Veritas Economics Environmental Policy Simulation Model (EPSM)

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1851 Evans Road
Cary, NC 27513
Office: 919.677.8787
Fax: 919.677.8331

VERITAS
Economic Consulting
VeritasEconomics.com

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Veritas Economics Environmental Policy Simulation Model (EPSM)

The Environmental Policy Simulation Model (EPSM) is an analytical tool developed by Veritas Economics to assist policy makers and corporate strategists in their evaluations of alternative electricity system regulatory and resource allocation choices. EPSM can be used to evaluate environmental policies at the national, regional, or local level. It can also be used to evaluate the choice among new electricity generation alternatives, or the impacts of demand changes at specific locations. Results from the model include the physical, economic, and financial performance of the electricity system and of its elements and institutions.

EPSM intends to represent the modeled systems in a manner that is both conceptually appropriate and reasonably transparent. Conceptual correctness refers to the incorporation of appropriate system information and economic principles in the model specification. Transparency ensures that users and reviewers can readily ascertain how the model performs. The EPSM solves by simulation, based on established behavioral rules for each supplier in a market. The interactions of these agents, given their technological, economic, and financial constraints, determine the system, element, and institutional outcomes.

The physical characteristics of all thermal generating units, including heat rate, capacity, and fuel type, are incorporated in EPSM. The interannual, temporal decay in the efficiency of these generation assets is calibrated to historical data. Capacity and generation from new units are modeled such that EPSM's baseline electricity price and quantity projections are consistent with external forecasts from the National Energy Modeling System (NEMS) or individual independent system operator (ISO)/regional transmission organizations (RTOs).[1] New generation is specified as aggregate units at the regional level. These units include heat rates typical of new combined cycle or combustion turbine units. Fuel prices are exogenous and taken from external sources, for example, the U.S. Energy Information Administration (EIA). The responsiveness of electricity demand to electricity price changes is modeled through the use of specified estimates at the market level.

The operating decisions evaluated in the EPSM are long-run for two reasons. First, the policy or strategic choice of interest will typically not be implemented for some time. Thus, the consequences will play out over years. Second, because the electric industry consists of durable capital assets, decisions by system managers are forward-looking. Consequently, the

[1] NEMS refers to National Energy Modeling System. Independent system operators (ISO) and regional transmission organizations (RTOs) coordinate control and monitor the operation of the electrical power systems.

simulations in EPSM take place over a 30-year horizon. To facilitate modeling over this period, the 8,760 hours in a year are collapsed into fourteen annual load periods. These load periods represent the typically modeled periods (seasonal peak, shoulder, and baseload), as well as superpeak hours to support transmission security modeling. The model dispatches generating units over these load periods to maximize unit-level profits in each period subject to the equilibrium requirement that the demand for electricity is satisfied. Prices needed for this equilibrium are found for each load period and year. The baseline model can be calibrated to production-model simulated or historical unit operating information and market economic outcomes including load period-specific prices, quantities, and capacity factors.

Because EPSM is designed to evaluate the impacts of environmental regulations, simulations are conducted using the “with-and-without” context. The business as usual (“without”) baseline may be either a single point in time (e.g., current conditions) or a trend/forecast. The (“with”) policy or strategic choice of interest is modeled against the specified baseline; the differences between the two scenarios represent the impact of the policy or strategic choice. The with regulation scenarios are based on a long-run re-dispatch that produces new equilibrium electricity prices and quantities, as well as new projections of unit operating behavior and profitability. A unit commitment (UC) model is available for evaluating sensitivity of unit operating behaviors and profitability to simplifications employed in the long-run re-dispatch model.[2] This UC model is a mixed-integer program that is solves via a large scale commercial optimizer.

EPSM is programmed in Analytica® with user interface rendered in Microsoft Silverlight via Analytical Decision Engine. It can be operated as either a desktop installed or web-based application. The user interface is graphical and employs both intuitive geographic information system (GIS) and traditional interfaces to access results and models. Figure 1 depicts the top-level user interface. Beginning from the main interface, a user can look at the units that are subject to a particular regulation or group of regulations.

[2] The long-run dispatch approach does not directly incorporate inter-temporal restrictions, such as ramp rates, or certain costs, such as start-up costs.

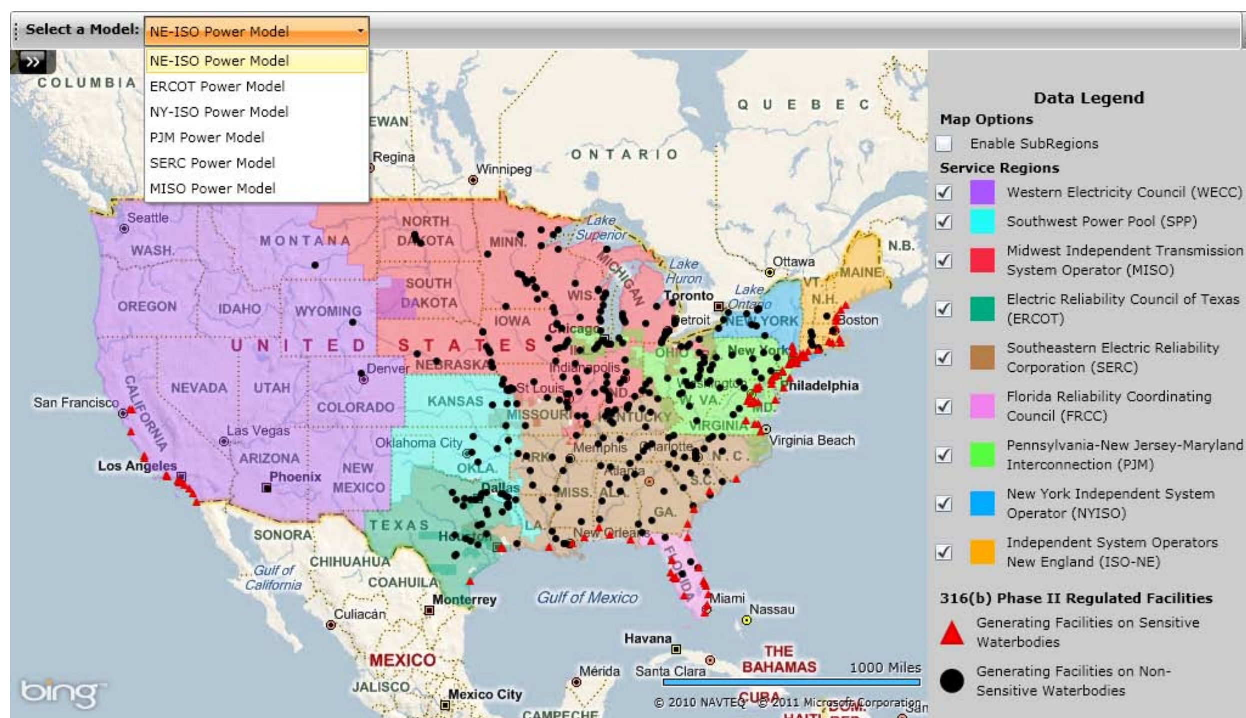


Figure 1: Main Interface

In this figure, plants with units subject to 316(b) requirements are indicated by the black circles and red triangles. A red triangle indicates at least one of the units withdraws water from a sensitive waterbody (ocean, estuary, or tidal river).

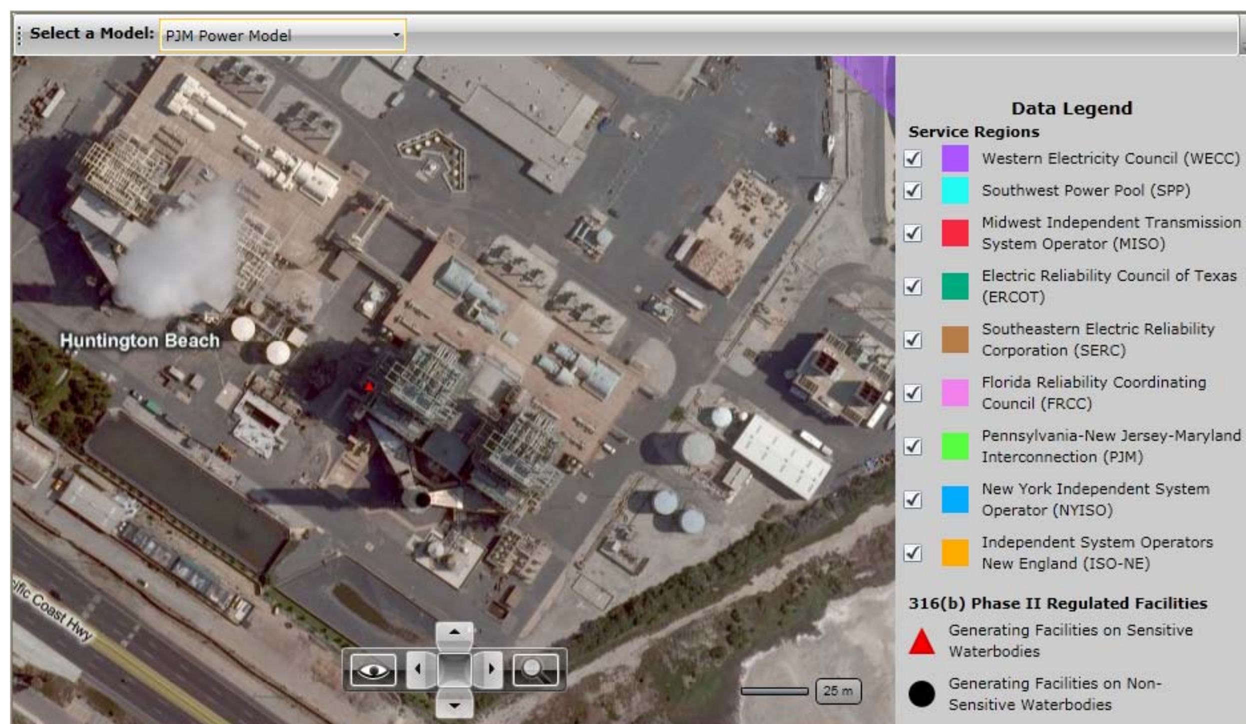


Figure 2: Zoom to Plant View

As depicted in Figure 2, clicking one of the icons representing a regulated plant allows quick visual inspection of site features. As indicated in Figure 3, regional analysis is available by selecting the region to be evaluated.

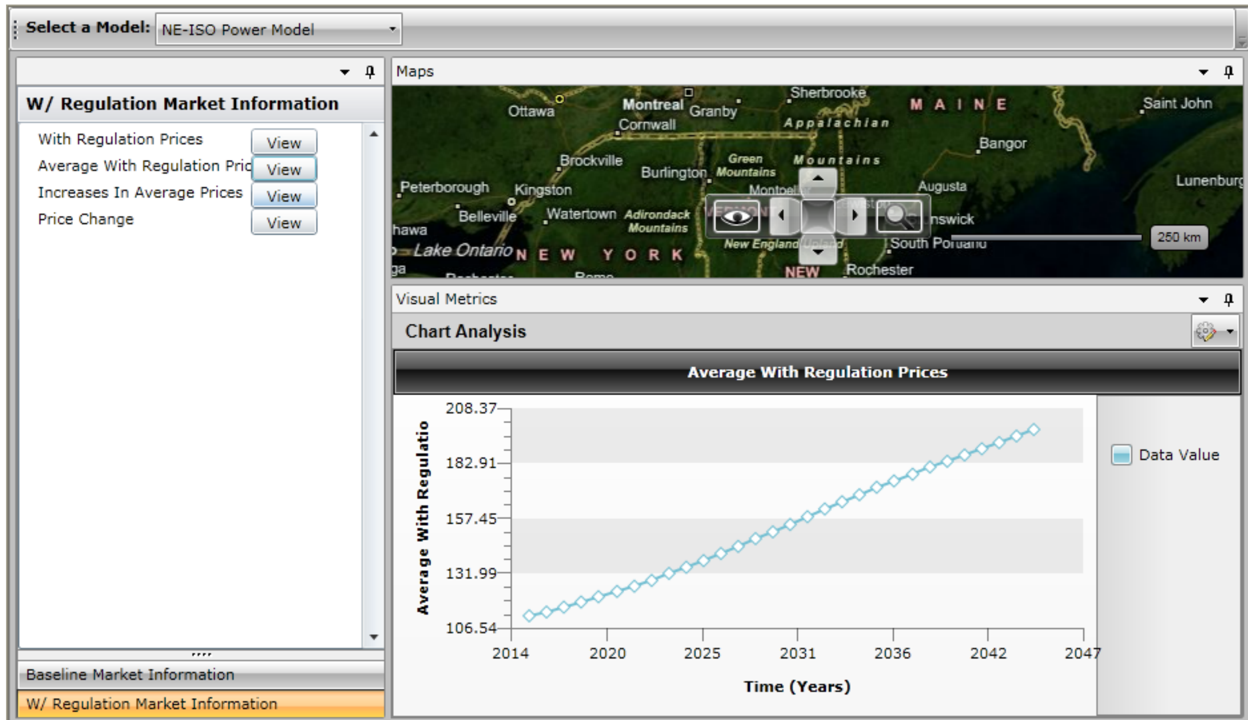


Figure 3: Conduct Regional Analysis

As indicated in Figure 3, regional analysis is available by selecting the region to be evaluated. In this figure, New England ISO price impacts are being assessed. The remainder of this document describes the context and approach for generating analytical outputs.

1. Overview of the Electricity System

The electrical system is represented in EPSM in a systems modeling framework at the level of detail needed to evaluate many policy and strategic choices. Understanding how and why EPSM operates the way it does is enhanced by a basic understanding of electricity systems. The electricity supply chain is the physical system that connects energy sources to the ultimate consumers of electricity. It establishes the electricity production/consumption opportunities and constraints available to society. Lack of storability is the most important constraint. Because it is not economic to store significant amounts of electricity, load and generation must always match throughout the system. Load continually changes across space and time, making this balancing a very complex undertaking. The trend in national electricity generation (and consumption) has been upward. The main drivers of this increase are the growth in population and economic activity. The transmission system offers the potential for meeting this load with alternative generating sources. Fluctuating demand and bottlenecks in the transmission system lead to prices that vary widely in time and space.

Electricity is generated through the combination of an energy source and a power production technology that become more efficient over time. Within this broad description are numerous variants. The nation's generation mix is heterogeneous for two significant reasons. First, electricity demand is highly variable both temporally and geographically because no single technology is economically efficient in all settings. For example, water resources for hydroelectricity generation are relatively abundant in the northwest while coal for steam-electric generation is relatively abundant in the mid-Atlantic region. Second, the power plants in place today are the legacy of decisions made some decades ago. As Figure 1.1 indicates, although the mix is heterogeneous, the vast majority of generating capacity is thermal, with the greater part of that being fossil units.

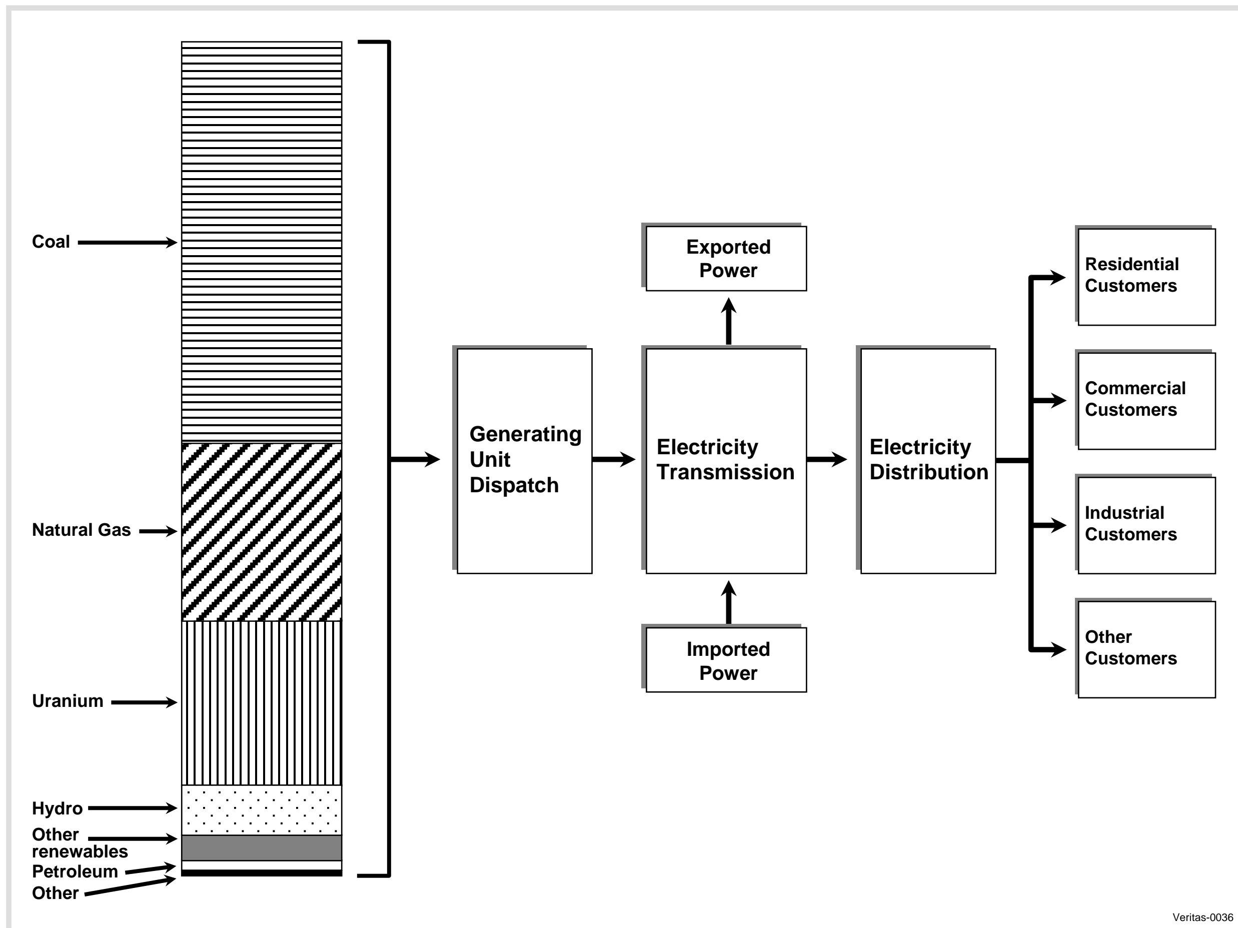


Figure 1.1: Overview of the Electricity System
Source of fuel data: U.S. Energy Information Administration (2010)

The industry derives revenue from the sale of electricity and related products and services. The issue of new stock or debt instruments may occasionally provide an additional source of cash. Cash flows from the industry include outlays for fuel and energy; payments to suppliers of new capital equipment, including environmental compliance capital; payments to suppliers of other materials and services, including holders of emission allowances; employee-related payments, such as wages and salaries, pensions, and health care; tax payments (as well as any penalties) to federal, state, and local governments; dividend disbursements to stockholders; and debt service (interest and principle repayment) payments.

Generation and transmission activity occurs within the oversight of the various organizations (e.g., the North American Electric Reliability Corporation [NERC], the Federal Energy Regulatory Commission [FERC], and ISOs) in maintaining electrical system reliability and planning for capacity retirements.

2. The Supply Side

The supply data are compiled in databases constructed from responses to forms EIA-860a, 860b, 767, and 906, and FERC Form 1. The *Annual Electric Generator Report*, EIA-860a and b includes location, operating status, fuel type, capacity, plant fuel consumption and generator-level production. Statistics collected by EIA-767, the *Steam-Electric Plant Operation and Design Report*, include the relationship between boilers and generators as well as boiler fuel use, boiler generation, and operating status. Wind and hydropower production are reported in EIA-906.

2.1 The Physical Characteristics of Thermal Generating Units

The model is based on an engineering specification of thermal generating units.[3] Central to this is the specification of the input-output curve. Thousands of these input-output curves specific to individual thermal units are employed in the model. The input-output curve represents both the heat rate and capacity of a thermal unit. It begins at the lowest level of output (here somewhat less than 50 megawatts [MW]) and terminates at the unit's capacity limit (Figure 2.1).[4]

[3] Thermal units are the great majority of generation and capacity and are also directly impacted by environmental regulations.
[4] Both heat rates and capacity can vary over the course of a year. Input-output curves can be both unit and time specific.

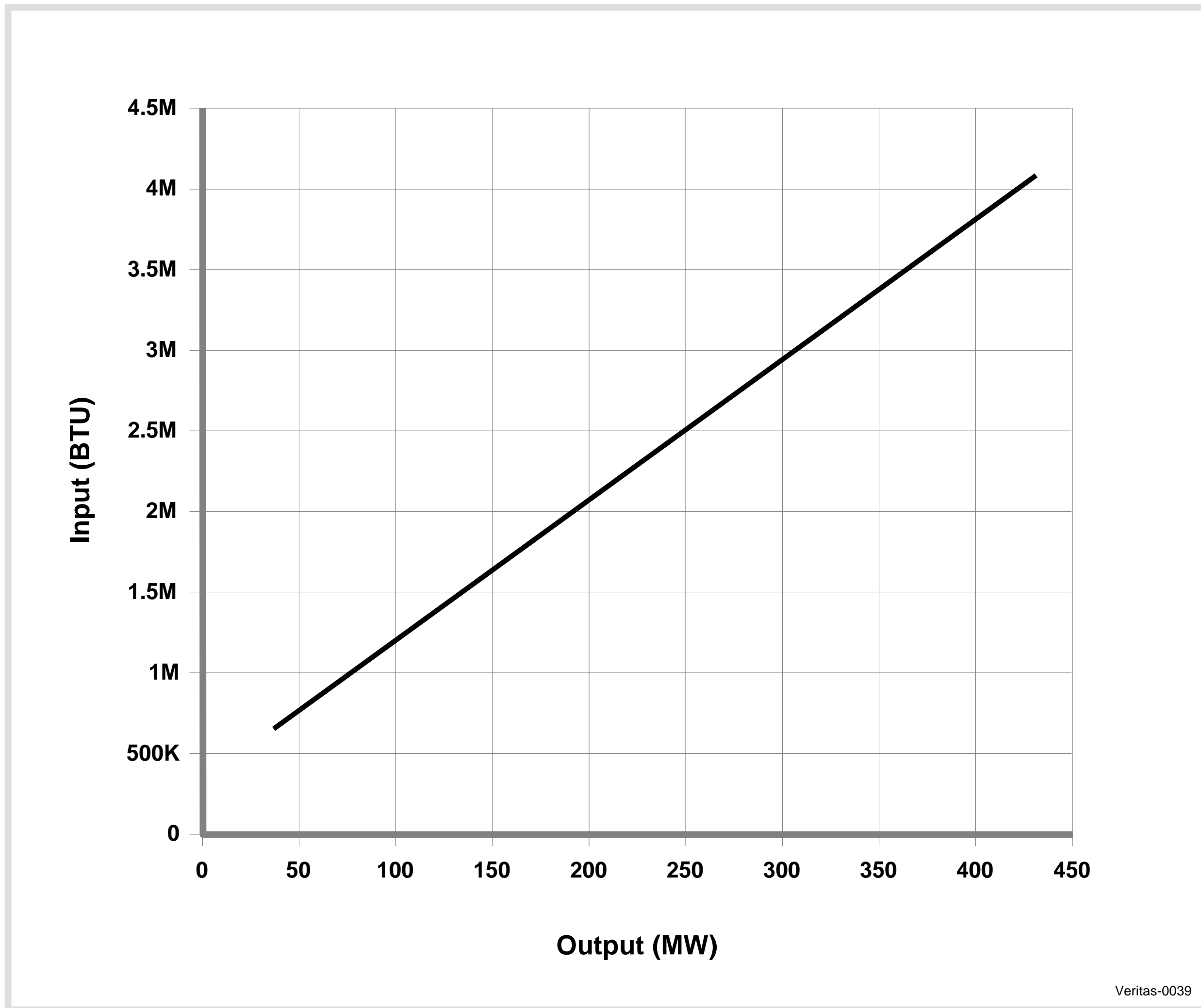


Figure 2.1: Graph of Input-Output Data for an Example Unit

For modeling purposes, the input-output curve in the EPSM is represented as a marginal heat rate curve. The marginal heat rate curve as depicted below (Figure 2.2) is the amount of heat necessary to produce successive additional units of electrical output.

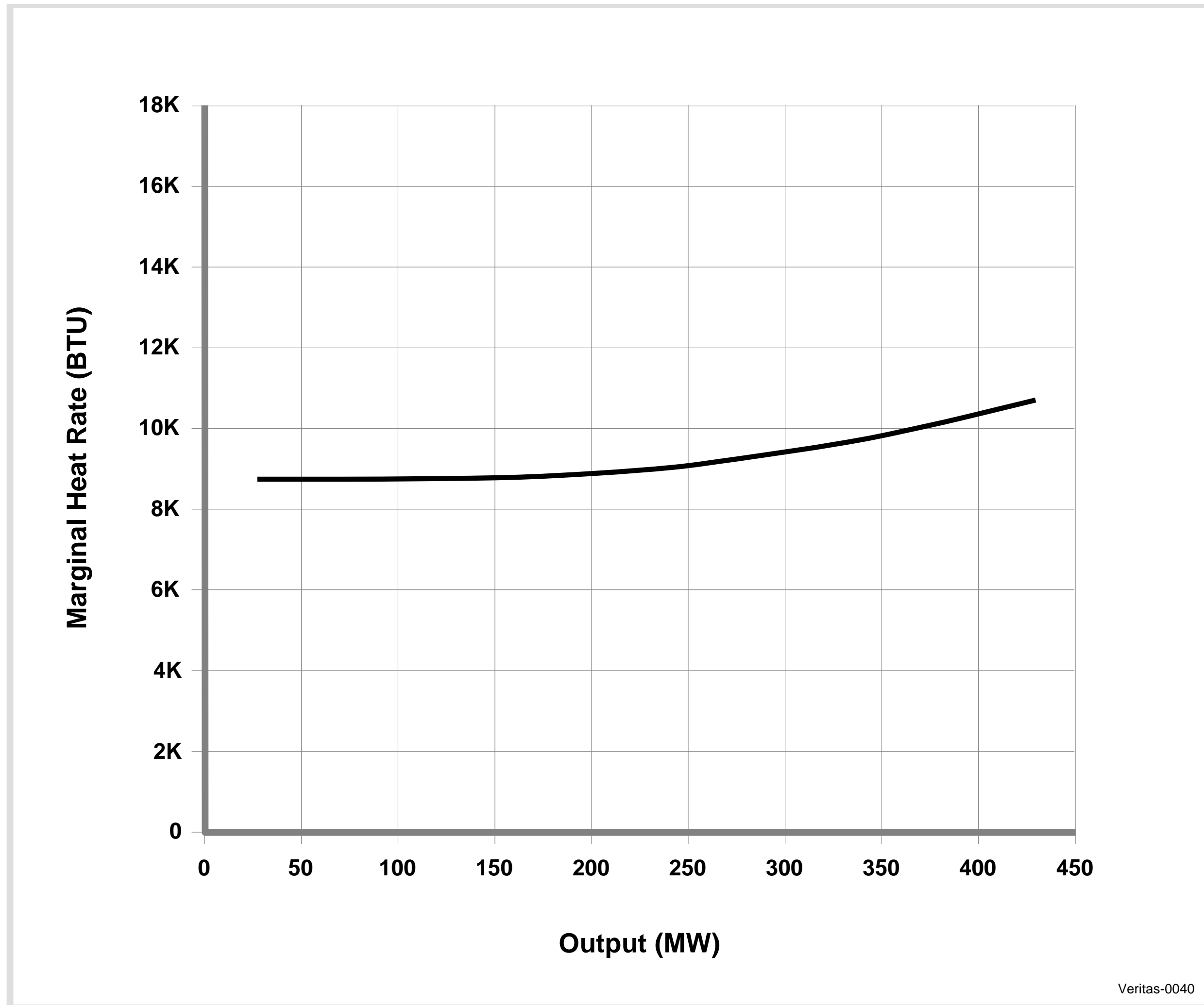


Figure 2.2: Marginal Heat Rate

Fuel cost is typically the largest component of variable costs for thermal generating units. The product of the marginal heat rate (mmBtu/MWh) and the cost of fuel ($/mmBtu) is the marginal fuel cost curve ($/MWh). This incremental cost curve depicted in Figure 2.3 represents the incremental fuel cost of generation.

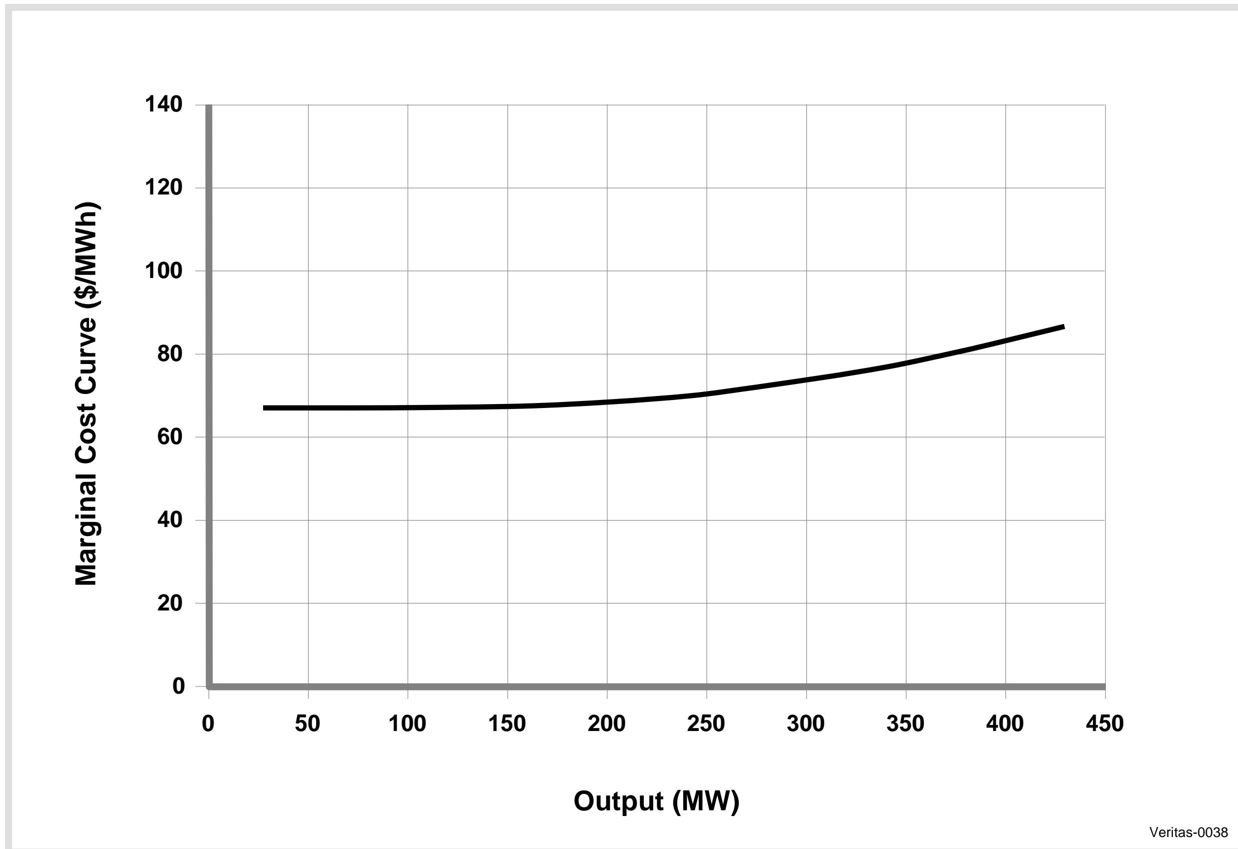


Figure 2.3: Marginal Fuel Cost

Fuel costs are the majority of operating costs for a thermal unit. However, there are additional costs associated with operating a unit such as the cost of emissions control and monitoring and equipment maintenance. Adding hourly operation and maintenance (O&M) costs to the marginal fuel cost curve (Figure 2.4) completes the specification of variable costs.

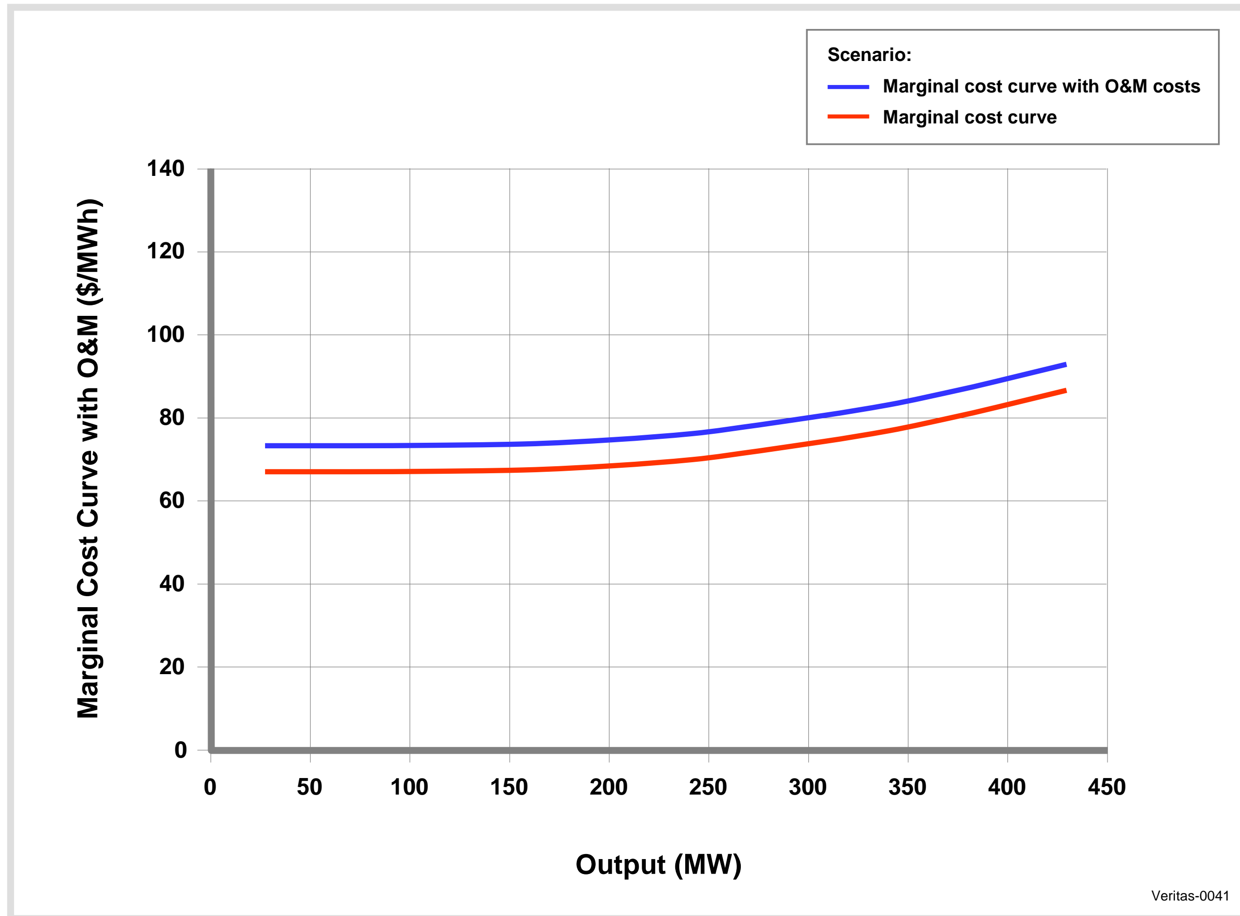


Figure 2.4: Marginal Variable Cost Curve

2.2 Specification of Technology Decay

For thermal units, important inter-temporal effects are reflected in the heat rate. Over time, the heat rate tends to deteriorate, punctuated by temporary improvements when major maintenance is performed. The deterioration in heat rates results in the upward drift in cost functions for generating units over time. The gradual decay in unit efficiency is modeled using the "vintage capital" approach in which external estimates of efficiency decay are applied to unit heat rates. Thus, the model considers the impact of time on these engineering-based specifications of heat rate. In the model, the generating unit becomes less efficient over the years it operates, requiring more heat to generate the same amount of electricity as time passes. Figure 2.5 shows a graph of the modeled shift over time.

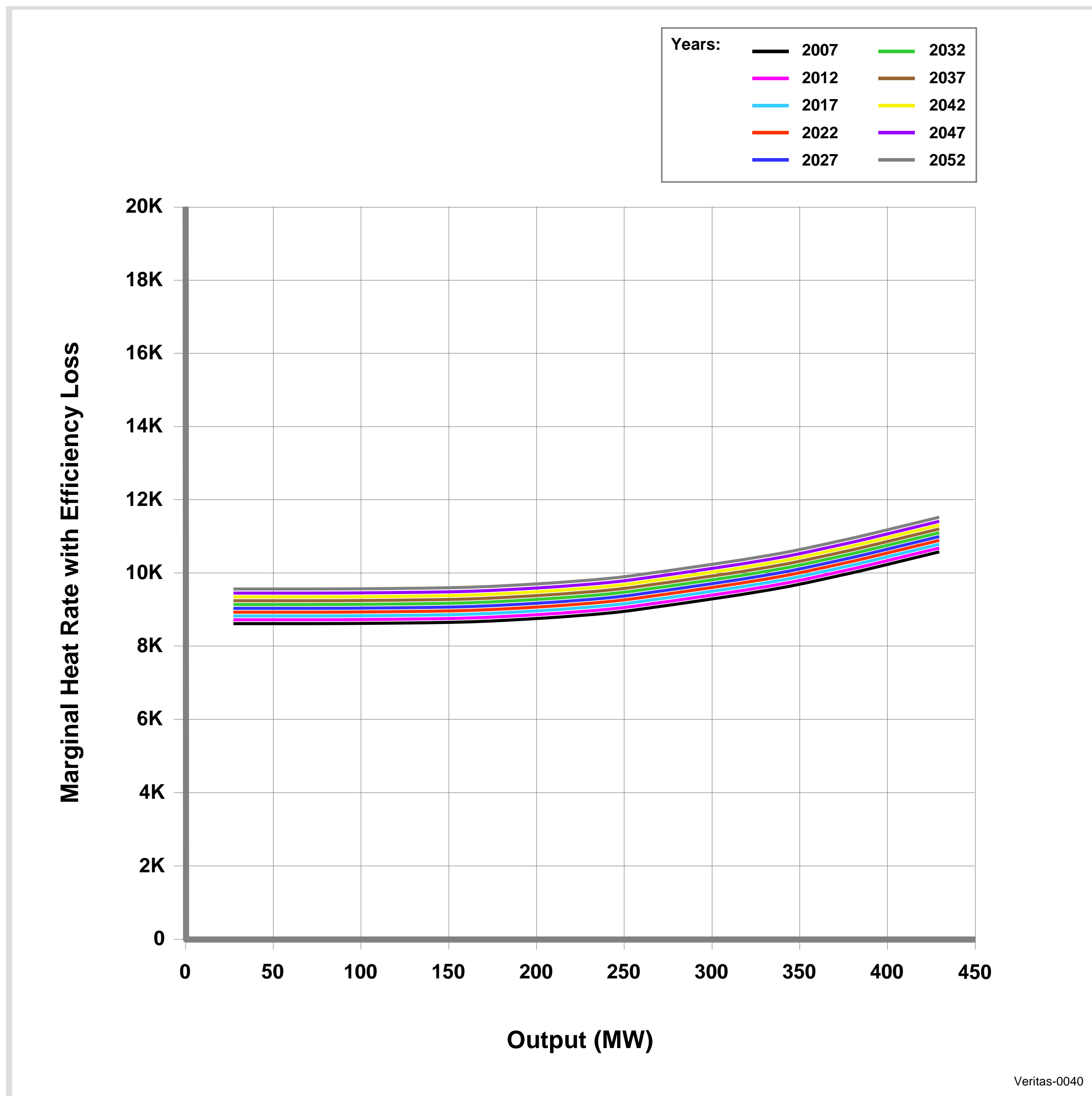


Figure 2.5: Marginal Heat Rate Curve Efficiency Decay

This depicted decay is not a perfectly accurate representation of engineering relationships because this slow decline is not punctuated by intermittent improvements in efficiency as typically occurs with maintenance. The specification of annual efficiency decay is sufficient to produce what is observed in markets over time as new more efficient units are introduced. Over time as existing plants become relatively more expensive to operate, plants that were traditionally used to meet the baseload migrate to the shoulder periods. The overall

decline of the unit efficiency as specified exogenously can be calibrated to produce the sort of gradual reduction in capacity factor that occurs as thermal facilities age.

Although, the impacts of decay on unit efficiency are not necessarily constant over the generation range, they are modeled as constant. Outages typically increase with facility age and result in cost and generating capacity impacts. Increased maintenance outages arising as the unit ages are not explicitly modeled.

The increasing costs that units experience as they age combined with the introduction of new more efficient technologies can render them uneconomic. In the model, unit output gradually decreases. When units become uneconomic, they no longer generate output.

2.3 Specification of New Generation

The model produces investment in new supply year by year. New units are represented as combustion turbine and combined cycle capacity with appropriate investment and operating costs. These cost functions are assumed to be linear and constant per unit of output, terminating at the generation rate associated with the typical load factor for the technology.

The specification of new generation considers available information. New generation that is planned up to 2016 is directly entered into the facility data base for the appropriate year. Generation decision makers are assumed to have perfect foresight regarding electricity prices for the years 2017–2043 and thus can make investment decisions that are profit-maximizing. For years after 2016, sufficient new generation is made available to offset projected load growth.

2.4 Financial Situation of Generating Units

The financial condition of each generating unit is based on a projection of annual profitability. This calculation occurs over units (i), load periods (l), and time (t). Annual profits are the difference in the revenues resulting from the sale of electricity and the costs incurred to provide the electricity:

$$\pi_i = Total\ Annual\ Revenue_i - Total\ Annual\ Cost_i \quad \textbf{(2.1)}$$

Within the model context, this is represented as

$$\pi_i = (Total\ Annual\ Revenue_i - Total\ Variable\ Cost_i) - Total\ Fixed\ Costs_i \quad \textbf{(2.2)}$$

To identify total annual revenue, generation revenues for each unit and load period are identified as $P_l^* \times Q_{li}^*$ where P_l^* is the market clearing price for each load period, identified via

simulation, and Q_{li}^* is unit i's solved-for optimal output for load period l at the market-clearing price for that load period P_l^*.[5] Variable costs for each hour are identified by integrating under the marginal cost curve up to the solved for optimal output Q_{li}^* as depicted below (Figure 2.6). Annual variable costs and revenues for each unit are then calculated as hourly costs and revenues, multiplied by hours per load period, and summed over load periods.

$$Total\ Revenue_i = \sum_{l=1}^{14} P_l Q_{li} H_l \tag{2.3}$$

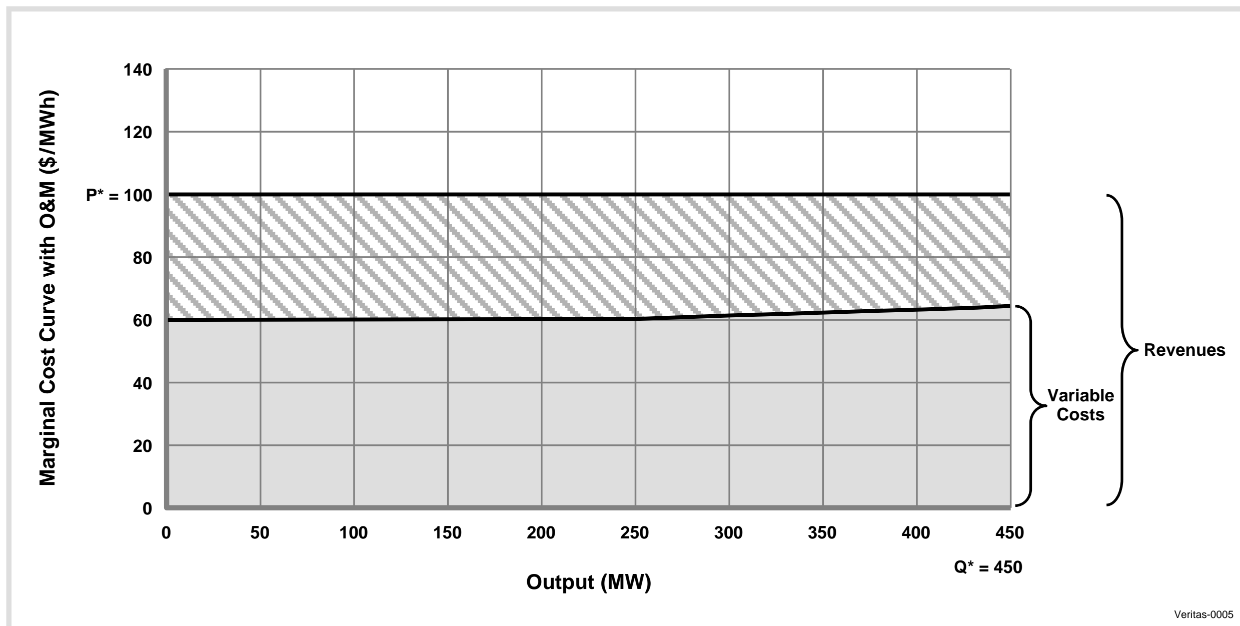


Figure 2.6: Identification of Revenues and Variable Costs by Load Period

Fixed costs are those costs associated with the decision to be in operation but are not specifically affected by rate of generation such as capital payments, some taxes, rents, insurance, security, some wages. Fixed costs are specified via the generation-specific scale factors in the National Electric Energy Data System (NEEDS).

Calculating revenues minus annual fixed and variable costs returns estimated annual net cash for each unit. This approach is used to calculate annual profitability for each unit. This stream of profits over time is converted to present value terms by discounting. The discounted present value of profits is:

$$DPV = \sum_{t=1}^{n} [\pi_t'/(1+r)^t] \tag{2.4}$$

[5] The identification of market clearing prices P* and optimal quantities Q* is discussed in Section 4.

where

r = required minimum return on the compliance capital outlays

t = time in years

n = number of time periods in the planning horizon

π = profits.

3. The Demand Side

Load originates as residential, commercial, and industrial organizations use air conditioners, machinery, lighting fixtures, and other equipment to provide services that contribute to household utility, business profits, or public welfare from government services. Wholesale consumption depends on a number of factors including the time of day, season, weather, prices of different energy sources, and the price of electricity. Within the day, the demand for electricity shifts following the diurnal pattern of human activity, as illustrated in Figure 3.1. Over the year, the demand shifts primarily because of the temporal pattern of heating and cooling loads. Demand in northern latitudes is typically highest during winter; and in the southern latitudes sometime during the summer. In the EPSM, load periods are developed based on similarities in load within season.

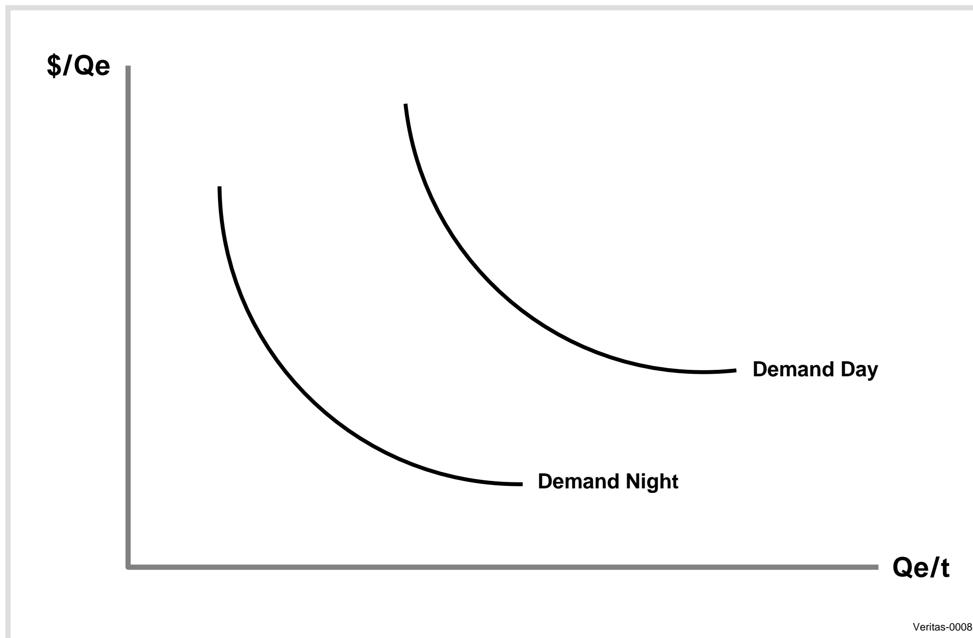


Figure 3.1: Illustration of Diurnal Shifts in Electricity Demand

Demand for electricity at a particular point in time may be represented as

$$QD = D(K, W, P, Pa) \tag{3.1}$$

where

QD = consumption rate of electricity

K = stock of electricity-using capital

W = weather

P = price of electricity

Pa = price of other energy sources.

In this function, the consumption of electricity is inversely related to price. Specifically, lower prices increase consumption, and higher prices decrease consumption (Figure 3.2). This relationship results from the optimizing behavior of households who seek to maximize their welfare and business enterprises who seek to maximize their profits.

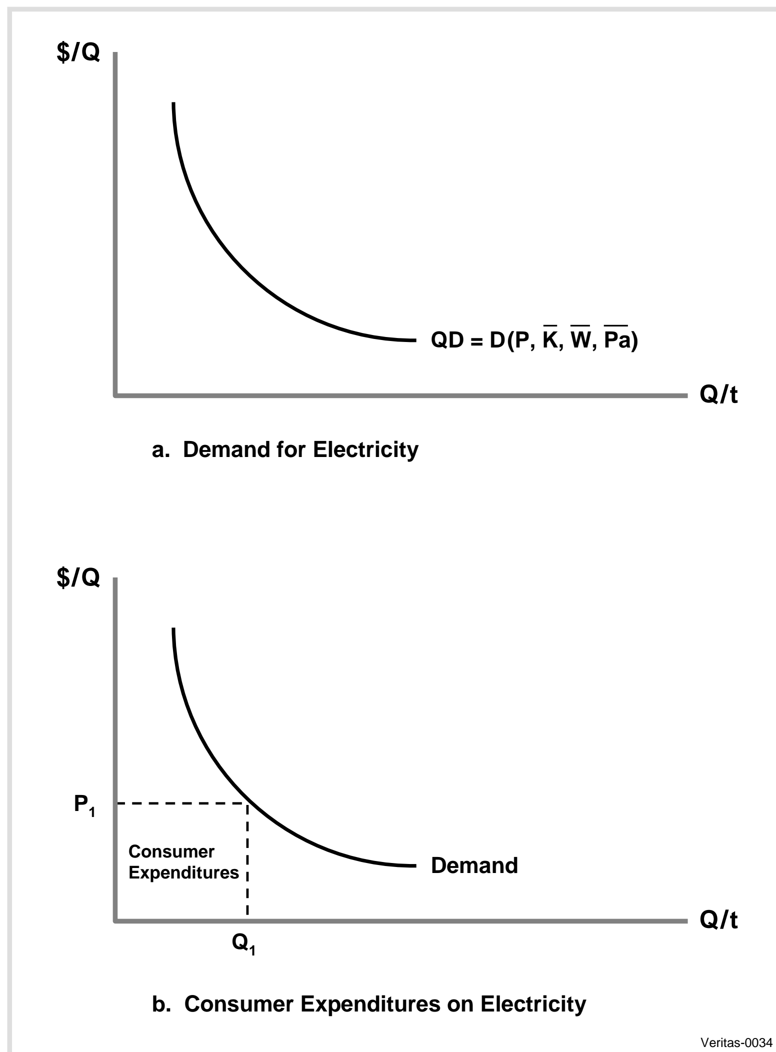


Figure 3.2: Retail Electricity Demand and Expenditures

With this inverse relationship, there is a single quantity for every price. In the simulation context, identifying the Q*ly for any given P*ly is accomplished by plugging P into the demand

equation and calculating the result. Similarly, the consumer's expenditures on electricity are the area P_1*Q_1.

The model employs a constant elasticity of demand curve of the following form

$$QD = \alpha * P^{\eta} \tag{3.2}$$

where

α	=	shift parameter
P	=	price of electricity
η	=	elasticity of demand

The shift parameter α captures all non-price variables that affect electricity demand. The values for α are based on load projections for each of 14 load periods in 2016, calibrated algebraically. This calibration takes into account the market-clearing price through the elasticity of demand by solving for α given P, Q, and η.[6]

[6] The elasticity of demand for electricity has historically been found to be very unresponsive to price. A typical model specification is η = –0.2.

4. Modeling Electricity Markets

Electricity markets take on various forms. Some states are close to the deregulated model envisioned by proponents of electricity deregulation, while in other states, the movement to competition has been less complete or absent. EPSM employs a perfectly competitive market representation in which the outcomes in the market for wholesale power result from the interaction of the demand for electricity and its supply.[7] Prices both ration demand and provide producers with a production incentive. Figure 4.1 shows market demand and supply and the equilibrium outcomes (P*, Q*) for a particular load period and year.

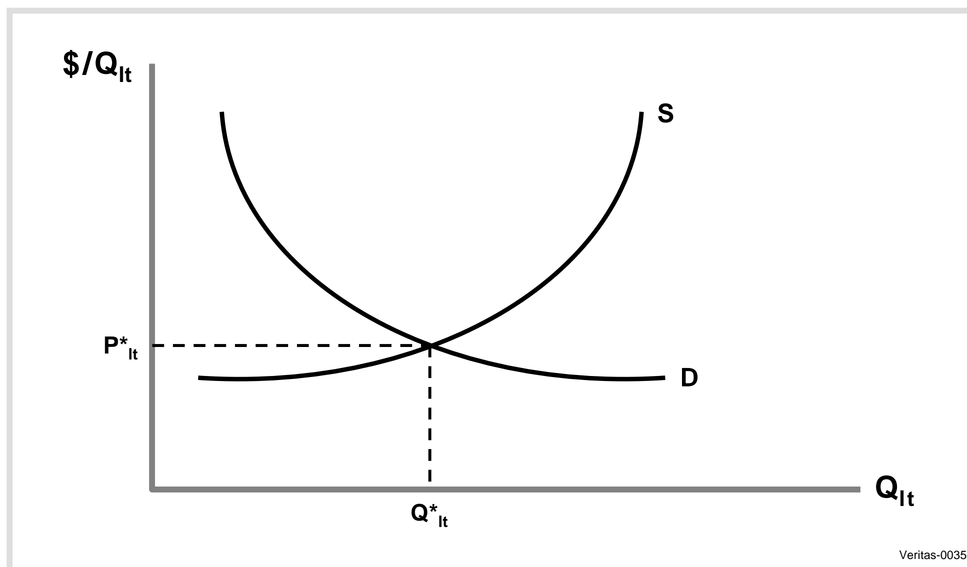


Figure 4.1: Market Demand and Supply and the Equilibrium Outcomes

The electricity supply curve (S above) is specific to each region, and is typically characterized by an area with little slope where the baseload units operate.[8] The curve then slopes steeply upward where the peaking units operate. Electricity demand (D above) is typically steeply sloping because demand is insensitive to price. A simulation approach is used to identify P^*_{lt} and Q^*_{ilt}, the point where supply and demand are in equilibrium. The EPSM identifies unit operations and financial conditions by simulating electricity markets to identify electricity prices for each load period and year (P^*_{lt} from the preceding discussion) and generation for each unit, load period, and year (Q^*_{ilt} from the preceding discussion). These

[7] In perfect competition, both buyers and sellers take price as given: they are unable to influence it, usually because they are individually insignificant to its formation.

[8] This is similar to the merit order approach of ranking generating assets in ascending order based on their short-run marginal costs of production.

simulations employ supply curves that vary somewhat over years and load periods, in conjunction with demand curves that are price insensitive and shift significantly throughout the day and year.

4.1 Dispatch

In daily and hourly operational situations, an important decision is the proper operating rate of the generating units. Costs and restrictions associated with electricity production include ramping, start-ups, and shut-downs, which depend upon the current state of the unit as well as previous states. Most generating units earn the majority of their revenues from the sale of electricity. However, ancillary services, such as reserve power and voltage regulation, can also be sources of revenue.

Algorithms that identify optimal operations with full consideration of these factors are called "unit commitment" models. These models are typically calculated at hourly (or smaller) intervals and for periods ranging from days to a year. Although unit commitment models are state-of-the-art for identifying profit-maximizing outputs, they are complicated and can require significant computational resources. Because EPSM evaluates over extended time periods, unit commitment modeling is not practical for the baseline scenario.[9] Rather, a simplified approach that can be calibrated to measured output (i.e., the Continuous Emissions Monitoring System [CEMS] or reported capacity factors) or output simulated from a unit commitment model.

In the EPSM, generators select the production rate for a generating unit where profits are maximized. The simulated choice is how much electricity to produce in one load period. Profits are the difference in the revenues resulting from the sale of electricity produced in one hour and the costs incurred to provide the electricity.

This optimal condition is shown graphically in Figure 4.2 using the stylized unit cost curves. With an electricity price of P^*, optimal output is Q^* and the contribution of the unit to profits is represented as the cross-hatched area, where P^*Q is total revenue and $AVC_1 {}^*Q_1$ is total variable cost.

[9] A unit commitment model is available for calibrating with-regulation results of the simplified dispatch model.

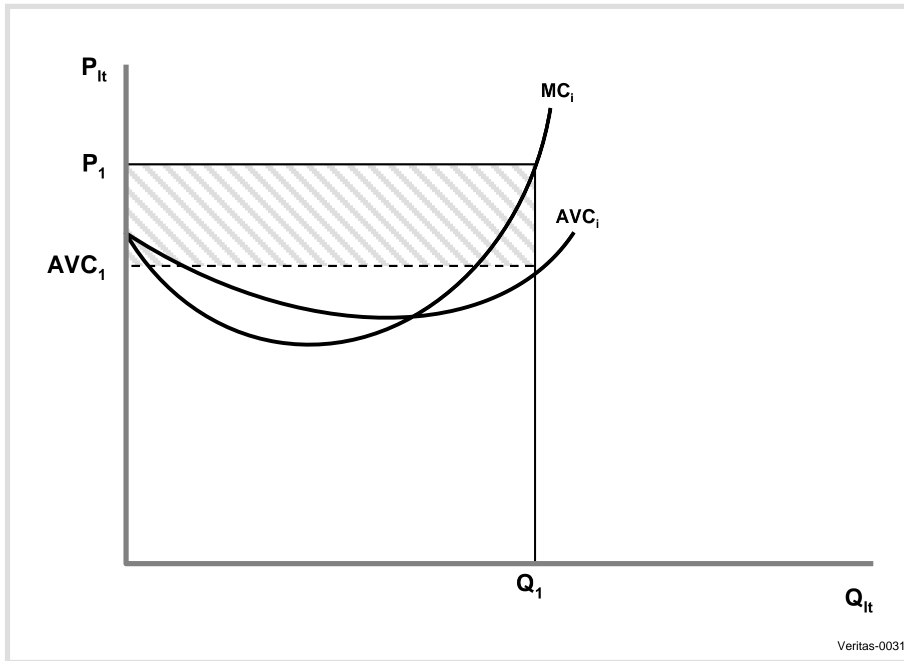


Figure 4.2: Optimal Production

In EPSM, profit maximization leads decision makers to select the production rate for the generating units where the market price of electricity equates to the marginal costs of each unit. When the profit-maximizing outputs for each unit are summed at each price, the market supply (merit order) curve is created. Figure 4.3 shows the dispatch function for three units with constant unit costs to their capacity output. Construction of market supply curves in EPSM is similar, but with many more units comprising the market curve.

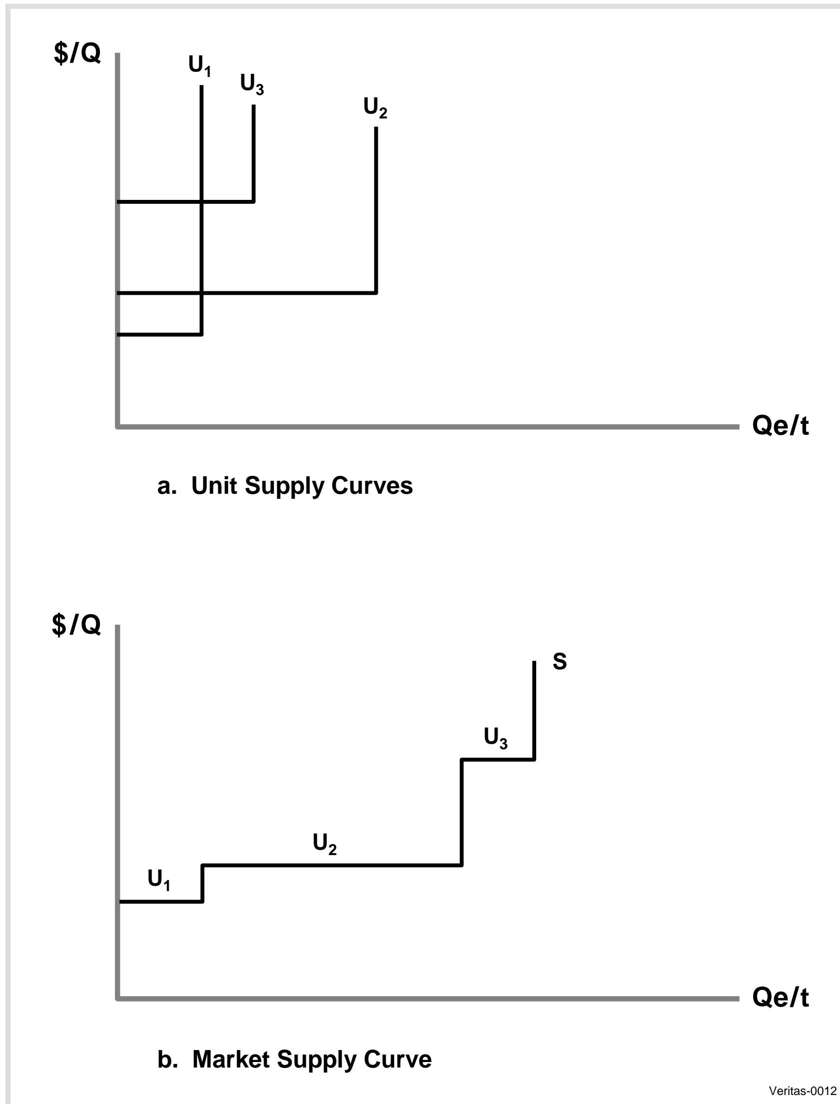


Figure 4.3: The Market's Short-Run Supply Curve

4.2 Market Simulation

Supply and demand interact via a market-clearing simulation as depicted in Figure 4.4. This market clearing module equilibrates supply and demand to identify market-clearing prices in aggregated time periods (load periods). These groups include base, shoulder, peak, and superpeak for winter, summer, and spring/fall.

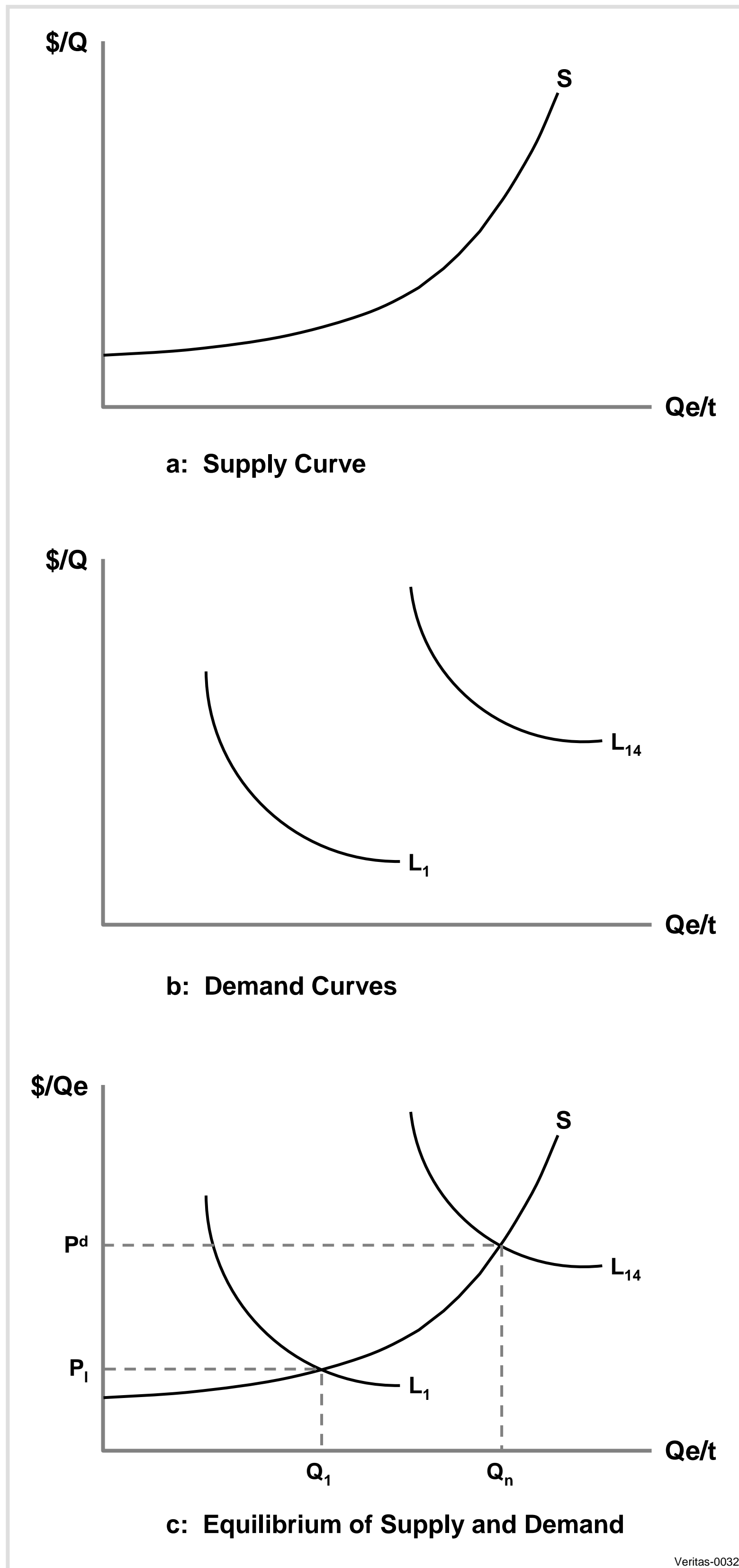


Figure 4.4: The Market for Electricity through Time

Figure 4.5 demonstrates a market clearing outcome. The upward sloping curve is supply, and the downward sloping curve is demand. Market prices and outcome are associated with the intersection of the supply and demand curves. When the market simulation is run, markets clear in each load period. Equilibrium prices and quantities are identified.

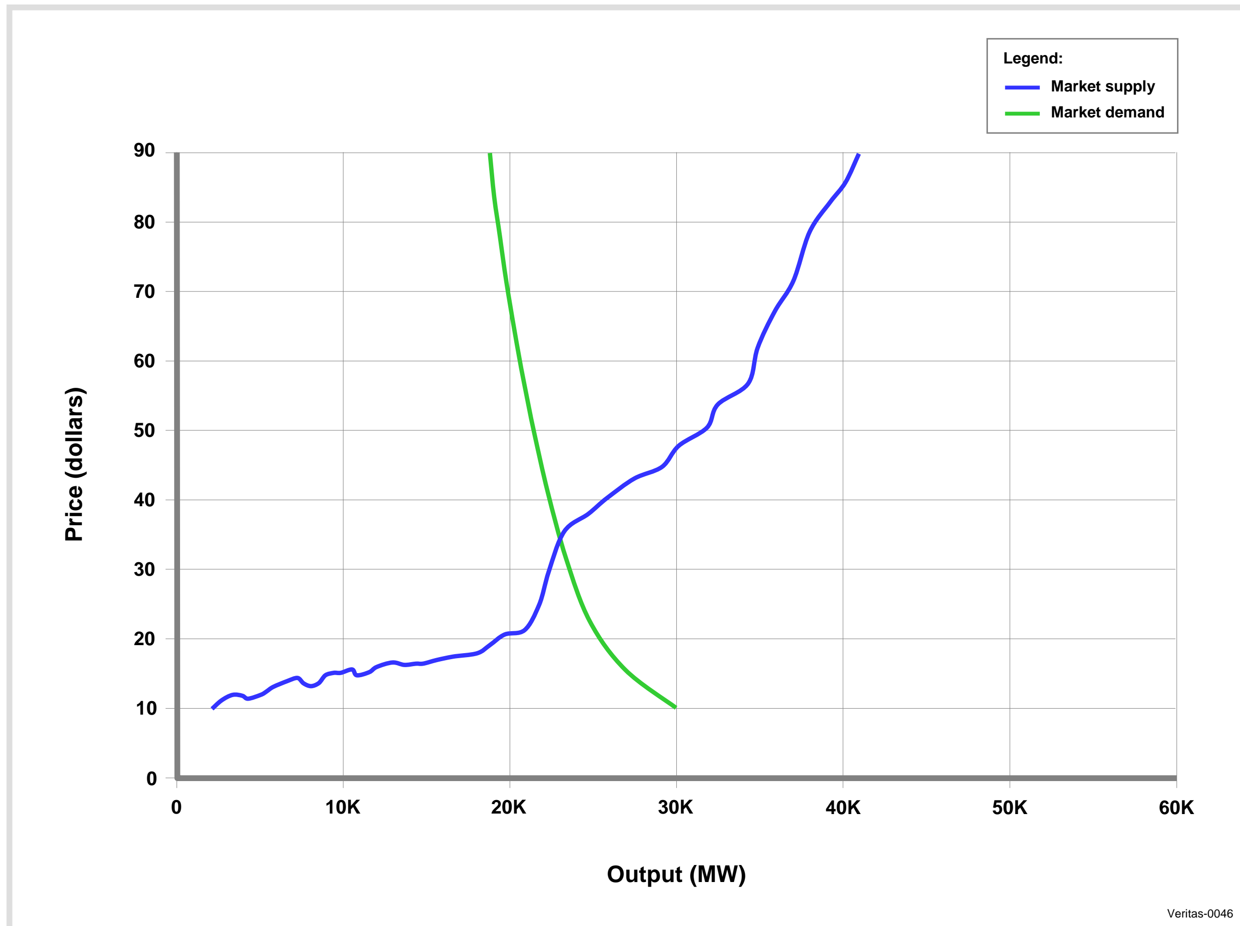


Figure 4.5: Market-Clearing Outcome

5. Baseline Model Calibration

The EPSM baseline model can be calibrated within years and over the model horizon. Calibration within years supports improving the accuracy of the dispatch approach. Calibrating over the model horizon allows the model to be synchronized with external forecasts for load and prices of fuel and electricity.

5.1 Calibration to Hourly Production Data

Supply in each load period for each unit is modeled as the profit maximizing output at a given price. Supply curves are created by combining variable cost information with agent-based profit maximization.[10] This simplified approach ignores numerous system constraints ranging from ramp rates to transmission bottlenecks.

The process used to simulate locational prices and unit operations can be calibrated based on unit commitment data, and transmission topology data. The unit commitment process takes into account unit availability based on factors such as maintenance cycles, the likelihood of forced outage or retirement, start-up costs and times, and resource availability. It also takes into account cost factors such as primary and secondary fuel types, fuel availability, fuel cost, heat rate, fixed and variable maintenance costs.

Transmission topology data mathematically represent the transmission system used to deliver the electricity. This mathematical model (also referred to as an impedance or admittance model) includes information on the allowable thermal ratings of the transmission lines, pre-established inter and intra regional transfer, and the location of the loads within the system. It is largely the constraints or limitations imposed by the transmission topology that create regional differences in electricity prices.

These within-year simulations are calibrated to unit commitment simulations that produce location-specific electricity prices and unit-specific operations. The modeling process accounts for market-specific aspects, either as input quantities or as parameters fed into the "with regulation" scenario. The flow chart in Figure 5.1 depicts the process.

[10] Renewable generating units such as solar, wind, and run-of-river hydro are modeled as having zero input costs and modeled based on expected output.

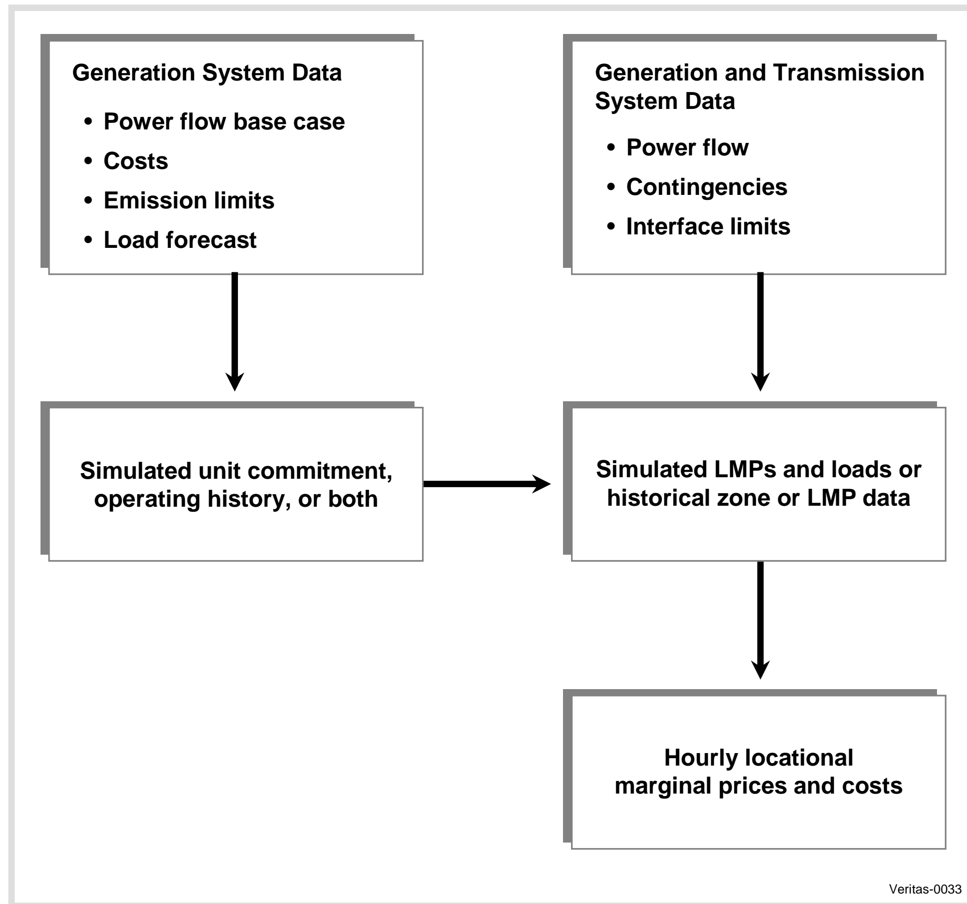


Figure 5.1: Location-Specific Price and Unit-Specific Operation Forecasting Process

Calibrating EPSM to this system provides a linearized approximation to the complicated time and location specific features of electricity markets. Units can be calibrated for individual load periods. Figure 5.2 depicts a comparison of generation by load period from EPSM simulated and production model simulated operations.

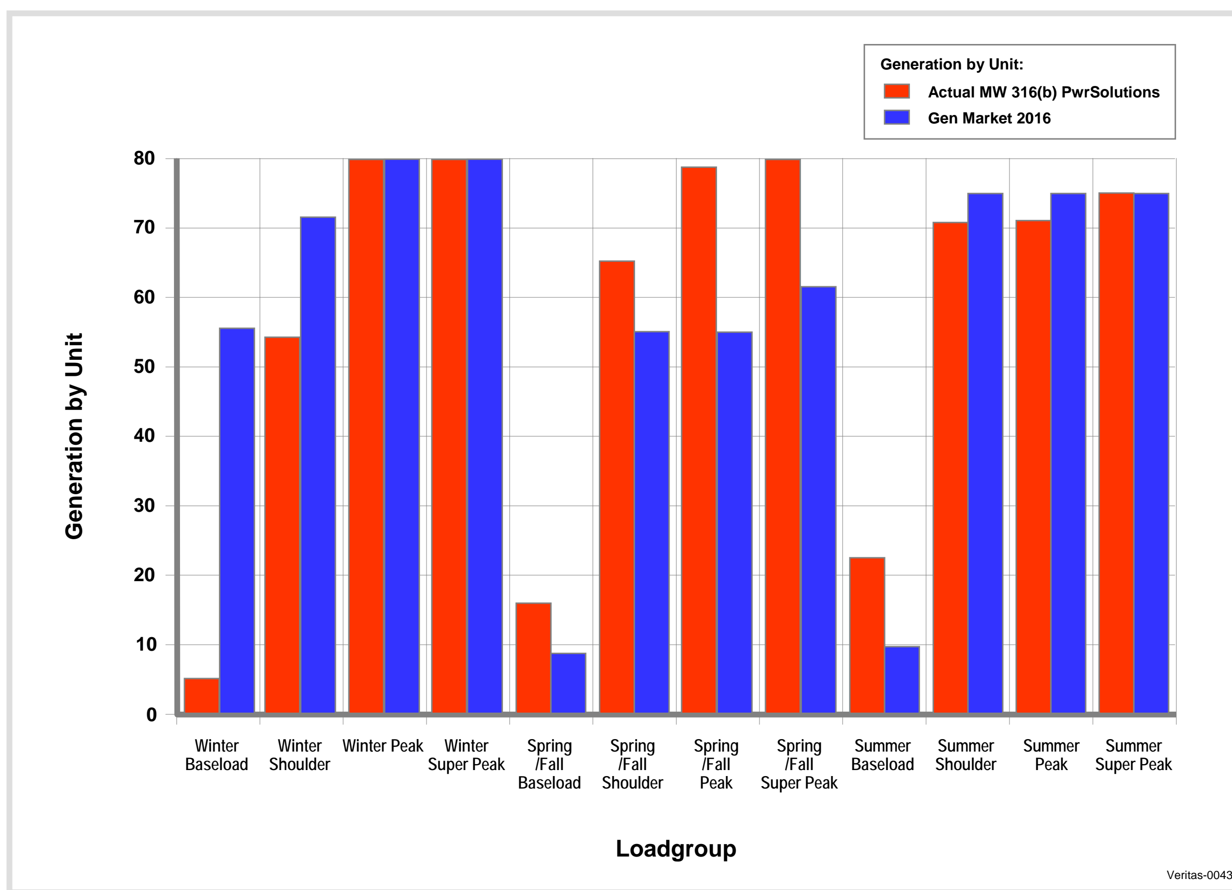


Figure 5.2: Calibrating Operations

5.2 Long Run Baseline Scenario Specification

Electricity generation systems change through time. For example, investment in new generation capacity must be sufficient to offset load growth and unit retirements. Increasing use of renewable energy sources, gas-fired combined cycle power plants, and long distance transmission of electricity over longer distances mean that the current system delivering electricity is different than the system that delivered electricity twenty years ago, and the system that delivers electricity twenty years hence. Since decisions in the electricity industry are long-lived, the model includes inter-temporal considerations. These factors include unit aging and retirement, the development of new generation including renewable sources, load growth, and price changes. The baseline model allows calibration to external forecasts of dynamic conditions to support identification of regulatory impacts. For example, load growth is driven by demographic factors. For this reason, external statistical modeling is better suited to the task of

load growth modeling than an internal approach.[11] Similarly, long-run prices of energy inputs such as coal, oil, natural gas, and uranium and prices for electricity are put in the model and an internally consistent set of future prices and quantities for electricity are developed.

For example, Figure 5.3 depicts the long-run calibration input screen. The implications of the scenario depicted below are that coal, oil, and natural gas prices increase by 2%, 2.2%, and 2.3% annually. The efficiency of existing units decays by 2% a year, new combustion turbines have heat rates of 11,000 and new combined cycle heat rates are 7,000.

Calibration Price Increase	1.02	Thermal Generation Calibrator	Edit Tab
Forecast % Load Increase	1.02	New Thermal Generation Calibrator	Edit Tab
Coal Inflation Rate	1.022	Calibration Sl...	Edit Tab
Natural Gas Inflation Rate	1.023	Calibration Interc...	Edit Tab
Oil Inflation Rate	1.025	RenewableMaxMW 2016	Edit Tab
Thermal Efficiency Decay Factor	0.98	RenewableMaxMW 2045	Edit Tab
New Generation Combustion Turbine Heat Rate	11K		
New Generation Combined Cycle Heat Rate	7000		Run Baseline
VOM Rate New Gen Wind (\$/MWh)	22		
		NEISO Calibration Price Comparison	Calc mid
		GenMW FuelType Baseline	Calc mid
		Cumulative GenMW Fuels Baseline	Calc mid
		Calibration GenMW % of Total	Calc mid

Figure 5.3: Long-Run Calibration User Interface

With these parameters for input costs and technical efficiency, a calibrated baseline model is developed such that electricity prices and quantities are consistent with external forecasts. Figure 5.4 depicts the calibration process. During the calibration, each value in the forecast period is the result of a market-clearing simulation where the demand for and supply of electricity are equated.

[11] These approaches usually employ time trends where estimated historical relationships between electricity generation and economic and demographic conditions that affect that generation are projected into the future based on trends in the independent variables.

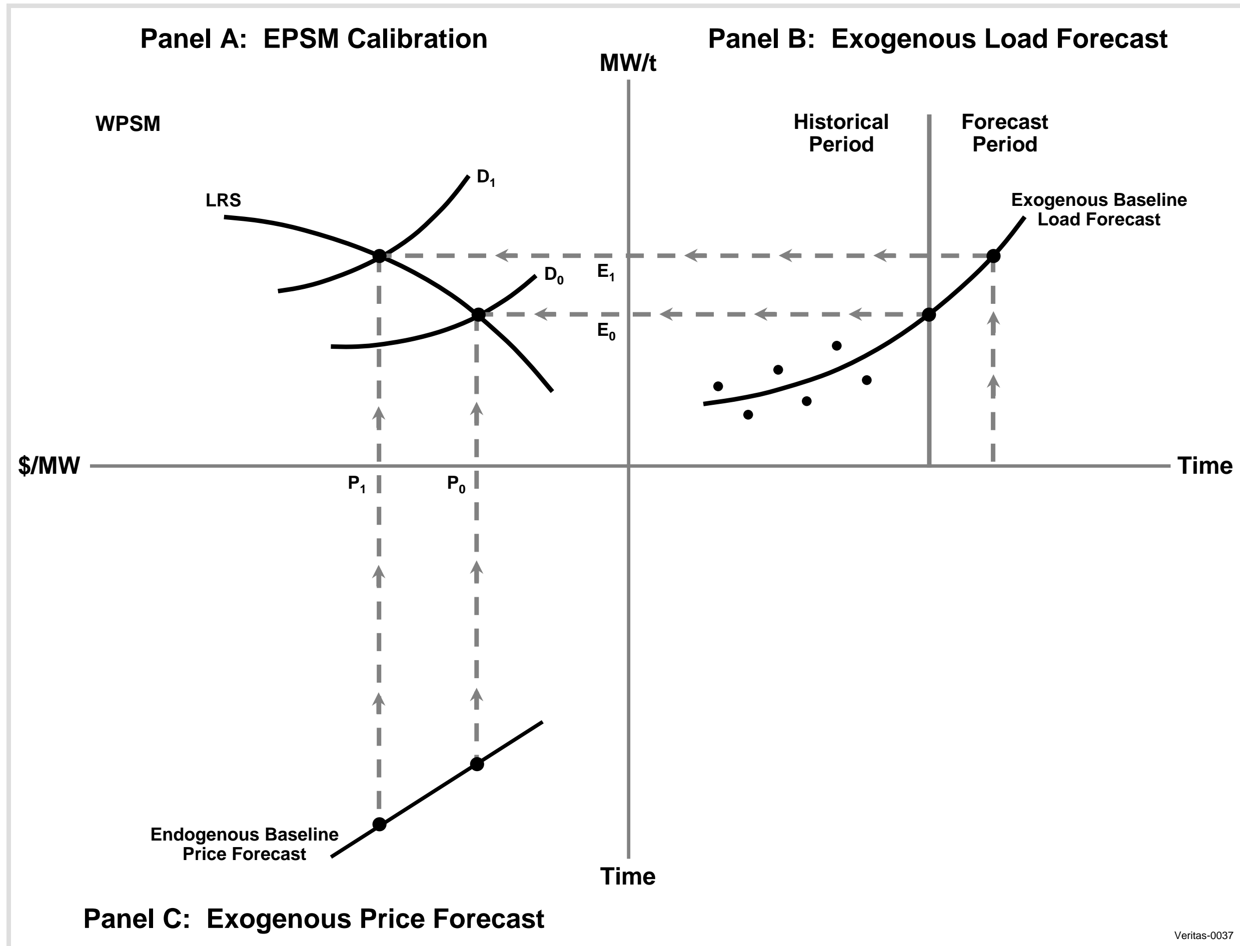


Figure 5.4: Calibration to an Exogenous Load and Price Forecast

This is illustrated in the north-west quadrant where demand in time t_0, D_0, and long-run supply, LRS, are equated at quantity E_0 and electricity price P_0. In the first year of the forecast period, time t_1, the forecast is for a generation rate of E_1. Thus, the demand curve in period t_1, D_1, must pass through that point on the electricity long-run supply curve. The model solves for the demand curve parameter (α in the demand equation) that produces that result. As this value is resolved within each year and load period, sufficient new generation is introduced such that the price resolves consistent with external forecasts. This exercise is completed for each year in the forecast period. The result of this exercise is the calibration of the policy analysis model to the exogenous load and price forecast.

6. Modeling Compliance in the Post-Regulation Market

EPSM models regulatory compliance decisions. These include both short-run operational decisions and long-run choices about whether to incur compliance capital costs to keep a unit operational.

6.1 Modeling Compliance Decisions

EPSM models responses to regulatory requirements in the context of a capital budgeting process that considers alternative uses of capital based on net present value calculations. Inputs for these calculations arise from simulations of the post-regulation marketplace. For example, an illustrative set of choices and their net present value calculations are shown in the decision tree in Figure 6.1. Each choice has unique revenue, operating cost, and capital cost impacts over the planning horizon. The generator selects the choice among that has the highest net present value. For example, the net present value of compliance option 1, V_1 (remain open and burn coal) is a function of the present value of revenue (R_1), the present value of costs (C_1), the capital costs of compliance (I_1), and the present salvage value (S_1).

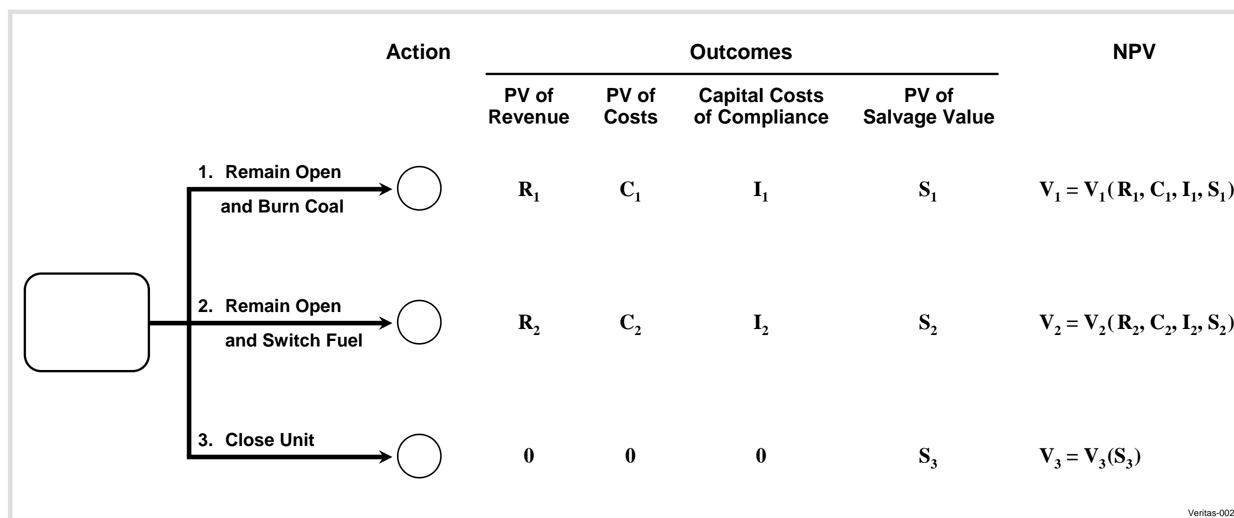


Figure 6.1: Illustrative Decision Tree (make "fuel switch' change operations add de-commissioning costs)

Figure 6.2 below depicts the variable cost curve being shifted upward based on an exogenously specified increase in variable costs that result from compliance with a new environmental regulation. The costs described in Figure 6.1 are both fixed costs and variable costs. Capital expenditures are specified directly in the model in the year in which they are

expected to occur. Changes in variable costs are modeled in EPSM as shifts in the cost of electricity generation at the unit level.

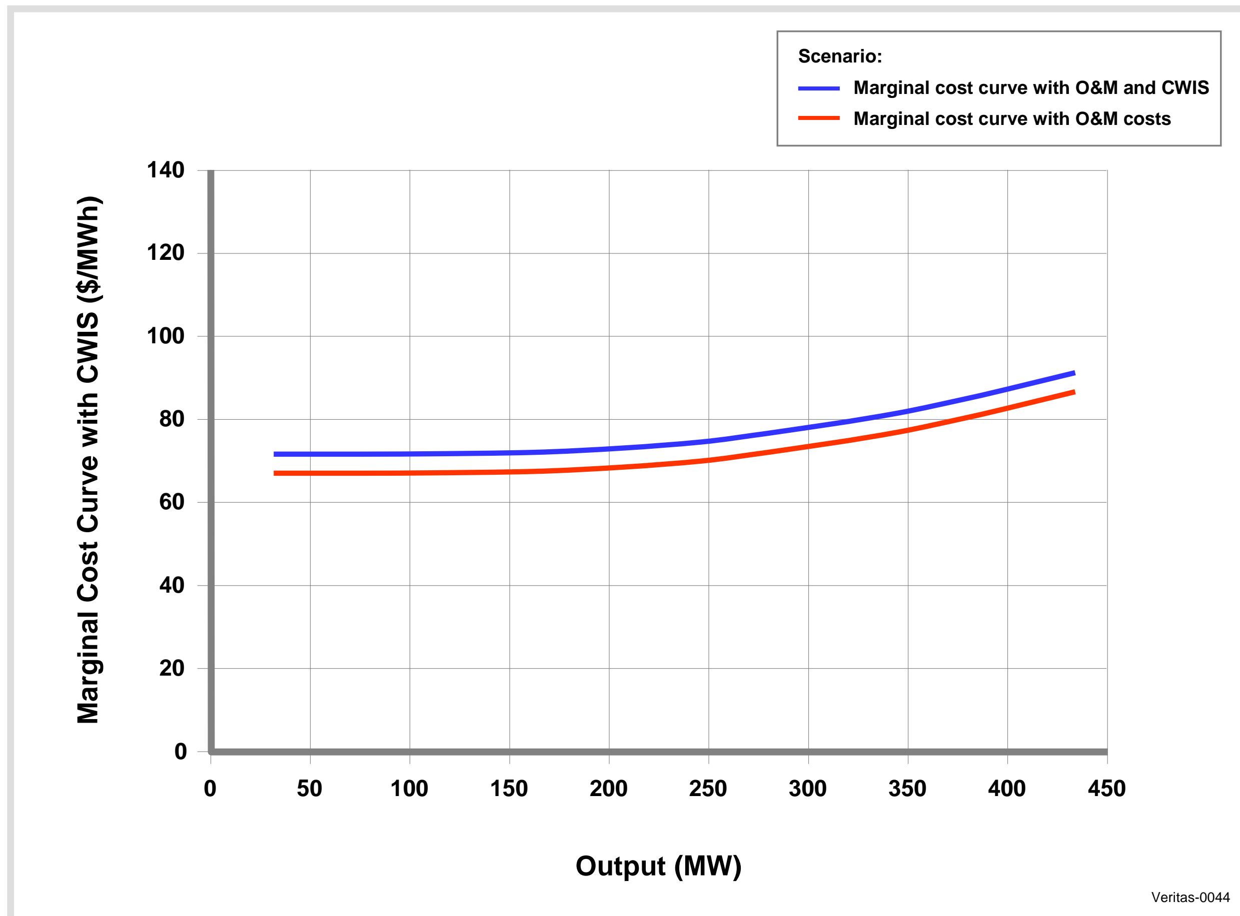


Figure 6.2: Shift in Fuel Cost Curve from Regulatory Compliance

Some costs might not be constant. For example, cooling towers require power to operate pumps and fans. An illustrative impact of parasitic load on an input-output curve is depicted in Figure 6.3. The dashed input-output curve in Figure 6.3 represents an expected change to the input-output curve associated with operating a cooling tower. This dashed line extends further from the previous solid line as output increases to represent percentage level impacts.

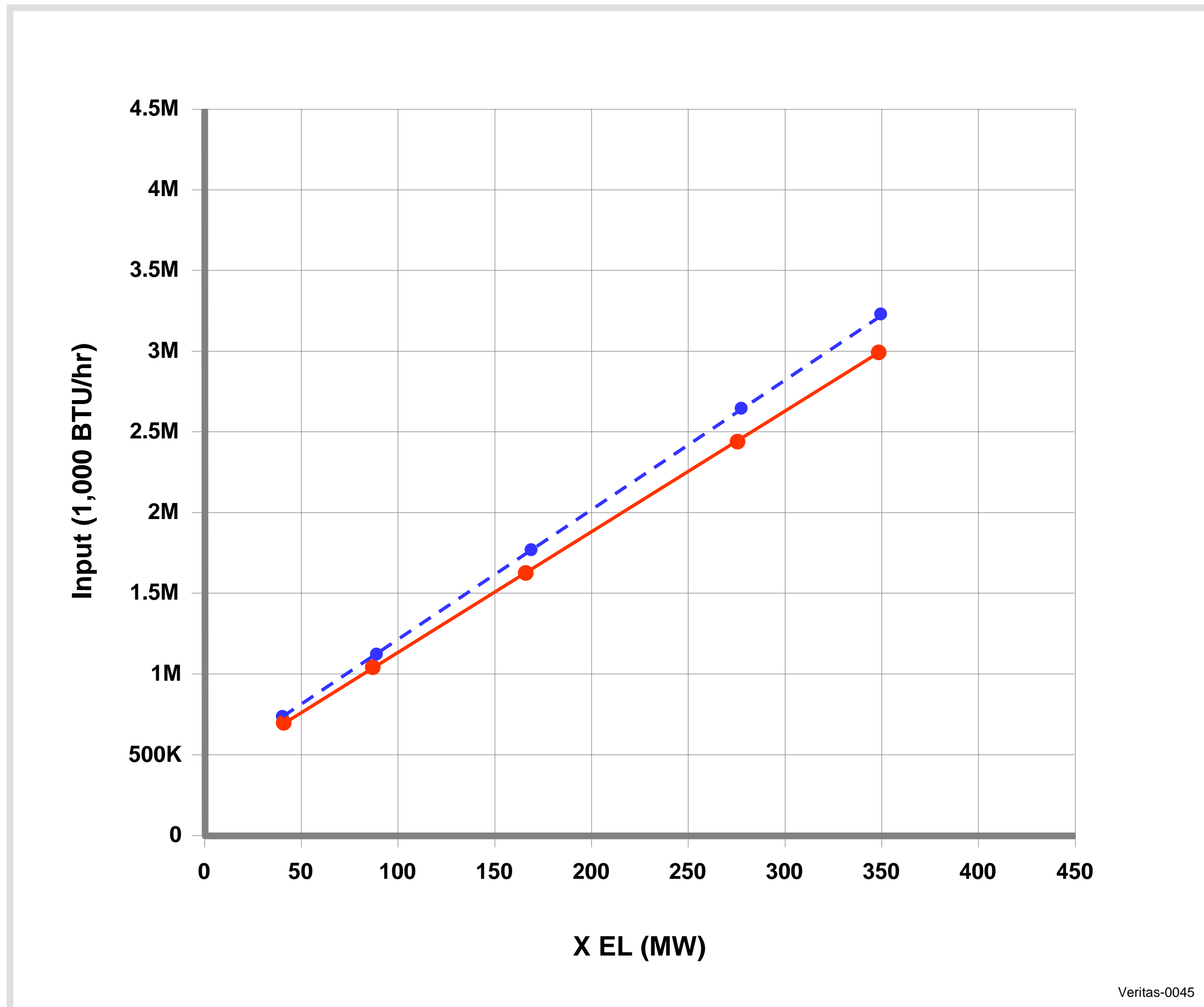


Figure 6.3: Illustration of Cooling Tower Impact on Input-Output Curve

6.2 The Post-Regulation Market

The "with regulation" scenario is created by adding the compliance costs to the baseline estimates of the unit's generation costs and then determining the expected industry responses. Both the baseline and the "with regulation" scenarios are developed using the economic model configured for a particular study region. This approach recognizes that significant environmental regulations can change the profit-maximizing output levels of generating units. As depicted in Figure 6.4, this change in production would alter electricity prices, potentially to the benefit of those who choose to produce in the post regulation marketplace.

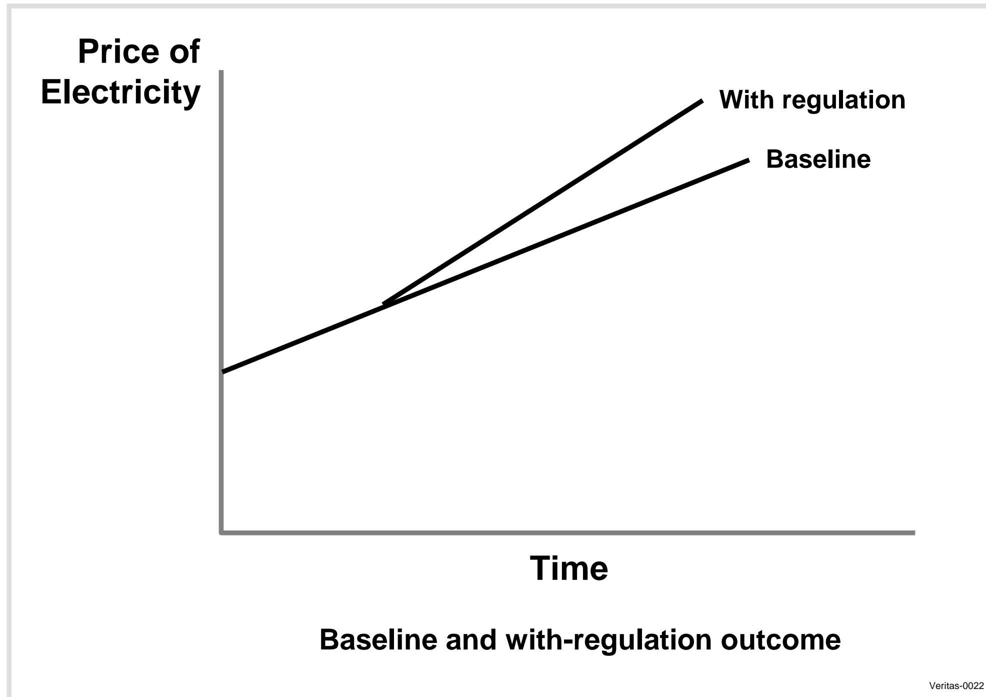


Figure 6.4: Illustration of Price Impacts from an Environmental Regulation

For this reason, EPSM models compliance with consideration of the impact of the regulation on electricity prices. Accordingly, short run profit maximization is revised from the "without regulation" case as:

$$\pi max = max[(Pe'*Qe') - Px'* g^{-1}(Qe) + Pk'*Qk'] *[1-ATR] \quad \textbf{(6.1)}$$

where

Pe'	=	price of electricity "with regulation"
Qe'	=	quantity of electricity produced by the generator "with regulation"
Px'	=	price of the variable input "with regulation"
$g^{-1}(Qe)$	=	inverse of the generator's production function "with regulation"
Pk'	=	price of the fixed input "with regulation"
Qk'	=	quantity of the generator's fixed input "with regulation."

Within-year operations are adjusted accordingly.

Within this new market, the long-run regulatory compliance decisions (i.e. stay open or retire prematurely) of electric generators is an investment/disinvestment decision. The

investment is warranted if the net discounted present value of all future cash flows after compliance less initial capital cost is positive:

$$NPV = DPV - CK \quad \textbf{(6.2)}$$

where CK is the initial capital cost.

The discounted present value of profits with compliance is:

$$DPV = \sum_{t=1}^{n} [\pi net'_t/(1 + r)^t] \quad \textbf{(6.3)}$$

where

r	=	required minimum return on the compliance capital outlays
t	=	time
n	=	number of time periods in the planning horizon
$\pi net'$	=	after-tax profits.

This calculation occurs with consideration of prices in the new marketplace that arise from the regulation.

6.3 Validation of Post-Regulation Re-dispatch by Unit Commitment Modeling

The unit commitment (UC) problem is the scheduling of availability and production of electric power generating units so as to accomplish an objective such as maximizing social welfare, minimizing costs, or maximizing profits. Unit commitment was historically solved by heuristics such as priority lists. Over the past 40 years, a variety of optimization techniques have been implemented. Ideally solutions must account for technical restrictions such as ramp rates limits, minimum up and down times, maximum and minimum output. The objective function includes costs associated with energy productions, ramping, start-ups and shut-downs. Because there are inter-temporal restrictions and cost effects, it winds up being a large-scale nonlinear mixed integer problem with only approximate solutions.

The UC problem is different for different systems and evolves as market structures evolve. In traditional systems, anticipated demand is an input variable and the problem is solved for multiple generators, which were owned by the same utility. Improved solutions lead to reductions in system costs and changes in operations. Impacts to operations of individual units are less important as they have a single owner. In deregulated markets, generators have to self-commit optimally and explicitly consider projections of electricity and ancillary service

prices along with input costs and technical restrictions. In these new markets, electricity prices exhibit great variance. Small changes in total cost can be associated with large changes in profitability of individual units.

For this reason, the re-dispatch developed by load period in EPSM may not match the more sophisticated (and efficient) dispatches developed via unit commitment models. To evaluate this, a unit commitment model is available within EPSM for the with-regulation scenarios. Evaluating the unit commitment model under model simulated baseline and with regulation prices allows the comparison. EPSM includes the ability to verify and calibrate aggregated dispatch with hourly dispatch based on a price forecast and all relevant technical restrictions. These include:

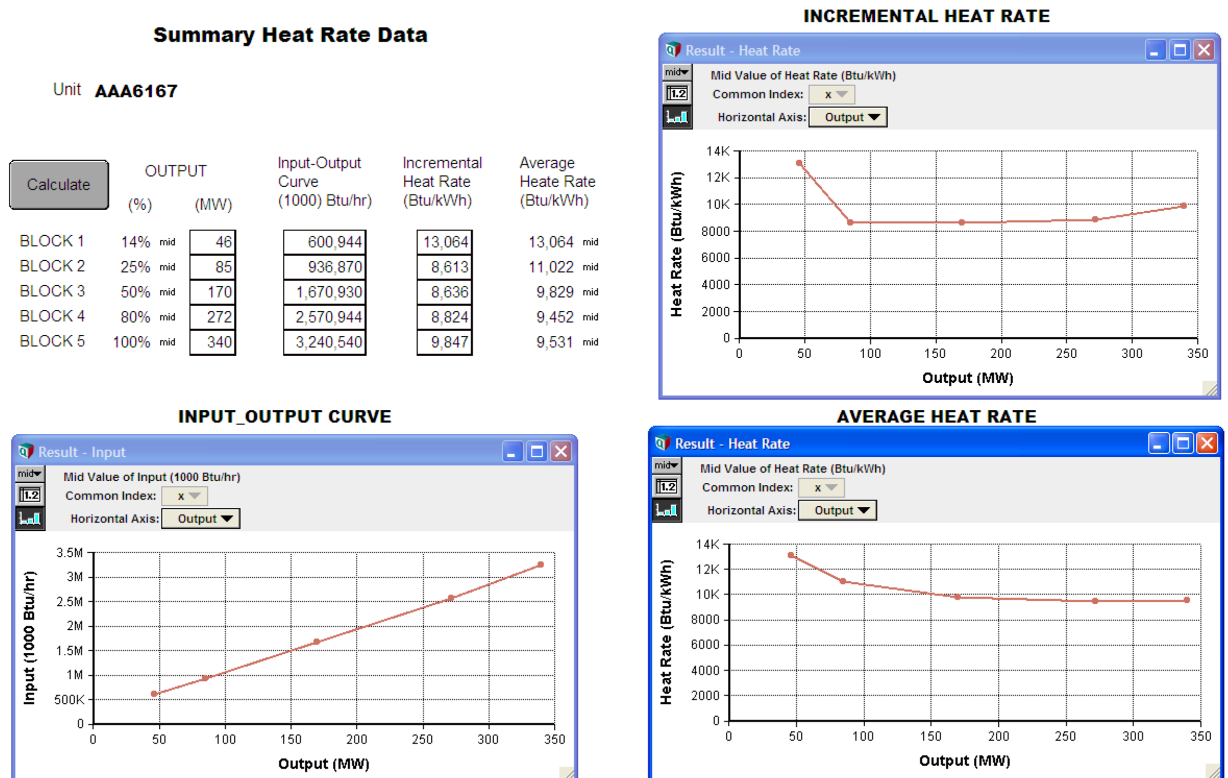
- **Minimum and Maximum Output (MW)**—Specified as 0 and maximum capacity of the unit.
- **Heat Rates**—Specified as piecewise linear with breakpoints at 25, 50, and 75% of full load. Heat rate curves can be specified in blocks as depicted in Figure 6.5.
- **Minimum Capacity (MW)**—Model can be specified as unit-specific when info is available or as % of maximum generation.
- **Minimum Up Time (hrs)**—Minimum time a unit can stay on.
- **Minimum Down Time (hrs)**—Minimum time a unit can stay off.
- **Ramp Rates (MW/hr)**—Restrictions on the increase/decrease in generation from one hour to the next.
- **Startup Costs (Btus or dollars)**—This is currently specified as a single number. Working toward differentiated specification for example hot starts could be anything less than 8 hours of downtime, while a cold start was greater than 72 hours with interpolation for intermediate cases.

Summary Heat Rate Data

Unit **AAA6167**

Calculate	OUTPUT (%)		OUTPUT (MW)	Input-Output Curve (1000) Btu/hr)	Incremental Heat Rate (Btu/kWh)	Average Heate Rate (Btu/kWh)	
BLOCK 1	Calc	mid	46	600,944	13,064	Calc	mid
BLOCK 2	Calc	mid	85	936,870	8,613	Calc	mid
BLOCK 3	Calc	mid	170	1,670,930	8,636	Calc	mid
BLOCK 4	Calc	mid	272	2,570,944	8,824	Calc	mid
BLOCK 5	Calc	mid	340	3,240,540	9,847	Calc	mid

Figure 6.5: Input Screen for Blocks


Summary Heat Rate Data

Unit AAA6167

Calculate	OUTPUT (%)		OUTPUT (MW)	Input-Output Curve (1000) Btu/hr)	Incremental Heat Rate (Btu/kWh)	Average Heate Rate (Btu/kWh)	
BLOCK 1	14%	mid	46	600,944	13,064	13,064	mid
BLOCK 2	25%	mid	85	936,870	8,613	11,022	mid
BLOCK 3	50%	mid	170	1,670,930	8,636	9,829	mid
BLOCK 4	80%	mid	272	2,570,944	8,824	9,452	mid
BLOCK 5	100%	mid	340	3,240,540	9,847	9,531	mid

Figure 6.6: Visual Evaluation of Piecewise Specification

After entering breakpoints in the input-output curve, the user can view the associated marginal and average curves (Figure 6.7).

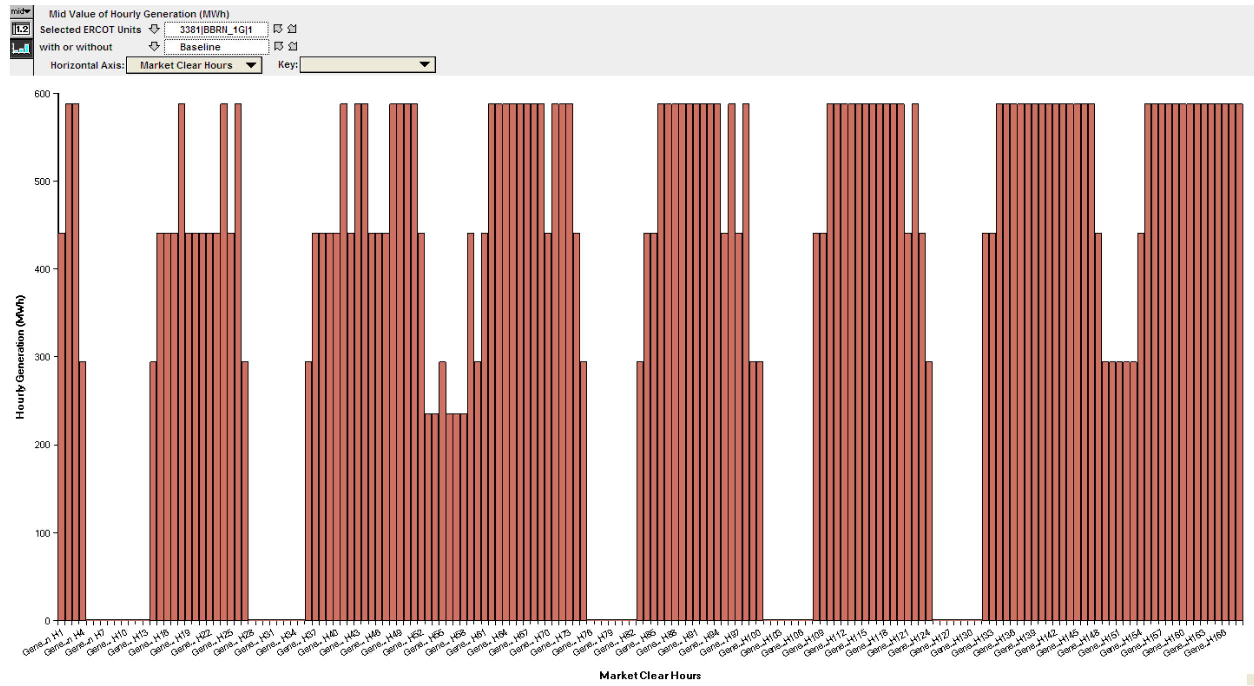


Figure 6.7: Dispatch Predicted Operations

Mapping dispatch predicted output from load periods back to hours produces an hourly representation of output from the dispatch model (Figure 6.8).

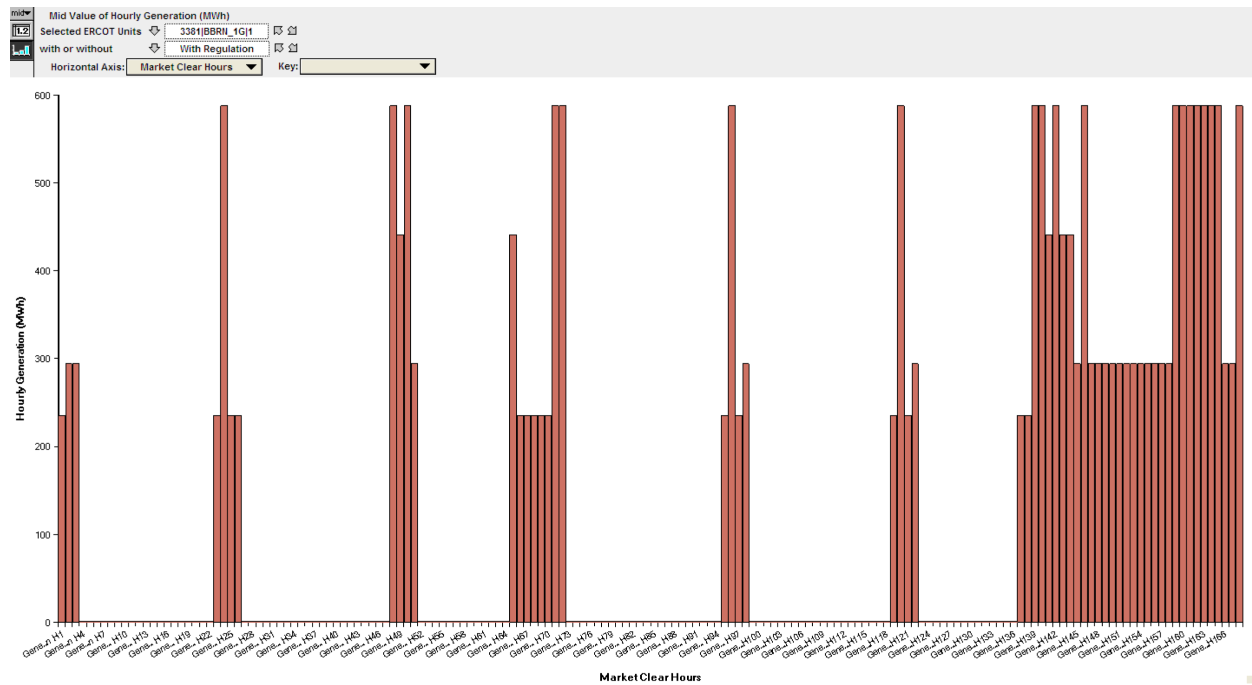


Figure 6.8: Dispatch Predicted Operations

Running the unit commitment model returns profit maximizing hourly output given prices that were solved for using the dispatch simulating model in EPSM. Comparing output from the two allows an assessment of the accuracy of the dispatch model.

7. Societal Impacts

EPSM supports evaluating socioeconomic impacts through the assessment of effects within the electricity markets and the calculation of changes to physical impacts of operating a unit. This section describes the direct effects and the indirect effects.

7.1 Direct Electricity Market Effects

EPSM market-clearing simulations interact demand and supply to establish equilibrium prices and output rates, as shown in Figure 7.1. This outcome is economically optimal in the sense that it maximizes the sum of consumer and producer surplus.[12] Consumer surplus (CS) is the difference between the maximum amount of money per unit of time that consumers would be willing to pay for a given amount of the good rather than to forgo it in its entirety minus what they actually do pay. Producer surplus (PS) is the difference between the revenue that producers receive minus the minimum amount of money per unit of time that producers would require to supply a given amount of the good.

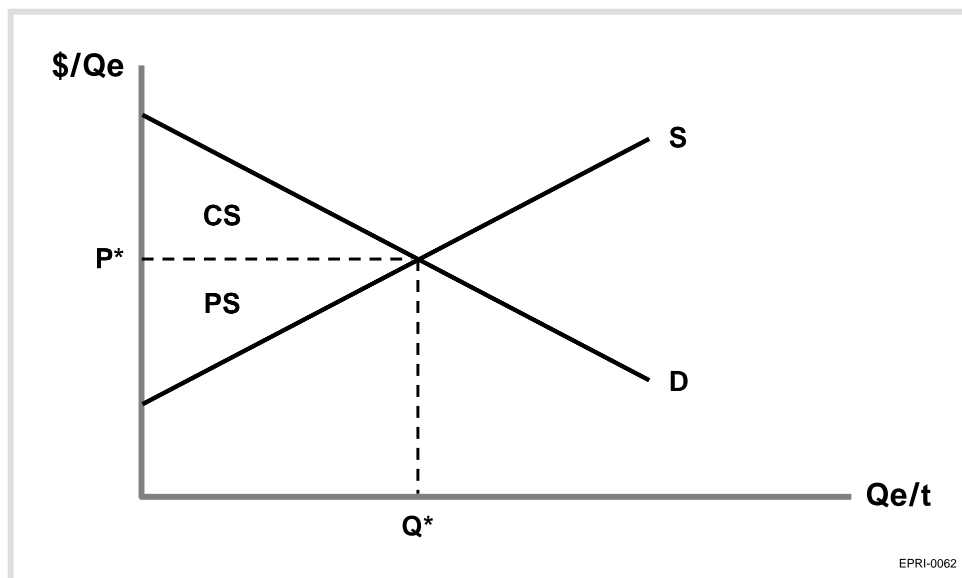


Figure 7.1: Competitive Market Outcomes and Pareto Optimality

[12] This outcome is termed as "Pareto optimal" after Vilfredo Pareto (1848–1923), the Italian sociologist/economist who pioneered the field of welfare economics.

The remainder of this section illustrates how the ESPM can evaluate an environmental policy.[13] With the regulatory requirement, the market supply curve shifts upward, reflecting the higher operating costs for some regulated facilities and closures for others. This upward shift changes the market-clearing price and output. Figure 7.2a shows the change in consumer surplus with the regulation. The higher price (represented by area P_1P_2ab in Figure 7.2a) causes consumer surplus to decrease. Consumers lose economic welfare as they experience higher electricity prices.

The impact of the regulation on producer surplus is more complex. The reduction in electricity production by area bcd in Figure 7.2b causes producer surplus to decline. On the new production rate, Q_2, it decreases because of the higher compliance costs by area efgdc. However, it also increases on that quantity due to the higher price by area P_1P_2ag. Thus on balance, producer surplus changes by the algebraic sum of the losses and gains or – (bcd) – (efgdc) + (P_1P_2ag), as shown in Figure 7.2b. This sum, in the aggregate, may be positive or negative. For individual producers, however, some may gain (e.g., those with existing closed-cycle-cooling systems) and some may lose (e.g., those with open-cycle cooling).

[13]This case study focuses on the effects of a closed-cycle-cooling regulation transmitted through the economic system. It ignores the extra-market effects, specifically, the changes in economic welfare due to the environmental effects of the rule.

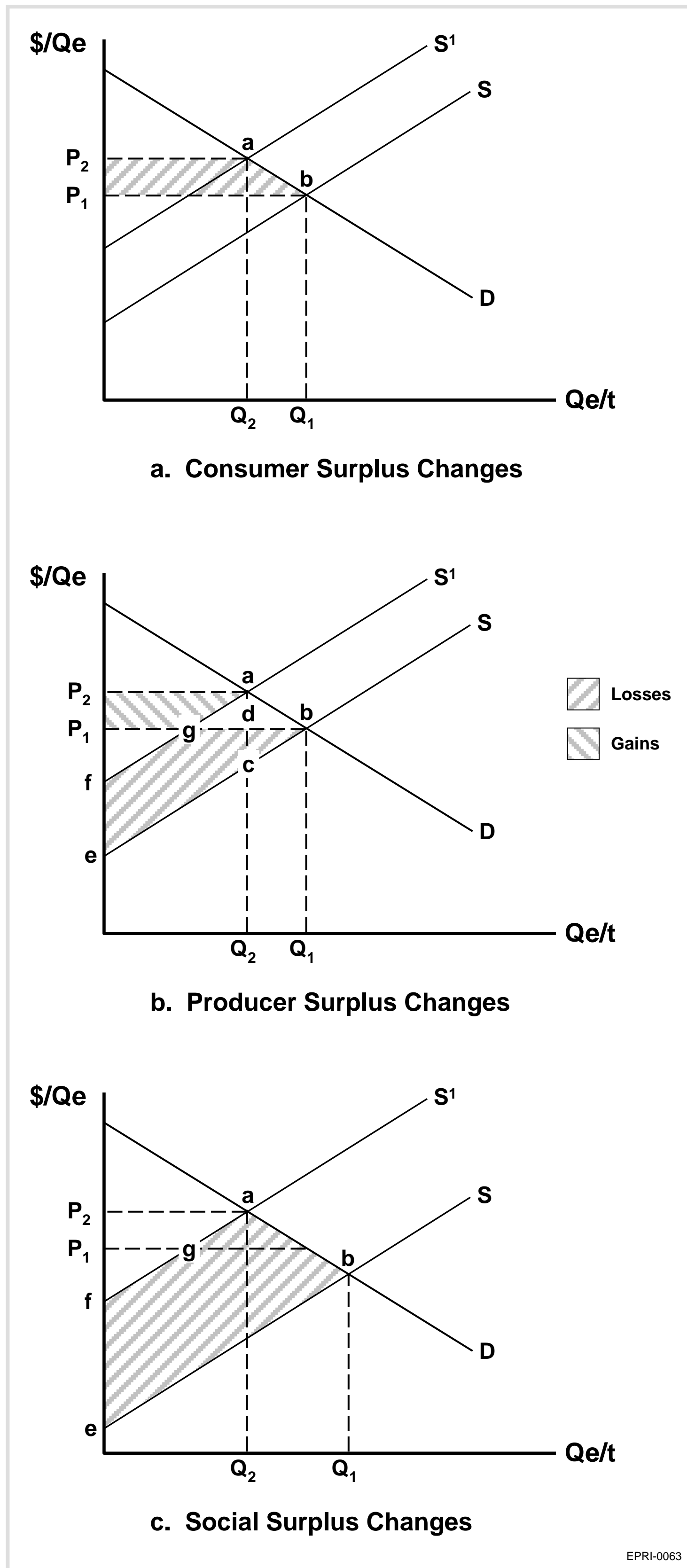


Figure 7.2: Economic Welfare Impacts of a Regulation Requiring Closed-Cycle Cooling

The net change in the economic surplus provided by electricity is the algebraic sum of the changes in the components of the economic surplus (consumers plus producers), as shown in Figure 7.2c. Some of the consumer surplus losses are offset by producer surplus gains, specifically the area represented by P_1P_2ag. This is a transfer in incomes, not a net loss to society. The costs to society of the regulation are represented by the area of efab in Figure 7.2c. Table 7.1 summarizes the changes in consumer and producer welfare, as shown in Figure 7.2.

Table 7.1
Changes in Consumer and Producer Economic Welfare Shown in Figure 7.2

Changes	Area in Figure 7.2
Changes in consumer surplus	– (P_1P_2ab)
Changes in producer surplus	– (bcd) – (efgdc) + (P_1P_2ag) = – (efgb) + (P_1P_2ag)
Changes in the economic surplus: Change in consumer surplus + change in producer surplus	– (P_1P_2ab) – (efgb) + (P_1P_2ag) = efab

The distribution of the change in economic welfare is estimated from the perspective of the changes in consumer and producer welfare.

Changes in consumer surplus are evaluated as:

$$\Delta CS = \sum_{t=1}^{n} [CS_t'/(1 + drcs)^t] \tag{7.1}$$

where

- CS'_t = consumer surplus difference between the baseline and “with regulation” conditions
- *drcs* = discount rate applied to consumer expenditures
- *t* = time
- *n* = number of time periods.

Changes in producer surplus are evaluated as:

$$\Delta PS = \sum_{t=1}^{n} [PS_t'/(1 + drps)^t] \tag{7.2}$$

where

PS'_t	=	producer surplus difference between the baseline and "with regulation" conditions
drpc	=	discount rate applied to producer income
n	=	number of time periods.

Annualization of these present values places them on a flow basis at an average annual rate. The annualized value is:

$$DPV[(dr^*(1/dr)^n)/(\ (1/dr)^n - 1))] \quad \textbf{(7.3)}$$

where

dr	=	appropriate discount rate.

7.2 Indirect Impacts (IN PROGRESS)

Environmental regulations are typically undertaken to forward some environmental improvement. Indirect impacts from a regulation occur through changes to the environment and socioeconomic conditions such as employment.

EPSM market-clearing simulations interact of demand and supply to establish equilibrium prices and output rates. These output rates are associated with emissions. Emissions rates for SO_2, and CO_2 are assigned to generators from CEMS data, EIA-767, and AP-4211. Baseline NOx rates are taken from *Analyzing Electric.* Emissions rates for mercury arise from the combination of fuel mercury content and flue gas desulfurization capabilities. The changes in environmental impacts associated with a regulation are assessed by comparing outputs across scenarios. Unit-specific emissions are calculated under both cases and compared.

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9. Biographical Sketches

Matthew F. Bingham is a Principal Economist and Founding Partner of Veritas Economic Consulting (Veritas). Mr. Bingham has led Veritas' custom modeling design and development efforts to evaluate and address complex market and non-market valuation questions. Mr. Bingham's specific experience includes leading the design and development of Veritas' Environmental Policy Simulation Model (EPSM) that evaluates the effects of potential regulations on electricity production, pricing, and reliability; commercial and recreational fishing models for North Atlantic and Mid-Atlantic Coastal, Great Lakes, California Coast, and numerous U.S. inland fisheries; and Veritas' Alternative Restoration Options Model that evaluates the costs and benefits of restoration alternatives. Mr. Bingham has more than 15 years of experience in applying microeconomic theory, econometrics, statistics, and bioeconomic modeling in Veritas' development and evaluation of custom economic models.

Mr. Bingham has provided and/or presented the results of his models for policy analysis, regulatory impact analysis, regulatory compliance, expert testimony, or litigation support. The results of Mr. Bingham's custom models have been used by and/or provided and presented to the Electric Power Research Institute (EPRI), the United States Army Corps of Engineers (USACE), the U.S. Environmental Protection Agency (USEPA), the California Regional Water Quality Control Board, Pennsylvania Department of Environmental Protection (PADEP), Texas Commission on Environmental Quality (TCEQ), Texas Parks & Wildlife, and the Michigan Department of Natural Resources (MDNR).

Mr. Bingham is a member of the International Association of Maritime Economists, the Association of Environmental and Resource Economists, American Economic Association, American Water Resources Association, and American Fisheries Society. Mr. Bingham has published numerous peer-reviewed articles in well-recognized environmental, health, forestry, and pharmaceutical economics journals including *Land Economics*, *Value in Health*, *the Journal of Forest Economics*, and the *Journal of Toxicology and Environmental Health*.

Dr. Stephen A. Johnston has extensive experience in energy and public utility economics. He has supported the design and development of Veritas' Environmental Policy Simulation Model (EPSM) that evaluates the effects of potential regulations on electricity production, pricing, and reliability. Dr. Johnston has developed and led projects in energy industry restructuring; energy pricing; electric utility ratemaking and regulation, assessments of new technologies and their market potential; and design and evaluation of energy efficiency, customer retention, green energy, and economic development programs. Dr. Johnston has conducted impact, market, and process evaluations for utility-sponsored energy-efficiency and pricing programs for residential, commercial, and industrial customers. He has developed experimental designs and applied engineering simulation models and statistical estimation techniques in impact evaluations using billing, load research, survey, and engineering data. Dr. Johnston has conducted market evaluations using innovative customer survey and behavioral research techniques. He has applied the results of these analyses in benefit-cost and profitability analyses.

Dr. Johnston is a member of the Southern Economic Association, the International Association of Energy Economists, the Association of Energy Engineers, and the Institute of Electrical and Electronics Engineers. He coauthored the book *Electric Utility Load Management* , has published several articles, and has delivered several industry presentations. He currently serves as Vice Chairperson of the Board of Directors of North Carolina Green Power and Chairperson of the Board's Resource Committee.

Mr. Eric J. Olson is a senior software developer at Veritas Economic Consulting. He has been developing custom software for more than 15 years across a variety of platforms, including local area network applications using Visual Basic and Access scaling up to client-server applications using VB.NET and SQL-Server. At Veritas, Eric leads the custom modeling efforts in the power sector. He has developed custom models of electricity economics and reliability, population dynamics of fisheries, and random utility models of recreation for travel-cost and site-choice models.

Mr. Tayler H. Bingham has specialized in regulatory analyses of the economics of policies designed to improve the quality of the environment. Mr. Bingham has supported the design and development of Veritas' Environmental Policy Simulation Model (EPSM) that evaluates the effects of potential regulations on electricity production, pricing, and reliability. He has also evaluated the economics of food safety and estimated the social returns to government support of R&D. He has employed microeconomic, financial, and technical modeling, as well as benefit-cost, cost-effectiveness, and economic impact analyses to evaluate alternative policies. He has developed innovative approaches to modeling the economic effects of policies and programs based on microeconomic theory and valuing these effects using applied welfare economics principles. Mr. Bingham has managed many dozen contracts and projects for federal government clients.

Mr. Bingham has more than 35 years of administrative and technical experience leading research programs and conducting analyses of the economic benefits and costs of public policies and programs employing microeconomic analytic methods to support informed decision making. He has developed and managed research programs, designing and implementing successful competitive strategies to secure funding; hiring and developing an entrepreneurial and professional staff; and providing professionally conducted research products for a set of synergistic research programs. He has developed and contributed to the development of durable administrative systems designed to support the effective performance of research programs.

Mr. Bingham is a member of the American Economic Association and the Association of Environmental and Resource Economists. He authored a book chapter on environmental benefits valuation and has published papers in the *Journal of Environmental Economics and Management, Public Finance Quarterly*, and *The Review of Economics and Statistics* and served as a reviewer for professional journals. Mr. Bingham has taught microeconomic theory at North Carolina State University for over 20 years and environmental policy at Duke University and North Carolina State University.

Mr. Zhimin Li works on projects in electricity market simulation, unit commitment modeling, experimental design, conjoint analysis, electric car diffusion, and recreation demand modeling. As part of his efforts, Mr. Li has supported Veritas' custom modeling efforts, including the development of Veritas' Electric Vehicle Adoption Model and Electricity Policy Simulation Model (EPSM). The Electric Vehicle Adoption Model forecasts location-specific electric vehicle adoption rates given changes in technology, public infrastructure, consumer education, or gas spikes. The EPSM is a computerized simulation model that identifies baseline values for electricity generation assets and evaluates the impact of environmental regulations on regional United States electricity generation and delivery systems.

Mr. Li's efforts were instrumental in developing the technical aspects of each model. He is skilled in statistical estimation and econometric modeling, including discrete choice modeling (conditional logit, nested logit, and random parameters logit). He is fluent in several computer programs, including Stata, Analytica, Biogeme, and Matlab.