Deregulating into Permanent Boom and Bust: Prospects for the Electric Power Industry*

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Abstract

The wholesale power industry is in glut in many regions in the US, and will be for several years. Deregulation of the late 1990s changed the decision-making within the power markets, specifically on when to construct (and stop construction of) power generation plants. Not only did deregulation trigger the boom in construction, which created today's glut, but the current regulatory regimes have made the electricity market far more cyclical going forward. Simulations and logic both indicate that another round of shortage, overbuilding and glut will follow the current glut, with some types of earlier recoveries leading to more extreme overbuilding than the last episode. Investors who view the market as cyclical will a) not wait for firm prices before initiating more capacity construction (since prices are a lagging indicator of capacity investment opportunity) and b) not rely solely on industry standard models (which do not fully anticipate disequilibrium and market cycles). Regulators have both a responsibility and an apparently limited window of opportunity to implement market changes to stabilize the market.

Keywords—electricity market, power generation, boom and bust, cyclical commodities, disequilibrium dynamics, glut

Contents

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1. Introduction: Enduring glut, but then what?

It has become a cliché to say that the wholesale electric power industry is in turmoil. Following the Federal Energy Policy Act legislation of 1992, several state legislatures compelled varying degrees of divestiture, and utilities within these states separated themselves from their power generation plants. Shortages of generation capacity (whose origins will be discussed below) then boosted wholesale electricity prices around the turn of the century, most notably in California (in combination with weather and natural gas abnormalities). But in 2001 through 2003, a glut of new capacity has arrived, prices are severely depressed, and bankruptcies and forced asset sales are looming.

What does the future hold? Unlikely as it may seem, among the clearest paths to understanding the situation is in essence to start in the middle of the story: where we are now and the "extrapolatable" future—what we can see by extrapolating from where we are now. Then we can look back to see the underlying causes—including how deregulation changed the underlying rules of the game and resulting market behaviors. Armed with that understanding, we can look further forward, out beyond straightforward extrapolation from the present. In the approximate words of Winston Churchill, "the further back you look, the further forward you can look."

There is still some wishful thinking on when conditions will clear up. Generating equipment makers can look abroad to hope to sell more turbines and generators, to China for a surge of demand, or to Europe to replace hypothetically-retiring coal plants. Then there is the school of thought that "if it takes us two years to get into trouble, they should clear up in not much more than that."

Unfortunately, this logic is quite wrong. It did take only a few years to build more power plants, but those plants will be around for decades. Retiring them, and making no money at all from them, is seldom an option.[1] The big question is how many years it will take for normal demand growth to soak up the excess capacity.

The range of answers is not encouraging. For illustration, we can examine US figures. Even though the US market comprises distinctly different regional markets, the aggregate figures are broadly representative.[2] Figure 1 shows North American Electric Reliability Council (NERC 2003) historical data and (starting 2002) forecasts for US Summer generating capacity[3] and peak demand plus a (15 percent) reserve margin.[4] By regulation, custom, and prudence, generating capacity is supposed to exceed expected peak demand by a reserve requirement, which varies state to state, market to market, and in some cases, city to city. To cut through the details, we have increased the peak demand numbers by a reserve margin 15 percent, which is a fairly typical planning margin.

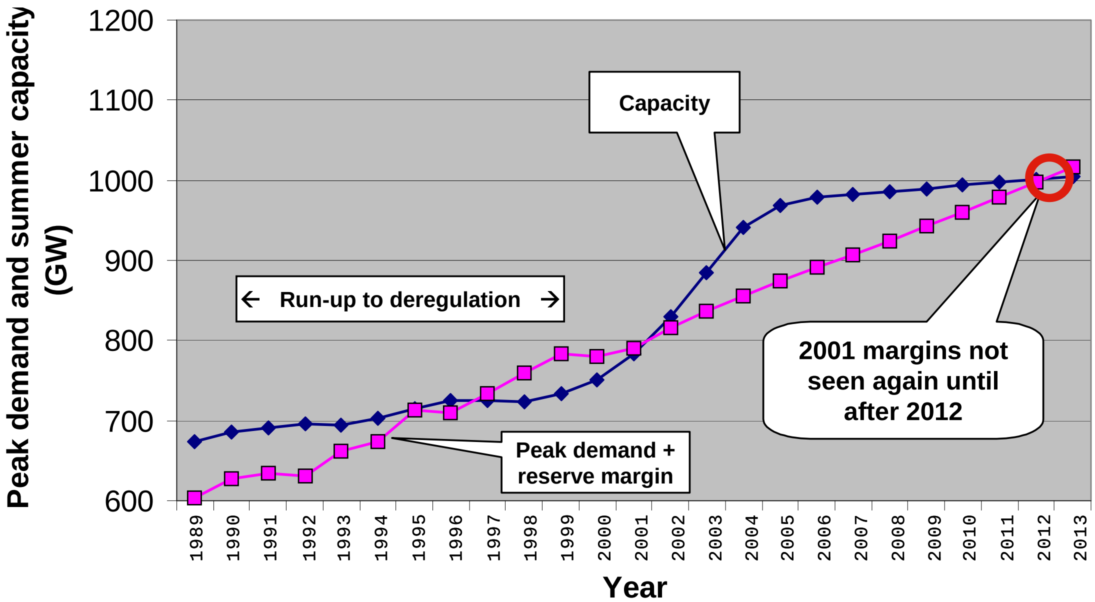

Figure 1. Industry-standard data and forecasts for capacity and peak demand (from NERC 2003)

Despite the current capacity excess, capacity continues to grow faster than demand for 2004 through 2006. This largely represents completion of plants already committed and under construction before the current glut became compellingly clear, plus plants going into locations isolated by transmission constraints and thus in need of further construction even amidst general excess capacity.

After about 2006, very few capacity additions happen, and demand begins to catch up to the supply. But the lines do not cross (representing a return to the reserve margins present in 2001) until the year 2012. At an annual growth rate of only 2 percent per year, it takes many years to work through the present capacity excess.

Figure 2 provides another view of the historic data and forecasts, explicitly showing the reserve margin of the Summer generating capacity over the peak demand. Demand growth generally outpaced capacity construction over the entire period during which deregulation was being debated, defined and implemented. This caused falling reserve margins, reaching a low point in 1999, representing significant capacity shortage, and thus vulnerability to shocks and high prices from fuel prices or weather-driven demand, which is indeed what happened in 1999. But deregulation permitted price and profit incentives to create a wave of new capacity coming on line. Reserve margins are forecast to triple almost from 1999 to 2005. The years of declining reserve margins result from demand gradually growing up into the standing capacity. By these numbers, it will not be until after 2012 that reserve margins (and profitability of operating generating plants) can return to 2001-like conditions.

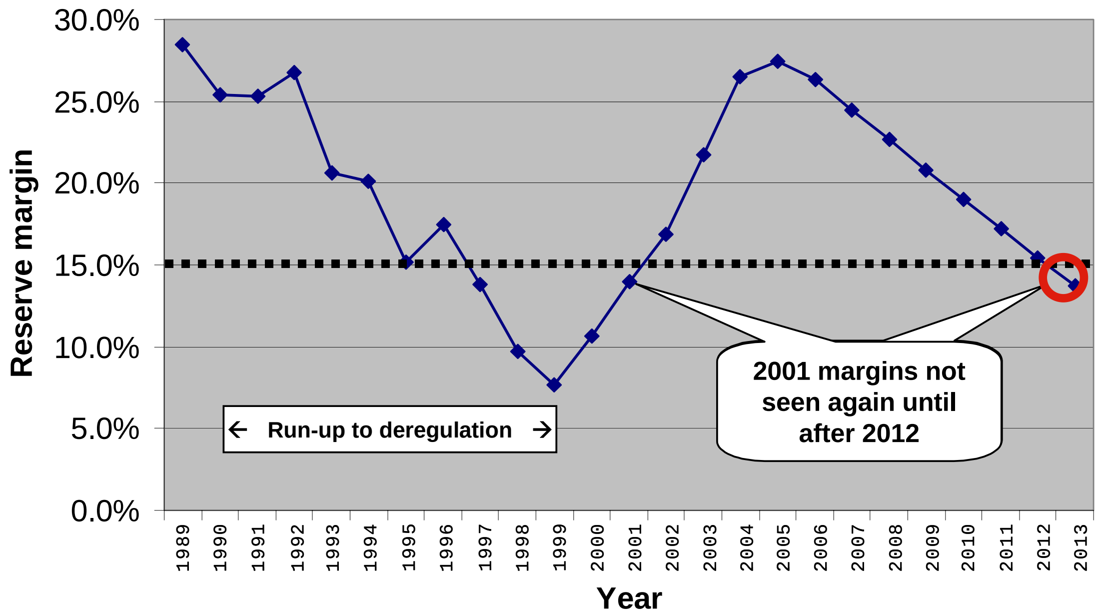

Figure 2. Reserve margins computed from NERC data and (for 2002 on) forecasts.

But what of the uncertainties? The continuing addition of generating capacity may be regarded as pessimistic. Figure 3 shows the capacity and demand figures for 2001 and beyond, overlaying by a line representing capacity, on the assumption that no net growth at all happens after 2004. So even if some construction projects go on line after 2004, they are assumed to be exactly balanced by retirements. Making this assumption does move the data at which 2001 margins return from after 2012 to 2009 (i.e. when the capacity line next crosses the demand-plus-reserves line), which still implies several hard years of glut.

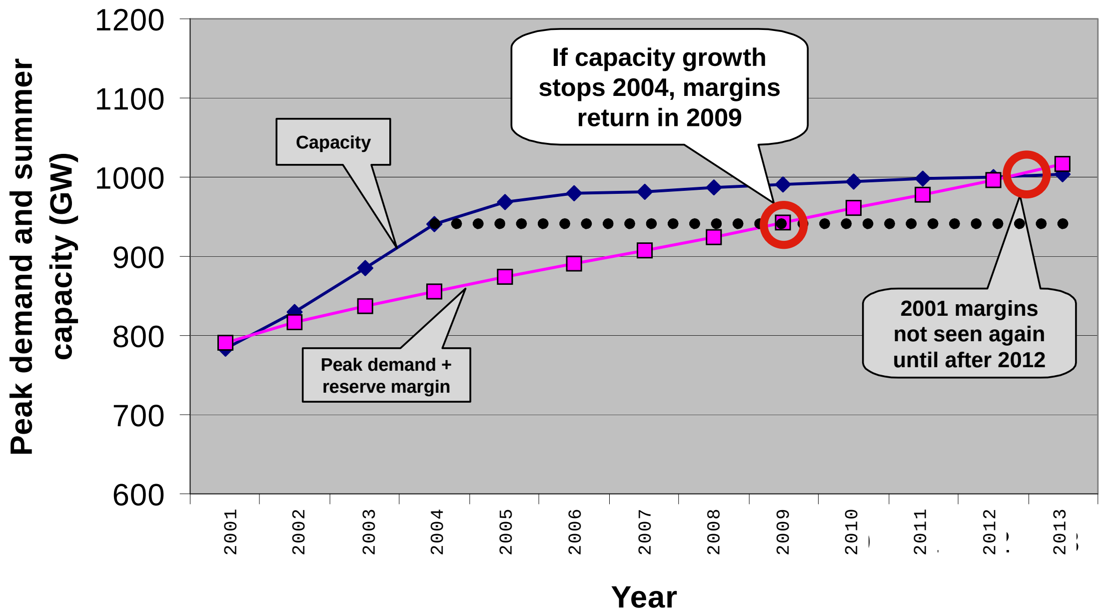

Figure 3. NERC forecasts (with 2001 actuals) for summer capacity and peak demand plus reserve margins, overlaid with more a optimistic assumption for capacity.

Figure 4 adds a similar exercise for assumptions about demand growth. In addition to the roughly 2 percent annual growth rate shown in Figure 3, Figure 4 adds an alternative curve growing 3 percent per year, from the 2001 actual value. This is a growth rate rarely equaled even in unusual sub-regions, and so represents a distinctly optimistic assumption. Increasing the assumed demand growth rate moves the return of 2001 margins from after 2012 to 2009.

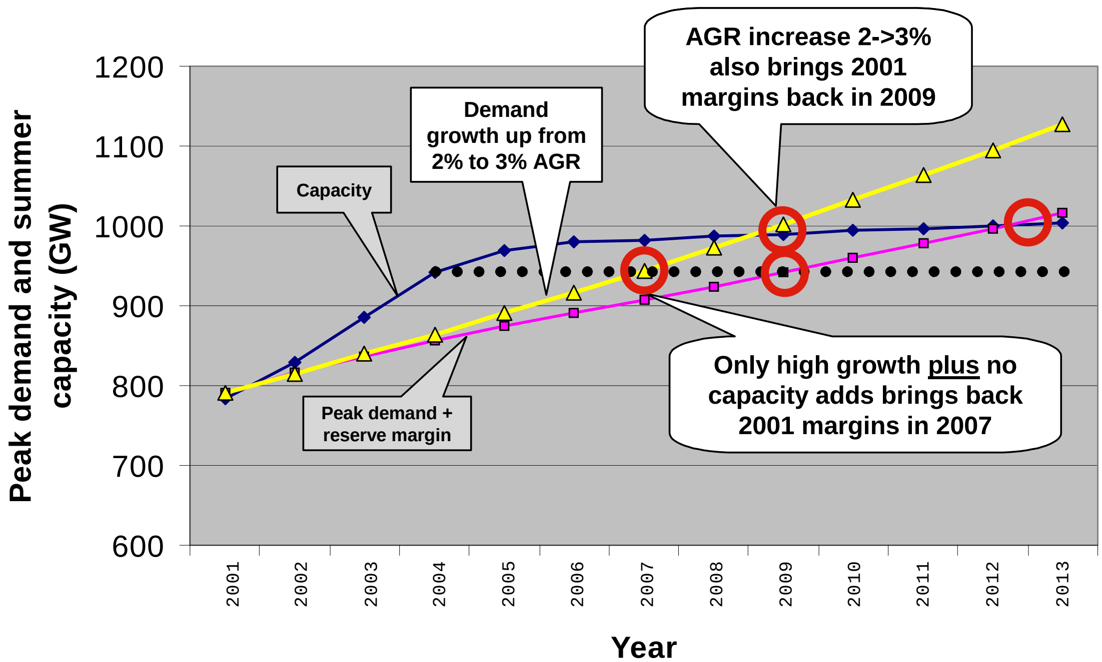

Figure 4. NERC forecasts (with 2001 actuals) for summer capacity and peak demand plus reserve margins , overlaid with more optimistic assumptions for both capacity and demand growth.

If one makes the doubly-optimistic assumptions both that capacity growth will cease utterly, and that demand will grow well above historical expectations, then the return of 2001's roughly 15 percent reserve margins moves earlier still, but only to 2007. So barring a truly extraordinary set of events (for example a combination of both significant retirement of coal plants due to environmental regulation and economic growth well beyond that of the 1990s), very few events could substantially reduce the capacity glut and the attendant depressed prices and cash flows any faster than 4 years. 4 years is the very optimistic number indeed. In brief, the wishful thinking is wrong, and the realistic thinkers and pessimists are correct; US power markets will be in glut for several more years.

But for planning power generation, even if only a marginal possibility, 4 years in advance is well within an appropriate and responsible lead-time to plan for dealing with the end of the glut. There are several major questions that need to be answered:

- What caused the run-up in prices and overbuilding? Was it inexperience in newly-deregulated markets, or a transient effect from the change in regulations, never to happen again? Or has deregulation changed the game permanently?
- Will the glut end with a "soft landing", prices reasonably stable around a moderate value, or can we anticipate another price run-up?

- What can players in the wholesale power do about the situation? How should they approach strategy questions under the new regulatory regime?

To address such questions, we created a dynamic simulation model. That model (described in the Appendix) represents operation of power markets and investment in power generation in specific regions in the US. We both involved industry experts extensively and tested this model against data for several regions, simulating both pre- and post-deregulation decision-making and market behavior. We believe it to be a well-tested theory of short-, medium- and long-term power market behavior, and of regulatory impact on that behavior. The model provided a test-bed for answering these questions. To begin building answers, we look first at how deregulation impacted decision-making and thus the events of the 1990s and early 2000s. In the discussion that follows, we will use data and simulations for the PJM (Pennsylvania / New Jersey / Maryland) region. That region represents a middle-ground in the impact of deregulation, having shown neither the largest nor the smallest market fluctuations.

2. Why did the current cycle happen?

Deregulation shifted electricity generation away from regulated monopoly toward competitive markets, transforming electricity from a regulated utility with a single provider to a commodity with multiple providers. In so doing, the electricity generation industry has gone from a relatively stable industry to one that is much more likely to lurch from boom to bust and back. To see why this has happened, we must examine deregulation and its impact on decision-making, particularly on decisions to invest in generating capacity.

2.1. Deregulation changed the rules, the players, and thus the decision-making

Three facets of wholesale power deregulation underlie the boom-bust behavior to be examined: 1) the uncertainty for investors that derived from the years-long process of deciding to deregulate, 2) the entrance of multiple generators in a given geographic market and 3) the creation of energy markets where participants could price electricity on a competitive basis. These interact to change decision-making in four ways:

Uncertainty prior to deregulation created a need to build. The former regulatory regime provided electric utilities with a geographic monopoly, with an obligation to serve regional users in exchange for a regulated rate of return on invested capital. Utilities built new plants to meet projected needs. When these new plants began generating, the cost of the plant plus the regulated rate of return went into the retail rate base, setting a retail price that guaranteed the utility a profit on invested capital. Operational costs such as fuel, operations and maintenance, and taxes were passed through to consumers in the retail rates. Regulators required utilities to demonstrate a need prior to including a plant in the rate base, but the basic construct was to encourage utilities to build adequate capacity to reliably meet regional needs.

During much of the 1990s, important details of deregulation were unclear. Discussions at the US Federal level culminated in the Energy Policy Act of 1992, but state regulation and organization of markets took years more—for example, the PJM market wasn't fully operational until 1999. Prior to finalization of deregulation schemes, what the utilities knew was that they may be required to divest or separately manage their generating assets. Whether or not generating assets would be part of the rate base, and whether utilities could recoup their investment through regulated retail prices was uncertain. Some state regulators in fact told utilities that new plants would not be included in the rate base. Under such circumstances, it would be imprudent to construct new power plants, and many utilities avoided construction, even in the face of impending electricity needs. So by the time the deregulation regime was defined and implemented, there was a built-in need to build more power plants within the coming few years, simply to catch-up with the demand growth that had continued to advance during those years of uncertainty.

Requirement for profits makes the "build" signal come later. In the regulated regime, utilities built power plants when a need was forecast between future capacity and future demand. Prices (from merchant generators who accounted for a small fraction of total capacity) didn't much matter to the construction decision. Utilities built to serve future need, and costs went into the rate base.

Deregulation opened electricity generation to market competition. Regional wholesale markets were created to provide a place and means for trading electricity products and services and for clearing supply and demand.[5] Generator profitability became a function of expected market price and production costs, instead of the former guaranteed return on invested capital. New investment was opened to all comers; and price and profits became the signal for entry to or exit from the market place. But note that higher prices happen when *current* demand is too close to *current* capacity.[6] By comparison to the regulated period, the (price) signal for "start building capacity now" arrives several years later than the (forecasted capacity gap) signal once did. Both price and operating (utilization) forecast are usually anchored in current and recent market and operational behavior. When prices were high in 1999, 2000, and 2001, developers tended to forecast prices to continue being high. Twenty-year volatility forecasts were commonly based on 1999 and 2000 volatility activity without accounting for future changes in the supply and demand balance. Expectations on future capacity utilization factors are also commonly based on current and recent activity by plants with similar characteristics.

Although the market structure has changed, the process of developing power plants remains much the same. Power plants are large, long-lived capital assets. Asset life ranges from 20 to 100 years; construction costs range from $300 to $1500 per kilowatt built, depending on the type of facility. It typically takes 1 to 3 years to site, permit and finance a project and from 1 to 3 years to construct. So deregulation has created an imbalance, where only immediate need motivates construction, but construction still has substantial lead times before new capacity can meet the need.

Market pricing makes the "build" signal louder. Prior to deregulation, utilities commonly contracted with other utilities or independent power producers to buy and sell electricity. However, prices were generally cost plus a small markup. In a regulated environment, excessive profits from energy sales were generally returned to consumers via rate discounts. High prices and profits were rare, and there was little incentive for utilities to sell power in the wholesale market on a competitive basis.

Deregulation created energy and capacity markets where buyers and sellers could trade energy and capacity at competitive prices to match supply and demand.[7] The ability to set prices based on supply and demand allowed generators to command a premium when supply was tight. Since generation supply was generally tight around the country when deregulation was first implemented, prices tended to reach historical highs when loads were high. Since electricity is generated and sold on a real time basis, price across the day and from season to season recorded unprecedented levels of volatility the first years of deregulation. This sent extended price/profit signals to developers until new capacity could be brought through the development pipeline.

Prices and opportunities for optimism make the "stop building" signal weaker and later. As regulated monopolies, utilities prior to deregulation had complete knowledge and control of power plant construction in their region. The utility knew what plants were being constructed and which ones would finish when. Apart from incorrect demand forecasts and possibly construction problems, there was almost no possibility of over-building.

Deregulation changed the picture. No longer was a single entity planning for and providing generation in a single market. Now multiple players were competing in the same market with potentially overlapping market share goals and less than perfect knowledge about the regions development activity (and hence future capacity). Even though information about announced plants and plants actually under construction was available to all, lack of confident knowledge of other player's plans created opportunities for optimism. If one assumed that many older plants would retire, or that a competitor wouldn't really complete an announced plant, then starting another plant could be considered acceptable, even when the raw figures showed an impending capacity glut.

Moreover, if prices and profits remain high while the boom of construction is making its way through the construction pipeline, developers are balancing a lack of future need for generating capacity against clear evidence that building capacity is very profitable. And as long as plants are profitable, should one really care about load forecasts? In the words of one executive we interviewed, people were making "the maximally optimistic defensible assumptions".

To some extent, the new market rules created new roles and incentives that amplified the need to make optimistic assumptions. Major organizations would now be judged, not on their service to the public, but in major part on the volume of their deal flow.

Of course, all of this doesn't mean that developers don't eventually decide that enough is enough. But in typical deregulated markets, the "stop building" signals become fully effective only when a capacity glut has become obvious—when it is inevitable.

To summarize, deregulation changed the rules and the players, and thus the decisions in four key ways:

1. Uncertainty prior to deregulation created a need to build
2. Requirement for profits makes the "build" signal come later
3. Market pricing makes the "build" signal louder
4. Prices and opportunities for optimism make the "stop building" signal weaker and later

With this background, we can now examine the history of how such decision-making impacted market behavior—the root causes for the present state of affairs.

2.2. Decisions play out to create boom and bust: The PJM example

The stage for the recent boom was set by the deregulation process itself. As discussion of deregulation began and progressed in the early to mid 1990s, power plant construction in many parts of the country came to a virtual halt. Figure 5 shows power plant capacity for the PJM region, which grew less than 1 % between 1994 and 1998; peak load growth exceeded 5% for the same time period. Interviews with industry executives indicated that utilities and independent power producers were hesitant to invest in new capacity while the market rules (and even deregulation itself) were an uncertainty.

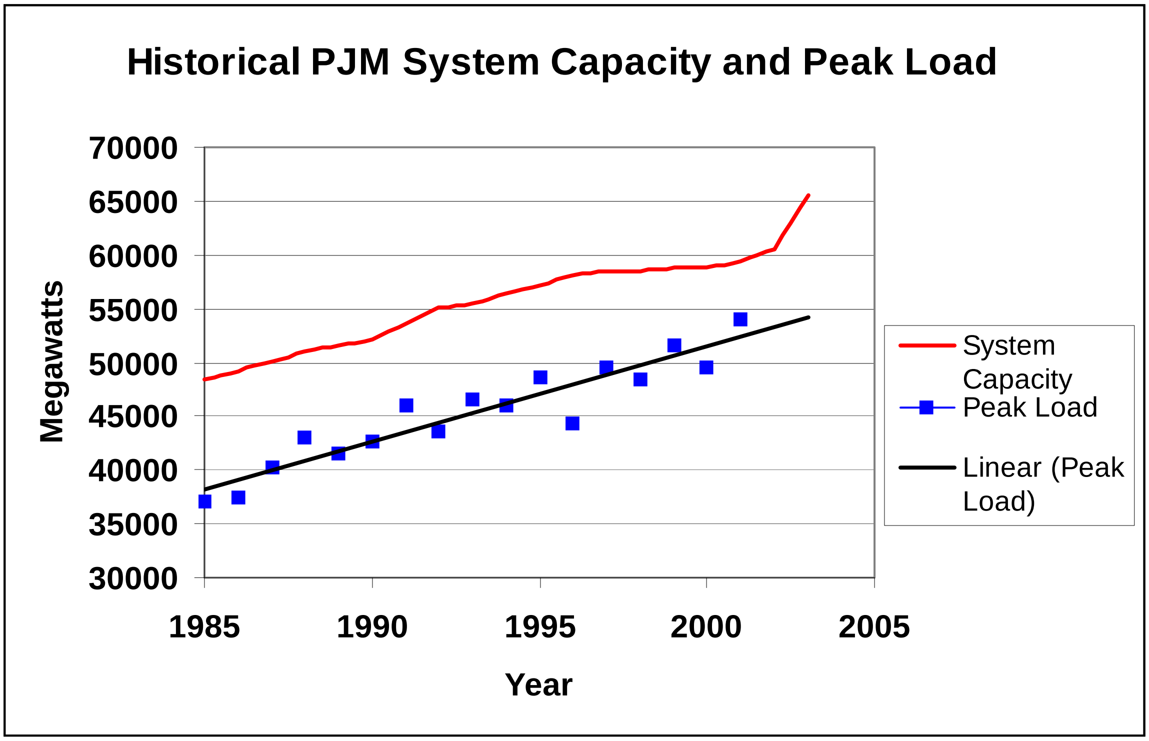

Figure 5. PJM capacity and peak load from 1985 thru 2002

This dearth of generation investment in the years prior to the formation of competitive wholesale markets meant that as the first markets were formed in 1999, reserve margins (excess capacity required for system reliability) were very tight around the country. Figure 6 shows reserve margins for PJM. As the new electricity market began, a real need for additional generation capacity existed and the stage was set for the boom soon to come.

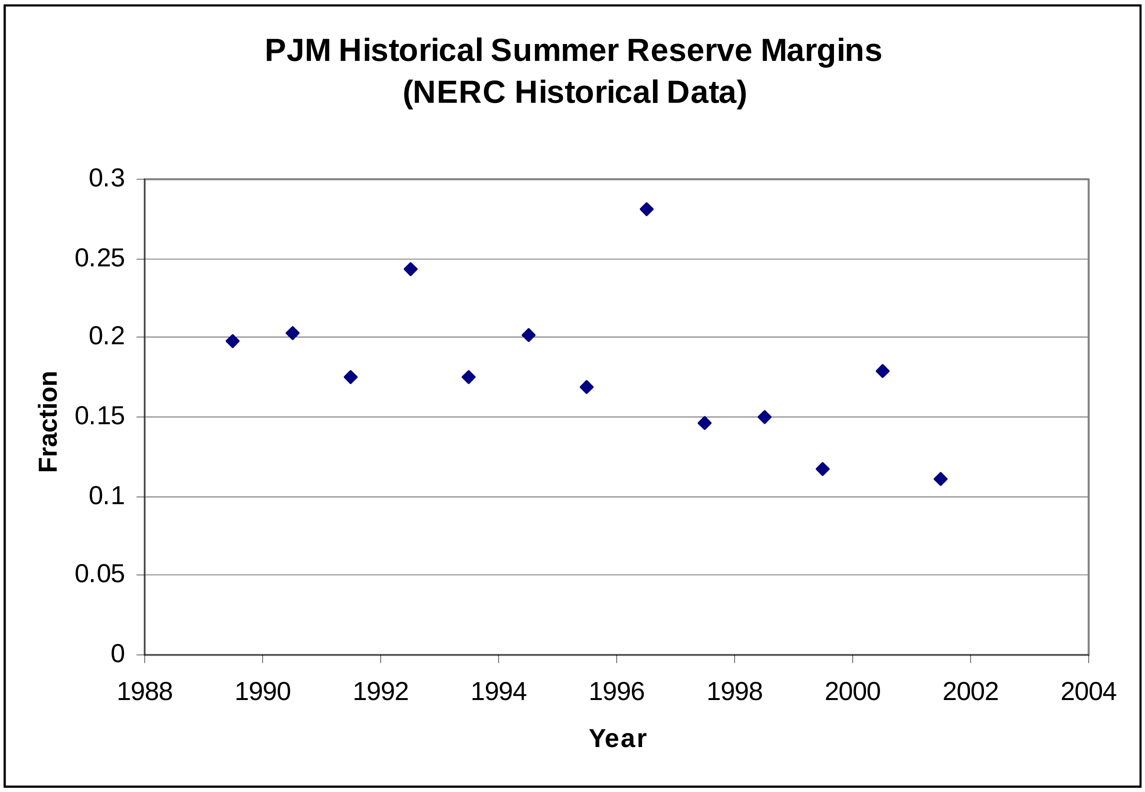

Figure 6. PJM Historical Summer Reserve Margins. Source: WWW.NERC.COM

The summer of 1999 brought higher than average temperatures and with that record electricity loads in much of the United States. PJM saw electricity prices hit $1000 per megawatt hour in the summer of 1999. In addition to a new overall peak price, the maiden year of the PJM energy market recorded unprecedented price volatility.

Deregulation created the opportunity for new entrants to participate in electricity markets that were previously restricted to the monopolistic utility. This opened the door for utilities in one region to compete in another region, for foreign utilities to enter the U.S. market, for existing independent power producers to expand their operations, for other utilities such as gas to enter electricity and for totally new operations to start-up. Table 1 shows several companies that entered the PJM market following deregulation. In some states existing utilities were required to divest generating assets, thereby requiring new entrants. In other states, new entrants competed directly with existing utilities. In either case, multiple competitors changed the dynamic within the industry.

Company	**Type of Generator**	**Home Location**	**Notes**
AES Enterprise	Independent Power Producer	Virginia	
AmerGen Energy Company, L.L.C.	Merchant		Joint venture of Exelon & British Energy
Calpine Corp.	Independent Power Producer	California	
Cinergy	Utility	Ohio	
Conectiv	Utility	PJM	
Consolidated Edison Development Corp.	Utility	New York	
Covanta Energy Corp.	Independent Power Producer	New Jersey	
Duke Energy	Utility	North Carolina	Electricity & Gas
Edison Mission Energy	Merchant	California	Owned by Edison Mission
El Paso Energy Corp.	Merchant	Texas	Gas & Electricity
Enron Corporation	Merchant	Texas	
Exelon Generation	Merchant	Chicago & Philadelphia	
FPL Energy, Inc.	Merchant	Florida	Owned by Florida Power & Light
Mirant Corp.	Merchant	Georgia	Founded by Southern Company
NRG Energy, Inc.	Merchant	Minniapolis	Owned by Ecel Energy
Reliant Energy, Inc.	Merchant	Texas	
Sithe	Independent Power Producer	New York	
Statoil Energy, Inc.	Merchant	Norway	Owned by Statoil
TXU Energy Industries Co.	Merchant	Texas	
Williams	Independent Power Producer	Oklahoma	Gas & Electricity
* Merchant generators are defined as non-regulated companies owned or associated with regulated utilities			

Table 1. Sample of companies owning power plants in PJM

Between 1999 and 2002, the electricity industry within much of the United States experienced a dramatic boom in power plant construction. In 1998, there was approximately 725,000 megawatts (MW) of generation capacity in the United States. Currently, the North American Electric Reliability Council, NERC, projects that there will be approximately 885,000 MW by the end of 2003, and 970,000 MW by the end of 2005 when most current construction will have come online. Nationally, that is a 30% increase in generating capacity over seven years in an industry where demand growth has generally averaged around 2% annually.

Power plant construction has not been evenly distributed across the country. The northern plain states, MAPP region, saw virtually no capacity growth while many of the mid-western states, ECAR region, will see capacity expansions of close to 50%. Figure 7 provides a regional breakdown of capacity expansion.

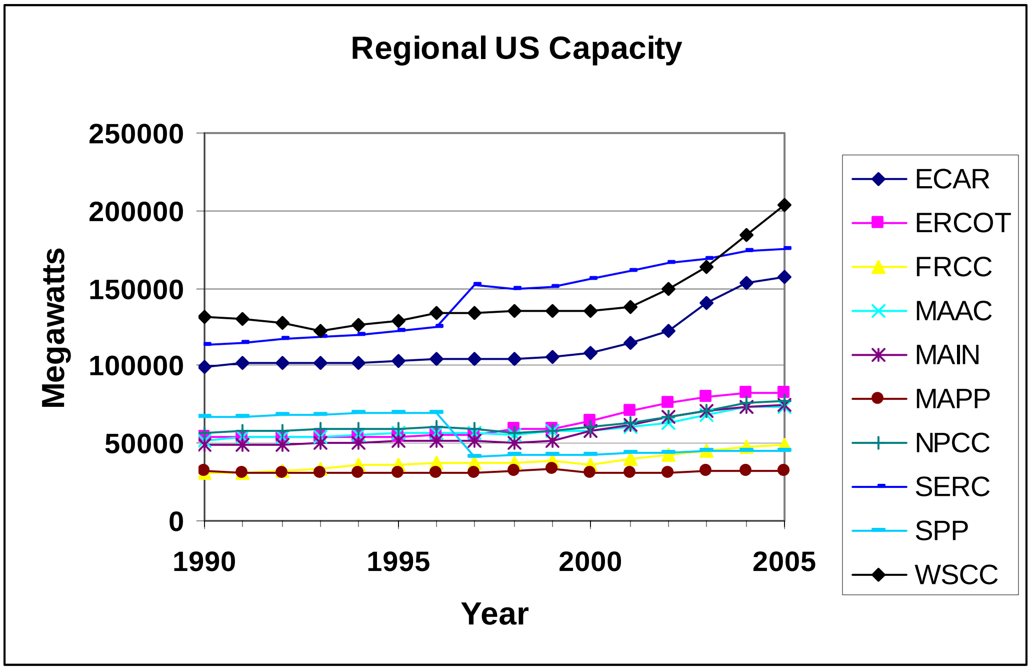

Figure 7. Historical Capacity Data by U.S. Region (Source: NERC: www.nerc.com)

The PJM market (listed as MAAC in Figure 7) is a representative example of the investment boom. At the end of 1999, PJM had approximately 58,700 MW of generating capacity. In 2000, roughly 700 MW of new capacity came online, followed by roughly 1,000 MW and 5,000 MW in succeeding years. And at the beginning of 2003, there was over 6,000 MW of generating capacity under construction in PJM; this is expected to come online in 2003 and 2004.

As new capacity came online, prices fell dramatically. By the end of 2002, energy prices in PJM had largely returned to pre-deregulation levels; capacity prices had collapsed to near zero. New development activity had come to a halt, and of the few plants still in the pipeline, some will be completed, some will be completed very slowly, and some will be mothballed. The boom is over, and the glut is here. We are now in a position to draw conclusions about the impact of deregulation.

3. Deregulation permanently changed decision-making and vulnerability to boom and bust

3.1. Structural vulnerability and triggers

Deregulation changed the decision-making process for building and operating generation capacity, and allowed a boom and bust behavior to emerge. Deregulation has changed the nature of the wholesale power market into something more closely resembling other cyclical commodity products. The picture in such industries is a generalization of the picture that emerges for wholesale electricity. Supply (capacity), demand, and price interact through feedback loops—as in any market—but there are delays in the response of both supply and demand to price signals, as illustrated in Figure 8. These delays, as we have seen, allow overshoot in capacity investment (booms) and later undershoot in investment. So if the system is disturbed (as by the under-investment that preceded deregulation), there is a structural vulnerability to boom and bust—cyclical—behavior.

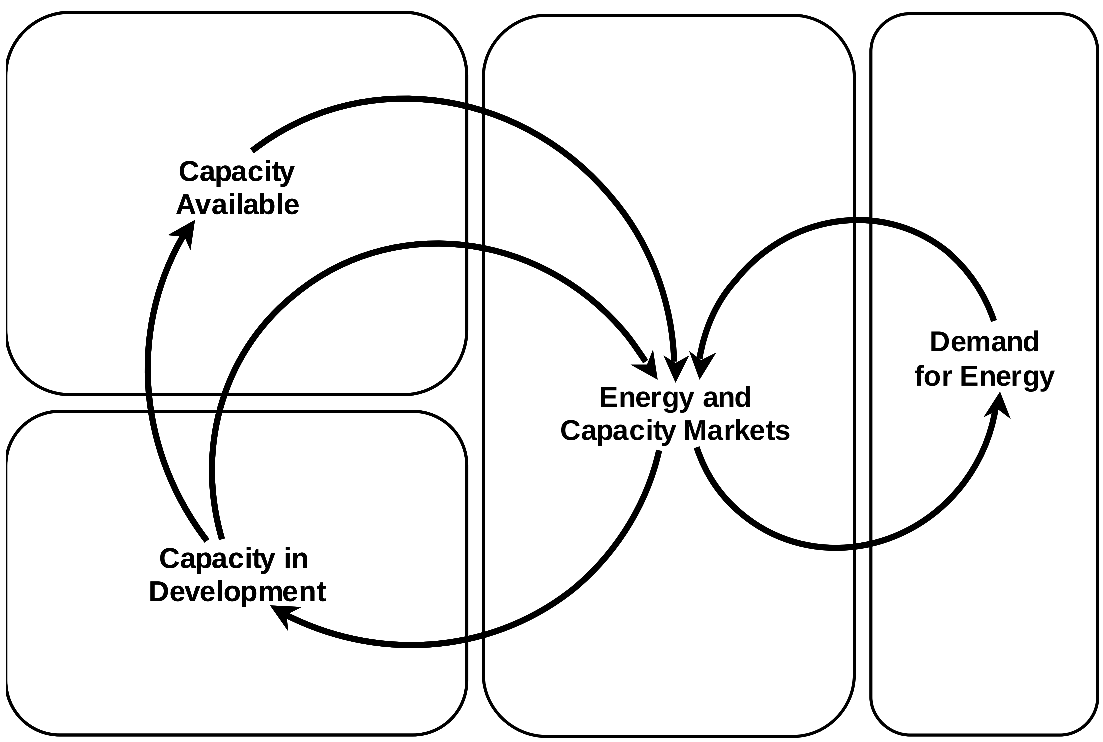

Figure 8 Basic Feedback Structure of Electricity Markets

Vulnerability to cycles is not the same as necessarily exhibiting boom and bust. Some triggers are usually required. By analogy, automobiles with worn shock absorbers are likewise vulnerable to lurching up and down (and perhaps making their passengers ill). But a car with bad shock absorbers will not lurch up and down just sitting in the garage—it needs to be driving, where irregularities in the road, or even abrupt driving will trigger the up-and-down motion. But it must be noted that sometimes, if the motion has been triggered strongly enough, the up-and-down will persist through several cycles, each cycle triggered by the momentum of the previous one.

Similarly, many conditions can trigger market cycles. Deregulation, new technologies, economic upturn or downturn, and changes in related markets, e.g. in fuel prices and availability can and have triggered boom and bust. In addition, just the "echo" of a previous boom and bust will suffice to trigger another cycle.

3.2. Echo from this boom and bust will cause another cycle

Consider the likely industry conditions for 2003 through, say, 2008. With the depressed market conditions, new construction projects are unlikely to start. Projects that were already in construction during 2003 will mostly have been completed. The construction pipeline will be almost completely empty.[8] The dearth of power plants in the pipeline will in fact be as significant as it was leading up to 1999 and the ensuing construction boom—this time due not to uncertainty about future regulations, but due to uncertainty about future prices (which, as we have seen, are expected to follow current prices).

So much the same decision-making will again come into play, with construction starting up, but no capacity relief for several years, high prices in the interim, and profit incentives driving over-investment. Figure 9 shows a simulation that applies the same (deregulated) decision-making rules continuing to be applied beyond 2003, with another boom resulting?

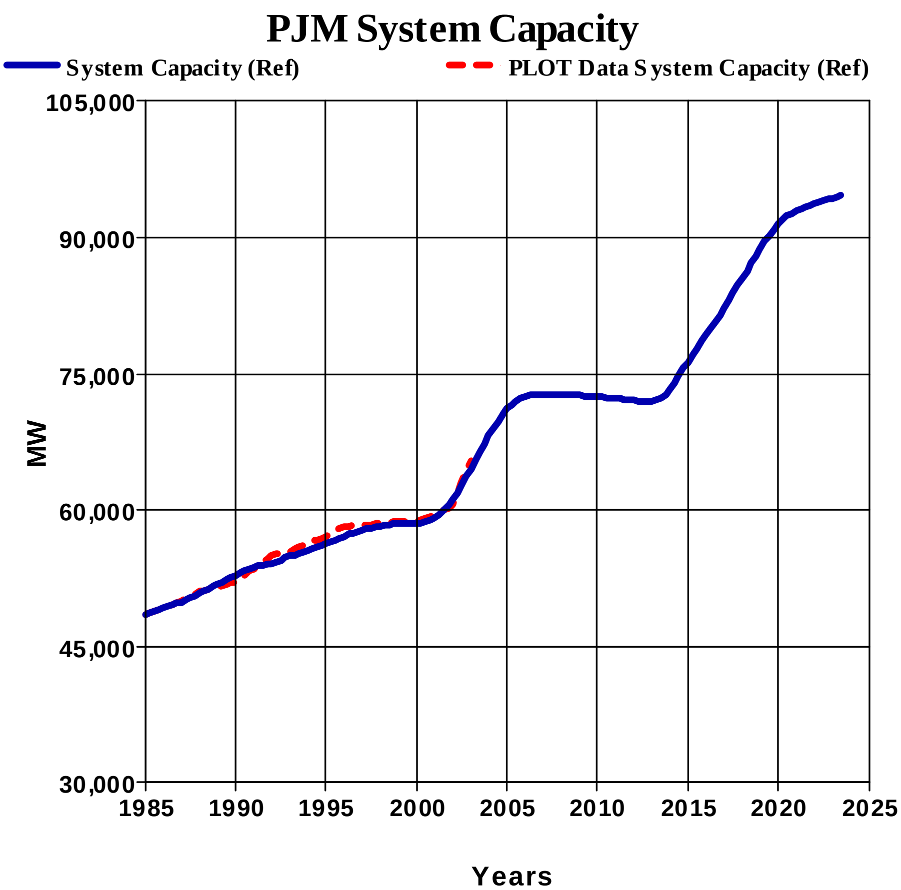

Figure 9. Simulation of PJM System Capacity.

Will participants learn and avoid the next cycle? This seems unlikely, as the same organizations, roles, and personal and corporate incentives are in place as before. History shows that in many other cyclical markets, the short-term incentives are too powerful for participants to go against. Who will call for massive new investment in the midst of terrible market conditions?

The likely occurrence of a "rebound boom and bust" answers two important questions:

1. Did deregulation cause the previous boom and bust? *Yes, both in creating the structural vulnerability and most of the trigger.*
2. What's the prognosis for the coming years? *Given that the construction pipeline is as empty as it ever was, there won't be any smooth return to normal conditions, but a relatively rapid switch from bust back to another boom.*

Before drawing implications of these conclusions, let us explore each a bit further, and then return to their implications.

3.3. Would a glut have happened without deregulation?

It is unlikely that without deregulation, the recent boom in power plant construction would have occurred. Deregulation set the stage for the power boom by 1) creating extended market uncertainty that dried up capacity investment prior to market creation, 2) allowing multiple participants to enter the market, and 3) by creating a market structure that allowed participants to competitively price. These three factors combined with the inherent delays in acquiring new capacity created a strong price/profit signal that was observed by multiple competitors over several years. Multiple developers initiated projects. Although most participants knew of competitor activity, until construction began there was significant uncertainty whether competitors would follow-through with projects in the development process. By that time significant momentum was built into the development process as contracts for construction had been committed to, turbines and other equipment had been purchased, and potentially energy contracts had been acquired. Without deregulation, the basis for the boom would have not likely been present.

If the markets had remained regulated, utilities would have likely continued construction to keep pace with load growth; prices would have remained cost based; and only one player, or few players, would have been active per geographic area (thereby having perfect information of the regions development activity). Construction may very well have picked up as utilities moved to newer technologies, but then more depreciated capacity would likely have been retired too – as plants moved out of the rate base and no longer produced profits. As with historical experiences over and undershoot of capacity would have been guided with over or under forecasting of load growth.

3.4. Uncertainties and Monte Carlo

What course will generation capacity in the PJM and other U.S. markets follow over the coming years? This paper has presented a theory on the structures that drove the recent boom and current bust in the PJM electricity market. Yet the behavior that these structures project going forward is heavily dependent upon assumptions outside the scope of the created model, such as underlying load growth, retirement or mothballing policies of the participants, fuel price trajectories and even the weather. To judge the range of possible behavior to come in the PJM electricity market it is necessary to explore the created model under a variety of scenarios. Individual scenarios can provide some insight into possible ranges of behavior, and Figures 10 and 11 display system capacity trajectories and average annual peak price trajectories for a series of individual scenarios where near term retirement strategies are explored. (Peak price is the two week average energy price between the hours of 7 am and 11 pm.) Given that the current market has excess capacity, one might expect participants to seek to remove capacity from the market place. This is an uncertain assumption. The electricity market has seen excess capacity before, but there has never been large scale retirement of power plants. (In the late 1970s and early 1980s load growth dramatically decreased from historical growth levels of approximately 7% annually to a more moderate level seen since of approximately 2% annually.

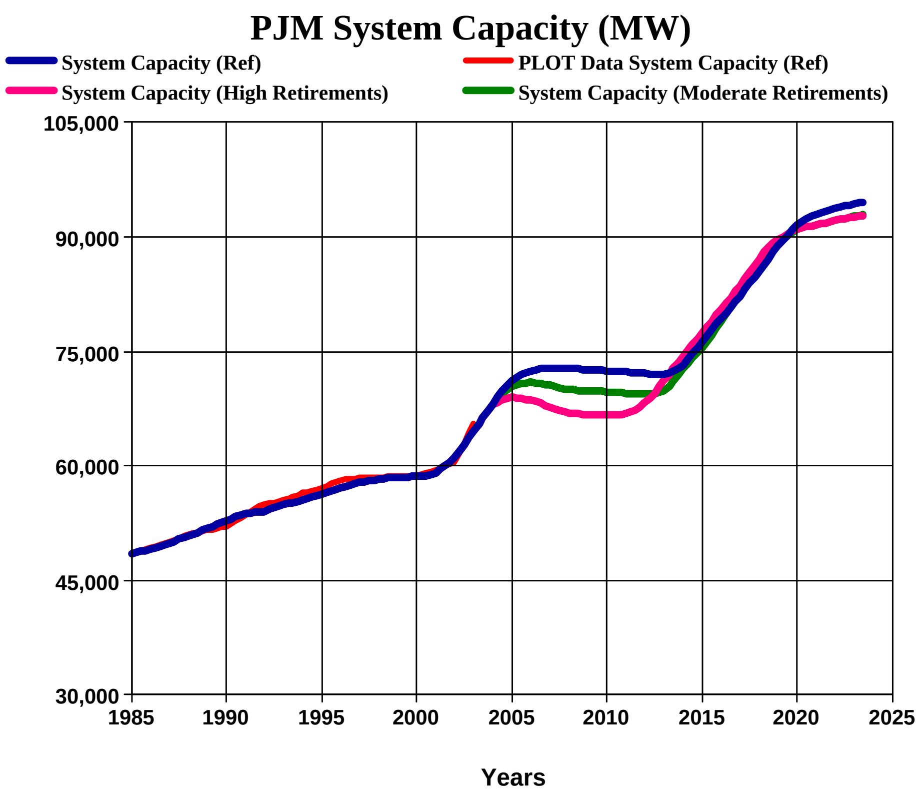

Figure 10. PJM Generating Capacity.

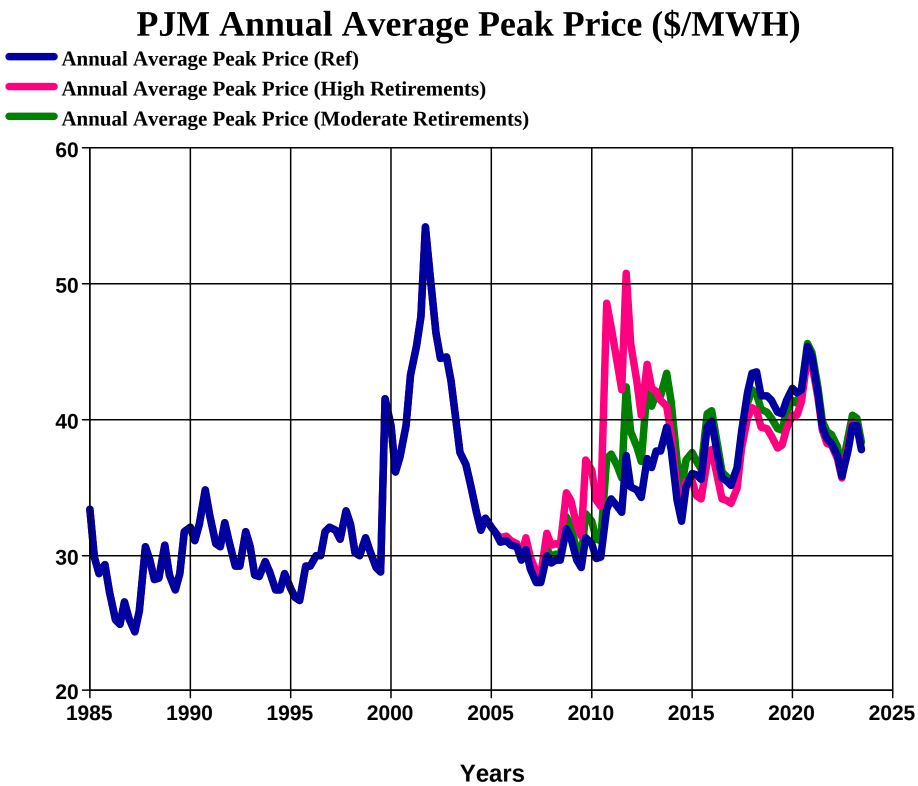

Figure 11. PJM Annual Average Peak Prices.

Instead of simulating a series of individual future scenarios, an alternative analysis technique is to perform a series of Monte Carlo simulations varying a variety of future assumptions within expected ranges to bound the likely path that the PJM electricity market will take. Figures 12 and 13 present output from such an analysis, displaying possible ranges of future construction activity and energy prices.

Figure 12 displays a Monte Carlo analysis of PJM capacity under construction. A range of values were investigated for future retirement policies, future load growth rates, fuel price trajectories, and week to week weather variations. The red mean line represents the point to point mean, not the average simulation. A host of trajectories create this mean; a few sample trajectories (individual simulations) are overlaid on the distribution. The shaded areas represent gradients in likelihood of projected behavior, with each band of shading representing a 25% likelihood of values falling within that band

This series of simulations suggest that PJM is unlikely to see significant construction activity until the end (or toward the end) of the current decade. The current glut seems likely to depress new construction activity for at least the next 4 to 5 years and possibly as much as 10 years.

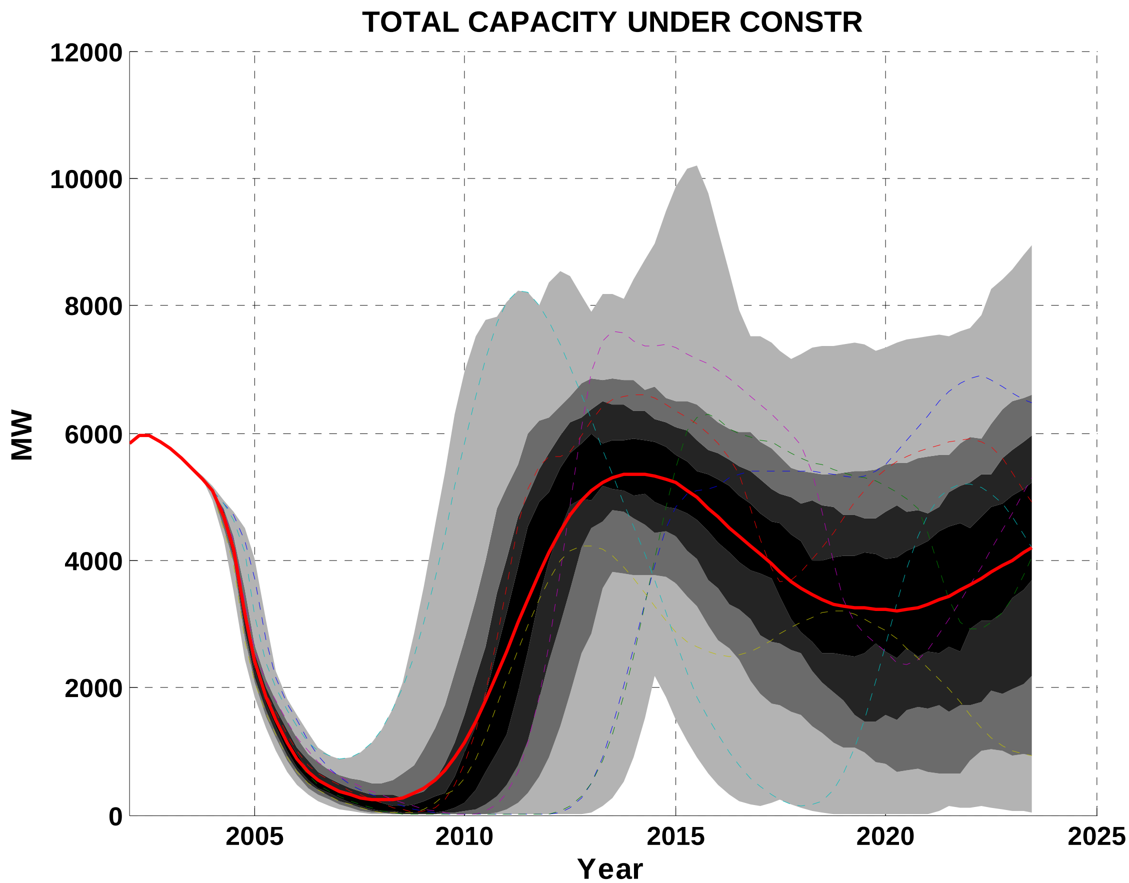

Figure 12, PJM Monte Carlo Analysis of Capacity Under Construction.

Construction activity is likely to remain low because the current glut will tend to depress prices throughout the current decade, until some combination of load growth or capacity contraction (retirements or mothballing) bring reserve margins back to a more competitive level. Figure 13 indicates that prices are likely to be in relative stable till the end of the decade. At that time significant uncertainty arises as to what price levels will be seen. Various combinations of growth, retirements, fuel prices and year-to-year weather patterns begin to combine to create significant uncertainty what prices levels will be seen. A significant probability exist that the next decade will bring high energy prices and a new construction cycle in the electric power industry.

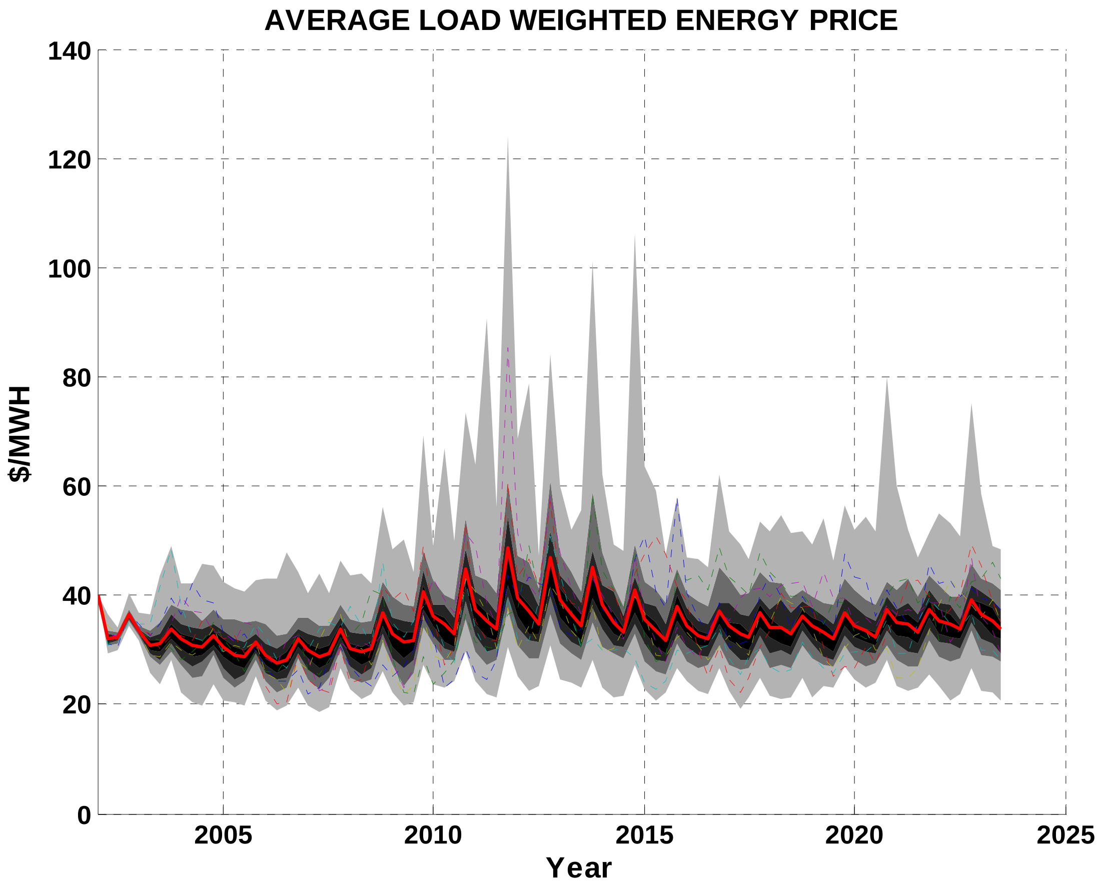

Figure 13. PJM Monte Carlo Analysis of Energy Prices.

4. Implications

4.1. Deregulation means the future is likely boom and bust

The discussion above makes it clear that "rational" decision-making on investment in new capacity is almost certain to create an approximate repeat of the earlier price run-up and subsequent over-investment. Glut-scarred investors will require firm prices to assure the profitability of new investments. This means future investment will likely wait until demand is already pushing the limits of existing capacity. At that point, it will be several years before new plants can be sited, financed, and constructed. Given typical variability of weather and demand, there will be multiple years of high demand and very profitable generation—ample incentive to again invest optimistically, and thus in excess.

Strategists would do well to think specifically in terms of a cyclical market (admittedly of somewhat uncertain timing), where delaying investments has its own risks—joining the herd and "buying at the peak". A kind of courage will be required, to look at trends in capacity and demand as they emerge, and to understand and ultimately trust analytical results. Only with such courage will investors begin investing in time to have capacity on line when (as prices show) it is needed. Only with such courage will investors stop investing in time to avoid money-losing "me too" plants.

4.2. Early recovery may mean more violent boom and bust

The timing of recovery of the power and capacity markets depends on several uncertain factors. One of these is how quickly demand grows. If demand growth exceeds expectations and allows earlier recovery, it will likely be a mixed blessing, because this will also tend to make the next boom and bust more pronounced. The higher the growth rate during the time when new plants are being constructed, the larger the imbalance will be between supply and demand, the higher prices are likely to get, and the more difficult it will be to stop construction in the face of obvious oversupply.

4.3. Price is a lagging indicator of investment opportunity

How will investors know when the appropriate time to begin new investment arrives? The discussions above make it clear that waiting until prices firm up is a strategy for late investment. Better indicators, indicators that in fact lead opportunity, would be trends in capacity and peak demand, and trends in "swing" capacity factors. Some plants (most notably combined-cycle plants) can function as either expensive baseload plants, or low operating cost peak load plants. To the extent that these move from peak operation to steadier operation (with correspondingly increasing capacity factors), that is an indication of impending tightness of capacity.

4.4. From now on, responsible regulation must consider long-term market stability

In retrospect, the discussion before deregulation was incomplete, given that it focused primarily on efficiency. Few knew to ask the question "do we want to deregulate if it turns electricity into a strongly cyclical commodity? What's worth more—prices lower on average, or stable prices?"

To be fair, cyclicality, even though present in many other industries, was still only a theoretical possibility when the deregulation discussions started. However, now that boom and bust has been closely associated with not only energy deregulation but also telecommunications deregulation during the 1990s, and a number of academically rigorous studies have linked deregulation to cyclicality, the theoretical possibility has become reasonably well-established fact.[9] Boom and bust are being discussed as serious issues in regulatory submissions.[10]

The question of efficiency versus stability bears asking again, as (de)regulation is still evolving. The US Federal Energy Regulatory Commission (FERC) is refining and promulgating the Standard Market Design (SMD) for energy and capacity. And FERC rulings are motivating the formation of Regional Transmission Organizations (RTOs), which in many respects perform the same market functions for use of transmission assets as do Independent System Operators (ISOs) for generating assets.

What can or should be done to address the stability issue? Let us consider one possibility as a representative of wider discussion and analysis that should take place.

The discussion above has repeatedly come back to the point that any regime is bound to be destabilizing if it makes investors wait until prices are already high to begin new construction. As suggested above, one cannot count on history changing individual's behavior in the face of powerful current incentives. A surer route would be to change the system that creates the incentives.

While some regions have markets for capacity contracts, on the theory that payments for capacity should defray construction costs (and payments for power defray operating costs), the capacity contracts usually have relatively short terms—months or quarters. And capacity prices are known to plummet rapidly if capacity is in excess. So as presently constituted, developers have few means to assure themselves of adequate return, before prices firm up. One simulation study by Andrew Ford on supply and demand for combined cycle generation[11] suggests that consistent capacity payments stabilize the electricity markets, by stabilizing projected return on generation construction, and hence not delaying construction as demand (plus required reserves) approaches capacity.

In general, the more power and capacity transactions that can be executed with long-term contracts, the more stable one would expect returns, capacity expansion, and hence wholesale (and retail) prices to be. Of course, during a glut and very low prices, no producer wants to lock in those money-losing prices. Correspondingly, during a shortage and high prices, no utility or other Load Serving Entity (LSE) would want to commit to years of paying high prices. In practical terms, the only realistic opportunity regulators would have to extend the market's use of longer-term contracts would be in the transition period between bust and boom. Consider the market for long-term bonds. Although the interest rate does rise and fall, it does so very modestly in comparison to short-term rates, representing smaller changes in the market's view of long-term market prospects. If a similarly deep and liquid market for long-term power and capacity could be institutionalized, investors would be back in a regime where long-term returns are <u>relatively</u> well-known and stable, and the construction decision comes back to forecasts of whether there will be demand when the construction is finished. This would be a "virtual re-regulation", duplicating with market instruments (and regulatory requirements) the kind of planning that all utilities formerly did.

The point here is not to advocate this change or any other, but to raise a critical issue coupled with a plausible and time-critical solution. Given what is now known about market cyclicality, responsible examination and evolution of regulations must explicitly consider this dimension of their impact on the market.

4.5. Standard production cost models offer only partial insight into issues of cyclicality

Production cost models, an industry standard, are a two-edged sword. On the beneficial edge, these detailed models of generation, dispatch and “production cost” use actual plant data for the first five years or so of their calculations for plant economics. They offer extraordinarily detailed, very fact-based results.

On the less beneficial edge of the sword, simplifying assumptions begin to creep in, even for early years. Modelers must make judgments about construction cancellations and slowdowns, but without benefit of a means of quantifying the feedback between cancellations, anticipated market conditions, and further cancellations.

More seriously, for the outer years of calculation, since current plant data no longer indicate what capacity is likely to be present, the production cost models hypothesize appearance of enough capacity to just meet assumed demand with adequate returns. Projections from 1999 would have interpolated from near-term high prices (possibly starting to descend) to acceptable prices in a 2009 equilibrium. Such projections, unless manually “judged down” would miss the portion of the decade in which prices were severely depressed. Investment decisions based on such price projections would (in retrospect) have been systematically optimistic.

Analyses based on data but not quantification of capacity investment behavior are caught in a dilemma: They are accurate and dependable only over time-spans where anyone is powerless to do much different to impact the market and its disequilibrium behavior.

Models that do not dynamically trace out investment, cancellations, capacity and price trajectories, while very useful for many questions, should be supplemented by results from a dynamic model when dealing with questions of return over the medium and long term in a disequilibrium market. And clearly, for evaluating market stability and disequilibrium, models that assume equilibrium are substantially less than fully appropriate when used in isolation.

This is definitely not a recommendation to abandon production cost models; we and our colleagues are acutely aware of the enormous usefulness of production cost models. Indeed, part of PA’s development of the current dynamic model was extensive testing against production cost models. And we anticipate a continuing synergy between dynamic models and standard production cost models. The role for each, and their use separately and together, depends ultimately on the questions being answered.

Appendix—Description of the Electricity Capacity Investment / Market Model

This appendix provides an indicative orientation on the dynamic capacity investment / market model used to arrive at the conclusions discussed above. Before enumerating the contents and functioning of the model, the process by which it was constructed bears brief description.

System Dynamics modeling was the obvious methodology of choice, dealing as it does with explicit feedback control in disequilibrium situations (like market dynamics), with potentially nonlinear and changing feedbacks (like deregulation).[12] System Dynamics has a long history of dealing with cycles in general,[13] as well as commodity cycles in particular.[14] Energy and electricity have long been a focus.[15]

For the task of understanding the impact of deregulation, we undertook to evolve a model structure (starting from an existing model) that could be parameterized to represent three different regions in the US: PJM (Pennsylvania / New Jersey / Maryland), ISO-New England, and ISO New York. We interviewed seven industry executives as well as power systems experts within the research team on their views of what went into the decision-making post-deregulation. Most data on pre- and post-deregulation market behavior came from public sources, although some data were proprietary compilations.

So the modeling task was to make these three bodies of knowledge—prior theory, industry knowledge, and numerical data consistent. The process was iterative, involving both parameter-tuning and questioning the theory and numbers, visually at first, then using "fit" statistics.[16]

The model is implemented in PA's Jitia simulation software.[17] In the version reported here, there are a bit less than 5,000 state variables, reflecting considerable duplication of structure for different plant technologies and age groups, and expectations of various kinds (for each of the plant types) over multiple time horizons. The model simulates the years 1985 to 2025 on a standard laptop in under a minute.[18] This is a large model by academic System Dynamics standards, and a medium-sized model by the standards of commercial System Dynamics.[19] This is a tiny model by comparison to the power industry's standard "production cost" models.[20]

But enough background. What's in the model? At the highest level of abstraction, the model implements the classic feedback loops among supply, demand, and prices that typically underlie disequilibrium, cyclical commodity market behavior, as illustrated earlier in Figure 8.

At the next level of detail are the sorts of variables that virtually any causal, fundamental model of power markets would have.[21] Figure A.1 illustrates.

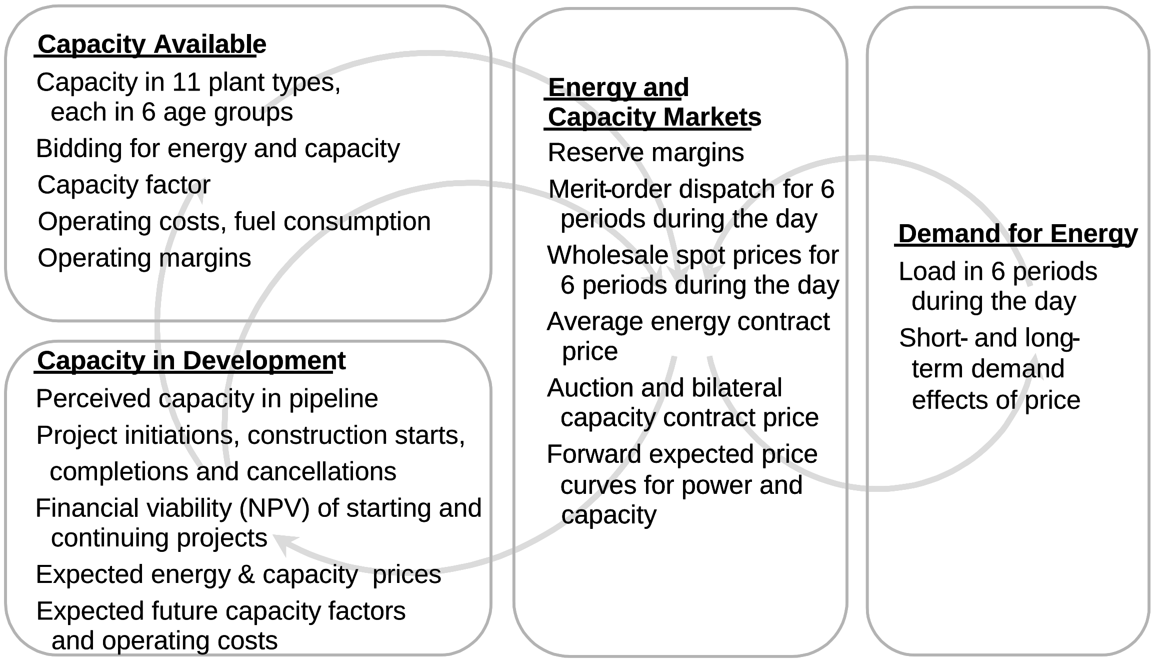

Figure A.1. Decisions and quantities determined dynamically within the model, as a function of other internal variables and the outside inputs.

But the distinguishing feature of the dynamic power generation model is not so much what variables are present, but rather how they are connected. Figure A.2 illustrates at high level: Traditional production cost models do not simulate the link between market prices and investor behavior. Instead, they use massive data on generating plants already built, and under construction or announced, and simulate the operation of each. This allows an enormous amount of specificity in the near-term about the operating economics of specific plants. But lack of endogenous (internal creation) of new investment means that such models do not have the infrastructure to simulate cyclical or other disequilibrium behavior that goes out beyond the limits of the data—typically around 5 years.

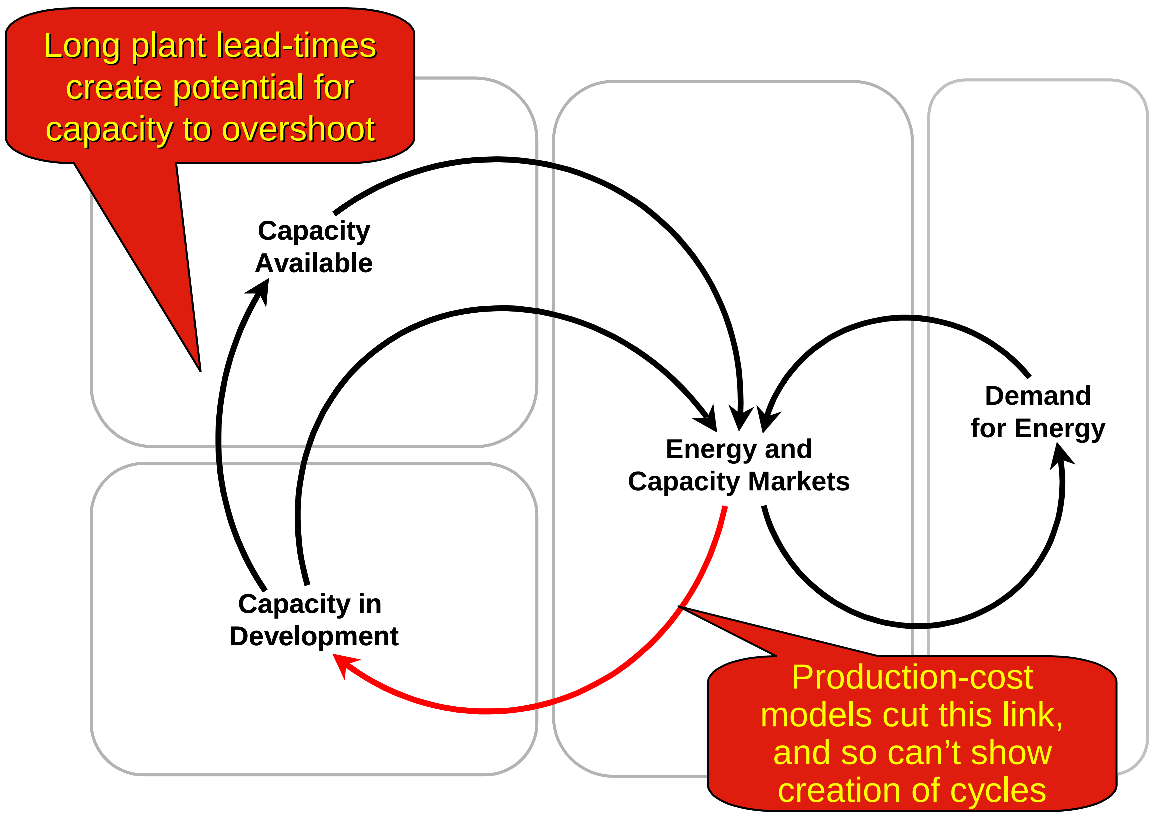

Figure A.2. At a high level of abstraction, it is explicit representation of feedback loops that distinguishes the dynamic power generation model from industry-standard production cost models.

Figure A.3 shows the feedback loops at a more detailed level. Each of the captions is a model variable (possibly a vector with many values, e.g. for different plant types). The connections between variables, however, are much simplified for this diagram. The diagram shows several related markets. There is trade in both power (actually running the generator to put power into the grid) and capacity (having plants physically and contractually available to be run). Implied but not shown are the longer-term expectations formation and bilateral contracting in power and capacity. Expectations for many quantities are explicitly represented, and folded together in the financial evaluations that say whether plant construction of each type is expected to be profitable over the life of the plant. Parallel financial evaluations look at the advisability of slowing down or canceling construction already under way, and retiring older plants.

It is important to note that the information for structuring the model equations comes from economic theory, prior modeling, and industry interviews and general power systems knowledge within the team. There is nearly always enough knowledge available (including sporadic quantitative information) to construct a first model, well before systematic data collection and model calibration. Calibration against data is an independent confirmation (or disconfirmation) of the other sources of information.

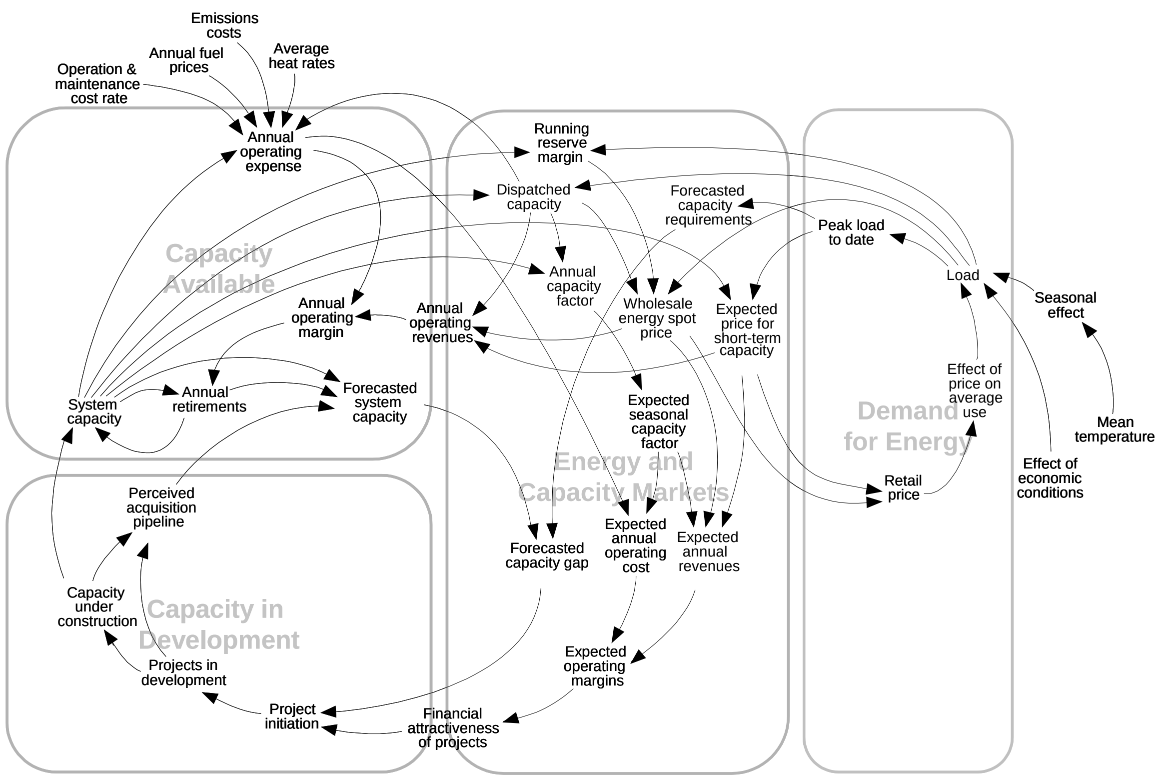

Figure A.3. More detailed view of feedback loops, in particular the multiple related power and capacity markets, and the expectations formations that drive investment in power plant construction projects.

Figure A.4 shows all of the external inputs that drive the system. Simulation models operate very differently from, say, spreadsheet models. In simulation modeling, most of the variables change as a cause and effect result of other variables, usually in feedback loops. Capacity drives price, which drives investment, which drives capacity. Capacity (except for initial values), investment, and prices are not fed into the model. Only the variables shown in red in the Figure are fed, as time series, into the model. A test of model adequacy is whether the model, started off with known initial conditions, and driven by the same external inputs (red) as was the real system, produces the known behavior of the real system, solely from correct cause and effect and a handful of external inputs.

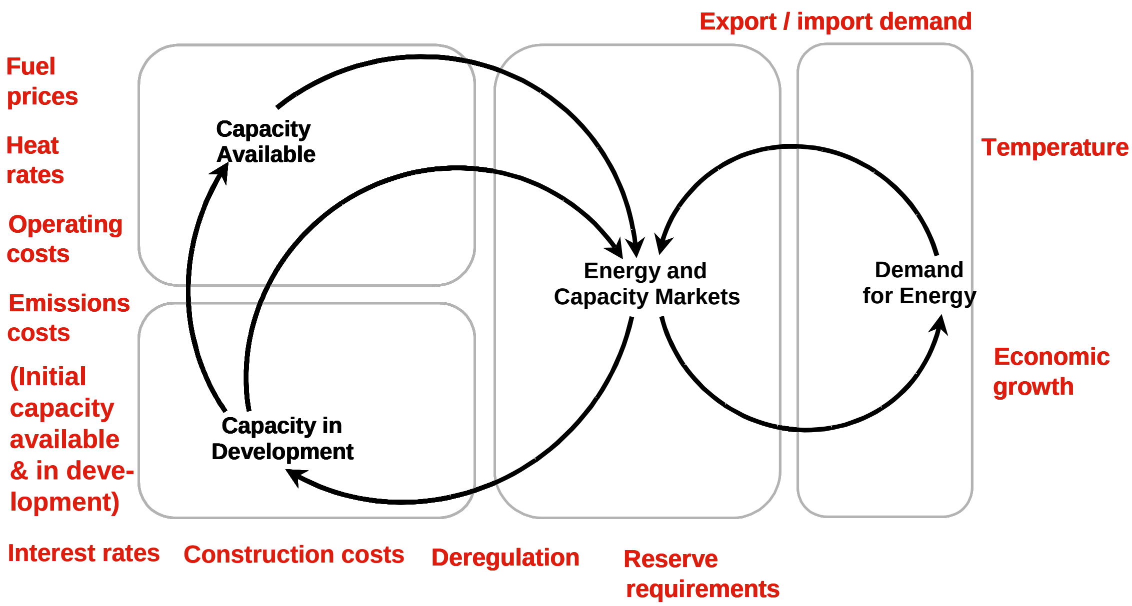

Figure A.4. Outside inputs to the model that provide potential triggers to cyclical behavior. To a major extent, these are the "handles" that define alternative scenarios and Monte Carlo random trials. These are also the historical inputs that, when they drive model behavior, are expected to cause the model to re-create historical market and investment behavior.

Figure A.5 illustrates such comparisons, and some of the variations involved. From left to right:

1. Data on system capacity available (total Megawatts of generating capacity in a region) is recorded and available for many years. The time series is quite smooth, and the independent simulation matches it well.
2. Capacity in development (under construction, but not yet online) is available only at the level of specific plants; we totaled up two "snapshots" at specific times to create data (the red spots) to compare to the simulation.
3. Hourly price data is available, but only in recent years. So the time scale is different from other plots. But the simulation matches this erratic time series surprisingly well, and speaks well for the realism of the cause and effect structure of the model.
4. Demand is modeled in a relatively simple way, as a function of temperature. So although this erratic time series is well-duplicated in the model, this is not a difficult test to pass and does not represent a major model validation.

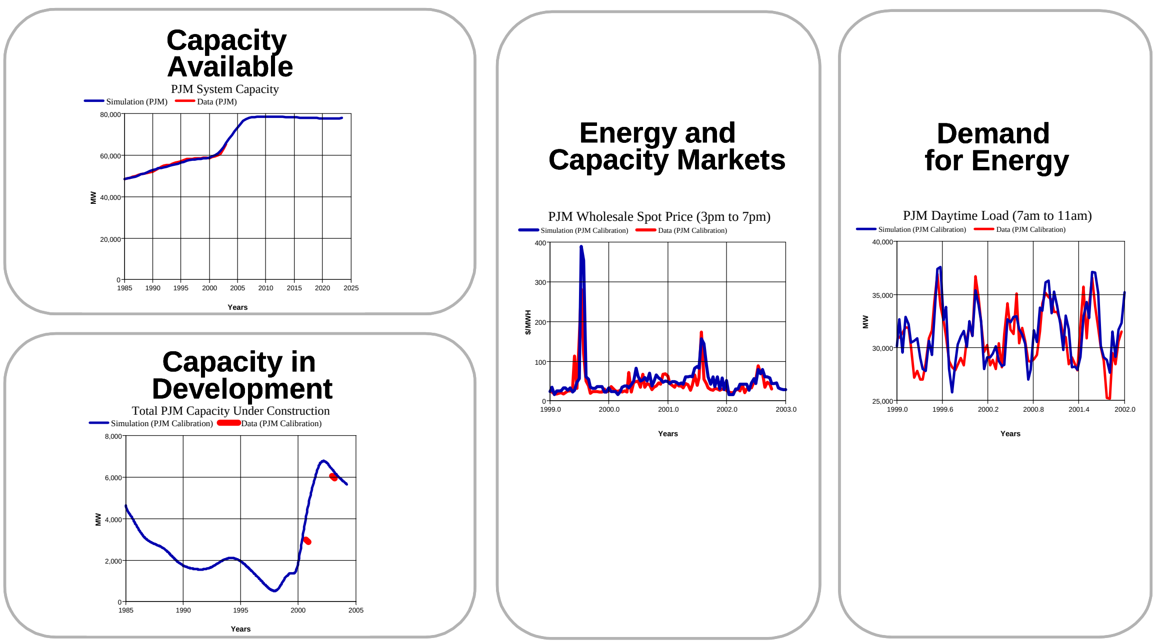

Figure A.5. Illustrative checks of simulated behavior against real data, for the PJM (Pennsylvania / (New) Jersey / Maryland system.

Figure A.6 illustrates the scope of data comparison. Clearly, data were not available for every model variable. Equally clearly, aside from outside inputs, model variables drive (and are driven by) feedback loops, and all loops are compared to data at some point. Moreover, many of the variables not measured have well-known relationships to those that are measured. In the simplest case, consider Annual Operating Expenses or Expected Operating Margins—their relationship to their inputs are accounting relationships. And the expectations formations, while there is some degree of latitude, must show plausible relationships to the variables whose expected values they represent.

By analogy, running an electrical network or a chemical plant, it is expensive and unnecessary to measure the system at every point to ensure good operation. Similarly, it is not necessary to check every variable against data to have good confidence in model results.[22] (Of course, this is true only for models constructed with abundant prior information about model relationships. Purely statistical models need all the statistics.)

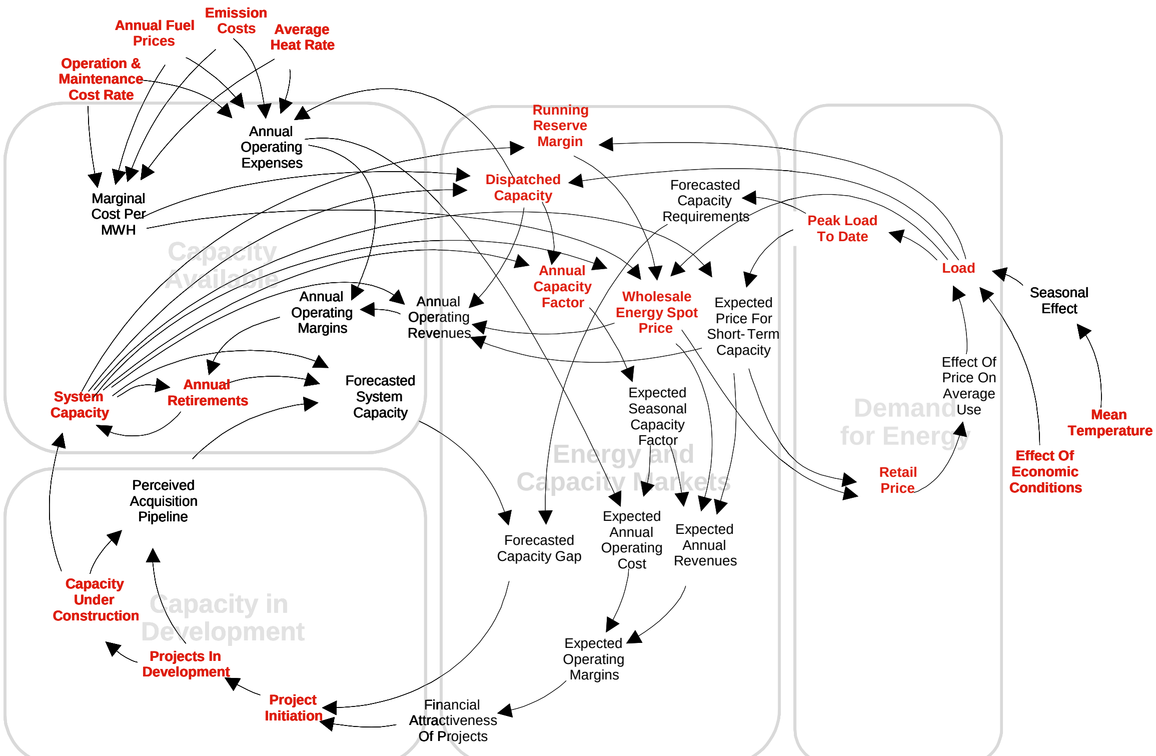

Figure A.6. Mapping the calibration process. Red indicates variables for which real data exist and were checked against model behavior. No model variable is very far from variables that are checked against data. Thus it is difficult to be far off the mark.

The impact of deregulation is a key theme for this paper. There is no explicit structure in the model that tracks ownership of generating assets and the shifts (often divestitures) forced by deregulation. Rather, we modeled decision-making on investment, bidding for power generation work, and retirement. And we specifically undertook to represent how deregulation impacted such decision-making. Figure A.7 summarizes the impacts that we first hypothesized from earlier work, heard in internal and external interviews, and corroborated by simulation match to data.

Of the seven impacts, probably the first four are most important to understanding market stability.

1. Adding prices and margins into the investment decision means investment happens later than it would when utilities just looked at demand, filled it, and charged whatever it cost.
2. Creating multiple investors in a region allows optimism to creep into predicting how much capacity will actually be built by others and how much will be forced to retire. This makes overbuilding possible and in fact likely.
3. Deregulation allowed producers to bid well above cost, which regulated utilities did not do. This allowed stratospheric prices during high-demand periods, which seemed to mesmerize investors into impossible optimism.
4. Prior to resolving the political discussion on deregulation, uncertainty about the “rules of the (investment) game” deterred investment in capacity and unwittingly provided the first trigger for the boom and bust that followed deregulation in most regions.

Issues and decisions	Regulated	Deregulated
Basis for investing in new power plants	Total long-term cost of serving load, sufficient to meet base and peak loads	Most profitable, given Favorable aggregate supply / demand balance, and Based mostly on recent prices and margins
Allowance for the capacity pipeline in investment planning	Capacity development pipeline fully counted	Capacity development pipeline discounted in the decision process
Energy bidding and dispatch	Marginal cost	Bids at marginal cost plus more when market is tight
Uncertainty on market rules deters investment	No	Yes, in years between serious consideration and actual deregulation decision
Basis for retirement decisions	Variable cost relative to other plants and fixed cost to maintain	Positive operating margins
Weighted Average Cost of Capital (WACC)	Less perceived risk -> lower risk premium -> lower	More perceived risk -> higher risk premium -> higher
Construction sensitivity if economics turn adverse	Uncommon for slowdowns or cancellations	Significant slowdowns and cancellations
Reliance on long-term capacity contracts	Implicitly, complete reliance	Variable reliance

Figure A.7. Multiple impacts of deregulation on decision-making, obtained from interviews and confirmed by check against behavior.

[1] Under special circumstances, it may be profitable for an operator with many types of generating assets within a region and a fairly large market share to mothball some plants, in order to raise prices obtained by the others still on-line. In the medium term, when demand again comes close to supply, rapid de-mothballing could moderate the price spike and resulting over-investment in new capacity, stabilizing the market.

[2] The near-term capacity forecast is reasonably good, since it represents plants that exist, or that are under construction or announced. The uncertainties are retirements in the near term (which don't seem to be happening to a significant extent) and cancellations or slowdowns (which penalty clauses and cash flow considerations usually mitigate against—better to finish and generate some case). In the medium term, the uncertainty is the extent to which special niches will continue to pop up where power plants are needed and constructed in particular locations for particular purposes, despite overall excess capacity.

The demand growth curve likewise reflects uncertainties about future economic growth versus growing energy efficiency of future electrical equipment. We will briefly address these uncertainties shortly.

[3] Generation capacity differs between summer and winter for power generation from combustion, because colder outside temperatures allow combustion to create greater amounts of energy. For comparison to peak demand, which happens in the summer in most regions, summer capacity is the relevant point of comparison.

[4] The official forecasts end in the year 2011. But the capacity relative to demand has not returned to 2001 levels within that time frame. So for illustrative purposes we have extended both the capacity and peak demand series another four years, at the annualized growth rates from 2006 to 2011.

[5] Electricity markets in fact deal with multiple products and services: energy (megawatt hours generated), capacity (the option to call on a power plant for generation when needed), and ancillary services (voltage and frequency control, short notice and spinning reserves, and other services). Energy markets match the generators with load serving entities (LSEs), which are predominantly utilities, to meet the day to day electricity needs of end users. Capacity markets match generators with LSEs who must demonstrate to regulators that they have sufficient capacity under contract to meet peak loads plus a reserve. Ancillary services are generally contracted directly by the system operator for system stability and reliability purposes.

[6] In theory, futures or "forward markets" provide a way for impending capacity needs to create tangible price signals. In practice, expectations and transactions are dominated by, if not the here-and-now, then the relatively close-in past and future. Markets for generated power have seldom been liquid beyond roughly 18 months into the future, and the tiny markets for options to call on generating capacity (where they exist) are for even shorter terms. Our executive interviews confirmed that expectations about future prices, as far as investment in power plants goes, are dominated by market conditions of the previous year or two.

[7] In a National effort to encourage alternative sources of power, the Public Utility Regulatory Policy Act (PURPA) was passed in 1978 requiring utilities to buy from non-utility generators at the utility's avoided cost of power. By requiring utilities to purchase power from qualified facilities, PURPA created the first wave of Independent Power Producers. The wholesale power markets began to deregulate in earnest in the early 1990s with the Energy Policy Act of 1992 and FERC Orders 888 and 889 that provided for open transmission access. Independent system operators were formed in the late 1990s in several regions of the United States. In 1999, market rules for wholesale power sales were initiated in PJM (Pennsylvania, New Jersey and Maryland), California and New England.

[8] Almost no generality is completely true. Electric power is distributed over a transmission system with clear limitations. Even if capacity overall is well in excess of demand, there can be locations with transmission limitations such that more power is difficult to deliver. So over the coming years, demand growth in particular areas may best be met by power plant construction near that location, and such plants are needed and will be profitable, even in the midst of general capacity excess.

[9] A later endnote to the Appendix will give more extensive references, but for an explicit comparison of the electricity industry to other, known-cyclical, industries, see (PA Consulting 2001). Also see the discussion of cyclicality in the telecommunications market in (Godfrey and Graham 2003)

[10] See, for example, (PacifiCorp 2003, pg. 17)

[11] The (Ford 2001) study goes through a number of scenario experiments aimed at stabilizing the power market.

[12] The System Dynamics approach to structural change is similar across many application venues: model how the system manages itself, particularly how the decisions are made, and then examine how those decision rules change when organization, incentives, or even market structure changes. For a concise example in the area of reorganizing

an organization and privatizing some parts of it (the London Underground), see (Mayo, Callaghan and Dalton 2001). For early energy industry examples, see (Lyneis 1985), (Lyneis and Bespolka 1994) and (Larsen and Bunn 1994)

[13] For instance, see (Mass 1975), (Graham 1977), (Forrester 1982)

[14] The first major academic synthesis of commodity cycle dynamics was (Meadows 1977). (Sterman 2000) reviews and summarizes research on macroeconomic cycles in Chapter 19, and Chapter 20 does the same for commodity market cycles. For an example of commercial application, see (Pugh-Roberts Associates 1980).

[15] Much of the energy work in System Dynamics is oriented toward energy policy of broader scope, including issues of conservation and renewable resources in the overall energy economy. While a complete bibliography is beyond the scope of this paper, for policy-oriented work see (Energy and Environmental Analysis Inc. 1980), (Ford and Bull 1989),(Naill 1992), (AES Corporation, 1993), (Bunn and Larsen 1997). For work focusing on electricity market dynamics, see (Coyle and Rego 1982), (Backus and Baylis 1996), (Ford 1997), (Bunn Dyner *et al.* 1997), and (Ford 2002)

[16] For description of use of fit statistics, see (Lyneis and Reichelt 1996) and (Lyneis, Reichelt and Bespolka 1996), also (Sterman 2000). The treatment of parameters in System Dynamics is quite different than in traditional econometric modeling, allowing for considerably more use of a priori information about relationships and parameter values. See (Graham 1980), (Richardson and Pugh 1981) and (Sterman 2000) for discussion.

[17] The Jitia software is described in (Eubanks and Yeager 2001). Hierarchical and highly scalable, it offers several graphical interfaces with which to understand model structure and behavior. It is used only by PA Consulting and its clients.

[18] The simulation speed results partly from judicious and purposive handling of short-term demand variations. The industry-standard production cost models generally simulate demand, pricing, and generation every hour or two. The dynamic model, seeking a balanced treatment of short-, medium- and long-term dynamics uses a different approach. The dynamic model divides days into 6 4-hour periods, so that the peak load periods and their demands on generation capacity are properly recognized. The model simulates each of those daily periods over a two-week time step, to allow variability due to weather (with appropriate adjustment for the difference between volatility of single-day versus two-week average demand for each of the daily time periods. In this way, the dynamic model provides a reasonable approximation of short-term variabilities, but with a time step 366 times less frequent than hourly.

[19] This level of detail reflects a tradeoff: In markets where data is generally available but not abundant, we can use knowledge of details to construct some important higher-level relationships. For example, the relationship between demand and price emerges dynamically and realistically from a bidding process among subsets of all plants (mirroring how power generation decisions are made in real life)—there are enough “bidders” that the system approximates the behavior that emerges from a large population of plants bidding to sell electricity.

[20] The traditional production-cost models often track the hourly operation every generating plant in several regions, each separately, and subject to operating and transmission constraints. So they simulate 5 years in around 10 to 20 hours, whereas the dynamic power generation model simulates 15 years of history and 25 years forward in under a minute. Different tools for different questions.

[21] This discussion generally excludes the purely statistical models of markets, typically used for trading and risk management of portfolios of tradable assets. Based on historical variability of asset prices and returns, and covariances among them, these models are extensively used and useful. But for questions involving medium- or longer-term strategy, they have a major weakness: the statistics of the future in a cyclical market are usually quite unlike the past statistics in important ways.

[22] The system dynamics modeling process is generally rich in cross-checks to ensure model adequacy to the intended use, from the way information is gathered, to the way the models are formulated, and above all, to the multiple way that both the model behavior and the model conclusions are tested. To put a point on the matter, there are explicit tests for confidence bounds for dynamic models, described in (Graham, Moore and Choi 2002) and (Graham, Choi and Mullen 2002).

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