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The Cambridge-MIT Institute

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Insufficient Incentives for Investment in Electricity Generation

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In theory, competitive electricity markets can provide incentives for efficient investment in generating capacity. We show that if consumers and investors are risk averse, investment is efficient only if investors in generating capacity can sign long-term contracts with consumers. Otherwise the uncovered price risk increases financing costs, reduces equilibrium investment levels, distorts technology choice towards less capital-intensive generation and reduces consumer utility. We observe insufficient levels of long-term contracts in existing markets, possibly because retail companies are not credible counter-parties if their final customers can switch easily. With a consumer franchise, retailers can sign long-term contracts, but this solution comes at the expense of the idea of retail competition. Alternative capacity mechanisms to stimulate investment are discussed.

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1 Introduction

In California, Norway, Sweden, Brazil, New Zealand and Italy wholesale electricity prices increased significantly when geneartion capacity became scarce. This has instigated a debate whether liberalized electricity markets provide sufficient incentives for investment in generating capacity to ensure electricity supply at affordable prices. According to the theory of spot pricing, electricity spot markets can achieve efficient outcomes both in the short-term operation and in long-term investment decisions (Caramanis et al., 1982). The (spot) price varies, similar to spot prices in other markets, to match demand and supply. However, the variations are more frequent and extreme than in other commodity markets, because storage of electricity is too costly for commercial application, other than pumped-hydro (cf. Shuttleworth, 1997; Hirst and Hadley, 1999). Observed shortages of investment in generating capacity are generally attributed to artificial obstacles to the proper functioning of the market mechanism, such as price caps on spot markets, or permit requirements and planning approval for new investment.

It is not uniformly accepted that removing these obstacles and regulatory risk will suffice to guarantee adequate investment (De Vries and Hakvoort 2002, Turvey 2003). Hence England and Wales, under the pool regime, and Spain and a number of South American systems use capacity payments to stimulate investment in generating capacity (Vázquez et al., 2002), while systems on the East Coast of the USA (PJM, the New York Power Pool and the New England Power Pool) use capacity requirements (PJM Interconnection, L.L.C., 2001; Besser et al., 2002). Most European systems, on the other hand, expect the energy market to provide sufficient incentives for investment and have not implemented additional policies.

We start from the premise that a market with appropriate risk management tools allow parties to manage uncertainty efficiently and provides competitive generating companies with an incentive to produce an optimal volume of generating capacity. The optimal equilibrium volume of generating capacity would require consumers to sign contracts with generating companies for their expected electricity output for a number of years in advance. In the current model of competition between retail companies, the retail companies would have to sign these contracts. However, they cannot carry the price risk involved in such contracts, so in turn they would want to specify in their contracts with final customers a termination period of an equal number of years or a cancellation payment. However, regulators currently strive to reduce the barriers against switching by final customers in order to increase retail competition and reduce retail margins. If switching of electricity contracts would take years, or would alternatively involve switching costs similar to those observed in the refinancing of bank loans, then the struggle of regulators for retail competition would be lost. Hence the paradigm of retail competition is incompatible with long-term contracting for electricity.[2]

If the above described reason or other constraints restrict long-term contracting, then the market cannot implement the first-best solution. This has three implications. First, consumer welfare is slightly reduced, because consumers cannot hedge electricity price risk. Secondly, investment in peaking capacity is only remunerated in times with generation scarcity, and hence faces volatile returns. Investors require higher rates of return, and postpone their investment until the expected electricity price is higher. Third annual price volatility also increases volatility of revenue streams for base load generation if sales are not covered by long-term contracts. This increases the required rate of return, capital costs and hence investors will choose less capital-intensive generating technologies, even if this creates higher fuel costs. A lack of long-term contracts biases technology choice against energy efficient technologies and might further increase costs of providing electricity.

The lack of long-term contracting on behalf of consumers creates additional costs. Green (2004) shows that the inability of retail companies to sign long-term contracts increases the energy sales volume in the spot market and induces generation companies to exercise more market power and push up equilibrium electricity prices. Green suggests reinstating consumer franchises such that supply companies face a stable customer base. The

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[2] Oren (2003) quotes a proposal by Reliant that retail companies sign long-term hedging contracts. The customer base of individual retail companies is difficult to anticipate, hence the indipendent system operator (ISO) is requested to sign long-term hedging companies as a supplier of last resort and sell them at any point in time to retail companies at cost-based rates. This proposal seems attractive for retail companies, if generating capacity turns out to be abundant, then they buy cheap hedging contracts from the market, if it is scarce, then they obtain these contracts from the ISO at initial purchasing costs. The profit-maximizing strategy for retail companies seems to be to buy short term. This implies that the ISO needs to

challenge is to ensure that the supply companies with the local monopoly granted through the franchise face sufficient incentive to negotiate low contract prices with generators. Green suggests using yard-stick competition between franchises to achieve this objective. Alternatively one could envisage tender auctions for long-term contracts to ensure low prices, as successfully implemented in New Jersey for the supply of residual residential customers.[3]

Cowan (2002) assesses the effect of the price volatility of fuels used to generate electricity. He also concludes that consumers are best off if they hedge their price risk with long-term contracts for their expected demand. In addition, they should be exposed to marginal prices for any deviations from the expected demand so that short-term efficiency is achieved. The authors assume that consumers either sign direct hedging contracts in parallel with their electricity contracts or choose between flexible and fixed tariffs. However, as argued section 4, retail companies exposed to competition cannot offer fixed retail tariffs corresponding to long-term hedging contracts. We share Cowan's perspective on the value of hedging energy prices and expand it to implications of long-term contracts on the investment volume. If consumers or retail companies hold long-term contracts on behalf of consumers, these reveal the consumers' expected future demand to the generating companies and reduce quantity risk for investment.

This paper does not address the more general question of system security. Insufficient investment in generating capacity will increase the frequency with which system operators are forced to shed load. However if security margins are retained, then this should not affect system security. Arguably, system operators can delay load shedding by reducing the operating margin of the system. They are exposed to complaints if load is shed and do not fully internalize the risk to which their strategy exposes neighboring system operators in the entire network. This may mean that reduced generation adequacy may affect system security. It is currently being discussed to what extent shortages in Norway, Sweden, New Zealand and Italy were caused by insufficient generation capacity

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negotiate all long-term hedging contracts and effectively takes over the main objective for the creation of retail competition – bargaining for low energy prices.

[3] An auction was implementd to purchase one-year and three-year contracts for total of 18,000MW of generation on behalf of PSE&G, JCP&L, ACECO and RECO. (See optimalauctions.com)

(Woo et al., 2003; Nilssen and Walther, 2001; Lindqvist, 2001; Leyland, 2003; Fraser and Lo Passo, 2003).

This paper is structured as follows. The next section briefly recapitulates the theory of spot pricing as the starting point of the analysis. Section 3 analyses the impact of uncertainty on the amount of contracts risk neutral and avers consumers and investors would sign. Section 4 illustrates why in the current market design generation companies are reluctant to sign long-term contracts with retail companies, and Section 5 approximates the implications on electricity prices. Section 6 presents additional sources of distortions of investment in generating capacity. Section 7 discusses capacity mechanisms to increase investment, and Section 8 reflects upon the impact of inter-system trade. We conclude in Section 9.

2 The theory of spot pricing

Caramanis et. al. (1982) show that investors in a well-defined, unregulated market will provide sufficient investment in generating capacity. One frequently quoted requirement for the success of such liberalized energy markets is that demand is sufficiently price-elastic so that the supply and demand functions always intersect. In practice, the observed short-term price-elasticity of electricity demand is low and supply and demand functions may not intersect. Revealed price elasticity is even lower, because high costs for equipment and operation of real time metering implies that few customers are exposed to real time prices (Littlechild 2003).

Hence the system operator sometimes needs to shed load by interrupting electricity supply to groups of customers. A price cap needs to be instituted in the short-term market to protect consumers against excessive prices during these times (e.g. Ford, 1999; Hobbs et al., 2001b; Stoft, 2002). If consumers are not involved in real-time price setting, they otherwise may find themselves paying more than their value of lost load (VOLL). It is difficult, however, to establish the correct level for the price cap, because the value of lost load is difficult to determine. Estimates suggest that the value of lost load is some two orders of magnitude higher than regular electricity prices, but they vary widely among each other (Willis and Garrod, 1997; Ajodhia et al., 2002).

Stoft (2002) shows that in a perfectly competitive market, a price cap at VOLL results in an optimal level of investment in generating capacity, with an optimal duration of power interruptions. This suggests that spot pricing is applicable even if revealed demand is fully inelastic. Rotating black-outs at times when demand exceeds supply at the price cap cause inefficiencies because consumers are inhomogeneous and some would prefer to pay a higher price to ensure uninterrupted electricity supply, while others would prefer more frequent interruptions if that would lower their electricity bill. However, even a public enterprise with benevolent management would face the same dilemma.[4] It can only be resolved with real-time metering and pricing or active demand side management. It is unclear whether the installation and transaction costs of such technology are justified.

Borenstein and Holland (2003) analyze intra-annual price volatility and conclude that full real-time pricing attains the first-best capacity investment (result 3) while time-invariant retail prices result in inefficient consumption decisions and distorted investment decisions. Intra-annual price volatility is averaged over the course of a year and therefore creates little price risk for agents. Hence their analysis ignores the effects of risk aversion. We complement their analysis by focusing on the inter-annual price volatility for which risk aversion can no longer be ignored. To simplify our analysis we abstract from the intra-annual price volatility.

Even with long-term contracting, spot markets will are needed to allow parties to trade imbalances relative to their contractual positions or even to replace their own generation with electricity bought in the market if that is more economical. Spot markets provide a reference price for contracts for difference, multi-part tariffs or demand-side management programs which allow for savings if some load can be interrupted. An example of the latter is a tariff that specifies that a consumer can always receive his average annual electricity demand at the fixed retail price. If the consumer reduces demand, then he will be paid for at the difference between wholesale price and retail tariff, while if he increases demand, he has to pay according to the wholesale price for the additional energy. An extreme version of this program was successfully implemented

[4] Joskow (1976) provides a survey of marginal cost pricing by regulated utilities and Chao (1983) shows the joint impact of uncertainty about demand and supply.

in Brazil to combat the energy shortage of the hydro system in 2002. Consumers could receive 80% of average consumption at usual retail rates.[5] If they exceeded this level of consumption, they were first warned and subsequently disconnected. This extreme version was probably required in a society with high inequality to ensure that not only poor people, who are more price sensitive, contribute to the solution of the energy crisis. One would expect that in countries with less inequality price based mechanisms would work equally well.

When we subsequently refer to long-term contracts, we imply that consumers or franchises sign contracts for differences on behalf of consumers to cover the price risk on their expected consumption, or are exposed to a fixed retail tariff for their expected demand which is based on the prices paid for long-term contracts. These tariffs would be complemented by mechanisms to encourage demand side management as described above.

3 Risk aversion in the absence of long-term contracts

3.1 Introduction

The investment decision can be describe as a two-stage game (Figure 1). In stage 1, investors decide how much generating capacity K to provide, and in stage 2 the spot markets determine how these capacity is allocated to different consumers C. We abstract from daily and seasonal demand volatility and only assess a representative demand and consumption for each year. This simplification can possibly be justified by the observation that in liberalized markets price spikes, which develop during a limited number of hours when demand is close to available capacity, provide the main revenues to cover fixed and capital costs. Hence the volume of generating capacity and demand during these hours have a crucial impact upon consumer expenditures, generator profits and investment decisions. We assume that consumers and investors behave competitively.

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[5] Information about the Brasilian electricity crisis can be found at: http://www.energiabrasil.gov.br/EnergiaBrasil.htm

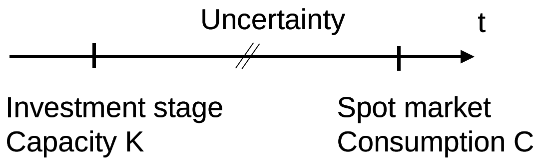


Figure 1: Two-stage investment model

As investments in generating capacity take years to complete, we will introduce uncertainty about future demand between these two stages. To facilitate the analysis, we assess different causes of uncertainty which affect different groups of users. In section 3.2 we assume one homogeneous group of consumers, all of which are affected simultaneously by e.g. a cold winter. Section 3.3 assumes that two groups of consumers, industrial and private, are connected to the network. In this section, certain causes of uncertainty, like the business cycle, are assumed to impact industrial demand but not to affect private consumption directly.

For each of these cases we first calculate the generating capacity that risk-neutral consumers would contract for. This corresponds exactly to the volume of capacity that risk-neutral investors would finance if they fund the investment with revenues from the spot market. In the absence of risk aversion, hedging contracts are not necessary and short-term contracting suffices to implement the first best solution. We use the volume of generating capacity which risk neutral agents would install as a reference.

In the second part of the analysis for each type of uncertainty we assume that consumers and investors are risk averse.[6] We calculate how the volume of long-term contracts signed by consumers (and hence the equilibrium volume of generation investment)

[6] While the assumption of risk aversion on the consumer side appears widely shared, for investors risk aversion can easily be justified for all price risk that is correlated with the market evolution by using the capital asset pricing model. Electricity demand growth is highly correlated with the evolution of the GDP and therefore with the performance of the economy and stock markets. This implies that low growth brings about both low electricity prices and low stock returns, which is an unfavorable situation to investors in electricity generating capacity. So investors are risk-averse because they cannot hedge the risk of low electricity prices in other markets. Furthermore, for two reasons investors do not appreciate volatility of annual profits that is uncorrelated with the stock market. Firstly, it is costly because it distorts the signal of profits as an incentive mechanism for management, which was the initial justification for privatization. Secondly, it requires hedging over larger geographical regions or over several industries to smooth the volatility. This implies that ownership is more international, with the drawback that regulators are less

changes if consumers are risk averse. The first entry in the Figure 2 shows that, if all consumers face the risk of a common negative shock during which consumer utility decreases while consumption increases (e.g. due to a cold winter), risk aversion causes them to increase the volume of generating capacity they contract for.

Source of Demand Uncertainty		Consumer Reaction		Investor Reaction
Aggregated	negative shock	K ↑	>	K ↓
	Positive shock	K ↓	=	K ↓
Exogenous		K~	>	K ↓

Figure 2: Change of installed capacity K caused by risk aversion

Likewise we assess how the equilibrium volume of generation capacity provided by investors who sell their output through short-term contracts changes if they become risk averse. If investors are faced with uncertainty about future demand, then risk aversion reduces the equilibrium quantity of generating capacity they will provide in the market. Combining the equality for risk-neutral consumers and investors with the inequalities caused by risk aversion allows us to conclude that under an aggregate negative shock, risk-averse consumers will contract for more generating capacity with investors than risk-averse investors would provide if they did not sign long-term contracts for the marginal generating unit, but had to finance it based on revenues from short-term markets. Hence the equilibrium level of investment is reduced from the efficient, first-best volume if generators are not able to sign long-term contracts with consumers. A similar analysis, performed for other types of uncertainty, is presented in Figure 2.

3.2 Weather-related uncertainty of demand

Because all consumers are affected similarly by weather, we assume only one homogeneous group of consumers. We calculate the volume of long-term contracts that consumers would sign with investors. We compare this to the equilibrium volume of generating capacity that investors provide who recover their investment in the spot

committed to respect the interests of the shareholders. Shareholders anticipate this and require higher returns.

market. Without uncertainty, both approaches result in the same volume of generating capacity. In the presence of uncertainty about future weather, risk-neutral agents develop more generating capacity than is required to match expected demand. The same equilibrium volume of generating capacity develops whether financed through long-term contracts by consumers or with spot-market revenues. In a third step we assume that consumers and investors are risk averse. They want to avoid decreases of their total utility, which is a function of their residual available money and their utility from electricity consumption. We find that risk-averse consumers contract for more generating capacity than risk-neutral consumers, but risk-averse investors offer less generating capacity than risk-neutral investors.

3.2.1 Consumers' perspective on weather-related uncertainty

To begin with, we will assume that all consumers are exposed to the same unexpected cold winter which increases energy demand, e.g. for electric heating, lighting and water circulation. The weather condition ε influences the monetary value that consumers derive from consuming a volume C of electricity: $M(C,\varepsilon)$. A positive ε means a colder winter than average. We further assume that (a) consumers benefit from more electricity, that (b) their comfort is decreased in colder winters but that (c) in colder winters the marginal monetary value of an additional unit of electricity increases:[7]

$$a)\frac{\partial M(C,\varepsilon)}{\partial C} > 0 \qquad b)\frac{\partial M(C,\varepsilon)}{\partial \varepsilon} < 0 \qquad c)\frac{\partial^2 M(C,\varepsilon)}{\partial \varepsilon \partial C} > 0.$$

To solve the model for the case of weather related uncertainty we assume the following, linear, relationship between C and ε, which will be defined differently in section 3.3 and 3.4:

$$M(C,\varepsilon) = M(C-\varepsilon),$$

[7] In this section the following notation will be used:

K	Installed Capacity	ε, σ_ε^2	Shock on demand or utility Utility function
C	(private) consumption	D	Industrial demand
M	Monetary value of electricity	π	Consumer wealth (money and consumption)
M=M'	Marginal monetary value	U	Utility derived from wealth
P	Short-term electricity price	G	Minimum investment per investor

and to avoid third derivatives define m as the willingness to pay, which is convex:

$$m(C-\varepsilon)= M'(C-\varepsilon)>0 \qquad m'(C-\varepsilon)<0 \qquad m''(C-\varepsilon)>0. \tag{1}$$

Consumers decide how much generating capacity K to invest in or contract for through long-term contracts. Without loss of generality, we normalize variable costs of generation to be 0. The cost of generating capacity therefore is cK, with c the long-run marginal cost of capacity.

As we assumed that only one homogeneous group of consumers exists, no trade occurs to adjust for the realization of ε and each consumer uses all his available capacity $C=K$. We define consumers' wealth π as the monetary value of the electricity they consume M plus the other sources of wealth at their disposition (normalized to zero), minus their expenditures on electricity, which equal cK. Without uncertainty (ε=0), consumers' wealth π is:

$$\pi(K)=M(K)-cK \tag{2}$$

Using the first order condition with respect to K gives the optimal volume of generating capacity K_W **w**ithout uncertainty:

$$c=m(K_W) \tag{3}$$

If risk-neutral consumers face uncertainty about their future demand due to uncertainty about the weather, they will maximize their expected wealth, which is defined as follows:

$$\pi(K)=E[M(K-\varepsilon)-cK]. \tag{4}$$

The first order condition with regard to K renders the optimal volume of generating capacity for a risk-**n**eutral consumer K_N:

$$c= E[m(K_N -\varepsilon)]. \tag{5}$$

Willingness to pay m for energy is convex $m''>0$, therefore $E[m(K_N - \varepsilon)]> m(K_N)$. Willingness to pay for energy is also decreasing in consumption $m'<0$, therefore (3) and (5) can only both be satisfied if $K_W<K_N$. The optimal volume of generating capacity K_N in an uncertain world with risk-neutral consumers exceeds the capacity K_W, which would have been installed in the absence of uncertainty. Stoft (2002) already described this

result from the theory of consumption and investment under uncertainty, when he introduces uncertainty regarding the availability of generating capacity.

Risk-averse consumers

Let us introduce consumer utility U, which is a monotonic function of the wealth π: $U'(\pi)>0$. Utility of risk-neutral consumers increases linearly with wealth π.[8] By contrast, risk-averse agents exhibit a decreasing marginal utility with higher wealth levels: $U''(\pi)<0$. Consequently, *(4)* transforms into:[9]

$$U=E[U\{M(K-\varepsilon)-cK\}]. \tag{6}$$

The FOC of (6) with respect to K gives an equation for the equilibrium volume of generating capacity K_R which risk-averse consumers contract for:

$$\mathrm{c}=\mathrm{E}\left[\frac{\mathrm{U'}\{\mathrm{M}(\mathrm{K_R}-\varepsilon)-c*\mathrm{K_R}\}}{\mathrm{E}[\mathrm{U'}\{\mathrm{M}(\mathrm{K_R}-\varepsilon)-c*\mathrm{K_R}\}]}\; m(\mathrm{K_R}-\varepsilon)\right] \tag{7}$$

Equations (5) and (7) differ in the weighting factor $w(\varepsilon)=U'(\varepsilon)/E[U']$. Using (1) gives $\partial w(\varepsilon)/\partial\varepsilon=-U''m/E[U']>0$ and $\partial m(K_R-\varepsilon)/\partial\varepsilon=-m'>0$, hence the average of a convex function exceeds the value the function takes at the avereage:

$$E[w(\varepsilon)m(K-\varepsilon)]>E[w(\varepsilon)]E[m(K-\varepsilon)]=E[m(K-\varepsilon)]. \tag{8}$$

If we assume (hypothetically) that $K_R=K_N$, then the expected value of additional capacity (right hand side of *(7)*) would exceed the marginal costs c. Therefore risk-averse consumers contract for additional capacity $K_R>K_N$. They reduce the downside risk of cold winters by contracting for more energy than risk-neutral consumers.

3.2.2 Investors' perspective on weather-related uncertainty

In a world without uncertainty, the spot-market price P equal the willingness to pay $m(K)$. In a competitive world, new investors will enter the market until the equilibrium

[8] Formally: $U(\pi)=\lambda\pi$. The value of λ is arbitrary; therefore we can set $\lambda=1$ so that U is the same as π and use the simplified approach of maximizing wealth of risk-neutral consumers in (3) and (5).

[9] Our representation of the utility function differs from the more general utility function. The general utility function states utility as two-dimensional function of consumed energy C and discretionary income -cK: $V(C,-cK)$ and hence depicts R^2 into R while we only use two functions depicting R into R. The more general representation coincides with our representation if for all C, cK: $V_1=U'M'$ and $V_2=U'$.

price P equals costs c of additional generating capacity, so $P=c$. Combining these two equations gives $c=m(K)$, which is identical to (3). The market will therefore provide for the optimal investment quantity K_W.

In the presence of uncertainty, risk-neutral investors will ensure that, on average, they can recover their costs: $c=P=E[m(K-\varepsilon)]$. The exact correspondence with (5) shows that even in the presence of uncertainty the market will provide the appropriate volume of generation investment K_N, as long as consumers and investors are risk neutral.

If investors are risk averse, then their expected benefit from investing in G units of generating capacity at the aggregate investment level K_I is:

$$\pi=E[U_{invest}\{G\cdot(m(K_I-\varepsilon)-c)\}] \tag{9}$$

As investors are risk-averse, the marginal utility is decreasing in wealth (U'>0, U''<0), therefore:

$$E[U_{invest}\{G\cdot(m(K-\varepsilon)-c)\}]<U_{invest}\{G\cdot E[(m(K-\varepsilon)-c)]\}. \tag{10}$$

If risk-averse investors would invest the same volume of generating capacity as risk-neutral investors K_N, then the right hand side of (10) would be zero, which would imply that the left-hand side would be negative. To increase the left-hand side, as required to satisfy (9), the investment level K_I needs to fall below K_N, because $U'>0$ and $m'<0$. The volume of generating capacity provided by risk-averse investors is therefore smaller than the volume provider by risk-neutral investors. Summarizing:

> ***Proposition 1:*** *In anticipation of aggregate weather-related uncertainty of demand, risk-averse consumers which can sign long-term contracts will contract for more generating capacity than risk-neutral agents* ($K_R>K_N$)*. Risk-averse investors who recover their investments in short term markets, however, construct less generating capacity than risk-neutral agents* ($K_I<K_N$).

3.3 Exogenous demand uncertainty

Now we will assume that we have a homogeneous group of private electricity consumers and a second homogenous group of industrial consumers. Industrial demand is subject to unexpected shocks, mainly due to the unpredictable development of the business cycle. Both industrial and private consumers are connected to the same electricity network and are part of the same market. Therefore private consumers are subject to price volatility induced by industrial consumers.

If private consumers have signed a volume of long-term contracts K for their expected energy demand, then they retain the option to cover their anticipated consumption at no extra cost. However, they can improve upon this situation by increasing consumption if additional electricity can be bought cheaply at the wholesale level and by decreasing consumption if they can re-sell some of their energy at higher prices to the wholesale market. Hence private consumers with long-term contracts benefit from both types of deviations by industry demand. Obviously the argument equally applies to industry customers who have signed long-term contracts for their expected demand and deviate from their consumption to adjust to changes of private customers' electricity demand.

We will show that risk-averse investors who fund their generation investment with spot market returns will provide for less generating capacity than risk-neutral investors. Risk-averse consumers will wish to contract for equilibrium quantities of capacity that exceed the quantity provided for by risk-averse investors. However, as individual consumers only contract small quantities beyond their expected demand, the marginal unit of generation investment to satisfy industrial demand would continue to be provided by merchant investors, unless industrial consumers sign long-term contracts.

3.3.1 Consumers' perspective on exogenous demand uncertainty

In contrast to the previous section, consumers are note directly exposed to shocks, hence the monetary value of electricity M is only a function of consumption C. As two groups of agents are active, they now have the option to trade in the spot market. Relative to equation (2), the wealth function of consumers π therefore not only contains the decision variable K for the investment or long-term contracting decision, but also the option to trade in the spot market by choosing consumption C different from K. The spot market price P results from total installed capacity K minus industrial demand D, which is subject to a shock ε and private consumption C which adjusts with industry demand shock ε.

$$\pi(K,C(\varepsilon))=M(C(\varepsilon))-cK+(K-C(\varepsilon))\cdot P(K-D-\varepsilon-C(\varepsilon)) \qquad (11)$$

To determine the optimal consumption decision of consumers, we differentiate (11) with respect to C and obtain $M'(C)=m(C)=P(K-D-\varepsilon-C)$. The willingness to pay for electricity m equals the spot market price of electricity P. Note that individual consumers are not assumed to influence the market price, so $P'=0$.

How does the consumption of consumers change with changes of industry demand ε? We differentiate $m(C)=P(K-D-\varepsilon-C)$ with respect to ε and, as all private consumers are acting simultaneously, also consider the impact upon the market clearing price, using $P'<0$. As expected, private consumption decreases with increased industry consumption ε:

$$\frac{dC(\varepsilon)}{d\varepsilon}=\frac{-P'}{m'+P'}<0 \qquad \frac{d^2C(\varepsilon)}{d\varepsilon^2}=\frac{m'P'}{(m'+P')^3}\left(\frac{P''}{P'}m'-\frac{m''}{m'}P'\right) \qquad (12)$$

To determine the optimal investment quantity K for risk-neutral consumers under uncertainty we form the expectation of (11) over all possible realizations of ε:

$$\pi(K)=E[M(C(\varepsilon)) - C_\varepsilon P(K-I-\varepsilon- C(\varepsilon))] + KE[P(K-D-\varepsilon- C(\varepsilon))-c]. \qquad (13)$$

Differentiating with respect to K and remembering that competitive consumers do not consider their impact on the market price ($P'(C)=0$), we find again the equilibrium quantity K_N of risk-neutral consumers:

$$c=E[P(K_N -D-\varepsilon- C(\varepsilon))]. \qquad (14)$$

To determine the equilibrium price, we expand (14) as a second order Taylor series and use (12). As the industry demand shock ε is normalized, so $E(\varepsilon)=0$, the first order term is zero and the dominant term is of second order:

$$P=c-\frac{\sigma_\varepsilon{}^2}{2}\left(m''\left(\frac{P'}{m'+P'}\right)^3+P''\left(\frac{m'}{m'+P'}\right)^3\right) \qquad (15)$$

If the demand function is convex ($P''>0$, $m''>0$), investment is higher under uncertainty and hence the market-clearing price P at expected demand (ε=0) is below the long-run marginal cost c (14). This corresponds to the previous result that equilibrium installed generating capacity is higher under uncertainty than required to cover the expected demand: $K_W < K_N$.

<u>Risk-averse consumers</u>

Now let us assume that consumers are risk-averse, which we will represent, as before, by inserting a concave utility function: $U'>0$, $U''<0$ in (13).

$$U(K)=E[U\{M(C(\varepsilon)) - C(\varepsilon)P(K-I-\varepsilon- C(\varepsilon))+K(P(K-I-\varepsilon- C(\varepsilon))-c)\}]. \tag{16}$$

Differentiating with respect to K and then expanding in a second order Taylor series in ε and substituting C' and C'' from (12) gives:

$$P = c - \frac{\sigma_\varepsilon^{\ 2}}{2}\frac{m''\left(\frac{P'}{m'+P'}\right)^3 + P''\left(\frac{m'}{m'+P'}\right)^3 + 2\frac{U''}{U'}(K-C)\left(\frac{m'P'}{m'+P'}\right)^2}{1+\frac{\sigma_\varepsilon^{\ 2}}{2}\left(\frac{U''}{U'}\left((K-C)\left(m''\left(\frac{P'}{m'+P'}\right)^3 + P''\left(\frac{m'}{m'+P'}\right)^3\right) - m'\left(\frac{P'}{m'+P'}\right)^2\right) + \frac{U'''}{U'}\left((K-C)\frac{m'P'}{m'+P'}\right)^2\right)} \tag{17}$$

Risk aversion has two counterbalancing effects. In the denominator it adds the third term relative to the risk-neutral case (15). This term is negative and therefore reduces investment beyond expected demand. It corresponds to a similar term in the function for investors (which is discussed below) and shows that risk-averse consumers, like investors, are less likely to take this speculative position. This reduction of generation investment is countered by the denominator decreasing in volatility (assuming U''' is positive (as for log utility) or not too negative to dominate the first term). Consumers can choose a convex combination of consumption and revenues from selling contracted capacity and are hence more inclined to contract for additional generating capacity.

3.3.2 Investors' perspective on exogenous demand uncertainty

Assume that investors face uncertainty about price, identical to (9). As both risk-averse consumers and investors reduce the equilibrium volume of generating capacity relative to the risk-neutral reference case, we will quantify their reduction to allow a comparison. Replace $m(K-\varepsilon)$ with $P(K-D-\varepsilon-C(\varepsilon))$ in (9) and then make a second-order Taylor expansion in ε. As for consumers, second order is required because $E(\varepsilon)=0$. Then developing around the risk free equilibrium quantity K_0 with $P(K_0)-c)=0$ in first order, and using $U_{invest}(G(P(K_0)-c)) = U_{invest}(0) = 0$ gives:

$$P = c - \frac{\sigma_\varepsilon^{\ 2}}{2}\left(m''\left(\frac{P'}{m'+P'}\right)^3 + P''\left(\frac{m'}{m'+P'}\right)^3 + \frac{U_{invest}''G}{U_{invest}'}\left(\frac{m'P'}{m'+P'}\right)^2 \right). \qquad (18)$$

Comparing (18) and (15) we observe that risk-aversion adds an additional, negative component on the rhs. (*U’’<0, U’>0,* bracket>*0*). Therefore they will invest less, in equilibrium, than risk-neutral investors or consumers. Comparing risk averse investors with risk averse consumers we note that the denominator of (17) exceeds the value of the bracket in (18) if

$$G\frac{-U''_{invest}}{U_{invest}'} > 2(K-C)\frac{-U''_{consumer}}{U'_{consumer}} \qquad (19)$$

The condition is satisfied if there are transaction and information costs associated with investing in merchant generation, so that it hence requires a sufficiently large investment volume G per investor which exceeds the excess contracting K-C, even if it is scaled by a factor of two and the curvatures of investors’ and consumers’ utility functions. Furthermore, as noted above, the denominator of (17) is smaller than 1, which reinforces the effect that consumers will contract in equilibrium for more generating capacity than would be provided for by risk averse investors.

> ***Proposition 2:*** *In anticipation of an exogenous demand shock (e.g. to another country or industry), risk-neutral investors and consumers contract for the same volume of generating capacity, which is larger than the volume contracted for by risk-averse investors. Typically risk-averse consumers contract for more generating capacity than would be provided for by risk averse investors.*

3.3.3 Conclusion about effect of risk aversion and uncertainty

The discussed sources of uncertainty result in less investment in generating capacity than the first-best solution, which allows for long-term contracting. So why do we anticipate that consumers do not sign a sufficient volume of long-term contracts?

4 Obstacles to long-term contracts

In most instances, generators do not sell their electricity directly to final consumers but to retail companies which act as intermediaries. One might expect that retail companies constitute an appropriate counterpart for long-term contracts. Figure 2, however, illustrates why generating companies would only sign a limited volume of long-term contracts with retail companies in an environment of strong retail competition. Assume that the price of a long-term contract corresponds to the average wholesale price during the period shown in the figure. In periods with average wholesale prices and retail prices above long-term contract prices, like in 2003, retail companies benefit and generators lose from their long-term contracts. In exchange, generators would expect to win from long-term contracts in periods with low wholesale prices, like during 1999-2000. But in such periods, new retail companies may enter the market and offer cheap retail electricity. If the regulatory agencies succeed in achieving retail competition, then switching costs will be low for consumers and they will move towards these new retail companies. Under such circumstances, all retail companies would need to follow. Retail companies with existing long-term contracts would incur losses. Some eventually would go bankrupt and would not honor their contracts. Generators would anticipate the resulting decrease in profits from long-term contracts and therefore be reluctant to sign significant volumes of long-term contracts with supply-companies. Analysis by Woo et al. (2003) confirms the implied result - trading of forward and futures-contracts is thin in liberalized markets.

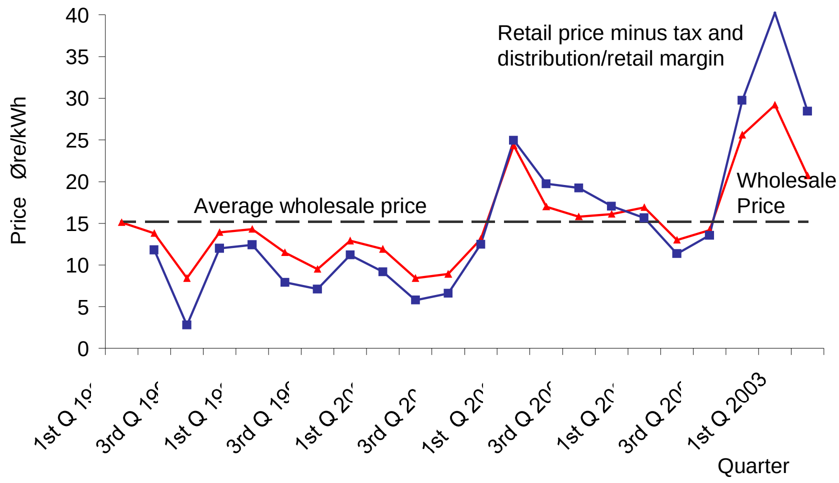


Figure 2: Norwegian retail prices linked to wholesale price.[10]

The risk to generators stems from the fact that retail companies may lose their customers to new retail companies in times when their long-term contracts exceed the short-term price. Car or liability insurance contracts pool the risk over a group of people at any period of time and hence can be switched at any point in time, which facilitates competition. Long-term electricity contracts average the risk over time and would therefore need to be signed a number of years ahead of time, with a rolling horizon of at least the same length. Therefore any switching by consumers would require a transfer between consumer and retail company equal to the current difference between the value of the forward electricity contract and the average spot price for the duration of the contract. This could potentially involve large sums, which would inhibit switching. Long-term energy contracts would hence be more similar to life insurance contracts, which are typically only signed once in a lifetime, with large commissions involved, and therefore require strict regulation.

An institutional change, which would create a credible counterpart for generators to sign long-term contracts, could solve the problem. If, for example, retail companies held

[10] Source: Statistics Norway, http://www.ssb.no, The distribution/retail margin was assumed to be the average difference between retail price excluding tax and wholesale price during the observation period: 7.15 Øre/kWh.

regional monopolies, consumers would not have the option to switch. The most direct way to maintain generation adequacy would therefore be to retain the consumer franchise (Newbery, 2002).

A less direct approach is to allow retail companies to offer long-term contracts to consumers, accepting that such contracts might increase switching costs and thereby limit competition at the retail level.[11] It is uncertain, however, whether consumers would sign such long-term contracts if they have not yet experienced high peak prices. If the majority of consumers do not sign long-term contracts, the regulator may still intervene at times of high prices, rendering long-term contracts useless for individual consumers.

If final customers have difficulty switching retail companies due to the transaction costs, then retail companies effectively own a franchise and can sign long-term contracts with generators. The reduction of competition brought about by restrictions on switching is likely to require regulatory price controls of retail tariffs. If tariffs need to be regulated, then there seems to be little benefit from `competition` at the retail level, and transaction costs for systems to allow for switching can be avoided by retaining the consumer franchise.

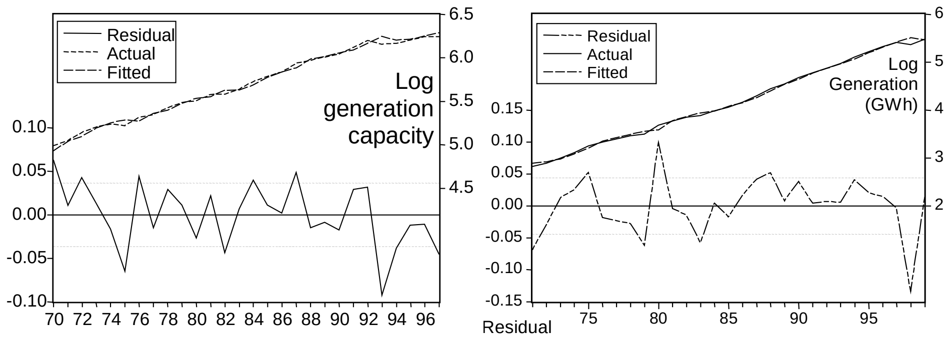
One might argue that vertical integration by generators into the retail sector, which is common, has the (side) effect of effectively creating long-term contracts between generation and retail companies. However, if the retail market is competitive, then integration of supply and generation companies does not provide the required long-term contracts to secure investment, because final customers are not included in the long-term contract. At times of low wholesale electricity prices, final customers could continue to switch suppliers and vertically integrated retail companies will also lose their customers. Therefore vertically integrated generation and retail companies cannot offer electricity tariffs corresponding to long run marginal costs, but will vary the tariffs with the average wholesale price.

[11] In the UK, retail companies are now again allowed to sign long-term contracts with final consumers to improve investment in energy efficiency (The Guardian, 24.11.2003).

As an alternative to long-term contracts signed by retail companies, one can envisage consumers signing financial contracts for differences with generation companies. Such contracts would not need to be linked to electricity demand or supply but would only be risk-hedging instruments (which banks or other institutions could distribute). If wholesale prices exceed the long-term average price, then generation companies reimburse consumers for the difference; if they fall below the long-term average price then consumers pay the difference to the generation companies. In a simplified, theoretical perspective this approach would provide the same degree of risk hedging as long-term contracts signed by the retail company. However, practical implementation may suffer from several factors. If electricity prices are low and generation companies expect money from customers they may face the typical difficulty of a creditor – it is costly to collect money from individual small customers. Furthermore, in a society that is becoming increasingly mobile, it appears difficult to collect debt from customers who have moved away, while the same customers would be substantially more willing to stay in contact if they could receive money at times of high wholesale prices.

5 Quantification of the Effect

Electricity demand is intrinsically difficult to forecast as it is driven by climate, technological evolution and business cycles. The logarythmic representation in Figure 3 shows that the long-term trend of electricity demand growth is stable. However, the random variations in the year to year changes are difficult to predict.



Assume peak demand evolves in parallel with annual consumption, then Figure 4 illustrates not only the variations of annual electricity demand but can be interpreted as errors in the prediction of future peak demand.

	Average Growth	Standard Error	Period
S-Korea	9.7%	4.5%	70-99
China PR	8.8%	2.7%	70-99
USSR	4.1%	1.4%	70-91
W-Germany	3.4%	3.5%	70-91
France	5.5%	3.0%	70-97
UK	1.2%	2.8%	70-97
USA	3.0%	2.4%	70-97

Figure 4: Annual average growth rate and standard deviation based on UN Energy Statistics

To ensure that peak demand is covered even in years with unexpected high electricity demand generation capacity has to be provided to cover these peaks.[12] In line with the crude approximation in this section assume that such peaks are expected to occur in one out of four years. The extra capacity installed has to cover fixed and annual fixed costs of operation during this one out of four years, hence peak prices have to rise in this year. As we are mainly concerned about revenue and cost streams it suffices to compute the impact on the average annual electricity price which will rise in the peak years by a level such that fixed costs of peak units can be recovered. In our calculations we assume an open cycle gas turbine with investment costs of £300/kw.[13,14] If contractual arrangements ensure constant revenue streams, then such peak units could be financed at weighted

[12] The alterantive option is to cover peaks with demand side response. Figure 4 is based on generation and hence already includes demand side response as generation equals demand minus demand side response minus losses.
[13] The capacity price is taken from Rob and Richey (1998).
[14] We ignore annual fixed costs (e.g. network connection and staff) which can potentially be avoided due to mouthballing but would otherwise increase the observed price volatility and if financed through the capital market also the impact of higher weighted average costs of capital.

average costs of capital of approx 7%, implying annual capital costs are 8.5% of investment volume if economic life time of the asset is 25 years.[15]

Would the capital costs for the back up capacity be distributed over 8760 hours per year then the capital cost of peaking capacity are £2.8/MWh. However, peak units only recover their fixed costs at times of higher demand. Hence prices in high demand years have to rise sufficiently to allow peak units to recover their fixed costs in these years, average electricity price will increase by £11.4/MWh in one out of four years. This implies a standard deviation of annual electricity prices of £5.7/MWh, which corresponds to calculations for Nordpool of £5.9/MWh (Green 2004).

Average electricity price

This uncertainty in revenue streams is anticipated by investors, and following anecdotal evidence, we assume that merchant peaking plants imply at least 14% weighted cost of capital, hence the annual capital cost rise to 14.5%, and the capital cost of a peaking units distributed over 8760 hours increase to £5.0/MWh. The higher rate of return for peaking units increases the average electricty price by £2.1/MWh.

Technology Choice

If the institutional environment prevents large fractions of demand to be covered by long-term contracts, then new generation has to be build on a merchant base. Assuming that peaking capacity has to be financed at 14% weighted cost of capital then the time weighted electricity price will has to increase by £20/MWh in one out of four years to recover the capital costs and hence the standart deviation of annual electricity prices is £9.9/MWh. This annual price volatility is significant given average electricity prices in the order of £25/MWh. Even so this volatility should average out over the livetime of a plant, anecdotal evidence suggests that investors prefer stable revenue streams and hence add a risk premium to projects with voliatie revenue streems. This can significantly distort the technology choice. For a combined cycle gas turbine financed at 7% weighted cost of capital the capital cost contributes approximately 20% to average cost. An increase in weighted cost of capital from 7% to 12% increases capital cost by 50% and

[15] We have tried to use conservative estimates, so that the effects that we describe may be larger.

long run marginal cost by 10%. Contrast this to a renewable energy plant which is typically assumed to be capital intensive, lets 70% of long run marginal costs are capital costs. The same increase of the required rate of return increases long run marginal cost for the renewable plant by 35%. Hence even if the renewable plant would have been in a position to compete with the combined cycle gas turbine in a market framework which allows for long term contracting, its long run marginal cost will exceed the gas turbine by 25% in the environment without long-term contracting.

Consumer impact

The main impact of lacking long-term contracts or similar arangements on consumers will be due to the increased electricity price caused by higher financing costs. The volatility of electricity prices, e.g. an increase of 11.4£/MWh (lower bound) in scarce years, implies an increase of final consumer prices of approximatly 20%. One third of the households in the UK spend 8% of their total household income on energy,[16] and if we assume the average split between gas and electricity bill 45% also applies to this group, then they have to spend an additional 1% of their household income on electricity in times of peak demand. Given large fractions of household income are typically commited to rent and other long-term commitments the this volatility will be noticed.

6 Additional distortions of investment decisions

The previous sections argued that risk-averse investors who cover their production with short-term contracts will provide for less generating capacity than in the first-best world that allows for long-term contracting. Investors typically only have imperfect information about future demand and supply (Hobbs et al., 2001c; Stoft, 2002). To calculate their revenues, investors need to anticipate future electricity prices which are a function of difficult to anticipate demand and available generating capacity (Hobbs et al., 2001a). Long-term contracts reveal information about both demand and supply side and hence can reduce this uncertainty.

[16] Detailed break downs of fuel poverty in England in 2001, version July 2003, Summary report presenting data produced by the Building Reseearch Establishment on behalf of DTI and Defra.

Regulatory changes increases investment risk and therefore adversely impacts the willingness to invest. For example the Electricity Directive that was recently adopted by the EU (Directive 2003/54/EC), the large combustion plant directive (2001/80/EC) or the recently adopted CO_2 emissions trading scheme (EC, 2002/EC 2003) will influence country-specific regulation, as does the liberalization process of the European gas market. A second source of regulatory uncertainty is caused by possible lack of regulatory commitment. Will a regulator sustain the public pressure in a period of high prices and not react by reducing the price cap in order to limit the pries?[17] If the possibility exists, then generators have to discount future revenues during high price periods while they are unlikely to expect symmetric regulatory support during periods with low prices (Skantze and Ilic, 2001).

Ford (1999) uses a system dynamics model to show that investment in electricity generation facilities is inherently unstable if investment decisions are influenced by current prices rather than by predicted future prices. Anecdotal evidence suggests that investment projects are delayed when spot prices are below long-term average costs. When spot prices reach long-term average costs and investment projects can move forward, then the time delay to bring the new capacity online implies that prices will first increase well above the long-term average costs before the addition of new generating capacity brings them down again. Visudhiphan et al. (2001) contend that investment cycles are not inevitable, as long as investors are able to anticipate market developments. However, it is likely that investors put excessive weight on current and past observations.

A significant vulnerability of electricity markets is that generating companies have both opportunity and incentives to increase electricity prices, as demonstrated during the electricity crisis in California (Joskow and Kahn, 2002). When the capacity margin is slim, the low price-elasticity of demand means that a unilateral reduction of the supply of electricity, e.g. by listing generating units as requiring unscheduled maintenance, can be profitable even for small generation companies (CPUC, 2002). Price increases due to market power should attract more investment, as they represent an opportunity to make more profit. In the UK, new entry was possible in the past, because low gas prices

[17] In San Diego, even already a brief period of high consumer prices proved politically unacceptable (Liedtke, 2000).

allowed entry with relatively small combined cycle generators. The long-term contracts for the generating companies' output, which the retail companies signed, facilitated the investment by securing revenues for the generating companies. On the other hand, if new market entrants know that the high prices are a consequence of market power, and not of real scarcity, they may hesitate to enter the market, as an increase in competition could cause prices to drop to the marginal cost of generation. Because market power is mainly exercised at times close to full capacity utilization, it is difficult to assess whether high prices are caused by market power or scarcity. This uncertainty also affects policy makers and regulators, who may react to the perceived abuse of market power with the implementation of a price cap below the value of lost load. Such price caps reduce the expected return on electricity investment and thereby reduce the equilibrium investment volume (Oren, 2000; Newbery, 2001).

Incumbent generating companies may benefit from entry barriers which prevent third parties from providing new generating capacity: permitting is likely to be easier at existing locations, where there often is space for an additional unit (e.g. in the place of a dismantled old unit), and because at these sites the cost of a new unit is lower, if the fuel supply, electricity and cooling infrastructures already exist. In addition, large incumbent firms may obtain the necessary capital more easily. If entry is restrained, then Von der Fehr (1997) shows that incumbents may limit capacity investment to increase spot prices.

Boom (2003) compares a monopoly and duopoly in a two-stage model of investment and energy market with fixed retail tariffs and uncertainty about future demand. The duopoly may provide for less generating capacity then a monopolist, if this ensures higher energy prices in the energy spot market where the players compete in a Bertrand like game.

7 Capacity mechanisms

A number of adjustments to the market structure, which we will call capacity mechanisms have been applied or proposed, for the purpose of securing the adequacy of generation resources. A brief overview of the most important ones follows.

Capacity payments

Payments for installed or available capacity attempt to convert the irregular revenues from price spikes to a more constant revenue stream for generation companies. They have been applied in the former England and Wales Pool and subsequently in Spain (as part of the stranded cost reimbursement) and several South-American countries.

Strategic reserve

An option which often is proposed is a so-called 'mothball reserve', a collection of mothballed old plants maintained by the system operator as back-up capacity. A variation is the tendering procedure, which is proposed in the new directive of the EU (Directive 2003/54/EC). The open question is when to deploy such reserve capacity. If the market is to perform its regular task and invest in generating capacity, it should be able to rely upon periodical price spikes to finance its investment in peaking units. This means that the reserve should only be deployed at a high price, namely a price equal to the value of lost load. Will it be politically sustainable to allow prices to rise to the strike price for any length of time if earlier deployment of mothball reserve can easily reduce the price?

Operating reserves pricing

Another option is for the system operator to contract operating reserves in excess of the reserves which are contracted to maintain system stability. This provides a revenue stream for peaking units. If spot prices exceed the maximum price the system operator is willing to pay for strategic reserve, then generators will sell the capacity in the spot market and no longer to the system operator (Stoft, 2002). The system operator's demand for reserve capacity increases the frequency and duration of price spikes, but his maximum willingness to pay limits their height. Spot prices can only exceed the system operator's willingness to pay when all capacity that usually is contracted by the system operator as strategic reserves is offered in the spot market. This system can be interpreted as an increase of demand with a price-elastic section, which reduces price volatility and therefore makes it easier to determine future revenues from price spikes.

Capacity requirements

A system of capacity requirements, such as the ICAP system, is used by PJM on the East Coast of the USA (described in Besser et al., 2002.). In this system, large customers and retail companies who represent small customers are required to purchase firm capacity to cover their expected peak demand. Capacity can be provided by either generators within the control area, by out-of-area producers if corresponding transmission capacity can be secured, or by interruptible load. The system ensures that generating capacity generators receive a revenue stream in addition to the energy market.

Reliability contracts

A disadvantage of capacity requirements is that they do not mitigate the incentive to use market power to increase the electricity price by withholding generating capacity. An alternative which is intended to mitigate this shortcoming is provided by reliability contracts. These are a form of call options which the system operator purchases from the generation companies (Vázquez et al., 2002). When the spot price exceeds the strike price of the options, the producers are required to pay the system operator the difference between the spot price and the strike price. Operating power plants are a perfect hedge for the generators: their net income is equal to the strike price. Generation companies who have sold options which are not covered by available generating capacity when the options are called, lose on those options. This provides an incentive to generation companies to sell an option volume, which is equal to the available volume of generating capacity under their control. A second advantage is that the risk of exposure to high spot prices gives an incentive to generation companies to maximize the availability of their generation units during periods of scarcity. The system operator determines the level of overall generation adequacy by the volume of options he purchases.

8 Trade between electricity systems

Trade between liberalized electricity systems should not change the basic market dynamics. If the involved systems are liberalized in similar ways, trade between them only represents an increase of scale. The scale of the system does not impact the question of generation adequacy, as it is addressed in this paper. A benefit of a larger interconnected system is that they allow aggregating over errors of demand and supply predictions and therefore relative error margins should be smaller.

In practice, interconnected electricity systems often have quite different rules, both within their markets and for access to the interconnection capacity. In the European

Union, Article 24 of the Directive allows member states ‘in the event of a sudden crisis’ to take unspecified ‘safeguard measures’ (Directive 2003/54/EC). This can be interpreted as giving member states the right to curtail exports temporarily in an emergency. While there may be technical reasons for doing so, this means that in case of a shortage of generation capacity, the European internal market may divide into a number of unconnected national markets. Does this require that each country needs to provide for its own generation adequacy?

Trade between systems with different rules complicates the implementation of capacity mechanisms. During a regional episode of scarcity, systems which choose to provide incentives for generation investment may find that the output from some of their plants is sold to neighboring systems, which did not incur the costs of capacity mechanisms. Harmonization of rules clearly is the solution, but may not be feasible in the near term. Countries seeking to implement a capacity mechanism can either wait for a regional consensus to emerge, or implement an individual solution, which may be more costly and less effective than a regional solution.

9 Conclusions

The theory of spot pricing suggests that energy spot markets will provide sufficient incentive to invest in generating capacity. This result still holds in the presence of uncertainty. However, we show that without long-term contracts or similar mechanisms the result no longer holds if investors or final consumers are risk averse. We identify several types of uncertainty that induce risk-averse investors to reduce the equilibrium volume of generating capacity relative to risk-neutral investors. In contrast, if consumers could sign long-term contracts or invest directly in electricity generation, they would provide for more investment quantity than risk-neutral investors or consumers.

The high inter-annual price uncertainty in electricity markets may prompt regulators to intervene during periods of high prices, which limits the expected revenues and therefore reduces the incentive to invest in generating capacity. Because the construction of generation plants is characterized by a long lead-time and their economic life is long as well, incomplete information about the future evolution of demand and supply increases investment risk. The limited predictability of future electricity prices induces generating companies to rely more upon current prices in their investment decisions. This may result in investment cycles.

Electricity prices are higher and more volatile if investment is funded through spot market revenues. High inter-annual price volatility results in a higher risk-premium on capital. If this risk-premium is not a function of underlying fundamentals, but is caused by failures in market design, then it biases investment towards less capital-intensive technologies. This presents a particular obstacle to renewable energy sources, which tend to have the highest ratio between capital costs and operational expenditure.

Generation adequacy is improved if institutional arrangements allow generators to sign long-term contracts with final consumers or if competition between retail companies is weak. If switching by consumers is unlikely, retail companies are better able to sign long-term contracts on behalf of them. However, in this case it is likely that the retail tariff needs to be regulated, and one may ask whether it would be better to reinstate properly regulated consumer franchises. A number of capacity mechanisms have been proposed to make the demand for reserve capacity more explicit and reduce investment risk for generation companies.

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