# Generation Investment and Capacity Adequacy in Electricity Markets

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**Introduction**

One of the major challenges in restructured power systems is to maintain a level of generation capacity that ensures an acceptable level of certainty against power interruptions. A power market with a well-functioning spot market and long-term markets for allocation of risks between consumers and producers should in theory generate optimal investments in new power generation capacity, but this may not always be the case. In this paper we describe potential problems for adequate generation investments in electricity markets. We also discuss different policies that have been implemented and proposed to address the problem of capacity adequacy. Finally, we look at the experience so far with generation investment in some restructured electricity markets, focusing on Scandinavia and the United States.

**Potential Problems for Generation Investments**

There are a number of complicating factors that can prevent the electricity spot market from providing sufficient incentives for investments in new power generation capacity. We briefly describe some of the main problems below.

***Limited Demand Side Participation***

Stoft (2002) describes two demand-side flaws, which can have severe impacts on the price formation in the electricity market. First, the lack of metering and real-time billing limits demand response to price. If there is limited or no short-term price response on the demand side one can end up in situations where the market does not clear and the price must be determined through a regulatory price cap. Unless the price cap is set equal to the value of energy not served, this will give wrong investment signals. Second, the lack of real-time control of power flow to specific customers prevents physical enforcement of bilateral contracts and, therefore, discourages customers from buying long-term contracts.

***High Financial Risks in Generation Investment***

The risk involved in investing in new power generation is high due to the high volatility in electricity prices. In particular, peak load plants are exposed to the price risk due to their low capacity factor. The long lifetime of generating assets adds to the investment risk. The lumpiness of generation investments may also deter investments, as a new large-scale plant may reduce prices and profitability. Furthermore, a power plant investor faces substantial regulatory risks, both in terms of electricity market design and environmental regulations (e.g., policies to address climate change). Unless there are liquid long-term markets where investors can efficiently hedge their financial risks, these uncertainties can significantly reduce investment in new generation capacity.

***Market Power***

Market power is often a concern in electricity markets. Industry restructuring has triggered a number of mergers and acquisitions, increasing the market concentration in many electricity markets. Large incumbent companies may choose to postpone generation investments to drive up prices and profits from existing assets, unless the barriers to entry are low for new investors in generation capacity.

***Procurement and Use of Operating Reserves***

Procedures used by the system operator for procurement and use of operating reserves may distort energy prices and, therefore, investment incentives. If the system operator is willing to reduce the operating reserve requirement in critical peak load situations, this will influence the prices in the energy market. Furthermore, if there is a maximum price paid to generators called upon in real-time, this price effectively caps the price in the day-ahead energy market and thereby reduces the long-run investment incentives.

**Market Design for Capacity Adequacy**

Given the potential problems outlined above, combined with the detrimental impacts of capacity shortages, it is not surprising that authorities in several countries have not been comfortable with leaving the decisions on generation investments to market forces alone. Below we give a brief discussion of different market

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designs for generation capacity adequacy. The first three schemes are used in existing electricity markets, whereas the last two have been proposed as alternative mechanisms to address capacity adequacy.

#### *Energy Only Market*

The electricity markets in Australia, Scandinavia (Nord Pool), United Kingdom and several other European countries are basically based on the energy only market design. In an energy only market, the only revenues to generation owners are through the sale of electricity in the energy market. In each settlement period a market price is established based on the intersection between the supply and demand curves. Under most circumstances prices reflect the operating cost of the marginal generator (if we assume a competitive market). During peak load conditions the price may represent the willingness of the marginal consumer to pay, generating a scarcity rent which compensates for the fixed cost of the marginal peak generators. If there is no demand elasticity, the price should ideally reflect the real value of energy not served during periods of curtailment.

Several of the problems discussed in the previous section may prevent the energy only market from providing sufficient generation investments. In particular, it is important that the prices during peak load situations are not suppressed, so that incentives for new investments are not distorted. Hogan (2005) proposes an adjusted energy only market design, with a demand curve for operating reserves. This will influence prices in the energy spot market and provide better scarcity pricing and investment incentives. Another approach is to have a strategic reserve in the system. This consists of a set of generating units that are kept available for emergencies by the system operator. The strategic reserves should only be deployed when there is a physical shortage of electricity, and the price must be set to a high level, since it effectively caps the spot market price. A combination of a technical, reliability based activation criterion with a price that is higher than any other bids in the market is a compromise that minimizes market interference (De Vries 2004). In the Nord Pool market three of the system operators hold strategic reserves.

#### *Capacity Payments*

A capacity payment is a regulatory mechanism that establishes a payment to generators, which comes in addition to the income from the energy market. The capacity payment encourages investments by increasing and stabilizing the volatile income of generators from the energy market. The market designs in Spain, Argentina, Colombia and Chile include a fixed capacity payment, which is administratively determined. The old electricity pool in England and Wales also had a capacity payment, which was added to the half-hourly energy spot prices. The dynamic capacity payment was based on the loss of load probability and the value of lost load.

#### *Capacity Requirements and Capacity Markets*

This policy is used in several markets in North East U.S. The objective is to ensure that the capacity levels necessary to maintain system reliability are available. A forecast for a planning period (e.g. years, months, day-ahead) is determined to establish the level of capacity resources that will provide an acceptable level of reliability consistent with agreed upon engineering standards. Based on this forecast, a requirement is established to ensure a sufficient amount of capacity to meet the forecasted load plus reserves to provide for outages, demand uncertainty, and planned maintenance. At the same time, a capacity market is established where load serving entities can purchase capacity in order to meet their capacity obligations.

#### *Financial Reliability Options*

Vázquez et al. (2002) propose a regulatory framework based on an organized market where reliability contracts based on financial call options are auctioned. Hence, both the price of the contracts and their allocation among different generating plants are determined through competitive mechanisms. In addition to stabilizing the income of generators and thereby providing incentives for new investments, the proposed mechanism also hedges end-users against the occurrence of high market prices. Similar approaches have also been proposed by Oren (2005). The main advantage of the financial reliability option scheme is that is based more on market mechanisms and demand side participation than the administratively determined capacity payments and installed capacity requirements.

#### *Capacity Subscription*

A market design based on capacity subscription was proposed by Doorman (2005). This mechanism requires consumers to install a Load Limiting Device (LLD). The LLD is normally inactive. However, when the demand for electricity exceeds available generation capacity, the system operator activates the LLDs, and each consumer's electricity use is limited by the LLD. Consumers can choose their individual demand limit during LLD activation by buying capacity. In the short run, no new capacity can be constructed. The price of capacity, therefore, represents the consumers' willingness to pay for uninterrupted supply within the existing system. The payments made to producers for capacity represent the costs of keeping generation capacity available, while the price of electricity represents the variable cost of electricity production. Through this mechanism, incentives are introduced for consumers to manage their own loads and rationing occurs in an economically efficient manner. However, the advantages must be weighed against the considerable costs of implementation, including large-scale installation of LLDs.

**Experiences so Far from Nord Pool and U.S. Markets**

***Nord Pool***

The restructuring of the Nordic power market started in Norway in 1991, continued with Sweden and Finland in 1996/97, while Denmark finally followed in 2000. Nord Pool is basically an energy only market, but the transmission system operators (TSOs) use additional instruments to ensure system adequacy. The Swedish and Finnish TSOs hold emergency gas turbine reserve capacity. The Norwegian TSO recently also invested in 300 MW gas turbine capacity to ensure energy adequacy in an area with significant transmission constraints. In sum, this emergency gas turbine capacity can be viewed as a strategic reserve, although there is currently not a uniform set of rules for how to use this capacity. In addition, the Swedish, Norwegian and Danish TSOs have established option markets for operating reserves, which help to ensure system security and generation adequacy.

There is little doubt that there was a considerable surplus of generating capacity in Norway and Sweden at the outset of market restructuring. A simple comparison between installed capacity and annual peak load shows a reserve margin of 44 % in Norway in 1990 and 41 % for the whole Nord Pool region in 1995. The Nord Pool market is hydro dominated with about 50% of total generation from hydro. Traditionally hydro power was dimensioned with excess capacity to deal with the high variability in inflow.

Figure 1 shows the development of generating capacity and load in the Nord Pool system since 1994. The figure shows a decrease in installed capacity in 1998 and 1999, when low prices resulted in the closing down of oil-fired thermal capacity. 600 MW of nuclear capacity was decommissioned in Sweden for political reasons in 1999 and again in 2005. The average annual load growth between 1994 and 2006 was 0.9 %, but total demand has hardly changed since 2001, in spite of significant economic growth. The decrease in demand in 2002/03 was caused by a drought in the autumn of 2002, causing an extreme price increase (Figure 2). Figure 2 illustrates the high variability in prices and also shows that the price level has increased after the price spike in 2002/2003. This is partly due to a tighter capacity balance, higher fuel costs, and the introduction of a $CO_2$ emissions trading scheme in Europe.

To judge if there has been "sufficient" investment in new capacity, we can first compare the present reserve margin with the one in the mid-1990's. The margin has been reduced, but not

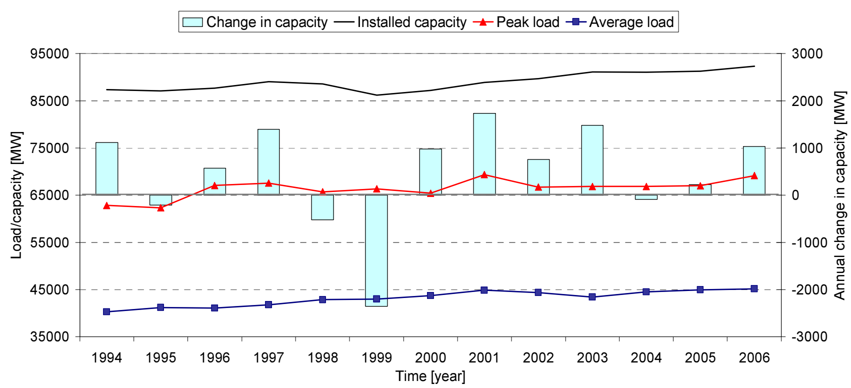


*Figure 1*
*Installed Capacity, Peak and Average Load, and Annual Change in Installed Capacity (right hand axis) in the Nord Pool Market*
Source: Nordel.

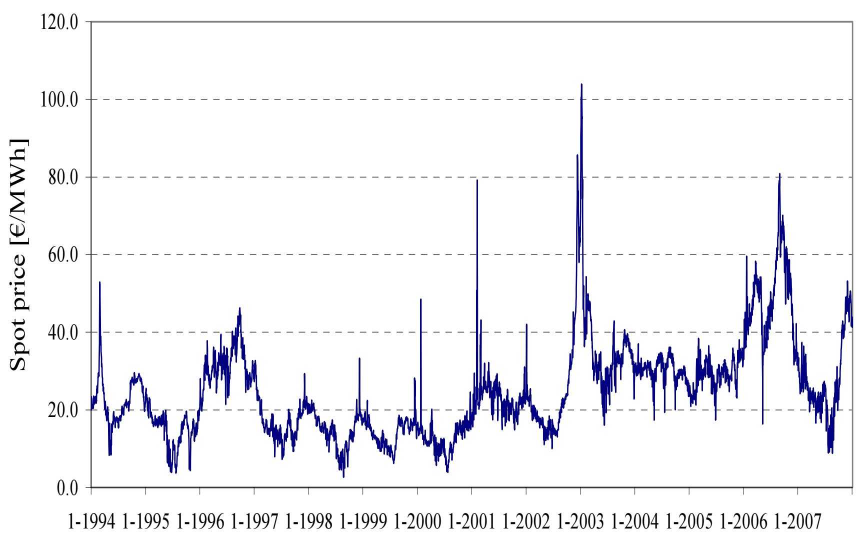


*Figure 2*
*Average Daily Prices in Nord Pool Market, 1994-2007 in €/MWh*
Source: Nord Pool.

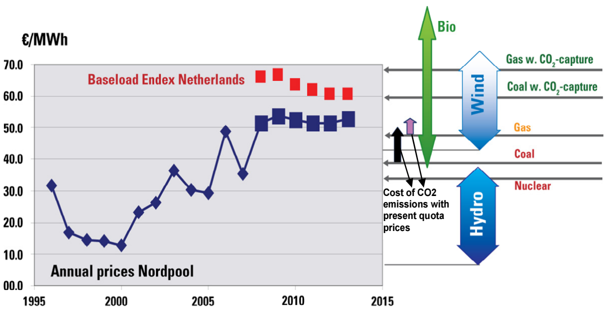


*Figure 3*
*Nord Pool Market Prices (historical and futures prices) and Total Levelized Costs of New Generation*
Source: SINTEF Energy Research, Norway.

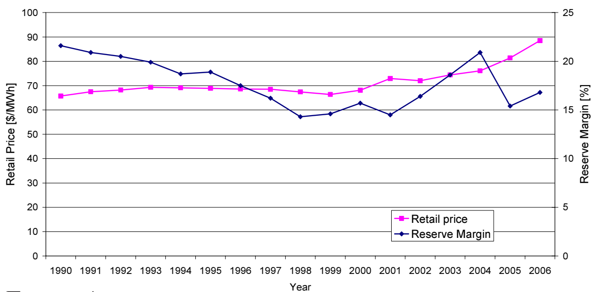


*Figure 4*
*Development of Reserve Margin and Average Retail Electricity Price in the United States*
Source: EIA.

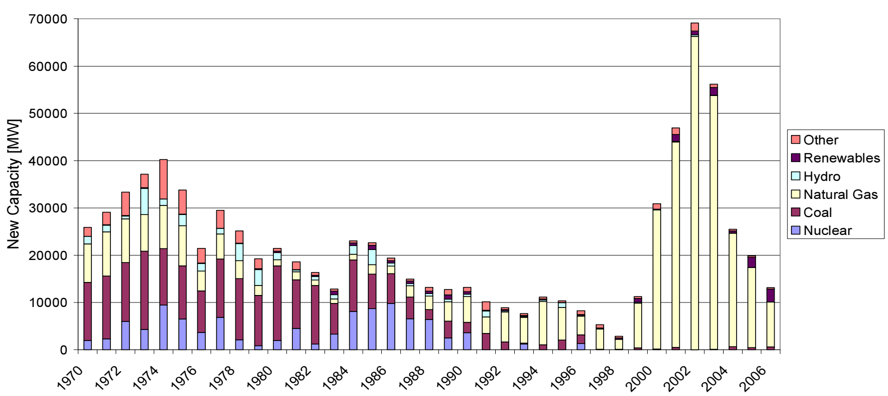


*Figure 5*
*New Generation Capacity in the U.S. by Energy Source, 1970-2006*
Source: EIA.

| | PJM | ISO New England | New York ISO | ERCOT (Texas) | California ISO |
|---|---|---|---|---|---|
| Reserve margin | 14 % | 10 % | 17 % | 14 % | 12 % |
| Peak load | 8.1 % | 4.6 % | 5.6 % | 3.5 % | 10.7 % |

*Table 1*
*Reserve Margin (2006) and Peak Load Growth (2005-2006) in Five U.S. Wholesale Electricity Markets*
Source: FERC.

| | PJM[1] | ISO New England[2] | New York ISO[3] | ERCOT[4] | California ISO[5] |
|---|---|---|---|---|---|
| 2004 | 41.73 | 53.72 | 63.16 | 42.63 | 46.84 |
| 2005 | 60.89 | 78.54 | 93.77 | 66.81 | 55.52 |
| 2006 | 50.07 | 60.94 | 70.90 | 51.98 | 39.64 |

[1]PJM Western Hub [2]Mass Hub [3]New York City Zone [4]ERCOT North Hub [5]SP-15

*Table 2*
*Average Annual Prices in Five U.S. Wholesale Electricity Markets for Selected Hubs/Zones, 2004-2006*
Source: FERC.

dramatically given the initial surplus situation. Another relevant analysis is to compare the market prices with the cost of new generation. Figure 3 clearly shows that only hydro, nuclear and coal power are profitable with the price levels expected up to and beyond 2010. In line with this analysis, present investments are in small and medium sized hydro power (Norway) and nuclear power (Finland), as well as subsidized wind power in Denmark and Sweden.

Overall, investments in generation capacity do occur, partly on commercial conditions, partly based on subsidies for renewable power. However, the necessarily tighter balance will inevitably lead to periods with high prices that consumers must learn to cope with. Nord Pool has a fairly well developed retail market, where end-users can choose between contracts that follow the spot price and longer term contracts with a fixed price. Although consumers to some extent can hedge against price fluctuations through long-term contracts, most consumers still choose spot price related contracts and are, therefore, exposed to the short-term price variations.

***United States***

Over the last 10 years regional wholesale electricity markets have been established in some parts of the United States, mainly in the North East, California, Texas, and the Mid West. However, there are a number of states where the electric power industry is still basically operated as traditionally regulated monopolies.

Figure 4 shows that the overall reserve margin in the U.S. power system is much lower than in the Nord Pool system. A likely explanation is that hydropower makes up a much smaller fraction of the total generation capacity in the U.S. The reserve margin was falling during the 1990s. A low level of investments in new generation capacity, combined with a relatively high load growth (average growth in peak load was 2.1% from 1990 to 2006) explain the decrease. The reserve margin increased substantially from 2001 to 2004 due to a boom in generation investment in this period (Figure 5). A striking observation is that almost all the new generation capacity over the last 10 years has been gas-fired, mainly combined-cycle plants. Average retail prices remained almost constant during the 1990s, but have increased over the last years, probably due to higher fuel prices. There is no apparent link between the reserve margin and the retail price (Figure 4).

One should be careful in assessing capacity adequacy in U.S. electricity markets based on national figures, given the various states of restructuring in different parts of the country. Below we, therefore, provide some statistics from five of the regional wholesale electricity markets. Table 1 shows that the reserve margins are small in these markets, particularly in the New England and California markets. At the same time there is high growth in peak demand.

Table 2 shows the average annual prices in the same markets. The average prices can be compared to the US Energy Information Administration's current estimates of total levelized costs for new natural gas, coal, nuclear and wind generation, ranging from 55 $/MWh to 68 $/MWh (EIA 2007). With some exceptions, like the New York City Zone, the historical prices tend to be below the total cost of new power generation. In fact, several investors in new gas-fired generation capacity during the recent investment boom ended up going bankrupt.

Low reserve margins combined with what appears to be insufficient revenues from the energy market to recover new generation investments may explain why several U.S. markets (PJM, ISO New England, New York ISO) have capacity markets. In their original implementations, a fixed capacity obligation was determined for each load serving entity (LSE), according to the system reliability criterion and the LSE's share of total system demand. The capacity obligation was accompanied with a capacity market, where LSEs could purchase capacity in order to meet their obligations. However, these capacity markets are undergoing a number of modifications. An administratively determined capacity demand curve is now typically used to determine the capacity price, which also depends on the location in the network. At the same time, a longer forward procurement period is used to allow for new generation to compete in the capacity auctions (Crampton and Stoft 2006, Hobbs et al. 2007). California ISO is also considering introducing a capacity market, whereas the ERCOT market in Texas is basically an energy only market.

**Looking Ahead**

As the discussion above illustrates, there is no uniform solution for capacity adequacy in electricity markets. The choice of market design will depend on the conditions in the specific country or region, such as load growth, generation mix, amount of renewables, level of demand response, etc. Administrative capacity payments and capacity market constructs deviate from market-based solutions and involve significant transfer of wealth from consumers to producers. Consumer preferences are better represented in the proposed reliability options and capacity subscription schemes.

We believe that the long-term solution lies in increased demand participation in electricity markets, both in terms of short-term price response and increased participation in long-term markets. This will enable better scarcity pricing and more liquid and mature long-term markets for risk management. Over time, this should eliminate the need for specific capacity adequacy policies. A prerequisite for this development is that it becomes politically acceptable that consumers are exposed to varying and occasionally high prices.

Finally, since most electricity markets are still relatively young, the overall experience with generation investment and capacity adequacy policies is very limited. Modeling and simulation can, therefore, play an important role in testing different policies and designing robust electricity markets. Examples of recent simulation studies that address the long-run consequences of electricity market restructuring include De Vries (2004), Botterud et al. (2005, 2007), Kadoya et al. (2005), Hobbs et al. (2007), and Doorman et al. (2007).

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