Electrical Generating Plant Valuation

Michael J. Remsha, P.E., ASA, CMI

The U.S. electric generation industry is a collection of investor-owned, cooperative, municipal, state, and federal utilities, as well as a collection of power-generating companies that are not classified as utilities. In 2008, according to the *Electric Power Monthly*, a publication issued by the Energy Information Administration ("ELA"), investor-owned utilities ("IOUs") represented approximately 60% of the industry's electricity generation in the United States.

The electric generation industry was developed in the early years of the 20th century in the United States. Over the years, technological advances have altered the operations of the industry, but the physics of generating electricity has not changed. Electricity is generally produced by rotating a magnet inside a coil of wire. The rotating magnet is the rotor, and the coil of wire is a stator; together they form an electric generator. The rotor can be spun by the wind, as in a windmill; by falling water, as in a hydroelectric plant; by steam produced in a coal, fuel oil, gas, or nuclear plant; or by expanding gases, as in a gas combustion turbine or diesel generator. A simplified diagram, showing a coal-fired electric generating plant is shown below.

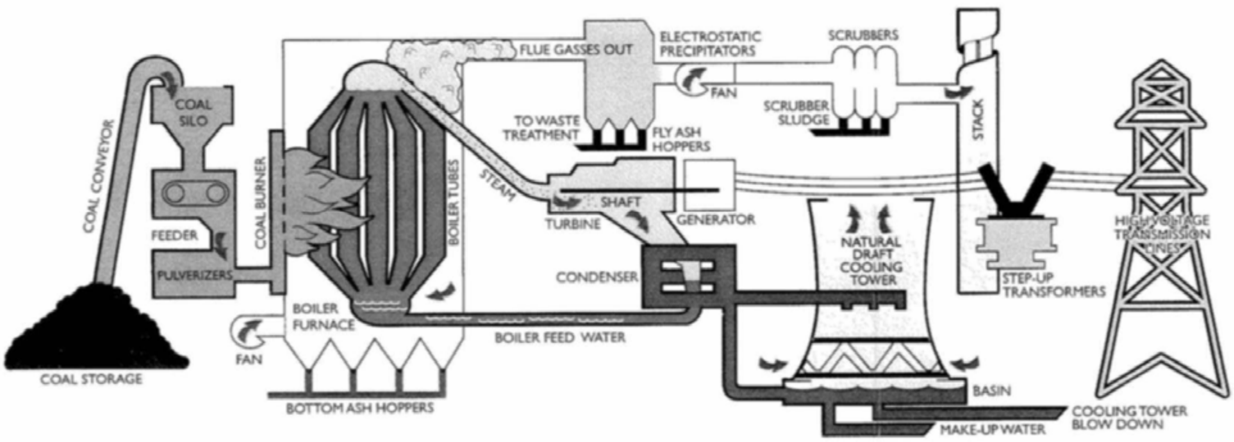


Diagram courtesy of Seminole Electric Cooperative, Inc.

Because electrical energy cannot be economically stored, it must be generated when the customers demand it. Hence, generating plants must be able to meet the maximum demand of the customer base. Utilities must have the transmission and distribution systems available to deliver the electric energy to the customer. In addition, utilities must have extra capabilities available to accommodate maintenance and equipment outages, and unexpected fluctuations in demand during hot summer afternoons and cold winter nights.

Electricity generating companies meet the requirements of their customers through the use of three primary types of power plants: base load, intermediate, and peaking. A base load plant is very large, frequently rated at over 1,000 megawatts ("MW"), and is designed to be operated continuously at capacity factors of 60% to 95%, depending on the design and fuel source. Fuel is typically coal, uranium, or natural gas. Coal and uranium are inexpensive sources of energy, but the cost of plant construction is high - $2,000 per kilowatt ("kW") to $4,000 per kW. Natural gas is an expensive source of energy, but the cost of construction is low - $800 per kW to $1,000 per kW. While natural gas is expensive in comparison to coal or uranium, operating expenses and heat rate (the ability to convert energy to electricity) of natural gas-fired plants are low.

Natural gas-fired plants were popular in the late 1990s and early 2000s, until the price of natural gas increased dramatically. With the price of natural gas too high, relative to the price of electricity, to support the operation of many gas-fired plants, coal-fired plants are being built again. Nuclear plants are being seriously considered. The primary negative aspect of coal-fired plants is the magnitude of emissions into the atmosphere. Emissions from coal-fired plants are a significant issue. Legislation is being considered to force coal plants into either installing technology to reduce or stop all emissions or buy carbon credits/allowances. The increase in operating expenses are significant and will dramatically affect the economics of coal-fired plants. An investigation is underway of new coal technology, FutureGen, that will emit zero emissions and even produce hydrogen as a by-product, but at this time the estimated cost of construction is more than double the cost of a more conventional coal plant.

An intermediate or cyclic plant runs during the time of day when demand is higher. These types of plants are more expensive to operate than base load plants; hence, the price of electricity must be higher for them to run economically. Frequently, intermediate plants are older and somewhat obsolete base load plants. Fuel sources are typically natural gas or fuel oil. Capacity factors, commonly in the 30%-to-50% range, are lower than those of base load plants, although the capacity of intermediate plants can be as large as base load plants. New intermediate plants most likely would be natural gas-fired using combined-cycle technology. New, environmentally friendly technology, wind or solar powered plants would also be considered cyclic plants. Wind and solar plants can only operate when the wind is blowing or the sun is shining. While they are environmentally friendly, they tend to be uneconomic unless subsidized by the government.

Peaking plants are expensive to operate and, thus, are used only when electricity is high in demand and, hence, is priced high. Capacity factors are low, commonly less than 5% to 20%. At times, these plants are old facilities that have been converted to use natural gas or fuel oil as a fuel source. The most modern peaking plants are simple-cycle-combustion turbine plants that are fueled by natural gas or fuel oil.

In addition to the primary types of power plants are black-start units. Black-start units are typically small trailer- or skid-mounted diesel-fueled turbine generators that are seldom operated. Their primary advantage is that they can be started up without electric power from the transmission system in a very short time. They are small in capacity and expensive to operate. Because black start units are independent of the transmission system, they can be used to start up other generating units that require electric power from other sources to start.

The Deregulated/Restructured Market

The electric generation industry has changed. Historically, the regulated investor-owned utilities have had exclusive franchises to provide vertically integrated services to customers in contiguous areas, typically within a state. These highly regulated utilities, many of which were created under the Public Utility Holding Company Act of 1935, are now exposed to competition in the generation and wholesale power markets and in many states are being exposed to competition at the retail level.

In 1978, three important laws were passed: the Power Plant and Industrial Fuel Use Act ("PPIFUA"), the Public Utility Regulatory Policies Act ("PURPA"), and Natural Gas Policy Act ("NGPA"). The PPIFUA was passed because of the concern that the United States was running out of natural gas; this act prevented utilities from building natural gas-fired plants and focused primarily on coal-fired and nuclear plants.

The goal of PURPA was to create a new class of nonutility electrical generators to promote conservation of electrical energy. This act encouraged small power producers to use renewable resources and cogeneration plants. Cogeneration plants had to produce electricity and another form of useful thermal energy (frequently steam) through a sequential use of energy. Plants that met the requirements of PURPA were called qualifying facilities ("QF's"). The Federal Energy Regulatory Commission ("FERC") had additional requirements regarding ownership and efficiency. Electric utilities were required to interconnect and purchase power from the QFs at the utility's own avoided cost (the cost to the utility of the next type of generator it would bring on line) of production, which guaranteed a market for the QFs. The avoided cost was typically represented by a type of peaking unit. Two types of generators frequently took advantage of the PURPA, small nonfossil fuel plants under 80MW and cogeneration facilities producing electricity and a useful thermal energy, commonly using natural gas as a fuel source. Generally, the state or federal government did not regulate the QFs.

The passing of PURPA encouraged many small hydroelectric generating plants to start up again throughout the United States. These plants could be restarted with little investment, and the local utilities had to buy the electricity generated, whether or not it was needed. In addition, a transaction market was created for PURPA plants. Operating plants with a PURPA contract were valuable assets; they represented an operating business with working capital, tangible assets, and intangible assets such as the PURPA contract. Prior to this period, almost all electricity generating plants were owned by regulated public utilities, municipalities, the government, or cooperatives.

The NGPA dismantled price controls on natural gas sold in interstate commerce and took gas pipeline companies out of the purchase and sales business. As a result, customers could purchase gas in the market and have it transported for their use. Incentives to bring new gas supplies to market increased supply and drove gas prices down further, making gas an attractive fuel in the new nonregulated power generation market.

Competition, created by the National Energy Policy Act of 1992, empowers the Federal Energy Regulatory Commission ("FERC") to direct electric utilities to provide wholesale wheeling (transmission service) at cost from any electricity generating plant to another utility, regardless of whether the transmitting entity is another utility or an independent power producer ("IPP"). These recent changes in the nonregulated power marketing and trading segment of the industry have formed the foundation of deregulation.

In 1996, under the mandate of the National Energy Policy Act of 1992, the FERC issued Order 888 and Order 889. Order 888 requires utilities that own, control, or operate transmission lines to provide transmission service for wholesale transactions on an open, nondiscriminatory basis. This order laid the foundation for an Independent System Operator ("ISO") concept. An ISO is an entity formed to control and operate the regional transmission systems including the wholesale power grid. In addition, Order 888 supports the recovery of prudently incurred, wholesale stranded costs from departing customers. Stranded costs are generally the difference between the net book value of the assets and their fair market value.

Order 889, set up the Open Access Sametime Information System ("OASIS"), and requires electric utilities to make certain information about their transmission systems electronically available to other utilities and providers. In addition, each utility must unbundle its records of wholesale power marketing and transmission operations to allow customers to compare prices for these services.

In 1999, FERC issued Order 2000 to encourage all public and nonpublic electric utilities to place their transmission facilities under the independent control of a Regional Transmission Organization ("RTO") to manage the transmission grid in a regional territory. An RTO is to assure nondiscriminatory access while increasing efficiency and reliability. In general, an RTO would have more authority than an ISO to eliminate discrimination.

The deregulation of the industry was intended to increase competition and to loosen the electric utilities' monopoly on power generation. Arguments have been made over time that the traditional utility rate base regulation, based on the cost of service, does not give the utility companies an incentive to be efficient. As a result of wholesale price deregulation, the price of electricity is based on the market fundamentals of competition, and supply and demand. This competition has caused the least efficient generating plants to shut down and has encouraged the construction of new modern and efficient plants. Not all states have deregulated the electrical generation industry. In addition, deregulation is not the same in every state.

Current Trends

The National Energy Policy Act of 1992, FERC Orders 888 and 889 in 1996, and Order 2000 in 1999 encouraged the growth of the merchant electricity generation market and power trading. Utilities in many states were required or encouraged to divest generating plants and become distribution and transmission companies. This allowed the growth of merchant generating companies, which bought the existing generating plants from the utilities and began construction of new modern plants using environmentally friendly, natural gas-fired turbine technology. Natural gas was available by pipeline in most of the United States and was inexpensive. These plants run as merchant generators, selling electricity either in the newly developed spot market or through power purchase agreements ("PPAs") to utilities or power traders. Many of the PPAs were signed at prices before increased competition and deregulated gas prices caused electricity prices to fall. In some markets, capacity payment contracts also were signed with the merchant generators to guarantee a supply of electricity should the utility need it. A capacity payment contract provides revenues to generators whether they are used or not. This guaranteed revenue source provides a reasonable return to the owner of the generating plant, whether it is actually generating electricity or not. Not all markets provide capacity payments; in fact, they are controversial in that they artificially keep obsolete or excess capacity from shutting down. Without the PPA or the capacity payment contract, many plants would not have been built. PPAs and capacity payment contracts are intangible assets and are considered a part of the operating business enterprise of the generating plant.

Current Operations

A common term used in the electric power industry is capacity factor ("CF"). Typically, capacity factor is defined as the actual operating capacity of a plant as measured by the ratio of a plant's average electrical energy output to rated output. When the capacity factor is at 100%, the plant is actually operating at its normal design capacity. However, plants experience outages for repairs and routine maintenance, causing the CF to drop below 100%. A lack of demand in the market also will contribute to reduced CFs.

During the late 1990s, generating plants began to be sold in the marketplace on a regular basis. When deregulation became a reality, many utilities were forced or encouraged to become either generators or wholesalers of electricity or strictly transmission and distribution ("T & D") companies. Companies that became T & D companies sold off their generating assets; the first assets to go were frequently the nuclear power plants because of their high operating costs and social risk. As the energy markets became more competitive, more selling of generation assets and consolidation occurred. Groups of coal-fired and older gas- and fuel oil-fired steam plants were sold. The transactions frequently included a PPA, commonly short term, that allowed the seller to continue to buy electricity from the sold plant while the deregulated market was forming and, also, allowed the purchaser to have a buyer for the electricity that would be generated at the plant, while the deregulated market was developing. Typically, the PPA was at a benchmarked rate that reflected the buyer's and seller's forecast of the market price of electricity. It reduced the risk of both the buyer and the seller.

Power Plant Economics

In the regulated industry in which most power plants have operated over the last 80 years, profits associated with the plant operation were almost guaranteed based on the plant's rate base (original cost less depreciation) and its operating expenses. The cost to the customer, the rate payer, for electricity was set using a market-based return on the total rate base of the utility (power plants, transmission lines, meters, and similar assets) and the recovery of the utility's operating costs; the power plant was just one of many assets that provided a return to the utility. Usually, the utility received a reasonable return on its investments, and the customers' electricity rates were protected from the utility's monopoly status by the Public Service Commission's ("PSC") control over the utility's earnings. The utility was required to serve the public by providing electricity in a reliable and generally inexpensive manner. Although for the most part this proved to be true, rising electricity rates in some states during the late 1970s through the early 1990s drew the attention of the PSCs and the Federal Energy Regulatory Commission ("FERC").

In an unregulated environment, the basic economic principles that determine the value of the product of an electrical power plant, that is, electricity, are supply and demand, and competition. As demand for electricity increases and the supply of electricity remains constant, the price of electricity increases. But increased profits invite competitors who increase supply. As a result, supply increases, prices fall, and profits decrease. To manage the unregulated sectors of the market, regional electricity Independent System Operators ("ISO") coordinate the wholesale generators (electricity supply) and transmission systems with the industrial, commercial, and residential customers (the demand), to ensure that when demand is greatest, the supply is available and provided by the lowest cost plants.

Valuation Approaches

The valuation of an operating electrical plant assumes the transfer of ownership as of a particular date. The transfer price is based on the concept of a willing seller and a willing buyer, neither being forced to participate in the transfer and, also, both being reasonably knowledgeable of the relevant facts associated with the operations and the business. To determine the transfer price or value of the plant, three approaches to value are available to review: the sales comparison approach (based on sales of similar plants), the income approach (based on projected cash flows), and the cost approach (based on the cost of construction less depreciation).

Sales Comparison Approach

In the sales comparison approach, transactions in the marketplace are used to derive a value for a plant based on the actions of buyers and sellers. Actual sales are analyzed and adjusted to the subject plant. Adjustments to consider include (a) size - the generation capability of the generators; (b) production expenses - compare the cost to produce electricity per kW between the plants; (c) time - adjust for the economics between the appraisal date and the date when the sale took place; (d) age - compare the age and level of technology; and (e) location - adjust for different economics between the subject's location and that of the sale; in other words, is the subject in a better or worse location when considering its ability to receive fuel and transmit power to the grid at a profit? A spark spread or gross margin (revenue per kW less cost of fuel per kW); can be used to adjust for time (market conditions) and location. Several other adjustments can be made depending on the circumstances. When taking into account the purpose of the valuation, any fuel inventories, intangible assets, power purchase agreements ("PPAs"), transmission assets, or other assets should be removed, as necessary, from the transaction price to result in only the price of the tangible plant assets under review.

The sales comparison approach can be a powerful tool when appraising an electricity generating plant, if comparable sales can be found and properly investigated. In the late 1990s, when the industry began to restructure in some states, many nuclear, coal, and older style steam generating plants were sold in the market. After appropriate adjustments to the subject plant, a sales comparison indicator of value could be derived.

However, during the early 2000s, a few more nuclear plants were sold, but most of the transactions were natural gas-fired combustion turbine ("CT") or combined cycle gas turbine ("CCGT") plants. Almost every one of the natural gas-fired plants that traded in the market sold with a contract that guaranteed a revenue stream. Plants without contracts generally did not sell. Many of them were mothballed after construction was complete, never completed, or sold piecemeal. These plants were located in states where deregulation was anticipated but never happened or because of the severe increase in the price of natural gas, the plants just could not compete against hydroelectric, nuclear, and coal-fired plants.

So why did they sell? They sold because the contract provided a revenue stream to the owner whether or not the plant was operated. Frequently, plants were built because they had a power purchase agreement ("PPA") that provided capacity payments to compensate the plant for being ready and capable of operating when needed to generate electricity. If they were CCGT, the plants were expecting to operate over 60% of the time, and, if a CT, at least over 5% of the time. With the price of natural gas rising and the price of electricity remaining low because of the abundance of inexpensive sources of power, the natural gas-fired plants were not needed; however, they still received capacity payments according to the PPA. The owners of the plants received capacity payments which compensated them for, at least, a portion of their operating expenses, but the companies providing the payments were left with a major liability.

Then, several events occurred. The company providing the capacity payments bought the plant and the PPA and, hence, liquidated the contract; then the buyer either incorporated the plant into a regulated rate base utility, shut it down or sold it. At times, the plant and the PPA were sold to an independent third party who continued to receive the capacity payments or operated the plant as a merchant plant without a PPA. Or, the PPA was transferred to an independent third party who was paid to take it and to continue making the payments. The tangible plant assets did not necessarily sell, but the PPA was transferred.

That leads to the question, where is the value in a natural gas-fired plant with a PPA – in the plant's tangible assets, in the PPA, or both? It leads to reason that the PPA would not exist without the plant's tangible assets and the plant would not have been built without the PPA.

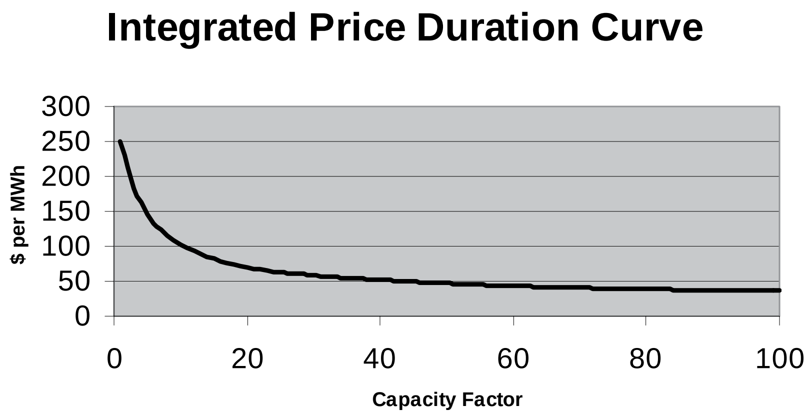
When a state deregulates the electrical generating industry and forms an ISO, the plants within the control of the ISO sign a contract to operate under the control of the ISO. They operate primarily when the ISO tells them to. There is no guarantee that they will run and hence, be paid for the energy they generate and there is no guarantee that they will receive any capacity payments. They do have the ability to contract through a PPA to another market participate their capacity, but they must be available to provide energy to the ISO if called upon. The earnings for the less efficient plants are not guaranteed. It varies from ISO to ISO and state to state.

Income Approach

The next indicator of value based on future income realizations is developed using the income approach. This method is used most frequently by buyers and sellers in the marketplace. But, forecasting the future is difficult because power plants are income-producing assets. Buyers and sellers often use a matrix of income approaches to test their forecasts in as many different ways as possible, thus developing a range of values for use in negotiating sessions. Buyers and sellers also are knowledgeable of plant sales (they often participate in the bidding process for plants) and the cost of new construction and the basic concepts of physical deterioration and obsolescence.

Items to be forecast in the income approach include capacity factor (electricity production), prices of electricity and fuel (energy costs), operating expenses, emission credits, future capital expenditures and sustaining capital requirements, additions to the decommissioning trust fund (for a nuclear plant), and the capitalization or discount rate. Forecasts for prices of electricity are frequently available from various published sources or consulting firms specializing in economic forecasts. Many consultants forecast electricity prices on an hourly basis, based on computer models, and supply and demand relationships. Integrated price duration curves, as shown on Chart 1 below, can be derived to develop electricity prices based on capacity factors from 1% to 100%. These charts project the average price of electricity a plant will realize based on the percentage of the time it operates during the year. Chart 1 is a hypothetical example.

Chart 1

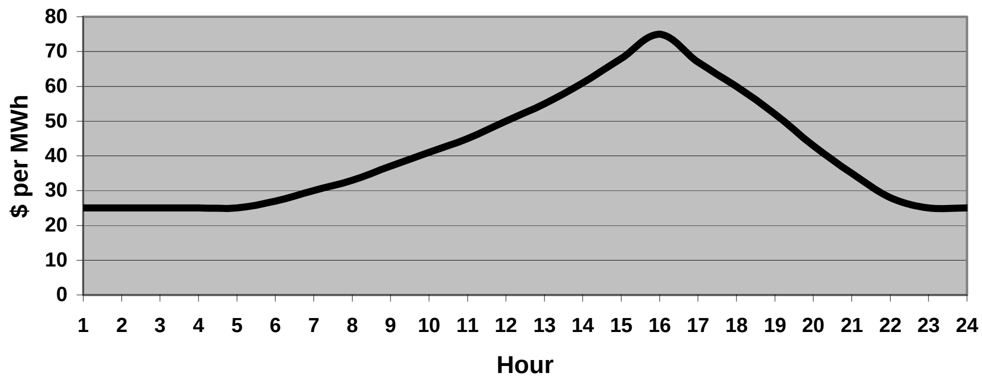


For example, if a plant were to operate only during the hours of the year when the price of electricity was the highest, probably some time in early August, it would sell its power at say $250 per megawatt-hour ("MWh"), as shown above. If the plant were to sell its power only when the price was the lowest, probably some time in May, it would sell its power at say, $25 per MWh (this is lower than the average price at 100%). But if it were to sell its power during the entire year, at a 100% capacity factor, the plant would sell its power at an average selling price of say $35 per MWh. Base load plants would realize an average price closer to $35 per MWh, and peaking plants, closer to the $250 per MWh range. Again, base load plants are built to be run continually, while peaking plants are built to take advantage of peaks.

Wholesale prices vary during the day. During the off-peak hours, generally from about 10 p.m. until 6 a.m. (Hour 22 through Hour 6), demand for electricity is low, and hence, the price is low. This is the period of time when only the least expensive plants to operate provide energy to the market. During the on-peak hours, generally from about 6 a.m. to 10 p.m. (Hour 6 through Hour 22), demand rises, and the price of electricity increases. Chart 2 below shows how price movements vary during a typical day. Again, Chart 2 is hypothetical.

Chart 2

Hourly Price Movements

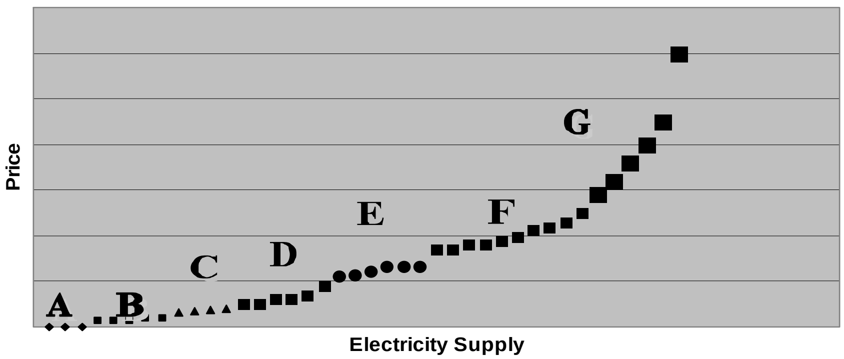


Peaking plants tend to operate when the price of electricity is highest, near Hour 16 in the above chart. The least efficient plants will operate for a very short period of time, while more efficient plants will operate longer, but still during the peak period price hours of the day. New modern peaking plants, typically CTs, can start up and reach maximum production in about 30 minutes; hence, they can "cherry pick" when they operate. Older, less efficient peaking plants, typically old steam plants, must start up earlier because their ramp-up times are usually several hours. Thus, to take advantage of the peak prices, these plants must operate earlier in the day and also later in the day when the price of electricity will not cover their short-run marginal cost. Hence, they actually are not profitable for much of the time when they are running. Sometimes the ISO will compensate the less efficient plants during these time periods with additional sources of revenue. Also, plants may be are compensated every time they start up. A typical hypothetical supply curve is shown in Chart 3.

Referencing the above supply curve, the least expensive plants with the lowest short-run marginal cost are hydroelectric generators, A. These plants have a zero cost of fuel, flowing water, and minimal variable expenses. Their fixed costs are also very low because of a very small workforce. Generally they operate whenever they have water available to rotate their runners (turbine blades). Nuclear plants, B, are the next least expensive to operate. Their cost of fuel is low and their variable expenses are low. While their fixed expenses are very high, that does not affect their short-run marginal cost. The other plants on the supply curve and their order, in cost to operate (low to high), are as follows: coal-fired plants, C; CCGT plants, D; steam plants, E; CT plants, F; and high-cost diesel-fueled plants, G.

Chart 3

Electricity Supply Curve



Electricity production and capacity factors can be forecast by reviewing past performance and the future budgets for the plant. Operating expenses can be projected by reviewing operations over the last three to five years. Future capital expenditures are commonly budgeted by plant management for three-, five-, or ten-year periods. Beyond the budget time period, 2% to 3% of the reproduction cost is necessary for sustaining capital, which is needed to keep the plant in safe operating condition. For nuclear plants, it is especially important to review the decommissioning trust fund and also the decommissioning cost forecast. It is most common to develop a discounted cash flow (“DCF”), rather than just capitalizing one year. Capital expenditure patterns and planned outages vary over multi-year periods such that one year’s data is frequently not stable enough to forecast a normalized income stream, although there can be exceptions. Participants in the market develop after-tax, debt-free cash flow (“free cash flow”) streams that reflect the income level received by equity and debt holders. Depreciation is calculated using the modified accelerated cost recovery system or MACRS tables to reflect the buyer’s new tax basis. Pretax cash flows also can be developed and, at times, can be a meaningful indicator of value.

The discount rate to be applied to the after-tax, debt-free cash flow stream is typically developed utilizing a weighted average cost of capital (“WACC”). This method requires an investigation of publicly traded guideline company stocks to develop a typical capital structure (equity and debt weightings) and beta (volatility or systematic risk inherent in the industry). The capital asset pricing model or the build-up method is used to derive an equity investor’s required return on an investment in the merchant plant electrical power industry.

The equity return must be adjusted for risks inherent in the single plant under valuation and the additional risks of equity ownership, compared with a larger participant in the industry who most likely owns several plants. Additional risk factors, unsystematic risk, must be considered to reflect the additional risks of equity ownership. Because debt cost is also high due to the single plant nature of the investment, higher risk industrial bonds (higher risk but not junk) are utilized. The WACC is then calculated on an after-tax basis and applied to the forecasted cash flow stream.

Caution must be exercised to utilize a capital structure that reflects an investor’s long-term perspective of the industry. During the early 2000s, many publicly traded companies were in bankruptcy and their capital structure did not reflect a long-term perspective because the value of equity had deteriorated. Using a capital structure reflective of these companies would result in a capital structure that is too heavy on debt and would result in an artificially low discount rate. If necessary, the after-tax discount rate derived using the WACC can be converted into a before-tax discount rate by dividing by 1 less the marginal composite tax rate where the composite tax rate = [1- (1 – federal tax rate) x (1 – state tax rate)].

The result of the income analysis is the value of the entire business enterprise associated with the operating plant. To determine the value of the tangible assets alone, a normal level of net working capital is deducted (based on the guideline company analysis, frequently measured as a percent of revenue); in addition, the intangible assets must be valued, then deducted. Intangible assets include, but are not limited to, the trained and assembled workforce and management team, operating manuals and procedures, licenses and permits, PPAs, emission credits, and software. The resulting income indicator of value for the tangible assets includes the real estate comprising land, buildings, and land improvements; and the personal property, both electrical generation equipment units and support assets.

Cost Approach

The final method to be investigated is the cost approach. This approach requires a certain level of knowledge about the economics of the industry and the technology utilized in the industry. To apply the cost approach, the appraiser must calculate the current cost of a plant, the reproduction cost new (an exact replica) and/or a new modern replacement. The difference between the costs is a form of functional obsolescence (loss of value from within the property) due to excess capital costs. The reproduction cost new ("RCN") is typically calculated by trending the original cost to a current cost based on translators derived from the Handy-Whitman Indexes, which are specific indexes developed for the utility industry. An alternative method would be a modeling approach based on published construction cost data or unit costing the entire plant, which is a very time-intensive exercise.

The cost of replacement ("COR") represents the cost of a new modern plant with the same capacity and utility of the subject plant. Such a plant represents current technology from a cost and performance perspective. In the late 1990s and early 2000s, the modern replacement plant was a combined cycle gas turbine ("CCGT") for base load use and a combustion turbine ("CT") plant for peaking use. But now, in the first decade of the 2000s, the price of natural gas has made the use of natural gas-fired plants less economic. They still are being built because they are inexpensive and environmentally friendly, but unless they are included in the rate base of a regulated utility or under contract, they may be uneconomic to operate. Many of the existing CCGT plants that were built for base load operations are now used as peaking plants. Coal-fired or nuclear plants are now being considered as the base-load plant of choice, depending on the plant's location. Several coal-fired plants are under construction in the first decade of the 2000s. Their cost of construction will be very high because of all of the environmental controls included in the design. Several companies have already announced construction of a new nuclear unit, using an already approved NRC standard design, to be built on an existing nuclear plant site. These plants are projected to be in operation within the next ten years.

A deduction from the COR for physical deterioration, based on wear and tear experienced by the property, must be made. This can be calculated based on an age-life relationship of the entire plant, of major component parts of the plant weighted based on the current cost investment in each component, observation, or a combination of the analyses.

Economic obsolescence (a loss of value from an external economic force) also must be investigated. This investigation may include a study of spark spreads or gross margins, inutility, supply/demand relationships, competition, and return on capital; economic obsolescence also can be derived from actual market transactions if appropriate data are available.

The next deduction is another form of functional or operating obsolescence caused by changes in technology. New or different technology frequently results in better control systems, which increase yield and reduces labor and energy requirements; as a result, the new modern plant becomes more valuable. The most frequent difference between an older plant and a new modern plant is reduced operating expenses and a lower heat rate (the ability to convert fuel into electricity). To reflect functional obsolescence due to excess operating expenses or operating obsolescence, an adjustment based on the present value of the after-tax operating expense penalty is made in the cost approach.

The last deduction is a form of both functional and economic obsolescence and sometimes is termed a necessary capital expenditure. Such a capital expense is required by a government agency primarily for environmental reasons. In the case of a coal-fired plant, it is the additional environmental equipment the plant must install to remove various types of emissions, or other types of government-required changes to the plant that do not make the plant larger or more efficient. In fact, most government-required changes tend to make the plant more expensive to operate. For nuclear plants, it is primarily the additional contributions to the decommissioning trust fund. Additional costs could be related to cooling-water environmental concerns related to fish and other water life, or sometimes just temperature changes in the discharge water. Again, based on the capital budget, the present value of these capital costs is deducted.

After all these deductions are made, the value of the land is added after deducting any known and budgeted clean-up costs from the land value as if clean. This typically is not a major deduction, but should be investigated. The result is the cost indicator of value.

Traditionally, appraisal textbooks describe the sequence of deductions in the cost approach, after deriving the current cost of the subject, as first physical, then functional and economic. If all of the deductions are percentage or dollar deductions, the sequence is immaterial; the resultant cost indicator of value will be the same. However, if the deductions are derived in a manner that is a mix of percentage deductions (typically physical deterioration is calculated as a percentage) and dollar amount deductions (typically operating obsolescence is calculated as a dollar amount because it is the present value of an operating expense differential), the percentage deduction must be made first. Economic obsolescence can be a dollar amount or a percentage amount, depending on how it is derived. Functional obsolescence (“FO”) due to excess capital costs is quantified by subtracting the COR from the RCN. Depending on the type of asset and technological changes within the industry, FO could be positive or negative. Deductions in the cost approach must be developed in a logical manner. Following the traditional sequence of physical, functional, and then economic, can lead to an incorrect indicator of value. The appraiser must analyze how the components of the cost approach are developed and then make the deductions in a logical sequence.

Correlation

At this point, three indicators of value have been developed for the subject plant. The value indicated by the sales comparison approach can be a very strong indicator of value because it directly reflects the actions of buyers and sellers in the market. Using even one, two, or three sales gives the appraiser a range of value into which the subject property’s value should fall. Even in a market where few sales are available, the appraiser cannot ignore the market. Of course, the sales must be investigated to ensure the sales data used reflect an electrical generating plant similar to the subject. The sold plants do not have to be exactly the same as the subject, as adjustments will be made to the sale prices; however, they should be as similar as possible. Any other assets, such as PPAs and other nonoperating assets, must be deducted from the sales comparison indicator of value. Because sales of operating plants, actually an operating business, can reflect the investment value of the plant to a particular owner, not a true market value, recognition must be given to the fact that sales prices also can include hidden assets, contracts or agreements, and financing arrangements that may not be public information. In addition, plants that have sold for unusually low or high prices may not reflect a true open market transaction; buyers of operating plants sometimes just want to buy into a market, not only to buy the plant operations.

The income approach, as mentioned above, is the method buyers and sellers rely upon to make a decision. Buyers and sellers make the market; appraisers only reflect that market. In preparation for negotiating a price, participants in the market typically develop several income approaches to develop a range of reasonableness because they cannot forecast the future with any degree of certainty. No one can! Now, appraisers use the results of buyers and sellers in the sales comparison approach and try to imitate their actions by developing an income indicator of value based on projections and an industry-based discount rate. Application of the income approach can be very volatile based on minor changes in the forecast. Although the income approach is a useful valuation tool, it should be supported by either the cost or sales comparison approach to value to increase this approach’s reliability.

The cost approach is especially useful for unique property where sales do not exist and an income approach is not possible. In this approach, the current cost of the property being valued, less all forms of depreciation and obsolescence, plus land value, is developed. One problem, however, is that the appraiser must be knowledgeable of the industry’s economics and technology. Preparing a complete and detailed cost indicator of value is very time consuming, but the cost approach can produce the most subject-specific detail of any of the three indicators of value. Unless they are inserted in the cost indicator of value, working capital and intangible asset values are not included.

When fully developed, the three approaches to value reflect all attributes of the market. The most supportable appraisal, a complete appraisal, utilizes all three indicators of value. In a perfect world, they all support the same value conclusion, or at least a narrow range. All three indicators reflect the market. The market is defined by the actions of buyers and sellers, projections of electricity, fuel prices, operating expenses, future capital investments, the required returns of equity investors, the cost of debt, an industry capital structure, the cost of new modern construction, all forms of depreciation and obsolescence, and industry economics.

When deriving a conclusion from the investigation and analysis of the market, the appraiser must use judgment, experience, and common sense to correlate the final conclusion of value. The conclusion must be based on market indicators. Appraisers don't make the market, appraisers reflect the market, but when the market speaks, appraisers listen.

Michael J. Remsha *is a Vice President and Principal with American Appraisal Associates, Inc., in Milwaukee, Wisconsin. In this capacity, he provides direction and technical support on the valuation of energy, utility, and personal property. He has been a full-time appraiser in the energy sector since 1977.*