LongGen: Determining the Long-Term Outlook for Regional Wholesale Electricity Prices

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Madison, Wisconsin
September, 2005

Introduction

LongGen is a structural model of wholesale electricity markets based on mathematical functions to describe underlying market processes. ***LongGen*** determines future prices for energy and the implied prices for reserves by simulating the demand for and supply of generation services. Hourly electricity prices are estimated for day types of individual months and years. Estimated wholesale prices are projected either for groups of control areas within regions or regions as a whole, though individual control areas can also be modeled.

Structural models are particularly well suited to electricity price projections over long-term timeframes – say, beyond one month.[1] A structural approach can readily capture and embody the major elements of uncertainty contained in wholesale prices. They also provide a means to assess alternative scenarios, and to explore the sensitivity of results to changes in data inputs, assumptions, and model parameters. In the case of electricity, market processes involve hourly variation in electricity demand, the manner in which

[1] The challenge of estimating wholesale electricity prices in forward timeframes can be approached in several ways and it is useful to mention other approaches. In particular, observed prices of forward and futures contracts can be used to estimate spot prices. That is, *expected spot prices* can be inferred from forward prices by applying the equivalency condition:

$$S_t * e^{-\mu * t} = F_t * e^{-r*t}$$

or,

$$S_t = F_t * e^{(\mu - r)*t}$$

That is, the spot price in period t, S_t, is equal to the forward price, F_t, adjusted for the difference between the risk-adjusted and risk-free discount rates, μ and r respectively. The risk-free discount rate reflects the value of time and expected inflation, while the risk-adjusted discount rate reflects time, inflation, and perceptions of risk that attend electricity spot prices. The price of the forward contracts and risk-free interest rates are readily observable for the near term. The risk-adjusted rate harbored by market participants must be estimated, and methods to do so have been developed.

Another approach, *time series methods*, identifies sequential patterns in historical price data, and uses these patterns to extrapolate the price series into the future. A commonly applied approach is known as the auto-regressive moving average model (ARMA). Time series methods are often used in commodity markets, and are frequently used to estimate model parameters for forecasting fuel prices and electricity loads.

generator units are committed and dispatched, the determination of reserves, and the effects of expectations of possible supply outages (scarcity) on price outcomes.

Because the outlook for wholesale electricity prices contains considerable uncertainty, our framework provides the capability to estimate the expected value of wholesale prices, and to explore price uncertainty over long-term timeframes.

Regional Demand for Electric Service

Regional Electricity Loads: Electricity demand is manifested as hourly loads of the region. Hourly loads for day-types are determined from the historical record of hourly loads for the major incumbent electricity service providers of the region. The hourly historical loads for these companies are weather normalized *annually*, while preserving the hourly and daily load variation in order to retain the effects of extreme weather in the analyses.[2]

Once developed, the regional hourly loads are calibrated to match the generation portfolio, which includes all supply-side units of independent power producers, incumbent electric companies, and public companies that reside in the states of the relevant region. These loads together serve as the regional system loads for a baseline year.

Growth in Electricity Demand: Long-term trends in electricity demand are largely determined by trends in economic activity at the national and regional level. Regional economic activity is determined by the historical relationship between the U.S. economy and the states of the region. Given a range of possible growth in U.S. economic activity, long-term regional activity is projected. In turn, growth in regional electricity consumption and peak demand is derived from the historical relationship between the electricity consumption, and economic activity.

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[2] An alternative methodology, which can be referred to as *inferred hourly loads using conditional demand analysis*, is applicable when regional hourly loads are not observed or available. Conditional demand analysis obtains hourly loads for typical days from monthly class energy sales, regional economic activity, and weather data. This method develops regional hourly loads by estimating the relationship between electricity demand and economic activity, electricity prices, and weather conditions with econometric analysis procedures. This approach utilizes the following data, which are available for a representative group of utilities in the region of interest:

- Hourly system loads
- Monthly sales by customer class
- Economic data (annual or quarterly)
- Weather data (daily or hourly)

A two-stage estimation process is used. The first stage determines *average daily consumption* per month by customer class as a function of the economic and weather variables. In the second stage, the average daily consumption generated by the first stage is allocated to hours in such a way as to match the hourly system load. Information on hourly or daily weather conditions is used to assist in the allocation.

Where appropriate, it is also possible to adjust the hourly loads for changes in *marginal retail prices*, if projections of such prices are available.

National economic activity is projected on a basis of labor force and productivity change over the long term time frame, and as specified as parameters. These parameters are determined from recent historical experience, contemporary labor force and national productivity studies, and judgment. The result is future projections of economic activity for the U.S, stated as real gross domestic product. As a general rule, alternative scenarios of economic activity and electricity demand are developed. Future sales levels matters most in the determination of the short-term outlook, as regional generating capacity cannot respond to near-term changes in weather and economic activity, which affect short-term electricity demand.

Regional Supply of Electricity and Reserve Services

Long- and Short-Term Supply: Future supply has both long-term capacity and short-term operating aspects. The determination of capacity involves the estimation of capacity – essentially, capacity additions – and running costs, which is mainly a matter of determining long-term primary fuel prices. The determination of short-term supply involves near-term operating and maintenance decisions, given the installed capacity, unit running costs, and availability. Long- and short-term aspects will be discussed separately, beginning with primary fuel prices.

Primary Fuel Prices: The forecast outlook uses three alternative scenarios of long-term prices of primary fuels, including natural gas, oil, and coal. The scenarios rely upon current forward prices for fuels, and long term trends.

Observed NYMEX settlement prices of a recent month for gas, oil and coal futures contracts for monthly delivery are used to estimate the expected value of the implied spot prices for the months of the immediate two-year outlook. The estimation procedures to determine the implied spot prices are based upon modern finance theory, which describes the implied relationship between forward and spot commodity prices.

Long-term trajectories of natural gas, oil, and coal prices over 2004–2012 are determined as extensions of the long-term trends in real fuel pries including uncertainty, as observed over the 1986–2002 historical period. This historical experience is assessed using time series methods (log percent change).[3] The standard error of the trend variable, following conversion, is used as the basis for the low and high growth price paths.

Current prices of primary fuels particularly coal have reached very high and unsustainable levels, and the clear expectation is that a downward adjustment is in order. The question is with regards to the timing of the adjustment prior to the resumption of the long-term path. The working assumption is that, for the low, moderate, and high fuel price scenarios, the long-term price path will resume in years 2008, 2008, and 2010, respectively. The primary fuel prices for the interim years are obtained with non-linear interpolation.

Natural gas is a special case, in view of the limits of indigenous supply within the continent. Accordingly, the approach is to cap (set) natural gas prices at price estimates of delivered liquid natural gas (LNG) import into the U.S. The LNG import price sets the

[3] It is perhaps useful to mention that, where desired, the time series methods including ARIMA, factor models, and Ornstein-Ohlenbeck are used to determine alternative trajectories of primary fuel prices.

natural gas price in 2008, 2008, and 2010 for the low-, moderate-, and high-growth paths, respectively. The price path for natural gas assumes the long-term historical trend over all years thereafter.

Once estimated, the real prices of primary fuels over future years are converted to nominal dollar terms, using assumed rates of overall inflation for the U.S. economy.[4] Also, regional differences in the costs of primary fuels due to transportation and, in the case of coal, the market value of emissions (SO2 allowance prices) are accounted for. SO2 allowance prices are currently at very high levels (≈$800/ton) in anticipation of enactment of some version of the proposed Clean Air Interstate Rule (CAIR), and as a result of transport constraints regarding Power River Basin coal. In addition, the costs of environmental compliance for NOx, mercury and potential CO2 limits are accounted for.[5]

Generating Capacity Additions: Generator capacity in future years is determined by balancing scenarios of regional supply and demand in future years. The working assumption is that the inherent market incentives, as represented by expected market prices for electricity, will perturb sufficient new generation supply to obtain 15% capacity-based reserves in the region.

The procedures to estimate reserve needs – and thus capacity additions – begins with estimates of future peak load and energy demand over the future years as discussed above. Once the long-term scenarios of peak demand and energy are selected, sufficient new generating units are added to the regional generation portfolio to satisfy peak demand and reserves, at pre-defined planning reserve levels. For the near-term years, however, current capacity and expected unit additions roughly satisfy electricity demand and reserve needs.

Generation Technology Mix: The estimation of generation mix in future years begins by determining hourly loads (MWs) to be served by non-nuclear and non-hydro generating technologies in the region. These loads are obtained by decrementing future regional loads (electricity demands) for expected nuclear and hydro output (MWs) in the region. The result is the relevant load shape, consisting of 8760 hourly loads in future years, to be served by technologies of the generation choice set, which consists of fossil steam and non-steam technologies including, as a matter of assignment, pulverized coal, fluidized bed coal, combined cycle gas, and simple cycle gas generating units.

A constrained optimal mix to serve fossil steam and non-steam loads is then determined for the years 2006 – forward based upon a corollary to long-run marginal costing. Essentially, workably competitive prices should approach long-run marginal cost and

[4] The rate of overall inflation is determined by monetary policy exercised by the Federal Reserve. Monetary policy has been remarkably well disciplined in recent years, and has contributed to the stable prices enjoyed since the early 1990s. The analyses implicitly expect the current policy to be sustained indefinitely.

In view of the sizable current and projected deficits of the federal governments, risks of higher inflation are nevertheless present. Indeed, history suggests that the short-term political burden of large deficits can foster and encourage central banks to monetize debt used to finance current deficits. In turn, debt monetization inherently advances money supply thus increasing the overall price level.

[5] Should the U.S. adopt standards for CO2 emissions, it is likely that such limits would be implemented through so-called Cap and Trade programs, which have increasingly wide support.

give rise to the least-cost resource employment mix, given the resource costs of the technologies of the choice set. Resource costs include the annual costs for carrying charges on investment and non-fuel O&M expenses, and the running costs during hours of dispatch for each of the technologies of the choice set.

The long-run marginal cost studies determine the breakeven running hours for the choice set. Technologies of the set are then added to the current mix in proportions that give rise to a so-called constrained least-cost generation supply for the region as a whole.

Natural gas units have dominated unit additions in recent years. In view of the high prices and supply limits of natural gas, however, there is renewed interest in coal, particularly advanced coal including fluidized bed and integrated gas combined cycle technologies. Accordingly, the simulations suggest that a significant share of the new units will be coal-based technologies, for most regions.[6]

Short-Term Supply: Once determined, installed capacity of each year of the valuation period serves as the basis to estimate short-term supply. Essentially, ***LongGen*** determines the effective MWs of operating capacity by simulating maintenance, unit commitment, and unit availability.

Maintenance Status: Maintenance is determined by random unforced outages of units. ***LongGen's*** model procedures cannot identify for sure which individual units will be down in future periods. However, ***LongGen*** can simulate maintenance for the region as a whole based on the likelihood that the generators of various technologies are in unforced outage states for maintenance. The maintenance modeling procedures are based upon Monte Carlo methods and are applied seasonally.[7] The result is the determination of maintenance status by season and year, which defines the units available for commitment.

Unit Commitment Process: Once the maintenance status is determined, ***LongGen*** then simulates a merit order unit commit process for non-hydro and non-nuclear generating units in the region based upon the capacity needs to satisfy expected peak demands and operating reserve requirements. The unit commitment procedure determines the commitment status of units, and is performed for individual months of each simulation year.

Unit Availability, Short-Run Supply, and Cost Function: Once committed units have been determined, ***LongGen*** then determines the availability of units. Forced outages of units, or unit availability, are determined with Monte Carlo methods. This procedure determines availability status. The output of available units is then ranked by ***LongGen*** according to the unit's marginal running costs (merit order) and dispatched to satisfy hourly loads. Essentially, the ranked output of units determines the short run cost function of the region. Maintenance units, committed units, available units, and thus the generation cost function over the numerous future time steps of the valuation timeframe

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[6] It appears likely that renewable resources including at least five technology types will play a progressively larger role in future generation nationwide, particularly in the Northeast, Midwest, and the West. Renewable resources can be incorporated into the wholesale outlook as scenarios.

[7] The seasonal maintenance parameters used in these analyses are not fully calibrated, and need to be rebalanced across seasons. Specifically, the current parameters are high during the fall season, and somewhat low during other seasons.

cannot be known. Hence, ***LongGen*** simulates a *set* of possible operational merit order cost function for the region, for each timeframe.

Reserve Services: The methodology presumes that regional wholesale power markets will, over the long term, evolve toward competitive market arrangements for both energy and reserve services. This approach, however, is consistent with either an *explicit regional market for reserves,* or for an *internal least-cost* commitment and dispatch of generators.

An *explicit market* for reserves assumes that individual generators bid prices and quantities within markets for generation services, including energy and reserves, in a manner that maximizes the expected profits obtained from participation in these markets. *Internal least-cost*, on the other hand, presumes that the system operators of control areas commit generators in a manner that jointly meet energy and reserve needs at the least total system cost.

These two conceptual approaches to reserve markets are *duals* and therefore imply the same outcome. That is, the actions of profit-maximizing individual generators obtain market prices for reserves that are equivalent to the marginal costs of reserves for a total cost-minimizing system.

Reserve prices are determined using linear programming (LP) analysis. The LP analysis simultaneously solves for a set of energy and reserve prices over a range of demand and supply conditions. The analysis begins by determining the requirements for regulation, spinning, non-spinning, and backup reserve categories. The requirement for each category is defined in terms of a percentage of the expected demand over the commitment period. The total reserves provided by the four categories are aligned with the region's reserve requirements, as discussed above.

The LP analysis requires unit running costs, generator unit operating parameters, demand levels, and regional capacity stacks as inputs. Numerous generator capacity stacks are obtained from the Generation Dispatch Module. Roughly 1200 LP runs are conducted for each region.

The LP analyses are evaluated with regression analysis procedures, the results of which are embodied within the generation supply model as input parameters for modeling reserves. The end result is projections of wholesale prices *with uncertainty* for energy and reserve services over long time horizons. The LP analysis has been conducted for the ECAR, MAAC, and SERC regions of the Eastern Interconnection although the analyses herein utilize the parameters of the ECAR region.

Scarcity Rents: Market evidence suggests that, under conditions of tight supply, wholesale prices do not necessarily clear at a level equivalent to marginal energy cost. Under these conditions, prices reflect uncertainty of supply continuity and market imperfections, and prices may reach levels substantially above the marginal costs of energy and reserve services. Our approach draws upon the historical record to obtain estimates of the so-called *scarcity rent content* within wholesale prices, and incorporates scarcity into wholesale price forecasts.

Market context is important. Specifically, perfectly competitive markets obtain prices equal to the marginal costs of supply. While the notion of perfectly competitive markets has its attractions, numerous technical, institutional, and behavioral factors impede markets from achieving this idealized state. It is more useful to judge the condition of markets by a more relaxed benchmark, which can be loosely identified as a *workably competitive standard*. Workably competitive markets can be described as those which:

1) present market participants with incentives that move prices toward marginal costs;
2) contain no major institutional impediments to entry and exist;
3) obtain prices that, over the long term, approach the marginal costs of supply; and
4) preclude the sustained and systematic deviation of prices from marginal costs.

Arguably, wholesale markets for generation services within the Eastern Interconnection meet the workably competitive standard *much of the time,* though market imperfections in the form of exercised market power, inefficient use of scarce transmission capacity, and inefficient price discovery processes persist. Generally, we characterize this vast region as a market wherein:

1) wholesale prices for power follow the pattern of marginal supply costs;
2) new supply can readily enter the market; and
3) prices reflect the balance of demand and supply, with very high prices reflecting *scarcity rents* during tight conditions.

Scarcity rent is the component of price that ensures balance between supply and demand under rather tight market conditions. Scarcity rents, and the relative magnitude of them, are short-run market phenomena that can be incorporated into the outlook for prices. Over time, the historical presence of scarcity *builds expectations of future rents* that, in turn, precipitate new supply. That a surge in new supply follows shortly after a period of previously unobserved high and volatile prices with significant scarcity content suggests that high prices cannot be sustained. Market concentration notwithstanding, high prices beget their own demise as scarcity, in the long term, is mitigated by additional supply.

Scarcity rents can be modeled in two ways. First, estimates of scarcity can be endogenized directly within our generation model as a function of operating reserves, which generally reflect the condition of *tightness* of market supply and demand.

Second, the *scarcity content* of observed historical wholesale market prices under various market conditions can be simulated. Estimates of daily peak-period rents can then be mapped to simulations of future market conditions (tightness), and added to the estimates of energy and reserve prices for those conditions.

This latter method is the approach currently taken. In recent studies, scarcity rents are simulated for the various day types, months, and seasons over the 1999 – 2000 timeframe. The daily rents, as estimated, are the difference ($/MWh) between day-ahead block forward electricity prices, as observed for regional hubs, and simulations of marginal running costs for the sixteen-hour block.[8] The result of the historical assessment is a range of estimated daily rents for each of the weekday day types.

[8] Let the simulation of the marginal running cost-based energy price in hour *h* on day *d* be represented by P_{dh}, the block forward price be BP_d ,and the average running cost-based price over the same block forward

The historical analysis also determines the supply-demand balance condition of each of the individual as described by γ, a coefficient measuring supply-demand tightness, or margin. The relationship between the simulated daily rents and market conditions (γ) is then assessed with statistical methods.

Supply-demand conditions and γ values are simulated for future timeframes. The historical relationship, as identified by the statistical assessment, is then used to estimate daily scarcity rents over future periods, conditional upon simulated conditions (γ).

Hourly scarcity rents are derived from the daily rents and *assigned* to the simulated hourly marginal running cost-based energy and reserve service prices over future timeframes. The hourly allocation approach is based upon a max function methodology. Let the scarcity component, SP_{dh}, in hour h on day d be defined as,

$$SP_{dh} = Diff \; * \max [0, P_{dh} - \alpha p_d]^{\beta} / \Sigma_{h\in BF} \; \max [0, P_{dh} - \alpha p_d]^{\beta} \quad \text{with } \beta > 0$$

where p_d is the maximum marginal running cost-based hourly price in the block forward interval (peak period), with,

$$p_d = \max_{h\in BF} [P_{dh}]$$

Here, α is a parameter between zero and one, and β is a power that should be greater than zero. Recent analyses have employed parameter values of $\alpha = 0.30$, and $\beta = 1.50$.

Finally, the *shaped* scarcity component, SP_{dh}, is added to the simulated marginal running cost to obtain a so-called *inclusive price*, P^*_{dh}, for day type d and hour h defined as,.

$$P^*_{dh} = SP_{dh} + P_{dh}$$

In general, lower parameters for α and higher parameters for β tend to narrow the allocation of daily scarcity rents to peak hours of wholesale electricity prices, as simulated. The scarcity rent content in prices is calibrated to the regional day-ahead forwards for the 2003 and 2004 through August, as observed for Into Southern and the FRCC regions.

Determining Wholesale Electricity Prices

Projections of wholesale prices for generation services are simulated over a range of possible future supply and demand conditions. The *range of future wholesale prices* are determined by observing the set of price points at which projected demands intersect the set of supply functions, as obtained from the generation dispatch module. If, for example, a forecast run incorporates fifty simulations of supply (iterations), a set of fifty prices for each demand level – *i.e.,* hourly load – is obtained. In this manner, a *range* of wholesale prices is determined for each of the 24 hourly demands, for each day type, season, and year.

The *expected value of wholesale price* for each demand level is obtained by averaging the estimated price outcomes. The prices are reported for each load level, day type, month,

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hours be described as $AP_d = \Sigma_{h\in BF} P_{dh} / 16$. Then, the difference between average running cost and the block forward price is defined as,

$$Diff = 16*(BP_d - AP_d) = 16*\Sigma_{h\in BF} (BP_d - P_{dh})$$

and year. Because the model approach simulates a range of possible supply and demand scenarios, much of the uncertainty attending future prices can thus be captured.

The reporting capability provides the standard deviation, the maximum, and the expected value of simulated prices for each hourly demand level. Price profiles for the various day types and seasons are obtained. Also, the model approach can provide hourly price profiles for annual periods.

Data Inputs, Assumptions, and Model Parameters

Both approaches will require substantial but readily available data, as follows:

- hourly system loads; [9]
- generation data parameters including heat rates;[10]
- assumptions regarding long-term reserves *if* new generation is not modeled;
- projections of new generation additions (and retirements);[11]
- parameters of primary fuel prices, by fuel type;[12]
- environmental compliance cost parameters and limits;[9]
- weather data;[9]
- where applicable, price response coefficients for general categories of retail market segments;[13] and,
- wind output response parameters and functions (for wind generation).[9]

Though substantial, virtually all of these inputs are readily available within the public domain, or can be estimated directly from public data.

[9] These data are available within the public domain.

[10] Much though not all parameters for generators is within the public domain. However, some parameters such as the output of hydro units must be determined through reasonable assumption. Hydro units can be modeled according to the principles foregone value of resource use, or ad hoc schedules. The approach taken herein is the latter.

[11] For long-term market assessments, new source generation can be endogenized into ***LongGen*** using a rational expectations approach, though it is complicated to model.

[12] Trends in primary fuel prices are available in the public domain, or can be developed from historical data. Christensen Associates has available primary fuel price data, as developed for regions using two approaches: Ornstein-Ohlenbeck techniques and time series.

[13] If the impacts of demand response are incorporated into the analyses, price response coefficients (demand elasticities) are needed. Christensen Associates has extensive experience in the empirical estimation of electricity demand and demand response. Reasonable values can be provided if needed.