# 3. Investment and Competition in Decentralized Electricity Markets: How to overcome market failure by market imperfections?

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## 1. Introduction

During the design of the market electricity reforms, the issue of investment in generating capacity generally received insufficient attention in the reference model for reforms. This model is a vertically and horizontally de-integrated industry facilitating entry and allowing effective competition on each market from wholesales to retail sales. Regulation tends to limit vertical integration and long term contract between producers and suppliers, and between suppliers and consumers and to incite historic producers-suppliers to divest in generation in order to limit the classical incumbents' advantages and to ease entries in view of effective competition.[ii] In a number of jurisdictions in North America, Australia and Europe, it has been the reference model for defining new industrial structures and market rules and it is still be for the sectoral regulators and the antitrust authorities which tend to condemn historic suppliers' long term contracts and vertical integration as barriers to entries and restriction of potential competition.

The canonical business model in generation is the merchant plant, a stand alone producer which sells all this production on short term markets and without long term contract at fixed price and develops its new capacities under project financing by non recourse debt. The producer is supposed to bear all the risks (project risks, price risk, input cost risk and volume risk).

This insufficient attention was starkly highlighted by the crises on electricity markets that were partly due to inadequate capacity and by the focus of generators' investment decision on gas generation technologies which could create an excessive specialization of the technology mix. Then after these crises, theoretical and practical considerations on generation investment largely focused on incentives to develop peak generating capacity and ensuring a reserve margin to guarantee reliability, i.e. short-term security of supply. An abundant literature develops on this issue, in particular on various payments of capacity (see for instance Oren 2003, Cramton and Stoft 2006, De Vries 2007, Joskow 2007).

But little attention was paid to the conditions for investments by entrants in base load and semi-base load equipments, because of a strong confidence in the quality of the price signal on the hourly markets to trigger and orient pure producers' investment decisions: their anticipation of infra-marginal rents of low variable cost equipments (hydro, nuclear large renewable, eventually coal generation) are supposed to trigger decision to invest in these technologies (see for instance Hunt and Shuttleworth 1997, Hunt 2002, Oren 2003). In particular basic principles of risk management applied by competitors end in non-optimal technology mix distorted in favor of low capital intensive but high and volatile fuel cost technologies as gas generation plants. For the government and the regulator their development do not present the same risks for the whole system as inadequacy of total capacity and system unreliability risk, but their excessive development contribute to increase the volatility of market price and to move away the optimal technology mix.

Capital intensive equipments, such as coal generation, nuclear and large scale renewables which could show advantage in terms of lower expected levelized costs and higher expected net present value could show a significant advantage for producers, but investments are more risky. They have few possibilities to allocate part of their investment risks on the suppliers or the large consumers by vertical arrangements. These arrangements which are propitious to investments in various technologies are impeded by regulation when they could be developed by historic operators, and undermined by the specific characteristics of competition on the wholesale and retail markets when pure producers could be candidate to develop them. The consequence is a non-optimal orientation of the overall technology mix and the non timely development of capacities in liberalized electricity industries reformed along the referential model. The long term consequence is that because the mix of capacity is wrong and characterized by a lack of base-load equipments, hourly market price will be unduly high during a large part of the year comparatively to a situation with an optimal mix; and finally it will be at the expense of the social surplus, the loss of the consumers being higher than the supplement of net profit of the producers, as shown by R. Green (2006).

We address here the organizational unsuitability of the decentralized market model and the necessity to adapt it to long term issues of generation investment allowing not only adequate capacity development, but also optimality of the future technology mix. The first issue of capacity adequacy has been studied in numerous publications focused on the capacity mechanisms to add to market design (see Cramton and Stoft 2005, Joskow 2007, Finon and Pignon 2008 for some overviews). We focus here on the issue of incentives to competitors' investment choices related to risk sharing, in order to make their capacities converging towards the optimal technology mix. We introduce risk management issues as the main factor of market failures in investment in the technology mix and as central determinants for the needs of vertical arrangements. These issues cover large scale investment hedging problems as well as "hold-up risk" problem related to investments securitized by contracts with large buyers.

Methodologically we choose to develop the analysis of market failure in generation investment on the theoretical decentralized market model which is the referential, even if in reality the different electric reforms are more or less at distance of this model for different reasons (political acceptability of de-integration of pre-existing utilities, resilience of performing utilities, absence of a one for all solutions in a complex electricity industry). Empirical facts on generation capacity developments in “imperfect” reforms, i.e. in countries where vertical integration and horizontal concentration have not been systematically opposed by the legislator and then the regulator, will be used as elements of demonstration of the necessity of vertical arrangements and the rationale for large-size companies (and so horizontal integration) to overcome market failures.

So in the next section, we present the premises of capacity development in the canonical model of the decentralized electricity market and we discuss each premise; their limits show theoretical and practical hurdles to investment that arise by inadequate risk allocation. The third section identifies the conditions allowing vertical or quasi-vertical arrangements to be set for workable allocations of investment risks, in particular the way that investors can meet credible counterparts in long term contracting or by default to rely on vertical integration. Fourth section integrates this need of vertical arrangements in electricity markets to find an equilibrium between short term efficiency by perfect competition and long term efficiency by imperfect completion allowing equipment development on the optimal technology mix trajectory. In the sixth section we identify elements of the good balance between market imperfections (i.e. vertical arrangements and horizontal integration) and long term efficiency (i.e. capacity adequacy and generation investment in the technology mix).

## 2. Risk allocation as barrier to investment in generation in the decentralized market model

It is worthwhile to remind the simplicity of risk allocation in the former model of vertical monopoly and cost of service regulation. In this model utilities taking the decisions to invest in generation were comfortably insulated from the risk associated with those decisions on a market. Given the cost-of-service regulation, their costs and risks of investment were carried on the consumers. So they built plants with debt financing at the bond-market rate and without risk premium that is with a low cost of capital.

In the market model, the reference business for generation, the merchant plant, is an independent generator which owns a portfolio of assorted production technologies and sells its electricity on short term market. It does not own a supply business and a portfolio of customers or at the most only very partly. To identify market failures which limit investment in electricity markets, we first consider the underlying four premises on generation investment by the de-integrated market players in the reference market model of a liberalized electricity industry. In the second sub-section, we will determine if the premises are sound approximations of problem of investors in electricity industry.

### 2.1. The four premises of investment decision and risk allocation in decentralized electricity markets

Extending the characterization of paradigm of investment risk allocation in theoretical liberalized electricity markets by Chao, Oren and Wilson (2008) to financial arrangements, we stress four premises concerning the efficiency of risk management on generation investments along the chain of market activities:

First premise, the former vertical integration of utilities regulated in cost of service can be replaced by bilateral contracts between generators and retail suppliers or large customers, assisted by organized markets for spot trading, which are a priori the most efficient form of trade. Investment decision and technological choices will take place based on electricity price signal without regulation interferences. Energy is priced at the marginal bidder's variable cost on the hourly markets during the major part of the year, with demand-side setting the price during scarcity hours. Infra-marginal rents, as well as scarcity rents during peak periods exactly cover fixed costs at the long run equilibrium for the different technological plants.[iii]

In the new electric market paradigm, the revenues of any particular plant, the new as the existing ones, will be determined each hour by the market price determined by the balance between power demand and capacity, the marginal cost of the last generating equipment and eventually by the market power of competitors during peak hours for scarcity rents. The effects of such factors on prices are supposed to be foreseeable in expected value. Fixed cost recovery for new plant will be allowed by the so-called "infra-marginal rents" i.e. generation gross margins between power prices and fuel costs during each hourly market along the year, when the equipment is not among the marginal plants and hourly price is not aligned on its variable cost.[iv]

A competitive market which is cyclical by nature would give the right signal for investments in different technologies when capacity development must respond to demand growth and old plants obsolescence and it would allow the fixed costs to be recovered with a correct return of capital. One might expect to see spot prices as well as forward prices rising well above complete costs of new equipments when operators anticipate scarcity, and to maintain during some times after realization of some equipments by competitors.

**Figure 3.1: Infra-marginal rents on hourly market equilibrium with hockey stick production curve**

Second premise, consumers and intermediates compete to buy electricity by bilateral forward contracts to different generators among which entrants and on the power exchanges by managing their risks by portfolio strategy. Consumers which are well informed and wish to hedge such risks are supposed to express their preference for technology and fuel diversity. They will hedge either by long term fixed price contracts with specialized producers by low fuel cost equipment to limit their dependence upon the wholesale market price or by financial contracts with gas producers to hedge risks from hourly market price determined by CCGT producers' bids. Willingness of the consumers to manage their own risks in their purchase of electricity would be expressed also for the reliability of their supply: for instance Oren (2003) considered that bilateral financial contracts on capacity rights between consumers and producers would be sufficient to incite to invest and guarantee the right level of reserve margin.

At the level of the intermediation between producers and consumers, suppliers have to manage a portfolio of different types of sales contracts with time-spans and price formulas adapted to the different segment of clienteles, with volume risks inherent to their customers' switching. They are supposed to harmonize risk management between their portfolio of sourcing and their portfolio of sales contracts. Suppliers have different means to manage their risks; in particular they could manage them by co-managing their risks in their portfolios of sourcing contracts and sales contracts. In particular every supplier should seek to maximize their share of market-based retail contracts with price directly reflecting the spot price (IEA 2007). Stephen Littlechild expresses the same opinion: "If the contract is really worth signing, the retail supplier could match any price reductions to customers and still come out ahead. A consequence of retail conception/competition is that suppliers who wish to sign long term contracts have to back their own judgment rather than pass the risks to consumers; this is likely to improve the quality of decision making" (Littlechild 2002).

Third premise, on the top of forward contracts complete markets for financial instruments will offer all the means for hedging risks of generators, suppliers and consumers, besides physical contracting. Various alternatives for managing market risk for producers by specific long-term financial contracts - long term options, contracts for differences, swaps - all play a role in securing investments in generation (Chao and Huntington 1998). Moreover long term future markets would have an important informational function on the market fundamentals and the revenue advantage to invest in generation in the future. This hypothesis of complete market would give substance to

Arrow-Debreu theoretical model of decision-making under risk in electricity markets for short-term and long term decision coordination and efficient choices (Arrow et Hahn 1971).

The price volatility would normally be manageable by electricity producers, wholesale buyers and consumers if they could develop the contractual arrangements necessary to efficiently allocate the risks across generators, intermediaries, and consumers. In this logic of financial optimism, the producers would have no interest to secure generation investment by long term forward contracts with suppliers or large consumers because they lose opportunities to make temporal high profits. The rewards will balance the higher risks (IEA 2007). So, in this perspective, hedging risks through long term contracts could be seen as handing over these opportunities for greater to other parties who arguably are not in such a good position to make the decisions as the power companies themselves.

Fourth premise, generators could obtain capital on comparable terms directly from financial markets; such as formerly regulated utilities could do with their assured fixed cost recovery. Innovative structure finance offers new ways to finance new generation equipments in "project finance", i.e. without non-recourse debt and high leverage (e.g. 60 to 80% of debt and only 20% to 40% of equity). The lender's collateral resides in the projected cash flow of the project and the resale value of the production asset (Esty 2001 and 2004). Originally, because of the confidence in the market mechanisms, the lenders lobby for vertically de-integrated industrial structures and the greatest transparency for the pricing by the market. They are so confident about the functioning of the new electricity markets that they do not require collateral in the form of fixed price long-term contracts guaranteeing the project's revenues. Merchant plants are supposed to have revenues by spot sales (on energy and ancillary services markets) or short term contracts. The investor will take his decision to finance a project after exploring returns that different technologies may deliver under a number of different assumptions on competitors projects, fuel prices, influence of fuel price on electricity prices and their spread, hourly and seasonal demand pattern and capital cost. At the end the financial approach thinks out the generation firm as a series of separately financed projects in view of transparency in risk management--approach which falls both within the province of the Arrow-Debreu theory of optimal investment under uncertainty and the theory of modern finance as developed by Etsy (2004).

**3. Market failures on investment in the decentralized market model**

In this section we show the limitations of the four premises on investment in decentralized market model, and we insist on the disalignment of investors' and consumers' interests because it is the first factor of market failures in the technology mix development. For this analysis we combine the perspective of risk allocation and the transaction cost economics (TCE) perspective because the latter one identifies opportunism of the parties in a contract linked to a specific technology investment as source of internal risk the so-called "hold-up" risk.[v]

We underpin in annex our statement on difficulty to share risks and to establish credible commitment between producers and wholesale buyers by empirical facts based on the record of investment in electricity generation in countries where the decentralized market model having implemented. This record of investments between 1997 and 2007 in the United States, in Europe and in Australia shows that institutional conditions of successful capacity development in base load and semi-base load equipments are long term contracts and vertically integrated company. Indeed we observe three facts in the most liberalized markets in terms of vertical and horizontal de-integration: the failure of pure producers without long term contracts, even with CCGT plants in the US and the UK markets; a move to vertical integration in the UK, Australia and the US which is partly motivated by search of investment hedging ; and exceptional decisions of coal plants and nuclear plants, which are always the lot of integrated firms, except for one case of pure producer, but which is backed to contracts with remaining regulated franchised supplier.

### 3.1. Limits on the four premises

#### 3.1.1. Market failure in fixed cost recovery

Fixed cost recovery is not guaranteed at all in a stochastic perspective. Price spikes after the commissioning of the equipment are particularly difficult to anticipate in magnitude and duration whereas they are a significant part of the discounted net cash flow. Generators and investors are confronted not only to a problem of cost minimization, but to a problem of combining net present value maximization and risks minimization when choosing an equipment in a stock of technologies to invest (Gas Turbine, CCGT, Coal, Nuclear or Wind Farms). Putting aside some specific risks under the control of the regulators and the policy makers[vi], there are firstly risks under the control of the company on construction cost and operation performance (see Table 3.1). In second place there are risks the management of which investor has to anticipate before deciding to invest and ask for loans to lenders, namely the fuel price risk, the electricity price risk and the volume risk related to the demand variability and the non-dispatchability possibility.

**Table 3.1: Cost structure and risks of different electricity generation technologies**

Source: Adapted from IEA, *Comparison of electricity generation costs*, 2005

The conclusions we stress from Table 1 are the following. First cost of gas generation kWh (gas turbine &\and CCGT) has a relative low share of investment cost which reduces financial exposure. Because of their high share of fuel cost, CCGT tends to become the marginal equipment on the hourly market and "makes" the electricity marginal price during the major part of the year when gas price is established at high level. This has a first positive effect: a good correlation between gas price and electricity price during the major part of the year, which means that they benefit from self-hedging effects. But conversely if investment has been decided for supplying base-load, a risk of bankruptcy when the equipment is much less called when gas price increases sharply because of higher price bid offer, what is called the "dispatchability risk".

Second on the opposite, coal plants are very capital intensive but the fuel cost is relatively low and coal price a low volatility. They are therefore more exposed to the financial risks of whether they can repay the capital based on the volume and price of electricity off taken from the project. So it is for mostly up-front capital investment in nuclear or renewable. With high operating leveraging, i.e. high net cash flows, small changes in revenues have large effects on profitability. So they have greater needs of risk management than the costs of CCGT with a low ratio of investment and capital costs.

To say in other words pure producers which invest the more capital intensive equipments, the less "self-hedged" by input price and electricity price correlation and the less flexible (as nuclear plants and to a lesser extent coal plants) are obliged to develop a large range of transactions to sell their production and hedge their different risks, by comparison with the CCGT producers which benefit from the advantage of self-hedging. At the end, investments in the highly capital-intensive equipments (coal generation, nuclear plants, hydraulic plants, renewable) are hampered. As shown by approaches in terms of mean variance theory of portfolio (Roques et al. 2006, Roques 2010), producers are deeply incited to only invest the CCGT plants. And this is what is roughly observable on the generation investment record since the beginning of the reforms, in deeply reformed markets and even in the markets "imperfectly" reformed (see below).

The character of the uncertainty on electricity markets, rooted in its limited stochasticity, -- the non-storability of electricity results in an exceptional variability of hourly market price and a slackened consistency of the price-making with the separation of hourly markets -- adds to negative incentive for equipments presenting no advantage of correlation of its production costs with electricity price.

### 3.1.2. No possibility of long term contracting to share investment risks without possible safeguards

The premise on the viability of consumers' and retailers' risk management combining different time-span contracts in a portfolio approach has also limitations. Investors and producers fail on difficulty for establishing long term contracts with creditworthy buyers, given retailers' risk aversion to commit on long term if the latter ones have no possiblities to pass through their risks on their customers. Conversely a producer who might find a suppliers encline to sign up long term fixed-price contracts could suspect it to ask for renegotiation or to break the contract in case of price downturn on the wholesale market; this risk of coutnterpart's opportunistic behaviour could be a disincentive to contract in order to secure an investment in capital intensive equipment and so to develop a portfolio mix (De Vries and Neuhoff 2004). Given these difficulties a generator cannot rely on long term contracting for hedging its new generation investment in the decentralized market model. More generally there is disalignment of interests of investors (or entrants) and large buyers and it could be considered as a market barrier because of the impossibility to secure long term revenues for new generation equipments in the pure market model (De Vries and Hakvoort 2003). We shall elaborate on this market failure in the next subsection, given that it determines limitation on the other premises.

### 3.1.3. The incompleteness of markets

The premise that a rapid and adequate development of markets for forward contracts and financial instruments will offer all the means for hedging risks of new generators, suppliers and consumers has been demolished by experience of the first decade of market reforms. First observing the markets reveals that the duration of physical contracts and financial contracts, between generators and wholesale buyers (including large industrial consumers) is, at most, two years, generally one year and less. They are too short to accompany the development of specific new capacities. Second the use of derivatives to manage electricity price risk is difficult, because the simple pricing model used to value derivatives in other energy industries does not work in the electricity sector, given the non-storability of electricity and the lack of stochasticity of price variations (DOE 2002, Geman 2005, Defeuilley and Meunier 2006). The non-elasticity of real time supply and demand does not allow the futures or the forward price to represent a correct anticipation of its price realization. This situation complicates investment decisions because financial investors do not attribute informational quality to spot price and forward price, in the sense that they hardly reflect the situation of fundamentals. It dissuades banks and hedge funds from playing the role of counterparty on such markets for futures and OTC, though they commonly speculate on other commodity markets and create liquidity. Long term derivatives cannot develop in such a context of risk profile.

### 3.1.4. The failure of project finance arrangements

Consistently with the previous premise, as said above, lenders have adopted the method of project financing of merchant plants without securing vertical arrangements, but confident in the net cash flow of the equipments that they (Etsy and Kane, 2001; Etsy, 2004). But as it finances the project by raising as much as debt finance as possible via non recourse debt and project financing in the individual framework of "special purpose vehicle", this imposes the self-financial sustainability of the project by its net cash flow without backing on cross subsidy from the producer's other generation assets in period of low price. This means that technological options were reduced to self hedged CCGT. This means also that the profitability of each project will be critically dependent of the net revenues during the price spikes of the market after the commissioning of the equipment. Conversely it will be altered dramatically by market change which alter revenues (price downturn, reduction of dispatchability period) as show the bankruptcies of all the CCGT merchant plants in the US liberalized market and in the UK in 2001 and 2002 (see for instance Joskow 2006, Michaels 2006).

Since then, even if CCGT remains the technology the most in adequation with risk management as shown by existing some existing merchant plants in high prices electricity markets in Europe (see Annex), investors and producers are now convinced that pure merchant plant is not a viable business models. The approach of separated projects in separated "special vehicle" is also theoretically disputed in particular because it misses the interaction effects among equipments (Williamson 1996). In the electricity industry it ignores both the technological and industrial realities of electricity industry which gives advantages to have a portfolio of different assets related to different economic dispatchabilities on hourly markets, as well as vertical arrangements to hedge investment.

## 3.2. Disaligned interests between producers and wholesale buyers to share investment risks

To go further on the limits of the premises of the decentralized market model concerning generation investment, even though the price-risk would be considerable, that does not, in and of itself, signify market failure. In another words there is no theoretical reason why risks on the market price should impede investments in generation. And the fact is that there is investment in sufficient capacities when needed, but there is a specialization of investment on CCGT technology. The problem results from the fact that the risk is not manageable for the investor, because it could not be adequately allocated with buyers. Project in any technology should be better developed if an allocation of risks onto the consumers could be achieved in a way or another in the decentralized market model.

In the following we focus on the limits of the second premise, i.e. the difficulties of alignment of interests of producers who invest in new plants with the wholesale buyers' interests, because it is the key factor of the market failure. So institutional conditions should be identified which could remedy this de-alignment. As soon as such conditions could allow risks sharing between investors and "consumers", financial arrangements (premise 4) could be established for investing in capital intensive technologies; and fixed cost recovery (premise 1) will be guaranteed, allowing optimal technology mix to have more chances to be reached.

A first glance, interests of investors and large wholesale buyers are converging. Indeed the fundament of this is that interests of producers and large purchasers who have to look for hedging their risks appear to converge for signing long-term fixed-price fixed quantity contracts. Ideally such a contract protects the producer against sustained low prices while consents to get lower revenues during a period of high price to the benefits of the purchaser. And symmetrically the contract protects the purchaser against sustained high prices while foregoing higher revenues to the producer during the periods of lower prices. Moreover with such a long contracting, the generator can use the contract as security to obtain loans to finance construction. And it could also use it as guarantee to negotiate a long term fuel supply contract in good conditions of risk allocation.[vii]

Anyway, in the reality there are not such long term contracts in the decentralized electricity markets with effective competition on industrial and mass-market segment. A first glance interpretation of the difficulties to establish fixed-price fixed-quantity contract would be consumers' passive opportunism because they avoid showing their need of hedging to these generators. Such wholesale purchasers which are well informed and wish to hedge such risks do not express their preference for technology mix and fuel diversity by contracting directly with entrants or specialized generators. But if we go in the details, the problem is fundamentally elsewhere: there is no converging interest in fixed-price fixed-quantity contracting when investment is at stake.

First most of the consumers do not need fixed prices, because electricity is a small part of their cost and changing price is cheaper. The exception is electric intensive industries which need long term supply contracts with 10-20 years predictable prices, in a particular situation: when firms have to invest in new industrial capacities. In this situation they want to be hedged against electricity price upraise (Longva 2010). But their problems have two other dimensions: their international competitors are supplied in different markets with better conditions and their product price does not follow energy prices in the short term. Price Indexation clause could link contractual electricity price to output price variation as well as foreign currency exchange rate; but it is much less favorable to the new electricity producer than a stable price related to its cost price.

Second for a supplier, a fixed price fixed quantity contract protects him from the price risk during the episodes of price spike, but increases its volume risk and its price risk. Indeed the suppliers sell their electricity under three types of retail contracts offered to industrial and commercial consumers as well as households: first the fixed-price contract for one to two years (it could be tailored to the consumer load profiles, as the electro-intensive firms with a rather flat annual load curve to which flat price contracts can be offered); second the standard variable contract where the supplier may adjust the contract price either at regular intervals, or after some delays, when changes in supply costs occurs; finally the market-based contract where the price directly reflects the spot price plus a margin. In most of country suppliers' contract portfolios are dominated by the first two ones, because a tradition of no direct pass-through of wholesale prices in retail price.

This raises two problems inherent to the supplier business. First problem the supplier's quantity management is generally dependent upon the load variability on the short term and the uncertainty on his market share on the long term. The quantity clause, either with firmness or non firmness, which contributes to protect the generator investment, exerts restrictions on the need of flexibility of the suppliers which could not have only such contracts in their portfolio of sourcing. Indeed they prefer flexibility to meet their changing loads and to seek market shares in overall demand growth increment. Moreover in non firm contract, the buyer is quite exposed to moral hazard from the producer, observation which in line with Hart's observation (1995) about the disadvantages of not owing production equipment. Indeed in the long term contract, power buyer is in an information asymmetry concerning the operating conditions of the equipment as well as the effects of environmental regulatory changes.

Second problem, the supplier is locked by his downstream portfolio of mid-term sales contracts with flat prices without few possibilities to adjust the price upward shortly after wholesale price increases[viii]. Their problem of price risk management is increased by the fact that, generally, regulators define favorable rules to consumers to switch in order to help retail competition. The latter have the legal opportunity to leave their contractors for switching to another one with a delay of a couple of weeks. So in case of price downward, they have to follow the move of the wholesale price, to limit the risk of important consumer's switching before the end of running contracts.[ix] Medium and large customers are always on the lookout for a lower price and, in the event of a drop in wholesale prices, they will switch to new entrants which will capitalize on the new price if their original supplier does not pass the wholesale price decrease in their sale price. If they are locked to the long term contracts by incentives of high penalties, the risk of bankruptcy is high.[x] Following a number of authors (Michaels 2006, Joskow 2006, Chao, Oren and Wilson 2008), it is the reason for which they do not wish to be bound by agreements with fixed prices on a long time-span.

So in such a situation, even if suppliers enter long term contract related to a new equipment with a generator, they will be suspected by the latter to be tempted to exit and break the contract when the wholesale market downturn (Neuhoff and De Vries 2004), because they are the party the less committed in such a long term contract related to a new equipment. They would not provide credible guarantees for the producer investing in generating capacity. Before committing to investment investors must anticipate the possibility of revenue losses if any of the long-term contracts they may sign are challenged. Thus, they will be reluctant to engage in, and invest on the basis of, any long-term contracts on significant volumes.

The other ways to build long term contracts do not solve the issue of sharing risks on equipment projects other than CCGT. Innovative contracting allows different modes of risk allocations which could decide suppliers or large consumers to commit. Call option contracts, indexed price contracting, and tolling contracts, all these intermediate forms of contracting require at least one and usually both of the parties to bear risks of one kind or another, but it is always at the expense of one of the parties. The first one, the financial call option contracts were a sort of insurance contract against volatile price. They are only favourable to the buyers'interest. Call option enables them to hedge against high price risk without exposure to the volume risk that it would have in the first types of contract if the contracted quantity exceeds the amount required to serve its market.[xi]

The two other ones are quite similar. Indexed-price contracts generally index the price of electricity to the cost of the fuel used to generate the electricity. The ability for an investor to pass through fuel price risks appears as a key issue to trigger investment. Indexing the contract price of electricity to the price of the fuel stabilizes net cash flow for fossil fuel generation plants. With such an indexation in a coal project, the fuel price risk is allocated to the buyer because the buyer receives a variable-priced product; at the end of the day this type of contract is considered as if the buyer committed in the long term contract will be the owner-operator of the coal plant. In the case of CCGT project, the fuel price risk is allocated to the buyer because the buyer receives a variable-priced product;[xii] but the risk is limited in systems where CCGT are the main marginal equipment during the year. In this case this type of contract converge in terms of risk sharing with the so-called tolling agreement whereby the power purchaser delivers fuel to the generator and takes delivery of the resulting kWh more clearly allocates the risk of fuel price variability to the buyer. This one in fact leases the generation plant for converting natural gas to electricity. The seller is paid not only for the use of its facility, but also for simply being available to generate[xiii]. It is noteworthy that these types of indexed-price contracts do not fit with the risk profile of investment in capital intensive equipment with a low share of fuel cost or not all as nuclear, hydro or renewables plants. In their case a constant-price and fixed-quantity contract stabilizes the cash flow whatever fluctuations in the spot price.

In any case in the set of contracting possibilities, there is no more immediate solution to reconcile interests of producers investing in new equipments and wholesale buyers in the decentralized electricity markets with effective retail competition. One solution sets in conditions which allow credible commitment from wholesale buyers and equitable risk sharing.

## 4. Institutional conditions for risk sharing via vertical arrangements

The need of risk sharing and control of hold up risk in vertical arrangement necessitates that suppliers are able to transfer their sourcing risks on a large part of their customers, and that electro-intensive industrial consumers will be involved in the generation investment.

### 4.1. Incentives for suppliers to search long term contracts with new productions

Suppliers-retailer would commit in long term purchase contracts at fixed price (or with indexed price) only if they could hedge their downstream risks. At the exception of very few countries (Norway in particular for cultural reasons), suppliers cannot be hedged by making both sides of their portfolios follow the market. On their side pure producers who invest in high sunk cost technologies need creditworthy purchasers on the side of suppliers. Two ways get round these two combined difficulties: an imperfect reform allowing dominant position for historic suppliers with a large core of sticky consumers (or a franchise on mass-market consumers) and vertical integration of production and supply.

#### 4.1.2. The complementarities between long term contracts and de facto retail monopoly

Suppliers' commitment to long term PPA at fixed price with new generation entities should be in fact the major means to secure investment in high sunk cost equipment. But the competition is quite active in some Australian, American and European retail markets in which high cumulated rates of switching (i.e. the total of switching since the opening of the markets) are observable when effective unbundling, historical supplier's brand changes and switching costs lowering have been realized by the regulator[xiv]. As the retail market is supposed to be completely open to competition with market rules that eliminate switching costs, suppliers bound by long-term fixed-price contracts with generators are vulnerable to the previously mentioned price squeeze, because they risk losing their market share to entrants if they do not follow the price downturns on the wholesale price.

However in most of the US, European and Australian markets, on the households and commercial market segments, there remain a very large number of inactive customers which are pasted to the historical supplier, and in confidence prefer flat prices contracts or else the standard variable contract where the supplier may adjust the contract price at regular intervals. This is a matter of fact which is not simply linked to the dominant suppliers' strategies of branding and consumer loyalty building, but to the customers' deep aversion to price volatility and to continually monitor and control their consumption. There is a continuous role for suppliers in providing inter-temporal smoothing of retail prices, as did formerly the cost-of-service regulated utility in the previous regime. This is an implicit premise of risk management on decentralized markets which is totally challenged by the facts. In concrete terms, given that this large part of the consumers do not want to manage the price risk, the incumbent suppliers should assume this function for them, but in exchange should pass through major part of their sourcing risks to them. This converges with the investors' interest to meet suppliers able to commit in long term purchase contracts at fixed price (or equivalent).

To go further in this direction, it should be tolerated that historic suppliers retain *de facto* a very significant segment of its initial clientele that remains quasi-captive. After the complete opening of retail to competition, the retail market reform should leave the historic suppliers a significant base of "sticky" customers. These conditions would enable them to pass the cost differential of the fixed price in purchase contracts over the wholesale market price in their retail prices in period of price downturn. It allows these suppliers to shift their risk onto some consumers and pass changes to the wholesale price on to their retail prices without risking the loss of too many clients. This situation appears to be the solution for curtailing opportunism risk of the suppliers, as Joskow (2007) suggests. It must be underlined that it essentially concerns the historic suppliers. Their position is generally comforted (or protected) by their role in default service supply which, in most of the cases they keep, because this gives them a real competitive advantage to retain their initial costumers, or when it is allowed, to make previous switching consumers back to default tariffs. In certain jurisdiction as in Australia, these imperfect markets are conceived as contestable markets, in the sense that the regulators retain a regulated retail price cap. It is noteworthy that this price cap is calculated by reference to the wholesale price, but aimed also to predictability for generation investment. In the NEM (Australian National energy Market), the wholesale energy component of the default tariff is a derived from the so-called "prudent retailer approach" hedging (definition of both a median spot price and combinations of base swap and peak swap, with financial allowances for load forecast errors, volatility, etc.) (Shimashauser 2010).

In such contexts of imperfect competition in the retail supply with large core consumers, experience shows that these suppliers sign long term contracts with new production entities in Britain, Germany, New Zealand, the Netherlands, and several jurisdictions in the USA and Australia (Shioshansi 2007, Shimshauser, 2009).

#### 4.1.3. Backing the contractual credibility of suppliers to a consumer franchise

Another unconventional solution to be evoked is the preservation of partial franchise on the small consumers segment for historic suppliers. In US jurisdictions where reforms do not concern municipalities or organize some form of retail franchise, it is noteworthy that after the bankruptcy of pure CCGT producers, several IPP projects find financing solutions because they have a power purchase agreement with municipalities or a historic supplier which retains a form of franchised monopoly. This gives some grounds to the position of some scholars as Green (2004) and Newbery (2001) who stress the limitation of the advantages of retail competition extension to the households segment, regarding the long term efficiency issue of adequate investment in capacity.

A limit of this imperfect system lies in the difficulties to regulate partial monopoly as stressed by Littlechild (2006). Regulation is complex and information costly. A disadvantage of retail monopoly is that utilities and regulators who do not have to test their judgments in the market, are typically not well placed to judge the costs and risks of long term contracts or physical hedging by installing and producing by own generation assets. The same is for calculating default service tariffs of historic supplier. The regulator must define a future path of evolution of spot prices and forward price and refer to a benchmark of purchase strategy by the historic suppliers, to assess the different risks and allocate them between producers, historic suppliers and consumers for each local or regional situation. The control problem could be solved by auctioning the long term contracts of suppliers with partial franchise or with default service obligation in order to benefit from the pressures of market mechanisms as suggests by Ropkoff (2007).[xv] If it is considered that this approach does not guaranteed revenue stream for contracting on long term with investors in high capital intensive technologies, retail tariff or default tariff regulation could be a blended weighting of this market based approach and theoretical cost of the long run marginal cost of supplying the load i.e. given prevailing capital cost and investment costs of different technologies. Indeed if forward prices used in the market component reflect conditions of transient oversupply, there would be a bias unfavorable to long lead time investment in different technologies.

#### 4.1.4. Vertical integration production-supply

From a general point of view, vertical integration is an entirely predictable outcome in decentralized electricity because of high wholesale price volatility and discrepancy between wholesale market price and retail market price. It improves investment by improving risk management in different directions. Partial or complete vertical integration is another for a supplier a way to hedge part of its sourcing, and conversely for a producer who develops a portfolio of different technologies. This leads to analyze the fitness of vertical industrial organization based upon both a successively grown portfolio of various generation technologies and a developed set of customer relations, with the stake to invest in a variety of generation technologies to lower in average its production costs.

On the supplier's side this evolution is observed in the exemplary case of Centrica strategy of electricity sourcing which was at the end of the nineties a pure electricity supplier on the UK retail market. In a first stage it entered in different long term contracts. But the development of physical assets progressively becomes the most important element. Centrica buys a number of existing gas-fired power stations of a total of 1650 MW and in 2007-2008 is developing a new one of 890 MW. It will supply more than half of their power sales by his physical assets. More recently in 2009 it enters for 25% in the stock share of British Energy the nuclear producer to benefit direct access to existing nuclear plants' production at cost. The case of Centrica is not isolated, because it could be observed for other former British pure suppliers (e.g. EDF Energy), the four major Australian suppliers and different US suppliers. This suggests that for a pure electricity supplier, majority integration presents a necessary complement for risk management to long term and short term contracts. It is now a common practice that suppliers hedge at least 100% of their sourcing for their mass-market customers segment by developing or acquiring physical assets.

On the side of the pure producer, entry on a market by investing in equipments of different technologies could be secured by developing vertical integration by acquiring a local supplier: it allows to the vertical entity that off-taken quantities and sales prices of its new productions will be guaranteed in a way or another and the fuel risk could be transferred on to the supply unit, i.e. the internal buyer.[xvi] This is the Electrabel's strategy of combined entry in generation and supply business into the German, Dutch and Italian markets.

### 4.1.5. Comparison of long term contracts and vertical integration for securing generation investment

Given the alternatives between long-term contracts related to a new equipment and vertical integration, the quest for vertical integration between generation and supply can be understood, from the two perspectives of the producer and the supplier, as a strategy for reducing endogenous risks of opportunistic behaviors of eventual contractors as well as external risks. There are also transaction cost savings, with regard both to negotiating the contract, monitoring contract performance (amending clauses, renegotiating, etc.) in a context of information asymmetry with the producer on operating conditions and impact of changing input costs and market regulation. In more mundane terms, the vertical entity controls the risks associated with asymmetrical changes in profit margins at each stage of the value chain under the effect of market price fluctuations. The case is clearer for a supplier than for a producer. Vertical integration stabilizes and secures the terms of its wholesale purchases, even if it does not completely control its volumetric and price risks in resale.

**Table 3.2: Comparison of risk sharing between suppliers' long term contracts and suppliers' vertical integration**

Considering a supplier who has the choice opened to vertical integration (by physical asset development or acquisition), long term contract at fixed price (or indexed price) and short term purchase, vertical integration makes risk management easier than in the pure supplier model with some long term contracts. Incentives to adopt vertical integration rather than long term contracts at fixed price (or price not indexed on spot price) are threefold. First as suppliers benefit from a segment of sticky customers to limit their volume and price risk, they are inclined to develop a portfolio approach by segmenting both their outlets and their sourcing. They can efficiently manage their risk on the small consumers segment by investing in capital intensive equipments with cost-price non-correlated to spot, while they could keep open their options for their sourcing on the industrial segment for which both sides of the portfolios follow the market.

Second complexity in risk management is increased by their responsibility of load servicing entity. This gives to partial physical hedging some advantages to a vertical integration over sourcing only based on short term purchases on spot market and long term contracts with new producers. Indeed in a long term arrangement between a supplier and any new producer, there is a clear opposition between its need of volume flexibility and the generator's need of off-take guarantee. Developing own flexible equipments such as gas turbines or CCGTs consolidates its hedging strategy.

Considering now the pure producer who invests in a high upfront cost technology not propitious to self-hedging. While the long-term contract allows the sharing of investment risks (construction, fuel price, market price, volume risk) between different parties by a variety of provisions, under vertical integration all of them would be managed by a single entity. That means in particular that adaptation to uncertainty is more efficient inside the governance structure of the firm than in the framework of long term contracts in which adaptation needs delays and transactions costs.

#### 4.1.6. Combining generation portfolio and consumers portfolio: an ideal back-up for financing generation investment

Vertical re-integration is generally associated to a diversified portfolio of generation equipments, what gives an advantage in terms of hedging to investment projects of the vertically integrated company by comparison to a merchant plant project even backed to a long term contract with a credible party. In the producer perspective, ownership of a diversified portfolio of generating equipments gives them a greater capacity to spread the operating risk attributable to the volatility of input prices (fuels, CO2 permits), as well as market risk. This ability can be acted in trade strategy of portfolio bidding. In the vertically integrated supplier perspective, generation portfolio approach presents the advantage to diversify risks by owning and operating flexible CCGT, some coal generation plants and non fossil fuel plants, in particular wind power plants and nuclear plants. The supplier-producer could produce in an optimal way along the different hourly loads of its customer's portfolio. If it could commit both in investment in large capital intensive units with low operational cost and in flexible, low capital intensive generation units from the standard CCGT technology, it could have chance not only to manage ideally market risks, but also to minimize its averaged generation costs.

Combination of production and consumers portfolios is perceived now as an ideal profile for risk diversification. For any non-integrated producers, a diversified portfolio gives them an advantage for accessing to cheaper debt. Lenders are henceforth attracted by diversified portfolio of assets, and reluctant to lend to merchant plants (Lacy 2006). When asset portfolio diversification is extended to supply business by offering also the advantage of risk sharing by vertical integration it gives another advantage; it could be extended from the production business on one market to several markets. Lenders and financial investors have understood that their risks are better controlled by corporate finance with a normal debt-equity ratio of 50-50 to an asset-diversified power producer than by project finance for each equipment to be developed.

Finally beyond a certain threshold, asset diversification and large size combine their advantage to help financing and reduce capital cost of investment. Firms benefit from good ratings and do not bear risk premium on their capital costs. Large size allows large scale and indivisible investment with normal financing arrangement. Corporate finance with large total of equity investment in several nuclear builds could stack up to reach the precautionary threshold of 15%-20% of market capitalization, for instance €6 billion in equity for 4 plants for a market valuation of €40 billions, than one nuclear build for a small company.

To these advantages in risk management and cost of capital we shall add their possibility to negotiate long term contracts for their fuel purchase with favorable conditions. So it is a means for the biggest among them to have bargaining power in their dealings with the manufacturer's oligopoly. These different advantages help them to invest not only in €200 millions CCGT projects, but ten to twenty times more in capital intensive project*s* as a nuclear plant with corporate financing and a normal capital cost.

### 4.2. Establishing vertical arrangements between new productions and large consumers.

When energy costs are an important share of their costs of production, large consumers could search to access to physical resource of power plants the cost-price of which is independent or few correlated to wholesale price. As pointed by P. Longva (see chapter in this book), motivation to search long term contracting at fixed price is the consolidation of its location on an industrial site, or more largely in a country. Three options are of interest in this issue: First the long term contract solution at fixed price between large consumers and new production; Second the development of own generation capacity and a variant of it, a cooperative of different industrial consumers owning and operating new equipment; Third the capacity development in a producer-consumer joint venture. They could be compared in terms of risk sharing but also of hold up risk disincentives (see Table 3.3).

The first solution which has been already studied above is the long-term fixed price arrangement between generators and industrial consumers related to a new equipment. It is the solution which is the least demanding for the industrial consumers in terms of risk sharing and guarantee for financing.

**Table 3.3: Comparison of the implications of large consumers in different arrangements linked to a new production**

Rather than to develop their own equipment to hedge electricity purchases in the face of random short-term price fluctuations because electricity generation activity is not in its core business, a large consumer can seek such long-term supply contracts. But, as said above, interests are not completely converging with the producer who will invest. The producer is exposed to the risk of relocation or bankruptcy of its buyer. So it is for the incentives to opportunism of the latter during the periods of low prices on the wholesale market or when they are confronted to downturn of the international market of their products with no relation to energy and electricity price cycles. On the side of producer, the arrangement will not give opportunity to make more margins over cost when market prices are set at a high level. So to make this kind of contract interesting to invest in a new capacity for a producer, it must provide for sufficient volume and time to be associated with the construction cost recovery. So large consumers interested by such contracts related to new production do not easily find investors to ex-ante contract in such a way. The reasons are both the need of buyer's creditworthiness and the commitment from the buyers' part that the investor needs in financial and risk sharing terms. Large upfront cost and risky investment need the buyer's participation.

The second type of arrangement is the producer-consumer joint venture which offers implicit protection against any risk of consumer's opportunism, by the common ownership and operation of a new generation equipment. This common ownership constitutes "hostages" in the relation of the industrial consumer with the electricity company. As bout ten European examples show between 2000 and 2009, electricity companies and large industrial consumers (chemicals, metallurgy) can make joint ventures to develop large CCGT units with cogeneration of heat and electricity.[xvii] The dominant product for the industrial consumer is the heat for the industrial process. They divide the power between the needs of the industrial partner and sales on the wholesale market. In order to let an important power surplus independent of the constraining process need in steam or heat, the electric power capacity is dimensioned above the industrial partner's needs of power, with some flexibility in the production between heat and power. The supplementary power production is owned by the generator partner and can be sold on the market with high margin over cost during period of high market price. This intertwined production reinforces the common interest of the parties.

The third way for large consumers to proceed is horizontal arrangements in a consumers' cooperative of production as an alternative to vertical integration in self production with capital intensive equipment in hydro plants or nuclear production. The example of the Finnish TVO consortium which ordered a large nuclear plant in 2005 is illustrative of that way to share risks of a new generator installation in order to control their electricity supply cost. Long before the 1996 market liberalization reform, an electric cooperative in generation owned by several very large consumers (pulp and paper) and local distributor was already established. Its purpose was to construct and operate large generating facilities yielding benefits from electricity sold at the cost-price in the framework of long-term contracts (40 years) signed ex ante and which gives off-take rights to each participant. After the reform, this type of long-term arrangements was reproduced to allow the order for a three-billion € nuclear reactor of 1700 MW in 2005. The large consumers want to be unaffected by the effects of random hydro inflow situation, future CO2 price and be protected against the market power risk. Fixed-price purchase agreements independent of the NordPool market price and harmonized with the levelized cost of around 30€/MWh at low cost of capital of 5% were signed for "ribbon" deliveries, allowing the generator to obtain corporate financing with high leverage ratio (75% of debt) and borrow at low rates (Tampere University 2004).

Whatever it could be, contractual solutions that are designed to reduce price risk for large consumers help to collateralize and secure investments in generation. But as they represent at the most a fifth of consumption in mature economies, they can be only one means of developing generation capacity in liberalized markets. However these types of vertical arrangements could raise some problems regarding to competition principles which are defined in relation to the premises of decentralized electricity market model and the issue of imperfect competition.

## 5. Market imperfections versus long term efficiency

This issue of long term contracts and vertical integration in decentralized markets must be balanced with the issue of investment in generation. Discussion should have to be raised about eventual drawbacks of these different arrangements on the effectiveness of competition and the market efficiency with increased risk of foreclosure and market power exercise. Competition authorities are indeed skeptical to long-term contracts, extended vertical integration and oligopolistic concentration for different reasons.[xviii]

Long term contracts and vertical integration are seen first to prevent the development of transparent pricing mechanisms. Indeed they reduce the amount of transactional trade on the organized market, that is supposed to reduce liquidity and increase volatility, itself propitious to exercise market power. Moreover contract flexibility on quantity prevents a bit more the development of the spot market (Longva 2010). Such developments on spot markets would undermine entry and incentivize market players towards vertical integration and long term contracting in a self-reinforcing effect. Second reason if they include exclusivity clauses, -- for instance a buyer cannot resell its contractual electricity -- they are seen to deny market access for new entrants (foreclosure).

Concerning vertical integration typically hampers competition by reducing spot trade and limiting entries. For instance entrants in production have to rival with newly integrated producers, and for overcoming the latter's competitive advantages, to combine investment in production with acquisition of a supply business. So it is for large size of vertical and horizontal companies when, given their market share, horizontal concentration in their home market is quite high (See for instance the European Commission's sector inquiry report (DG Comp 2007).

Barriers to entries and risk of market power abuse could balance the social benefits coming from the larger ability to invest in capital intensive generation equipments by controlling costs and risks. But it is not a clear conclusion. Long-term contracts redistribute market power. Following Allaz et Villa (1989) general results, theoretical arguments in electricity markets have been developed which tend to show that long-term contracting by dominant producers incentivize them not to exercise their market power on spot markets by capacity withholding because increases in prices would only be profitable on the uncontracted part of their supplies (Green 2004, Willem and Corte 2008). Another conclusion is that in the short term, LTC or partial vertical integration tend to prevent double marginalization problems, which results in both higher profits and lower prices, and facilitate entry when sufficiently long (Onofri 2005).

We do not develop further the discussion on these issues. We consider that structured contracts and vertical integration combined with imperfect competition in retail are key for risk sharing and investment development in generation. This is extensively developed here in different chapters (Meunier 2010, Hauteclocque and Glachant, 2010). Regulatory approach on contracts must be delimited to certain contracting clauses to break foreclosing relationships. We must however underline that ensuring the stability of this amended electricity market model should force regulators and competition authorities to consolidate market monitoring.

In a competition policy perspective, imperfect competition structures are tolerable as much as there is no monopolization in the American sense, i.e. creation and perpetuation of a dominant position by practices which limit competition and deterring entries. The stabilization of the market structures must not be based by comforting incumbent positions. This completely justifies the European Commission's "fight" to limit long term contracts by historic suppliers (Hauteclocque, 2009). But the focus of competition policy would be more appropriately oriented on market concentration than on vertical arrangements. In a "contestable markets" perspective, the preservation of entry possibilities to maintain credible threat should be sought to discipline the oligopolistic competition.

## 6. Conclusion

Even though the price-risk and volume risk is considerable in the decentralized market model, that does not, in and of itself, signify market failure. In another words there is no theoretical reason why risks on the market price should impede investments in generation. And the fact is that there is investment in sufficient capacities when needed, at the exception of the missing money problem for investment in peaking units. But none of the far-reaching experiments in electricity industry liberalization on the basis of the de-integrated market model proved able to develop capacity along the optimal technology mix. There is a specialization of investment on CCGT technology. The problem results from the fact that the risk is not manageable for the investor in other technologies, because it could not be adequately allocated with buyers. Moreover apparent consistency between decentralized market model and project financing arrangements has proved to be ineffective even with the CCGT projects if we observe the number of bankruptcies of pure producers. The benchmark decentralized market model features market failures attributable to the specific volatility of market prices and the impossibility of transferring the various investment risks borne by the generator onto suppliers and consumers in order to allow development of capacity with various technologies. Project in any technology should be better developed if an allocation of risks onto the consumers could be achieved in a way or another, which means to introduce market imperfections in the decentralized market model. Regulating competition by the quest for the maximum transparent market price for all stages of the electric industry, including the retail market, tend to hamper investments in generation by restricting possibilities of vertical integration and long term contracting for an efficient allocation of investment risks between consumers and investors.

In the risk management and TCE perspectives we analyzed different ways of securing large capital intensive investment in generation equipments in a context of uncertainty, hold up risk and transactional complexity. As for vertical arrangements with suppliers, analysis suggests that regulatory adjustments for allowing credible commitments by generators' counterparts may prove theoretically justified, in particular by helping historic suppliers to keep *de facto* or *de jure* a large share of core consumers. Alternatively vertical integration between generation and supply business, as well as combination of generation assets portfolio and consumer's portfolio present both some advantages in terms of risk management and transaction cost minimization in this respect. Finally combination of large size, vertical integration and horizontal diversification appears to be an economic advantage to manage large scale investment risks at low capital cost, provided that it would be at the expense of a too large market concentration. This last statement invites to be careful about barriers to entries and risk of market power abuse which could balance the social benefits coming from the larger capacity to invest in capital intensive generation equipments by controlling costs and risks.

## 7. Appendix: record of investments in generation capacity between 1997 and 2007 in different liberalized markets

The record of investments in generation capacity between 1997 and 2007 after market liberalization in the United States, in Europe and in Australia shows that institutional conditions of successful capacity development in base load and semi-base load equipments are long term contracts and vertically integrated company. We observe three facts in the most liberalized markets in terms of vertical de-integration: the failure of pure producers without long term contracts even with CCGT plants, the development of coal plants and nuclear plants by pure producers backed to contracts and a move to vertical integration partly motivated by search of hedging.

The US jurisdictions which liberalize their electricity industry along the decentralized model (mainly in north east, Texas and California) witnessed a boom of investment in the late 1990s incited by a series of price spikes and anticipations of new capacity needs. Over 230 GW of new generating capacity was projected with any coordination mainly in these states (90%) and added between 1997 and 2005, among which a lot of gas turbines for production during peak and two third were CCGTs supposed to partly substitute to old conventional gas and coal plants. This massive wave was exclusively made in merchant plants relying on project financing without long term contracts. The problem is that most CCGT projects went bankrupt after 2001 when gas prices increase and limit their dispatchability and average wholesale market prices collapsed at the same time.[xix] In consequence, the large pure producers (Dynergy, Mirant, Williams, etc.) were quite jeopardized by successive years of lower revenues and profitability. Today banks only lend money for generation investment in corporate financing, or they lend to vertically integrated incumbents and merchant plants in project finance only if the project is backed to long term contracts with credible counterparts. These are exclusively the historic suppliers which retain a large segment of core consumers or a regulated business, or else municipalities (Joskow 2007, Chao et al. 2008). As a first example, in California over 90% of the 8 GW of new capacity installed since the 2001 crisis has been financed by long-term fixed-price and fixed-quantity contracts that a state agency purchases. As a second example, investment financing of the first two new nuclear reactors ordered in the US since 1979 (more precisely in Georgia) is backed to long term contracts with municipalities.

In the Australian markets regrouped in the NEM (National Electricity Market) at the wholesale level (Shimshauser 2010), the initial greenfield investments (before 2000) in the NEM (e.g. the 840MW Millmerran coal plant launched in 1999) and privatized generators in Victoria and South Australian regional states were able to obtain project finance on a merchant basis. However, they experienced a subsequent financial distress in the years following 2000. By that date, private sector merchant projects (i.e. reliant on spot and short-dated hedge contracts) represent just 9% of investments. A large 73% of all new plant between 1997 and 2007 (around 5000MW) has either been originated or by public power producers or underwritten by regional governments. Investments of 4050MW, all of which have occurred since 2002, have been originated or underwritten by vertically integrated entities, all of which have investment grade credit ratings.

In the British market, after the first reform of 1990, there have been a large stream of new investment in generation, despite initial spare capacity, under two types of arrangements: First investment by the two dominant producers which modernized their portfolio of coal generation assets affected by new environmental regulation (5 GW of CCGTs) were backed to vested contracts with the regional distributors-suppliers; Second investment by new entrants after the signature of bilateral 15-year contracts with distributors-suppliers which retain a regulated captive market segment. Most of the new capacity (around 7.5 GW) was built by these new entrants to generation that were themselves minority subsidiaries companies of the former distributors-suppliers. These ones look for having some hedging against the market power of the two dominant generating companies, diversifying their purchases and to earn some unregulated income[xx] (Newbery 2001). After the suppression of retail monopoly in 1998, in confidence with market price prospects, a number of CCGTs projects (5,8 GW in total) -- among which some "merchant plants" developed by subsidiary of oil and gas companies were programmed backed to a long term contract of "tolling"[xxi] -- before being suspended by the moratorium encouraged by the regulator to limit overcapacity.[xxii] Independent generators (Edison Mission, AEP) with no foot in supply and large supplier (such as the TXU-Europe) with no generating equipment to hedge their risks preferred to retire from this market or were eliminated by bankruptcies after the downturn in the market following the switch from the mandatory Pool to NETA and the resulting drop in wholesale prices in 2001–2002(Newbery, 2006). Since that date generation projects are developed by newly integrated companies, and this concerns coal and nuclear projects.

In the other European liberalized markets in Europe,[xxiii] investments in production were made mainly in South European countries (Italy, Spain, Portugal) where there was a need of new capacities for base-load and mid-load production in growing demand markets. They have been almost exclusively made by companies which have an important downstream business (ENEL, ACEA, AEM in Italy; Endesa, Iberdrola and Fenosa in Spain), generators which already have developed a supply business (ENIPower, Edison in Italy) and generators linked by long term power purchase agreements (PPA) to historical national suppliers (EDP in Portugal). The entries into generation by creating facilities are carried out either on the basis of long term contracts with an historic supplier or by vertical integration, i.e. by alliances between suppliers and generators affiliated to foreign utilities. In the Nordic countries which were among the front runners of the reforms of their industries with a low vertical integration, systems are mature. Very few investments in generation have been made. The EPR nuclear reactor ordered in Finland is the only project for the base load supplies of power and it is realised and will be operated by a cooperative of large industrial users and municipal suppliers.

**Table 3.A1: Inventory of projects related to downstream supply business in the European continental market (Effective realizations and current projects)**

Source: "New Power Plant Tracker", *Power in Europe*, Issue 508, September 10, 2007
and "New Power Plant Tracker", *Power in Europe*, Issue 534, September 10, 2008.

In The Netherlands, Germany, France and Belgium which have mature markets, capacity developments were almost exclusively made from 1997 to 2005 in the development of very large CCGT projects on industrial sites in partnership with large industrial consumer, which let a large surplus of electricity to sell on the market (see below). Since the beginning of the new cycle of investment which begins in 2005, most of the projects are developed by vertical companies or assimilated. Almost all the capacity developments by independent producers are based on vertical arrangements (see Box 1) but there exist some cases of real merchant plants (see Box 2) set in markets where the average annual price (including revenues of opaque ancillary service markets) are high, namely the Italian and Spanish markets. There are also some cases in Germany and The Netherlands, but they have been postponed.

**Table 3.A2: Inventory of pure merchants in the European continental markets on the period 1998-2009**

Source: "New Power Plant Tracker", Power *in Europe*, Issue 508, September 10, 2007 and "New Power Plant Tracker", Power *in Europe*, Issue 534, September 10, 2008.

Some coal projects have been proposed and sometimes developed in Germany by the large energy groups E.ON, RWE and in the Netherlands by vertical companies Electrabel with has a large supply business and by Essent. Nuclear projects in France and Italy are the lot of respectively EDF and ENEL.

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## NOTES

[i] A first version of this paper, published in the LARSEN Working Paper, has benefited from the numerous comments of Yannick PEREZ, Assistant professor in economics, Technical University of Cergy-Pontoise to whom I address all my thanks for his useful initial contribution.

[ii]For an overview of reforms referring to this benchmark, see Joskow (1997, 2002 and 2008).

[iii] It is noteworthy that revenue on ancillary service markets (balancing mechanism, reserve market).

[v] The transaction cost economics (TCE) perspective (Williamson 1985) is in first place focused on the difficulties of contracting when the stake is the development of equipments specific to the transactions between investor and buyer and which will offer lower cost production and more benefits to all parties than standard technologies which are less performing for the same production, but are the sole technologies which could be developed in the framework of only spot market exchange. The TCE identifies the conditions determining the choice between different arrangements (spot transactions, contracts, vertical integration) in relation with the characters of the transaction. It take in consideration the degree of equipment specificity, the frequency of transactions, the transactional complexity (here the complexity of risk management issued from the characters of electricity markets) and the environment uncertainty (here the price risk in the input markets, the regulatory environment). In this respect the long term contract allows to share the risks of an investment in a relation-specific equipment (volumetric and price risks, technology risk), but the TCE introduces the dimension of the counterpart's opportunism which is a risk endogenous to the relation investor-buyer, the so-called "hold-up risk". The TCE considers that, because firms do not behave cooperatively, safeguards are needed in the long term relations, given this endogenous uncertainty in order to give credibility of the counterpart's long term commitment. Contractual guarantees should limit opportunistic behaviour of the counterpart, as could be the so-called "hostages" or common ownership of assets.

[vi] These risks concern changes of market rules on one side, environmental regulation (SO2 norms, Carbon regulation) and uncertainty related to equipment sitting procedure.

[vii] A contractual variant is the non-firm contract. It places the plant availability risks on the buyer in exchange of a lower price. It could be interesting for both parties when the technology of the equipment is mature and the constructor has good records.

[ix] Simulating situations in which retail companies with existing long term contracts would incur losses, Green (2003) estimates the effects of such situation on the wholesale markets by combining models of electricity retail competition and of wholesale competition. He shows that retail competition might raise wholesale price up to around 20%.

[x] The example of TXU-Europe bankruptcy in 2002 made professionals discover the risk attached to the pure supplier model and the necessity to hedge the supply business by more flexible contracts with indexed price and physical assets. (Cf. *Power in Europe,* December 2004). TXU-Europe which had 17.8% of the British market share sold 3.8 GW on its capacity of 6.5 GW that it owned yet in 2000 and which allowed him to hedge 80% of its sales. This reduces its physical hedging to 20% of its sales. When the wholesale price downturns in the British market in 2002 with the change of market rules to NETA, TXU-Europe was locked by long term contracts negotiated at quite high prices during the former periods.

[xi] The "contracts for difference" are in this category of option contract with symmetrical options "call" and "put". Signing up such contract reflect the mutual incentive of producers and buyers for price guarantee. It is noteworthy for the next developements in this paper, that such contracts which have been used in the UK up to 2000 have been made possible with historic suppliers by the fact that they benefit from a remaining franchise on which regulated default tariffs could pass through the price cost of their contractual purchases to their captive customers.

[xii] A variant is the "spark-spread contract" which enables the producer to hedge differences between fuel and power prices.

[xiii] The experience in California of the long term contracts which substitute to the power exchange after its crash in 2001 is illustrative of the diffusion of this innovative contracting. In their study of the long term contracts signed by the California Department of Water Resources (DWR) in 2001 after the crisis, Wiser et al. (2004) find that forty-one percent of the electricity is supplied in "tolling" agreements most of which give the DWR some flexibility to dispatch the facility. Fifty-nine percent of the electricity is supplied at fixed prices fixed quantity (i.e. non-dispatchable).

[xiv] In 2005, the shares of switching customers are respectively 11% in Finland, 13% in Spain, 25% in Norway, 32% in Sweden, and 45% in Britain for the most important ones (Defeuilley 2007). In the US liberalized markets only the Texas retail market exhibits high switching rates of 30%.

[xv] Rothkopf (2007) recommends that auctions must be under the control of the regulator and new capacity should be procured by forbidding any entity with significant ties with the supplier from participating to the auction. It is only if no independent candidate can be selected that these entities could compete.

[xvi] We put apart the issue of long term contracts in the transition period where a de-verticalization is organised by the regulators by blocking the retail price of the suppliers and their consequences on the competition. There is a vast literature about this choice of stepped liberalisation process in the USA, in particular after the Californian crisis and its consequences on bankruptcy of the historic distributor-suppliers restricted in their possibility to long term contract (For a synthesis, see Michaels 2006 ).

[xvii] Partnerships include in some cases a valuing of a secondary fuel as the blast furnace gas in the Dunkirk project developed by GDF and Arcelor.

[xviii] See for instance extended discussion on the European jurisprudence on long term contracts in electricity and gas industry by Hauteclocque (2008)

[xix]When gas price rose sharply, load factors of new gas plants were depressed and net cash flows did not allow debt payment. By 2004, 90 GW turned back to lenders, 23 GW had been bought by private investors and 10 GW had been repurchased by regulated utilities.

[xx] The Enron's 1875-MW CCGT "*Teeside project*" which was developed as a merchant plant was the exception.

[xxi] In a tolling contract the power purchaser delivers fuel to the generator and takes delivery of the resulting power produced. It is a way to allocate the fuel price risk on the buyer..

[xxii] But only two of them were effectively realized after 2002 given the trend in Britain has been toward vertical integration

[xxiii] Projects and realisation of new generation equipments are inventoried by the journal *Power in Europe* in its regular "New Power Plant Tracker". (*Power in Europe*, Issue 508, September 10, 2007; Issue 534, September 2008). Private reports such as the annual reports of the CERA-IHS *"European Power Watch"* entail a precise information about developments of capacity (technology, size) and prognosis about realization of projects.