Mapping Energy Futures:
An Integrated Economic, Engineering and Environmental Approach to Electric Power

John Taber
Cornell University
November 2011

ABSTRACT

There are a number of national energy models used for investment planning and studying the effects of proposed environmental policies on the electric grid. No model to date has included data about actual generators, a network model for the electric grid, and emissions. In this study, the SuperOPF, a full AC optimization/simulation framework with optimal investment developed at Cornell University is used to study the effects of regulations on the Northeast power system. The Northeastern power system is represented by a simplified system of 36 nodes, which offers a compromise between computational tractability and accuracy, particularly in modeling the limits on important inter-system transmission lines.

In this paper, I study the effects of a number of policies that aim to reduce CO_2, other emissions, or otherwise impact the operation of the electric grid: a base case, with no new environmental legislation; enactment of the Kerry-Lieberman CO_2 allowance proposal in 2012; following Fukishima, a retirement of all US nuclear plants by 2022 with and without Kerry-Lieberman; marginal damages from SO_2 and NO_X emissions charged to coal, gas and oil-fired generation; plug-in hybrid electric vehicle load filling; wind incentives in place; and two cases which combine these. The cases suggest that alternative policies may have very different outcomes in terms of electricity prices, emissions, and health outcomes. In all cases, however, the optimal strategy for future investment is investment in new natural gas combined cycle plants. Policies can change how much new generation is built, whether other plants are built, or what types of plants are retired.

Acknowledgements: I greatly benefited from the guidance of William Schulze, Antonio Bento, Gregory Poe and Benjamin Ho. I would also like to thank Ray Zimmerman, Richard Schuler, Daniel Shawhan, Charles Marquet, Kale Smith, Andy Kindle, the members of the E3RG at Cornell University for their input, and especially Jamie Rubenstein Taber for her comments and support. Support for this study was provided by the Power System Engineering Research Center and the U.S. Department of Energy through the Consortium for Electric Reliability Technology Solutions (CERTS) program. All errors, opinions and conclusions are the sole responsibility of the author.

Introduction

The electric power industry in the United States will face a number of challenges in the coming years. To facilitate energy independence, energy usage may swap from the transportation sector to the electricity sector with the addition of plug-in hybrid electric vehicles. Increased electricity loads may also arise as other energy users try to find sources of energy that emit less CO_2. Restrictive caps on CO_2 emissions from generation, and the possibility of regulations on the emissions which cause fine particulates will affect the electric generating industry and the usage of the electric grid. Finally, an artificial cap on offer prices in electricity markets prevents a free market solution for optimal investment, which requires ancillary markets in reliability, capacity, and planning.

Several energy and electricity planning models exist, though none of them have both integrated environmental modeling and a model of the electric grid that incorporates enough real-world engineering constraints to accurately model power flows. For example, the ICF's Integrated Planning Model (EPA 2011) is used by the EPA to estimate the effects of environmental policies on the electric grid, including the Cross-State Air Pollution Rule and the Transport Rule. However, while the IPM does have very detailed information about every generator in the United States including information about emissions for various pollutants, its transmission model lacks essential details. The IPM breaks the continental United States down into a few dozen regions for analysis. Within each region, transmission is unconstrained, and power flows between regions are constrained by aggregate flow limits. This model ignores the structure of the electric grid entirely, replacing it with a "bubbles and pipes" model for ease of analysis. The Resources for the Future Haiku model (Paul and Bertaw 2002) also uses constraints between regions to model flow limits, and uses "46 model plants" to estimate generation technology. The National Energy Modeling System (NEMS) supported by the Department of Energy has neither integrated modeling of air quality or a model of the electric grid (EIA 2009). These planning tools are useful, but may fail to capture the full impact of new policies because they ignore the realities of the electric grid, which constrain the ability to minimize costs and dispatch cleaner sources of energy.

The reduced network model of the electric grid described in this paper includes complete information about every generator in the Northeast Power Coordinating Council (NPCC), as well as an equivalenced model of the underlying electric grid. It may be used to model policies that may change the cost of generation, demand for electricity, and generation mix. Nine cases are analyzed to show the possible uses of this model, which use one or more of the following changes to the electric grid: a proposed carbon cap-and-trade law, the elimination of nuclear power plants, incentives on renewable electricity, emissions taxes based on marginal damages, and the addition of electric vehicles to the electric grid.

The remainder of this paper is organized as follows. In the next section, I describe the optimization problem solved to optimize investment and generator dispatch. A description of the network model for the electric grid and information about generators is also provided. In the third section, I describe the policies modeled to produce the nine alternative cases. In the fourth section, I discuss the results of each of these cases and compare them. In the final section, I provide conclusions.

Model Description and Data

To simulate actual real electricity generation and capacity investment in a power market, the following optimization problem is solved:

$$\max_{p_{ijk},I_{ij},R_{ij}} \{\sum_i \sum_j [(\sum_k H_k(B_{jk} - (c_i^F + a_{jk}e_i)p_{ijk})) - (c_i^T(p_{ij}^0 + I_{ij} - R_{ij}) - c_i^I I_{ij})]\}$$

$$\text{subject to}$$

$$\begin{aligned} p_{ij}^0 + I_{ij} - R_{ij} &\geq p_{ijk} \\ p_{ijk} \geq \alpha_i^{min}(p_{ij}^0 &+ I_{ij} - R_{ij}) \\ K_{ij} &\geq I_{ij} \\ \sum_j L_{jk} &= \sum_i \sum_j p_{ijk} \\ &\textit{DC network constraints} \end{aligned}$$

i: generator index
j: node index
k: representative hour index
p_{ijk}: aggregate real power output from generator i at node j during representative hour k
p^0_{ij}: existing generator capacity
R_{ij}: capacity retirement
I_{ij}: capacity investment
c^F_i: cost of fuel, operations and maintenance per MWh
c^T_i: cost of taxes and insurance per MW
c^I_i: annualized cost of new investment
H_k: hours system is at load profile k
e_i: emissions vector for generation type I, tonnes/MWh
a_{jk}: emissions cost vector at node j in hour k, $/tonne
α^{min}_i: min generation for type i
K_{ij}: max investment in fuel type I at node j
B_{jk}: Benefit function for demand response
L_{jk}: Net load

The objective function aims to maximize the net benefits of the value of generation minus the sum of power and fixed costs, subject to active power flow equations and transmission, generation, voltage and other constraints.[1] Since we are using a DC approximation of the actual AC electric grid, we can ignore costs and constraints involving reactive power and voltage angles. A DC approximation is a good model for these purposes (Schulze, 2009), and also ensures the problem is linear, which aids in computational tractability.

Each year is split into sixteen representative hour types: four representative hour types for each season. Figure 1 shows the percentage of the year modeled by each representative hour. The summer representative hours make up a greater portion of the year relative to the other seasons because in this model, summer comprises more months than any other season: May through September. The fall and spring hours comprise two months each: October and November, and March and April, with the remaining three months falling into the winter category.

Each representative hour is modeled as a deviation from the base hour, summer peak. Generators are de-rated in each season, which reduces their maximum power capacity, to simulates unit availability. Generator availability is highest during the peak seasons (summer and winter) because generators are required to carry out maintenance during the spring and fall, when demand is lower. Load can be scaled (separately for

---

[1] This step of the analysis was performed using the SuperOPF and MATPOWER, a collection of MATLAB M-files for solving "stochastic, contingency-based, security-constrained optimal power flow[s]." The MATPOWER home page can be found at: http://www.pserc.cornell.edu/matpower. The SuperOPF is still under development. In terms of the terminology in the SuperOPF, the different representative hours are treated as contingencies from the base case (summer peak), and the Positive Active Reserve Price is the fixed cost or the investment cost, depending on if the generator is an existing unit or a new (potential) unit. Since we are representing an entire year with each contingency instead of the normal time frame of the SuperOPF, ramp rates are unimportant, and each generator has ramp rates equal to its maximum power output. However, to keep coal plants from cycling on and off between seasons, their minimum contracted power is set to 15% of PMAX.

each area in the model) and different emissions costs can be applied. Figure 2 presents an average of the load scaling across all regions for each representative hour. The summer peak has the highest total system demand. Most regions experience their peak demand at the summer peak due to summer cooling needs. The Maritimes in Canada, however, actually has its annual peak during the winter. Investment in units, especially new units needed to meet this peak demand (often called peaking units), is driven by this representative hour. Although the summer peak represents only a small portion of total hours, there must be enough capacity on hand to provide for this demand, since storage on a utility scale is prohibitively expensive with current technology. In the real world, there exist peaking units that are only used for a few hours for a few days each year, usually on hot afternoons in July and August. These units are typically older oil or natural gas units that have very low fixed costs but very operating costs.

Accurate modeling of costs arising from emission policies is central to the accuracy of this paper. Many emissions laws in the United States propose cap-and-trade programs, which operate by putting a cap on the total amount of emissions, distributing emissions allowances, usually by endowment or auction, and establishing a permit market with a price for these permits. A firm that expects to exceed its emissions allotment based on the number of allowances it owns may reduce emissions or purchase additional permits. Firms are expected to minimize the costs of these two options to maximize their profits. A cap-and-trade program, like an emissions tax (which places a tax on each unit of emissions), puts a price on each unit of emissions. Examining the response of the power industry to a price on emissions allows us to predict the effect of a cap-and-trade program as well as an emission tax program. The term “emissions price” is used to refer to either the permit price in a cap-and-trade program or the emission tax rate. Firms that are endowed with permits should still value their opportunity cost even if they represent windfall earnings.

Information about fixed and investment costs for generation plants, as well as information about operating costs for new plants was obtained from the Energy Information Administration at the Department of Energy (2011). Four types of new plants were selected to be built: dual unit advanced pulverized coal, advanced natural gas combined cycle, dual unit nuclear, and onshore wind. These four plants represent efficient versions of four of the most common types of electric power used in the United States for which investment is possible. The overnight cost reported by the EIA was converted into a total cost by assuming an equal portion of the overnight cost was spent at the beginning of each year, and the debt accrued interest at an annual rate of 8%. A power plant can be expected to pay back its investment in the first 10 years of operation, so a capital recovery factor was calculated using equation (4).

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \qquad (4)$$

CRF: Capital Recovery Factor
i: Interest Rate (8%)
n: Compounding Periods (10 Years)

For ten years and an annual interest rate of 8%, a plant is built if it can cover 14.9% of the total construction cost in the first year of operation. Generation costs assume prevailing rates for fuels are the same as the average in the region for 2010:

$5.56/thousand cubic feet for NG and $2.82/MBTU for coal. In line with DOE estimates, natural gas prices increase by about 20% in 2022, and a further 23% in 2032. Coal prices decrease slightly (98% of 2012 costs) in 2022, and increase 4% from that value by 2032. Total capacity additions are limited to 15% of the maximum rate in a 5-year period in which each type of fuel has, historically, been built in the entire United States. This corresponds to the NPCC's share of total US electrical generation. For example, between 1985 and 1990, approximately 34 GW of nuclear capacity was built in the United States. Thus, 5 GW is a conservative upper limit for the nuclear capacity that could be built by 2022 in the NPCC.

The distribution of demand and the tradeoff between fixed and variable cost drives the investment and maintenance of different kinds of units. For example, roughly 30% of the year has an expected load at about half of peak load: The low demand case for each season in Figures 1 and 2. (And the entire year has a demand at half of peak load or more.) For a power plant running 8,760 hours a year, total costs for an average fossil-fuel plant range from a low of $356,000/MW for a coal plant to over $2.5 million dollars/MW for an oil plant. However, if a plant is only running for the summer peak, 184 hours a year, the average natural gas plant costs under $28,000/MW to operate, cheaper than any other plant type except for hydropower.

This analysis uses a network reduction of the Northeastern United States developed by Allen, Lang and Ilic (2008.) A diagram of this network is shown in Figure 3. In this work, Allen et al reduced the Northeast Power Coordinating Council area to a

36 bus[2] model, while maintaining important line flow constraints. Having an accurate model of the network over which electricity flows is vital. Consider the highly simplified power network depicted in Figure 4. In this network, power can flow from the generator on the left to the load on the right via two pathways. If each segment has equal resistance and length, Kirchoff's Law will predict that 1/3 of the electric flow will along the upper path, and 2/3 will flow along the bottom path. In an actual electric grid, power flows from generator to load along all possible pathways simultaneously, which means changes in generation or load at one node can cause transmission congestion at nodes far removed. Conversely, transmission limits at lines far removed from the shortest path between a generator and a load may reduce the total power able to flow from a source to a load. Lines which carry more power than their rated capacity for too long actually warm up and sag, which may cause them to dip into trees and ground out. One of the causes of the Northeast Blackout of 2003 were power lines in Ohio sagging into trees, which triggered a chain reaction and ultimately destabilized the electric grid.

Data on existing generating units, provided by Energy Visuals, came from the 2006 reliability planning process of the Multiregional Modeling Working Group, and includes data on units projected to be operational in the summer of 2008. Data on fuel type, heat rate, generation cost, and emissions of CO_2, SO_2 and NO_X are included for each plant. For more details on this stage of the analysis, refer to Schulze et al (2009.)

As electricity prices increase, whether due to natural growth of the system, or to added costs to generation from emissions prices, people will respond by cutting back their level of power consumption. In the long run, the elasticity of demand for electricity

---

[2] A bus is one node on the network, usually containing both load (customers) and generating units and connected to other busses via transmission lines.

is approximately -1 (Dahl, 1993). However, recent research suggests that, even in the short run, the elasticity of people responding to average prices (ie, utility bills) is -0.982 (Fell et all, 2011). Since each step of our model represents 10 years, an elasticity of -1 is used to represent demand response. Average distribution costs are assumed to be $70/MWh. In the NPCC, the average LMP for the base year is also $70/MWh. Thus, $140/MWh is a good estimate for retail prices with no new policies. A 2.5% reduction in demand would be expected as prices increased to $143.50, or an increase in LMP from $70 to $73.50. Because this optimization problem must remain a linear program, demand response is represented in ten blocks, each representing 2.5% of total load. The effective price for each block of demand response is at the midpoint of each interval. Load is also expected to naturally grow as a result of increasing population and demand for energy. The New York Independent System Operator (NYISO) estimates this load growth at 0.59% per year (NYISO 2009.)

Description of the Nine Cases

Each of these cases was simulated for an initial year without investment: 2022. Each cycle of investment is assumed to take ten years. Ten years is enough time for any kind of power plant, including a nuclear plant to be built, assuming regulatory and siting issues could be resolved. The first cycle of investment thus ends in 2022, and the second investment cycle ends in 2032. For comparison, the first case modeled includes no environmental regulations or subsidies for power generation or capacity. This case is referred to either as the base case or the no regulation case.

The second case modeled is the American Power Act, often referred to as the Kerry-Lieberman CO_2 Cap and Trade Bill. The Kerry-Lieberman Bill proposed cap and trade auctions for CO_2 beginning in 2012, with a cap starting at the 2005 level, and a targeted reduction of 17% by 2020 and 42% by 2030. However, the bill also included a price collar for CO_2 prices. The price floor would start at $12/ton, and increase by 3% annually in real terms, while the price ceiling would start at $25 and increase by 5% annually in real terms. Previous work (Schulze et al 2009) has shown that, with no new investment allowed, the targeted CO_2 reductions are unmet, and the CO_2 prices reach the ceiling by 2016. The addition of new investment might change this however.

In the third case, power plants are charged marginal damages equal to the health impacts of their SO_2 and NO_X emissions. The same air transport model from The Hidden Cost of Energy (2010) was used to calculate ambient SO_2, NO_X and fine particulate matter concentrations in every county in the NPCC as a result of emissions from every generator in the model. Finally, information about risks of morbidity and mortality from these emissions were used to calculate marginal damages for each plant. Table 3 shows summary information about these marginal damages and emissions. AES Cayuga, also known as Milliken Station, is a coal-fired power plant located on Cayuga Lake near Cornell University. It is an exceptionally efficient coal plant, mostly due to the fact that Cayuga Lake is a deep lake with an abundant supply of cold water, which makes for a very efficient thermal cycle. The maximum marginal damage coal plants are Portland Units H&L in Northhampton, PA, located less than 100 miles west of New York City. The average coal plant is 45 times more damaging than the average natural gas plant, and the most damaging coal plants cause twice as much damage as that. On the other hand, some coal plants, like AES Cayuga, are not very damaging. Nor are coal plants that lack significant population centers downwind, such as a coal plants on the Atlantic coast. Of course, the newest natural gas combined cycle plants are even more efficient than the average natural gas plants plant in this sample, and have correspondingly lower marginal damages in per MWh terms.

In the fourth case, electrifying the transportation sector was investigated. Using a report from Berkeley (Becker et al 2009), an estimate for the total number of electric vehicles in 2022 and 2032 was used to increase the low demand hours on the grid, assuming that vehicles were charging at night. In 2022, 703 MW would be added to the low demand hours at each node, as a result of almost 600,000 plug-in hybrid vehicles with a 2kWh battery, and over 200,000 electric vehicles with 16 kWh batteries. By 2032, the Northeast might have 5,412 MW of additional demand (over 2012) from over 725,000 plug-in hybrid vehicles and around two million electric vehicles. This assumes that adoption rates for plug-in hybrids and electric vehicles are equally spread across the country, though some estimates suggest that western states would experience faster adoption rates than the northeast.

In the fifth case, incentives for wind generation are added. Policies modeled include the United States production credit for wind generation, and similar credits in Ontario, Quebec and the Maritimes. Some states offer subsidies to reduce construction costs, such as Massachusetts and Delaware. Because many states are aggregated into some buses in this model, an average value for every state in a region was used to model these policies. (For example, Bus 1 includes generation from Pennsylvania, Delaware, Massachusetts, Maryland and New Jersey.) Wind incentives currently in force are expected to continue through 2032.

After the earthquakes, tsunamis and Fukushima disaster in Japan, there was talk in New York about shutting down nuclear power plants, particularly those close to large populated areas, such as Indian Point Energy Center. Expanding on this idea, the sixth policy modeled decommissions all nuclear power plants in the NPCC by 2022, with no other regulations. The system lacks enough spare generating capacity to decommission the plants without building new generators. In a separate case, decommissioning nuclear power plants was combined with the proposed Kerry-Lieberman cap and trade bill as well.

Two additional cases were also modeled which combine several aspects of the previous cases in order to predict the most likely path of the power system to 2032 given current policies and expected developments, the best guess case, and the socially optimal path of the power system through 2032. For the best guess case, wind incentives are expected to stay in place through 2032, PHEV load-filling is expected to occur, and some form of CO_2 emissions control is expected to be in place starting in 2022, modeled by having CO_2 prices at the Kerry-Lieberman CO2 price cap and applied to all units greater than 25 megawatts. Estimated prices for the EPA's new Cross-State Air Pollution Rule are included, although a full modeling of the rules will not be accurate until the entire Eastern Interconnect and all of the covered states is included (EPA, 2011.) For the purposes of this simulation, generators in New York, Pennsylvania, New Jersey, Maryland, Delaware and Washington, DC are counted as Group 1 states. Although in the current proposed rule, Delaware and DC are exempted, there are only a few generators included, so it should not significantly impact the model. Group 1 states are charged \$1,000/ton of SO_2 emissions in 2012, and \$1,100/ton in 2022 and 2032. Annual NO_X emissions permits are expected to cost \$500 in 2012 and \$600 in 2022 and 2032, with permits during the summer ozone season (which corresponds to the summer representative hours in the model) priced at \$1,300/ton in 2012 and \$1,500/ton in 2022 and 2032. These emissions price are only charged on units greater than 25MW, as with most EPA emissions prices.

In the socially optimal case, marginal damages on SO_2 and NO_X emissions, PHEV load-filling and a \$30/tonne price on CO_2 are applied starting in 2022. \$30/tonne is the value for the social cost of carbon used in the Hidden Cost of Energy. Note that as in the Marginal Damages case, these costs are applied to all units, regardless of size (unlike the Kerry-Lieberman CO_2 prices, which are only applied to units larger than 25MW.)

Results of the Nine Cases

Every case modeled has four figures. The first two figures show the actual levels of capacity and investment in the case, and the third and fourth figures show the changes in capacity (the left figure in each pair) and generation (the right figure) that occur from 2012-2022 and from 2022-2032. The maximum vertical scales on the first and second figures are the same for each case, to assist in comparing outcomes: 100 GW for the capacity figure, and 400 TWh for the generation figure.

The results for the no regulations case, also called the base case, are depicted in figures 5-8. For reasons having to do solely with the relative costs of the units, the optimal investment path for the system is to build new natural gas units and retire oil units. Oil units, especially in the Northeast, are mostly older units used as “peakers” to meet demand during peak load hours. They have some of the highest marginal costs, and it is not surprising that these units would be retired first. Approximately 12 GW of natural gas capacity is built by 2022, and a further 3 GW by 2032. The decline in natural gas generation between 2022 and 2032 is a result of older natural gas units being used less: their generation is 125 TWh is 2012, 69 TWh in 2022, and 46 TWh in 2032, while the generation of new natural gas units increases from 0 in 2012 to 92 TWh in 2032. Natural gas generation is essentially made up of two kinds of units: older natural gas generators, which are cheap to build but expensive to operation, and newer combined cycle turbines, which are a little more expensive to build (though still cheaper than any other generator) but cheap to operate.

Figures 9-12 show the results of the Kerry-Lieberman CO_2 case. Imposing CO_2 prices reduces the capacity and generation of coal and oil units while increasing the capacity of generation of natural gas units, though these increases are less than they were in the base case. 12 GW of natural gas generation is added by 2022, though as in the base case, some old natural gas capacity is simultaneously retired. In 2032, these retirements outweigh the (modest) capacity additions. The Kerry-Lieberman CO_2 case has less total capacity and generation because higher prices than the base case lead to more demand response and less total load. Load in 2032 is at 89% of 2012 levels, despite a 12% growth in the pre-demand response base level of load.

Figures 13-16 depict the results of the marginal damages case. Note that marginal damages are not applied until 2022, so the 2012 results are the same as for the base case.

This case is very effective at forcing coal plants to retire. Almost 80% of coal capacity is retired by 2022, and the system builds natural gas plants and retires less oil plants to make up the difference. Combined with the availability of more efficient natural gas combined cycle plants, natural gas capacity increase by over 50% by 2022, and natural gas generation more than doubles. Price increases keep load growth to minimal levels, which explain the modest investment in new natural gas plants between 2022 and 2032.

Figures 17-20 shows the results of the Plug-in Hybrid Electric Vehicles (PHEV) case. The results from the PHEV case are almost identical to the base case, except that slightly more natural gas capacity is built, and slightly more oil capacity is decommissioned. There are similar changes in generation as well. Raising the low demand hour increases the need for base load generation, which is met by new natural gas combined cycle units, and reduces the need for oil peaking. Generation from natural gas units increases from 2022-2032, the most obvious departure from the base case.

Figures 21-24 show the results for the wind incentives case. For the first time, something other than natural gas capacity is built: wind turbines. These wind generators are built at the expense of natural gas capacity, though almost 15 GW of new natural gas capacity is built by 2032, just a just a little less than the base case. The subsidies on wind generation actually lower the average wholesale price of electricity and lead to smaller decreases in load, so total generation is somewhat higher than in the base case. The decrease in natural gas capacity between 2022 and 2032 is, like the Kerry-Lieberman case, driven by the retirement of old natural gas generators, not newer combined-cycle turbine units.

Figures 25-32 show the results of the two no nuclear cases. In 2012, the no nuclear, no regulations case is identical to the base case. Without any environmental regulations, a much larger quantity of new generation is needed, so the system builds more natural gas capacity and decommissions less oil capacity. Although the same quantity of coal capacity is used as in the base case, slightly more coal and oil generation occurs, and much more natural gas generation. When nuclear plants are decommissioned and the proposed Kerry-Lieberman law is applied, the system behaves in a similar manner, though the magnitude of changes from the base case is less. There is more natural gas capacity and oil capacity than the base case and the original Kerry-Lieberman case, but less than the no nuclear case with no regulations. Likewise, there is less natural gas generation than in the no nuclear, no regulations case, but more than in the base case and the original Kerry-Lieberman case. Coal capacity and generation also declines, almost as much as in the original Kerry-Lieberman case in 2032, though not quite as much in 2022.

Next, Figures 33-37 compare all these cases to each other. In these figures, the order of the labels is the same as the magnitude of each line in 2032. In Figure 33, total demand is plotted for each case, and for the no demand response case to illustrate the level of load abatement due to increasing prices in each case. Note that the origin is not at zero, but rather 500,000 TWh. Starting from the base case, wind incentives and no regulations are almost identical, though the wind case has a little more demand and generation, because prices are somewhat lower due to wind subsidies in some low-demand hours. The PHEV case has more demand than the base case due to the fact that load filling at off-peak hours does not much affect prices but does add to total demand.

The no nuclear and no new regulations case has higher prices than the base case, which drives demand down somewhat, though as new generation is brought online, the differences in prices are reduced and demand recovers. Demand is nearly static for the marginal damages case because demand response due to price increases nearly balance out the natural load increases. Finally, the Kerry-Lieberman cases have the lowest load, because they experience the highest prices and thus the most demand response.

Figure 34 shows total capacity, which is broadly similar to total demand. Again, the origin of this Figure is at 100 GW to help differentiate the capacity paths of the various cases. The no demand response line shows how much new capacity is avoided due to demand response, in this case anywhere from 5 GW in the wind incentives case to 19 GW in the no nuclear Kerry-Lieberman case. Wind incentives have the next highest capacity, because so much wind capacity is built due to the incentives, which results in lower prices, higher demand, and thus higher capacity. The PHEV and the base cases have nearly identical capacity, because very little new capacity is needed to provide more generation at low-demand hours. The remaining cases all require less capacity because increased prices have reduced load, and thus capacity. This is especially true at summer peak hours. If the very expensive marginal oil units are brought online, summer peak prices may increase from \$300/MWh to \$1,000 MWh, resulting in a great deal of demand response, and thus less new capacity additions, since the summer peak drives capacity additions. The no nuclear cases both experience sharp declines in 2022 as nuclear plants are decommissioned, though both recover as new capacity is brought online, demand response lessens, and the need for new capacity increases.

Figure 35 shows average wholesale prices (weighted by load across busses and hours across representative hours.) Note again that this figure does not have an origin at zero to highlight the differences between the cases. The PHEV, no regulations and wind incentives all have low prices, with wind incentives having the lowest prices due to wind subsidies lowering the cost at some hours. Removing nuclear plants without imposing new regulations leads to slightly higher prices than imposing marginal damages in 2022, but the addition of new capacity reverses that trend in 2032. This is similar to the total demand results because total demand is essentially a function of average wholesale prices. Finally, the Kerry-Lieberman cases increase average wholesale prices the most, with the no nuclear case increasing prices more than the case with nuclear generators, because more fossil fuel units are needed, driving up the price of the marginal unit to more expensive coal and oil units, depending on the load profile.

Figure 36 shows CO_2 emissions for each case. Even with no regulations, CO_2 emissions decrease slightly as coal generation is replaced with more efficient and cheaper natural gas generation. Although the PHEV case has more total generation, taking into account the effect of displaced gasoline-powered cars, the total CO_2 emissions decline relative to the base case. Likewise, the wind incentives case has emissions slightly below the base case, as increased wind generation displaces some fossil fuel generation, even though there is more total generation because of slightly lowered prices. Removing nuclear plants produces a dramatic increase in CO_2 emissions, although with Kerry-Lieberman rules in place, these emissions drop below the base case by 2032. With the Kerry-Lieberman rule, CO_2 emissions are at the Kerry-Lieberman emissions cap in 2022, with prices just below the price cap, but by 2032, CO_2 emissions exceed the CO_2 cap and

CO_2 prices at the cap. Finally, and most surprisingly, the case most effective at reducing CO_2 emissions is the marginal damages case, which does not directly affect CO_2 emissions at all. However, it does make operating coal plants much more expensive than natural gas plants, which drives fuel-shifting and new investment to a much greater degree than Kerry-Lieberman does.

Figure 37 shows the expected number of lives saved relative to the base case for each case. The plug-in hybrid case is excluded because of insufficient information about the number of deaths avoided due to retiring conventional automobiles; displaying the results from just the generation would (incorrectly) show that the PHEV case caused more fatalities than in the base case. Mortality from power plant emissions is mostly caused as SO_2 and NO_X emissions create fine particulate pollution at receptor sites. At the low end of the chart, removing nuclear plants without imposing new regulations is expected to kill approximately 100 people a year. Taking just one plant offline, for example, Indian Point, would be expected to kill about 9 people a year. The proposed Kerry-Lieberman CO_2 bill, with and without nuclear plants, does a better job of saving lives as generation shifts from the more harmful coal plants to the less harmful natural gas plants. Finally, charging marginal damages saves over 2,000 lives every year, as coal generation is driven to less than 20% of base levels by 2032.

Figures 38-41 show the results of the best guess case. Aspects of both the wind incentives and the Kerry-Lieberman cases can be seen in the best guess case. There is more investment in and generation from wind generating units than in the wind incentives case, probably because of the additional incentives for less-polluting generation created by the Kerry-Lieberman price caps on CO_2 in 2022 and 2032 and the

EPA's Cross-State Air Pollution Rule. As well, there is increased demand at low-load hours because of the PHEV load filling in those years. There are slightly lower levels of oil and coal capacity and generation than compared to the Kerry-Lieberman case, and slightly higher levels of natural gas. These changes are likely due to the new EPA rule, which place high prices on the SO_2 and NO_X emissions that characterize coal plants. The EPA price forecasts for the Cross-State Air Rule used here are probably not accurately modeled – in the EPA's modeling, there are only small changes in power generation, while in this simulation, coal generation falls by over 40%. The reductions in SO_2 and NO_X are smaller in the Northeast than the new rules require, although the NPCC has less coal-fired generation, and a greater proportion of emissions reductions would be expected to come from the Midwest and southeast.

Figures 42-45 show the results from the socially optimal case. As in the marginal damages case, natural gas capacity increases rapidly and coal is almost completely eliminated from the system. The addition of the social cost of carbon reduces total generation, despite the addition of PHEV, relative to the marginal damages case by about 6%. No wind capacity is built in this case, either, so wind generation is only built in the presence of incentives for wind, even in the presence of prices for all three pollutants. Coal capacity is also slightly lower than in the marginal damages case, likely a result of the addition of a carbon price.

Finally, Figures 46-48 compares the results of the best guess, socially optimal and base cases in terms of average wholesale prices, CO_2 emissions, and expected number of deaths per year. Both cases have higher average wholesale electricity prices than the base case, though neither dominates the other for the entire time period, and the difference are not large. The prices from these two cases rival the Kerry-Lieberman case, and are only exceeded by the no nuclear Kerry Lieberman case. The socially optimal case has by far the lowest CO_2 emissions, beating the marginal damages case, 20% lower in 2022 and almost 40% lower in 2032. The best guess case is lower than the Kerry-Lieberman case, and it is even below the Kerry-Lieberman CO_2 cap and the marginal damages emissions in 2032. When it comes to the last comparison, the socially optimal case results in the most lives saved of any case, including the original marginal damages case. These estimate for lives saved are also a lower bound, because lives saved from reduced automotive emissions are not yet accounted for in this model.

Conclusions

Using a transmission-constrained model with actual generator data is essential for estimating impacts to the electric grid from large-scale policies. Transmission and generation constraints are a factor for all of the analyses in this paper, and provide a more realistic picture of the effects of policies than the “bubbles and pipes” models commonly used which neglect intra-region transmission constraints and greatly simplify inter-region transmission.

Looking at the policies in this paper, three facts stand out. First, demand response is incredibly important for accurately modeling the electric grid. Demand response can have a very large impact on CO_2 emissions and load, while having a relatively smaller impact on prices. Second, natural gas combined cycle seems to be the future of power plant construction, if forecasts for natural gas prices and construction costs for plants are accurate. Unless wind is subsidized, natural gas combined cycle plants are superior to every other type of generation in terms of annual costs with or without new emissions regulations, whether CO_2 or marginal damages. Finally, charging marginal damages for SO_2 and NO_X is the most effective policy for saving lives, reducing CO_2, and results in lower prices than strict carbon-reducing policies such as the proposed Kerry-Lieberman bill.

Works Cited

Allen, E. H., Lang, J. H., & Ilic, M. D. (2008). A combined equivalenced-electric, economic & market representation of the Northeastern Power Coordinating Council (NPCC) US electric power system. *IEEE Transactions on Power Systems*, *3*(3), 896-907.

Becker, T. A., Sidhu, I., & Tenderich, B. (2009). *Electric vehicles in the United States: A new model with forecasts to 2030*. Center for Entrepreneurship & Technology (CET), University of California, Berkeley. Retrieved from http://cet.berkeley.edu/dl/CET_Technical Brief_EconomicModel2030_f.pdf

Dahl, C. (1993). *A survey of energy demand elasticities in support of the development of the NEMS*. Retrieved from United States Department of Energy website: ftp://eia.doe.gov/pub/oiaf/elasticitysurvey/elasticitysurvey_dahl.pdf

EIA. (2011). *Annual energy outlook 2011*(Report Number: DOE/EIA-0383). Retrieved from U.S. Department of Energy website: http://www.eia.gov/forecasts/aeo/

EIA. (2009). The National Energy Modeling System: An overview (Report Number: DOE/EIA-0581). Retrieved from U.S. Department of Energy website: http://205.254.135.24/oiaf/aeo/overview/index.html

EPA. (2011, July 14). *Integrated Planning Model (IPM)*. Retrieved from http://www.epa.gov/airmarkets/progsregs/epa-ipm/

EPA. (2011, October 28.) *Cross-State air pollution rule (CSAPR).* Retrieved from http://www.epa.gov/crossstaterule/

Fell, H., Li, S., and Paul, A. (2011*) A New Approach to Estimate Residential Electricity Demand Using Household Expenditure Data.* Retrieved from http://www.rff.org/documents/RFF-DP-10-57.pdf.

Lamadrid, A.J., Maneevitjit, S., Mount, T.D., Murillo-Sanchez, C.E., Thomas, R.J., Zimmerman, R.D. (2008.) “A SuperOPF Framework”, *CERTS Report*. Retrieved from http://certs.lbl.gov/pdf/superopf-framework.pdf.

National Research Council. “Hidden Costs of Energy.” The National Academies Press, 2010.

NYISO. (2009, May 21.) *2009 Summer Outlook.* Retrieved from http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/NYISO_2009_Summer_Outlook__05212009_(2).pdf.

Palmer, K.L., Burtraw, D., Bharvirkar, R., and Paul, A. (2002). *The RFF Haiku electricity market model.* Resources for the Future. Retrieved from http://www.rff.org/Publications/Pages/PublicationDetails.aspx?PublicationID=9549. 2002.

Schulze, W.D., Thomas, R.J., Mount, T.D., Schuler, R., Zimmerman, R.D., Tylavsky, D., Shawhan, D., Mitarotonda, D., and Taber, J.T. (2009.) *Facilitating Environmental Initiatives While Maintaining Efficient Markets and Electric System Reliability.* PSERC Document 09-9. Retrieved from http://www.pserc.wisc.edu/documents/publications/reports/2009_reports/schulze_emissions_pserc_m-20_final_report_oct2009.pdf

Zimmerman, R.D., Murillo-Sanchez, C.E., and Thomas, R.J. "MATPOWER: Steady-State Operations, Planning and Analysis Tools for Power Systems Research and Education." *Power Systems, IEEE Transactions on,* vol. 26, no. 1, pp. 12-19, Feb. 2011

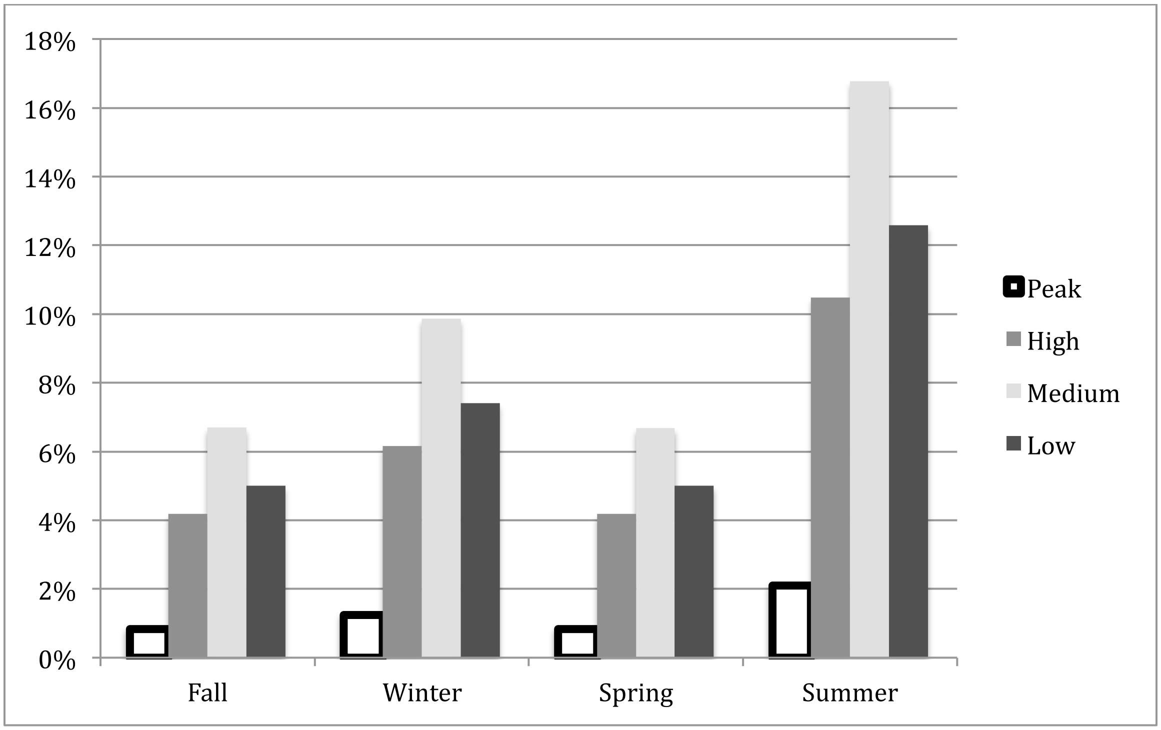


Figure 1: Relative Frequency of Representative Hour Types

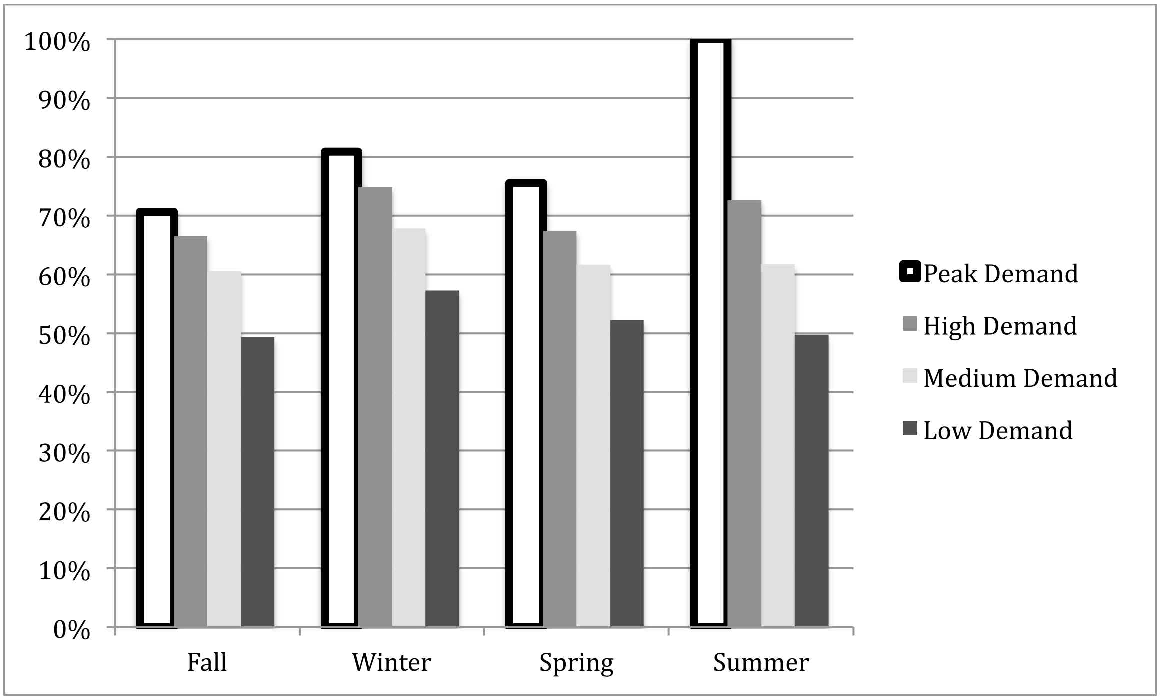


Figure 2: Average Demand Assumptions for Representative Hour Types

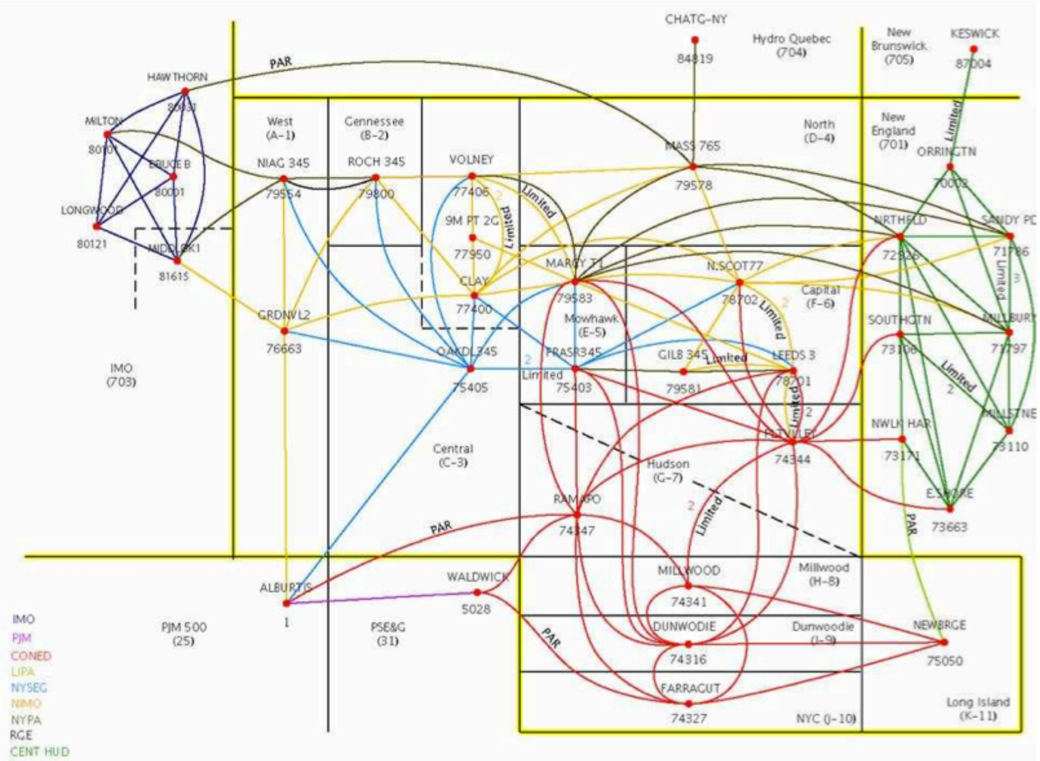


Figure 3. Diagram of 36-bus model from Allen et al (2008).

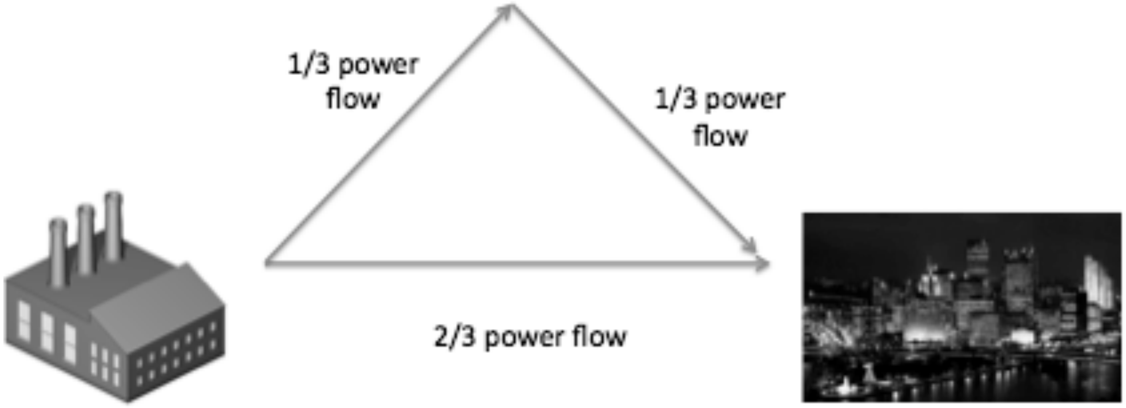


Figure 4. Schematic of Electricity Network

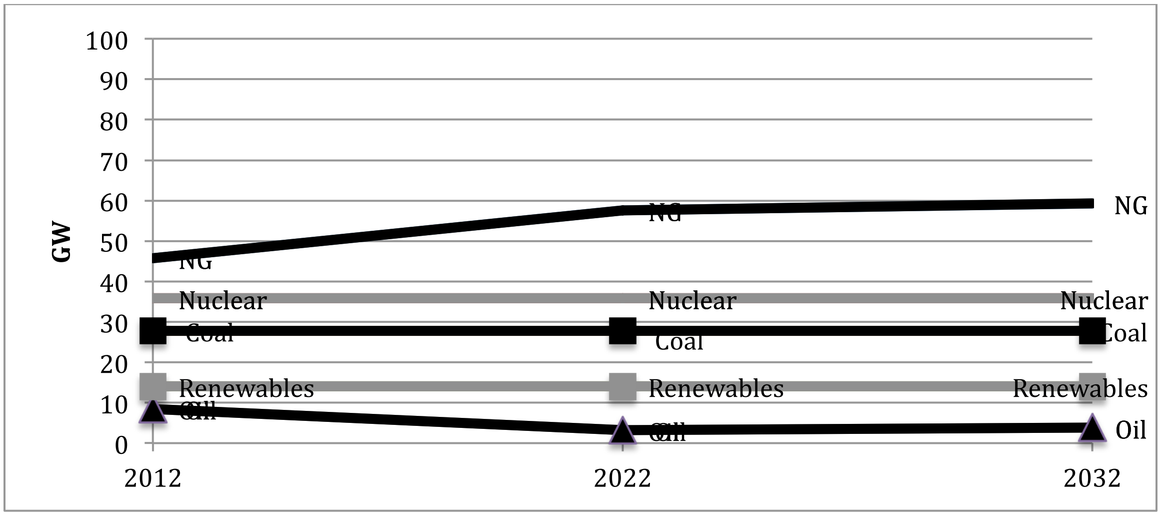


Figure 5: Capacity in the Base Case

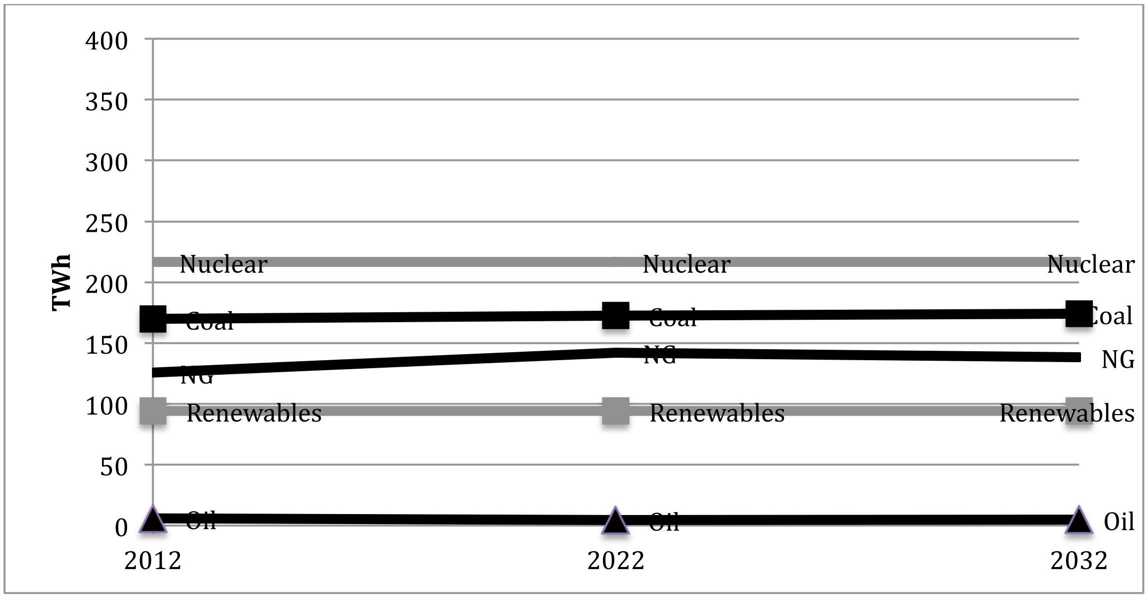
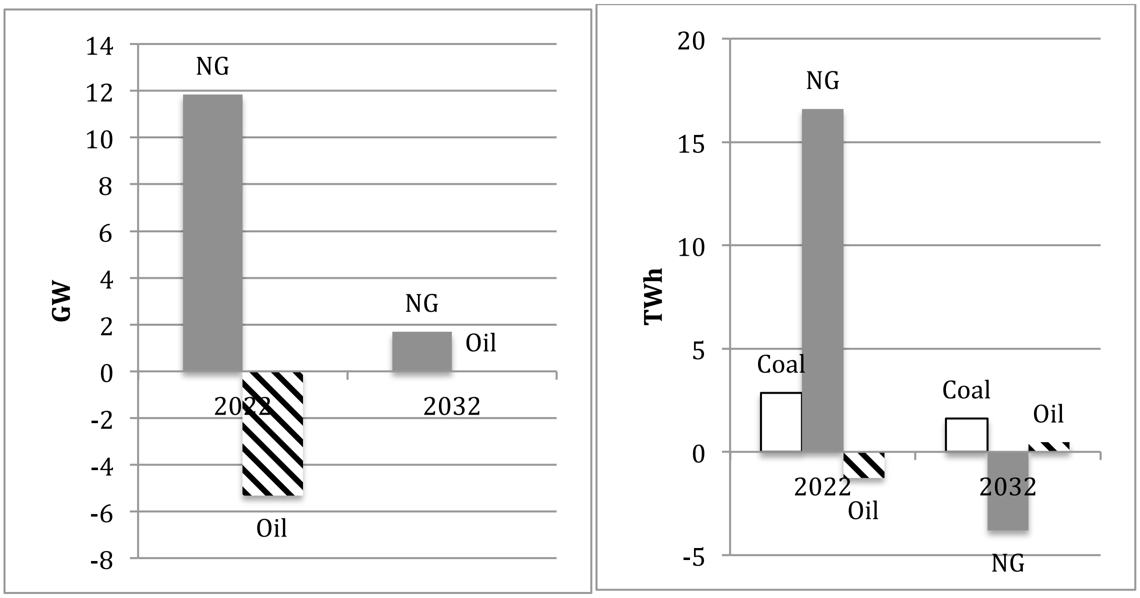


Figure 6: Generation in the Base Case



Figures 7 and 8: Capacity and Generation Changes in the Base Case

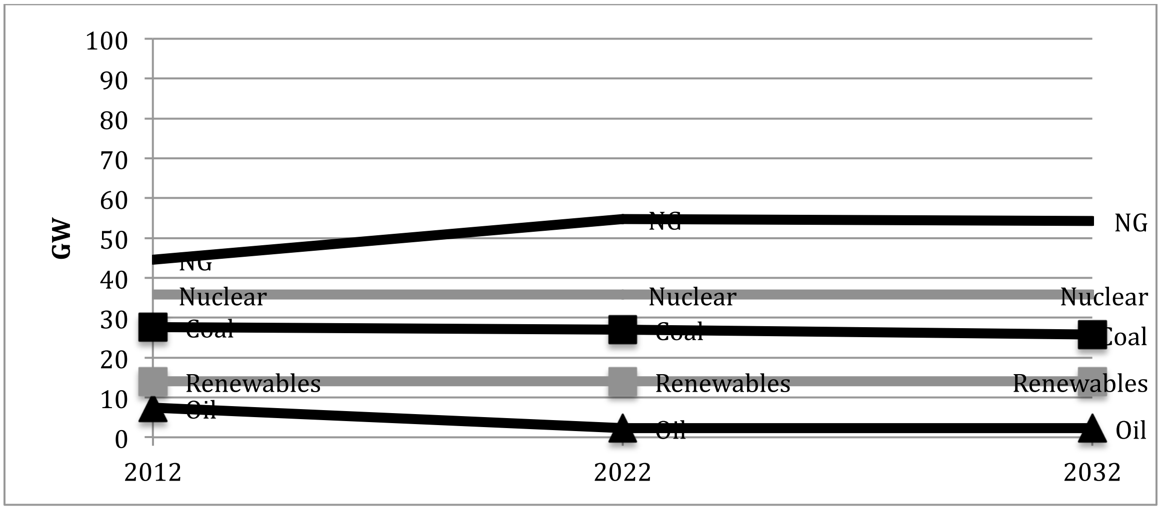


Figure 9: Capacity in the Kerry-Lieberman CO_2 Case

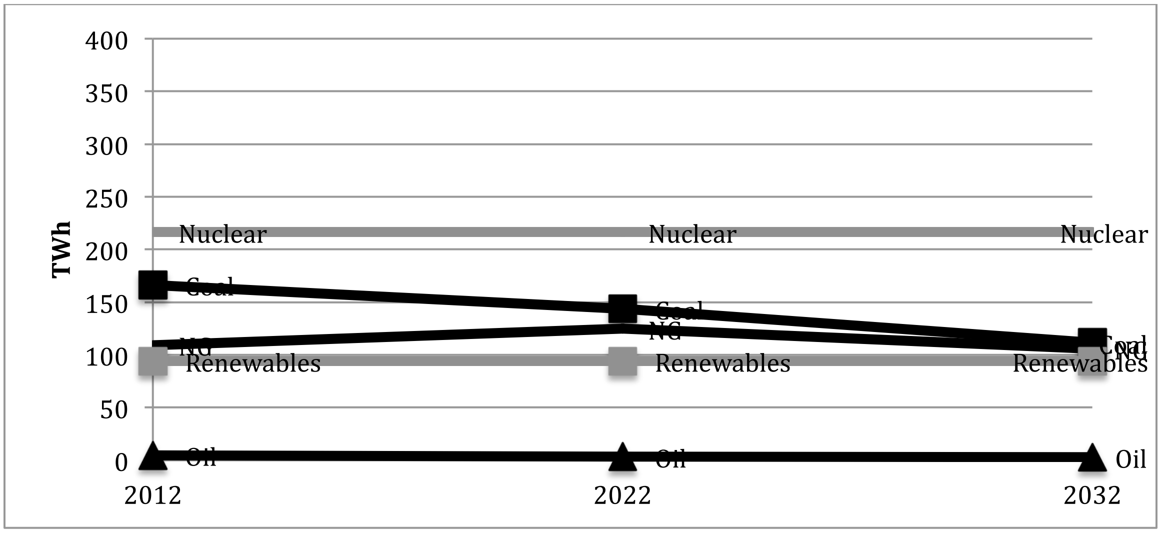
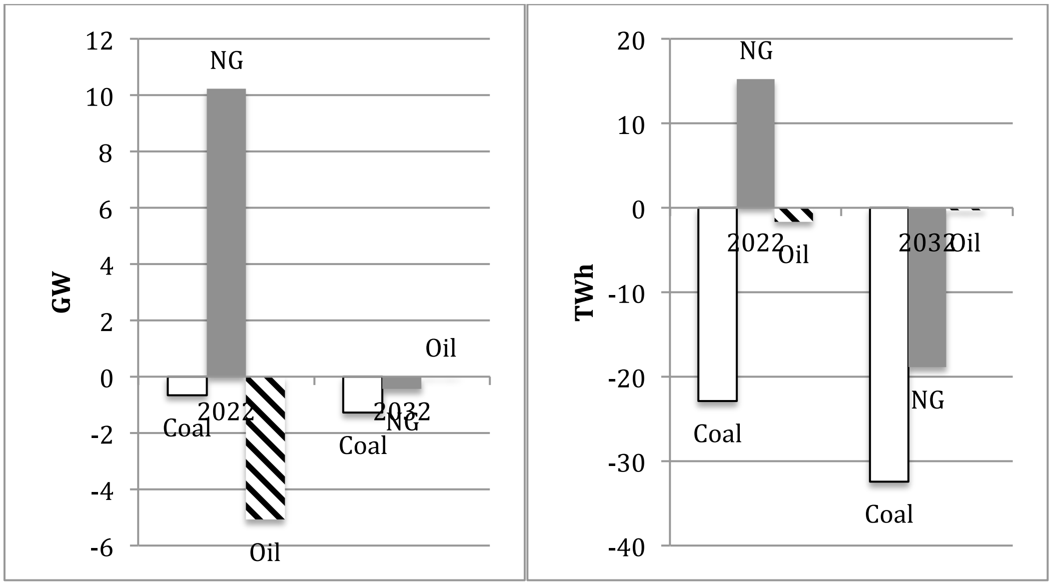


Figure 10: Generation in the Kerry-Lieberman CO_2 Case



Figures 11 and 12: Changes in Capacity and Generation in the Kerry-Lieberman CO_2 Case

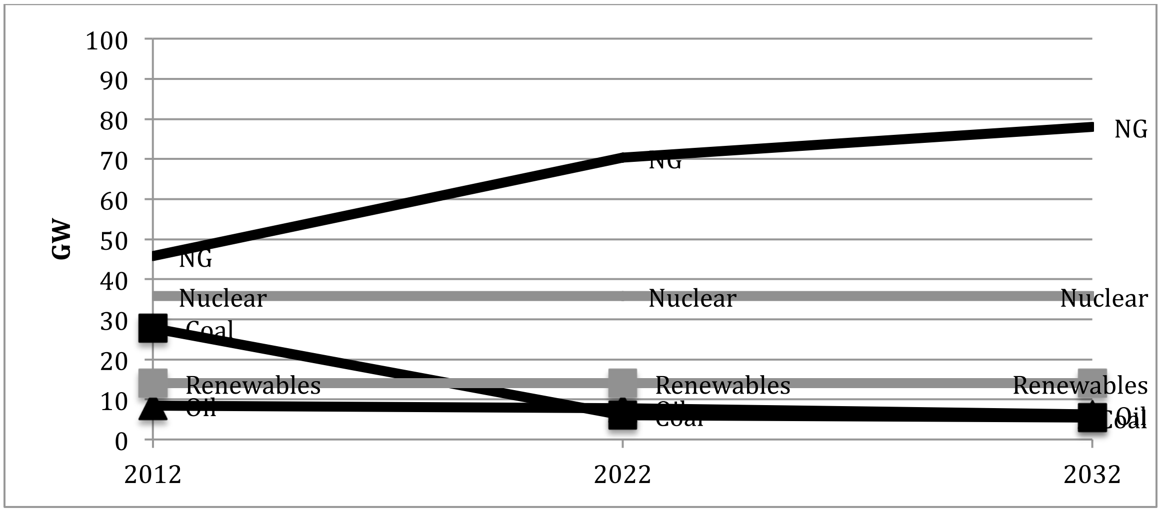


Figure 13: Capacity in the Marginal Damages Case

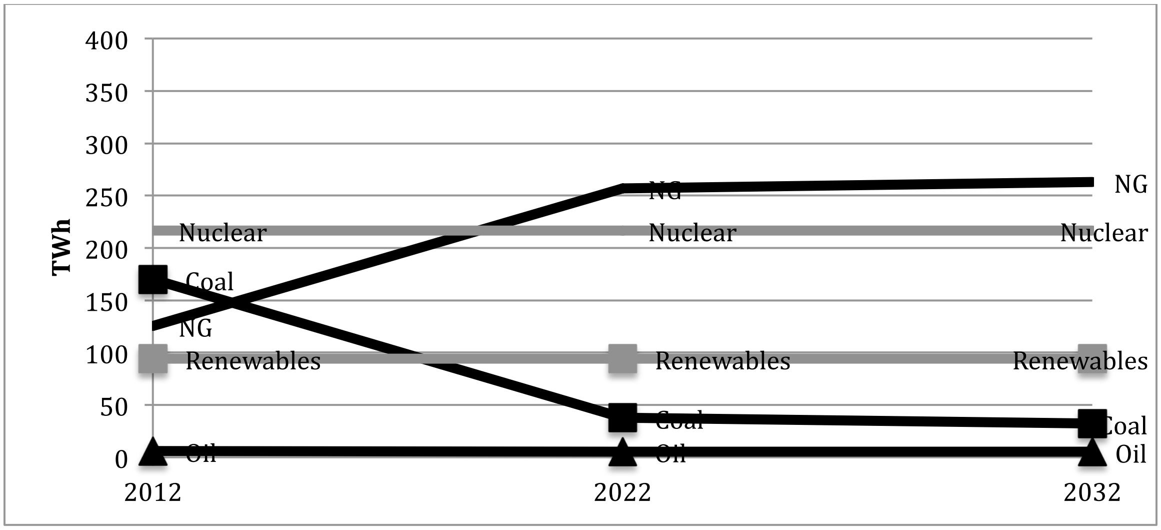


Figure 14: Generation in the Marginal Damages Case

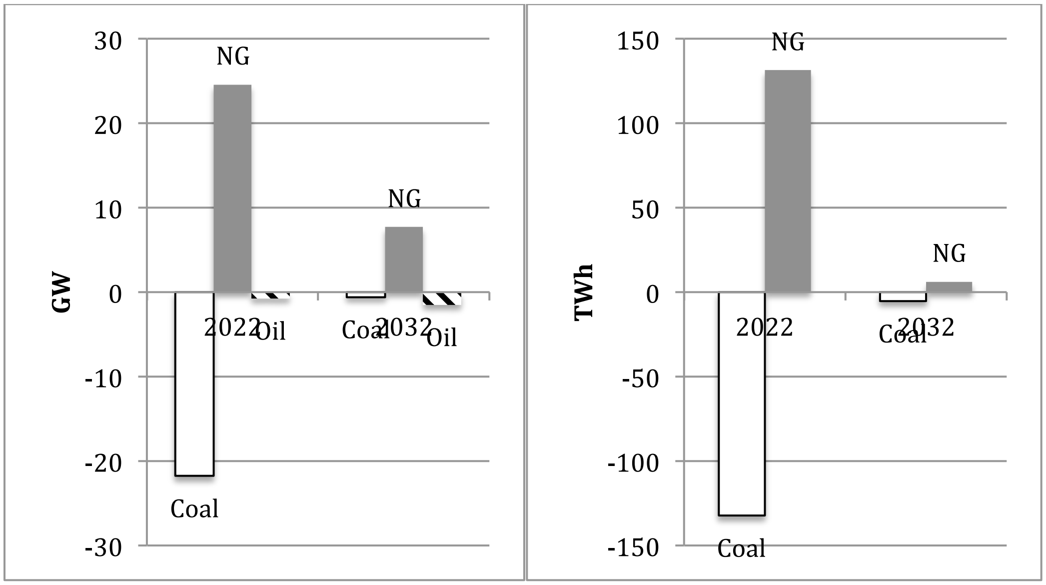


Figure 15 and 16: Changes in Capacity and Generation in the Marginal Damages Case

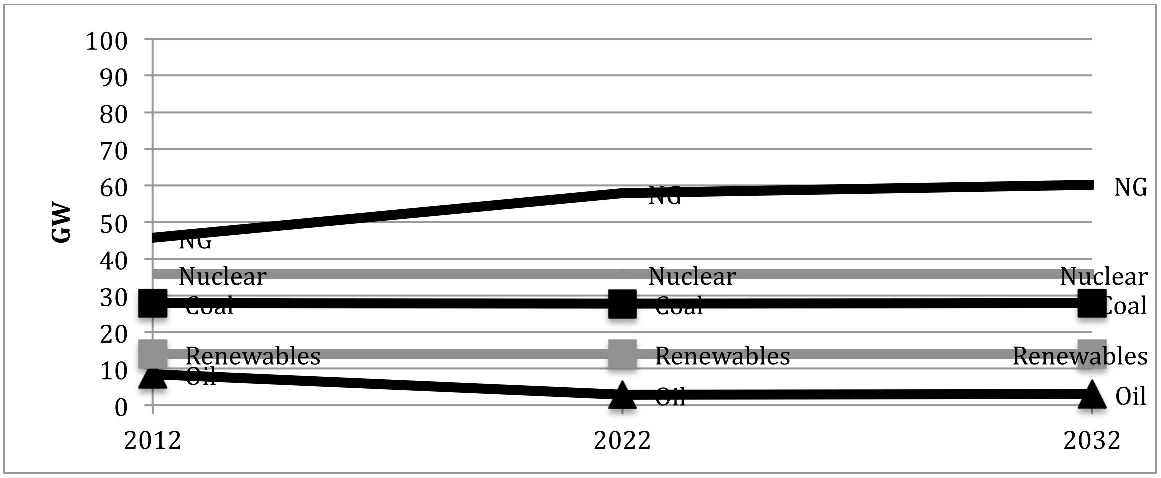


Figure 17: Capacity in the PHEV Case

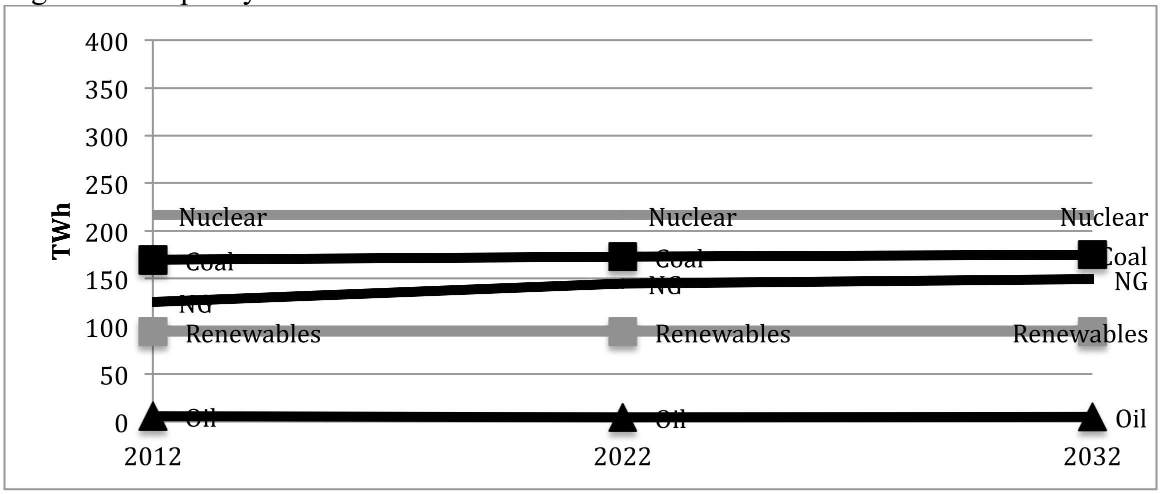
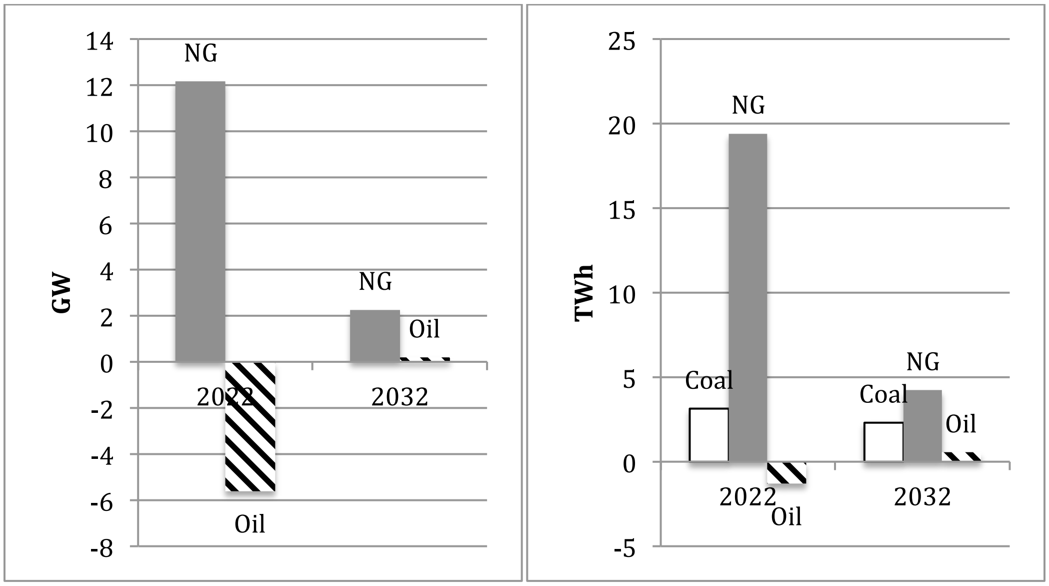


Figure 18: Generation in the PHEV Case



Figures 19 and 20: Changes in Capacity and Generation in the PHEV Case

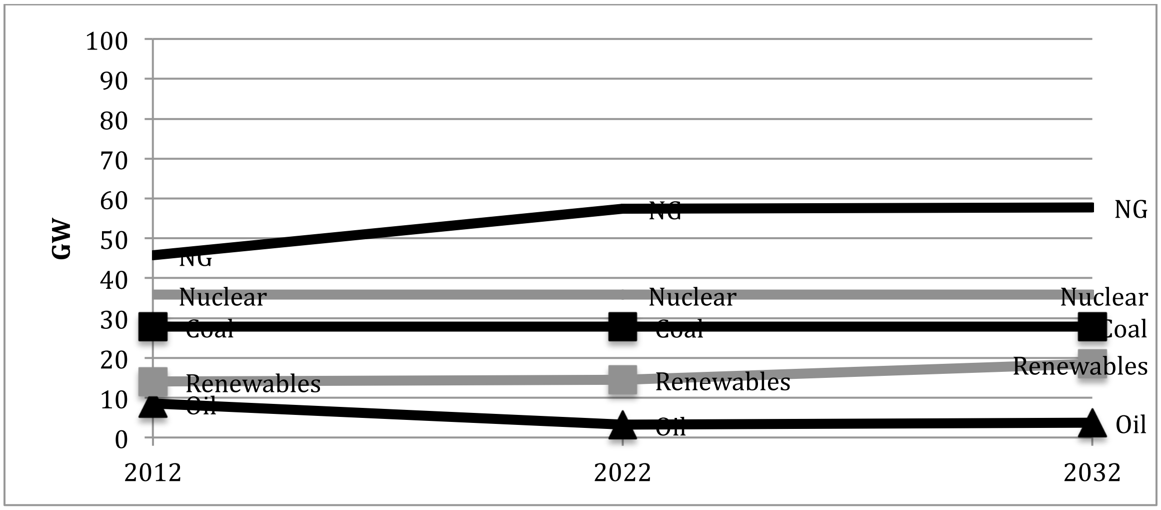


Figure 21: Capacity in the Wind Incentives Case

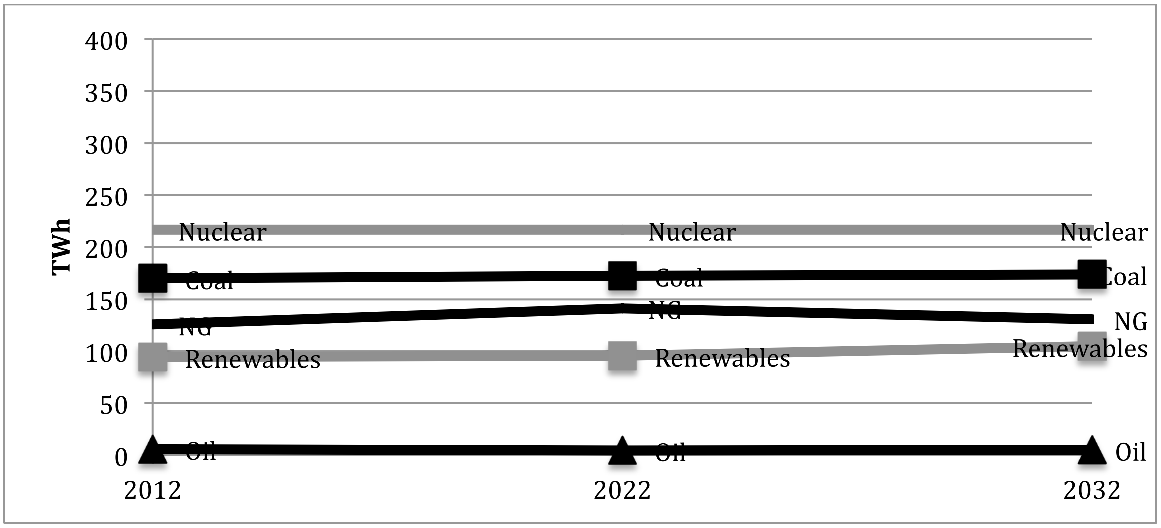
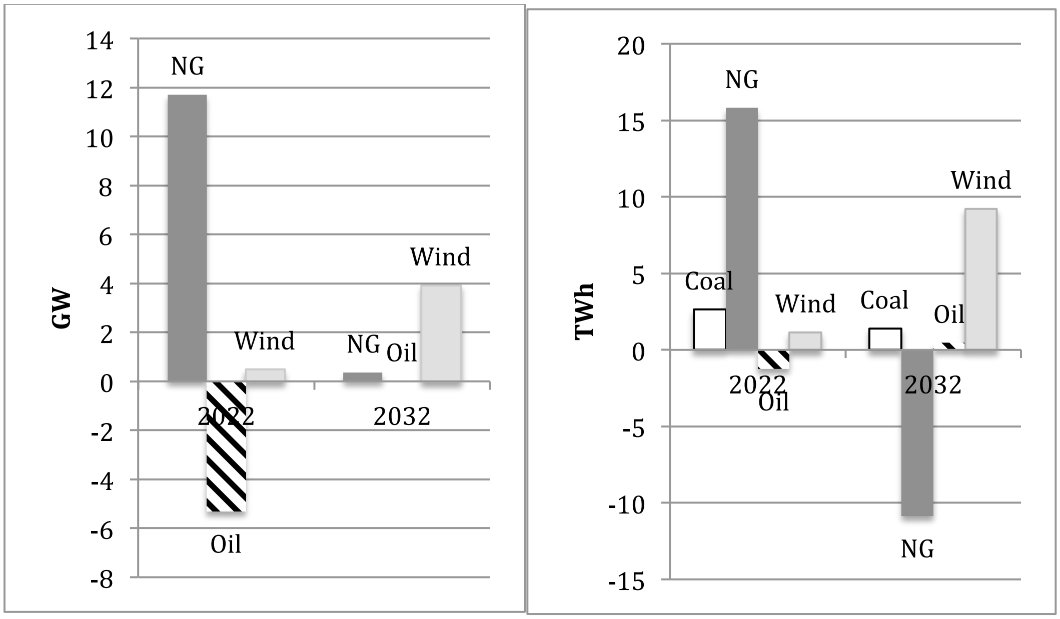


Figure 22: Generation in the Wind Incentives Case



Figures 23 and 24: Changes in Capacity in the Wind Incentives Case

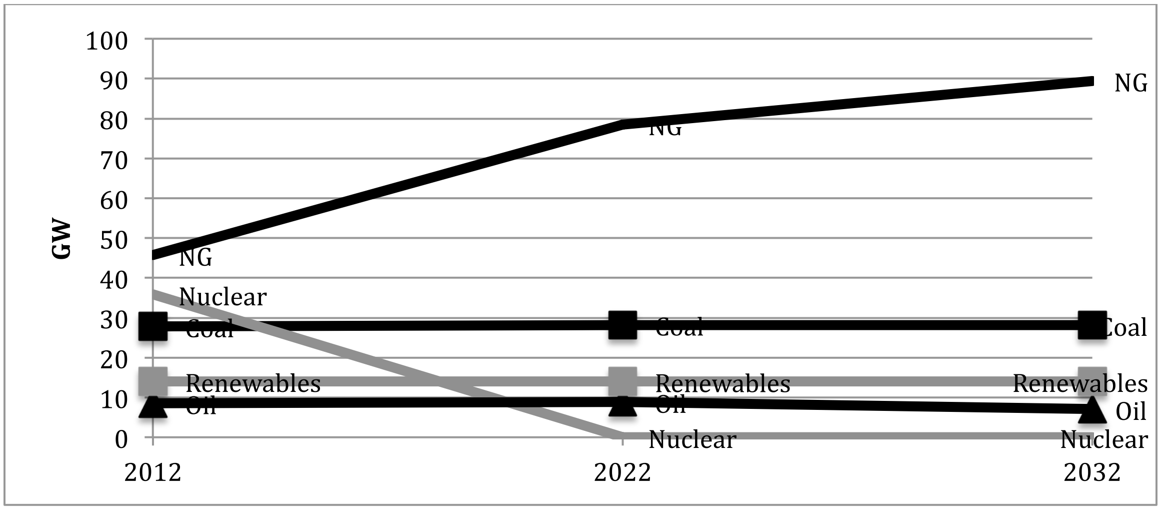


Figure 25: Capacity in the No Nuclear, No Regulation Case

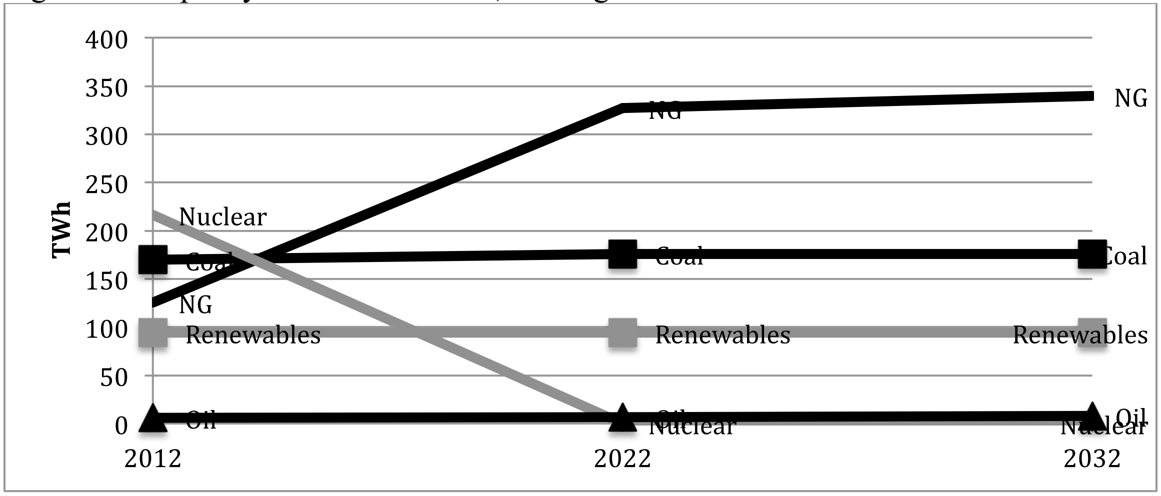
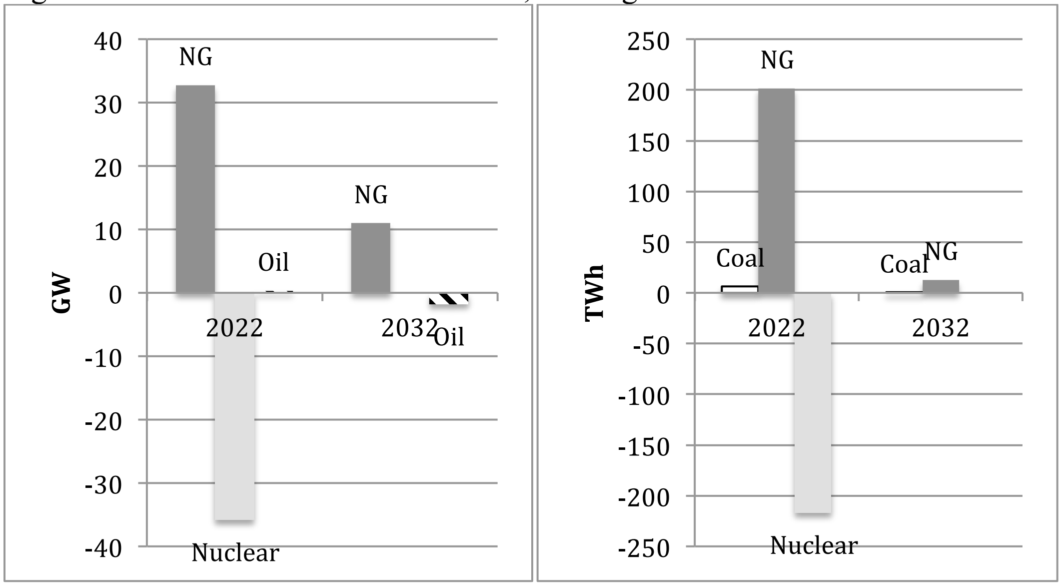


Figure 26: Generation in the No Nuclear, No Regulation Case



Figures 27 and 28: Changes in Capacity and Generation in the No Nuclear, No Regulation Case

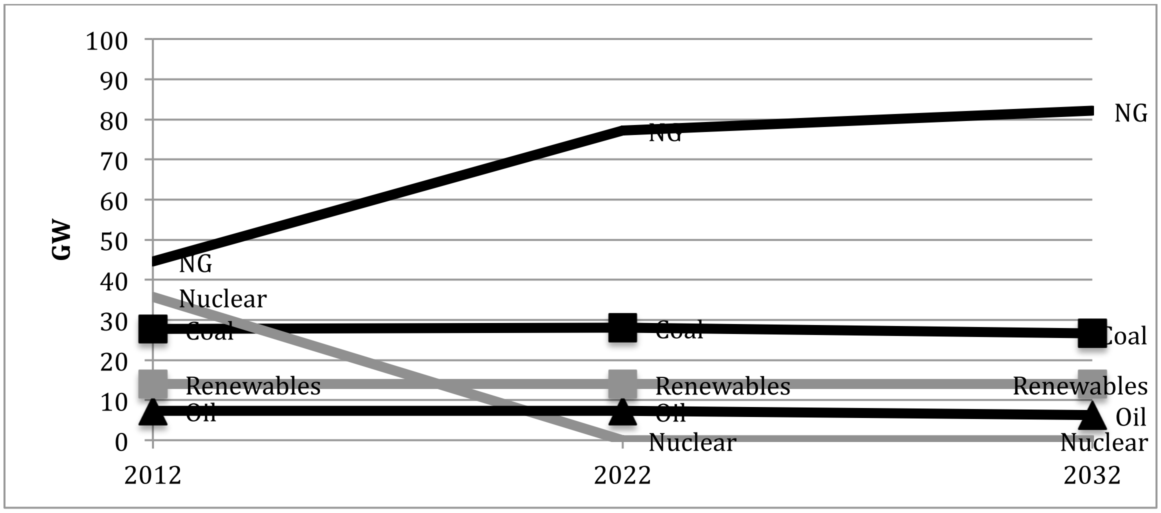


Figure 29: Capacity in the No Nuclear, Kerry-Lieberman CO2 Case

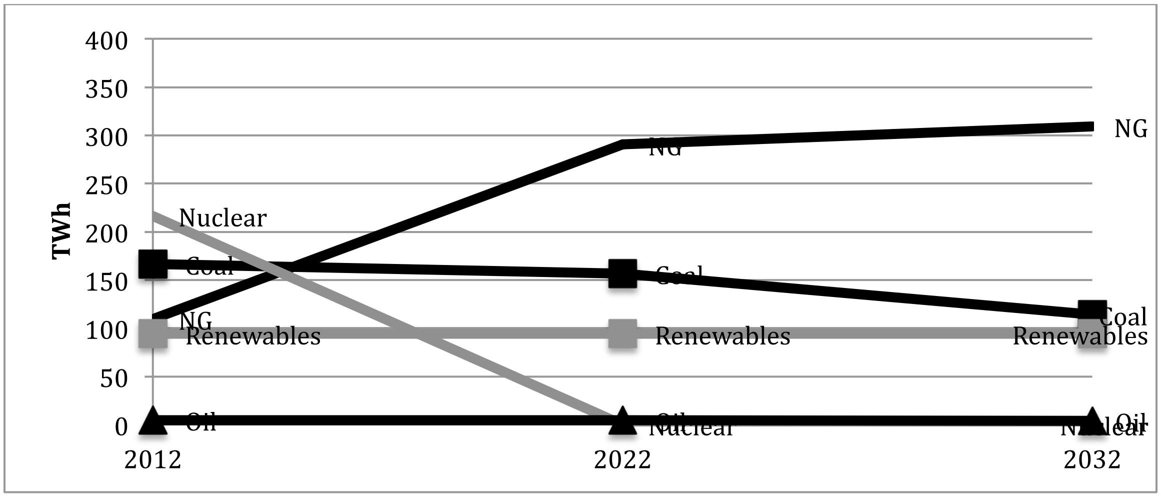
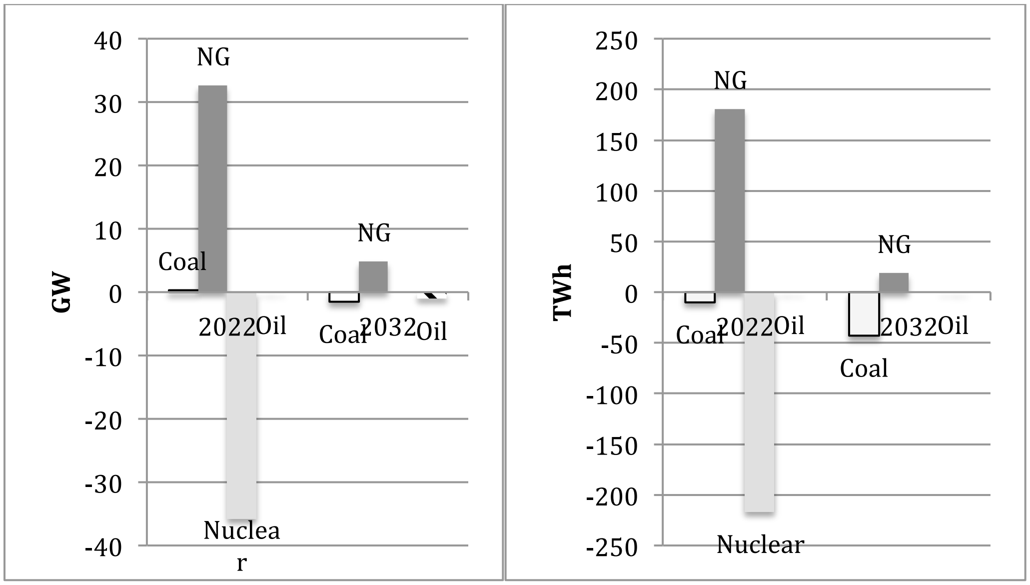


Figure 30: Generation in the No Nuclear, Kerry-Lieberman CO2 Case



Figures 31 and 32: Changes in Capacity and Generation in the No Nuclear, Kerry-Lieberman Case

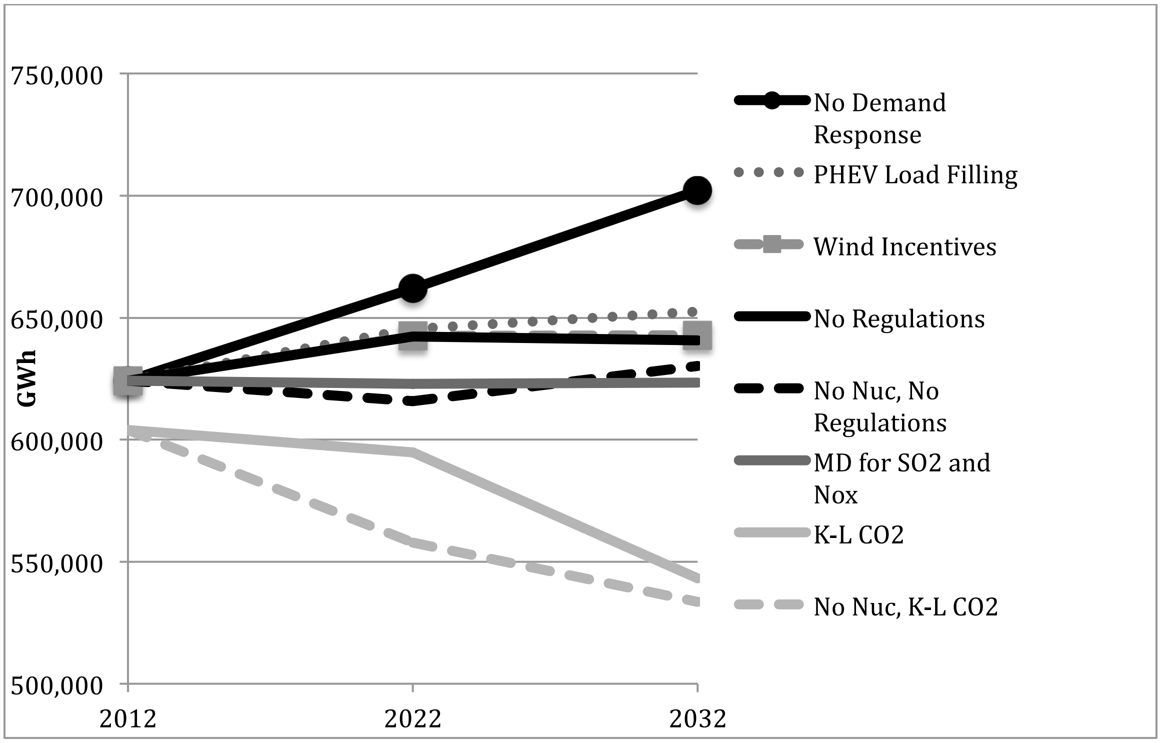


Figure 33: Total Demand

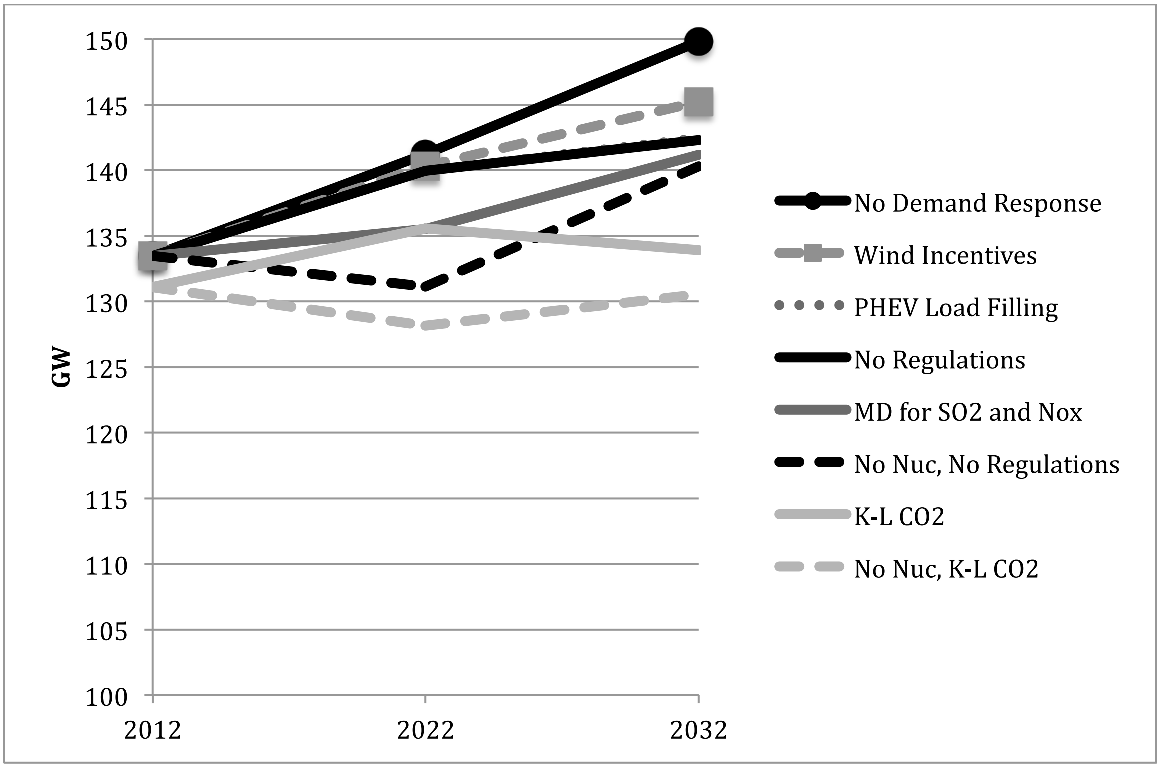


Figure 34: Total Capacity

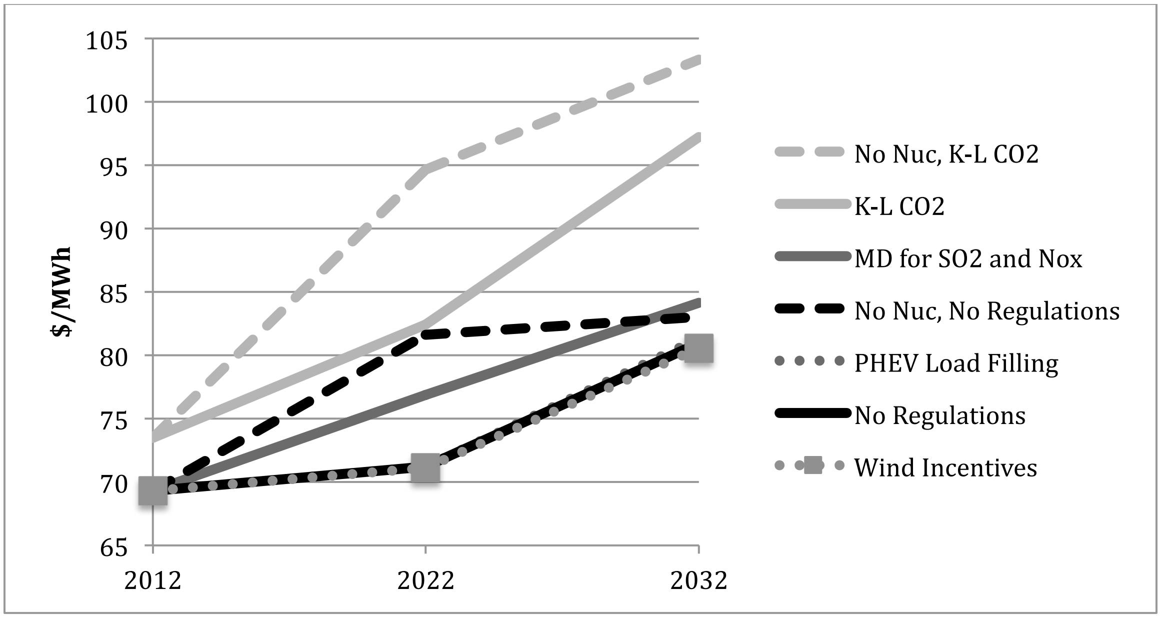


Figure 35: Average Wholesale Prices

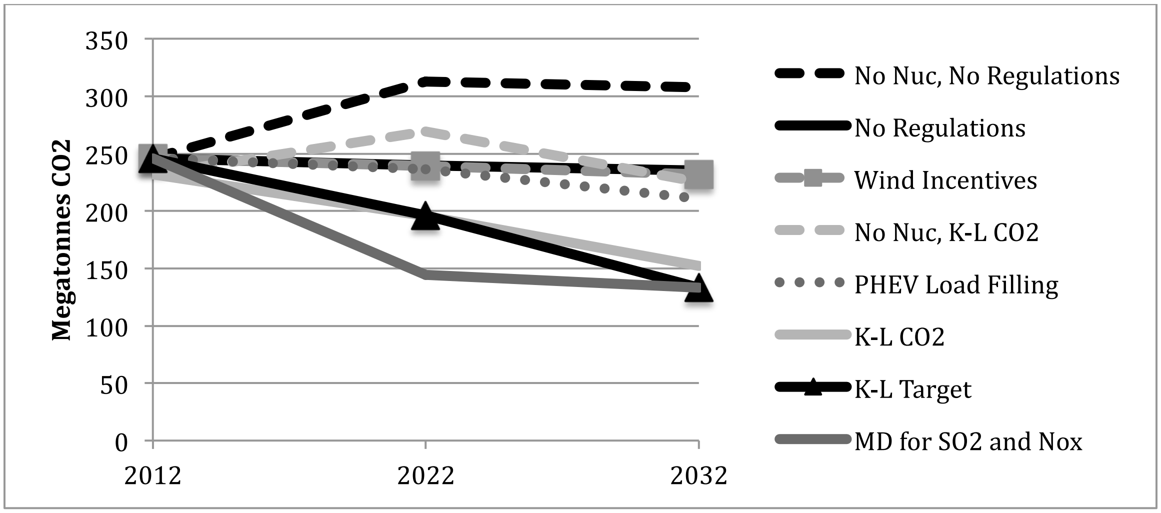


Figure 36: CO_2 Emissions

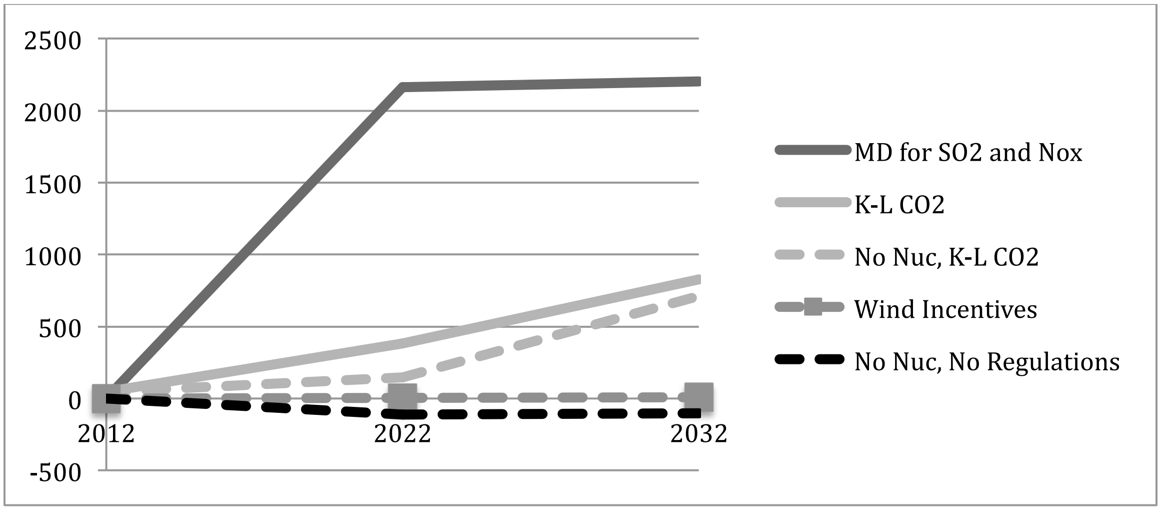


Figure 37: Expected Number of Lives Saved Compared to the Base Case

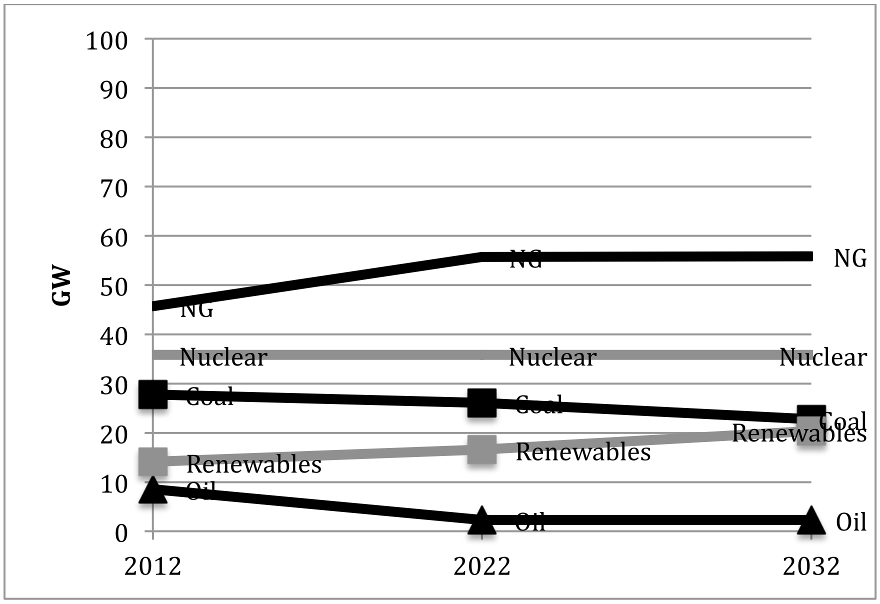


Figure 38: Capacity in the Best Guess Case

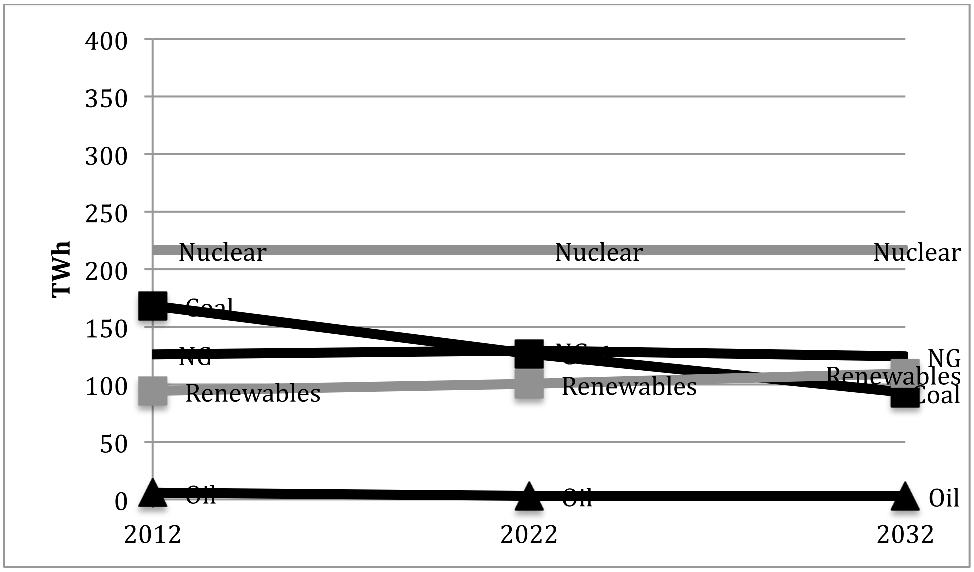
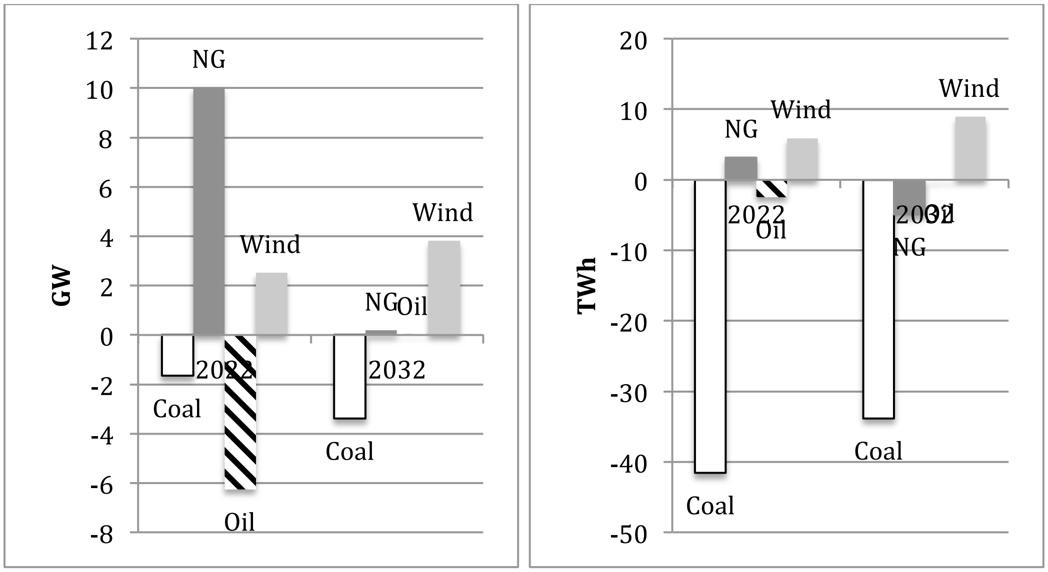


Figure 39: Generation in the Best Guess Case



Figures 40 and 41: Capacity and Generation Changes in the Best Guess Case

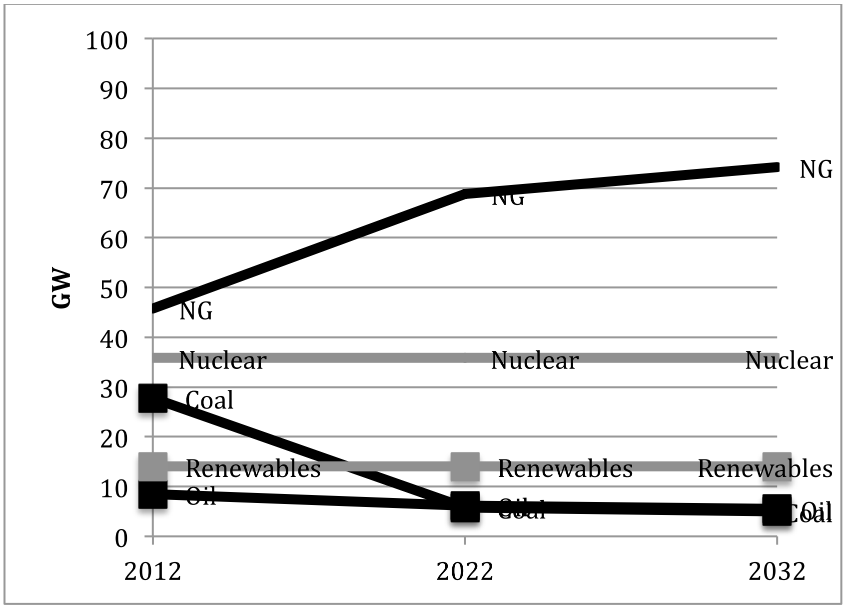


Figure 42: Capacity in the Socially Optimal Case

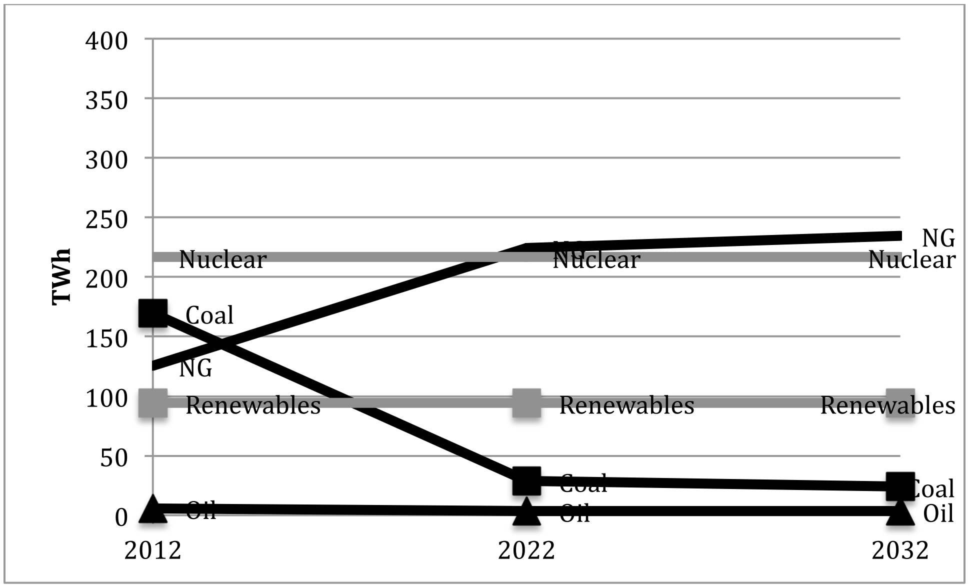
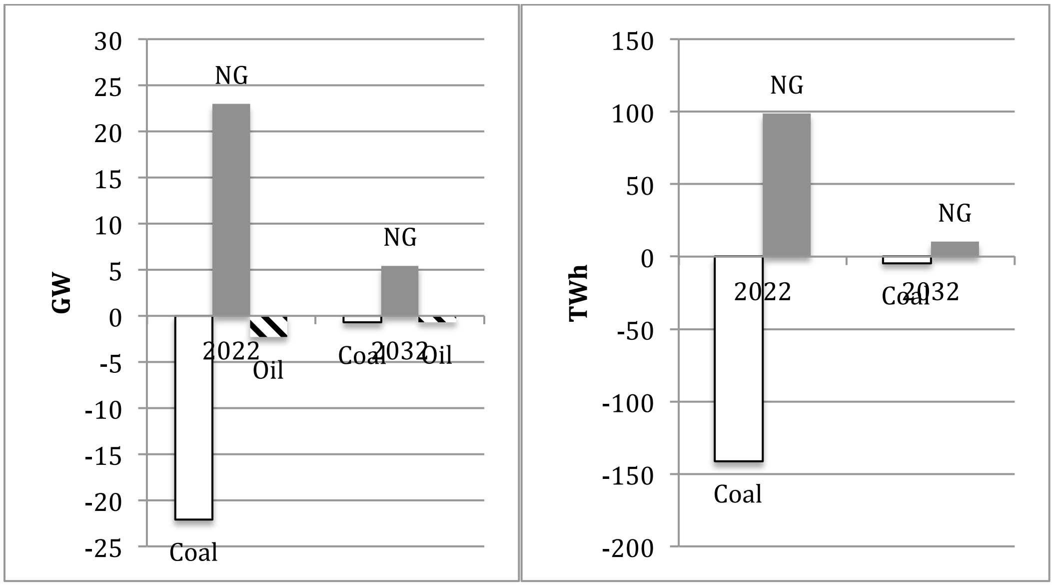


Figure 43: Generation in the Socially Optimal Case



Figures 44 and 45: Capacity and Generation Changes in the Socially Optimal Case

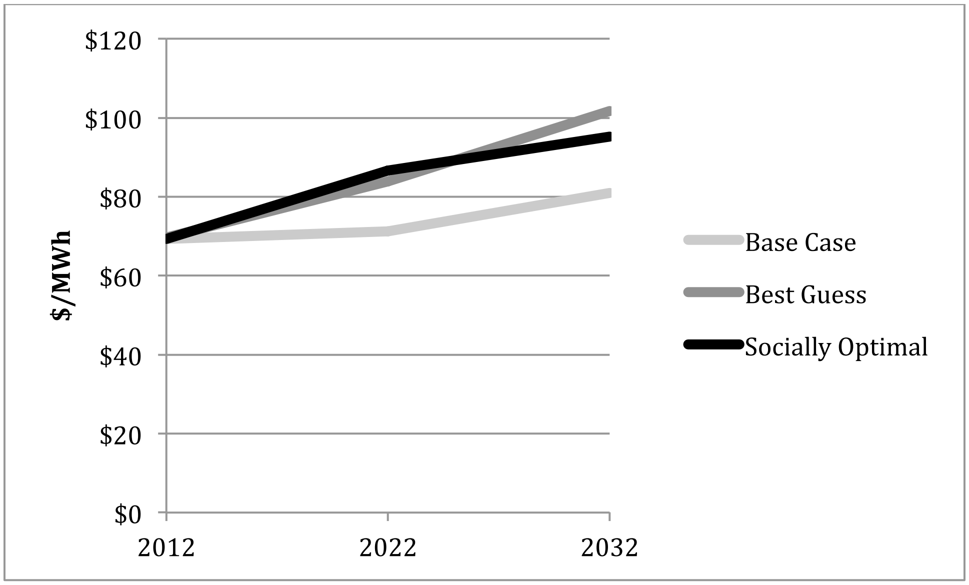


Figure 46: Average LMP in the Unified, Socially Optimal and Base Cases

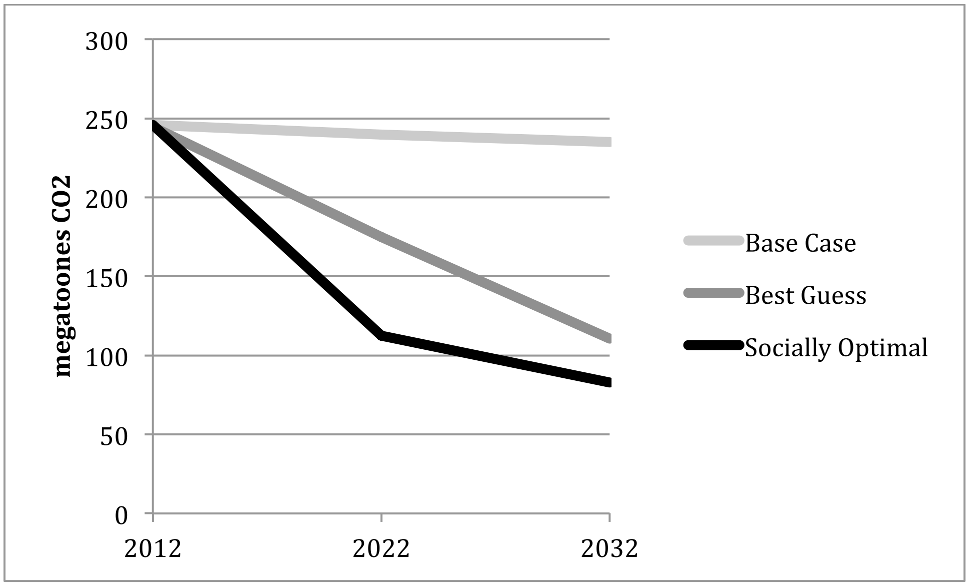


Figure 47: CO_2 Emissions in the Unified, Socially Optimal and Base Cases

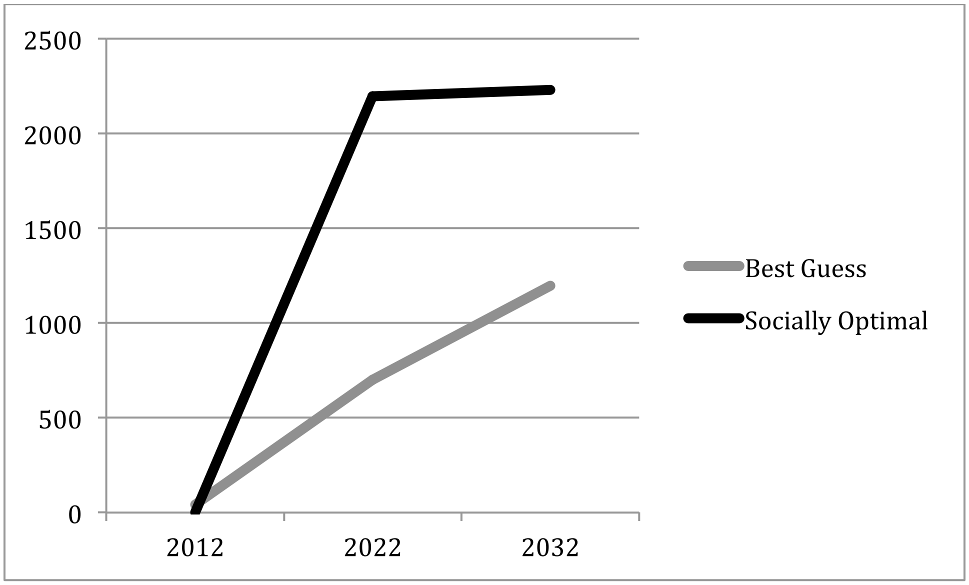


Figure 48: Lives Saved Per Year Relative to the Base Case

Fuel Type	Fixed Cost $/MW	Total Variable Cost $/MWh		
		Mean	Min	Max
Coal	$29,670	$37.26	$22.14	$293.16
Natural Gas	$14,620	$72.32	$39.47	$240.11
Wind	$28,070	$0	$0	$0
Nuclear	$88,750	$2.04	$2.04	$2.04
Oil	$14,620	$283.84	$31.47	$1,040
Hydro	$13,440	$0	$0	$0
MSW	$373,760	$0	$0	$0

Table 1: Information about Existing Generators

Fuel Type	Capital Recovery/Year $/MW	Total Variable Cost $/MWh	Total Possible Capacity Additions
Coal	$497,201	$29.05	10 GW
Natural Gas	$181,824	$39.05	32 GW
Wind*	$392,322	$0	3.5 GW
Nuclear	$1,141,454	$2.04	5 GW

Table 2: Information about New Generators

*Wind assumes an average capacity factor of 33%, excluding federal and state incentives.

Unit Name or Type	CO_2 Rate Tonnes/MWh	SO_2 Rate Tonnes/MWh	NO_X Rate Tonnes/MWh	Marginal Damages $/MWh
AES Cayuga 1	0.98	<0.001	<0.001	7.22
Average Coal	1.05	0.007	0.001	89.87
Max MD Coal	1.00	0.013	0.001	232.20
Average NG	0.65	<.0001	<0.001	2.36

Table 3: Emissions and Marginal Damages for example generating units