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Different Approaches to Supply Adequacy in Electricity Markets

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Abstract

This paper studies the electricity market design long run problem of ensuring enough generation capacity to meet future demand (resource adequacy). Reforms processes worldwide have shown that the market itself is not always enough to provide adequate incentives to invest in generation capacity reserves due to market failures intrinsic to the electricity industry. We study several measures that have been proposed internationally to cope with this problem including strategic reserves, capacity payments, capacity requirements, and call options. The analytical and practical strengths and weaknesses of each approach are discussed.

Resumen

Este artículo analiza el problema de largo plazo de garantizar suficiente capacidad de generación en un mercado eléctrico con el fin de hacer frente a la demanda futura (resource adequacy). Los procesos de reforma a nivel internacional han demostrado que el mercado, por sí mismo, no es, en muchas ocasiones, suficiente para proveer incentivos adecuados para la inversión en reserva de capacidad de generación debido a fallas de mercado intrínsecas a la industria eléctrica. Estudiamos diversas medidas que enfrentan el problema y que han sido propuestas internacionalmente: reservas estratégicas, pagos de capacidad y requerimientos de capacidad, entre otras opciones. Tales alternativas se discuten aquí en sus fortalezas y debilidades.

Introduction

The recent electricity power crises in California, New York, Italy, Norway, Sweden, Brazil, Argentina, Chile and New Zealand have dramatically showed the importance of a reliable electricity supply.[1] As of 2000, generation reserves have declined in most markets since liberalization.[2] Average reserves have also decreased in most IEA markets except for the UK An extreme case is Australia where there was significant initial overcapacity but reserves drop significantly after the reform. In the cases of UK, Sweden and PJM reserves in 2000 kept similar to those observed at the time of the original reform, but in Norway there was a decrease of 2% from 1991 to 2000, and in California a decrease of 7.5% from 1990 to 1998.

The change in reserve margins has occurred in most cases from a starting point of large reserves so that current reserves generally remain above 16%, which seems acceptable for reliability purposes. Likewise, several of the examples of electricity crises have been in systems that heavily depend upon hydropower. However, there is a justified growing concern on whether liberalized markets will be able to provide adequate incentives for sufficient investment in generation capacity. This is particularly problematic due to some intrinsic characteristics of electricity markets such as: a) a short-term inelastic demand that implies that the (long-term) supply-demand balance cannot be achieved through a market-clearing price; b) a lack of forward electricity markets beyond one or two years; c) the favorable arena for strategic behavior due to the difficulty to get market clearing prices in tight situations, and d) final consumers do not feel the need to engage in long-term contracts because they are usually isolated from spot prices by regulated tariffs.[3]

Several measures have then been proposed to ensure a sufficient amount of generation capacity reserves. As shown in figure 1, such measures might be analyzed in terms of their degree of centralization or decentralization with regards to the *amount* of capacity and the *price* of capacity (see Knopff, 2002). In this paper we carry out an analysis of each one of these measures

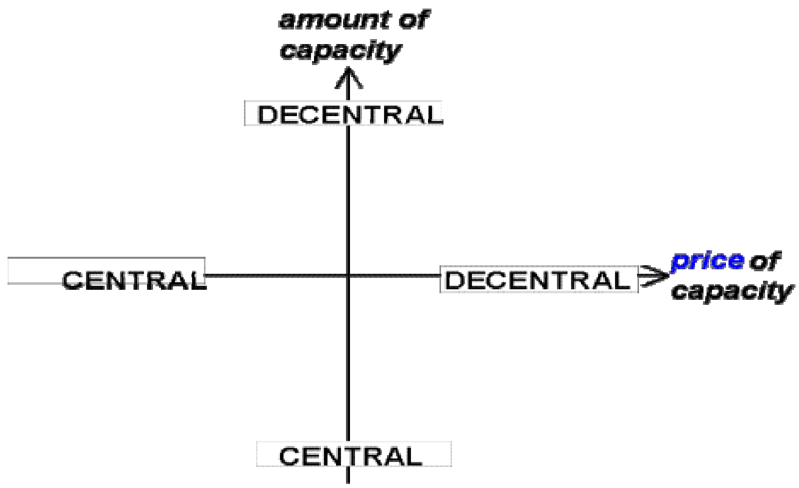
[1] Reliability in electricity markets is usually understood as the sum of adequacy and security standards. Adequacy (security) is generally associated with the long run (short run). Security describes the ability of the system to deal with contingencies, while adequacy refers to the ability of the system to meet the aggregate consumer energy requirements at all times. Security includes the so called ancillary services (voltage support, regulation capacity), spinning reserves, black start capability, etc.). See Singh (2002), and Oren (2003).

[2] Annex 7.1 presents data on generating reserves for IEA countries

[3] See Bouttes (2004), and Vázquez et al (2002). De Vries and Neuhoff (2003) carry out an extensive analysis of the market and institutional failures in the electricity industry that impedes the development of long-term contracts including: lack of generators' counter-parties to sign long-term contracts, producers' imperfect information of the demand function, regulatory uncertainty on whether the regulator will impose price caps in periods of price spikes, investment cycles due to long-lead times for new generation facilities, generators' market power, and so forth.

both studying their theoretical fundaments as well as their international application and assessment.

Figure 1



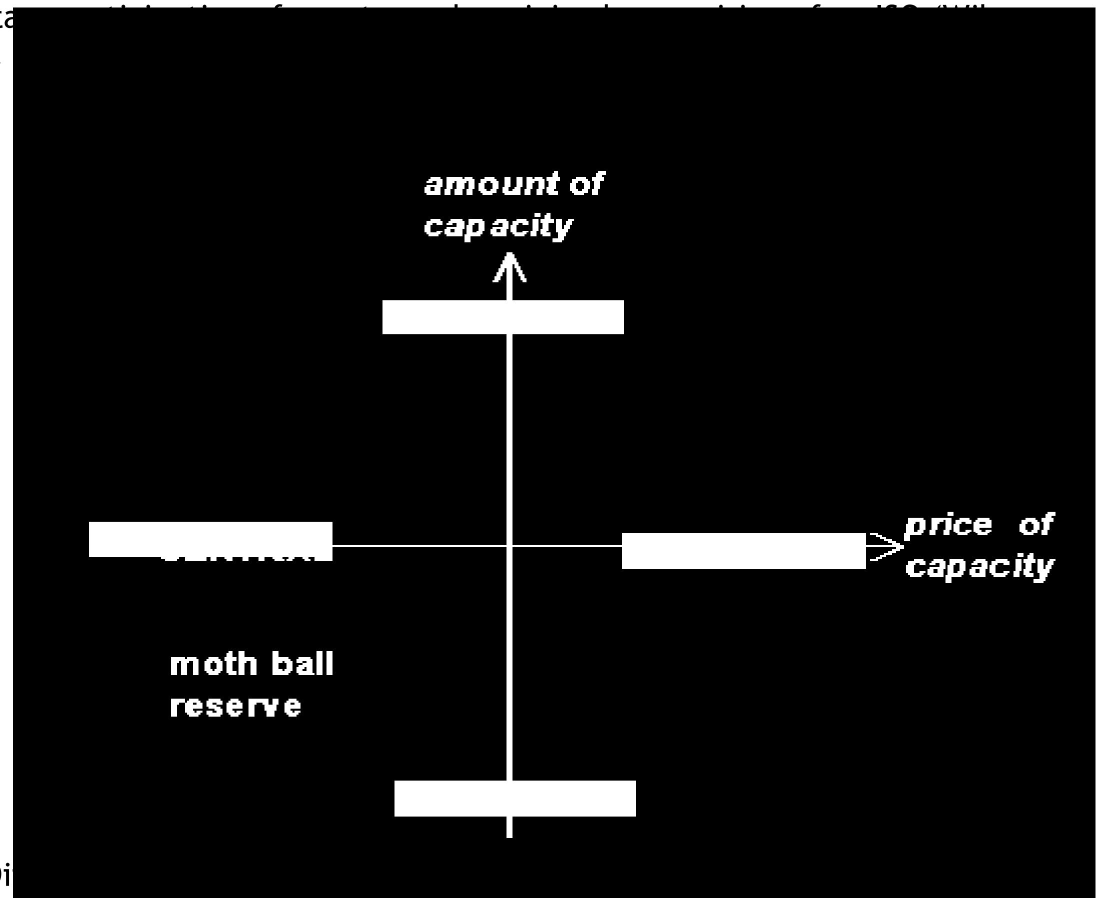
1. Totally Centralized vs. Totally Decentralized Resource Adequacy

We start analyzing two extreme approaches to resource adequacy and investment in capacity reserves. One extreme is a fully centralized solution where a vertically integrated utility centrally deals with imbalances and manages congestion and ancillary services using its own generation resources. This is the "wheeling" model that is utilized in the United States in areas that have not gone into a competitive structure and that have no spot market (Hunt, 2002).

Another centralized alternative is the creation of a "moth ball" (or strategic) reserve with government subsidy and centralized decisions regarding both amount and price of capacity (see figure 2). The moth ball reserve would imply an strategic reserve of generation capacity,[4] with an operation centrally controlled by the government and that would only be used during emergencies. There is of course a social cost to this procedure since subsidies would be financed through public funds at large. Supply of capacity reserves would then be categorized as a public service obligation (Knopff, 2002).

[4] In Norway and Sweden there is direct ownership of some peaking plants (Güllen, 2000).

An opposite extreme approach to resource adequacy is a fully decentralized solution where the market determines the amount and price of capacity resource that will grant resource adequacy. Under such a solution, the different energy markets would be separated and a sequential equilibrium would be reached in the spot market, the forward energy market, the market for capacity reserves, and the forward transmission market through the volunta
2002).



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Texas, California, Australian Victoria pool, and NETA in the United Kingdom.[5] The aim has been in some cases (NETA) to get the system operator out of the spot markets, so that traders manage the spot market as well as manage congestions, and separate arrangements are set up for ancillary services. Typically, the primary income for recovery of capacity costs is the difference between the market clearing price and the generators' marginal cost (scarcity payments).

Hunt (2002) argues that the basic problem of a decentralized model is precisely that it ends up creating private markets not only for spot energy,

[5] In England and Wales the existing integrated system was substituted with an extreme version of a decentralized model that discourages the use of imbalances and trading in markets remote from the system operator. According to Hunt (2002) this implies a reduction in the transparency of energy markets because imbalance prices do not reflect efficient contract prices.

but also markets for congestion energy, markets for imbalance energy, and markets for ancillary services. She states that all these markets deal with the same energy product, and in an efficient market all these products would end up being traded at the same price.[6] In reality, these prices do not converge, and alternatively higher prices, shortages, bureaucracy and new transaction costs are created.

This view is endorsed by Joskow (2003) who shows that wholesale market designs that separate energy and individual ancillary service markets have performed poorly and have made electricity markets subject to unilateral behavior that leads to price increases. California did an actual separation of five electricity markets (Hunt, 2002). Some theoretical studies try to find the optimality conditions for such an approach (e.g., Wilson, 2002, and Chao and Wilson, 2002). However elegant in theory, [7] the electricity industry practice has clearly shown the inconvenience of separating the different markets.

Borenstein (2002) also agrees that electricity markets are far from fulfilling the conditions for full competition to work, so that a decentralized sequential equilibrium of the different electricity markets is impossible. Market power and volatility are really inherent to electricity markets since demand is difficult to forecast and inelastic. Likewise, supply faces binding constraints at peak times, and it is inelastic and very costly to store. This implies that short-term prices are extremely volatile so that small changes in demand or supply conditions lead to price bursts, and even small-share generators can exercise market power. Borenstein then claims that the best way that regulators can handle market power is through long-term forward contracts between power buyers and sellers together with *real-time* pricing. Forward contracts help to lower the average price paid in both spot and forward markets, while real-time pricing also makes the demand curve flatter.[8]

Knopff (2002) describes another completely market-based mechanism for resource adequacy based on subscription of capacity. The desired generation capacity would be decentrally determined (see figure 3). When demand approaches supply every consumer is restricted to the peak capacity contracted in advance from generators. Peak capacity can be sold by each generator in any amount, and the price for this capacity is left to the market.

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[6] This is theoretically confirmed by Carreón-Rodríguez and Rosellón (2002) which show that prices in the capacity reserves, peak capacity and non-peak capacity markets converge to the same price in a model that separates these three markets.

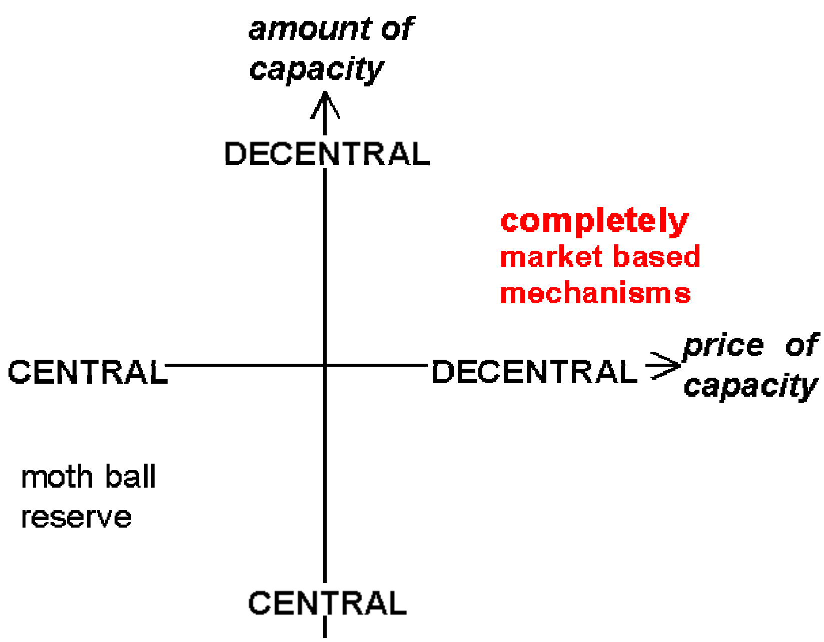
[7] For example, Chao and Wilson (2002) analyze the two-part Californian procurement auction for the market of spinning reserves. One part of the auction was designed for making capacity available, while the other part was for supplying incremental energy. A scoring rule is meant for comparing bids, while a settlement rule for paying accepted bids. The revelation principle applied to this model makes that each suppliers' optimal energy bid reveals their true marginal cost. Additionally, the ISO and the generators are not required to agre on the probability distribution of dispatched energy

[8] Most of the recent electricity reform proposals also promote the use of demand side bidding measures (see for example Commonwealth of Australia, 2002)

With this solution both the price and the quantity of peak capacity would also be decentrally determined.[9] However, at this moment, such a solution is not technically feasible.

Oren (2003) alternatively proposes to view long-term reserves as a price insurance and be treated as a private good but within the framework of a centralized provision of the ISO that imposes mandatory levels of such insurance on load serving entities (LSEs). These due to several obstacles for consumers to choose the adequate level of protection, such as technological barriers on metering control, politically barriers to set electricity tariffs efficiently, and so forth. Even more, when the market does not clear it might be necessary to institute a price cap (Ford, 1999; Hobbs et al. 2001). [10]

Figure 3



In the context of an integrated ISO that reaches a centralized equilibrium in all the electricity markets, De Vries and Neuhoff (2003) analyze the "energy-only" market solution. Such a solution relies on the spot market run by the ISO to take care of resource adequacy so that price spikes signal the

[9] Carreón-Rodríguez and Rosellón (2002) develop a two-stage oligopolistic model where generators decide first if they should enter to the long-term reserves market or the spot market. If they go into the spot market, they decide in the second stage to supply either peak or non-peak capacity. Therefore, both amount and price of long-run capacity reserves and peak capacity are set in the market. Also in a theoretical framework, Murphy and Smeers (2002) build a closed-loop Cournot two stage game that describes a situation where investments in capacity reserves are decided in a first stage while sales in the spot market occur in a second stage. Both stages take place in oligopolistic markets. Their framework does not include forward contracting. They find non-convexities in the first stage of the problem (a fact common of bi-level programs) but are able to conclude that a model with a spot market has lower prices and higher quantities than a model without a spot market.

[10] Stoft (2002) shows that in a perfectly competitive market a price cap equal to the average value of lost load results in an optimal level of investment in generation capacity.

need of investment in generation capacity. De Vries and Neuhoff argue that there are insufficient incentives for generators in an energy-only market to invest in capacity whenever there exists economic uncertainty, or fluctuations in demand. Moreover, they show that when generators and consumers are risk averse, the optimal level of investment from the perspective of generators is below the level consumers wish to finance with long-term contracts. The main reason is that market designs do not have the *institutions* that permit long-term contracts to develop sufficiently, and generators are restricted in the amount of risk that they can transfer to consumers. Likewise, complete reliance on price spikes is not advisable because they are usually not politically acceptable,[11] and they can also be manipulated by the generation companies. Even more, electricity markets that rely on short-term energy revenues might lead to shortfalls in capacity over time that might originate investment cycles where investment lags the demand in the market.

Regulators worldwide are then very concerned that energy prices are not enough to cover generators' capacity costs. Most markets have implemented some type of resource adequacy measure. Texas has recently changed to generation adequacy assurances, and FERC's Standard Market Design (SMD) also recognized the adequate contracted provision of capacity reserves (FERC, 2002).[12] California in 2001 also changed its market approach to capacity supply and prompted a proposal for an available capacity requirement (ACAP) to be imposed on LSEs.

It is therefore not surprising that several methods have been formally studied in the literature on incentives for investment in reserve capacity such as capacity payments, capacity requirements, and capacity options. The literature on resource adequacy analyzes these mechanisms in the context of an integrated ISO. We next study such mechanisms.

2. Capacity Payments

Capacity payments provide remuneration to generators for making available their generation capacity (whether they get dispatched or not). The price of capacity is set while the market determines the amount of capacity available. That is, prices are centrally determined while capacity decisions are decentralized (see figure 4). Capacity payments are collected from consumers through an uplift charge and determine the cost behavior of the firm but

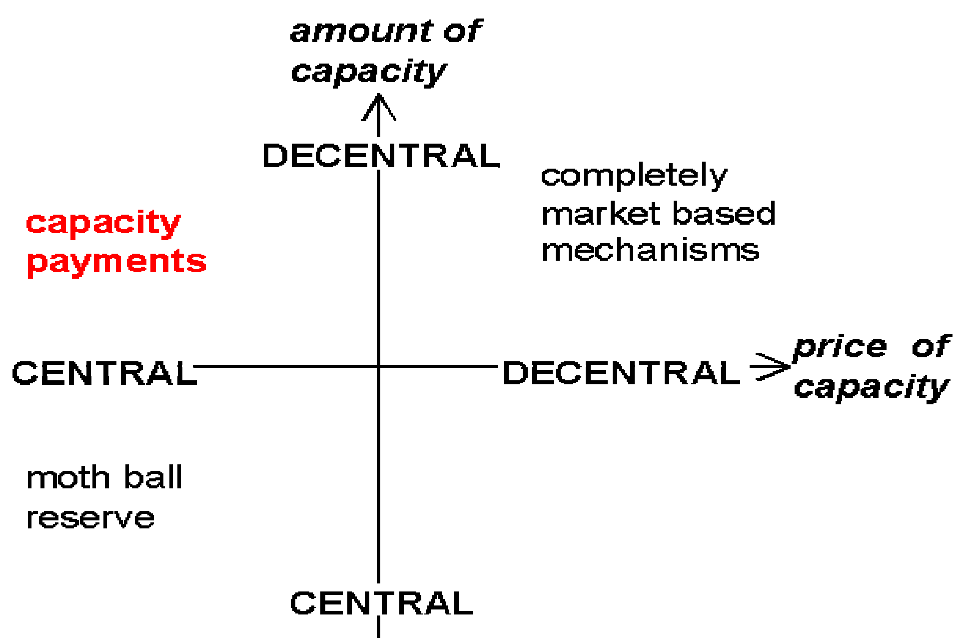
[11] Gülen (2002) shows that if the probability of lost load in the PJM market is 1 day in 10 years, price spikes in the range of $12,000-$30,000 per Mwh are needed in an energy-only market. Energy-only markets work however in Australia and New Zealand with maximum prices between $2,500 and $5,000.

[12] However FERC has recently backed of and recognized the State's jurisdiction over resource adequacy measures.

leave the amount of reserves uncertain. Oren (2003) explains that capacity payments are rooted in the theory of peak-load pricing so that energy is priced at marginal cost and a capacity payment is used to recover the fixed capacity cost imposed on peak-period energy users. The optimality condition is such that the shadow price of the capacity constraint is equal to the incremental cost of capacity.

Capacity payments have been used in Argentina,[13] Chile, Colombia, Peru, Spain (together with bilateral capacity contracts), and the United Kingdom.[14] Two different kinds of capacity payments have been applied in the international practice: fixed payments and fluctuating payments. Fixed per MW payments have been implemented in Spain, where the compensation depends on the availability and the technology of the power plant, and in Argentina, where the *Secretaría de Energía* set a $10 MWH ($5 for base capacity and $5 for reliability) payment paid during peak demand blocks (6am-11pm during workdays).

Figure 4



Fluctuating payments vary with the need for reserve capacity. They were implemented in the UK (England and Wales) electricity market. The market merit-order pricing rule is modified during periods of high demand when

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[13] Argentina changed to a capacity market in 2000.

[14] With the adoption of "NETA" in October 2000, the UK abandoned capacity payments based on the loss of load probability (LOLP) method along with the pool system.

reserve capacity margins are low. In such circumstance, the market price is defined as the weighted average of two factors: the price of the last accepted offer to generate (*LAO*) and the value of lost load (*VOLL*). The weight is the *LOLP*. The formula for the market price is then *market price = LAO * (1-LOLP)* + *VOLL * LOLP*, where: $0 \leq LOLP \leq 1$. The greater (lower) the surplus reserve capacity the smaller (higher) is *LOLP*. Generators would ideally add capacity when the expected sum of all these payments over all hours of the year is greater than the cost of installing new capacity. This formula also implies a price cap for VOLL when the system is short of power.

A main assessment of capacity payments is that they do not favor very much competition because they create artificial rents that might lead to increased market power in generation. In a simple Cournot model, Carreón-Rodríguez and Rosellón (2004) find the conditions under which a fluctuating capacity payment (as the one put in practice in the UK) might lead to worse results in terms of consumer surplus, profits and net social benefits compared to a system where the market price is not artificially increased and excess demand is satisfied in a regulated reserve (or standby) market.[15] They show that implementation of a bypass reserve market makes social sense in terms of prices only if there is a large efficiency gap between old and new generation plants. In such a case, the implementation of the capacity-payment solution would only create artificially high rents that could provide incentives for a development of oligopolistic generation markets.

In a similar effort, Joskow and Tirole (2004) analyze the effects of an uplift charge of an ISO to recover the costs of resources. They do so in the context of a general model that studies the effects on the theorems of welfare economics of market failures as those existing in electricity markets. They find that capacity payments grant inefficient results:

- When the uplift charge is applied both to peak and off-peak periods, large ISO purchases discourage the build up of base load capacity and push down the peak price.

- For small purchases, off-peak capacity decreases when the uplift is applied in both peak and off peak periods, and the peak capacity decreases when the uplift is only applied during the peak period.

In a model of imperfect information, Oren and Sioshansi (2003) analyze payments for reserve capacity in a joint day-ahead energy and reserves auction. Reserves are procured through the energy market using energy only bids, and capacity payments are made based on the generator's opportunity

[15] A similar approach to a standby market was applied in Victoria, Australia, with obligations to ensure capacity n an energy-only market.

cost. Oren applies the revelation principle to show that generators have an incentive to understate their costs so as to capture higher capacity rents.[16]

Such theoretical assessments are confirmed in practice by the case of Argentina that substituted its fixed capacity payment mechanism for a hybrid system of payments and contracts because fixed payments were found to distort the merit order dispatch and negatively affected the long-term financial situation of thermal generators. In the UK, the LOLP system was manipulated by large players at the end of the pre-NETA period.[17] In several other countries, capacity payments have also led to construction of inefficient peaking units, promote the use of one fuel over others, and eliminated the incentive for availability during crisis of deficit supply.

Likewise, Singh (2002) asserts that, as in any price-cap procedure, setting the optimal level of capacity payments is very difficult, and Knopff (2002) points out that a practical problem of fluctuating capacity payments is that variations in such mechanism happen in the short run, whereas the relevant time for investment in capacity reserves is the long term. Additionally, Gülen considers that the LOLP method is not adequate for largely hydro-based systems (as Brazil) as the LOLP would be very small during wet seasons, which would lead to disproportionate low revenues for thermal generators. Hunt (2002) then claims that any capacity adder should be designed to reflect the value of the plant to the system, which is in turn affected by the technology plant composition in such a system.

Capacity payments might be combined with price caps to protect consumers (International Energy Agency, 2002) because when capacity is paid separately there is no need that price spikes remunerate reserve capacity. Hobbs, B. F., Iñón, J. and S. E. Stoft (2002) show that the result of such combination could be a reduction in price volatility without affecting average prices and reserves. However, price caps can also have a locational influence on generators that would seek high price-cap areas.

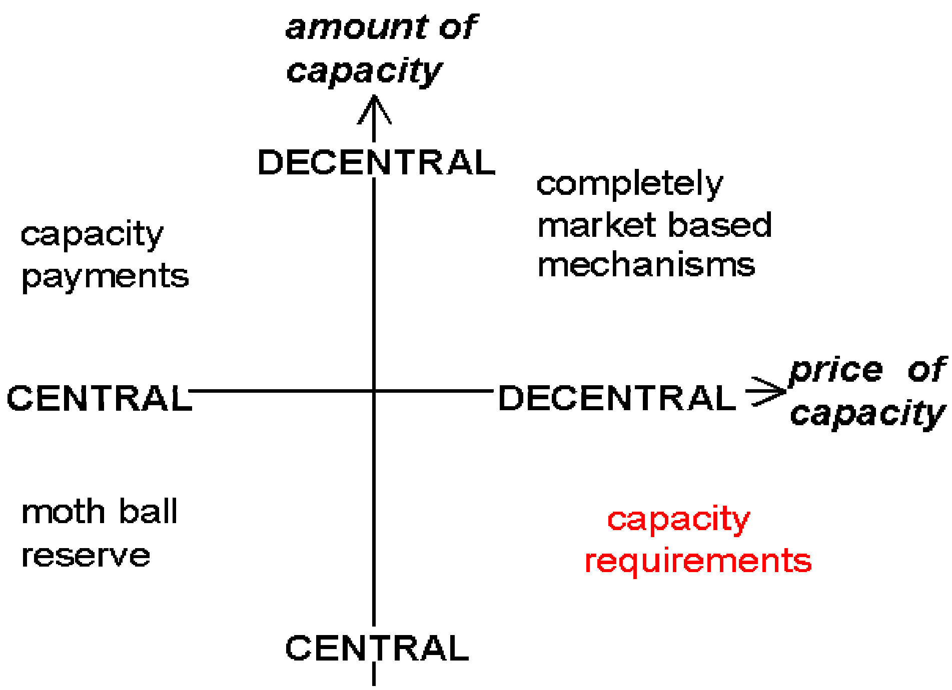
3. Capacity Requirements

Capacity requirements are set as an obligation to maintain a certain amount of reserve capacity. Such an amount is centrally determined through an administratively forecast of demand, and is usually imposed by the ISO (or the regulator) to load serving entities (LSEs). Conversely to capacity payments, the price is decentrally determined by the market once the amount of reserve capacity is set (see figure 5). LSEs must buy enough "capacity tickets" to

[16] See also Newbery (1995).
[17] See Green (2004).

meet the expected peak load of their customers multiplied by (1+X), where X is the expected reserve margin that will cover an estimated level of reliability to cope with random outages. The tickets are sold by generators who are usually allowed to export their reserve capacity to other markets. With a capacity requirement, the regulator is able to control the reserve level but the cost remains uncertain (IEA, 2002)

Figure 5



Capacity requirements are used in the Pennsylvania, New Jersey, Maryland (PJM), New York and New England markets where an obligation is imposed on LSEs to arrange for Installed Capacity (ICAP). In particular, PJM put into practice a bid-based, day-ahead and month-ahead ICAP markets.[18] LSEs are required to buy ICAP in order to be able to serve loads, and they can trade their ICAP with other LSEs. The ICAP requirements can be met by LSEs through self supply, bilateral transactions with suppliers, capability period auctions (several-month strip), monthly auctions, deficiency-spot market auctions, and so forth. Capacity resources can be exported from (or imported to) the PJM area. Generators sell a recall right that enables PJM to recall energy exports from capacity resources when required. When capacity is recalled, the supplier is paid the market price. The system operator

[18] On October 1, 1998, PJM initiated monthly and multi-monthly capacity markets, while daily capacity markets initiated their operation in 1999.

determines demand through the choice of obligations of LSEs, which must own or purchase capacity resources greater than or equal to their expected peak-load plus a reserve margin. If an LSE is short of capacity, it pays a penalty that equals the daily amount of deficiency in capacity times the number of days. When the system itself is short of capacity, the deficiency charge is the double of the capacity deficiency rate (equal in 2003 to USD 174.73 per MW-day).[19]

Creti and Fabra (2004) make a theoretical analysis of the PJM ICAP market. They build a two-stage game theory model. In the first stage, prior to the realization of demand, generators compete in the capacity market and receive their payments for the capacity amounts they commit. In the second stage, once demand is realized, generators compete in the domestic and foreign markets. When there is excess demand, the regulator recalls the suppliers' committed capacity resources, which are paid at market prices. Finally, suppliers get their payments for the energy sold. Creti and Fabra analyze this game for the monopoly and the perfect competition cases, and also study the role of the regulator in choosing the capacity requirement as well as in setting a capacity price cap.

Creti and Fabra derive several results from their model on:

1. The opportunity costs of committing capacity resources.
2. The firm's optimal behavior in the capacity market.
3. The regulator optimal decisions regarding capacity price caps and the optimal reserve requirement.

In their first result, Creti and Fabra show the trade-off that a generator faces between committing more resources to the capacity market against the foregone revenues from exports (in the case of being recalled). The difference between the foreign and domestic prices then determines the opportunity cost of committing capacity resources.[20] The second result shows that two types of equilibria are possible for the firm's optimal behavior given the value of the capacity price cap, and the reserve requirement set by the regulator. When the price cap is too "low", the generator's opportunity costs will not be covered and a capacity deficit would arise (*capacity deficit equilibrium*). When the price cap is "high" enough capacity resources are able to cover the needed capacity requirement (*market clearing equilibrium*).[21]

19 The capacity deficiency rate indicates the annual fixed cost of a combustion turbine in PJM plus transmission costs (PJM, 2003).

20 More specifically, the opportunity cost is also a function of the probability of recall, the amount of resources needed by the system to assure resource adequacy, and the intensity of price competition in the energy market.

21 Joskow and Tirole (2004) also build a model that shows how a combination of capacity requirements with capacity price caps might potentially restore investment incentives. Even in the presence of market power, a (Ramsey) optimum can be achieved when: (i) LSE capacity requirements can be met both by peak and base load generators, (ii) capacity requirements are determined using the demand from *all* consumers, and the capacity prices reflect the prices paid by *all* retail consumers, and (iii) the market for peaking capacity is contestable. However, this result is not true when there are more than there states

Finally, Creti and Fabra show that the regulator should always set the capacity requirement equal to peak demand so as to fully avoid the risk of shortage, and to set the capacity price cap equal to the firm's opportunity costs of providing full capacity commitment.

Creti and Fabra's results show the fragility of the ICAP system, which crucially depends on the capacity price cap and the capacity requirement. The administrative calculation of the latter variable is a subjective one,[22] while the optimality of the former variable depends on the market structure of financial transmission rights (FTRs) since the opportunity cost of the generator is given by the price difference between the domestic and foreign markets: if the FTR is subject to market power that will be reflected in the ICAP market.

In practice, ICAP mechanisms have failed to provide investment signals when they are most needed. ICAP markets were subject to market manipulation[23] that caused price spikes in 2000 in PJM. The pool was deficient some days in June, July and August 2000 since owners of capacity increased their exports for periods when external prices surpassed the PJM market price. In January 2001, there were price spikes of more than $300 MW-day with a deficiency in system capacity. Furthermore, high market concentration in capacity ownership has also been observed.

In New England, Joskow (2003) has showed that the scarcity rents generated are far below from what would be necessary to attract reserve "peaking" capacity to invest (or continue operation) so as to supply the needed operating reserves and energy during scarcity conditions.[24] This means that the combination of an ISO spot market with ICAP markets has not been capable to provide enough incentives to attract generating capacity to maintain adequate reliability levels. Similar results have been obtained for the New York ISO (Patton, 2002).

The ICAP system is flawed in part because it derives from short-term adequacy concerns rather than long-term, and since it depends on a subjective estimation of a "right" capacity market which depends on generation stocks, fuel prices, load shapes, and elasticity of demand for

of nature (where two state of nature are "off-peak" and "peak"). In such a case strict price-cap regulation might be used to alleviate market power off-peak and allow peakers to recover their investment (Joskow and Tirole, 2004, pp. 45-46).

[22] There have been efforts to improve the calculation of the capacity requirement. For example, in the New York ISO a demand curve is proposed to be constructed as an alternative to an ICAP market that intends to increase resource reliability by valuing additional ICAP above the fixed capacity requirement (Harvard Electricity Policy Group, 2003).

[23] ICAP gives incentives in the short run for manipulating the availability of plants to increase revenue. Anticompetitive behavior is potentially higher when capacity and system constraints are binding. Another practical problem of ICAP is the interaction among systems with and without capacity requirements, which might lead to inefficient distortions. (IEA, 2002).

[24] The average scarcity rents in New England of $10,000 Mw-Year are very low compared to the fixed cost of a new combustion turbine built to provide reserve capacity estimated in between $60,000-$80,000 Mw-year (Joskow, 2003).

reserves. Also, since ICAP is combined with the possibility of exportation of capacity, the value of the ICAP depends on the price differences across the adjacent markets. Further more, ICAPs have not provided incentives to build new generation facilities and, conversely, have contributed to keep old inefficient plants in place (Harvard Electricity Policy Group, 2003).[25]

PJM has then been looking to modify its ICAP system by developing a new methodology for peak load obligation, and by changing the month-ahead and day-ahead markets to a price-taker auction while retaining mandatory participation in the day-ahead market. Likewise, the ISO New England proposed a new locational installed capacity (LICAP) market since the capacity markets in New England were registering at certain times prices of zero while generation in constrained areas needed to be valued more highly (Davis, 2004).[26] The LICAP proposal includes basing prices in demand curves for Maine, Connecticut, metropolitan Boston, and the rest of New England. New prices are to be phased-in through capped increments in a five-year period. These proposals have been widely opposed by LSEs and other consumers since —in their opinion— it will only produce huge transfers from LSEs to generators, without providing long-term incentives to increase new generation (Davis, 2004).

FERC's original SMD (FERC, 2002) also criticized ICAP requirements and proposed instead the use of resource adequacy requirements with targeted curtailments, penalties for undercontracting, and long-term contracting mandatory measures (FERC, 2002). Chandley and Hogan (2002) argue that this is a further flawed policy because there is no objective way to solve the resource-adequacy problem in accordance with SMD without incurring the many difficult issues faced in ICAP design. They think that the best solution would be to allow prices to clear the energy and reserve markets (so that scarcity costs are properly signaled)[27] while allowing financial hedging contracts and demand-side measures. According to Chandley and Hogan, FERC should not mandate the replacement of ICAP mechanism while totally discouraging a market-clearing alternative for reserve capacity markets.

[25] Joskow and Tirole (2004) theoretically show that the inefficient dispatch of resources procured by the ISO in order to be used during reserve scarcity conditions will lead in the long run to substitution of base load units by peak units.

[26] Creti and Fabra (2004) deduce from their theoretical model the possibility that capacity markets clear at zero prices if there is no spread between national and foreign prices.

[27] This is of course confronted with the political motivation to keep prices low. However, from a strictly economic point of view, the experience in industries different from the electricity industry is that "the best cure for high prices is high prices" (Harvard Electricity Policy Group, 2003, p.18).

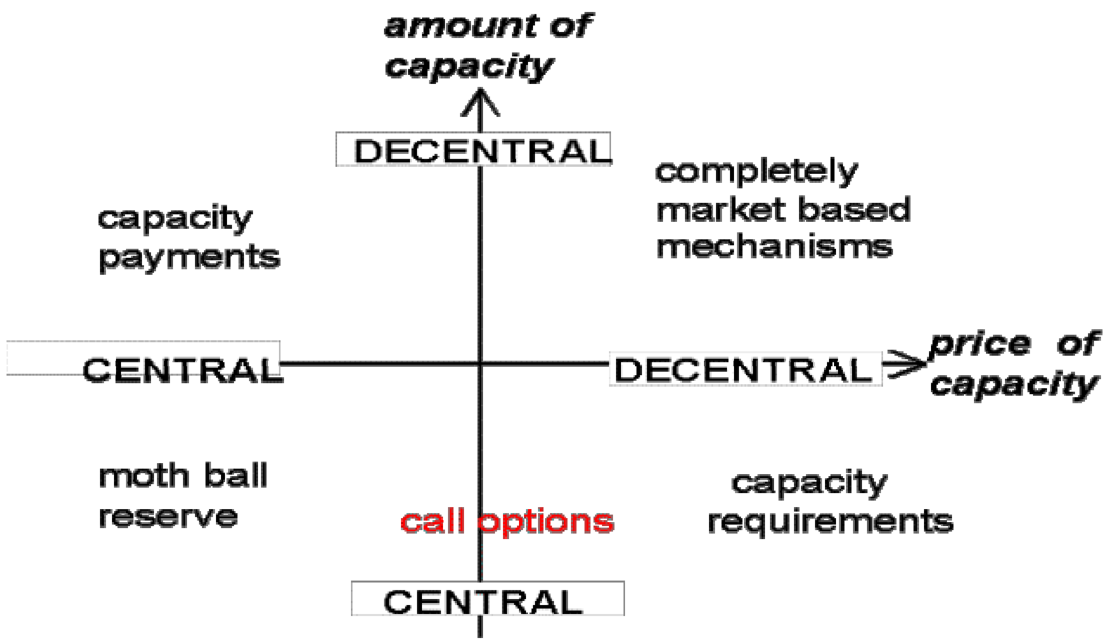
4. Call Options

As seen in the previous section, capacity requirements have the problem of artificially setting a capacity requirement and the value of maintaining such a capacity. Call options are proposed as an alternative system that would represent a more real value of capacity (Vázquez et al, 2001), and that bundles generation adequacy with price insurance. The desired capacity is centrally determined, while price is decentrally determined but consumers are hedged of huge price spikes (see figure 6). Typically, the system operator would purchase call options from the generators in a competitive bidding process that would cover the desired capacity.[28] The buyer exercises the option if the spot price is greater than the strike price (and receives a premium equal to the difference between the spot price and the strike price).[29] The strike price of options is used as a price-cap in case of emergencies, and high penalties are imposed for failure to deliver when the option is called. This assures that the promised capacity is really made available, especially during the peak periods.

The price cap of a call options system works as a protection to consumers, which will assure that prices stay within a socially acceptable range so that the regulatory intervention becomes a form of insurance against price volatility. Compared to the ICAP system, the risk is now changed to the system operator that now bears the uncertainty of whether the options are used or not. Risk is removed from generators that now face a more stable revenue horizon compared to an uncertain and volatile income for peak generation. The expected generators income for prices above the strike price equals the price of the call options, and the generators now receive a fixed payment for the option. Prices and corresponding capacity payments are then derived as market based premia from the market players' strategies for risk management.

[28] Alternatively, LSEs could be the buyers of options through self-provision from their own controlled resources or bilateral contracts with generators.
[29] The buyers of the call option may choose the strike price that suits their risk aversion: high (low) strike prices have small (high) premiums. Option premiums also work as substitute efficient signals compared to price signals generated by ICAPs (Singh, 2002).

Figure 6



Oren (2003) claims that the provision of supply adequacy through LSE's hedging obligations captures several important features. If the LSE obligations are adjusted (say) monthly to reflect fluctuations in forecasted peak demand, a secondary market for call options should emerge that would permit the trading of call options among LSEs. However, while secondary markets permit the LSEs to adjust their positions each month, price volatility in such markets increases the LSEs risk. Oren proposes then to treat hedging as another ancillary service, allowing LSEs self provision through bilateral contracts with the ISO acting as a provider of last resort. The danger is of course that this may interfere with incentives in the contract market, and be perceived by LSEs as an alternative to prudent risk management.

Oren (2003) further alerts that in countries where there is not a well-developed infrastructure of financial markets, LSEs or generators may assume more risk than they might reliably handle.[30] In particular, LSEs might not be able to manage risk in a socially optimal way, so that the regulator should

[30] Likewise, the capital market might not be able to provide the long term financing for generation investments commensurate to the associated risk. This combined with inexperience with commodity trading in the electricity industry and the perceived regulatory risk, might raise the cost of capital so much that the investment level will be far below than the needed for an efficient resource adequacy level (Oren, 2003).

need to set a minimum contracting or hedging level on LSEs. Then again, this would lead to non-market arbitrariness.

Vázquez et al (2002) analyze a call-option mechanism for the electricity market in Colombia. The regulator requires the system operator to buy a prescribed volume of reliability contracts that allow consumers to get a market compatible price cap in exchange for a fixed capacity remuneration for generators. This entitles consumers to enough available generation capacity. Reliability contracts then consist of a combination of a financial call option with a high strike price, and an explicit penalty for generators in case of non-delivery.[31] The regulator carries out a yearly auction of option contracts and sets the strike price (at least 25% above the variable cost of the most expensive generator) and the volume of capacity to be auctioned (in terms of the expected peak demand and the available installed capacity). However, generators decide how to divide their total capacity into different blocks (firm, less-firm, new entrants, and least-firm) and how to price each block, so that capacity assigned to each generator is a market result and not the outcome of an administrative process. The Vázquez et al proposal is very sensitive to market power. Therefore, they propose for implementation in the Colombian electricity market that: a) the maximum amount that a generator can bid is limited to its nominal capacity; b) portfolio bidding is not allowed; and c) the winning bids cannot transfer their obligations of physical delivery to other generators.

[31] When the market price *p* is greater than the strike price *s*, and the generator is unable to honor its obligation to produce, the generator will have to pay an additional penalty *pen* (apart from the difference *p–s*). The additional penalty is intended to discourage even more bids not backed by reliable capacity.

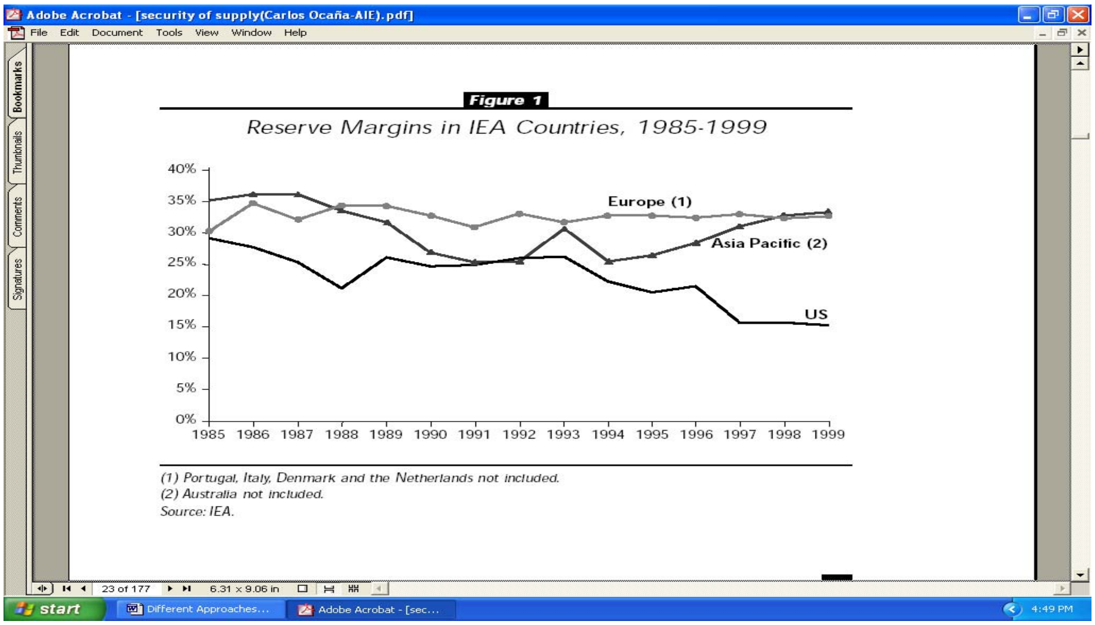
Concluding Remarks

This paper has surveyed the contributions made to the literature on the problem of supply adequacy in electricity markets. We studied the different main existing approaches and described their analytical properties and implementation characteristics. In assessing the different alternatives, the trend in the literature is to admit the necessity of some kind of transitory regulatory intervention that grants resource adequacy. Hunt (2002) especially claims that capacity obligations or capacity payments can be useful only if hourly metering, hourly pricing, and demand bidding are "woefully inadequate" and cannot be implemented expeditiously. Otherwise, the energy and the reserve markets should not be separated. The ideal would be an ISO that runs day-ahead markets and spot markets that takes car of imbalances and reaches equilibrium of all electricity markets in an integrated way. Market players would meet their long run expectations for the demand-supply balance in well-developed forward and futures markets.

However, the reality of electricity markets seems to be far away from ideal conditions by now, and the discussion of transitory resource-adequacy measures seems to be very relevant. The solution of a government subsidized strategic reserve is at odds with the international trend of liberalization of energy markets, while capacity payments and requirements alone have been found to be inadequate both in theory and practice. The most advanced developments in the literature then point to the use of some type of hedging instruments such as call options. Oren (2003) even argues that capacity payments or requirements might work efficiently if combined with risk management approaches and hedging instruments that promote demand side participation. Regulatory intervention would then be focused on promoting rules that facilitate liquid markets for energy futures and risk management.

Annex

Reserve Margins in IEA Countries



[1]

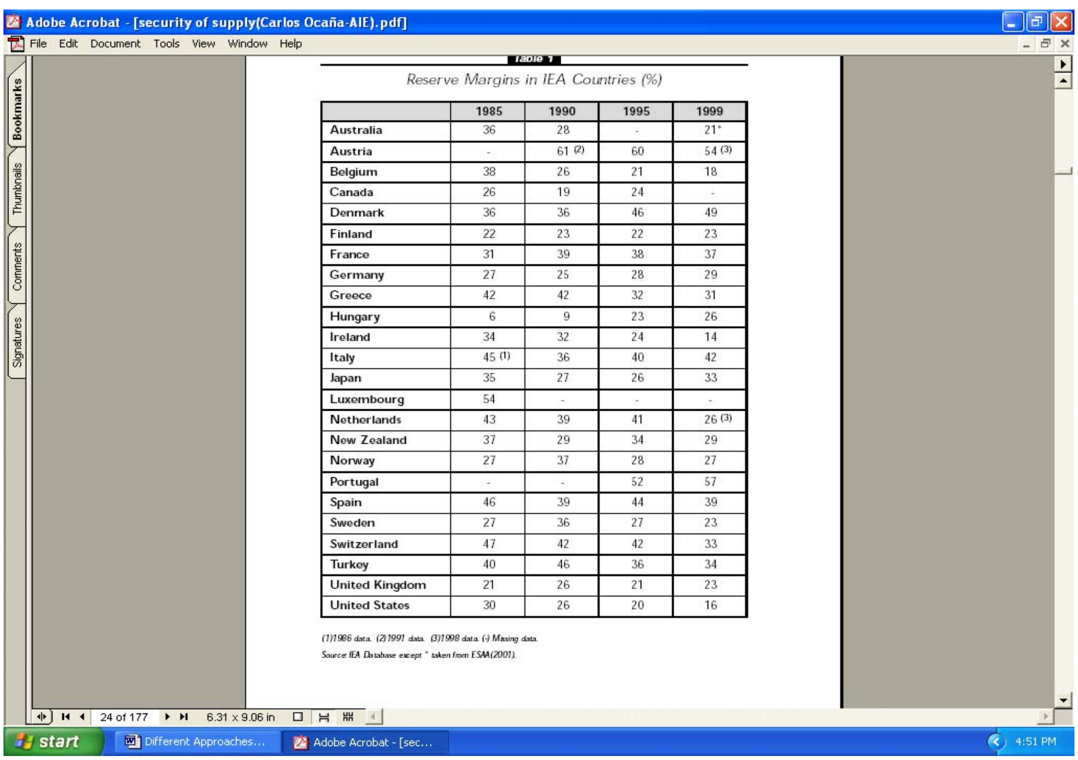


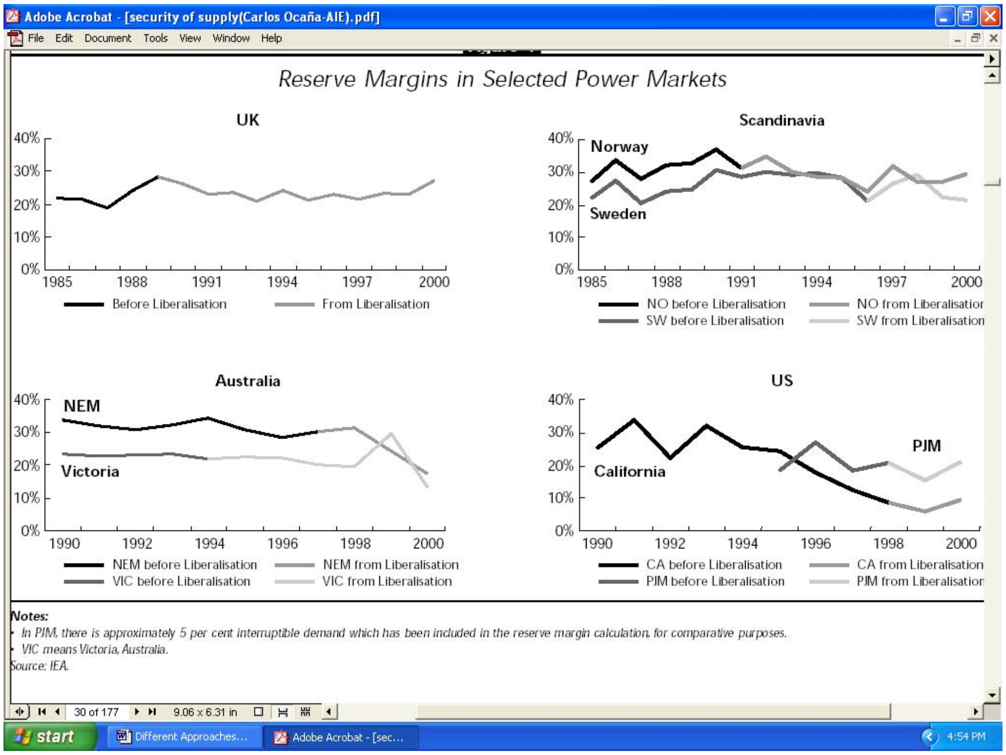
Table 1

Reserve Margins in IEA Countries (%)

	1985	1990	1995	1999
Australia	36	28	-	21*
Austria	-	61 (2)	60	54 (3)
Belgium	38	26	21	18
Canada	26	19	24	-
Denmark	36	36	46	49
Finland	22	23	22	23
France	31	39	38	37
Germany	27	25	28	29
Greece	42	42	32	31
Hungary	6	9	23	26
Ireland	34	32	24	14
Italy	45 (1)	36	40	42
Japan	35	27	26	33
Luxembourg	54	-	-	-
Netherlands	43	39	41	26 (3)
New Zealand	37	29	34	29
Norway	27	37	28	27
Portugal	-	-	52	57
Spain	46	39	44	39
Sweden	27	36	27	23
Switzerland	47	42	42	33
Turkey	40	46	36	34
United Kingdom	21	26	21	23
United States	30	26	20	16

(1)1986 data. (2)1991 data. (3)1998 data. (-) Missing data.
Source IEA Database except * taken from ESAA(2001).

[2]



[3]

[4]

Table 2

Change in Reserve Margins in the Reformed Markets

	UK	Norway	Sweden	Australia Victoria	Australia N.S. Wales	US: California	US: PJM
Change in reserve margin since year of liberalisation until year 2000	0	-2	0	-24	-13	1	0
Change in average reserve margin(1)	5	-3	-5	-16 (2)	-7	-7.5	-3 (3)
Year of liberalisation	1990	1991	1996	1994	1997	1998	1998

(1) Difference between average reserves in the five years before liberalisation and average reserves from year of liberalisation to year 2000.
(2) Average four years before liberalization in 1994.
(3) Average three years before liberalization in 1998.

Source: IEA.

4)

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