Veritas Economics Electricity Policy Simulation Model (EPSM)

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VERITAS
ECONOMICS

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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.

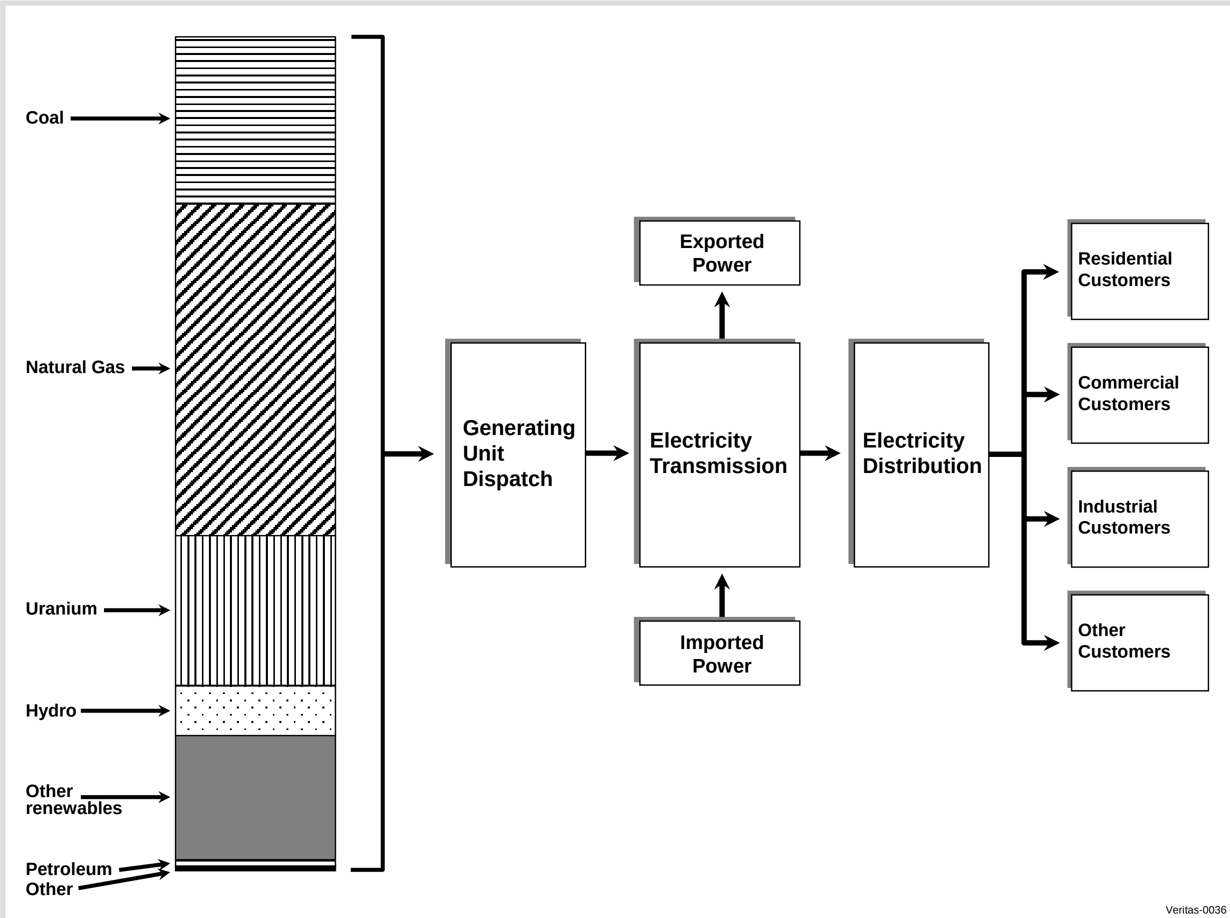


Figure 1.1: Overview of the Electricity System

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 electricity 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.[1] 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).[2]

1 Thermal units are the great majority of generation and capacity and are also directly impacted by electricity regulations.

2 Both heat rates and capacity can vary over the course of a year. Input-output curves can be both unit and time specific.

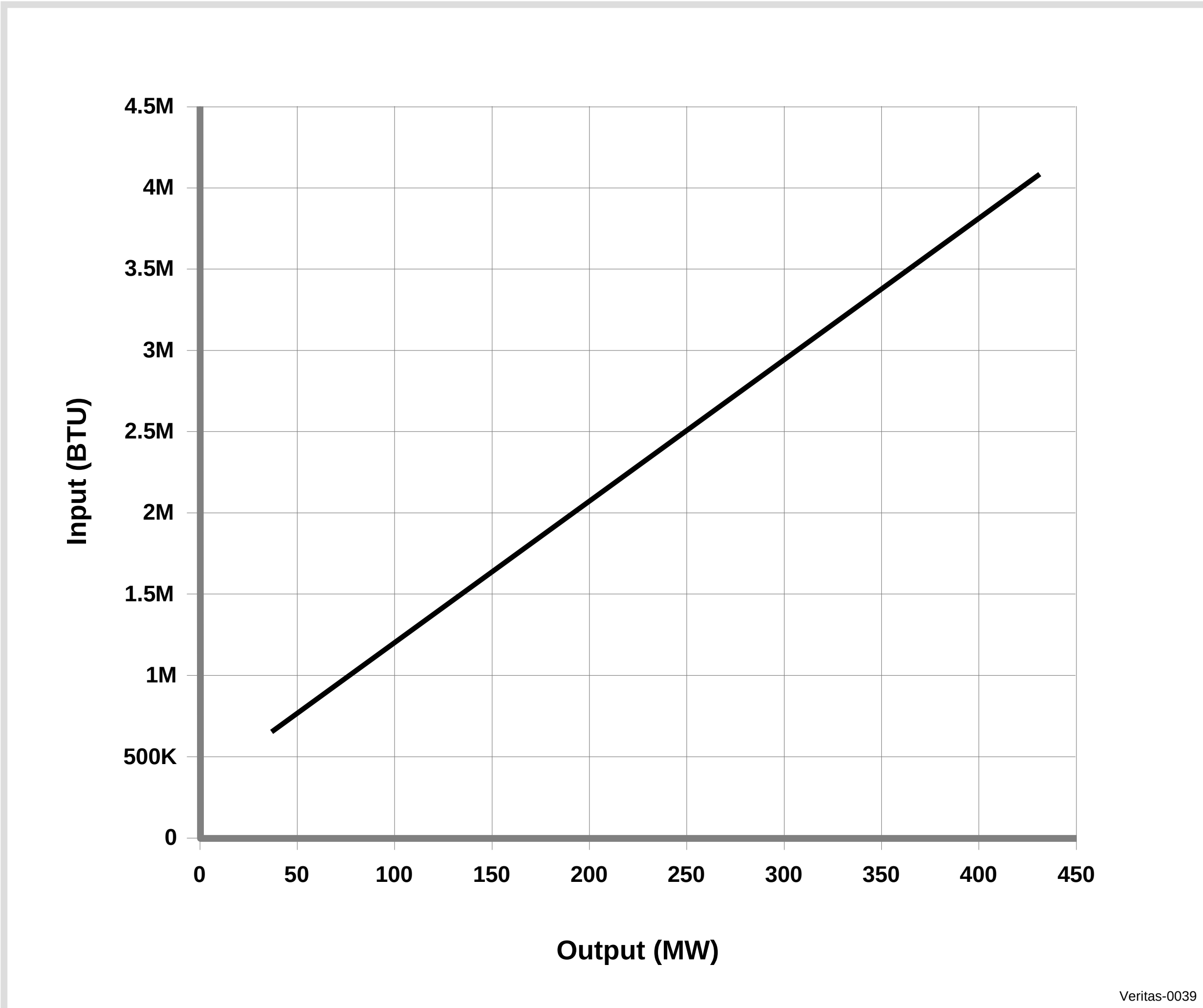


Figure 2.1: Graph of Input-Output Data for an Example Unit

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.

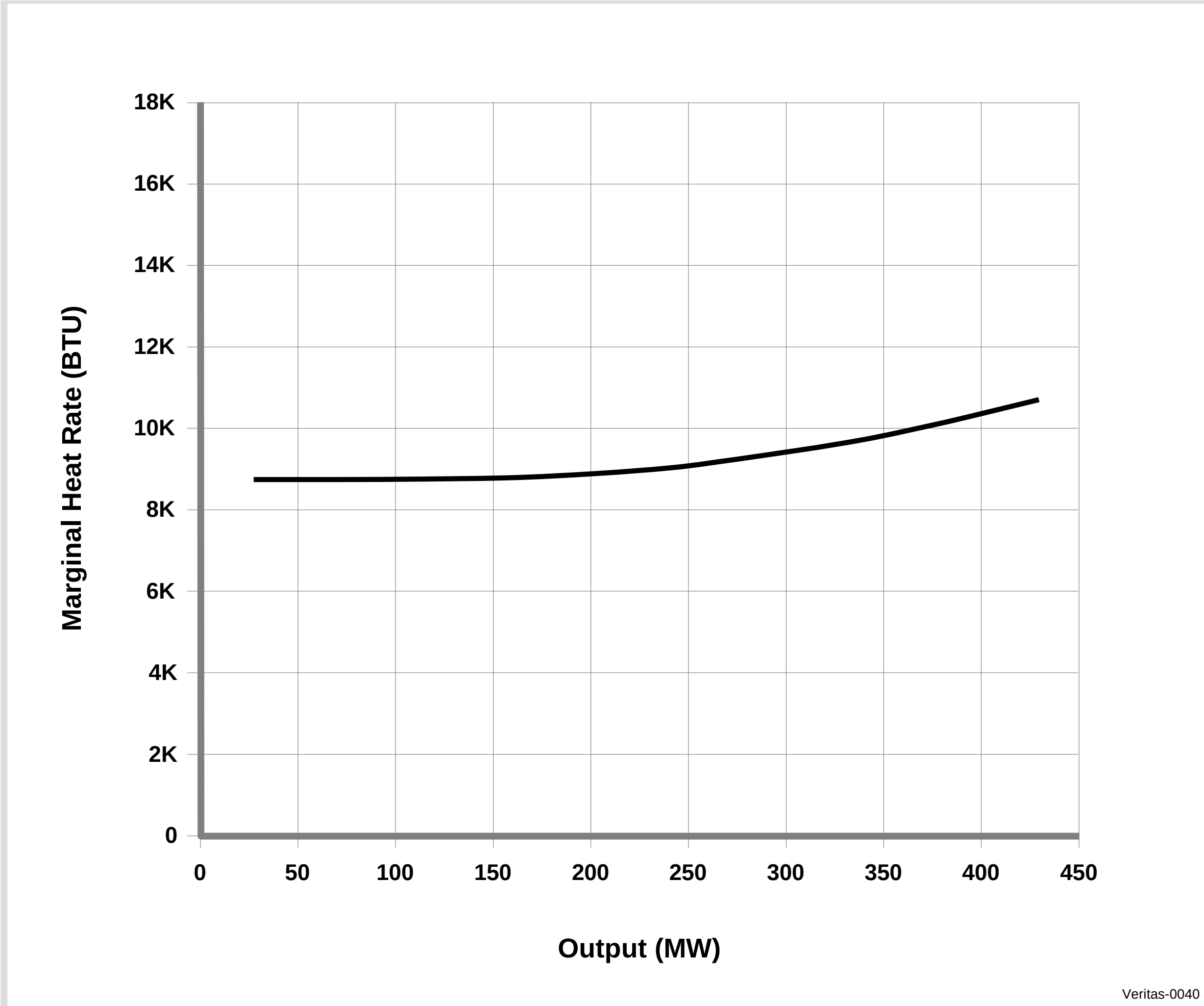


Figure 2.2: Marginal Heat Rate

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.

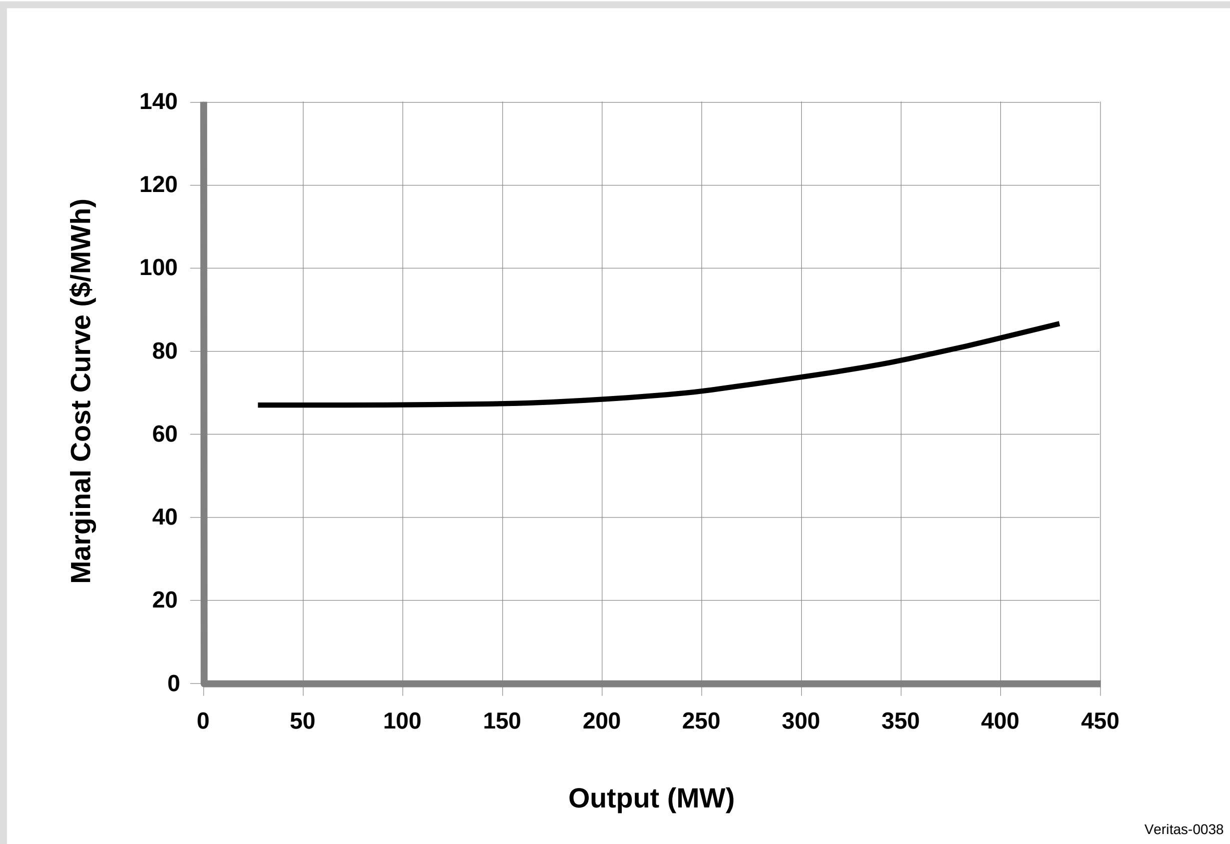


Figure 2.3: Marginal Fuel Cost

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.

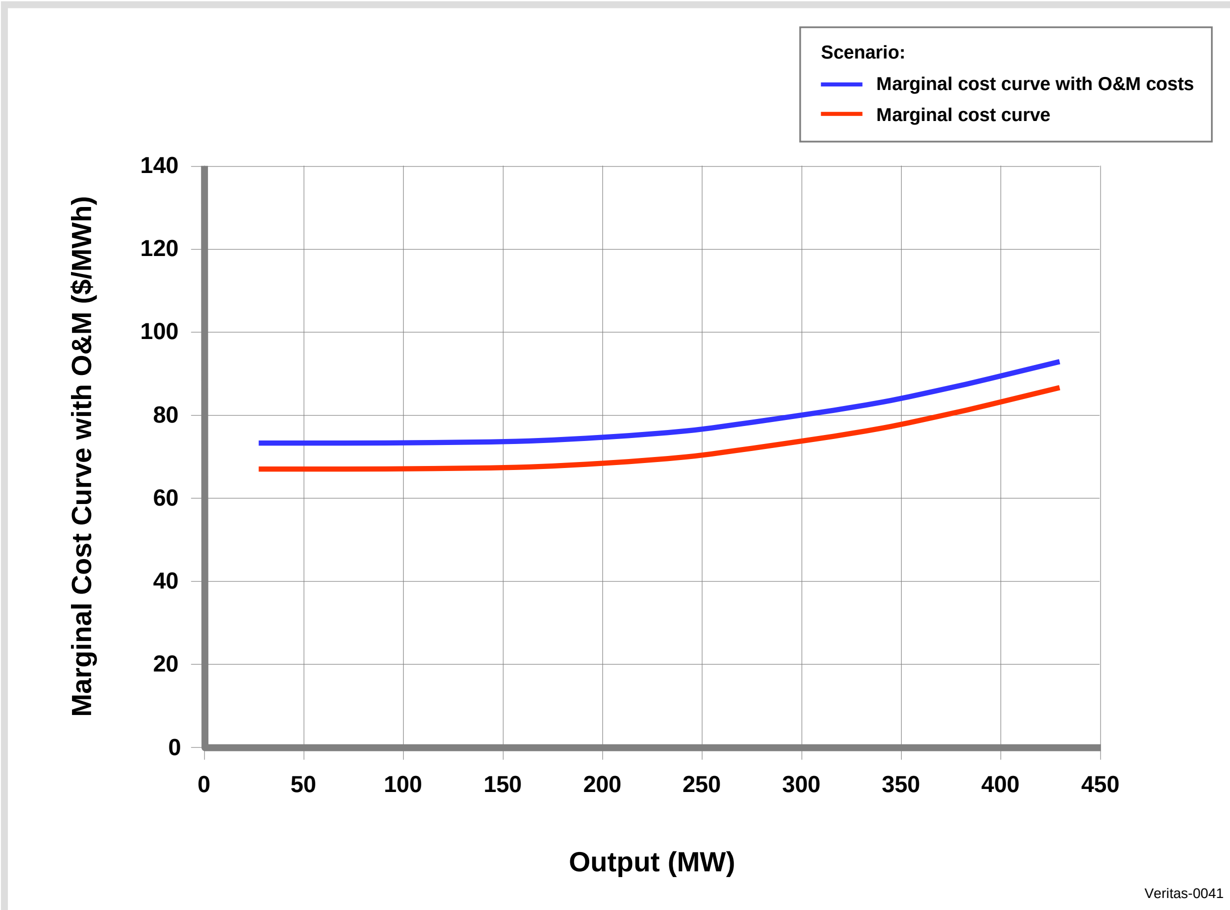


Figure 2.4: Marginal Variable Cost Curve

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.

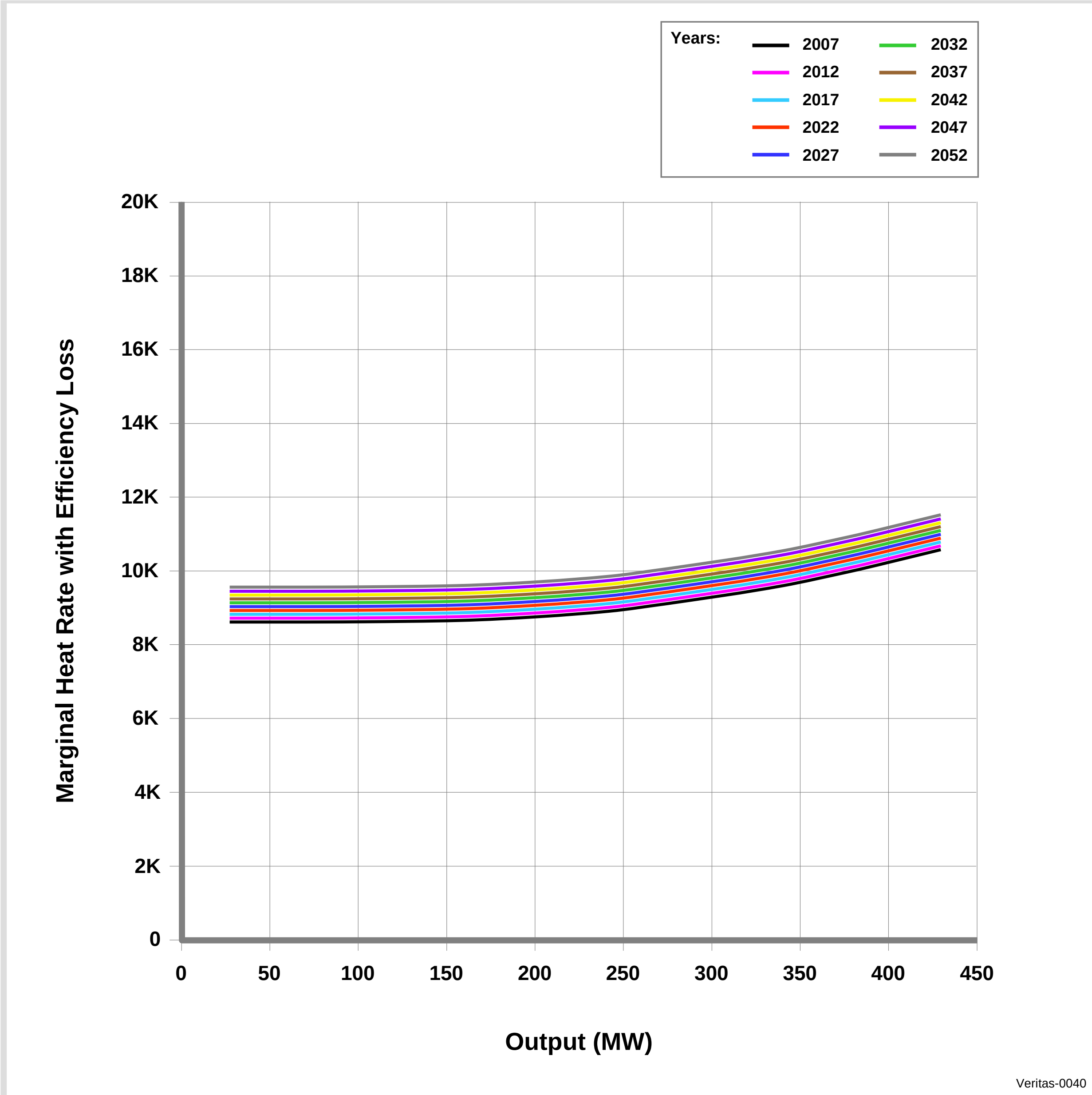


Figure 2.5: Marginal Heat Rate Curve Efficiency Decay

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 Thermal 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. The new generation that is planned up to 2023 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 2023–2043 and thus can make investment decisions that are profit-maximizing. For years after 2023, sufficient new generation is made available to offset projected load growth.

2.4 Predicting Solar and Wind Generation

Power systems increasingly employ solar and wind energy to generate electricity. Because these sources cannot be dispatched, it is important to predict their output prior to conducting dispatch modeling. For new generation, these sources are modeled based on specific locations.

Output from solar generation can vary widely by location due to area specific factors, such as irradiance and snowstorms. When empirical estimates of historical solar generation are unavailable or new solar capacity, EPSM accommodates a geographic analysis that identifies potential solar locations and estimates their hourly generation.

To model baseline solar output, EPSM uses location-specific Typical Meteorological Year (TMY) weather data from the National Renewable Energy Lab's National Solar Radiation Database (NSRDB) for counties where solar generation is anticipated. Hourly generation from each county is then summed to estimate hourly solar output.

The new generation from onshore and offshore wind turbines is estimated based on calculations from the best available information, including the number of towers, their blade length and efficiency, air density, and estimated hourly wind speeds. The technical information is used to calculate the swept area of each turbine. Combined with capacity limitations and hourly wind speed, this is used to estimate output from each turbine. Example hourly wind speeds are depicted below.

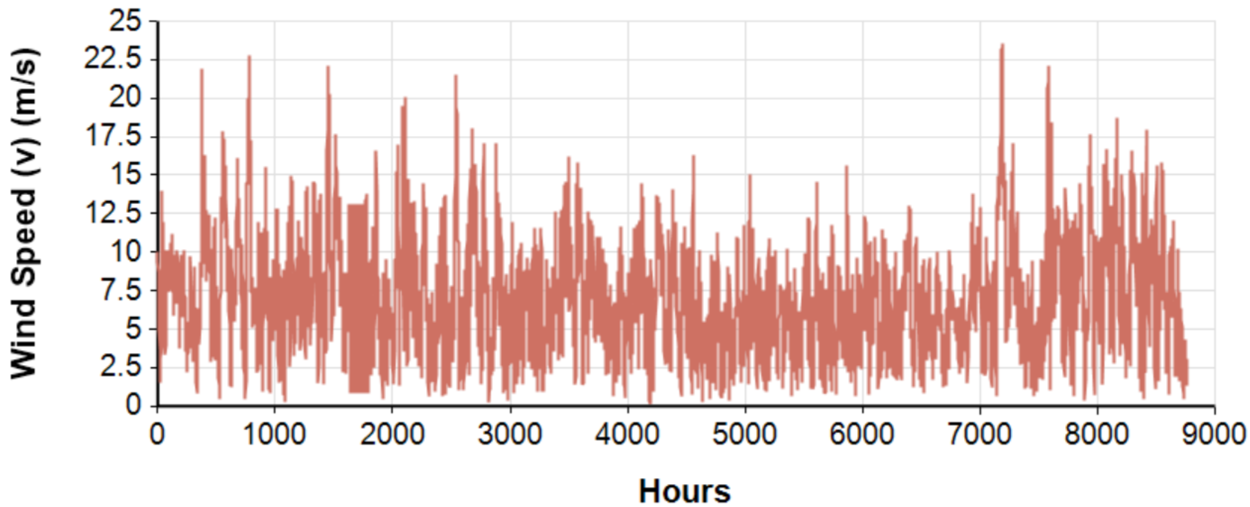


Figure 2.6: Example Hourly Wind Speed

Hourly wind speeds for each wind farm are based on the five-year average of the nearest site with hourly wind speeds scaled by the relative five-year average of that data and the nearest site with annual average information. With specified turbine features and meteorological conditions, wind speeds are converted to electricity output for each turbine. For example, for an offshore wind turbine with air density specified at 1.225 kg/m^3, efficiency of 50%, a 109-meter blade, and 12 MW capacity, the wind profile of Figure 2.6 returns the electricity output of Figure 2.7.

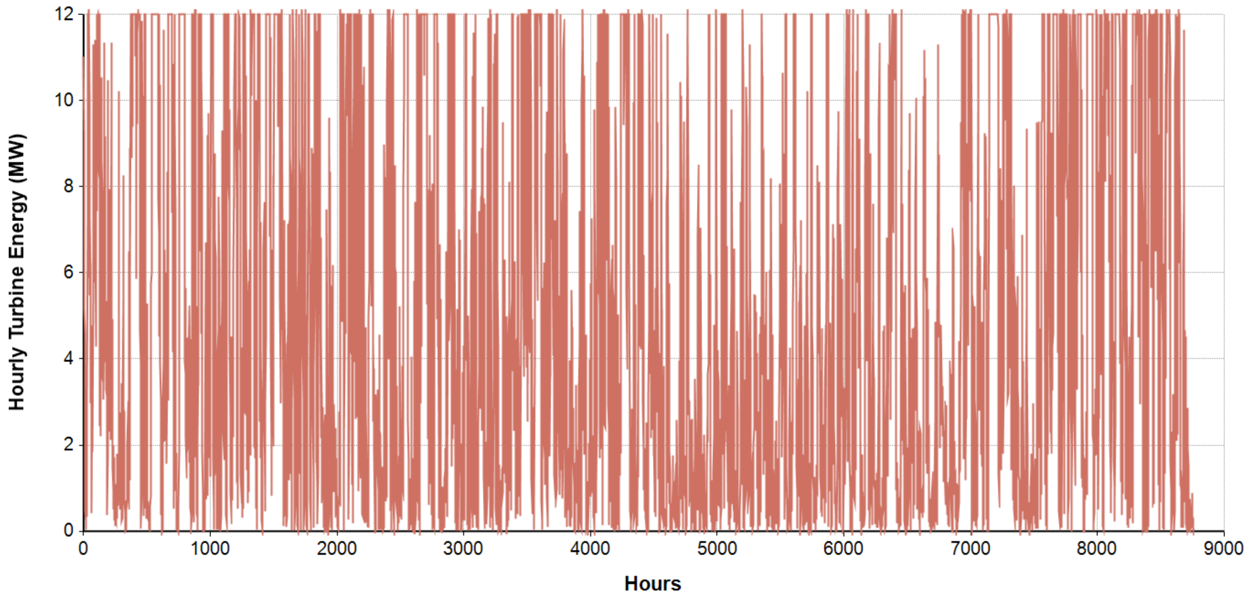


Figure 2.7: Single Turbine Estimated Generation

2.5 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:

$$\pi_i = \textit{Total Annual Revenue}_i - \textit{Total Annual Cost}_i \qquad \textbf{(2.1)}$$

Within the model context, this is represented as

$$\pi_i = (\textit{Total Annual Revenue}_i - \textit{Total Variable Cost}_i) - \textit{Total Fixed Costs}_i \qquad \textbf{(2.2)}$$

To identify total annual revenue, generation revenues for each unit and load period are identified as P_l^* x 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^*.[3] 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 2.8). 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.

$$\textit{Total Revenue}_i = \sum_{l=1}^{14} P_l Q_{li} H_l \qquad \textbf{(2.3)}$$

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

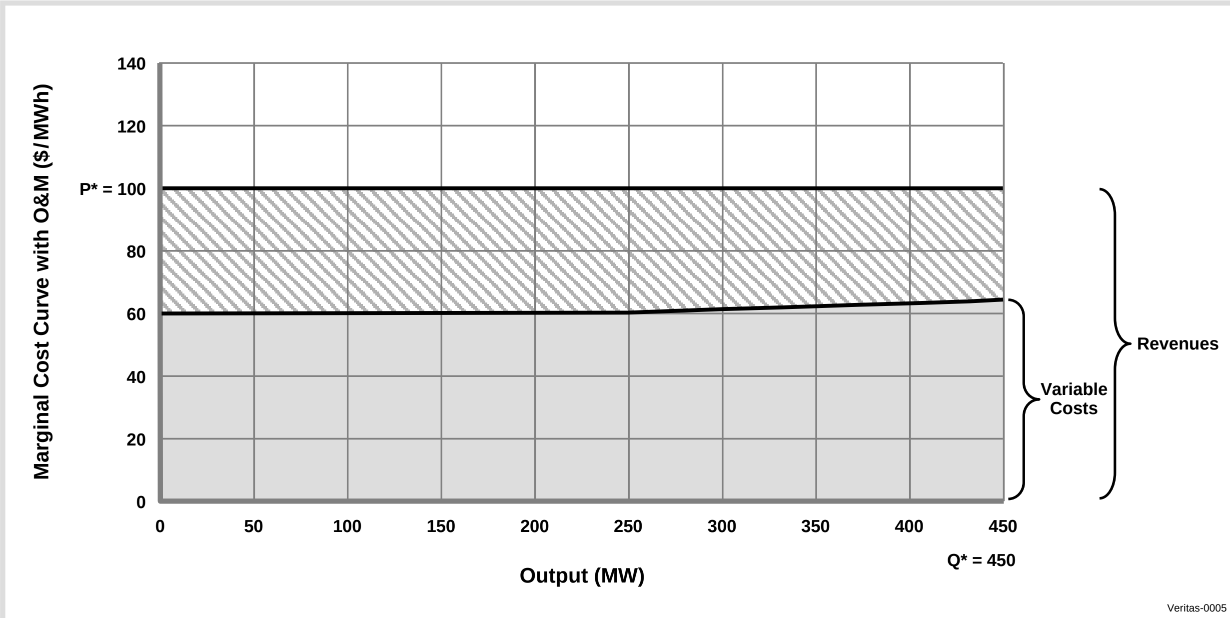


Figure 2.8: Identification of Revenues and Variable Costs by Load Period

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:

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

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.

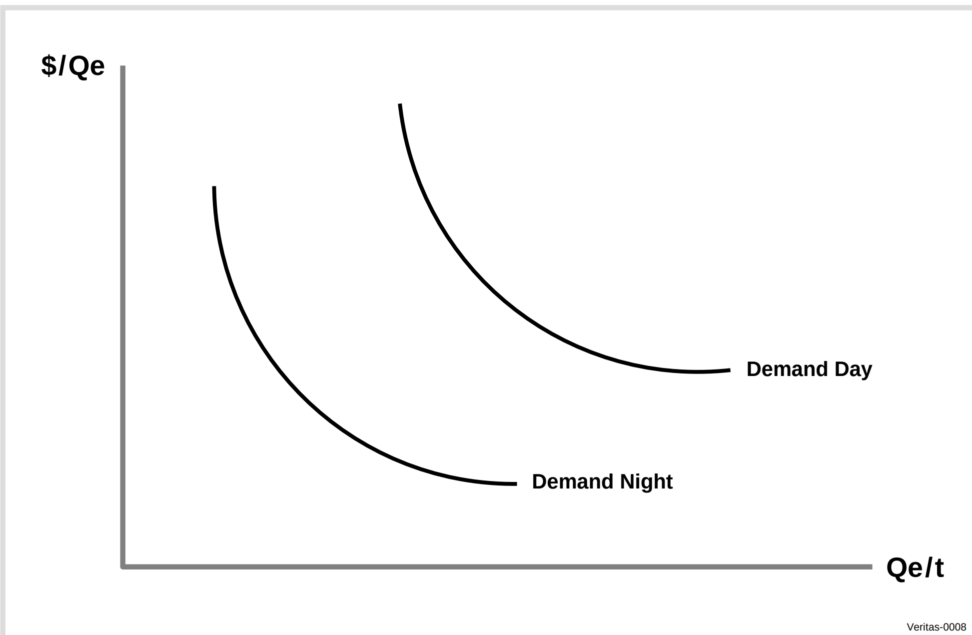


Figure 3.1: Illustration of Diurnal Shifts in Electricity Demand

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

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

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.

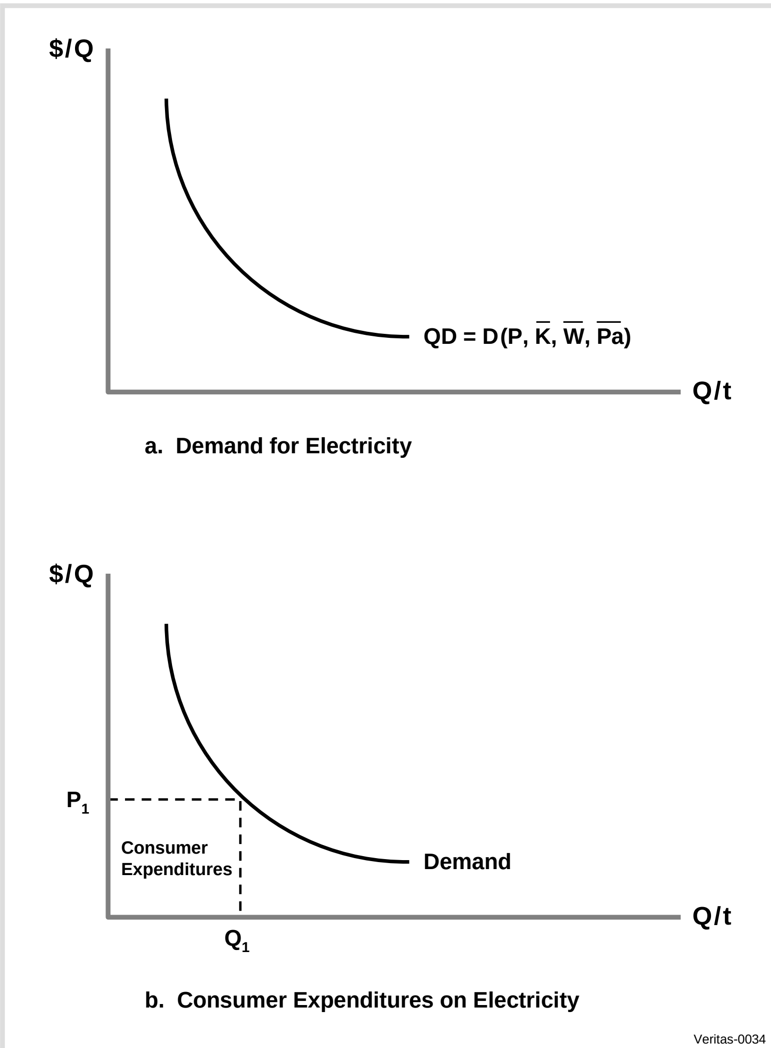


Figure 3.2: Retail Electricity Demand and Expenditures

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.[4]

[4] 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.[5] 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.

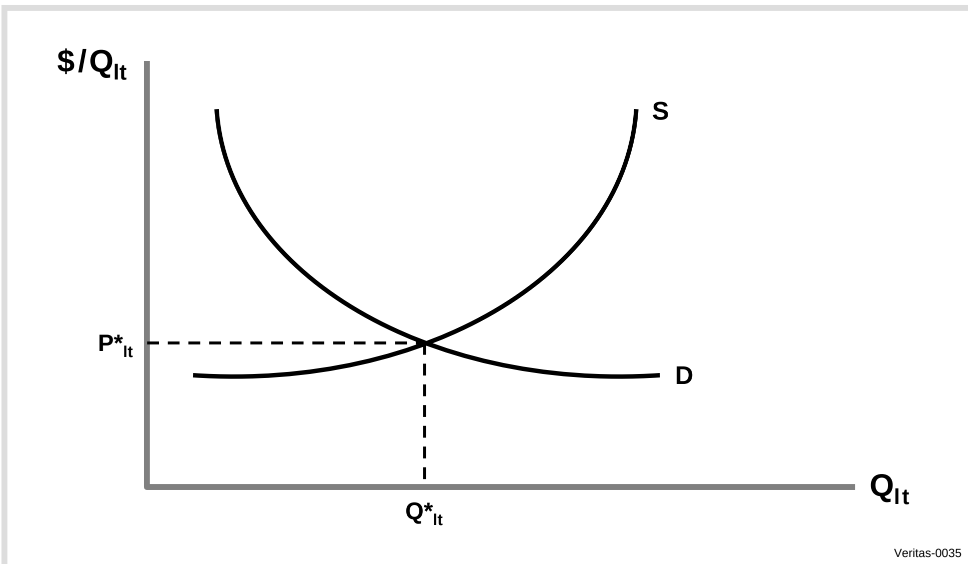


Figure 4.1: Market Demand and Supply and the Equilibrium Outcomes

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.[6] 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 simulations employ supply

5 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.

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

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.[7] 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.

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

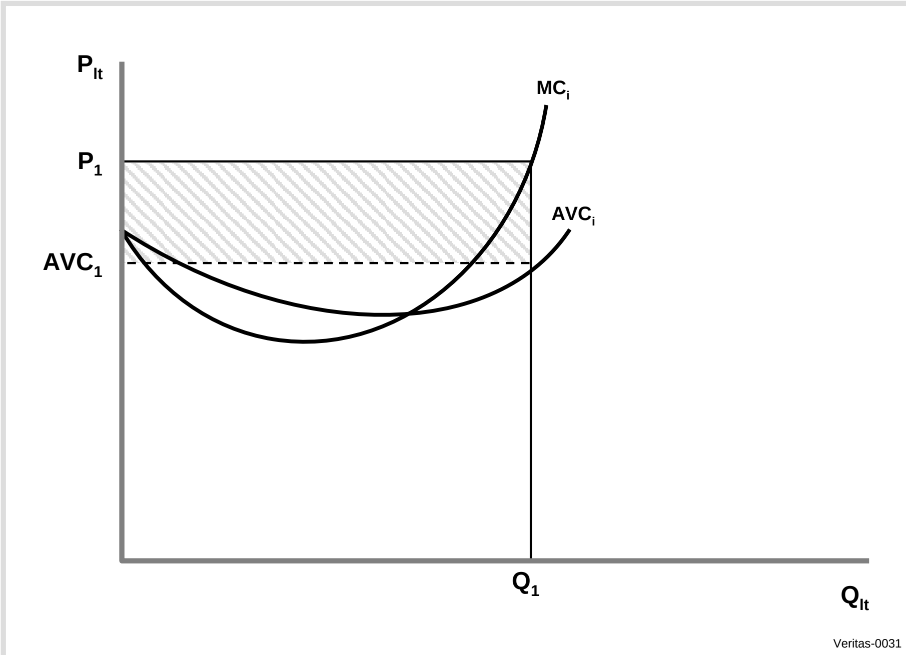


Figure 4.2: Optimal Production

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.

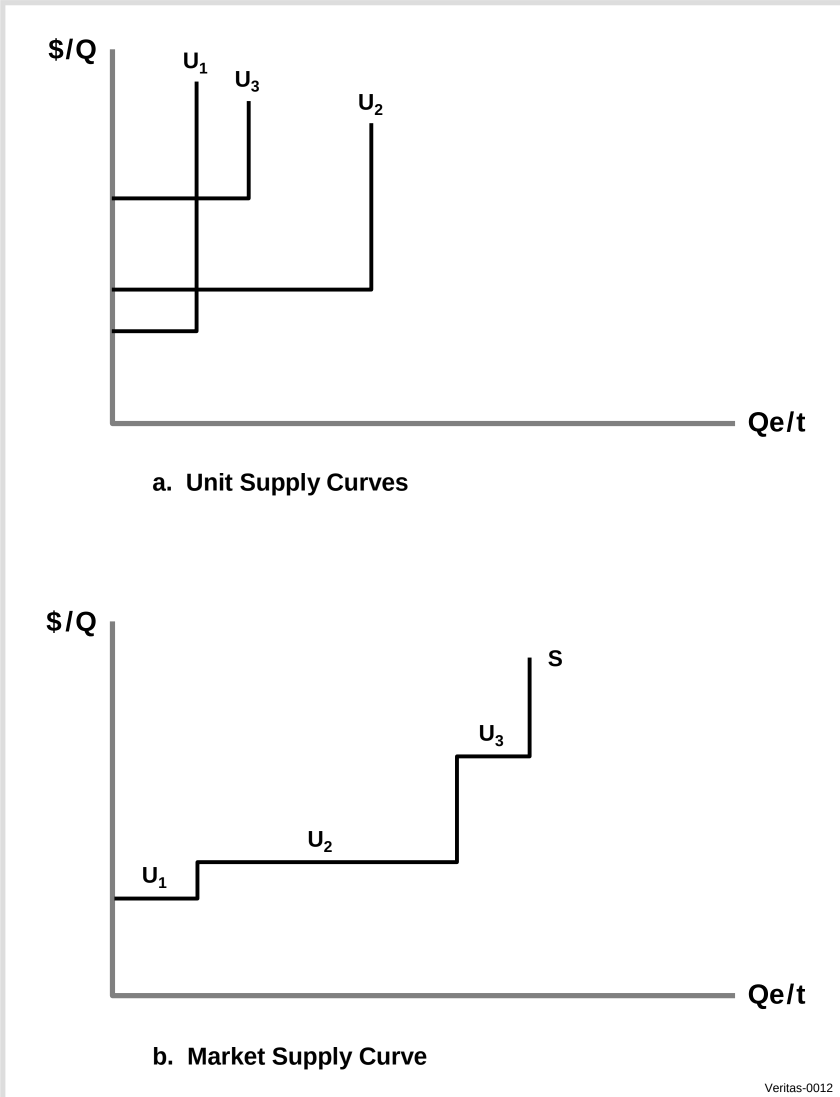
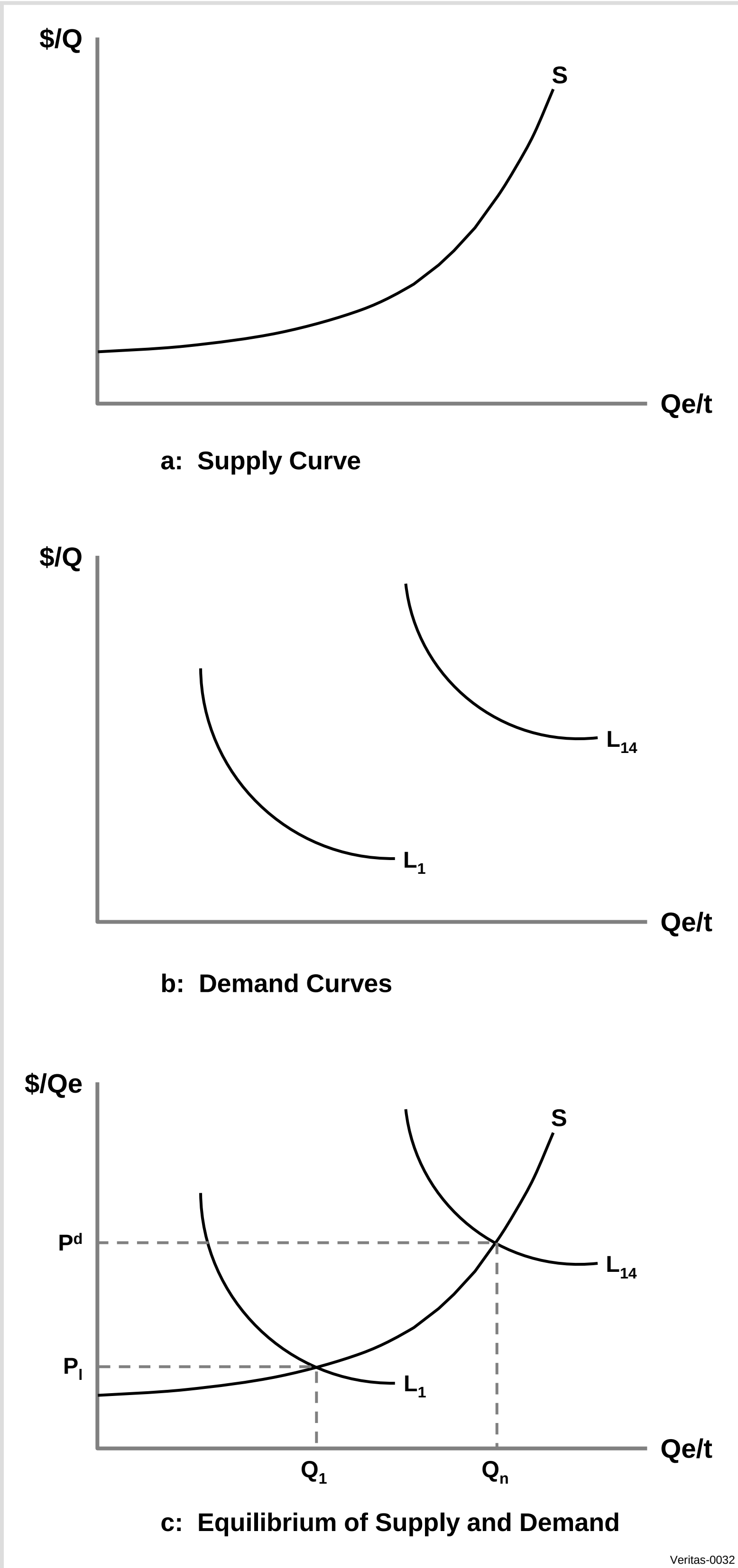


Figure 4.3: The Market's Short-Run Supply Curve

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.



a: Supply Curve

b: Demand Curves

c: Equilibrium of Supply and Demand

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.

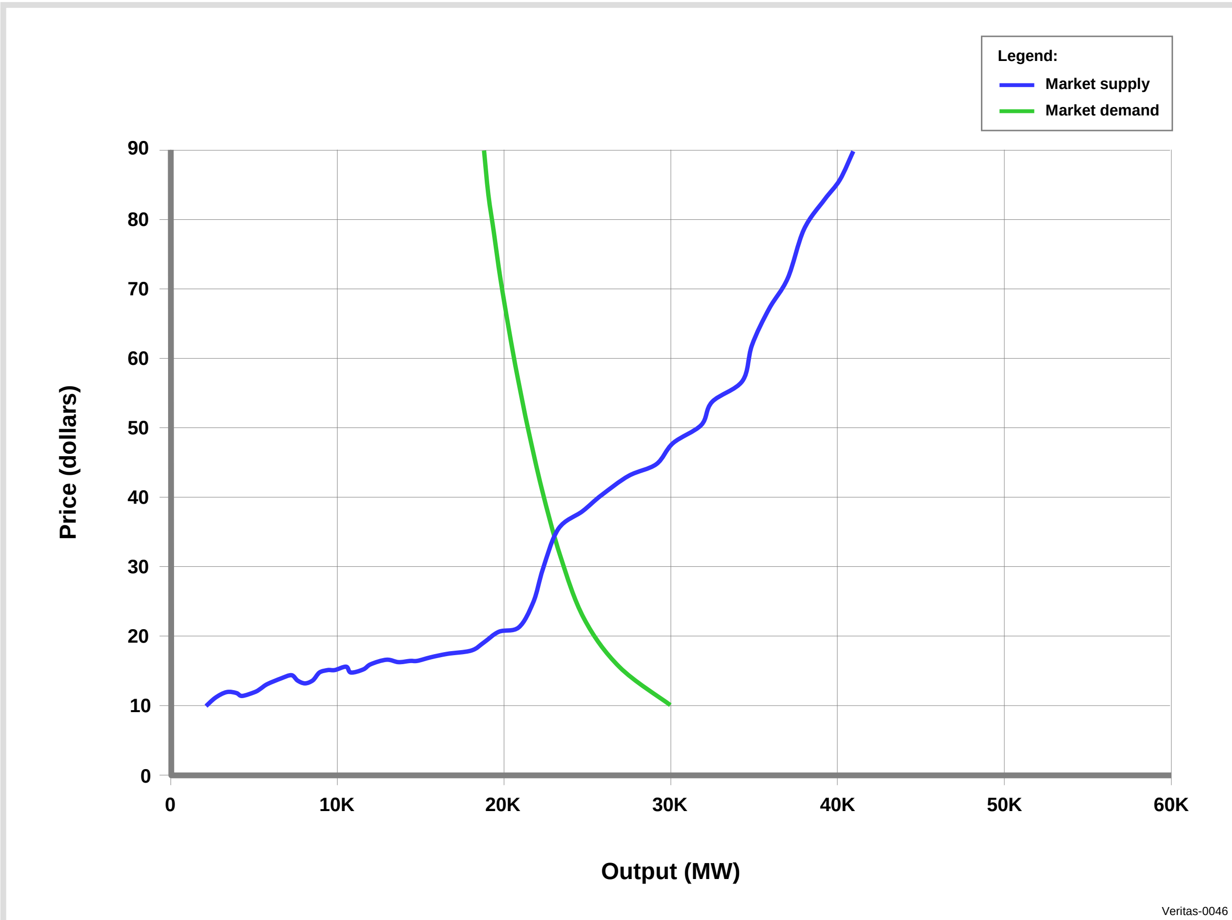


Figure 4.5: Market-Clearing Outcome

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.[8] 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.

[8] 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.

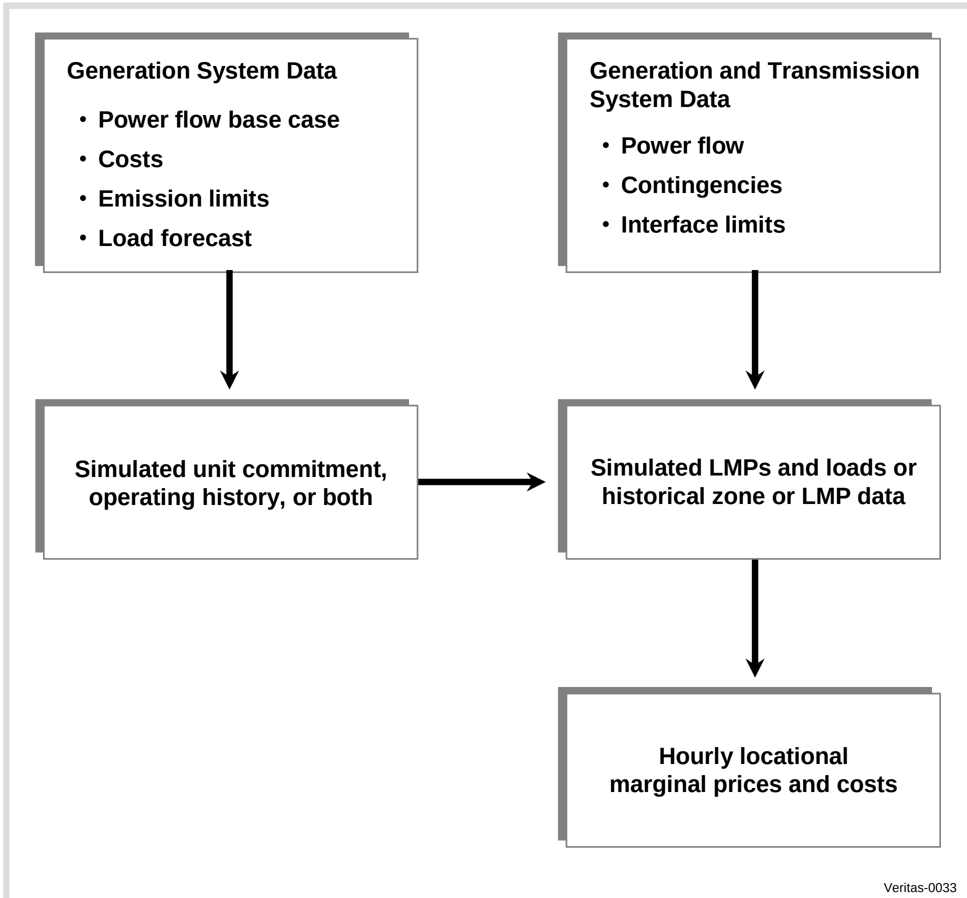


Figure 5.1: Location-Specific Price and Unit-Specific Operation Forecasting Process

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.

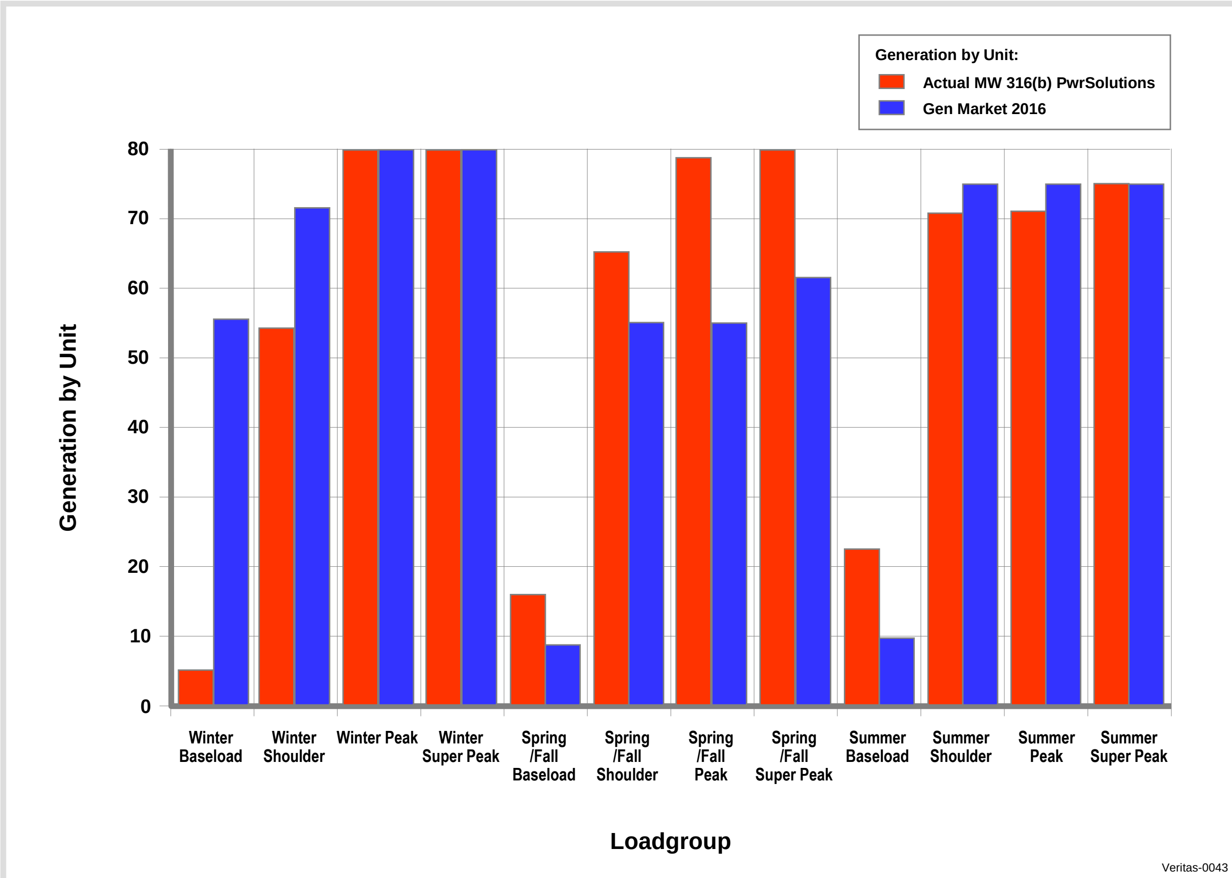


Figure 5.2: Calibrating Operations

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.[9] 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.

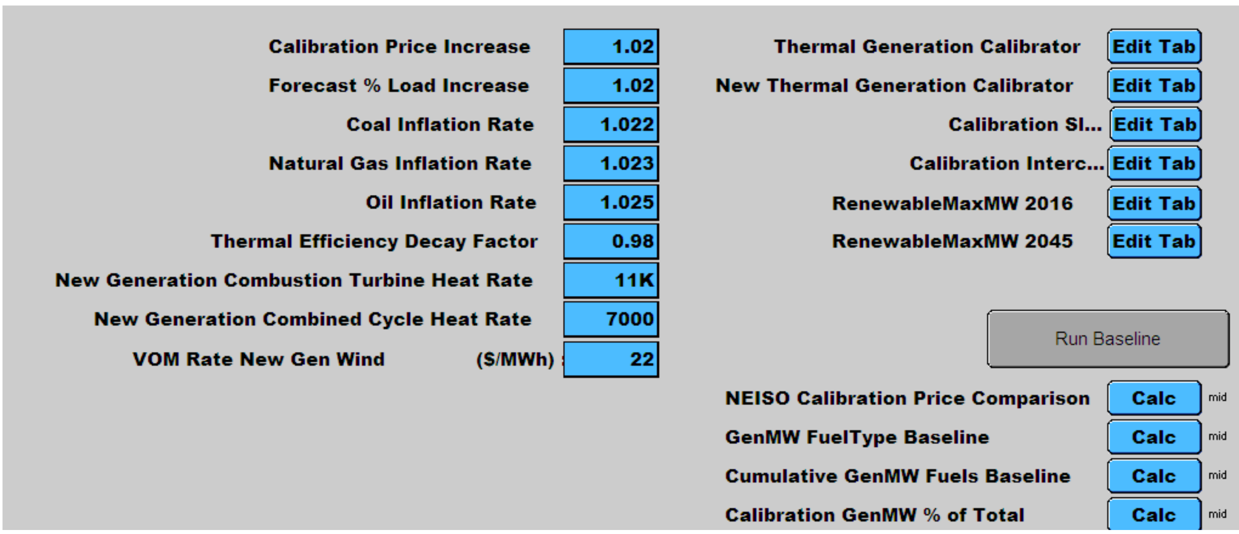


Figure 5.3: Long-Run Calibration User Interface

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.

[9] 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.

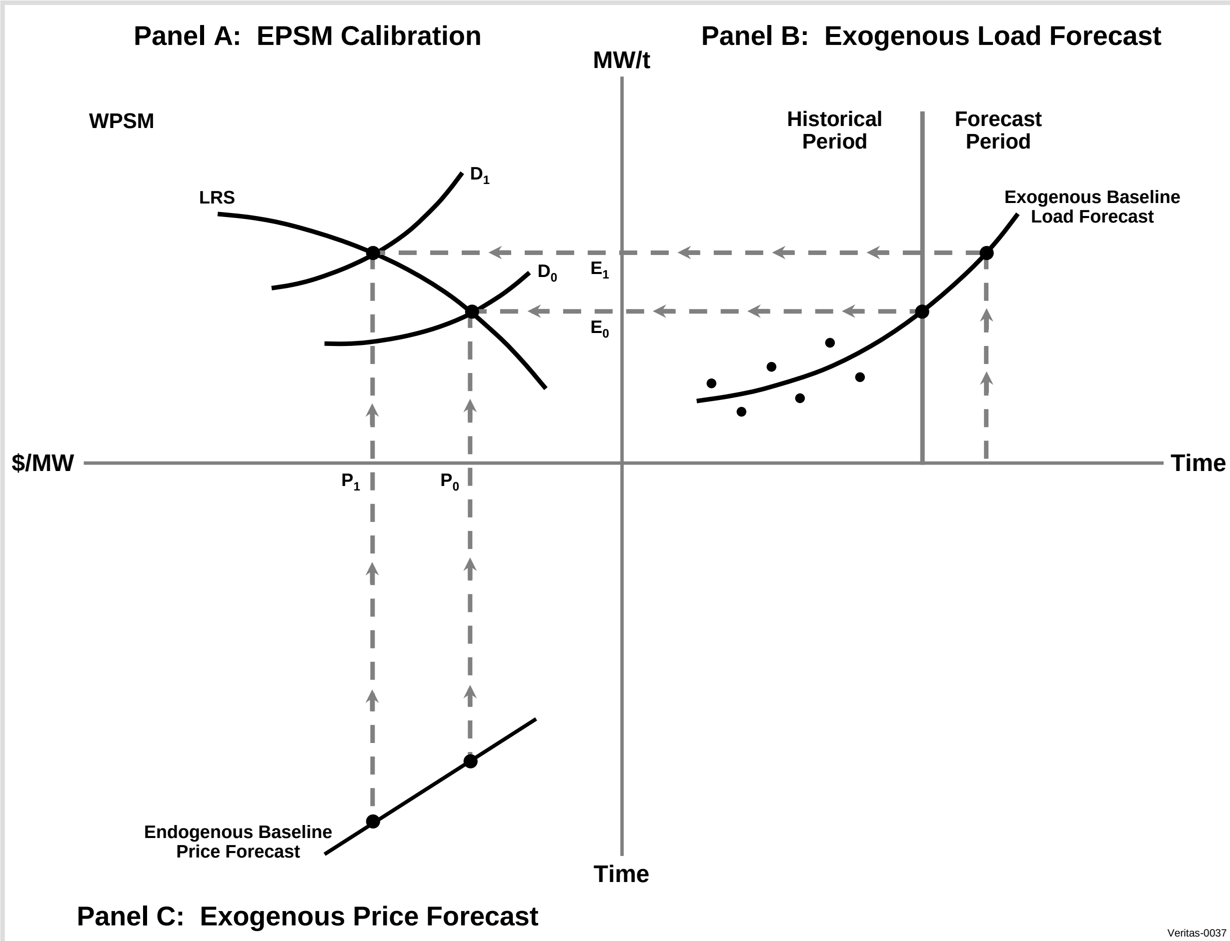


Figure 5.4: Calibration to an Exogenous Load and Price Forecast

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).

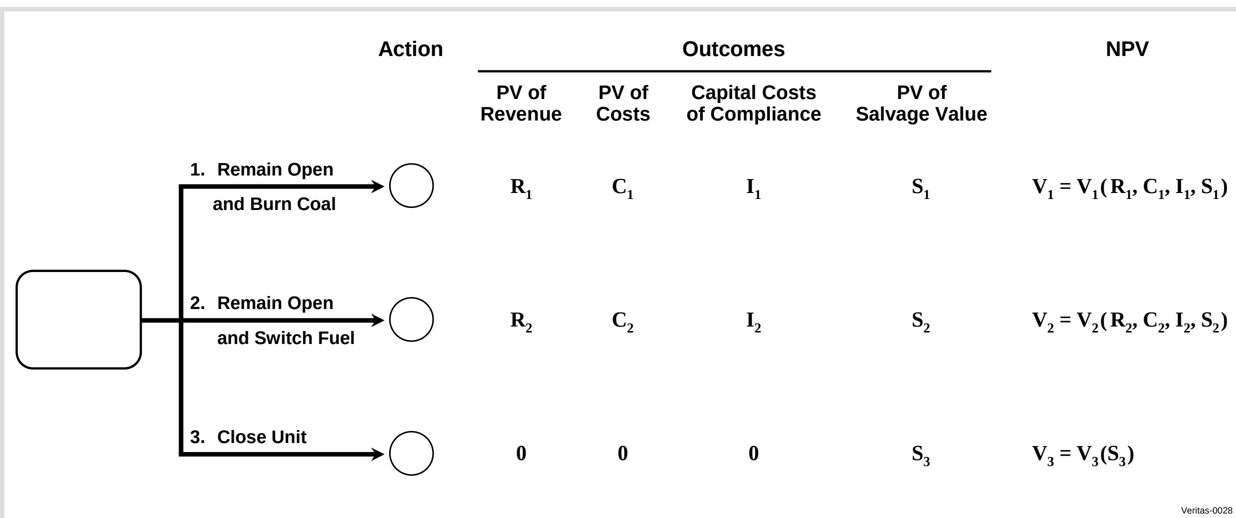


Figure 6.1: Illustrative Decision Tree

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 electricity 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.

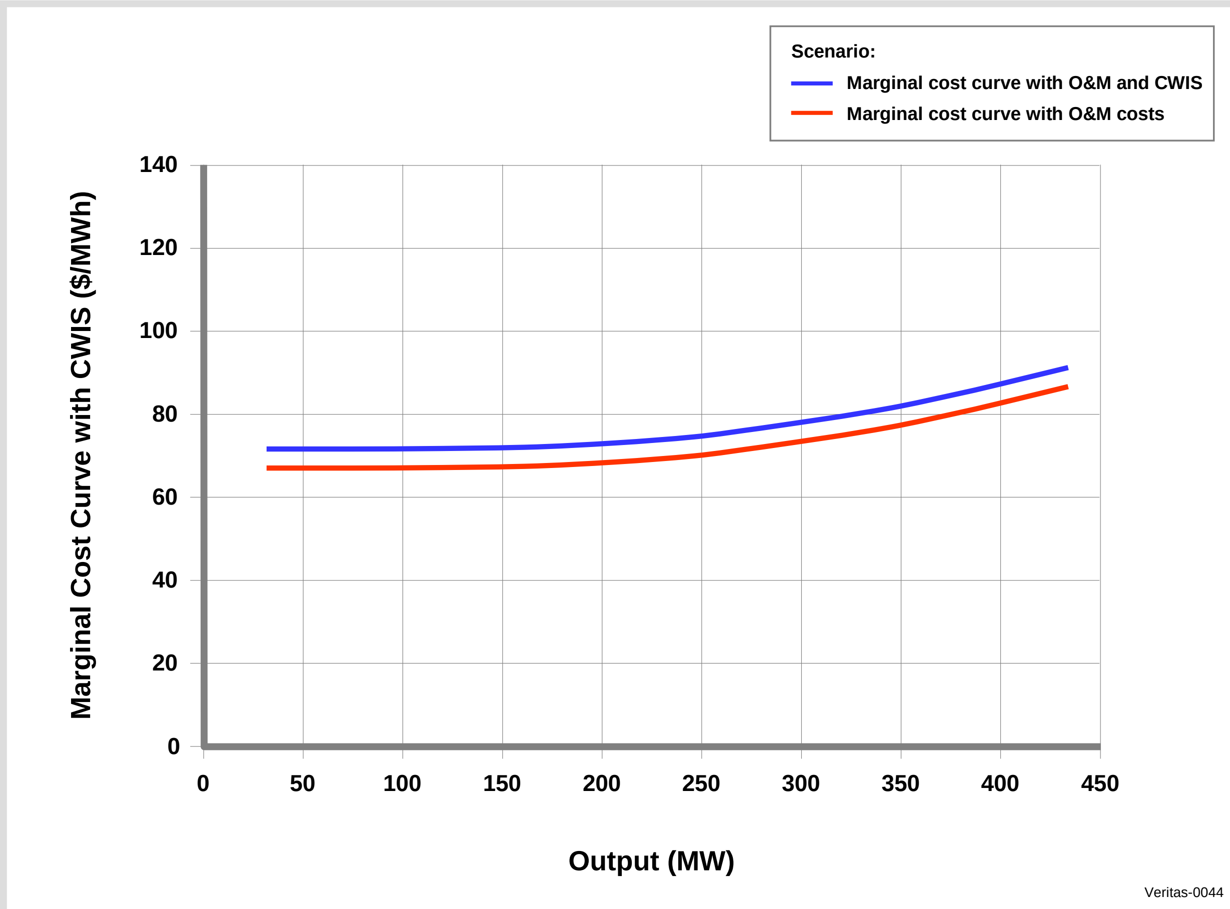


Figure 6.2: Shift in Fuel Cost Curve from Regulatory Compliance

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.

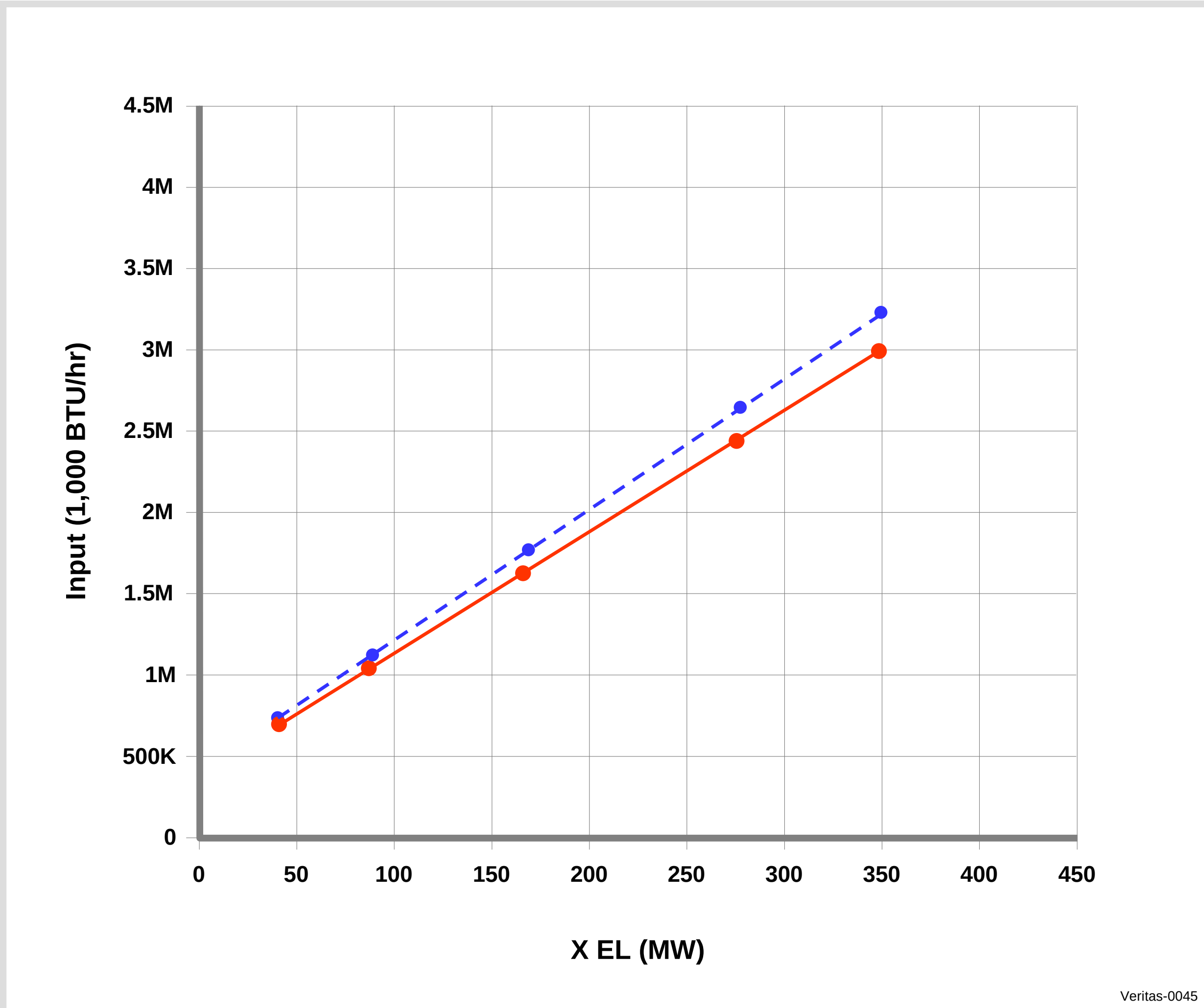


Figure 6.3: Illustration of Cooling Tower Impact on Input-Output Curve

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 electricity 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.

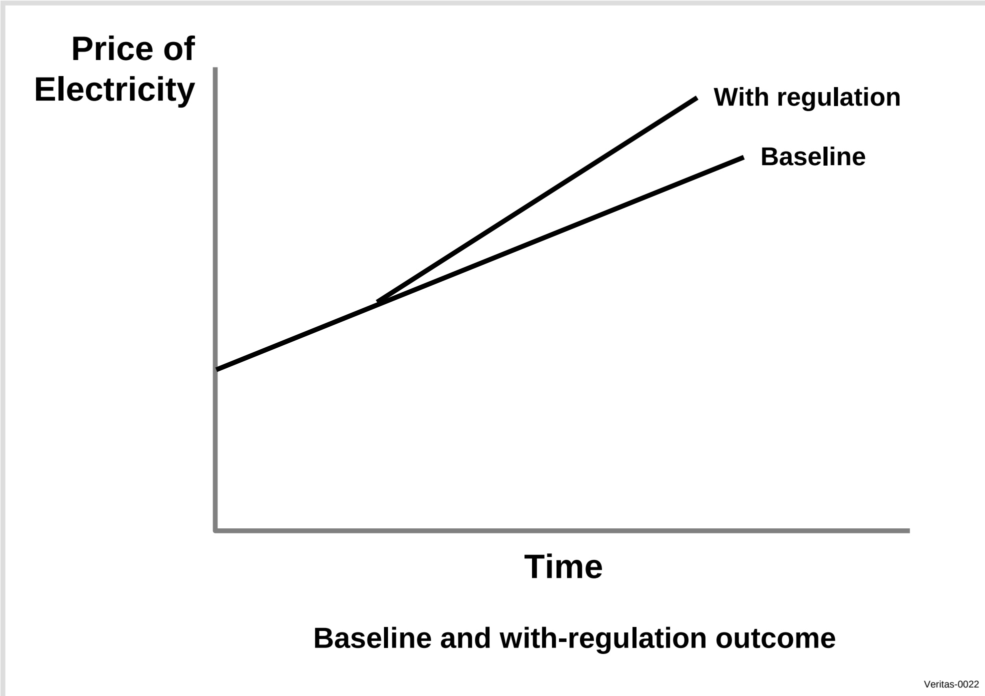


Figure 6.4: Illustration of Price Impacts from an Electricity Regulation

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:

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

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:

$$NPV = DPV - CK \tag{6.2}$$

where *CK* is the initial capital cost.

The discounted present value of profits with compliance is:

$$DPV = \sum_{t=1}^{n} [\pi net_t' / (1 + r)^t] \tag{6.3}$$

where

r = required minimum return on the compliance capital outlays

t = time

n = number of time periods in the planning horizon

πnet' = 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

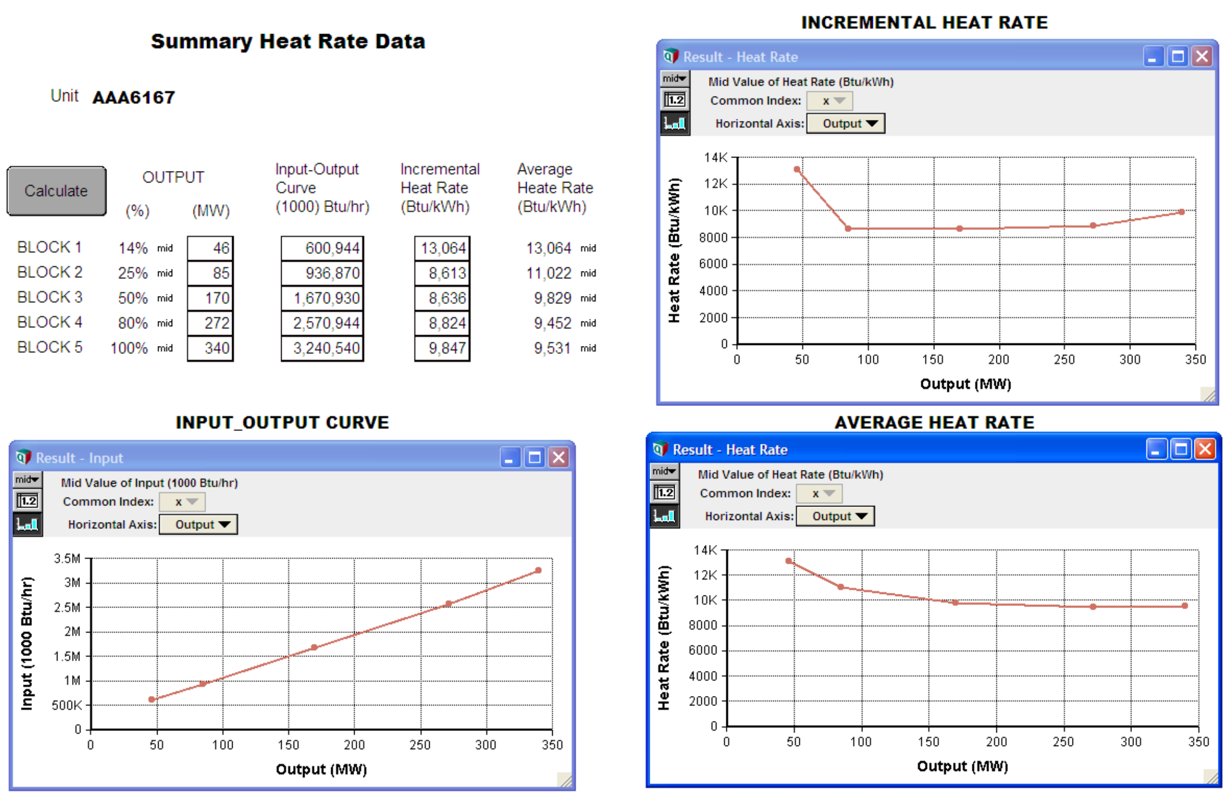


Figure 6.6: Visual Evaluation of Piecewise Specification

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

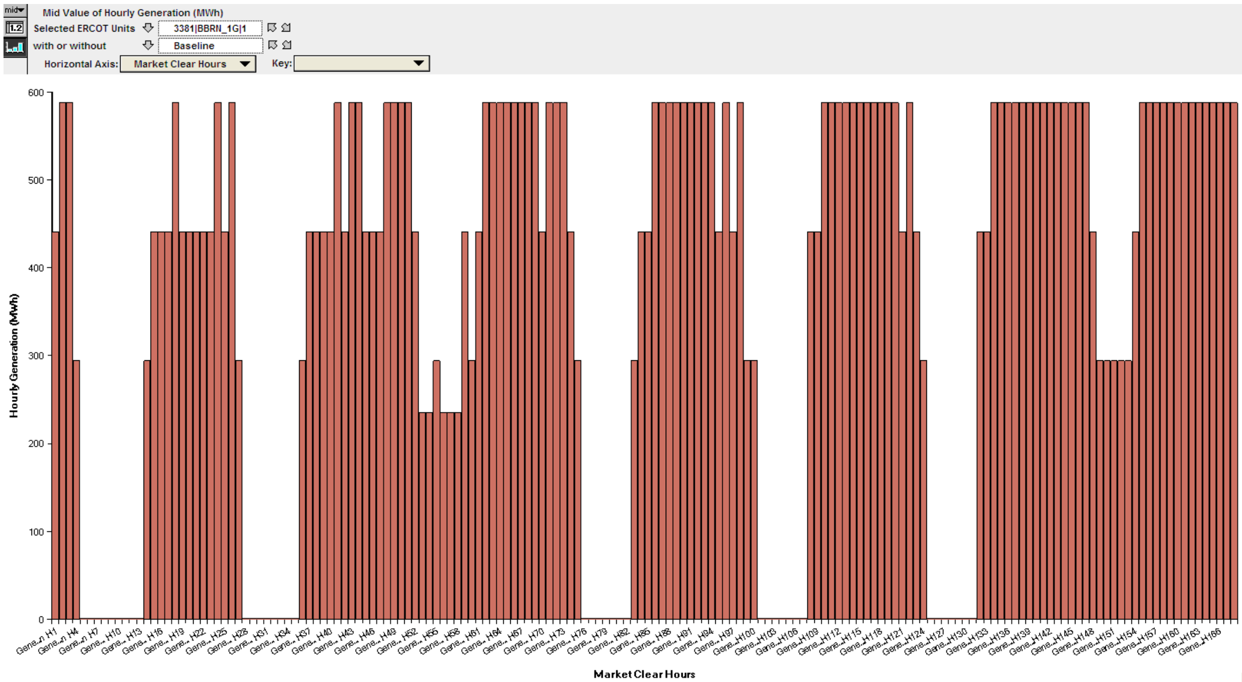


Figure 6.7: Dispatch Predicted Operations

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

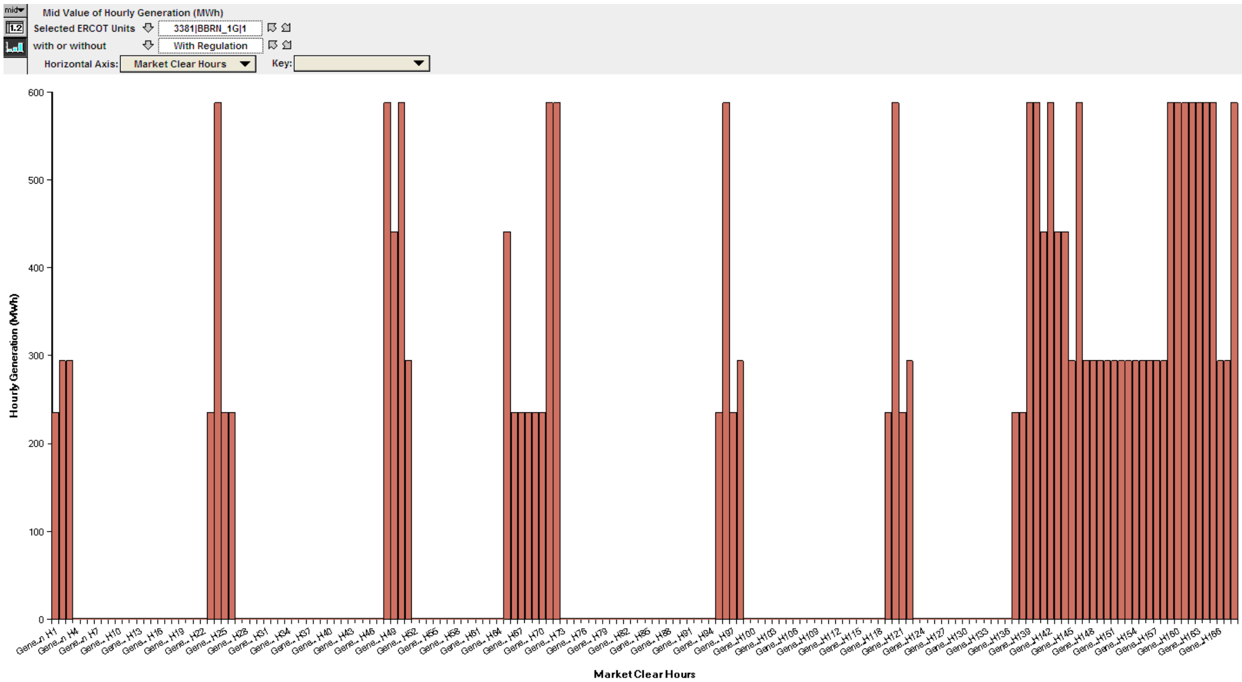


Figure 6.8: Dispatch Predicted Operations

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.[10] 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.

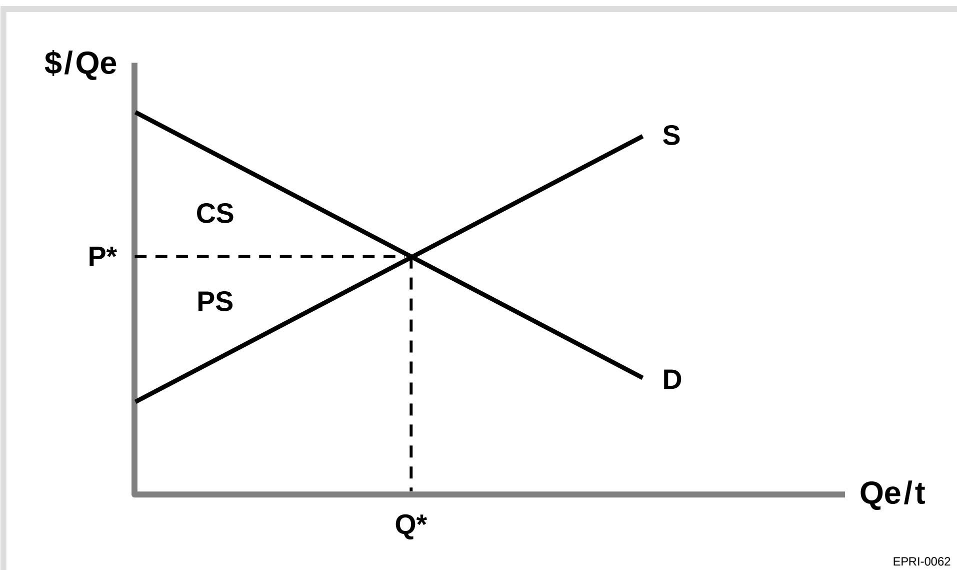


Figure 7.1: Competitive Market Outcomes and Pareto Optimality

The remainder of this section illustrates how the ESPM can evaluate an electricity policy.[11] With the regulatory requirement, the market supply curve shifts upward, reflecting the higher

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

[11] 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 electricity effects of the rule.

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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 P1P2ab 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).

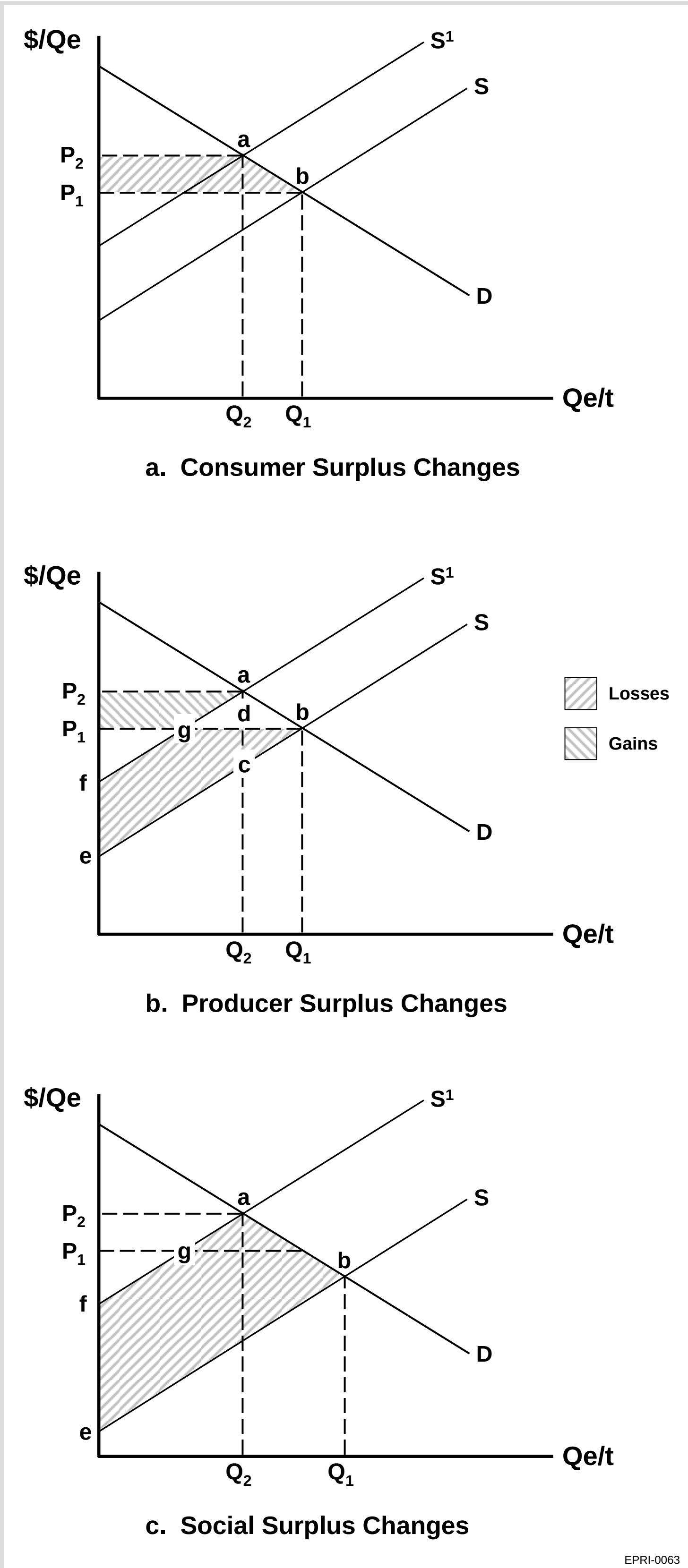

Figure 7.2: Economic Welfare Impacts of a Regulation Requiring Closed-Cycle Cooling

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:

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

where

dr = appropriate discount rate.

8. References

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