The RFF Haiku Electricity Market Model

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I. Introduction

The RFF Haiku model is a simulation model of regional electricity markets and interregional electricity trade in the continental United States. The model can be used to simulate changes in electricity markets stemming from public policy associated with regulation of the industry to promote competition and environmental benefits. Haiku calculates market equilibrium in each of 13 regions of the country conforming to the National Electricity Reliability Council (NERC) subregions, three seasons of the year, and four time blocks within each season.[1] A map illustrating the NERC subregions is presented in Figure 1. The model uses separate electricity demand curves for each of three sectors of the economy and supply curves that are endogenously determined using fully integrated modules that simulate, among other things, capacity investment and retirement, compliance with NO_x, SO_2, and CO_2 emissions regulations and accounting for mercury emissions, interregional power trading, and coal and natural gas markets. The supply curves are composed of 46 model plants that are each constructed by aggregating the generating unit inventory according to salient technology characteristics. Haiku has great versatility in simulating pollution abatement policies as well as emerging market structures, yet it is designed to be run on a desktop computer and can serve as a laboratory for sophisticated first-order policy analysis of the electricity industry.

The development of Haiku has benefited from the contributions of many persons, including primarily Dallas Burtraw, Ranjit Bharvirkar, David Evans, Karen Palmer, and Anthony Paul. In addition, Erin Mansur and Evelyn Wright also made contributions.

This document provides a narrative description and documentation for the Haiku model. The model is constructed using the Analytica modeling software. Each variable, index, or result is illustrated by an object in Analytica that appears as a node within an influence diagram. Hence, the screen views of the model itself provide additional documentation, and each object in the model has a description field that provides detail about how the model is solved.

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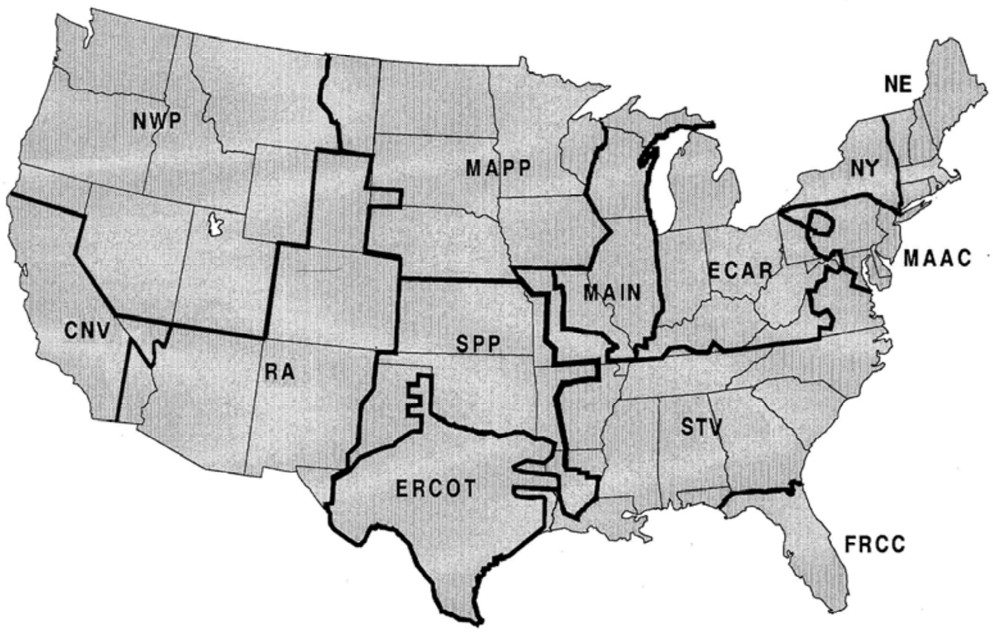
[1] The Haiku model includes the 13 NERC regions and subregions—New England, New York, MAAC, ECAR, STV, FRCC, MAIN, MAPP, SPP, ERCOT, CNV, NWP, and RA—as they were defined in 1999. Recently, Entergy Corporation has moved from the SPP region to the SERC region, but in Haiku it is still included in SPP. Identification of states in each region is provided in the section on Miscellaneous Model Parameters in the Appendix.

Figure 1. NERC Subregions circa 1999 as represented in Haiku.



II. An Overview of the Modeling Approach

Haiku uses a parsimonious approach in constructing a model that captures the detail of the national electricity market within a framework that can be used as a laboratory for exploring market economics and public policy. In this section we provide an overview of the level of detail represented in the model, and how the model solves.

Model Plants and Electricity Supply

Haiku constructs model plants that capture the distinguishing characteristics of constituent plants. Each model plant is described by six fields (not all are relevant to every model plant): prime mover (the power plant technology), fuel type, coal demand region, existing SO_2 scrubber (binary), relative efficiency, and existence status. The model plant capacity is calculated by summing the capacities of all generating units in the model plant; all other numerical parameters (latitude and longitude, emissions rates, costs, outage rates, heat rate) are determined by calculating the nameplate capacity-weighted average of the generating units. The capacity of each plant reflects the amount of time the plant is expected to be out for scheduled and unscheduled maintenance, and the availability of fuel supply in the case of wind and hydro technologies. Over time the available generation capacity changes as some existing plants retire, some new plants are built, and the availability of plants evolves according to rates that reflect technological improvement.

Supply curves in Haiku represent the schedule of variable costs for electricity generation within each season and time block. In each region of the country, the supply curves are composed of 46 model plants, 31 of which represent existing units, and the other 15 represent new plants that may be constructed in the future. Supply curves in each region are linked by the availability of interregional transmission capability.

Seasons, Time Blocks, and Customer Classes

Three seasons are represented in Haiku. Winter is a three-month season—December, January, and February. Spring-fall is a four-month season including March and April, and October and November. Summer is a five-month season that conforms to the ozone season in the eastern United States and the anticipated seasonal ozone trading policies in the region. The five-month summer season coincidentally does a good job of capturing peaks in temperature on the continent and associated peaks in summer electricity demand.

Within each season, hours are separated into four time blocks that reflect the level of aggregate electricity demand. The time blocks can be thought of as baseload, shoulder, peak, and superpeak. The baseload time block includes the 70% of hours in the season that have the lowest electricity demand. The shoulder includes the next 25% of hours. The peak includes the next 4%, and the superpeak includes the final 1% of hours in each season.

The total demand for electricity is aggregated from demand that is calculated for three customer classes: residential, commercial, and industrial. Each customer class has a unique willingness to pay for electricity and a unique response to changes in electricity price.

Simulation Years and Foresight

Power plants are long-lived investments, and capacity investment and retirement decisions must account for revenue and cost streams over a long time horizon. Haiku solves for a 20-year horizon and discounts future revenues and costs to the year in which an investment or retirement decision is made.

The Haiku algorithm does not solve for detailed equilibria every year. Instead, it solves for a number of simulation years and then interpolates to obtain data for intervening years. Typically, Haiku is solved for four to six simulation years, depending on the configuration of the policy being modeled. Years beyond that are represented as an extrapolation of the equilibrium that obtains in the last simulation year.

Equilibria in Electricity Markets

Equilibria in electricity markets involve the solution for a large number of control variables. Among the most visible of these variables is retail electricity price and electricity generation, and within the instantaneous electricity market equilibrium is defined as the point at which electricity supply equals electricity demand (while a wide array of control variables are simultaneously in equilibria). Considering the number of regions, seasons, and time blocks, electricity price equilibria are identified in 156 markets in each simulation year. There are hundreds of variables simultaneously converging toward equilibrium. An equilibrium or solution for the model involves the calculation of all these values.

Iteration and Control Variables

The Haiku model solves using an iterative algorithm that strives to achieve an equilibrium that satisfies all the constraints imposed upon the model. To do this, many endogenous variables are specified as control variables, and then iteratively adjusted until all constraints are satisfied. These control variables are a minimum set that provides adequate latitude to achieve equilibrium.

Data

The supply data used in Haiku are primarily from databases constructed from forms compiled by the Energy Information Administration (EIA) and from the Federal Energy Regulatory Commission (FERC), supplemented with data from the Environmental Protection Agency (EPA). Data from public sources are supplemented in some cases with data coming from specific industry studies that address one technology or region of the country.

The demand data used in Haiku rely primarily on information collected by the Energy Information Administration. Most of the estimates of the elasticity of demand are drawn from the academic literature, occasionally supplemented for a particular region by a specialized source of data.

Each of these items is discussed in more detail in the following sections.

III. Institutions and Policies

Haiku can be used to simulate changes in electricity markets stemming from public policy associated with changes in regulation, including environmental rules, and market structure of the industry, including competition.

Market Structure

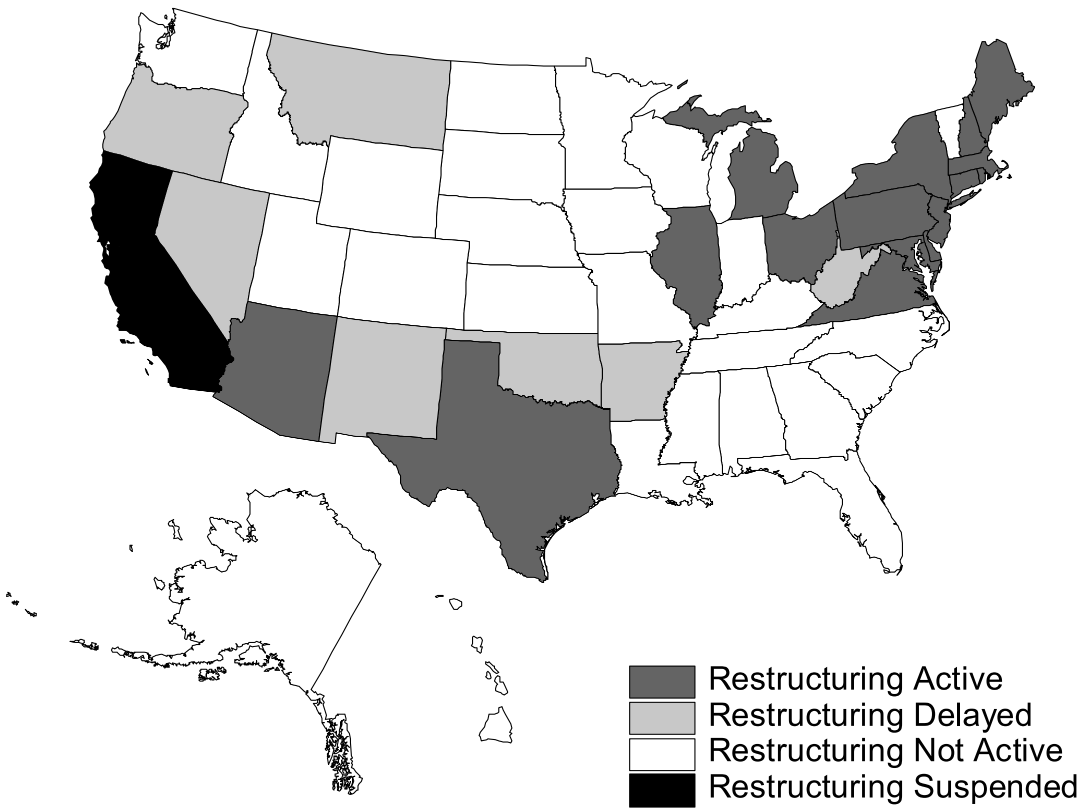
The passage of the Energy Policy Act of 1992 unleashed a process that is changing the regulatory and market structure of the U.S. electric power industry. The act called on the Federal Energy Regulatory Commission to order all transmission-owning utilities to open access to their transmission systems at nondiscriminatory, cost-based transmission rates to facilitate competitive wholesale power transactions. About half the states have now passed legislation or made regulatory decisions to allow retail competition. However, the timing varies among the states.

Changes in the regulation and market structure of the industry affect the incentives and behavior of participants in electricity markets, including generators, transmission owners, and electricity consumers. Important questions in the debate about electricity restructuring are the environmental effects of the move from regulation to competition, the mix of generation technologies, and the price of electricity.

In Haiku, two basic approaches are modeled to represent the alternative forms of utility regulation in practice. Regulated prices based on average cost of service are the traditional way of setting prices. The alternative is competitive prices based on the willingness to accept the cost of the marginal generation or reserve unit. Between these two polar approaches, subtle institutional details may vary along a continuum.

Each subregion in Haiku is assumed to use one method or the other to determine prices. In many applications, we look at the states within a region to identify those that have committed to competitive pricing by a date certain. When the majority of the population in a region lives in states that are expected to practice competitive pricing, then that region is treated as competitive. A glimpse of recent activity among the states is represented in the map in Figure 1.

Figure 2. Status of Restructuring as of November 2001. Source: U.S. Energy Information Administration, www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html.



Regulated Prices (Average Cost Pricing)

The retail price of electricity can be viewed as having two components: the price of generation and the price of transmission and distribution service. In regulated regions, the price of both components is set according to average cost. That is, total costs, including annual capital costs and variable costs, are divided by sales units (kWh) to achieve an average cost of service ($/kWh). In practice, the retail price may differ by customer class and is set to attract business and promote regional economic development, or to reflect the greater cost of providing service to residential and commercial customers if the distribution network is not important to many industrial customers. In Haiku, differentiation in prices among customer classes is reflected by an adjustment to transmission and distribution costs. Under regulated prices the generation component of electricity price is the same for all customer classes. Usually, it is allowed to vary by season. Therefore the average price paid over the entire year may vary if demand is spread over seasons in a different way for each customer class. Finally, reserve services are specified as a requirement that varies for each region, and the cost of maintaining reserves is added to total costs and folded into the price.

Competition (Marginal Cost Pricing)

In competitive regions, the price of generation is based on the marginal cost of generating electricity, but transmission and distribution services are still priced at average cost.[2] The marginal cost of generation includes the variable cost of the marginal unit providing electricity within a given time block. The degree to which cost categories, such as fixed operation and maintenance (O&M), are loaded into variable costs is an empirical question, and the model is flexible in changing this assumption. The default setting is that no fixed O&M and no capital costs are included in variable costs.

Competitive regions also differ from regulated regions in how the cost of reserve services is recovered. After the available capacity is ordered to provide electricity at the lowest possible cost, the remaining available capacity is reordered to identify the capacity with the lowest capital costs. Then, the marginal unit necessary to provide reserve services is identified, along with the payment necessary to keep that unit in service in each given time block after accounting for payments coming from other time blocks for either generation or reserve services. The payment to the marginal reserve unit is termed the reserve price. Finally, the reserve price is paid to all generating and reserve units to ensure incentive compatibility between units identified as generators and those identified to provide reserve service. The electricity price in a time block is therefore the sum of generation, reserve, transmission, and distribution costs.

An important distinction in practice is between wholesale competition and retail competition. The former describes competition in wholesale power markets, and the way that prices for bulk power in those markets are determined. The latter describes competition in retail markets, and the way that prices for sales to final customers are determined. In practice, a region may have wholesale competition, with generation prices determined by marginal costs, but it could still have reserve services provided in a variety of ways that resemble regulation. In Haiku, the identification of a region as competitive does not distinguish between wholesale and retail competition.

Time-of-Use Pricing

One important way that prices may vary between regulated and competitive markets is in the application of time-of-use (sometimes called time-of-day) pricing. Time-of-use pricing means that the price differs over the course of the day according to a predetermined schedule that is known to the consumer. If the price differs instantaneously with the level of electricity demand and available supply, it is termed real-time pricing. Although they have important differences in practice, in Haiku, time-of-use pricing and real-time pricing are analogous because costs do not vary within a time block. We adopt the convention of terming this time-of-use pricing.

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[2] Most regions that have implemented restructuring allow consumers to take "standard offer service" under capped rates that are generally somewhat lower than historical rates under average cost pricing. In most cases this option does not continue past 2008. We do not incorporate the possibility for standard offer service in our scenarios.

Under regulated pricing, customers typically do not see different prices over the course of the day, and that is the way this pricing regime is modeled in Haiku. However, competitive pricing may introduce time-of-use pricing. Most analysts assume that the use of time-varying prices of electricity will become more widespread as a result of restructuring, although the degree and pace of this change are very uncertain. In Haiku, one can choose to implement time-of-use pricing for individual customer classes within a region.

In many analyses, we represent the assumption that under competition there will be expanded application of time-of-use pricing for industrial customers in any region that has implemented marginal cost pricing. These industrial customers would face higher prices in peak periods and lower prices in off-peak periods than under average cost pricing. Typically, the price elasticity of demand for industrial customers is assumed to be –0.30, implying that a 10% increase in price in the peak periods will result in a 3% reduction in demand. Since prices in off-peak periods are lower, demand is expected to rise during those time blocks under time-of-use pricing.

For residential and commercial customers in all regions, the retail price is assumed not to vary between peak and off-peak times, but it can vary across seasons. However, these settings may be varied by the model user to examine alternative scenarios.

Effect on Technical Parameters

Competition in the industry is expected to quicken the pace of technological change. A priori, the characteristics of the postrestructuring electricity industry and market are highly uncertain, but several technological parameters may change as a result of restructuring. Productivity change is implemented in the model through changes in four parameters: improvements in the maximum capacity factor at existing generators, reductions in the heat rate at existing coal-fired generators, reductions in operating costs, and reductions in general and administrative costs at all existing generators. The rate of change in each is a function of the proportion of the country that has committed to marginal cost pricing. A single value applies to the entire country, reflecting the common availability of technology and the common investment climate shared by firms in different regions, as well as the expectation that marginal cost pricing and competition could spread to all regions in the future. As the number of regions committing to marginal cost pricing grows, the rate of improvement in these four parameters grows.[3]

Values that could be used as default settings in the model are presented in Table 1, which gives the ratio of parameters under a limited restructuring case compared with a case in which restructuring is achieved on a nationwide basis. The ratios compare 2008 values with 1997 values, based on assumptions developed by the collection of energy modelers who participated in Stanford University's Energy Modeling Forum Working Group 17 (2001).

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[3] Specifically, the rate of change in the three productivity change parameters is a weighted sum. The sum is the proportion of megawatt hours sold in marginal cost pricing regions times an optimistic rate of change, plus the proportion of megawatt hours sold in average cost pricing regions times the historical rate of change (under average cost pricing) in each parameter. The weights are constructed using electricity sales data from 2000, prior to the implementation of restructuring in most states.

Table 1. An illustrative characterization of economic regulation and distinguishing features in 2008.

Characterization	**Extent of Competition**	
	Limited	Nationwide
Pricing Institution	Mix of Regulation and Competition	Competition
Stranded Costs	n/a	Recovery of 90%
Renewables Portfolio Standard	None	Renewable Portfolio Standard
Transmission Capability	No change	10% Expansion
Ratio of Technical Parameter Values 2008 to 1997		
Maximum Availability Factor	1.02	1.04
Heat Rate	0.99	0.97
General and Administrative Cost	0.75	0.67
Nonfuel O&M Cost	0.76	0.70

Stranded Cost Recovery

The transition to competition has ignited concerns by many power companies that some portion of their previous investments may not be profitable under competition. The undepreciated portions, or the book value, of existing assets in 1999 are considered potentially stranded assets. Stranded assets could have a value, in principle, that is either less than or greater than the book value at the time of transition from regulated pricing to competitive pricing; these are termed stranded costs and stranded benefits. All or some portion of stranded costs or stranded benefits is recoverable (or chargeable) in Haiku. Table 1 illustrates one possible setting in Haiku—in this case, that 90% of stranded costs are recovered. The method for calculating potentially stranded costs and actual stranded costs, and for recovering a portion of those costs, is described below.

Transmission Policies

In general, transmission is modeled as the capability to send power among the 13 NERC subregions. The costs of transmission and distribution services are held constant. This approach is a compromise that balances two considerations. On the one hand, existing transmission and distribution capital is being depreciated, which suggests that costs should decrease. On the other hand, capacity is also being replaced and modernized, which imposes new costs. Additions to transmission capability are implemented without additional cost under the assumption that most improvements and expansion in capability are likely to come along existing easements and corridors, probably through software advances such as flexible a.c. transmission systems or FACTS technology, rather than through major new capital investments in new transmission lines.

The costs of transmission include line losses and a fixed transmission fee (a "pancaked" rate) applied to every bilateral transmission exchange. Our model assumes that there are no transmission constraints within regions, and therefore we do not model expansion of the intraregional transmission system. However, we do account for average losses associated with intraregional transmission and distribution to retail customers.

A key uncertainty surrounding the future of the U.S. electricity system is the rate at which transmission capability may be expanded. The move toward competition in the industry has proven unsettling for the future of transmission because of the confusing array of incentives, or lack thereof, for new investments in transmission. Consequently, the amount of new investment in transmission has fallen in recent years.

With more open markets there will be greater pressure to trade electricity, and presumably that pressure will be translated into expanded transmission capability. In many analyses, we anticipate this outcome by varying transmission capability between the regions with the pace of restructuring in the industry, as illustrated in Table 1. However, the model user is free to vary other parameters, such as the amount of transmission capability between NERC regions or the cost of transmission service, to determine the impact on power trading, electricity prices, and ultimately emissions.

Environmental Policies

Changes in the market structure of the electricity industry are thought by many to have important implications for the choice of generation technology in the future and thereby on the environment. In addition, the industry is facing an unprecedented array of environmental regulations and scrutiny in the public policy process.

Haiku can represent a wide variety of policies for the major air pollutants. The policies differ in their effect on electricity price and the incentives they provide firms and consumers. Haiku can compare the impact of policies that have been announced with policy surprises that emerge at any time over the model's planning horizon.

New Source Performance Standards

The Clean Air Act specifies emissions rates for new facilities using various generation technologies. These rates and the associated costs are represented in the characterization of model plant categories for new technologies.

Old Source Performance Standards

The imposition of new source performance standards and the evolution of technology have led to a differentiation in the efficiency and emissions rates of plants according to vintage. An old source performance standard, which would force all existing sources to achieve an emissions rate of some level, has therefore been proposed. This can be modeled as a technology standard in Haiku.

Tradable Emissions Permits (Emissions Allowances)

An alternative to a technology standard is a cap-and-trade program, such as that in place for SO_2 under the 1990 Clean Air Act Amendments. Haiku can model trading programs for SO_2, NO_x, and CO_2. The programs can be annual or seasonal, and they can cover the entire nation or a subset of regions. Multiple programs for a given pollutant can be modeled simultaneously. In the case of SO_2, banking of emissions over time can also be modeled.

Emissions Taxes

The analogue to a tradable permit program is an emissions tax. Haiku can model a tax as a cost on emissions. Emissions taxes can be modeled for SO_2, NO_x, and CO_2. As with tradable permits, Haiku can model taxes that differ by region and season, and it can model multiple programs for a given pollutant simultaneously.

Social Cost Adders

In the early 1990s there was considerable interest among state public utility commissions in factoring the anticipated environmental costs and other social costs into integrated resource planning. Adders are intended to affect the dispatch and capacity planning decisions of firms in a way that is strongly analogous to taxes. That is, a shadow price reflecting external social cost is added to the variable cost of a facility. However, adders differ from taxes because they are not actually charged to firms and therefore do not directly affect the price of electricity. Indirectly, they affect the price of electricity by providing incentives for a different mix of technologies for generation. Haiku can model adders for a set of policies that are analogous to those for emissions taxes.

New Source Review

Generation facilities that undergo major modification or renovation are required to bring their emissions rates up to new source performance standards, or if they operate in areas that are out of attainment with national ambient air quality standards, they are required to attain emissions rates comparable to those from the best available control technologies (BACT). New Source Review (NSR) is the regulatory process that governs this requirement. Haiku does not accommodate investments to expand generation at existing facilities. However, Haiku does allow for increased utilization of existing facilities, which could result from improvements in heat rates and other technical parameters over time or simply from increase in demand.

To represent NSR in Haiku, the user can impose a constraint that caps the utilization rate of existing coal units according to historical utilization rates. If turned on, the constraint allows utilization of a coal-fired model plant to increase only if best available control technology is installed on at least 10MW at the model plant.

Recently, the NSR program has involved enforcement activity and legal settlements by which many existing facilities have committed to install BACT technology for SO_2 and NO_x according to a timeframe that may play out over several years. Haiku represents the installation of postcombustion controls that are specified by these settlements.

Allocation of Revenues from Pollution Policies and Cost Recovery

Among the most important aspects in the determination of a pollution policy are how permits will be allocated, what will happen to the revenues collected under a permit or tax system, and what provisions will ensure cost recovery. Haiku can represent a wide variety of policies. Grandfathering refers to the allocation of permits (or revenues) to all or a subset of sources based on historical electricity generation or historical emissions. The generation performance standard (GPS) (or equivalently, output-based allocation) describes the allocation of permits (or revenues) on a basis that is continually updated to represent current or recent-year shares of electricity generation. An auction describes a distribution on the basis of willingness to pay, and revenues under the auction can be redistributed on any basis. Under GPS, some portion of permits may be allocated to provide an incentive for conservation, modeled as the demand conservation incentive (DCI).

Under regulated prices, typically the regulator allows firms to include the cost of pollution policies (permit or tax costs) as part of total costs, which can therefore be recovered in electricity price based on average costs. In competitive regions, however, whether the cost of pollution policies is recovered is analogous to the question whether any variable or capital cost is recovered. The answer depends on the cost of the marginal unit. Recognizing this, some regulators have provided for a recovery of specific pollution-related costs even when firms operate in competitive regions. This also can be modeled in Haiku.

Support for Renewables

Still another way that environmental outcomes are affected by regulatory decisions has to do with support for renewables. A popular way that some states support renewables is a renewable portfolio standard (RPS). Essentially, RPS is like a tradable permit program. Each firm is required to hold a number of renewable permits equal to some share of its total generation. A firm earns a permit for each unit of electricity generated by a qualifying renewable technology. This is modeled in Haiku; further details are provided below.

IV. Model Components within a Static Framework

The Haiku model proceeds through multiple iterations to achieve convergence to a large set of control variables. In this section we describe the main features of the model if viewed as a single iteration. By viewing the model in this way, one gets only limited feedback over the time horizon of simulation years; thus this description pertains loosely to a static one-period model that is solved for each simulation year.

A single iteration of the model takes as given the value of all control variables for the electricity industry, including capacity configurations, electricity prices, pollution controls and policies, interregional power trading and prices, and fuel prices. The behavior of the control variables that leads to convergence is described in Section V. The purpose of a single iteration is to evaluate a partial equilibrium at the given control variables so that adjustments to them can be made and the next iteration will be closer to convergence.

In the simplest way possible, a single iteration of the model can be described as calculating electricity demand, including interregional trading, in each region and time block, then meeting demand for both generation and reserves using a supply curve constructed of model plants. This is described in detail below. The results of these calculations are used to inform the next set of control variable values, which are described in the following section.

Demand

Using data primarily from the Energy Information Administration, Haiku classifies electricity demand by three customer types (residential, commercial, and industrial), by three seasons (winter, spring-fall, and summer), and by four time blocks (superpeak, peak, shoulder or middle, and baseload or off-peak hours). Demand within each block is represented by a pricesensitive demand function where each customer/season/time block is characterized by an elasticity value that is in principle unique, although in practice the values are limited by availability of data. The function is in the form:

$$D = AP^{\varepsilon}$$

where D is the quantity of demand, A is a constant, P is electricity price, and the superscript on price (ε) is the elasticity of demand with respect to price.

To use the demand functions, Haiku requires that A and ε be derived independently. The elasticity estimate ε is derived directly from historical data. The constant A is back-calculated using ε and historical data on demand and price. Once A and ε are available, Haiku can plug any quantity or price into the function to calculate the other. The sources of data and values for parameters in the demand functions are described in the section on data below.

The demand function is used to calculate native demand, but the amount of electricity demanded from suppliers in a region will be different from native demand because of intraregional power losses and interregional power trading and losses. A single iteration of the model takes as an input the quantity of power traded interregionally. Native demand values are adjusted according to interregional power trades and line losses to determine total demand for electricity within a region and time block. The suppliers in a region must satisfy this total demand plus a bit extra to account for intraregional line losses. Suppliers must also have capacity in reserve equal to a percentage of native demand.

Supply

Haiku supply curves are constructed from model plants using control variable data that are taken as given for a single iteration. Supply curves for generation are constructed according the variable costs, and supply curves for reserve services are constructed from the remaining capacity according to going-forward fixed costs (explained in detail below).

Production Capability

The capability of model plants to generate electricity and provide reserve services are a function of nameplate capacity, the ratio of nameplate capacity to generation capability, unscheduled outage rate, and the rate and allocation of scheduled outages.

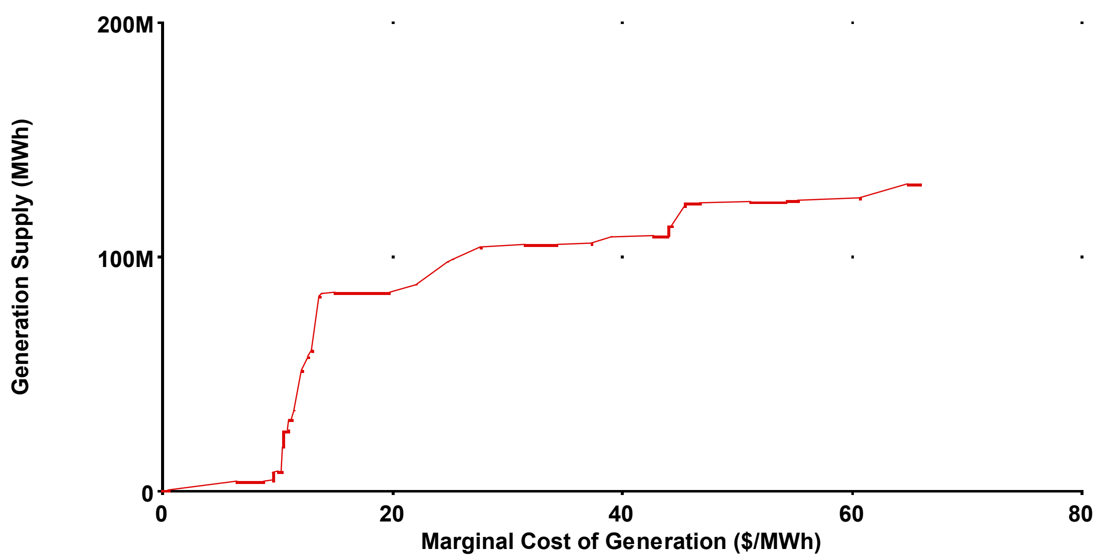
Model plant nameplate capacity is a given in a single iteration. The ratio of nameplate capacity to actual generation capability varies by season and is known from historical data. From these data the generation capability of each model plant is calculated. However, a plant is not able to produce this much electricity because it must occasionally be out of service for scheduled and unscheduled outages. Unscheduled outages are assumed to occur with equal frequency during periods of the year that the facility is scheduled to be in operation. Scheduled outages are allocated to seasons in which capacity is most expendable, according to the algorithm described in Section V. Thus, production capability of each model plant varies by season and is the product of nameplate capacity, the ratio of generation capability to nameplate capacity, (1 – unscheduled outage rate), and (1 – seasonal scheduled outage rate).

Generation

Model plants are ordered according to variable costs in order to determine their merit order for generation within a time block. Variable costs include variable operation and maintenance costs, including that of pollution controls, plus fuel costs, the costs of paying pollution taxes or buying pollution allowances, the cost or subsidy from a renewable portfolio standard, and the calibrator. Heat rate and therefore fuel cost as well as variable O&M for generation are not discrete numbers but continuous functions. Therefore the total variable costs are distributions that are uniform between a minimum and a maximum defined by the lesser of either the constituent plant range from the mean to the minimum observed variable cost (a function of heat rate and variable O&M), or the standard deviation. This feature serves to improve the convergence of the model while also better representing actual distributions in variable costs among constituent plants than a point estimate.

The figure below is an example supply curve for generation for a single region and time block. Using the demand for electricity generation described above, the model reads off the supply curve to determine generation by model plant. The marginal cost of generation is also read off this curve.

Figure 3. An illustration of generation and marginal cost.

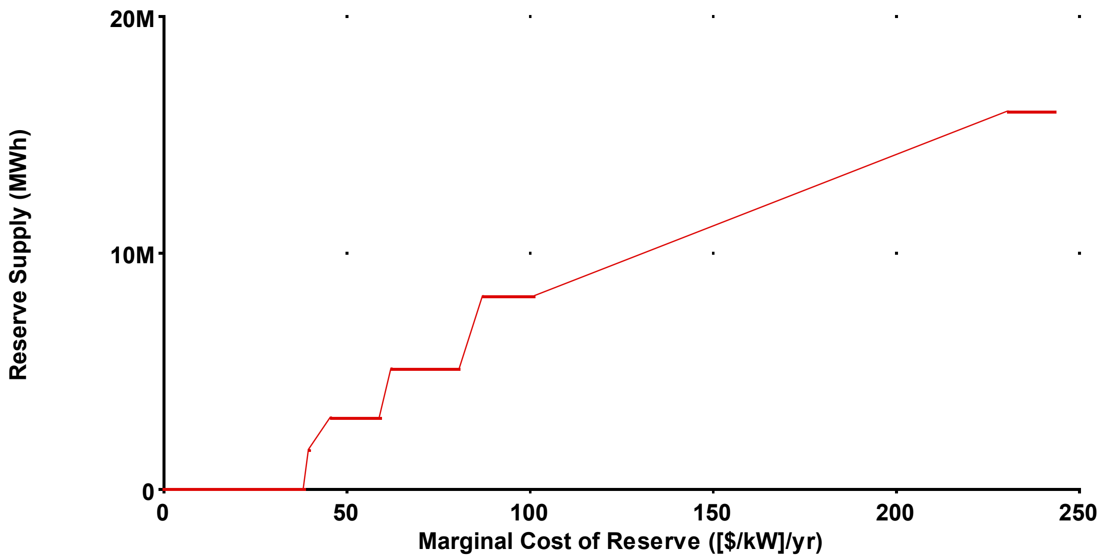


Reserve

The supply curve for reserve services is constructed in a manner very similar to that for generation. The generation capability of each model plant is reduced by the amount of generation that it performs to determine the reserve capability. This capability is ordered by annual going-forward fixed costs. The components of going-forward fixed costs include all capital costs for new model plants, capital costs for pollution controls at existing plants, and fixed operation and maintenance costs, including pollution controls, general and administrative costs, tax costs, and the cost of the premature displacement of existing capacity in regulated regions. Because fixed

O&M of generation is not a discrete number but a continuous function, the supply curve for reserve takes on a shape similar to that of the generation supply curve. The figure below is an example supply curve for reserve for a single region and time block. Using the demand for electricity reserve described above, the model reads off the supply curve to determine reserve by model plant.

Figure 4. An illustration of reserve and marginal cost.



V. Model Components within a Dynamic Framework

The Haiku model solves using an iterative algorithm that strives to achieve an equilibrium that satisfies all the constraints imposed upon it. To do this, many endogenous variables are specified as control variables, then repeatedly adjusted until all constraints are satisfied. These control variables are a minimum set that provides adequate latitude to achieve equilibrium. The control variables are as follows:

1. nameplate capacity by model plant (investment, retirement);
2. electricity, generation, and reserve prices;
3. fuel costs (coal, natural gas, and biomass);
4. interregional power trading quantity and price;
5. pollution controls and allowance prices;
6. stranded assets;
7. seasonal allocation of scheduled outages;
8. allocation of hydroelectric generation over time blocks;
9. real cost of capital;
10. percentage of biomass cofiring by model plant;
11. price of renewable portfolio standard (RPS) permits; and
12. value of demand conservation incentive (DCI).

For each control variable, Haiku makes an initial guess at its value, then solves the remainder of the model (one iteration). Using the constraints described in detail in this section, Haiku determines, for each control variable, what its value should have been assuming that all other control variables are unchanged. Because of the partial equilibrium nature of this calculation, it yields a new set of control variable values that may still not be internally consistent. So on the next iteration, Haiku does not use exactly this partial equilibrium value for each control variable, but instead uses a value that is between the previous guess and the partial equilibrium value. This new set of control variable assumptions may also not be internally consistent, but it moves the model closer to a set of control variables that are in equilibrium.

The selection of a precise new value for each control variable (between the previous guess and the partial equilibrium value) is vital for timely and accurate convergence of the model. Haiku employs a method of intelligent adjustments to the previous guesses that cause the control variables to converge toward equilibrium by making increasingly smaller adjustments, while allowing the control variables latitude to rectify large disequilibria.

Consider an example. The generation component of electricity price in SPP during the base hours of the summer is one control variable. Assume that the initial guess for this variable is \$75/MWh. Based on this assumption and the value of other control variables, Haiku calculates the electricity demand in SPP during this time block. This yields, based on other control variable guesses (investment and retirement, allocation of scheduled outages, interregional power trading, etc.), a marginal generation cost of \$37/MWh. Assuming that the scenario being modeled is one in which the generation portion of electricity price should equal the marginal cost of generation, the generation component of electricity price needs to be smaller. However, instead of adjusting the price all the way to \$37/MWh (which would yield a marginal generation cost much greater than \$37/MWh), we adjust only to \$61/MWh. This will raise electricity demand, which will tend to raise the marginal generation cost, which will tend to bring the generation component of electricity price and marginal generation cost closer together. Similar calculations are made for all other control variables, and the next iteration is then performed using an entirely new set of control variable assumptions. After many iterations, when the adjustments to all the control variables are approximately zero, equilibrium is achieved and the model is finished.

Control Variables

This section contains a description of each control variable and the set of constraints that govern its behavior.

Investment and Retirement

The electric utility capacity in Haiku is represented by model plants. Therefore, when considering capacity changes, Haiku considers not the individual generators but the model plants. Because the model plants are composed of many separate generating units, it is reasonable to allow a model plant to partly retire, as this represents the case when some constituent generators retire but others do not. Because each model plant represents a set of generators that have nonidentical parameters, the assumption is that the retiring fraction of a model plant has the least efficient capacity. The performance and cost parameters of the model plant improve because the remaining capacity is more efficient.

The investment-retirement algorithm relies on foresight. For it to function at its maximum capability, Haiku simulates multiple years simultaneously and through iteration informs each year with the other years. The determination of retirement and investment is made on the basis of maximizing profits. In average cost regions, profits are constrained to equal zero (total revenues equal total costs). In marginal cost regions, profits greater than zero may accumulate. The determination of retirement and investment is fundamentally the same in both cases. The revenues earned by a model plant are compared with the variable costs and appropriate capital costs to determine the going-forward profits of each model plant. The plants that make the greatest contribution to minimizing costs or maximizing profits expand over time while the ones making the least contribution either do not expand or actually shrink, if some of their capacity retires, depending on the cost of replacing the retired capacity with new capacity. These calculations are forward looking 20 years after the first year included in the simulation.

The specification of capacity bounds varies by whether the model is being run as a baseline or a policy case. For a baseline case, the bounds depend upon the capacity decision made in the most recent simulation year (MRSY). For example, if Haiku is set to solve for 2000, 2005, and 2010 based on 1997 data, the 2000 capacity bounds depend on 1997 data, the 2005 bounds depend on the 2000 solution, and the 2010 bounds depend on the 2005 solution. It is through iteration that Haiku is able to look both forward for profit maximization or cost minimization and backward for capacity bounds. The capacity bounds are set differently for each of three types of model plant: existing, planned, and new. For existing plants the lower bound on capacity is zero in all years, and the upper bound is the amount remaining in the MRSY. For planned plants the lower bound is the amount constructed by the MRSY, and the upper bound is the amount constructed by the MRSY plus the amount planned for construction since the MRSY. For new plants the lower bound is the same as that for planned plants, and the upper bound is the amount constructed by the MRSY plus an additional amount that is constrained by an exogenously specified annual capacity construction rate.

For a policy run, the capacity bounds behave in a similar way but are also constrained by the capacity configurations from the baseline run. Part of the specification of a policy run is the year in which the policy is announced. In any year before the policy announcement, the model is bound to have exactly the same capacity configuration as the baseline run. In any year after the policy announcement, the bounds vary according to the type of model plant—existing, planned, or new. An existing or planned model plant has the same set of constraints as a baseline run. A new plant has the same set of lower bounds as a baseline run but has different upper bounds for a short period. The upper bound baseline constraints begin after a delay after the policy announcement year. The delay is the construction lead time—the time it takes for a plant to be constructed once the decision has been made to build it. This varies by model plant and is in the range of two to four years. Before the baseline constraints begin, a new model plant is constrained to have no more capacity than the baseline run.

Within the capacity bounds, each model plant incrementally adjusts its operational capacity according the net present value of its going-forward profit stream. At the end of each iteration, Haiku applies the adjustment algorithm that determines whether each plant should have more, less, or the same capacity, then institutes the change and revisits the calculation at the end of the next iteration. The amount of capacity under consideration for addition or removal during each iteration is always a fraction of the total model plant capacity and shrinks as the model approaches equilibrium. The algorithm used to determine the direction of the change varies according to whether the user has specified average or marginal cost pricing. In either case, Haiku utilizes the going-forward concept of costs and revenues.

For all scenarios, Haiku assumes that no construction or retirement of hydroelectric generating capacity (both conventional and pumped storage) will occur.

Going-Forward Cost, Revenue, and Profit

Simply put, going-forward costs (GFC) are all costs that can be avoided with advance planning. For nonexistent plants (those under consideration for investment) this includes all costs: variable and fixed operation and maintenance costs, including pollution controls; capital costs, including pollution controls; general and administrative costs; tax costs; and the costs for the premature displacement of existing capacity in regions that are regulated. For existing plants GFC includes all costs except capital costs. GFC are used in the retirement-investment calculations because they are the costs that can be affected by the retirement-investment decision. Other non-GFC (existing capital) are unavoidable and are unaffected by the retirement-investment decision. Under average cost pricing, there is an additional GFC for new generators that is, in aggregate, equal to the undepreciated book value of existing capital that has been prematurely retired by the addition of new capacity.

Going-forward revenue (GFR) is that which can be attributed to a generator: revenues from exported power, reserve revenues, revenues from stranded assets recovery, and revenues from a tax credit policy. Going-forward profit (GFP) is the difference between going-forward costs and going-forward revenues. It is the appropriate measure of the profitability of a generator. A generator that has positive GFP is one that is desirable under all circumstances. A generator with a negative GFP is undesirable in a marginal cost pricing regime but potentially desirable in an average cost pricing regime (under which a generator that loses money but loses less money than the best alternative is desirable, since profits are counted at an aggregate utility level). GFP is calculated at each model plant for all years included in the simulation. For interim years the going-forward profit is interpolated, and the entire stream of profits is then expressed as a net present value.

Average Cost Regime

The retirement-investment algorithm for the average cost pricing regime has two essential elements. First, there must be exactly enough, without excess, capacity to satisfy regional electricity demand and reserve requirement, and second, this must hold at maximum aggregate regional net present value of going-forward profits (NPV of GFP). (Within an average cost region, the NPV of producer surplus is constrained to be zero—i.e., revenues equal total costs, except for the possibility of earning revenues from selling wholesale power outside the region.) These two criteria are satisfied for each region by a series of capacity additions and subtractions through the iteration process. At each iteration Haiku determines the amount of missing or excess capacity in each region in each year. If there is excess capacity, then the model plant fractions under consideration for removal are sorted according their NPV of GFP, and the least profitable are removed such that just enough capacity will remain to satisfy the regional capacity requirement. If there is inadequate capacity, then the model plant fractions under consideration for addition are sorted according to their projected NPV of GFP, and the most profitable are added such that just enough capacity will be available to satisfy the regional capacity requirement.

Marginal Cost Regime

The retirement-investment algorithm for a marginal cost pricing regime is simpler than for the average cost pricing regime. Under marginal cost pricing Haiku treats the electricity sector as completely divested to independent power producers (IPPs), who must see a profit at each generator. Therefore, under marginal cost pricing, each model plant's behavior is determined strictly by its going-forward profit. A plant that has positive NPV or GFP or is already existing and has a positive GFP adds the amount of capacity under consideration. A plant with negative NPV of GFP—either a new plant under consideration for investment or an existing or planned plant that also has negative GFP—removes the amount of capacity under consideration. Any model plant that meets neither criterion is unchanged.[4]

Electricity, Generation, and Reserve Prices

Electricity, generation, and reserve prices are the control variables that contribute most to the achievement of equilibrium in electricity markets. Generation and reserve prices determine the distribution of revenues to producers and are the building blocks of electricity price, which sets electricity demand. The charge for intraregional transmission and distribution (T&D) is another important element of electricity price, but it is not an endogenous variable in the model and is therefore mentioned only briefly in this section.

Electricity pricing varies substantially depending on whether a region is regulated or competitive. In marginal cost regions, electricity, generation, and reserve prices are set at the margin; in average cost regions, they are set to recover industry costs. The details of how they are set are explained in the remainder of this section.

Marginal Cost Pricing

Under marginal cost pricing a separate generation price and reserve price are calculated for each region and time block. The marginal generation cost is determined simply by reading the variable generation cost of the marginal unit from the generation supply curve in each time block. Generators earn the generation price for each MWh produced for native consumption.

The capacity reserve charge is less straightforward. At each iteration Haiku considers whether demand for reserve is met. If it is, then the capacity reserve charge is reduced. If not, then the capacity reserve charge is increased. It is through iteration that the model eventually settles into a capacity reserve charge that is in equilibrium. The allocation of reserve revenues is also a bit complicated. If the reserve price is higher than the generation price in a time block, then there is an incentive for a unit to forgo generation in favor of reserving. To remove this incentive incompatibility, reserve revenues are distributed evenly to all model plants that generate or reserve.

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[4] To be more precise, a plant must have negative GFP and negative expected GFP in the next period to have capacity reduced. The analogous case holds for adding capacity.

The time block–specific electricity price without intraregional T&D is the sum of three parts: generation price, capacity reserve charge, and stranded assets charge. The stranded assets charge is described below. Haiku allows marginal cost pricing with or without time-of-day pricing (TDP). Real-time pricing is the purest form of marginal cost pricing. TDP is the next best option and is employed by Haiku. With or without TDP, Haiku calculates the time block–specific electricity price without intraregional T&D described above. If TDP is employed, then the calculation of electricity prices is complete after the addition of intraregional T&D. Because T&D is specific to customer class, the resulting electricity prices are also customer class specific. Without TDP, the time block–specific electricity price without intraregional T&D values is used to calculate a customer class demand-weighted average electricity price that removes variability by time block but adds variability by customer class. To this the intraregional T&D charge is added.

Average Cost Pricing

The pricing algorithm for average cost regions requires much less sophistication. The electricity price is set so that the regional aggregate producer surplus is equal to zero (net of profits from exported power). It is calculated by comparing regional revenues (not including revenues from exported power) with regional annual costs (also not including costs for exported power). If revenues exceed costs, then the electricity price is reduced. If costs exceed revenues, then the electricity price is increased. No effort is made to allocate revenues for generation separate from those for reserve because the model plant's specific profitability is not important when setting the electricity price to make *aggregate* producer surplus zero.

Fuel Modules

Haiku has separate fuel market modules for coal, natural gas, and biomass. All other fuel prices are specified exogenously, with most changing over time. The coal and natural gas modules are derived entirely from Energy Information Administration data. The biomass module is derived from a database compiled by Oak Ridge Laboratory.

Natural Gas

EIA reports projections of natural gas consumption and national average wellhead price for the entire U.S. economy for three cases: low economic growth, reference, and high economic growth. Haiku uses these three data points to derive a linear natural gas supply curve for the entire U.S. economy. EIA also reports the projected natural gas consumption by all sectors of the economy except electric utilities. Using these data, Haiku calculates the national average wellhead price for natural gas based on endogenous natural gas consumption by the electric utility sector and exogenous consumption by all other sectors. Also from EIA data, a natural gas markup (transportation fee) is calculated for each region of the country, allowing Haiku to express the delivered natural gas price as a function of electric utility demand for natural gas.

Coal

EIA reports projections of coal consumption by electric utilities and mine mouth coal prices for a series of coal types from a series of coal supply regions. Haiku takes those data and aggregates them to a more manageable list of 14 coal supply categories, each with a known heat content, SO_2 content, and mercury content. EIA reports that a 10% deviation from the projected coal production will result in a 1% change in projected coal price. EIA also reports a markup (transportation fee) for each combination of coal demand region and coal supply region. With all of this information Haiku calculates a coal supply curve that describes the delivered prices of 14 coal types in 13 coal demand regions as a function of electric utility demand for each coal type.

Biomass

The biomass supply function in Haiku is constructed from projections of switchgrass and poplar consumption and prices (described further in an appendix). There are two projections—one for a low case and one for a high case—that are the two points used to define a linear biomass supply function that includes a transportation cost. There is an absolute annual regional constraint on the quantity of biomass available. The equilibrium biomass price may fall above the biomass supply function if the absolute quantity constraint is binding.

Interregional Power Trading

Haiku employs a reduced-form interregional power trading model. The model solves for the level of interregional power trading necessary to equilibrate differences between regional willingness to pay for and willingness to accept interregionally traded power. These transactions are constrained by the assumed level of available interregional transmission capability as reported by NERC, and they reflect interregional transmission losses and transmission fees.

Two types of trades are modeled. Firm trades represent prearranged commitments to provide power over the interregional transmission system. Historical data and EIA projections on firm trades are used to model trades into the indefinite future. The modeling of firm trades, including especially imports from Canada, is a limitation of Haiku because the practice of committing to firm trades is in flux and it is difficult to know what will be future practice.

The second kind of trade is an economy trade, which is based on instantaneous differences in marginal costs. The main point of the trading algorithm is to identify and represent economy trades. Firm trades serve only to reduce the capability of the grid to sustain economy trades, and their prices are averaged in with economy trades.

Willingness to Pay for Imported Power

The first step in calculating interregional power trading is to calculate the willingness to pay (WTP) for power imports and the willingness to accept (WTA) exports in each time block. WTP and WTA are equal, and both are set at the sum of the marginal cost of generation and scarcity value of marginal reserves. In marginal cost regions, these values are already known from the generation and reserve prices. In average cost regions, the marginal cost of generation is read off the generation supply curve. The scarcity value of reserves is trickier. First, Haiku identifies the marginal reserve unit. Then it calculates the percentage of annual generation and reserve that the marginal unit performs in the given time block. This fraction of the going-forward fixed costs of the marginal model plant is attributed to the time block in question, then expressed in \$/MWh. This is the scarcity value of reserves in an average cost region.

Interregional Trading Quantity

Once interregional WTP (and WTA, which is the same) is known in each region, the grid of potential bilateral trades can be evaluated. The bilateral comparisons are made inclusive of interregional line losses and costs. This means that regions with identical WTP will not trade. WTP in an importing region must exceed WTA in the exporting region by more than the costs of line losses and costs. By this criterion, any pair of regions that can trade to their mutual economic benefit and have unused capability will increase their quantity of power trading. Any pair of regions that don't meet this criterion will reduce trading if any exists. Equilibrium is achieved when there are (1) no pair of regions with unused capability that could trade economically and (2) no pair of regions that don't meet the trading criteria but are trading. Firm trades are executed without regard for WTP. They serve as a minimum for interregional trading quantity.

Interregional Trading Price

Once the WTP in all regions and the quantity of power traded are known, the prices for interregional trading are calculated. The price for firm trades is calculated separately from the price for economy trades. The quantity-weighted average of these prices yields the total price for interregional trades. Firm trades are priced at the maximum of the cost- and loss-adjusted WTA in the exporting year and the exogenously specified firm trade price. Economy trades are priced at the average WTP in the importing region and WTA in the exporting region.

Pollution Control and Allowance Prices

Steam units fired with fossil fuels have emissions rates for NO_x in the baseline—that is, the emissions rates do not reflect postcombustion controls, only compliance with Phase II of Title IV requirements. In the baseline, this corresponds to about 82% of coal-fired units assumed to have low NO_x burners, including wall-fired units (70% of coal-fired capacity) and tangentially fired units (12% of coal-fired capacity). In addition, we assume tangentially fired units have overfire air.

Haiku has four postcombustion abatement technologies from which utilities can choose to reduce NO_x emissions: selective catalytic reduction (SCR), selective noncatalytic reduction (SNCR), reburn, and hybrid. In the model and throughout this discussion, installing no postcombustion NO_x controls is treated as a fifth NO_x control option.

For SO_2, coal-burning model plants are distinguished by the presence or absence of flue gas desulfurization (scrubbers). Unscrubbed coal plants have only one potential SO_2 postcombustion abatement technology, a retrofit scrubber, but to reduce SO_2 emissions, firms may also select from a series of coal types that vary by sulfur content and price. Coal switching is assumed to incur no capital cost, which is not strictly true, but once the capital cost is incurred, the facility can vary the sulfur content of its coal in response to market conditions. Therefore, in Haiku the model plants are free to select any coal type in any year. This simplification allows the algorithm to operate on only two SO_2 control options, scrubber and no scrubber, while providing for a continuous option for fuel switching for plants located proximate to alternative fuel supplies.

The Haiku pollution control algorithm employs a forward-looking algorithm that allows it to make pollution control decisions with knowledge of the future. The total cost of pollution compliance is calculated for both NO_x and SO_2 for all model plants, control options, and years being simulated, given a set of permit prices and an expectation about capacity factors. This cost includes the costs of buying and running the abatement technology, the cost of compliance with a specific pollution policy (buying allowances or paying taxes), as well as any rebates that could be realized from allowance allocation. The model linear-interpolates between simulation years to get a complete set of pollution compliance costs for all years and control options before the end of the 20-year forecast horizon and expresses these costs in present discounted value terms. The total cost of installing each control in each year is calculated and expressed in net present value terms. The net present value of total pollution compliance costs is used for each model plant to select the cheapest compliance scheme along two dimensions: pollution control and installation year. This yields a preliminary compliance regime that must stand up to capacity constraints.

The constraints that Haiku imposes on the installation of pollution controls serve as simplifying assumptions and conform to expectations about the real world. When solving the model for a baseline case that can be used subsequently to compare with policy cases, it is assumed that no capacity will build pollution controls if that capacity will retire by the last simulation year. For a subsequent policy run to be compared against that baseline, there may be retrofit pollution controls already in place from a baseline run. The same constraint as in the baseline run is in force—that is, that no pollution controls will be installed on capacity that will retire before the last simulation year. But there is another constraint: any model plant that will retire capacity will first retire capacity that lacks baseline pollution controls. Only after this capacity has been retired will capacity with baseline pollution controls already in place be allowed to retire.

Pollution policy compliance is also achieved through generation capacity adjustments and alterations to the order in which model plants are dispatched to generate electricity. These changes are accounted for outside the pollution control algorithm. The algorithm chooses the cheapest method for pollution abatement, and capacity and dispatch order decisions are made with this information included. The capacity and dispatch decisions then inform the choice of pollution abatement when it is revisited in a subsequent iteration.

The price for emissions allowances is determined endogenously within Haiku. The price is determined through the iteration process such that total emissions in the specified region and during the specified time period are equal to the number of emissions allowances available.

Two other important pollutants, carbon dioxide and mercury, are tracked in Haiku, but no abatement technology is modeled currently.

Stranded Assets

Power companies are concerned that the transition to competition in many regions will render some portion of their previous investments unprofitable. Stranded assets—costs or benefits—are recoverable (or chargeable) in Haiku.

Potentially stranded assets are Haiku's estimation of the total book value of in-place capacity in 1999 by utility. To calculate the value in any given year, the model uses 1999 payments to capital by NERC region and then assumes a 3.3% annual decline in the payment to capital to get a stream of regional payments to capital on capacity existing in 1999 over the next 30 years. These regional payments are then allocated to utilities according to the percentage of regional generating capacity that is owned by each utility in 1999. This stream of payments to capital is expressed in 1999 dollars as a net present value and is treated by Haiku as potentially stranded assets.

The net present value of going-forward profits is offset against potentially stranded assets to calculate stranded assets. Going-forward profits are the difference between revenues and costs, not including stranded assets revenues (or costs) or capital costs. These going-forward profits by year (for the next 30 years) are allocated to utilities using the same 1999 generating capacity data mentioned above and then expressed in 1999 dollars as a net present value. The difference between potentially stranded assets and going-forward profits is the stranded assets, which are expressed as a single net present value for each utility.

Stranded assets are recovered by or charged to the utilities by adding a fee or discount to the price of electricity paid by consumers. This electricity price adjustment is done regionally; stranded assets are cumulative for all firms in a region and must be expressed by region instead of by utility. Stranded costs and stranded benefits are therefore expressed separately. Regional stranded costs are calculated by ignoring utilities with stranded benefits and aggregating the utility-specific stranded costs. Stranded benefits are calculated in a similar manner. The user specifies separately the fraction of stranded costs and benefits that will be recovered (or charged) as well as the number of years over which the recovery (or charges) will occur. Haiku then multiplies the net present value of stranded costs and benefits by the appropriate percentage and calculates the annuity that will yield recovery of the proper amount of stranded assets over the specified recovery horizon. This annuity is added to the electricity price paid by consumers.

Scheduled Outages

Each model plant in Haiku has a specified scheduled outage rate—the number of hours the plant is down annually for scheduled maintenance. Because Haiku is a seasonal model, the scheduled outage rate needs to be expressed by season, but the opportunity cost of a scheduled outage (electricity price) is not the same for all seasons. Generators tend to allocate more scheduled outages to low-price seasons and fewer scheduled outages to high-price seasons.

Haiku endogenously allocates scheduled outages to the three seasons according to the average seasonal electricity price. More scheduled outages are allocated if the average seasonal price is less than the average annual price, and fewer if the seasonal average price is greater than the annual average price. Scheduled outage rates vary by region and season. The implicit assumption here is that plants can choose during which season to take a plant offline but cannot choose to take a plant offline for only a part of day.

Hydroelectric Generation

Hydro generation is unlike any other electricity generation source because it is constrained not only by the capacity of the generators but also by the availability of water. Although hydro has no fuel cost, it is subject to environmental constraints that mandate a minimum amount of release from dams to maintain stream flows in all time blocks. For these reasons hydro cannot be dispatched with the other generators. Haiku handles this by pulling hydro out of the dispatch order, then separately allocating seasonal hydro generation to time blocks according to its highest valued use, subject to the environmental constraint.

Total hydro generation can vary from year to year based on the availability of water, so Haiku uses monthly EIA data to project future hydro generation as the average of hydro generation over the last five years. Haiku then allocates seasonal generation to the highest-value time blocks subject to the constraints that there be sufficient releases in all time blocks to maintain minimum stream flows and that the capacity of the hydro turbines is not exceeded. The value of the time blocks is evaluated differently under different regulatory regimes. Under marginal cost pricing, the value of each time block is equal to the sum of marginal generation price and marginal reserve price. Under average cost pricing, the model does not calculate the marginal generation and reserve prices and so uses capacity scarcity as an indication of the value of each time block.

Real Cost of Capital

The real cost of capital depends on the demand for capital. One component of capital demand is new capacity construction in the electric utility industry. The real cost of capital is therefore a function of the rate of capacity construction. The model uses a real-cost-of-capital function that is a function only of electric utility capacity construction. This curve is a third-order polynomial function and has been derived to indicate a response in the cost of capital when the level of new construction approaches that of historical peaks in construction. However, the parameterization of the function is assumption driven. In the absence of additional information, in the default setting the function is parameterized so that the real cost of capital is held virtually constant.

Biomass Cofiring

One of coal facilities' options for reducing emissions is biomass cofiring. Only coal plants are permitted to cofire with biomass, and they are usually bound to cofire at less than 3% of total generation. Biomass cofiring benefits generators because costs associated with emissions can be reduced, but additional costs are incurred, too, because biomass is a more expensive fuel than coal. When the trade-off between emissions reductions and fuel costs is to the benefit of the generators, biomass cofiring is increased. When it is to their detriment, it is decreased.

Renewable Portfolio Standard

One of the policies often suggested as part of a transition to competition is a renewable portfolio standard (RPS). The RPS imposes a requirement that a percentage of national annual electricity generation must be performed by renewable sources. It may be modeled via an allowance trading program that simulates the RPS. In Haiku, an allowance is equal to one MWh of renewable generation, and each utility receives one allowance for each MWh generated by a renewable source. A source that is partly renewable (e.g., biomass cofiring) receives allowances commensurate with the percentage of the generator that is powered by a renewable source. The allowances can be traded between utilities. At the end of each year every utility must have enough allowances to satisfy the RPS. For example, if the RPS requires that 5% of national annual generation be renewable, then a utility that generates 1,000 MWh in a year must have 50 RPS allowances.

Haiku calculates the value of the RPS allowances such that the prescribed RPS percentage is achieved. The subsidy value (for renewable sources) or cost (for nonrenewable sources) of the allowances is added to the marginal cost at which generators are dispatched. The user is able to cap the value of the RPS allowances using the RPS safety valve. If the allowance price reaches the safety valve price, then the allowance price is not allowed to climb any further, and the RPS percentage specified by the user will not be achieved.

Demand Conservation Incentive

An issue in market-based approaches to environmental regulation, such as the use of tradable emissions permits, is how permits are allocated to facilities. A complementary issue is whether some portion of permits should be allocated to other parties to provide special incentives. The demand conservation incentive (DCI) describes the allocation of some portion of permits to consumers as an incentive for investments to reduce demand.

The DCI is designed to work with a generation performance standard (GPS) for pollution permits. Under a GPS program, the utilities earn an allocation of permits based on generation, where each MWh of generation earns a fraction of a permit. The rationale for this system is that the electric utility industry exists for the single purpose of satisfying electricity demand, so the valuable pollution permits are allocated according to each utility's contribution to this goal. Reducing demand closes the gap between supply and demand just as effectively as generating electricity.

Under the DCI, permits are allocated equally for every MWh conserved in a commensurate fashion to the allocation under the GPS for every MWh generated. To calculate the value of a MWh, we need to know the total asset value of permits and the total amount of generation and conservation. Generation is easy to measure, but conservation is more elusive. An investment in conservation is expected to reduce consumption at a given electricity price. We define conservation as the reduction in consumption (demand) in a policy case compared with consumption at a given price in the baseline.

A = asset value of pollution permit (number of permits multiplied by the price of a permit) [$]

g_i = generation at utility i [MWh]

$G = \sum_i g_i$ = total generation [MWh]

c_j = conservation by demand group j [MWh]

$C = \sum_j c_j$ = total conservation [MWh]

X = G + C = contribution toward closing the gap between supply and demand [MWh]

A single MWh of generation or conservation earns A/X. This is the value for the pollution permit subsidy (for producers) and the value for the DCI (for consumers).

The generation at utility I (g_i) requires no special calculation, since it already exists in the model; however, the calculation of conservation (c_j) is more difficult. We illustrate with an example. Say the electricity price is $50/MWh and the DCI is $2/MWh. This means that each MWh has an opportunity cost of $52/MWh. Imagine that you are standing in front of your air conditioner and considering whether to run it for 1 MWh. If you do, you will pay $50. If you don't, you will receive $2. This means that you must derive at least $52 of utility from consuming 1 MWh to run your air conditioner to make it an economic decision. This can be expressed graphically by shifting the demand curve (D) down by $2. So demanders will now consume electricity according to this lower demand curve (D_{Aux}). The amount of electricity conserved (c_j) can be read as the horizontal distance between the two demand curves at the electricity price.

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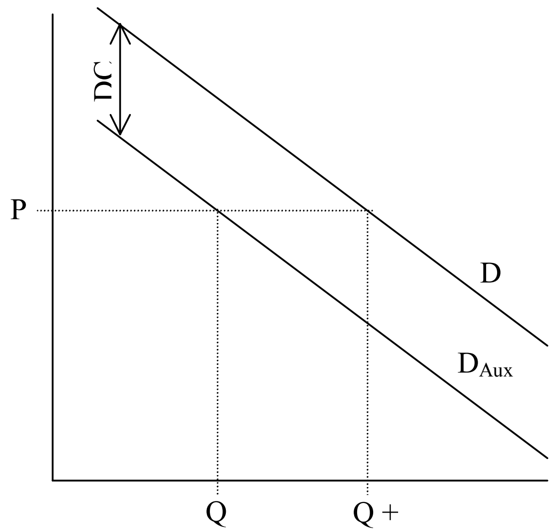
Figure 5. Demand to reflect opportunity cost under the demand conservation incentive.



In Haiku, we bound the fraction of the asset value that can go to demanders. This is implemented in the model simply by shrinking the DCI if the fraction of the asset value going to demanders rises above the bound. This yields a DCI that is less than the pollution permit subsidy value.

As an iterating control variable, DCI is calculated given A (total asset value), G (generation), and C (consumption). Haiku calculates DCI = A / (G+C) in each iteration of the model. As long as the bound is not violated, DCI is the pollution permit subsidy. If the bound is violated, then the DCI is adjusted downward.

Convergence Criteria in Identifying Equilibria

An iteration model such as Haiku continues to adjust indefinitely until a stopping rule is reached that is derived from criteria for judging adequate convergence in the model. In most applications the stopping rule is a number of iterations identified by testing the model with different starting values of the control variables. The rule we use is that key results of interest consistently vary by less than 1% when the model is launched using different starting guesses.

VI. Data

This section describes the sources of data in Haiku and how the data are used to construct the model.

Supply and Technology

Existing Facilities

The supply data used in Haiku come primarily from databases constructed from forms EIA-860a, 860b, 767, and 906, as well as FERC Form 1. The *Annual Electric Generator Report*, EIA-860a and b for utilities and nonutilities, respectively, provides generator-level information such as location, operating status, fuel type, and capacity. Other useful information reported in EIA-860b includes plant fuel consumption and generator-level production. Statistics collected by EIA-767, the *Steam-Electric Plant Operation and Design Report*, relevant to Haiku are boiler fuel use, boiler generation, operating status, and the relationship between boilers and generators. These data are supplemented by fuel consumption and emissions information reported in EPA's CEMS database. Fuel use and production observations from CEMS, EIA-767, and EIA-860b are used to calculate generator-level heat rates. These heat-rate observations are supplemented by heat rates reported on pages 402–3 (large generating plant statistics) of FERC Form 1. These pages of FERC Form 1 also solicit production costs incurred by large facilities, of which observations for steam plants are used in Haiku.

We characterize hydropower production using historical monthly generation data reported in EIA-906 and previous versions. Information on prime-mover capacity factors and outages are taken from NERC's Generating Unit Statistical Brochure 1995-1999. Other sources of data for Haiku on production costs and emissions controls and installations and their associate costs include the following:

U.S. EPA. 1998. *Analyzing Electric Power Generation under the CAAA.*

U.S. EPA. 2000. *The Emissions & Generation Resource Integrated Database (E-GRID).* http://www.epa.gov/airmarkt/egrid/index.html.

EPRI. 1993. TAG.

U.S. EPA. 2002. *Compilation of Air Pollutant Emission Factors, AP-42.* Fifth Edition, Volume I: Stationary Point and Area Sources.

U.S. EPA. 2001. *Coal-Fired Units Meeting Definition in Section 112(a)(8) of the 1990 Clean Air Act Amendments.* As determined in exploration of need for HAP regulation from these facilities; http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html.

Facilities Currently Planned

Planned utility capacity by fuel for each NERC region is reported in EIA's *Inventory of Electric Utility Power Plants in the United States, 1999.* The data are incomplete because information on regions with small quantities of planned capacity is confidential. In these cases we estimate the missing values by cross-referencing planned capacities reported for other geographical regions (state, Census region, etc.).

Ideally, Haiku would represent planned capacity not just by fuel but also by prime mover, which is the technology used. Unfortunately, the only information on planned capacity by prime mover in the EIA document is national planned capacity of combined-cycle systems. We use this information to estimate the amount of gas and oil planned capacity associated with combined-cycle and combustion turbine systems in each NERC region. We do so by calculating, for each fuel type, the percentage of combined-cycle planned capacity relative to total planned capacity at the national level. We then assume that these percentages hold for planned gas and oil capacity in each NERC region. We assume that none of the planned gas- or oil-fired capacity is steam.

Planned merchant capacity by fuel for each NERC region is reported in EIA's *Inventory of Electric Nonutility Power Plants in the United States, 1999.* These data suffer the same problems as the planned utility capacity data. In addition, this EIA document is completely silent on planned capacity by prime mover for any geographical area. Our solution is to apply the national ratio of combined-cycle to planned capacity from the utility data to the merchant data.

New Facilities Identified by Haiku

Data about costs and performance characteristics for new facilities are taken from supplementary tables in EIA's *Annual Energy Outlook.* New facilities are subject to a constraint that reflects the time required for construction. This constraint is relevant beginning with the base year, or any year in which a policy is announced. Data for the construction lag vary by technology and are taken from EIA.

Model Plants

Information on existing and new technology is aggregated to the "model plant" level based on the fuel type, technology (including boiler type for some coal-fired boilers) and vintage of each unit. The model plant definitions are adapted from those developed originally by EPA for the Clean Air Power Initiative project (U.S. EPA 1998). As a part of that project, EPA's contractor, ICF Inc., developed prototypical operating cost information for each model plant category. A list of model plants from a recent exercise of the model is provided in Table 2.

Table 2. An illustrative list of model plants in Haiku.

Existing	**Planned**
MSW	Comb Cycle : Nat Gas
All Other	Gas Turbine : Nat Gas
Comb Cycle : Nat Gas	
Comb Cycle : Oil	**New**
Gas Turbine : Nat Gas : Efficient	Steam : Coal : 1 : Scrub
Gas Turbine : Nat Gas : Inefficient	Steam : Coal : 2 : Scrub
Gas Turbine : Oil	Steam : Coal : 3 : Scrub
Hydro : Conv	Steam : Coal : 4 : Scrub
Hydro : Pump Storage	Steam : Coal : 5 : Scrub
Renewable : Nat Gas	Comb Cycle : Nat Gas
Renewable : Solar	Gas Turbine : Nat Gas
Renewable : Wind	Steam : Biomass
Steam : Biomass :	Renewable : Wind : 1
Steam : Coal : 1 : No Scrub	Renewable : Wind : 2
Steam : Coal : 1 : Scrub	Renewable : Wind : 3
Steam : Coal : 2 : No Scrub	Renewable : Wind : 4
Steam : Coal : 2 : Scrub	Renewable : Wind : 5

Steam : Coal : 3 : No Scrub	Adv Comb Cycle : Nat Gas
Steam : Coal : 3 : Scrub	Adv Gas Turbine : Nat Gas
Steam : Coal : 4 : No Scrub	
Steam : Coal : 4 : Scrub	
Steam : Coal : 5 : No Scrub	
Steam : Coal : 5 : Scrub	
Steam : Geothermal	
Steam : Nat Gas : Efficient	
Steam : Nat Gas : Inefficient	
Steam : Nuclear : Efficient	
Steam : Nuclear : Inefficient	
Steam : Oil	

The model plants in Table 2 are displayed by prime mover and categorized as existing, planned, and new facilities. Coal plants are sorted according to whether they are scrubbed or unscrubbed for SO_2 removal. Coal and wind plants are also sorted with a number that indicates characteristics of fuel supply. Coal plants in a given NERC region may obtain fuel from a number of fuel supply regions, each with different cost and quality. Wind plants are sorted by the class of wind resource where they are located. There are a limited number of the highest-quality sites, and after those sites are developed, only sites of lower value remain available. One of the distinguishing features of Haiku is the sorting of capacity into efficient and inefficient plants. This sorting is applied when a model plant (excluding steam coal plants) exceeds 5% of national capacity in aggregate. The efficient and inefficient designation is made on the basis of heat rates of the constituent plants, with approximately half the plants in each region assigned to each category.

Pollution Control

Postcombustion control for SO_2 is flue gas desulfurization (scrubbers). Data on the capital and operating costs of scrubbing are obtained from a document prepared by ICF Inc. for EPA.[5] Detail on the postcombustion technologies and costs for NO_x control was obtained from EPA, based on a study by Bechtel.[6] Data for both SO_2 and NO_x controls and an explanation of how they are modeled in Haiku are given in an appendix.

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[5] ICF Inc. 2001. Review of Data on the Impact of New Source Review on Investment Decisions: Power Generation and Refinery Sectors. Draft Report, EPA Contract No. 68-D9-9019 (June 22).

[6] U.S. EPA. 1997. Cost Estimates for Selected NO_x Control Technologies on Stationary Combustion Boilers, Final Report (June).

Calibration

Haiku is calibrated to match historical prices through the use of an adder that represents the difference between estimated prices and prices observed empirically. The adder is incorporated in the model as a variable generation cost and therefore directly affects the price of electricity. The adder accounts for costs not explicit in Haiku, including contracts with qualifying facilities under the Public Utilities Regulatory Policies Act (PURPA), long-term fuel supply contracts with terms that differ from those estimated in our fuel supply models, low-income assistance and conservation programs, other customer benefit programs, out-of-merit-order dispatch, regulatory failures, and costs of ancillary service, such as voltage regulation. On average, the adder is about 6% of the estimated electricity price. The adder is calculated by comparing actual average retail prices by NERC subregion in 1999 with prices calculated by the model for 1999; it does not vary across scenarios. By not varying the adder across scenarios, we are implicitly assuming that regulatory programs such as low-income assistance and conservation programs will be continued after restructuring at roughly current levels. Given that most states are incorporating some mechanism for funding these types of social programs into their restructuring laws or regulations and that most federal restructuring bills include similar provisions, we believe that this is a reasonable assumption. However, other components of the adder, such as the existence of contracts with qualifying facilities under PURPA and long-term fuel supply contracts, are diminishing in importance. Hence, we assume the adder decreases at a rate of 2.5% per year.

Demand

Data on historical demand are required to calibrate the demand function used in Haiku. As noted previously, the function is in the form:

$$D = AP^{\varepsilon}$$

where D is the quantity of demand, A is a constant, P is electricity price, and the superscript on price (ε) is the elasticity of demand with respect to price. The function is calibrated with data for D, P, and ε to solve for A.

Historical Electricity Demand and Price

The data on historical demand (D) and electricity price (P) are derived from EIA Forms 826 and 861 to calculate demand data (revenues and MWh of generation) by NERC region, month, and customer class in 1999. EIA826 provides disaggregated data but not for all utilities. EIA-861 provides complete coverage of utilities but is not disaggregated. We use the 826 data alone wherever possible but combine it with 861 data as necessary.

To disaggregate the demand data to time blocks, we use load duration curve data from ICF, obtained as part of the documentation for the Clean Air Power Initiative, and from FERC Form 714. The ICF source provided load curves (actually seven quantities on each one) differentiated by NERC region and customer class for the summer and winter seasons. We assume the spring-fall load curves to be the average of the summer and winter curves. These load curves are used to allocate season-specific demand data to time blocks.

Elasticity of Demand

The elasticity of demand (ε) can be modeled in great detail, in principle. However, empirical estimates are limited. Haiku incorporates short-run, intermediate–run, and long-run own-price demand elasticities for electricity that can vary by customer class, season, and region from the Dahl (1993) survey of electricity demand, occasionally supplemented for a particular region by a specialized source of data.[7] The study summarizes many studies reporting demand elasticity by time frame (short, intermediate, or long term), customer class, region, and season. Unfortunately, demand elasticity is not reported for all demand blocks. We use the disaggregated data to inform the disaggregation of the other demand blocks but are not able to achieve full disaggregation. For commercial and industrial customers, disaggregation across regions and seasons is impossible, so we have only a single value for each time frame for these customer classes. Long-term elasticities for residential customers also cannot be disaggregated by region or season. Intermediate-term elasticities for residential customers cannot be disaggregated by season but are disaggregated by four large regions. Short-term elasticities for residential customers are disaggregated both by season and by four large regions.

The Dahl study provides a function to calculate peak-period and base elasticities as a function of non-time-block-specific elasticity. Because we have four time blocks, not two, we treat all time blocks other than the base as peak time blocks when applying the function. The weighted average elasticity of demand across all customers and time blocks in Haiku is about –0.25.

Demand Constant

Using the historical and estimated data for demand, price, and elasticity, we calculate the demand constant (A) for 1999 using our demand function. Then the demand constant is adjusted for subsequent years using a demand constant growth rate derived from EIA data (reported in supplemental tables to *Annual Energy Outlook 1999*) that specifies electricity demand projections by year, customer class, and Census regions. We convert from Census region to NERC region using capacity-weighted averages.

Transmission

Interregional transmission of power is constrained by the assumed capability of the transmission grid. This section describes the data for modeling transmission.

Transmission Capability

Capability differs from capacity. In transmission, *capacity* refers to the thermal limit or rating of a transmission component; *capability* accounts for system factors, such as generation, demand, and system conditions assumed to exist. Hence, transmission line capacities cannot be added to determine capability.

The calculation of transfer capability is generally based on computer simulations of the operation of the network. In Haiku, the capability of the interregional transmission grid is taken

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[7] Dahl, Carol. 1993. A Survey of Energy Demand Elasticities in Support of the Development of the NEMS. October 19.

from data on summer and winter interregional transmission capability provided by the NERC regions. The data are developed by NERC[8] and characterize the first contingency incremental transfer and total transfer capabilities. The data we use are an aggregation of NERC data from EIA developed for *Annual Energy Outlook 1999* and used as input assumptions for the Stanford Energy Modeling Forum 17.[9] For convenience, these data are averaged to obtain an annual estimate.

Firm Power Trades

The firm transactions are those specified by long-term contract, and in Haiku they represent the minimum level of trade between two regions. Firm transactions can vary by year. Firm transactions can go in both directions, and when they do, both sets of transactions are included—they are not netted out. Sometimes firm transactions exceed maximum transmission capability. This is not especially surprising, because the data on transmission capacity are an estimate that results from a simulation. When data suggest that firm trades are greater than transmission capability, we push maximum capability estimates up to equal the firm amount.

Data on firm transactions were obtained from EIA (July 1999) and is the same as that used as input assumptions for the Stanford Energy Modeling Forum 17.[10] All imports from Canada are treated as firm transactions.

Emissions Rates

Typically emissions rates for SO_2, and CO_2 are assigned to generators from CEMS data, EIA-767, and AP-42[11]. As with generation, each dataset containing emissions data has shortcomings, so we are forced to use them all. NO_x emissions rates are treated differently, as described below. Emissions rates for mercury are calculated based on the mercury content of the fuel and on the presence or absence of flue gas desulfurization. For more information about mercury emissions, see the appendix on mercury control and coal fuel choice.

SO_2 and CO_2 Emissions Rates

The CEMS data report SO_2 and CO_2 (and NO_x) emissions for fossil steam plants and certain large combustion turbines and combined-cycle systems. The CEMS data are preferred because they include actual stack emissions associated with a particular boiler or turbine. Emissions data prepared by EIA in conjunction with the EIA-767 survey are used when CEMS data are unavailable. EIA-767 is applicable to large steam boilers that are now, or were at one time, subject to provisions of the 1990 Clean Air Act Amendments. Upon request, the EIA makes

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[8] See the "Reliability of Bulk Electricity Supply in North America" publications from NERC.

[9] Energy Modeling Forum. 2001. *Prices and Emissions in a Competitive Electricity Sector*. EMF Report 17 (May).

[10] Energy Modeling Forum. 2001. *Prices and Emissions in a Competitive Electricity Sector*. EMF Report 17 (May).

[11] U.S. EPA. 2001. *Compilation of Air Pollutant Emission Factors, AP-42, Volume I: Stationary Point and Area Sources.* Fifth Edition.

available its 767-vector file that contains estimates of boiler-level emissions. EIA estimates are calculated using AP-42 and are based on fuel use.

AP-42 is a total emissions estimation tool used by permitting authorities and for emissions inventory creation. It provides typical emissions rates for criteria and hazardous air pollutants for a variety of industrial processes. AP-42 fills in the gaps in emissions rates for internal combustion engines and gas turbines that result from the limited focus of CEMS and EIA-767. For combustion turbines AP-42 reports separate SO_2 and CO_2 emissions rates for natural gas-, oil-, and methane-fired turbines. Separate emissions rates are also reported for natural gas, oil (diesel), and gasoline internal combustion engines.

Even after application of those data, some generators still will not have SO_2 and CO_2 emissions rates. For these generators the capacity-weighted averages of the emissions rates for units of the same prime mover and fuel are used.

NO_x Emissions Rates

We treat the NO_x regulatory baseline in Haiku as Phase II of Title IV of the 1990 Clean Air Act Amendments. This approach simplifies policy analysis by identifying abatement decisions and costs associated with the various incremental NO_x control policies. To identify the costs associated with a new policy, one can run the model with existing policies coming in sequence after Title IV, such as the Ozone Transport Commission (OTC) program in the northeast states. Hence, we rely on the model to identify additional controls associated with a given policy, which then is used as the baseline for analysis of subsequent policies.

In practice, some coal-fired boilers had actual emissions below their mandated Phase II (Title IV) rates in the base year. Also, other generating units emitted below applicable Reasonable Available Control Technology (RACT) or New Source Performance Standards (NSPS) rates in the base year. This typically occurred in the context of the OTC NO_x budget program, which requires controls beyond Phase II rates. Nonetheless, Haiku uses the mandated rates so that one can measure the incremental costs of policies beyond Phase II.

For coal-fired boilers the baseline NO_x rate is the stricter of their Phase II rate or their NSPS rate. These rates are published in *Analyzing Electric.*[12] Baseline rates for oil- and gas-fired combustion turbines and combined-cycle systems are also taken from *Analyzing Electric.* NO_x rates for these sources vary by vintage, reflecting NSPS. Finally, AP-42 is used to assign baseline NO_x rates for oil and gas-fired steam generators and internal combustion engines. The liquid fuel steam boiler rates are distinguished based on firing type, which is reported in CEMS.

[12] U.S EPA. 1998a. *Analyzing Electric Power Generation under the CAAA.* Office of Air and Radiation (March).

VII. Pollution Controls

Nitrogen oxides (NO_x)

Primary Author: David A. Evans

Nitrogen oxides (NO_x) formation processes occur during combustion of any fossil fuel. *Fuel NO_x* is created by the oxidation of nitrogen contained in the fuel. For coal-fired boilers, fuel NO_x contributes about 75% of the total NO_x formed. *Thermal NO_x* is formed by the oxidation of the nitrogen in the ambient air. Thermal NO_x is the primary source of NO_x from gas- and oil-fired boilers and turbines.

NO_x control technologies for electric utility and large industrial boilers and combustion turbines can be divided into two basic types: combustion controls and post-combustion controls. Combustion controls are used within the fuel-burning process to mitigate the formation of NO_x. Post-combustion controls reduce the quantity of NO_x in the emissions stream.

Including emissions from units that do not produce electricity, turbines produce approximately 165,000 tons of NO_x emissions per year, or 3% of coal-fired and 22% of oil- and gas-fired utility boiler emissions. Because electricity-related turbine emissions are one to two orders of magnitude smaller than utility boiler emissions, NO_x controls for turbines are not included in Haiku.

Controls for Boilers

Older coal-fired utility boilers were engineered to produce maximum heat from their fuel without requiring a great deal of precision in operating conditions. Because compact, hot flames were considered desirable, sufficient air was let into the combustion chamber so that all the carbon in the fuel would be consumed regardless of variations in coal quality or operator behavior. These conditions produce large amounts of both fuel and thermal NO_x. To reduce NO_x formation, boilers must essentially be reengineered to reduce mixing of fuel and air (inhibiting fuel and thermal NO_x) and to lower combustion temperatures (primarily inhibiting thermal NO_x). Technologies that have been used include low NO_x burners, overfire air, computerized combustion controls and other combustion modifications.

Combustion controls are less expensive than post-combustion controls but have lower maximum NO_x removal capabilities, and were often considered those "reasonably available" for the purpose of state and federal regulations on existing units. However, moving beyond compliance with Title IV of the 1990 Clean Air Act Amendments (CAAA) will require substantial application of post-combustion controls.

Post-combustion controls reduce NO_x present in combustion gases and therefore are sometimes collectively known as flue gas treatments. It is expected that these controls will almost exclusively be applied to coal-fired boilers, since gas- and oil-fired units already have lower baseline NO_x emissions and should attain sufficient reductions with combustion controls.

One technology, reburn, uses an additional combustion stage to chemically destroy NO_x. The others use nitrogen-based reagents and can be paired with the combustion controls described above without impairing the effectiveness of either type of control.

In selective noncatalytic reduction (SNCR), ammonia or urea is injected into the stream of waste gases and chemically reduces the NO_x to diatomic nitrogen (N_2) with water as a by-product. This process is selective in that the reagent reacts solely with NO_x and not other components of the flue gas stream. The major cost of SNCR is the operating cost—essentially, the cost of the reagent and its handling. The retrofit of injection systems is relatively simple and does not interfere with boiler operation when not in use. Therefore SNCR is especially suitable for seasonal control. Whether SNCR is suitable for large (>200MW) boilers is questionable because completely mixing the reagent in the flue gas stream is difficult.

Selective catalytic reduction (SCR) is the most commonly applied post-combustion NO_x control. This process is very similar to SNCR except that a catalyst mediates the reaction. The process is applicable to all boiler types, and ammonia is generally used as the reagent. In practice, the intersection of regulatory demands and expense has generally limited removal rates on coal-fired plants to 70% to 80%, but reductions greater than 90% have been demonstrated.

The primary variable determining the expense of SCR is catalyst cost, which in turn depends on whether the expected catalyst lifetime is guaranteed or useful (or effective). When SCR is used as a seasonal control, flue gases are sometimes routed around the reactor to conserve the catalyst. For reasons of site congestion, capital costs for SCR retrofits can be expected to vary widely, even between boilers of the same type. A full-size SCR system is a large piece of equipment, and installation may require construction of considerable additional ductwork, strengthening of the boiler foundation and structure, and even the demolition and relocation of existing boiler equipment.

Combined SNCR and SCR, sometimes called hybrid selective reduction (HSR), could reduce NO_x emissions substantially at a lower cost than SCR alone. With this approach, flue gases first reach the SNCR reaction. Ammonia slip from the SNCR process serves as the reagent in the SCR process, which uses significantly less catalyst than SCR alone.

NO_x Reduction in the Haiku Model

Title IV of the 1990 Clean Air Act Amendments set maximum NO_x emissions rates for each major type of coal-fired utility boiler. Phase II requirements began in 2000 and affect all boilers. The requirements for each boiler type in each phase are listed in the next table. The model baseline assumes full implementation of Title IV of the 1990 CAAA.[13] Each coal-fired boiler type is paired with a combustion control, as shown in the table.

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[13] This approach simplifies policy analysis by identifying abatement decisions and costs associated with the various incremental NO_x control policies. To identify the costs associated with a new policy, one can run the model with existing policies coming in sequence after Phase II of Title IV, such as the OTC program. Hence, the model identifies additional controls associated with a given policy, which then is used as the baseline for analysis of subsequent policies.

In practice, some coal-fired boilers had actual emissions below their mandated Phase II rates in the base year (1999). This often occurred in the context of the OTC NO_x Budget Program, which requires controls

Table 3. NO_x Emissions Rate Limits, Thresholds and Technology under Title IV

Boiler Type	**Phase I**	**Phase II**	**Threshold Size**	**Baseline Technology**
Wall-fired boilers	.50	.46	25MW	LNB
Tangentially fired boilers	.45	.40	25MW	LNB with OFA
Cell burners		.68	25MW	Nonplug-in
Cyclones		.86	155MW	Gas reburn
Wet-bottom boilers		.84	65MW	Combustion controls
Vertically fired boilers		.80	25MW	Combustion controls

Source: U.S. EPA 1998a. All emissions measured in lb./MMBtu.

Alternative NO_x reduction policies representing requirements beyond the Title IV baseline, such as the NO_x SIP Call, can be modeled in Haiku. Each regime can be implemented in some or all NERC regions. In a performance standard policy regime, the least expensive technology that allows a model plant to comply with its performance standard is selected. In a tax policy regime (characterized as a charge per ton of emissions), the technology that produces the largest possible reduction at a marginal abatement cost below the tax rate is chosen. In a cap-and-trade regime, emission allowances are allocated to model plants to approximately equate (subject to the discrete set of technological options available) the marginal abatement cost of each model plant within each trading region. The equated marginal abatement cost, which is determined by the level of total allowable emissions and the available control technologies and their respective costs, is interpreted as the permit price.

To meet reduction responsibilities beyond the baseline, model plants may choose from a variety of add-on controls. Coal, gas and oil-fired boilers may select reburn, SNCR, or SCR. Another option, SNCR-SCR hybrid, has been tested but, because it is not selected, it is usually not included in order to speed the algorithm. Note that in all cases, baseline controls are assumed to operate; there is no backing out of baseline controls in favor of a post-combustion control.

Control Cost Information

New cost functions were published by the U.S.EPA in March 2002, and they are provided in the next table (U.S. EPA, 2002b). The significant changes in the SCR cost equation from the EPA's previous assumptions (U.S.EPA, 1998a) include an increase in expected control efficiency of technology and the distribution of costs between fixed and variable costs. The change in the accounting of costs reflects a system oriented toward complying with seasonal

beyond Phase II (Title IV) rates. This also occurred when firms used the NO_x emissions rate averaging provision to demonstrate Phase II compliance. The averaging provision also implies that certain boilers likely emitted above the rates generally mandated by Phase II. Nonetheless, Haiku uses the mandated rates so that one can measure the incremental costs of policies beyond Phase II.

restrictions yet may be operated at other times during the year. The cost of the catalyst is now included in the variable O&M cost rather than the fixed O&M cost.[14] In addition, capital costs are somewhat greater as the cost of a system by-pass is now included. The by-pass allows the unit to be disconnected from the flue gas stream when not in use, and in turn allows more refined catalyst management.[15] The higher capital cost also likely reflects a better understanding of the cost of the elevated structures often required for installing the SCR unit.

With the new cost equations, the treatment of these costs in Haiku also changed. Evaluation of NO_x post-combustion control cost parameters for each model plant at the mean capacity of the model plant underestimates the cost of these technologies by ignoring the convex shape of the cost scaling functions. Instead, Haiku uses a capacity weighted mean of each cost parameter evaluated at each constituent generator's capacity. Similarly, the baseline NO_x emission rate for each constituent plant is used by Haiku to more accurately determine the effective control efficiency of each control technology on a particular model plant.

Another coincident change in Haiku's treatment of NO_x post-combustion controls is that the installation of these controls is now restricted to units of a minimum size. Applications of SNCR and Reburn are limited to units larger than 50MW while SCR, following U.S. EPA (2002b), is now limited to units larger than 100 MW. This affects the amount of a particular control that a model plant can install as well as the calculations described in the previous paragraph.

References

U.S. Environmental Protection Agency (U.S. EPA). 1998a. *Analyzing Electric Power Generation under the CAAA.* Office of Air and Radiation. March.

______. 2000. "Selective Catalytic Reduction." *EPA Air Pollution Control Cost Manual.* Sixth Edition, Section 4.2. Chapter 2. October.

______. 2002a. *Cost of Selective Catalytic Reduction (SCR) Application for NOX Control on Coal-fired Boilers.* Office of Research and Development. January.

______. 2002b. *Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Mode (Draft).* Clear Air Markets Division. March.

[14] U.S. EPA (2002a).

[15] The SCR cost equation is designed to estimate the cost of a boiler retrofit of average difficulty (U.S.EPA, 2002a). As such, the SCR installation is not expected to appreciably lower the unit's heat rate (U.S.EPA, 2002b). However, in the case of an SCR system located downstream of other emission controls it may be necessary to reheat the flue gas to initiate the catalytic reaction, resulting in a substantial increase in the operating cost of the system (U.S.EPA, 2000).

Table 4. 2002 NO_x Control Cost Assumptions (1999 dollars)

NO_x controls	Capital ($/kW)	Fixed O&M ($/kW/Yr)	Variable O&M (mills/kWh)	Percentage Removal
Coal-Fired Boilers				
SCR	80.00	0.53	0.37	90
SNCR (Low NO_x rate)	17.10	0.25	0.84	35
SNCR (High NO_x rate, others)	19.50	0.30	0.90	35
Gas Reburn (Low NO_x rate)	33.30	0.50	-	40
Gas Reburn (High NO_x rate)	33.30	0.50	-	50
Gas- and Oil-Fired Boilers				
SCR	28.9	0.89	0.10	80
SNCR	9.70	0.15	0.45	50

Notes: Low NO_x rate ≤ 0.5 lb./MMBtu; high NO_x rate > 0.5 lb./MMBtu.

The minimum achievable emissions rate from SCR is .05lb./MMBtu.

To represent economies of scale exhibited in the control technologies the following scaling factors are applied to the Capital Cost and Fixed O&M parameters for coal-fired boilers: SCR : $(242.72/MW)^{0.35}$, Low NO_x SNCR : $(200/MW)^{0.577}$, and High NO_x SNCR : $(100/MW)^{0.681}$. The scaling factor also applies to the Variable O&M parameter for SCR. The scaling factor is multiplied by the parameter in the table and then added to .603212 to determine the cost of SCR per kWh. For SCR and Low NO_x SNCR these factors only apply up to 500 MW.

The Variable O&M cost of Gas Reburn is based on the price difference between natural gas and coal. It is presumed that gas constitutes 16% of the heat input of a boiler applying Gas Reburn.

For gas- and oil- fired boilers the following scaling factors are applied to the Capital Cost and Fixed O&M parameters: SCR : $(200/MW)^{0.35}$, SNCR : $(200/MW)^{0.577}$. These factors only apply up to 500 MW.

Sulfur Dioxide (SO_2)

Sulfur dioxide (SO_2) emissions come almost exclusively from coal-fired power plants, with some emissions coming also from oil plants. In both cases, the emissions and emission allowance costs are accounted for in Haiku. However, strategies to reduce emissions at a given facility are modeled only for coal-fired plants.

There are two ways that a coal-fired facility can reduce its emissions of SO_2. One is to switch away from a higher sulfur coal to a lower sulfur coal, and this is described elsewhere as part of fuel choice. The second way is to install postcombustion controls, and this is described here. The cost of postcombustion controls for SO_2 varies depending on whether controls are installed on new capacity or retrofitting an existing facility, and on the removal efficiency of the technology and the sulfur content of the coal.

Two types of flue gas desulfurization (scrubber) controls are modeled in Haiku. Wet scrubbers are more likely to be chosen as cost-effective at facilities burning higher-sulfur coal. Dry scrubbers are more likely to be chosen at facilities burning lower-sulfur coal. The following table reports the technological and cost assumptions in Haiku.

Table 5. Cost of flue gas desulfurization in Haiku (1999 dollars).

Type	**Removal Efficiency (%)**	**Capital Costs ($/kW)**	**Fixed O&M Costs ([$/kW]/yr)**	**Variable O&M Costs (mills/kWh)**
Wet	95%	357	12.24	1.83
Dry	90%	255	7.14	2.29

Source: ICF Inc. 2001. Review of Data on the Impact of New Source Review on Investment Decisions: Power Generation and Refinery Sectors, Draft Report, EPA Contract No. 68-D9-9019 (June 22).

VIII. Fuel Supply

Coal

Haiku uses constructions of supply and demand regions to model coal supply. A supply region may serve more than one demand region, and more than one supply region may serve a single demand region. Facilities are assumed to choose supply based on the cost and characteristics of the available coal.

Supply Regions

The Energy Information Administration (EIA) provides data on 25 types of coal from 11 supply regions. Haiku captures much of the interesting variation in prices, heat content, sulfur content, and mercury content with a smaller number of coal types and regions, which are listed in the table below.

Table 6. Coal supply regions.

Region	Coal Type	Mercury Content	Heat Content	Sulfur Content
		lbs/trillion Btu	*Btu/lb*	*lbs SO_2/million Btu*
North Appalachia	NAMB	14.75	12736	1.87
	NAHB	20.39	11305	**5.00**
Central and Southern Appalachia	CSCB	7.22	13364	0.97
	CSMB	11.29	13116	1.65
East Interior	EIMB	6.70	11718	1.80
	EIHB	8.38	**11000**	**5.30**
Gulf Lignite	GLML	36.43	6954	1.67
	GLHL	34.21	**6000**	**3.00**
Dakota Lignite	DLML	**21.00**	6489	1.77
Powder and Green Rivers	PGCS	8.34	8669	0.80
	PGMS	11.53	8407	**1.40**
Southwest	SWCB	6.81	11280	0.89
	SWCS	4.86	9507	0.74
	SWMS	6.03	8945	1.47

In the coal type abbreviations, the last letter indicates the thermal grade, where B = bituminous, S = subbituminous, and L = lignite. The penultimate letter indicates the sulfur grade, with C = low (compliance) sulfur (<1.2 lbs. SO_2 per million Btu), M = medium sulfur (1.2–2.5 lbs. SO_2 per million Btu), and H = high sulfur (>2.5 lbs. SO_2 per million Btu). The first two letters indicate the region.

From the EIA coal supply regions we eliminated those regions, or types within regions, that have relatively low production. EIA's premium coal types have also been eliminated, since these are not used to produce electricity. Two pairs of regions (Central and Southern Appalachia, and Southwest and Rocky Mountain) have been consolidated, using an average weighted by 1996 production, to group coals with similar characteristics.

Mercury, heat, and sulfur contents have been calculated from the U.S. Geological Survey’s coal quality database. For each of the samples in the database, mercury and sulfur contents were converted from parts per weight values to pounds per million Btu using the sample's heat content measurement. The samples were then grouped by supply region and coal type and averaged. Measurements in the database are remarkably inconsistent within coal types. Mercury content can vary by up to three orders of magnitude, sulfur content by a factor of 20, and heat content by more than 50%. We do not know how much of this variation is due to actual in-seam variation and how much to measurement error. Therefore mercury and Btu values were checked for consistency with a table prepared by the Geological Survey for the Center for Clean Air Policy (CCAP), and sulfur values were compared with the values used by EIA. Adjusted values are shown in bold in the table above.

Supply Curves

Supply curves have been constructed in Analytica in the following way. We have projections from EIA on price and quantity for all coal types for 1996 through 2020. EIA estimates that a 10% increase in quantity supplied causes a 1% increase in price. The Haiku coal supply curve function is derived by calculating the line that passes through the EIA price-quantity point and has the slope estimated by EIA.

Transportation Costs

We have constructed a matrix of 1996 coal transportation costs, derived from a similar matrix in EIA’s coal market module. This matrix gives the cost of transporting each coal type from each supply region to electricity generators in each coal demand region. EIA determines these values for 1996 from historical and contract data.

We derived our matrix from EIA's in three steps:

1. Aggregating over mining types. In its transportation matrix, EIA distinguishes between surface-mined coal and underground-mined coal. (So, for example, it reports separate values for North Appalachian low-sulfur surface coal and North Appalachian low-sulfur underground coal. Sometimes the transportation costs for these two types are different because of, presumably, differences in existing contracts rather than differences in the coal.) Since we do not distinguish between surface and underground coal, we aggregate over these categories using 1996 production data.

2. Aggregating from EIA’s supply regions to ours using a weighted average over 1996 production.

3. Transforming from EIA's coal demand regions to NERC regions. We have constructed weights for the transformation using the generator database described in another section.

All costs are modified for future years using a (de)escalation factor to account for changes in productivity, fuel costs, and other costs, as indicated in the next table. The multipliers for the four alternative cases (high oil price, low oil price, high economic growth, and low economic growth) differ from the reference case multiplier by only 3% in 2020, so we use the reference case multipliers. Multipliers for the intervening years have been interpolated.

Table 7. Escalation factors.

Year	Multiplier
1996	1.0000
2000	0.9761
2005	0.9523
2010	0.9163
2015	0.8717
2020	0.8197

Demand

Within Haiku, demand for coal is solved endogenously. Haiku operates at the NERC region level, but the coal supply curves and transportation costs table calculate coal price as a function of coal demand by coal demand region. To overcome this inconsistency, coal plants in Haiku have been broken into five types, which aggregate generation capacity according to the coal demand region in which the generators are located. This allows the translation of coal demand by NERC region to coal demand by coal demand region. The table below describes the coal demand regions.

Table 8. Coal demand regions.

Census Division	Coal Demand Regions	States
New England	NE	CN, MA, ME, NH, RI, VT
Middle Atlantic	YP	NY, PA, NJ
East North Central	OH	OH
	EN	IN, IL, MI, WI
West North Central	CW	MN, IA, ND, SD, NE, MO, KS
South Atlantic	SA	WV, MD, DC, DE, VA, NC, SC
	GF	GA, FL
East South Central	KT	KY, TN
	AM	AL, MS
West South Central	WS	TX, LA, OK, AR
Mountain	MT	MT, WY, CO, UT, ID, NV
	ZN	AZ, NM
Pacific	PC	AK, HI, WA, OR, CA

References

Energy Information Administration (EIA). 1999. *Annual Energy Outlook 2000*.

______. 1998. Coal Market Module Documentation, supplemental tables.

______. 1998. Coal Market Module input tables.

Gas

The natural gas supply module in Haiku consists of a natural gas supply function, a set of regional transmission markups, a set of regional demand functions, and an iterating procedure. The supply and demand functions and the markups are specified for each year from 1995 to 2020.

Supply Function

The supply function returns a source price (which is the weighted average of the U.S. wellhead price and the Canadian import price) corresponding to a quantity demanded by electricity generators. The supply function itself is just a linear function that looks to a table of supply function parameters to get the correct slope and intercept for the function in any given year. These functions are derived from EIA (2001) projections as follows.

EIA (2001) projects total U.S. gas supply (U.S. production plus Canadian imports) and source price for every year through 2020 for each of three cases: reference case (moderate economic growth, averaging 1.9% per year), high economic growth (averaging 2.4% per year), and low economic growth (averaging 1.3% per year). The primary impact of economic growth on the natural gas market is to shift the demand curve. Therefore, these three quantity-price points are essentially three points on a supply curve. So the supply curve is derived as the line that best fits the three data points.

Use of the Supply Curves

The supply curves constructed from EIA (2001) data relate source price to total U.S. supply. For the supply function to return a source price for a given electricity sector demand for gas, we must specify the amount of gas demanded by all other sectors. Since we do not currently model demand by other sectors, we simply use the EIA (2001) reference case demands by other sectors. We add the demand generated by Haiku for the electricity sector to this estimated other demand to get the total demand.

Supply Regions and Transmission Markups

There are no natural gas supply regions. Since natural gas is (approximately) the same everywhere, it would be an unnecessary complication to model where the gas is coming from. (The same is not true of coal.) Two explanations for our decision follow:

1. There are no serious transmission constraints in the time frame within which new power plants will be constructed (EIA 1998). Those few constraints that exist at the moment (e.g., into northern New England) should be alleviated by the time any new generation might come online. The restructured market seems to be functioning well in calling new investment into existence where it is needed. Every year for the past several years, new market hubs and trading centers have been constructed, and new storage facilities have come online to smooth out seasonal variation in supply availability and price. For example, in the *Annual Energy Outlook 1998,* projections for capacity utilization (expressed as a percentage of available capacity including capacity entering and exiting regions) rarely exceed 70% utilization and almost never exceed 80%. This moderate rate of utilization indicates that transmission constraints are not a serious concern.

2. The National Energy Modeling System (NEMS) has already solved the transmission problem for us, and we use its solution. That is, it has modeled supply regions, transmission capacities and costs, and the demands for gas by electricity generators in each region and then solved for the delivered price of gas to generators in each region. These results provide us with a transmission markup time series (equal to the difference between source price and delivered price) for each region. These markups do not change appreciably between the reference case and the high and low economic growth cases, so we simply use the reference case markups throughout. EIA provides the markups by Census region. We have used a weighting by generating capacity to convert Census regions to NERC regions.

References

Energy Information Administration (EIA). 2001. *Annual Energy Outlook 2002* and supplemental tables.

______. 1998. Deliverability on the Interstate Natural Gas Pipeline System. Office of Oil and Gas, DOE/EIA-0618(98). May.

______. 1997. *Annual Energy Outlook 1998.*

Biomass

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Biomass typically refers to agricultural and forest products or residues derived from living plants, but the term has been applied to landfill gas and other organic wastes. Since biomass absorbs carbon dioxide (CO_2), the entire process of growing, burning, and regrowing biomass is considered to be nearly CO_2 neutral. In certain cases, the biopower cycle can sequester additional CO_2 from the atmosphere by fixing carbon in the soil. More than 70% of biomass power is cogenerated with process heat. Wood-fired systems account for 88%, landfill gas 8%, agricultural waste 3%, and anaerobic digesters 1%.

The Oak Ridge energy crop county-level (ORECCL) database describes the likely yields of two types of energy crops (switchgrass and short-rotation woody crops) at the county level (Graham et al. 1996a, 1997b). In the 1996 version of ORECCL, only two short-rotation woody crops are considered—hybrid poplar and willow. Furthermore, a county is assumed suitable for either hybrid poplar or willow production but not both. Thus, the short-rotation woody crop data for a county are one or the other.

Switchgrass is the only herbaceous energy crop considered in ORECCL. The energy crop yields are based on expert opinion as of 1996 and represent the yield that might be expected using best management practices circa 2000 on existing cropland. For some crops in some regions (e.g., switchgrass in the Northeast, the Lake States, and the Northern Plains; willow in the Lake States), the ORECCL yield values are mostly educated conjecture because field data are few or nonexistent.

The farmgate prices for switchgrass and hybrid poplar are based on the BIOCOST (version 1) production model and BIOCOST's default assumptions, with two exceptions (Walsh and Becker 1996). First, 1993 rather than 1995 prices for equipment and fuels were used. Second, the expected returns to land and management used in the farmgate price calculations are not BIOCOST's multistate regional default values. Rather, they are county-level values created using the following equation.

County-level returns ($/acre/yr) =
1993 state cropland cash rent * (county farmland value/state farmland value)

This approach assumes that cropland cash rent is a good surrogate for expected returns to land and management and that farmland value is controlled by the potential profitability of the cropland; therefore, geographic differences in farmland value can be used to infer geographic differences in likely returns to cropland. The approach has the drawback that factors other than profit expected from farming can influence farmland value (e.g., potential for residential development). Thus the ORECCL values for returns to cropland are inflated in counties and states with significant development pressures. For example, DuPage County just west of Chicago has very high county-level returns in ORECCL and thus very high farmgate energy crop prices. Such counties usually have very little cropland, however, and their effect on the model's accuracy is therefore comparatively insignificant.

Tables below report data at the state level. This data is aggregated to the NERC subregion level for use in the Haiku model. There are two projections—one for a low case and one for a high case—that are the two points used to define a linear biomass supply function that includes a transportation cost.

Two options—switchgrass and poplar—are available and the model identifies the lower-cost option for each NERC region. The heat content of the fuels is assumed to be 8.5 mmBtu/ton for switchgrass, and 8.2 mmBtu/ton for poplar.

The technologies for the primary conversion of biomass for electricity production are direct combustion, gasification, and pyrolysis. Direct combustion is the only technology currently modeled in Haiku and the only one currently in widespread use. Direct combustion involves the oxidation of biomass with excess air, creating hot flue gases that are used to produce steam in the heat-exchange sections of boilers. The steam produces electricity in a Rankine cycle; usually, only electricity is produced in a condensing steam cycle, but electricity and steam are cogenerated in an extracting steam cycle.

Table 9. Average Recent Year Switchgrass Yield and Price, 1993 dollars.

State	Yield (dry tons /acre/year)	Farmgate Price ($/ton)	Suitable acres (thou.)	Cash Rent ($/acre/yr)
Kentucky	6.44	35.91	5,417	55.62
North Carolina	5.11	38.30	4,668	38.36
Tennessee	6.25	34.89	4,458	48.13
Virginia	5.63	35.18	2,727	35.58
West Virginia	6.23	32.57	616	34.99
Illinois	5.96	48.20	23,154	105.26
Indiana	5.91	45.11	12,623	89.60
Iowa	6.00	49.27	24,984	111.78
Missouri	6.09	39.72	13,796	68.41
Ohio	5.77	41.83	10,569	71.33
Arkansas	6.09	35.24	7,973	49.29
Louisiana	5.37	37.95	4,656	45.36
Mississippi	5.99	33.56	5,163	39.94
Michigan	5.04	39.18	7,339	46.39
Minnesota	5.41	42.41	20,115	66.22
Wisconsin	5.11	41.26	9,509	54.92
Connecticut	5.00	40.30	145	50.30
Delaware	3.39	55.54	446	59.06
Maine				
Maryland	4.30	47.37	1,453	55.22
Massachusetts	5.00	38.18	120	42.11
New Hampshire	5.00	44.41	27	66.30
New Jersey	5.41	38.93	477	51.81
New York	5.00	36.48	3,646	35.59
Pennsylvania	5.60	37.58	4,180	47.95
Rhode Island	5.00	41.30	18	54.19
Vermont	5.00	37.25	191	38.39
Kansas	5.04	35.24	18,595	35.75
Nebraska	5.41	45.42	13,709	83.69
North Dakota	4.39	38.57	19,970	38.52
South Dakota	5.09	38.42	12,642	49.13
Washington				
Oregon				
Alabama	6.19	31.44	2,643	32.50
Florida	4.78	49.24	761	64.98
Georgia	5.82	31.52	4,403	26.65
South Carolina	5.32	32.54	2,000	20.76
Oklahoma	5.50	35.71	5,360	32.13
Texas	5.35	38.40	8,500	37.32

Source: Oak Ridge energy crop county-level (ORECCL) database.

Table 10. Average Recent Year Short-Rotation Poplar and Willow Crops, 1993 dollars.

State	Yield (dry tons /acre/year)	Farmgate Price ($/ton)	Suitable Acres (thousands)	Cash Rent ($/acre/yr)
Kentucky	4.94	53.79	5,417	55.62
North Carolina	4.34	54.77	4,468	38.36
Tennessee	4.85	52.99	4,458	48.13
Virginia	4.34	53.76	2,727	35.58
West Virginia	4.21	54.31	616	34.99
Illinois	5.00	65.46	23,154	105.25
Indiana	5.00	61.65	12,623	89.60
Iowa	4.99	67.13	24,984	111.78
Missouri	4.78	58.56	13,796	68.41
Ohio	4.87	58.33	10,569	71.33
Arkansas	4.79	53.19	7,973	49.29
Louisiana	4.81	52.17	4,656	45.36
Mississippi	4.86	50.35	5,163	39.94
Michigan	5.03	49.80	7,339	46.39
Minnesota	4.74	58.01	20,115	66.22
Wisconsin	4.96	52.54	9,509	54.92
Connecticut	6.09	36.77	146	50.30
Delaware	4.50	58.81	446	58.06
Maine	4.13	49.69	469	40.48
Maryland	4.49	58.11	1,453	55.22
Massachusetts	5.43	39.29	164	36.75
New Hampshire	5.37	39.51	101	41.57
New Jersey	4.76	53.84	477	51.81
New York	6.03	34.81	3,916	34.77
Pennsylvania	4.73	52.73	4,180	47.95
Rhode Island	6.00	37.91	18	54.19
Vermont	5.05	42.23	493	37.76
Kansas	4.52	54.64	4,587	42.92
Nebraska	4.52	67.15	6,424	89.25
North Dakota	3.76	62.21	15,676	41.69
South Dakota	4.32	61.58	7,371	60.14
Oregon	6.03	79.68	991	217.14
Washington	5.90	86.13	283	243.74
Alabama	4.51	51.35	2,643	32.50
Florida	4.50	56.91	582	52.30
Georgia	4.44	50.39	4,403	26.65
South Carolina	4.39	48.99	2,000	20.76
Oklahoma	4.26	52.42	1,510	32.00
Texas	4.01	56.30	991	39.95

Source: Oak Ridge energy crop county-level (ORECCL) database.

Wind

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The Haiku model includes five model plant categories for development of new wind resources in each NERC subregion. Each is associated with a class of wind resource and an amount of maximum capacity, and distinguished by capital cost associated with developing the resource. The amount of energy available from new wind generators is determined on the basis of a maximum capacity factor assumption that varies by season and time block. Because variable costs are essentially zero, they are dispatched whenever they are available.

Three types of data are used in constructing the new wind model plant data in Haiku: base (capital and fixed O&M costs) costs, capacity by wind resource category and availability factors by region and season.[16] Data on the cost adjustment factor and resource capacity for each wind resource category are presented in the table.

Data on capital and fixed O&M costs for new generators comes from Table 38 of EIA's Assumptions to the Annual Energy Outlook 2002. These data are factored up to account for the cost of transmission investment and for the quality of the wind resource. The size of the adjustment factors are determined by a combination of the greater capital investment necessary in areas with lower wind resources in order to achieve a comparable amount of generation capability, and the higher costs of tapping wind resources located at greater distance from high voltage transmission lines due to the necessity of adding new transmission capacity. The cost adjustment factors range from 20% above base costs (associated with model plant category 1) for capacity associated with model plant category 2 to 200% above base costs for capacity associated with model plant category 5. Model plants in category 1 will be built first, followed by category 2 and so on. The capital costs of the wind plants are levelized over 17 years.

Data on availability factors comes from information about capacity factors supplied by EIA in conjunction with assumptions developed by the Energy Modeling Forum (EMF 2001).[17] These data were disaggregated for 9 subperiods of the year, mapped to three seasons and three EIA defined time blocks (base, middle, peak) and to seasons and Haiku time blocks. The resulting data in Haiku are maximum capacity factors that generally differ across seasons and between time block one (the baseload period) and the three other time blocks in the model, which generally share a common value. Energy output is a function of total capacity constructed at the model plant times the maximum wind capacity factor for each region, season and time block.

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[16] These model plant categories span wind resource classes 5 and 4 (and 3 in the case of MAIN only). The mapping between capacity in these wind resource categories and the model plant categories varies by region, depending largely on proximity to the transmission grid. Generally speaking, MP 1 contains capacity in wind class region 5 and the other wind model plants contain potential wind capacity from class 4 regions. EIA generally does not consider resources from class 3 regions to be economic, but we have made an exception in the case of MAIN based on data from NREL.

[17] Energy Modeling Forum. 2001. *Prices and Emissions in a Competitive Electricity Sector*. EMF Report 17 (May).

Table 11. Cost Adjustment Factors by Model Plant and Wind Resources by Region

Model Plants:	**MP1**	**MP 2**	**MP 3**	**MP 4**	**MP 5**	
Cost Adjustment Factor:	1.0	1.2	1.5	2.0	3.0	
	Wind Resources (Gigawatts)					
Region:						**Total**
ECAR	0.4	0.4	0.4	0.4	2.4	3.9
ERCOT	1.5	1.0	2.3	4.5	0.7	9.9
FL	0	0	0	0	0	0
MAAC	0.9	0.9	0.9	0.9	5.5	9.2
MAIN	0.75	0.75	0.75	0.75	6.0	9.0
MAPP	7.1	14.2	42.5	42.5	1310.8	1417.1
NY	0.3	0.3	0.7	0.7	1.4	3.4
NE	0.9	0.9	1.8	1.8	3.5	8.9
STV	0.2	0.2	0.4	0.4	0.7	1.8
SPP	2.4	4.8	14.4	14.4	444.5	480.6
NWP	7.7	13.2	8.6	1.5	275.2	306.1
RA	4.0	4.0	7.9	19.9	162.9	198.7
CNV	2.4	0.7	0.7	0.7	15.6	20.1
Total	27.7	40.5	80.6	87.7	2223.2	2459.6

Sources: Adapted from Table 5 at http://www.eia.doe.gov/oiaf/issues/wind_supply.html. And for MAIN from http://www.eren.doe.gov/windpoweringamerica/where_is_wind_illinois.html. The category sorting is based on a NREL map showing proximity of different class wind areas to existing transmission lines.

IX. Appendix: Miscellaneous Model Parameters

This appendix provides tables listing a miscellaneous list of parameters values used in the model. The parameters have been described previously in this document. The values reported here are often the default parameters in Haiku, but sometimes are varied.

Mapping of months to seasons

Summer	May, June, July, August, September
Spring/Fall	March, April, October, November
Winter	December, January, February

Demand elasticities (negative) by season and customer class
(weighted average over region, timeblock)

	Residential	Commercial	Industrial	Aggregate
Summer	0.116	0.228	0.299	0.206
Spring/Fall	0.359	0.228	0.300	0.300
Winter	0.262	0.228	0.299	0.263
Annual	0.219	0.228	0.299	0.246

Summer season demand elasticities (negative) by timeblock and customer class
(weighted average over region)

	Percent of season	Residential	Commercial	Industrial	Aggregate
Baseload	70	0.133	0.259	0.249	0.211
Shoulder	20	0.090	0.175	0.410	0.203
Peak	4	0.090	0.175	0.410	0.183
Super-peak	1	0.090	0.175	0.410	0.178
Average		0.116	0.228	0.299	0.206

NERC Subregions and commonly used reserve margins.

NERC Subregion	Geographic Area	Reserve Margin
ECAR	MI, IN, OH, WV; part of KY, VA, PA	13%
ERCOT	Most of TX	13%
MAAC	MD, DC, DE, NJ; most of PA	13%
MAIN	Most of IL, WI; part of MO	13%
MAPP	MN, IA, NE, SD, ND; part of WI, IL	13%
NY	NY	15%
NE	VT, NH, ME, MA, CT, RI	8%
FRCC	Most of FL	9%
STV	TN, AL, GA, SC, NC; part of VA, MS, KY, FL	13%
SPP	KS, MO, OK, AR, LA; part of MS, TX	13%
NWP	WA, OR, ID, UT, MT, part of WY, NV	15%
RA	AZ, NM, CO, part of WY	14%
CNV	CA	14%

Frequently assumed rates of technological improvement

	Economic Regulation	
	Limited Restructuring	**Nationwide Restructuring**
Ratio of Technical Parameter Values 2008 to 1997		
Maximum Availability Factor	1.02	1.04
Heat Rate at Coal Steam Facilities	0.99	0.97
General and Administrative Cost	0.75	0.67
Non-Fuel O&M Cost	0.76	0.70
Renewables Portfolio Standard	None	RPS with $17 per MWh price cap on tradable renewable credits (target 2% above base)
Transmission Capability	0.5% growth per year	10% more in 2008 than under baseline

Inter-regional transmission

Line Losses	percent	2%
Threshold	$/MWh	0
Transmission Cost	$/MWh	3.0

Available Transmission Capability for Economy Trades (annual average)

Megawatts	Demand (to):												
Supply (from):	ECAR	ERCOT	MAAC	MAIN	MAPP	NY	NE	FRCC	STV	SPP	NWP	RA	CNV
ECAR	0	0	2219	4389	0	0	0	0	3555	0	0	0	0
ERCOT	0	0	0	0	0	0	0	0	0	811	0	0	0
MAAC	4055	0	0	0	0	3403	0	0	3188	0	0	0	0
MAIN	5817	0	0	0	1963	0	0	0	3315	2295	0	0	0
MAPP	0	0	0	1727	0	0	0	0	0	1762	204	316	0
NY	0	0	1920	0	0	0	1658	0	0	0	0	0	0
NE	0	0	0	0	0	1505	0	0	0	0	0	0	0
FRCC	0	0	0	0	0	0	0	0	1938	0	0	0	0
STV	6804	0	3596	2911	0	0	0	3673	0	2576	0	0	0
SPP	0	959	0	2555	1581	0	0	0	2516	0	0	469	0
NWP	0	0	0	0	153	0	0	0	0	0	0	1398	10170
RA	0	0	0	0	316	0	0	0	0	469	1428	0	8533
CNV	0	0	0	0	0	0	0	0	0	0	8305	2412	0
Canada	0	0	0	0	0	0	0	0	0	0	0	0	0

Firm Contract Transmission Capability (summer)

Megawatts	Demand (to):												
Supply (from):	ECAR	ERCOT	MAAC	MAIN	MAPP	NY	NE	FRCC	STV	SPP	NWP	RA	CNV
ECAR	0	0	450	0	0	0	0	0	700	0	0	0	0
ERCOT	0	0	0	0	0	0	0	0	0	0	0	0	0
MAAC	0	0	0	0	0	959	0	0	0	0	0	0	0
MAIN	730	0	0	0	120	0	0	0	0	0	0	0	0
MAPP	0	0	0	252	0	0	0	0	0	0	0	399	0
NY	164	0	94	0	0	0	145	0	0	0	0	0	0
NE	0	0	0	0	0	0	0	0	0	0	0	0	0
FRCC	0	0	0	0	0	0	0	0	0	0	0	0	0
STV	696	0	0	28	0	0	0	1521	0	484	0	0	0
SPP	0	0	0	0	25	0	0	505	669	0	0	506	0
NWP	0	0	0	0	0	0	0	0	0	0	0	682	2734
RA	0	0	0	0	162	0	0	0	0	60	1905	0	4483
CNV	0	0	0	0	0	0	0	0	0	0	432	158	0
Canada	316	0	0	0	0	1660	452	0	0	0	930	0	0

X. Appendix: Example of Supply Technology and Cost

Filename = CH_020322_m3F.ANA: RFF Fuel Prices

Technology Characteristics and Costs (National Weighted Average)

All dollar values are in 1999 dollars.

Year for which numbers are reported = 2005

NEW PLANTS	Units	Coal	Combined Cycle	Gas Turbine	Biomass	Wind
Heat Rate	Btu/kWh	9,161	7,137	9,039	8,266	0
Capacity Factor	%	81%	69%	23%	53%	30%
Utilization Rate	%	100%	81%	29%	63%	100%
Avalability Factor	%	86%	90%	84%	86%	101%
Scheduled Outages	%	10%	6%	6%	5%	-1%
Forced Outages	%	4%	4%	10%	10%	0%
Fuel [a]	$/MWh	9.2	22.4	27.8	32.8	0.0
Pollution Permits/Fees/Subsidies [c]	$/MWh	0.3	0.1	0.1	0.2	0.0
Variable O&M Costs [d]	$/MWh	1.1	1.9	0.1	4.5	0.0
Other Variable Costs [e]	$/MWh	0.0	0.0	0.0	-17.0	-17.0
Total Variable Costs [f = a+b+c+d+e]	$/MWh	10.6	24.3	27.9	20.5	-17.0
Construction Cost	$/kW	1,531	713	376	1,466	1,040
Real Cost of Capital	%	9%	9%	9%	9%	9%
Economic Lifetime	Yrs	15	22	22	22	17
Annual Capital Cost	[$/kW]/Yr	222.3	81.2	42.8	174.7	130.4
Annual Fixed O&M Cost	[$/kW]/Yr	44.2	43.9	33.9	71.3	48.3
Capital Charge [g]	$/MWh	31.4	13.5	21.4	37.8	49.2
Fixed O & M Charge [h]	$/MWh	6.2	7.3	16.9	15.4	18.2
Going Forward Cost [=f+g+h]	$/MWh	48.2	45.0	66.2	73.7	50.5
SO_2	lb/mmBtu	0.1	0.0	0.0	0.0	0.0
NO_x	lb/mmBtu	0.1	0.1	0.1	0.2	0.0
CO_2	lb/mmBtu	205.2	117.5	116.9	0.0	0.0
SO_2	tons/MWh	0.00055	0.00000	0.00000	0.00004	0.00000
NO_x	tons/MWh	0.00050	0.00029	0.00036	0.00062	0.00000
CO_2	tons/MWh	0.94	0.42	0.53	0.00	0.00
Carbon	tonnes/MWh	0.23	0.10	0.13	0.00	0.00

Technology Characteristics and Costs (National Weighted Average)

All dollar values are in 1999 dollars.

Year for which numbers are reported = 2005

EXISTING PLANTS	Units	Scrubbed Coal	Unscrubbed Coal	Steam Natural Gas	Steam Oil	Gas Turbine	Nuclear	Hydro
Heat Rate	Btu/kWh	10,886	10,917	10,719	11,872	12,270	10,540	0
Capacity Factor	%	70%	73%	27%	6%	7%	81%	47%
Utilization Rate	%	87%	90%	34%	8%	9%	98%	49%
Avalability Factor	%	86%	86%	84%	83%	92%	88%	93%
Scheduled Outages	%	8%	8%	11%	11%	3%	7%	5%
Forced Outages	%	6%	6%	6%	7%	5%	5%	2%
Fuel [a]	$/MWh	11.2	12.4	33.1	42.6	39.8	7.0	0.0
Pollution Permits/Fees/Subsidies [c]	$/MWh	0.5	1.3	0.1	1.3	0.5	0.0	0.0
Variable O&M Costs [d]	$/MWh	2.2	1.8	1.0	4.1	0.9	8.4	3.4
Other Variable Costs [e]	$/MWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Variable Costs [f = a+b+c+d+e]	$/MWh	13.8	15.6	34.3	48.0	41.2	15.4	3.4
Construction Cost	$/kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Real Cost of Capital	%	9%	9%	9%	9%	9%	9%	9%
Economic Lifetime	Yrs	0	0	0	0	0	0	0
Annual Capital Cost	[$/kW]/Yr	30.3	35.3	38.5	57.0	38.1	33.9	25.2
Annual Fixed O&M Cost	[$/kW]/Yr	45.8	44.1	38.1	42.3	32.8	81.0	39.2
Capital Charge [g]	$/MWh	4.9	5.5	16.0	102.9	58.1	4.8	6.1
Fixed O & M Charge [h]	$/MWh	7.5	6.9	15.9	76.2	50.0	11.5	9.5
Going Forward Cost [=f+h]	$/MWh	21.3	22.4	50.1	124.2	91.1	26.9	12.9
SO2	lb/mmBtu	0.1	1.3	0.0	0.9	0.0	0.0	0.0
NOx	lb/mmBtu	0.4	0.4	0.2	0.3	0.2	0.0	0.0
CO2	lb/mmBtu	205.5	205.7	117.6	181.5	118.1	0.0	0.0
SO2	tons/MWh	0.00071	0.00682	0.00000	0.00558	0.00000	0.00000	0.00000
NOx	tons/MWh	0.00218	0.00197	0.00118	0.00148	0.00129	0.00000	0.00000
CO2	tons/MWh	1.12	1.12	0.63	1.08	0.72	0.00	0.00
Carbon	tonnes/MWh	0.28	0.28	0.16	0.27	0.18	0.00	0.00

Definitions:

Capacity Factor	Ratio of total annual generation to total nameplate capacity
Utilization Rate	Ratio of total annual generation to available capacity after accounting for scheduled and forced outages
Avalability Factor	Percent of time that a generating unit is available [or (1-scheduled outage rate)*(1-forced outage rate)]
Calibrator	This measure accounts for the difference between modeled costs and actual costs in the 1997 data year
Pollution Permits/Fees/Subsidies	All pollution policy related expenses that are part of the variable costs; not including abatement costs
Other Variable Costs	Tax credits or other credits such as RPS
Construction Cost	This measure is not applicable for existing capacity
Going Forward Cost	This measure is defined differently for existing and new or planned capacity.