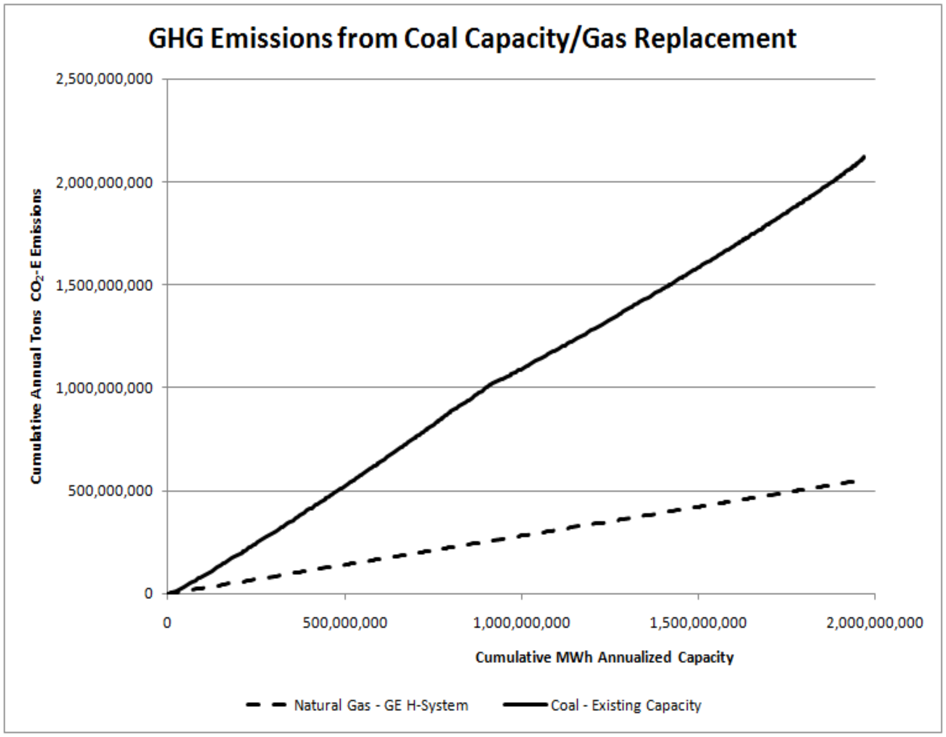


In each of these scenarios, the price of natural gas has been altered to reach a parity of competition between the two fuels. Without a price on carbon, natural gas would have to fall 55% from $5.58/tcf in the baseline scenario to $2.50/tcf in order for a significant portion of coal power to become more expensively produced than natural gas competition (Figure 11). This is unlikely to happen, especially without a corresponding change in coal prices as coal producers try to maintain their market share. A $15/ton carbon price leaves gas closer to competition where gas must only drop about 28% to $4/tcf in order to make significant entry into the baseload power market (Figure 12). As previously shown (Figure 10), a carbon price of $36/ton CO_2-e is sufficient for gas power to undercut that from coal in terms of production cost without additional gas supply.

Cumulative Results of Coal Replacement

Without considering the technical and political challenges of implementing a plan to replace existing coal capacity with modern natural gas generators, an analysis of the possible greenhouse gas reduction from such an undertaking provides substantial motivation. When contrasted with estimated cost, a more complete view of the overall results of this transition becomes apparent.

Figure 13:



The solid line in Figure 13 represents current emissions from coal plants. The dashed line represents the modeled emissions if the indicated coal capacity was replaced with the modern GE H System™ turbine. The right-side terminus of each line represents the possibilities resulting from replacing the entire existing coal plant with the selected gas generators. At this point, over 1.5 Gt CO_2-e of greenhouse gas emissions have been eliminated, representing a 74% reduction from the baseline coal emissions and more than a 25% reduction in total predicted 2010 greenhouse gas emissions. This complete transition away from coal is unlikely but these reduction figures have value as best-case targets. The environmental benefits of a more modest partial transition away from coal can be derived from calculating the reduction in emissions from reduced coal capacity minus the additional, lower, emissions from an equivalent amount of gas capacity.

While this reduction in GHG emissions has immense economic value, its attainment requires a large cost. In terms of construction capital, a complete replacement of the current coal fleet would require over 1,250 GE H System™ generators of 400 MW capacity operating at 0.70 capacity factor at a cost estimated at over $300 billion, as calculated from plant characteristics (Inland Empire, No year published). This assumes that theoretically all of these plants could be constructed overnight, without any estimate of financial cost or construction delays. In reality, the decision to fully replace coal capacity would result in many years of generator construction and installation. The capital expenditures would have to be amortized over the useful life of each plant and passed along to consumers in the form of increased electricity rates and possible higher taxes should the government decide to subsidize the transition. In a more realistic scenario, a portion of coal capacity could be replaced, which linearly reduces capital cost. In addition to initial start-up costs, these plants would run at higher marginal cost than the original coal plants given current fuel prices.

Figure 14:

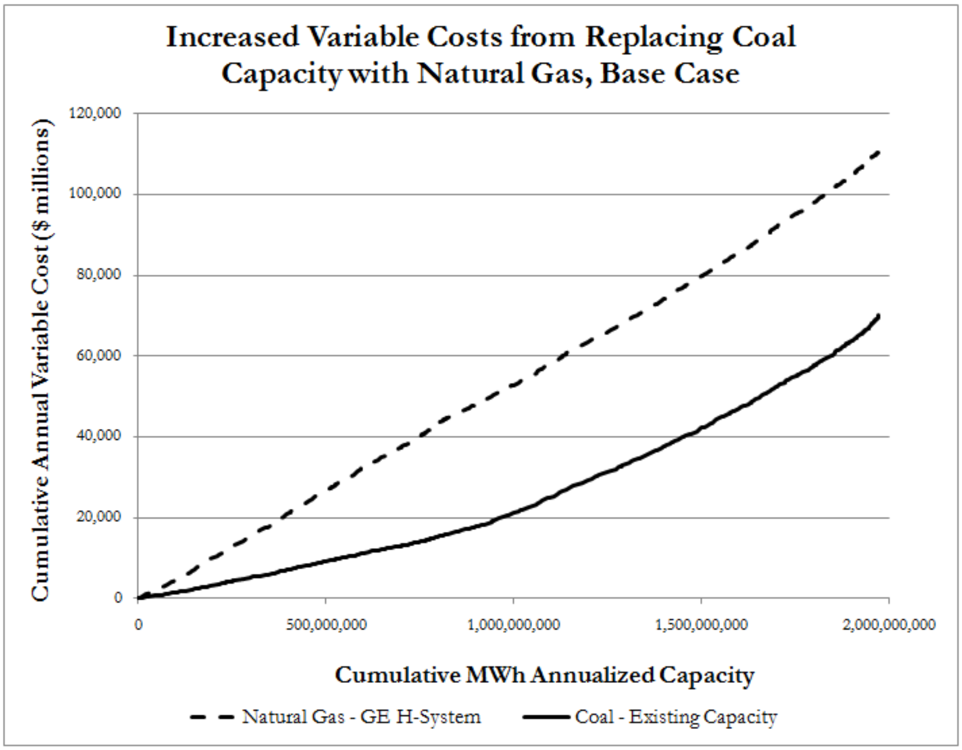


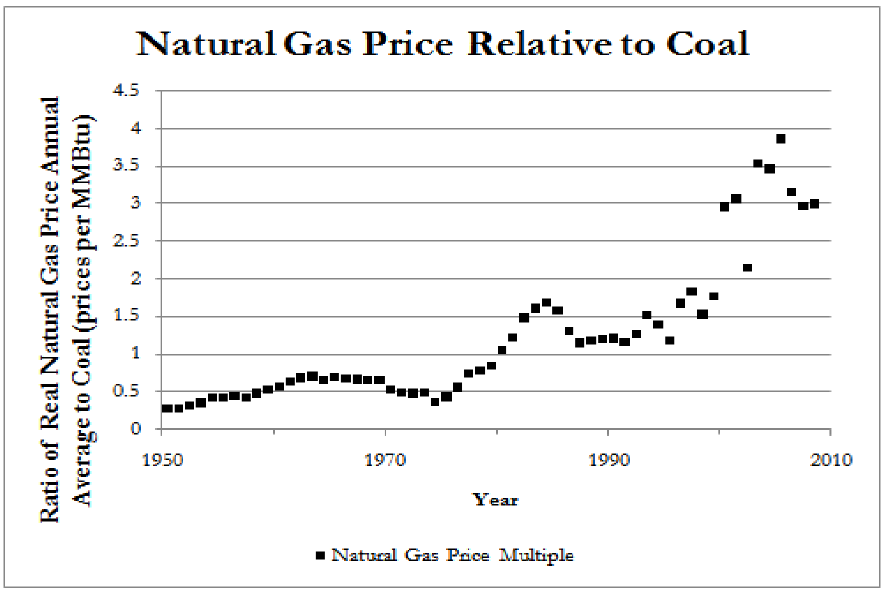
Figure 14 depicts the cumulative marginal costs of operating the existing coal fleet compared to those from operating H System™ gas generators. In the base case with current fuel prices and no carbon price, the replacement of all coal capacity would lead to an annual increase in baseload power cost of about $40 billion or 15% of 2008 utility operating expense in addition to the amortized rate increase due to construction expenses. Again, a carbon price would effectively work to reduce the cost burden by increasing the cost of coal in relation to natural gas.

Discussion

Historical Price Conditions

While gas and coal are related energy commodities and their price trends are therefore correlated, their prices respond to different market forces and have diverged in the past. The long term upward trend in the price of natural gas relative to coal is clear in Figure 15.

Figure 15:



By inputting historical prices into the supply curve model, it seems that the last time natural gas power could compete with coal on a marginal cost basis was during the early months of 2002. These low natural gas prices, however, were very short lived and quickly rebounded to a longer term equilibrium. Previous to 2002, however, natural gas prices were much lower than today as compared to coal. It is unclear why natural gas power did not expand further into the baseload power market but possible explanations include technical and domestic gas supply constraints. Looking to the future it seems unlikely that the price of natural gas will fall with respect to coal to prices low enough for a sustained period in order for gas to naturally displace coal generation.

Carbon Price

The likelihood of a price on carbon emissions has increased in recent years. The U.S. Congress has introduced several bills that attempt to implement this price though a permit-based system. The House of Representatives passed one likely candidate bill, H.R. 2454, more commonly known as the American Clean Energy and Security Act of 2009 or the Waxman-Markey bill, on June 26, 2009 (H.R. 2454, 2009). This bill places an $11/ton nominal price floor on carbon permits from 2012-2019. When corrected for inflation and the likelihood of permit demand, a price of $15/ton CO_2-e is a common estimate during this early 2012-2019 period. If the market for carbon emissions permits attracts additional demand and supply is constrained, the price could certainly rise much higher than this scenario. The Congressional Budget office suggests that prices will likely reach $36/ton CO_2-e in real 2005 dollars by 2030 (H.R. 2454, 2009). These price estimates form the foundation of the carbon price scenarios in this analysis. Of course, the exact likelihood of the enaction of any controversial legislative measure is unknown until the Presidential signature. It seems, however, that some sort of regulation on greenhouse gas emissions is likely in the near- to mid-term future. As described in this analysis, the replacement of coal power with natural gas is very sensitive to the price level of these emissions, and a price near the modeled $36/ton CO_2-e is much more likely to drive carbon reductions towards the upper targets. Legislative uncertainty reaches beyond the actual permit price in this situation, as well. Recent climate bills have contained widely-ranging provisions for permit allowances for specific industries. If the power sector is granted a high emissions allowance, a low degree of transition is likely.

Increased Gas Supply

Of course, fuel prices could change radically before any carbon policy is put into effect. As mentioned, domestic American gas supplies are projected to increase as newly economically recoverable unconventional reserves are discovered in shale formations. At the same time, global LNG capacity is rising, bringing with it the prospect of major intercontinental trade. While minor amounts of gas from both sources are now available, the majority of these new reserves will become viable once the threshold costs of costs shale gas extraction and LNG transportation plus profit margins are surpassed in the selling price in the gas market. The EIA estimates that enough unconventional reserves are available to keep natural gas prices in the $5-8/tcf (2007 dollars) range through 2030, with the possibility of lower prices if the cost of extraction falls (Natural Gas and Crude Oil Prices in AEO 2009, 2009). Another analysis indicates that some shale gas reserves are recoverable at prices lower than at present, but the majority of gas plays become economically recoverable closer to $9/tcf (Nagarajan, 2009). Before these reserves can enter the market, the selling price of gas must rise by over 50%, which is unlikely in the absence of a conventional supply shortage. Eventually, this situation is likely to occur which would force prices upwards and bring the new sources to market. In combination with a high price on carbon, power from even these increased natural gas prices could compete with carbon-intensive coal generation. Obviously, there is great uncertainty around the future of domestic unconventional reserves but great deal of analysis is likely given the immense value contained in these reservoirs.

Even though domestic U.S. reserves seem likely to satisfy demand for an extended period (Natural Gas and Crude Oil Prices in AEO 2009, 2009); they are dwarfed by international reserves. Energy company BP estimates that of total world proved reserves of gas, the U.S.

holds less than 4% (BP Statistical Review, 2009). Access to this gas is not easy, however. Only recently has large-scale LNG transportation made inter-continental trade of the commodity possible. As new markets open, purchasers face more diverse competition for supply contracts. Typically, prices are higher in Europe and Asia (BP Statistical Review, 2009) than in North America, causing much of the international trade to flow towards the most lucrative markets and an absence of LNG supply away from American markets (What role does LNG play as an energy source for the United States?, 2009). Until American gas prices rise to match those of global markets, LNG will not add significantly to domestic gas supplies. In times of future gas supply deficiencies, however, prices are likely to rise and LNG availability should have a dampening effect on the price surge.

In addition to changing characteristics of the power market, the introduction of climate legislation could be enough to influence fuel prices as well. Logically, if natural gas is able to compete with coal successfully due to the aforementioned possibility of a carbon price, more natural gas will be demanded putting upward pressure on gas prices. Fortuitously, the new gas sources of unconventional reserves and LNG importation should relieve some of this upward price influence. These new supplies could represent price ceilings as large amounts of the hydrocarbon become available above certain price thresholds.

Gas Supply Availability

Should the upper bound of a complete transition from coal to gas power eventually occur, consumption of gas would predictably rise considerably. This situation would likely require increased use of existing gas generation capacity as well as new capacity construction. For the purposes of establishing an estimate of supply availability, a modeled replacement of coal generation with H System™ gas generators is sufficient. In this scenario, U.S. gas consumption would rise by approximately 11 billion cubic feet of gas per year. This figure represents an increase of about 50% of 2009 gas use (Natural Gas Consumption, 2010). The EIA estimates that 1,588 trillion cubic feet of gas reserves exist domestically representing a 70 year supply at 2007 consumption levels (Natural Gas and Crude Oil Prices in AEO 2009, 2009). Even at an instantaneous elimination of coal power in favor of gas power from H System™ generators, this figure falls modestly to around 45 years of reasonable supply. In reality, the substitution of gas for coal would proceed much more slowly and reserves would support realistic use estimates for a period of a range between these two bounds. Global supplies of LNG will only vastly increase these estimates if international reserves become available to American markets. Supply availability should not be a prohibitive constraint to gas power expansion as already proven reserves provide assurance of gas throughout plants' operating life.

Challenges of Implementation

Interest in the potential for natural gas to displace coal is growing. The Congressional Research Service recently issued a report (Kaplan, 2010) investigating the possibility of redispatching existing gas capacity in order to displace coal. This study focuses mainly on the technical feasibility of such a change and concludes that significant barriers to increased gas plant utilization exist in transmission. This study indicates that only few existing gas plants are located near enough to coal plants so that increased gas generation could flow over the same transmission lines in a similar configuration as it does from existing coal power. Significant further study is required to determine the additional cost of the new transmission required to displace coal power either partially or entirely.

Even if the cost of gas power becomes economically preferable, a major amount of capital must be mobilized to develop new gas capacity. This could be a challenge to typically conservative utilities. These plants must be sited and constructed around the country which would take many years representing increased financial costs. In regulated markets, public utility commissions must allow the new investment and adjust rates in order to provide financial support to the developers. An additional technical consideration exists because gas is delivered to power plants through pipelines. As gas plants are already very widely dispersed, it should not be an insurmountable challenge to link new plants to existing pipelines. In many cases, developers can simply add new generators to existing plants.

Even if gas power becomes more economical and less environmentally detrimental than coal, there will be powerful interests against the transition between fuels. Between the coal, utility and railroad interests, large amounts of money will be spent on lobbying Congress to reduce the push away from coal. This will likely result in increased emissions permit allowances to coal users and regulations to make it difficult to reduce coal use in the future. If Congress remains intent on reducing greenhouse gas emissions, it can provide funding for carbon capture and sequestration technology which would allow coal to produce nearly carbon-free power. One study projects that the costs of carbon capture and sequestration will begin around $100-150/ton CO_2-e and fall to $30-50/ton CO_2-e as technologies mature (Al-Juaied and Whitmore, 2009). If the price of carbon capture and sequestration falls below that of unsequestered natural gas generation, as it will above a certain emissions price threshold, the prior technology will attain market penetration over the latter.

Analysis Limitations

This study represents a top-down generalized survey of the entire combined gas and coal power markets. As such, it uses broad methods. Importantly, the analysis assumes a pure economic dispatch of generation in which plants are selected for operation based on operational costs alone. In reality, the ability to match load fluctuations, exceed reliability standards and operate within transmission constraints will force a different call order. This analysis ignores this practice in favor of an attempt to determine system-wide underlying costs of generation from different fuels. While the data requirements of determining the cost disadvantage to natural gas with more accurate dispatch model are daunting, such a study should be attempted by an organization with access to this information. Additionally, more detailed financial analysis is certainly required to more accurately model marginal costs at each individual plant. This includes developing a tax model, considering non-greenhouse gas emissions costs and including financial costs in all new investment. Also, reliability of the power system is its primary goal. Any transition away from the most-used baseload fuel should be subject to detailed study on affects to reliability. As the markets for power, coal, gas and every input to the power system are highly linked, there should be some accounting for this in the model methods. If demand for natural gas power increases as coal falls, the price of gas will increase and that of coal will decrease which could result in an equilibrium of lower gas penetration than originally predicted. Ultimately, the decision to use natural gas as a fuel source instead of coal will be made at the individual plant level. Specific considerations at each site will promote one technology over the other or perhaps a different technology altogether. Any study that attempts to predict the trends of the industry as a whole must make certain generalizations in order to incorporate the most relevant considerations into a model.

Conclusions

Perhaps as expected, natural gas faces a cost disadvantage to coal that serves as a barrier to entry in baseload power generation. Without the introduction of a legislated mechanism to impose a cost on greenhouse gas emissions, it is unlikely that the price of natural gas will decrease enough to compete with coal in the provision of power. New discoveries for unconventional extraction of gas and the possibility of international LNG trade will provide security to current gas consumers and reduce potential supply deficiencies in the case of increased gas use, but will most likely fail to produce the degree of price change required for new utility consumers to transition away from coal.

Creating an effective price on carbon through legislation is certainly one viable tool with which to change the current plant portfolio but the effective level of this price is critical to the regulation's success or failure. In the absence of such a mechanism, a complete transition away from coal would increase American electricity prices by over 15% simply from additional marginal generation costs in addition to over $300 billion in construction capital. This analysis shows that carbon prices must reach the upper target of $36/ton CO_2-e as proposed in recent legislation before natural gas power displaces a significant portion of coal baseload generation at a cost low enough to incentivize utilities to act. While a lower carbon price could seem suboptimal in the short term, political reality suggests that the implementation of any price on carbon is a tremendous achievement and policy can be adjusted in the future to reach more aggressive targets of greenhouse gas reduction. In combination with the potential for increased gas reserve putting downward pressure on natural gas prices, there is a small possibility that price towards the lower $15/ton CO_2-e could be sufficient to increase gas power penetration in the baseload market.

Although unlikely, a complete transition from coal to natural gas power would save approximately 1.5 Gt CO_2-e representing a 25% reduction in total U.S. greenhouse gas emissions. This reduction is quite impressive considering that the suggested fuel transition relies purely on existing technology and retains a fossil fuel the major source of baseload power. Of course, it is very unlikely that coal power production would completely cease and also that natural gas would be the sole fuel to replace it. If natural gas power can be produced at a lower marginal cost than coal, however, it will achieve very high penetration and the emissions reduction will eventually approach this upper target as new gas capacity expands.

Any shift in fuel choice tendency must be supported by convincing motivation. To a utility, motivation exists in the form of reduced generation costs as well as reduced risk. This second concept could be more relevant in the likely short- to mid-term scenario where new gas sources come into production and the effective carbon price does not reach levels high enough to promote gas over coal use on terms of cost alone. Risk-averse utilities should welcome the reduced volatility introduced by the price ceilings resulting from large supply availability over threshold prices as a reduction in price fluctuation represents real value. If, as seems unlikely, the volatility of natural gas prices can be reduced below the corresponding volatility in coal prices, utilities could choose gas as a baseload fuel even if expected marginal costs are slightly higher.

When all of the likely future possibilities that could influence the relative market share of coal and gas power are taken into account, the balance seems to lean towards an increase in natural gas market share. In the current environment, this trend would come at significant cost but has the possibility for remarkable improvements in power sector greenhouse gas emissions. If changes in gas supply are able to reduce relative prices or volatility as compared to coal or if carbon becomes more stringently regulated, natural gas is poised to become a creditable baseload power fuel. While not as environmentally neutral as more advanced renewable power technologies such as solar or wind, natural gas generation relies on long-proven technology and possesses highly desirable technical operating characteristics. If society is to internalize the true cost of fossil fuel combustion, natural gas is uniquely positioned to become the transition fuel between coal and carbon-free sources.

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