

# **Investment Risk Allocation In Restructured Electricity Markets.**

## **The Need of Vertical Arrangements.**

**Dominique FINON**

**CIREN (EHESS-Paris), & LARSEN, (CNRS, Paris XI University & EDF R&D)**

**e.mail: [finon@centre-cired.fr](mailto:finon@centre-cired.fr)**

**&**

**Yannick PEREZ**

**Groupe Réseaux Jean-Monnet (ADIS,) &**

**LARSEN (CNRS, Paris XI University & EDF R&D)**

**Email : [yannick.perez@u-psud.fr](mailto:yannick.perez@u-psud.fr)**

**First Draft, March 2008**

### **Summary**

Not one of the far-reaching experiments in electricity industry liberalization proved able to ensure the timely and optimal capacity mix development. The theoretical market model features failures attributable to the specific volatility of prices, the difficulty creating complete markets for hedging, and we focus on this failure in this paper, the impossibility of transferring the various risks borne by the producer onto suppliers and consumers in order to allow development of capacity. Promotion of short term competition by mandating vertical de-integration tends to distort investments in generation by impeding efficient risk allocation. In the line followed by Joskow (2007), we develop an empirical analysis of the way of securing investments in generation by vertical arrangements between de-integrated generators and large purchasers, suppliers or consumers. Empirical observations as risk analysis show that the adoption of these arrangements may prove necessary. Various types of long-term contracts between generators and suppliers (fixed-quantity fixed-price contract, indexed price contract, tolling contract, financial option) appear to offer effective solutions of risk allocation. Vertical re-integration appears to be another effective way to allocate risk. But it remains an important complementary condition to efficient risk allocation: that retail competition is sticky or legally limited in order to make bear a large part of risks by consumers on the different market segments.

## 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.<sup>1</sup> 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.

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 focussed on incentives to developing 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 the different ways of capacity payment (see for instance Oren, 2003, Cramton & Stoft, 2006; De Vries, 2007; Joskow, 2007).

But little attention was paid to the conditions for other investments in base load and semi-base load equipments, because of a strong belief in the quality of the price signal on the hourly markets and the subsequent incentive that infra-marginal rents of low variable cost equipments constitute to invest in the same technology (see for instance Hunt and Shuttleworth, 1997 ; Oren, 2003 and 2008). In particular basic principles of risk management applied by competitors end in untimely development and non-optimal technology mix distorted in favour of low capital intensive and high fuel cost technologies as CCGT which can self-hedge. For the government and the regulator their development do not present the same risks for the whole system as inadequacy of total capacity and its impact on system reliability, but their excessive development contribute to increase the volatility of market price and to move away the optimal technology mix.

---

<sup>1</sup>In the first post-reform period in the United Kingdom the regulator imposes constraints on vertical integration in generation (no more than 15% in own generation assets within their own area. Europe is not different. In 2005 and 2007, the Directorate General of Competition of European Commission underscores that incumbents' vertical integration generation-supply and the historic suppliers' long-term sales contracts create a risk of foreclosure (European Commission; 2005a, 2007). In some of the liberalised US markets there are regulatory restrictions on long-term purchase contracts to provide an incentive for the suppliers to minimize their purchase cost of wholesale electricity in relation to the changing conditions of the market (Joskow, 2002; 2006). In California in the first reform the regulator had imposed straight divestiture of the generation assets and forbid long term purchase contracts to the three former utilities for a transition period of five years<sup>1</sup>, right up to the crisis which provoked the bankruptcy of two of them.

Problems also arise if insufficient attention is paid to the institutional and organizational conditions conducive to investment in different generation technologies by devising an efficient allocation of investment risks across the stakeholders able to bear them. In particular given the difference in both capital intensiveness and possibility to risk hedging, technology of combined cycle gas turbine (CCGT) appears to be unduly favoured in the competitors' investment choices at the expense of more capital intensive equipments, such as coal thermal and nuclear plants, while the respective expected levelized costs would show a significant advantage in the most probable scenarios of gas price evolution and CO<sub>2</sub> cost internalisation policies. Investments in the latter technologies are more risky for the producers and they need to have possibility to allocate part of their investment risks on the suppliers or the consumers by vertical arrangements. But in the de-integrated market model which was, and is still considered as, the reference of electricity reforms, these arrangements which are propitious to investments in various technologies are impeded by regulation or undermined by the specific characteristics of competition on the wholesale and retail markets.

In this de-integrated market model, the consequence will be a non timely development of capacities and a non-optimal orientation of the overall technology mix in the different liberalized electricity markets as new equipments will be added to the fleet of the competitors to follow the demand growth and to replace the old ones at the end of their working life. As shown by R. Green (2006), if the mix of capacity is wrong and characterised by a lack of base-load equipments, marginal 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.

We address here the organizational unsuitability of the de-integrated 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. We shall refer to Transaction Cost Economics (Williamson, 1985, 1995) to explain the suitability of combinations of vertical arrangements to allow better investments decisions by competitors and we introduce for that financial considerations as central determinants of the needs of vertical arrangements, because complexity to manage risks in electricity markets.

Next section brings some empirical observations on institutional and organisational conditions of generation investments in experience of different electricity markets since liberalization to show all the successful generation investments have been the case of vertically integrated producers, or of long term contracts with consumers (suppliers, industrial customers), and that pure producers (the so-called merchant plants) without securing vertical arrangements are the exception, not the norm. In third section, we analyse the theoretical and practical hurdles to investment that arise in the de-integrated market model, and we show that inadequate investment risk allocation can create barriers to entry in generation activity and more generally to invest. The fourth 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 could met credible counterparts. Fifth section integrates the need of vertical arrangements in the issue of vertical re-integration in liberalized market. Finally, we conclude.

## 2. Experiences of capacity developments on liberalized markets

We first turn to empirical observations on experiences of investment in generation in different liberalized markets to confirm the necessity of long term contracts and vertical arrangements to invest in generation. Putting aside the experience of developing capacity only for peak loads, the record of investments in generation capacity after market liberalization of the electric industries in the United States and in Europe shows that institutional conditions of successful capacity development in base load and semi-base load equipments are long term contracts and vertically integrated company. The failure of pure producers without long term contracts is indicative of an intrinsic obstacle to viable risk management in this organisational model.

### 2.1. Generation developments in the US markets

It is noteworthy that only half of the US states have liberalised their markets. In the other half, electricity industries remain in the cost of service regulation but only 10% of investment has been done there between 1997 and 2005 because of the maturity of the market in these states. The U.S. states which liberalise their electricity industry 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 added mainly in these states between 1997 and 2005, among which a lot of gas turbines for production during peak and two third were CCGTs supposed to partly replace incumbent's old conventional gas plant. This massive wave was made mostly by Independent Power Producers (IPPs) in merchant plants relying on project financing with highly leveraged arrangements and without long term contracts. The important issue is that IPPs are risky companies and they have to pay a high capital cost<sup>2</sup>. 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<sup>3</sup>. In consequence, the large pure producers (Dynergy, Mirant, Williams, etc.) were quite jeopardized by successive years of lower revenues and profitability. In response, Lenders have since then been much more cautious in their approach to financing new power projects. Lenders, Banks and financial markets have *de facto* changed their reference model of electricity markets, and now favour vertical integration and long-term contracts. 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 in some of the incompletely liberalised markets (Joskow, 2007; Chao, Oren and Wilson, 2008).

Since 2004, investments were made by traditional utilities in states with non liberalized markets investment is almost exclusively make by municipals that have not been subject to restructuring and by quasi-vertical integrated companies under corporate financing. As an 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

---

<sup>2</sup> some of the most prominent are financially distressed and reorganized after bankruptcy

<sup>3</sup>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.

purchase. The ultimate consequence is that viability of investments in new generation by IPPs is substantially impaired.<sup>4</sup>

## 2.2. Generation developments in the British market

In the UK which is the front runner in liberalization, 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 with installation of 5 GW of CCGTs and were backed to vested contracts with the regional distributors-suppliers; Second investment by new entrants after the signature of bilateral 15-year option contracts (as they are option, the strike prices are more or less independent of the spot price) 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<sup>5</sup> (Newbery, 2001).

After 1998, in confidence with market price prospects, a number of CCGTs projects (5,8 GW in total) -- among which some “merchant plants” developed by oil and gas subsidiary companies were programmed backed to a long term contract of “tolling”<sup>6</sup> -- before being suspended by the moratorium encouraged by the regulator to limit overcapacity<sup>7</sup>. Almost all the new projects are developed by vertical companies<sup>8</sup> with very few exceptions. Independent generators<sup>9</sup> with no foot in supply and large suppliers<sup>10</sup> 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 drop in wholesale prices in 2001–2002. In contrast, it is important to notice that vertically integrated generators-suppliers were able to pass their costs on to small and medium-sized consumers, which have few benefited from this price decline (Newbery, 2006).

## 2.3. Generation developments in other European markets

In Europe<sup>11</sup>, since liberalisation, investments in production were made mainly in South European countries (Italy, Spain, Portugal, Greece) where there was a need of new capacities for base-load and mid-load production in growing demand markets. They have been almost

---

<sup>4</sup> For example, Calpine has obtained regulatory approvals for sitting and construction of three new plants in California for which it has not obtained investment funds.

<sup>5</sup> The Enron’s 1875-MW CCGT “*Teeside project*” which was developed as a merchant plant was the exception.

<sup>6</sup> 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..

<sup>7</sup> But only two of them were effectively realized after 2002 given the trend in Britain has been toward vertical integration

<sup>8</sup> E.ON-UK, EdF Energy, RWE-NPower, SSE, Scottish Power, Thames Power, and Centrica for supplying its dual fuel retail market.

<sup>9</sup> Such as Edison Mission, AEP.

<sup>10</sup> Such as the TXU-Europe.

<sup>11</sup> All the 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, Cf. Issue 508, September 10, 2007)

exclusively made by vertical companies (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 to historical suppliers (EDP in Portugal, PPC in Greece) by long term Power Purchase Agreements (PPA) in Portugal and Greece. The entries into generation by creating facilities are carried out either on the basis of quasi-long term contracts with an incumbent distributor-supplier or by vertical integration, i.e. by alliances between suppliers and generators affiliated to foreign utilities. We could name some instances in Italy (the alliance of Suez-Electrabel with the Roman distributor ACEA with two CCGT projects, the alliance of Endesa with the Brescian distributor ASM with two other large CCGT projects, etc) and Spain (Gas Natural's CCGT installations for supplying electricity in dual fuel to some large industrial gas customers, etc.) (see Box 1)

**Box 1. Recension of entries of IPPs under long term contractual arrangements with historic suppliers in Europe since 1998**

(Effective realisations and current projects)

- In Germany a CCGT project of 400 MW developed by Electrabel in relation to the sourcing of two important local distributors (in Saar in particular) that it took over;
- In Germany the project of 800MW in CCGT in North Wesfalia developed by the Norwegian Statkraft and the Dutch Essent which have the control of a local distributor, and after signature of some 15-year PPAs with municipalities;
- In the Netherlands the project developed by EDF in partnership 50/50 with the distributor Delta a CCGT unit of 400 MW;
- In France the alliance between the pure supplier POWEO and the Austrian Verbund for installing a CCGT plant of 400 MW,
- In France the CCGT projects by Gaz de France that relies on its gas marketing business to sell electricity by penetrating the dual fuel energy market.
- In Italy the CCGT projects of the partnership Electrabel-ACEA
- In Spain the CCGT projects developed by Gas Natural
- In Portugal projects with PPAs with EDP

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

In the Nordic countries Norway, Sweden, Finland which were among the front runners of the reforms of their industries with a low vertical integration, systems are mature, dominated by hydro production and in Sweden a mixed of nuclear and hydro. They tended to be in overcapacity. Very few investments in generation have been made. The regulators have, however, become worried about the recent lack of investment, particularly in peaking units. The new EPR nuclear reactor<sup>12</sup> ordered in Finland is the only project for the base load supplies of power and it is realised by a generation cooperative of large industrial users.

In The Netherlands', Germany', France' and Belgium's mature markets, capacity developments were almost exclusively made from 1998 to 2006 by national and foreign energy companies in the development of very large CCGT projects on industrial sites with cogeneration of heat and power in partnership with large industrial consumer, which let a large surplus of electricity to sell on the market (see the examples in Box 2).

<sup>12</sup> EPR (European Pressurized Water Reactor) will be implemented for the first time in the nuclear unit called Olkiluoto 3 in Finland.

**Box 2: European experience of long term contracts between producers and industrial consumers with development of a new large equipment on site**

Among projects which have been developed in a contractual partnership between producers and industrial consumers, four cases concerned production on site.

- In France a joint venture between GDF and Mittal Arcelor for the development of CCGT of 800MW on the Dunkirk site using blast furnace gas as 40% of the gas and the corresponding heat and electricity is off-taken by Arcelor (225 MWe) while GDF sells the remaining electricity on the electricity market;
- In Belgium a long term partnership between Electrabel, RWE and BASF with a risk sharing arrangement for a large CCGT cogeneration of 400MW on site in Antwerp; each of them delivers up 150MW (with heat included for BASF);
- In the Netherlands, a partnership around a large cogeneration plant of 400 MWe (and total of 820 MWth) near Rotterdam (Rijnmond site) organised by a 15-year contract (with a five year fixed price and remaining years with indexed price) between the project developer InterGen and the electricity supplier Nuon in a first stage (the contract has been sold in 2007 to another Dutch supplier Eneco);
- In Italy an agreement between Suez-Electrabel and the chemical company Solvay for a combined cycle unit of 400 MWe in Rosignano (with 100 GJ/hour of steam off-take).

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

With the beginning of the new cycle of investment which begins in the second half of the decade in these countries, most of the projects are announced by the vertical companies. Almost all the entries by capacity development are based on vertical arrangements (see box 2) but there exist some exceptional cases of merchant plants set in markets where the average annual price (including revenues of opaque ancillary service markets) are high, namely the Italian and Spanish markets.

**Box 3. Recension of plants realisations and projects of pure merchant in Continental Europe since 1998**

- In Italy, the CCGT projects of the Swiss company EGL with a tolling contract with the parent company : the Rizziconi plant of 760 MW commissioned in 2007 and the Calenia plant of 760 MW
- In Italy, the CCGT projects of the Austrian Verbund in partnership with the Benedetti financing group (with the two Sorgenia projects of 770 MW),
- In Italy the CCGT projects of Tirreno Power project which is less archetypical because it is a joint company of different partners (Electrabel, ACEA, Verbund, etc) which some have supply business in retail sales.
- In Spain, a project of CCGTs of 1200 MW, developed by AES (71%) and Gaz de France (26%) which is backed to a tolling contract of 24 years with GDF which has not prior power sales agreement with electricity suppliers.
- In Germany, the Concord Power project of CCGTs of 800 MW in Lubmin (Mecklembourg) promoted by Saalfel Group with no PPA relations with electricity suppliers.
- In Germany, the Soteg (Luxmburg) and Gazprom's project of CCGTs of 800 MW in Eisenhutt (Brandenberg) with non PPAs relations, but a gas agreement with Gazprom.

Sources: "New Power Plant Tracker" *Power in Europe*, Issue 508, September 10, 2007.

Based on these facts, the question we raise now concern the risk allocation configurations for investing in generation of electricity in de-integrated market models. We will assume that the way of investment risks allocation exclusively on the producer can create barrier to invest in generation activity.

### **3. Risk allocation as barrier to investment in generation in the decentralised market model**

It is worthwhile to remind the simplicity of risk allocation in the former model of vertical monopolist utility 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. 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. The rationales to change this cost-of-service regulation are well-know. Criticisms addressed to this regulation have begun with Averch & Johnson (1962). They show that this system encouraged the use of the most capital intensive technologies, and with this structure, the accent was placed on the increase in the capacity and not on the search for productivity and . To counterbalance these limits, the industrial organization must be de-integrated as well as vertically and horizontally, to allow for effective competition by facilitating new entry in generation with capacity investment and in the retail activities. In this reference business model for generation the merchant plant, in which an independent generator 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 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 approximation of the risk management problem of investors in electricity industry. Then, third sub-section will synthesize the obstacles in term of risk management applied to long term contracting in the generation of electricity.

#### **3.1. The four beliefs of investment decisions and risk allocation in the reference model**

In the line of the new paradigm of investment risk allocation in the liberalised electricity market proposed by Chao, Oren and Wilson (2008)<sup>13</sup>, we stress four beliefs concerning the efficiency of risk management along the chain of business activities :

1. The former vertical integration of utilities regulated in cost of service can be replaced by bilateral contracts between generators and retail suppliers and large customers, assisted by organised markets for spot trading. Investment decision and

---

<sup>13</sup> We add the fourth belief on the role of intermediary of the suppliers in risk management by substituting it to their supposed willingness of the consumers and customers to manage their risks in their purchase of electricity. These authors develop in this paper a relevant and realistic revision of their hypothesis, given that they were the academics who promote the most de-integrated design of power markets in a very rigorous and formalized way in numerous papers (see for instance Chao and Huntington, 1998; Wilson, 2002)

technological choices will take place based on electricity price signal without regulation interferences.

2. Generators could obtain capital on comparable terms directly from financial markets without relying on arrangements with suppliers which could transfer risks on their customers; such as formerly regulated utilities could do with its assured cost recovery. Innovative structure finance would offer new ways to finance new generation equipments in “project finance”, i.e. without non-recourse debt and very high leverage of 80% of debt and only 20% of equity.

3. A rapid and adequate development of 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.

4. Suppliers 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. Downstream, they have to manage a portfolio of different types of contracts with specific time-spans and price formulas adapted to the different segment of clienteles, with volume risks inherent to their customers’ switching. They are supposed to harmonise risk management between their portfolio of sourcing and their portfolio of sales contracts.

In this new 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 of demand and capacity, the marginal cost of the last generating equipment and eventually by the market power of competitors, such factors being impossible to forecast, even in average. Investment cost recovery for new plant will be allowed by generation gross margin (i.e. the difference 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.<sup>14</sup> So a competitive market would give the right signal for investments when capacity development must respond to demand growth and old plants obsolescence and it would allow the fixed costs to be recovered.

### **3.2. Pitfalls and limits of the four beliefs**

The first belief is that market signals were deemed effective for guiding investors’ choices to an optimal technology mix with regard to the seasonal loads. The market ensures inter-temporal optimality thanks to hedging instruments. The interplay of complete and well-informed markets would lead to optimal investment choices, like those of a regulated monopoly, while also yielding the benefit of incentives to long term efficiency by market

---

<sup>14</sup> It is common to name infra-marginal rent the gross price-cost margin.

pressures, in particular in timely capacity developments (Hunt, 2002). But generators and investors are confronted not only to a problem of cost minimization, but to a problem of combining return maximising and risks minimizing when choosing an equipment in a stock of technologies to invest (Gas Turbine, CCGT, Coal, Nuclear or Wind Farms). For simplification purpose in the comparison given by table 1, we put aside here some specific risks under the control of the regulators and the policy makers<sup>15</sup>. We concentrate on a limited set of economic risks: the risks on cost under the control of the company (construction cost, operation performance), and the risks that the investor must know how to manage them before to decide to invest and ask loans to lenders, namely the fuel price risk, the electricity price risk and the volume risk related to the wholesale competition and the demand variability.

**Table 1. Characteristics of cost and risks of different electricity generation technologies**

<i>Technology</i>	<i>Capital Size per unit</i>	<i>Lead time</i>	<i>Capital cost share</i>	<i>Fuel cost share</i>	<i>CO2 cost</i>	<i>Fuel price risk</i>	<i>Regulatory risk on construction cost</i>
Gas turbine (100 MW)	Very low (€20 million)	Very short	Low	Very high	Medium	High	Low
CCGT (400-600MW)	Low (€100-200 millions)	Short	Low	High	Medium	High	Low
Coal (2x 700MW)	Large (€700-1000 millions)	Long	High	Medium	High	Medium	High
Nuclear (1500MW)	Very large (€2-3 billions)	Long	Very high	Low	Nil	Low	High
Renewables (Wind farm 200MW)	Medium (€300 millions)	Medium	Very high	Nil	Nil	Nil	Medium

Source. Adapted from IEA/NEA, *Comparison of electricity generation costs*, 2005

The conclusions we stress from table 1 are the following:

- Gas generation (gas turbine & CCGT) has relatively low cost of capital which reduces financial exposure, and generation tends to be quite flexible to follow the load on the market. Moreover when gas price increases, CCGT tends to become the marginal equipment on the hourly market, and “makes” the electricity marginal price during a part of the year. This has two opposite effects: a good correlation between gas price and electricity price during part of the year, 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.
- 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

<sup>15</sup> These risks concern changes of market rules, environmental regulation, uncertainty on equipment sitting with possible important implications for investment costs, revenues and financing conditions....

financial risks of whether they can repay the capital based on the volume and price of electricity off take of 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 sum up, investments in the highly capital-intensive equipments (coal generation, nuclear plants, hydraulic plants, renewable) are hampered and distorted by excessive volatility, whereas they do not benefit of correlation between fuel input cost and electricity price, as do the CCGT plants.

As suggested by the second belief, lenders have adopted this method of project financing of merchant plants, but without securing vertical arrangements. The lender's collateral resides in the projected cash flow of the project and the resale value of the production asset. Because of the confidence in the market mechanisms, the lenders who demanded the greatest transparency for the market rules were so confident of the functioning of the new electricity markets that they did not require collateral in the form of long-term contracts guaranteeing the project's revenues. Merchant plants were supposed to have revenues by spot sales (on energy and operating reserves markets) or short term contracts. Even if lenders were confident in these projects they were intrinsically risky as they were granted to a firm specifically created on the basis of its expected cash flow without being secured by a PPA at fixed price, or by risk management by a diversified assets portfolio. The investor will take his decision after exploring returns different technologies may deliver under a number of different assumptions on fuel prices, influence of fuel price on electricity prices (and their spread), demand patterns and capital costs. But as it finances the project by raising as much as debt finance as possible via non recourse debt and project financing, this imposes the self-financial sustainability of the project by its net cash flow without backing on eventual cross subsidy from the producer's other generation assets. This means 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.

The third belief 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. The price volatility would normally be manageable by electricity producers, wholesale buyers and consumers if they could develop the contractual arrangements necessary for efficiently allocating the risks across generators, intermediaries, and consumers. 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 (DOE, 2002, Geman, 2005, Defeuilley et Meunier, 2006)). The non-storability of electricity and the non-elasticity of real time supply and demand do not allow the future or the forward price to represent a correct anticipation of its price realisation. It dissuades banks and hedge funds from playing the role of counterparty on such markets—though they commonly speculate on other commodity markets and create liquidity. This situation complicates investment decisions because investors do not attribute informational quality to spot price and forward

price, in the sense that they hardly reflect the situation of fundamentals. It is noteworthy that the problem for investment decision in generation units does not lie solely on the fact that long term derivatives cannot develop in such a context of risk profile. In any capital intensive industry promoters of large projects with long time horizons never meet counterparties to cover all risks with an option contract that enters into effect when the equipment is started up and covers its pay-back period<sup>16</sup>. In any industry long term derivatives do not fully capture investments in production. The problem is informational. To conclude on this third premise, the very specific price-risk profile combined with the complexity of the existing spot markets, deters development of a liquid market for derivatives and financial contracts that would facilitate management of risks.

In the logic of the third premise 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, as stress in an IEA report on generation investment (IEA, 2007) :

*“The investment risks are expected to be borne by the power companies, based on their expectations of future prices. They face the risk of losing money if they make the wrong decisions, but it balanced by the incentive of making greater rate of returns if their decisions are the good ones. 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. Although the absence of long term contracts may lead to increased uncertainty, it may not be appropriate to consider this as introducing unstable investment decisions. The rewards will balance the higher risks. Potential investors must be able to form rational expectations of future prices that are not subject to manipulation by incumbent power companies”.*

Another aspect of the third belief is that, in the business model of merchant plant with no PPAs, risk is managed individually for each unit without portfolio approach, given the logic of project financing. This approach supposes that each production unit manages its risks more efficiently in an independent way than in interdependency with other production units. It restricts them to hedge their investments by diversifying their risks between different technologies on the same market, whereas portfolio approach for merchant plants give significant benefits to the producers, as it has been shown by Roques, Newbery et Nuttal (2006)<sup>17</sup>. Moreover, with a diversified portfolio, new producers as companies benefiting from

---

<sup>16</sup> In the oil industry an off-shore production project takes anywhere from 4-10 years from discovery to first production, and then produces for years or decades, while the futures market only trades out 6 years. It does not allow hedging the first year's production, until the project is well under way. Longer term over-the-counter could help such projects, but historically the bid/ask spreads - the difference between what the seller wants and what the buyer is willing to pay - on such thinly traded markets are prohibitive).

<sup>17</sup>This theory indeed helps to find the best risk-return portfolio of power plants assets for a de-integrated producer (Roques, Newbery et Nuttal, 2006). If there are two or more possible projects in which it can invest, the investor will get a better rate of return for a given risk or a lower risk for a given rate of return if it holds a combination of these projects than if it holds any one on their own. Portfolio approach increases the costs of fossil-fuel generation over the standard estimate, and makes nuclear and renewables more competitive, though they currently appear more expensive.

existing equipments can rely on “portfolio bidding” on the market, as it is usual that incumbent producers do in all the markets.

Finally in liberalised electricity markets, experience reveals that the business model of the merchant plant underwritten with project finance clearly fails, even when the CCGTs which allow the best risk management in a sort of self-hedging, are developed, as shows the bankruptcies of all the CCGT merchant plants in the US liberalised market and in the UK (Joskow, 2004; Michaels, 2006). Since then, investors and producers are now convinced that pure merchant plant is not a viable business model.

But the fourth belief on the viability of retailers’ risk management has also limitations which hamper the possibility to long term contracting by the new producers and beyond the possibility to break the deadlock. Indeed investors and producers are now convinced that for making merchant plants viable, vertical arrangements yielding a risk allocation adequate for establishing the required financial arrangements are needed. But they fail on the difficulties of establishing long term contracts with creditworthy buyers, given risk aversion of retailers to commit on long term.

This impossibility of long term contracting for hedging new generation investment in the de-integrated market model could be considered as a market failure because of the impossibility to secure long term revenues for new generation equipments in the pure market model<sup>18</sup>. Even though the price-risk would be considerable, that does not, in and of itself, signify market failure. There is no theoretical reason why risks on the market price, should impede investments in generation. The problem results from the fact that the risk is not manageable for the investor because it could not be adequately allocated with buyers in comparison of the former situation with all the risk transferred to consumers by cost-of-service regulation. This simply inflates risk management costs and, by raising the cost of capital, increase the anticipated trigger price the market must reach before deciding an investment in capital intensive equipments. But such projects should be developed if an allocation of risks onto the consumers could be achieved in a way or another in the de-integrated market model.

#### **4. The workable combinations of generation investment and long term contracting**

In this section we come back first on the basic dilemma for generators and wholesale buyers which is securing their respective net revenue by combining their respective risks. Second we show how consumers’ opportunistic behaviours restrict investment in generation. In the last sub-section, we will see how different long term contracting options mitigate the incentive of opportunistic behaviour by the use of safeguards.

##### **4.1. The basic dilemma of sharing investment risks between new producers and consumers**

---

<sup>18</sup> We follow De Vries and Hakvoordt (2004) in this direction.

We refer to the Transaction Cost Economics, a body of the economic theory which explains the prevalence of vertical integration and hybrid arrangements that allows the development of specialised investments in context of uncertainty and risks (Williamson, 1975, 1985 and 1996). A major aspect of the uncertainty, endogenous to the transaction, is the opportunism of the parties, i.e. the capacity of one party to take advantage on the other party which is the more engaged in the transaction<sup>19</sup>. Referring to difficulties and risks of contracting, TCE explains the choice between different institutional arrangements, spot sales, incomplete contracts, and vertical integration in relation to the necessity to protect investments. It considers several attributes of the transactions as the determinants of this choice: equipment specificity to the transaction, i.e. the mix of large sunk cost, long life and non-redeployability of the equipment (i.e. the impossibility to be moved or used for another production) which is the most important determinant, but also measurability, complexity, frequency and uncertainty in the environment of the transaction.

In the former electricity industries with no technological possibility to relate producer and off-taker in real time, the production assets were geographically specific to the area monopolies. Given their retail and transmission franchises, the local utilities would have been the monopsony power to exert their opportunism without the utility regulation. But, provided that cost-of-service regulation could help these buyers to assume all the costs and risks because they could pass through their costs and transfer their risks on the consumers, wholesale contracts could be incomplete but include provisions to cover the maximum of unlikely contingencies. This helps the buyer to avoid opportunism and to help the seller to recover all their sunk costs in case of negative contingencies.

When numeric technology went and allowed bilateral transactions of any producer and consumer after third party access liberalisation, competition could be introduced at the different stages of the markets. Geographical asset specificity to sell to the area monopoly disappears. New producers can sell their production on anonymous spot markets or bilaterally to any retailer or consumer. They could use fixed price long term contract to securitize a generation investment, as we shall argue later. But counterparts which are less engaged in the transaction than the producer who has invested would be always incite to renegotiate or to break the contracts as soon as the market.

At a first glance, interests of generators and large wholesale buyers are converging, as Chao, Oren and Wilson (2008) sum up. Indeed the fundament of this is that interests of producers and suppliers 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 supplier against sustained high prices while foregoing higher revenues to the producer during the periods of

---

<sup>19</sup> *Opportunism* is Williamson's concept of "self-interest seeking with guile." In a world of opportunism individuals cannot be assumed to keep their promises, to fulfill their obligations, and to respect the interests of their trading partners unless "safeguards" are in place. The task of economic organization, in Williamson's terms, is to "organize transactions so as to economize on bounded rationality while simultaneously safeguarding them against the hazards of opportunism."

lower prices. Moreover with 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. But such hedging solutions are not so simple because there are inherent obstacles to long term arrangements with reluctance of large consumers and intermediaries (suppliers) - virtually the only credible counterparties for a generator in a long-term project - to enter into long-term contracts, because of diverging interests and incentives of opportunism.

As suggests by the Transaction Cost Economics, an important condition for the credibility of the suppliers' long term commitment and the subsequent confidence of a future investor to sign up a long term contract and then install its new equipment is the existence of guarantee which limit opportunistic behaviour of the counterpart<sup>21</sup>. A basic option for securing this opportunistic behaviour is to include safeguards in the long term contract structure like hostages or common assets. The roots of opportunistic behaviour for buyers can be estimated by the difference between the exit costs from long term contract and the possible gain given by an alternative option for energy sourcing on the spot market. So, in the electricity sector, without these guarantees, wholesale buyers are tempted to exit and break the long term contract, if the possibility to shift their risks to their customers does not exist in one way or other in the line of a number of authors (Michaels, 2006; Joskow, 2006; Chao, Oren and Wilson, 2008).

The solution will lie either in an existing base of sticky consumers attached to historic suppliers, or a remaining franchise for the supply of households on them (Green, 2004; Newbery, 2001) or else the Joskow's solution which underlines the importance of last resort supplier provision to maintain a large segment of sticky consumers (Joskow , 2006). Indeed, in the US systems that are completely opened to competition in retail, the historic operators as suppliers of last resort can assume a large part of the investment since their diversified portfolio of retail clients contains a large base of sticky customers who are reasonably loyal to them, given this provision of last resort supplier. Under this provision, consumers who have opted out can come back to the historical supplier and benefit from the public price which remains under the supervisory of the local regulator. So when the retail market price increased in 2004-2005, a mass of customers came back to their utility (Chao et al., 2008). This provides them with the stable market share they require to render long-term purchase fixed-price contracts attractive for them. It creates de facto a protective niche where the consumers benefit from public prices monitored by the regulators and disconnected more or less from the volatility of market prices. It makes them able to pass the price differential of their purchase contract over the wholesale market in their retail prices. In the European markets last resort supplier provisions exist but does not give to the consumers the same opportunity to switch back to the historic company (This provision mainly gives a protection in case of failures of the customers' supplier). That means that, if there is a risk of high market price on the retail market, consumers will not have the opportunity to come back<sup>23</sup>. So

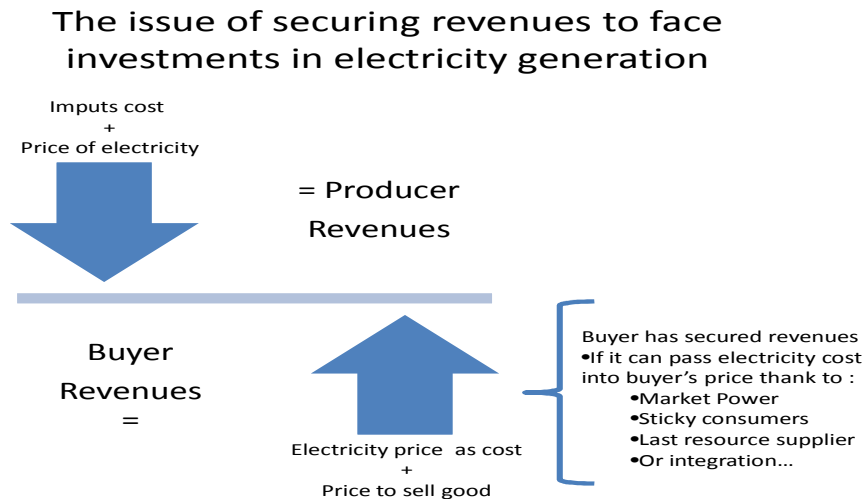
---

<sup>21</sup> In Transaction Cost Economics, opportunistic behavior is a key issue. Williamson (1985) considers that sometimes firms can behave cooperatively, but because it is not the case everytime, safeguards are needed in the long term relations, given that uncertainty.

<sup>23</sup> The observation of the active retail markets in Europe allows identifying segmentation between a large majority of inactive consumers, few variations in the annual rhythm of switching from the historical suppliers,

historic suppliers will keep a large fringe of inactive consumers to which they could transfer part of their sourcing risks, because these consumers have no interest to switch (see figure 1).

**Figure 1 : The securing revenues issues in generation of electricity**



#### 4.2. The risk of buyer's opportunism

In fact, suppliers do not wish to be bound by PPAs with fixed prices on a long time-span, which would be the most interesting agreement for a pure producer developing new equipment. Observing the markets reveals that the duration of bilateral physical contracts or financial options 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. Producers rarely find counterparts for longer sales contracts. In addition, in the real markets, the vast majority of medium-term bilateral contracts do nothing to hedge against price risk, since prices are simply harmonized with, and indexed to the hourly price on the power exchange, simplifying negotiations and curbing transaction costs.

In the same time the supplier is generally locked by his portfolio of mid-term sales contracts with flat prices without few possibilities to adjust the price upward shortly after wholesale price increases<sup>27</sup>. Their problem of price risk management is increased by the fact that, generally, regulators define favourable rules to consumers to switch in order to help retail competition. The latter ones have the legal opportunity to leave their contractors for switching to another one with a delay of few weeks (28 days in the UK for instance). Moreover, in some

---

and a consolidation of the segmentation between active and inactive consumers (Wilson and Waddam-Price, 2007). In particular because the segment of active consumers will be more and more fluid under the learning effect, this market will be more and more complex to understand by the inactive consumers and more and more opposite to their decisional routines (Defeuilley, 2008).

<sup>27</sup> There are three main types of retail contracts offered to small commercial consumers and households (Littlechild, 2002) : first the fixed-price contract for one to two years : second the standard variable contract where the supplier may adjust the contract price either at regular intervals, or when changes in supply costs occurs; and finally the market-based contract where the price directly reflects the spot price plus a margin (as it is used mainly in Norway, Amundsen et al., 2006).

markets such as the US liberalised ones, the consumers benefit from the provision of provider in last resort which allows them to switch back in any case to the historic supplier if the retail prices are changing. So in case of price downward, not only they have to follow the move of the price when contracts are renegotiated, but they are exposed to the risk of important switching before the end of running contracts.

In this context three reasons deter suppliers to commit to fixed-price and fixed-quantity contracts and to fixed price non-firm contracts, with producers or entrants on a long period:

1. First the suppliers which are buyers on the wholesale contract and spot markets are also sellers on the retail market. This position of intermediaries which makes them exposed to a risk of price squeeze constitute a clear incentive to opportunistic behaviour in case of market downturn. They are generally constrained by two facts. First the majority of their sale contracts are at flat price. Second they do not possess a stable base of sales contracts allowing them to assume the risk of signing such long term contracts with new generators. They are vulnerable to a high risk of losing customers by switching if they do not follow wholesale price developments. With their long term fixed-price procurement contracts when there is a significant downturn in the wholesale market, any of the suppliers having signed fixed price contracts with generators that provide for price guarantees will be tempted to break these purchase agreements, because they are simultaneously subjected to substantial risks in their client base<sup>28</sup>. 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 who 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.<sup>29</sup>
2. Second the fixed quantity clause, which contributes to protect the investment in generation capacity, 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.
3. Conversely the non-firm contract places plant availability risk on the buyer, whereas the firm contract price reflects the cost to the merchant generator of bearing the plant availability risk.

---

<sup>28</sup> 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. Given market long term markets and enough volatility, he shows that retail competition might raise wholesale price up to around 20%.

<sup>29</sup> 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 and then was unable to

4. So the benefits are not exactly symmetrical between producers and suppliers because the stakes for each party are not the same. Indeed by installing new equipment the producer irreversibly commit for a period of several decades while the supplier's advantage taken from the contract are confined to the duration of spike price periods.

In the perspective of Transaction Cost Economics, it appears that if the buyer behaves in an opportunistic way and breaks the contract, there will be always a cost for the producers to search new purchasers and few chances to contract in equivalent terms on the price and the time-span. It is noteworthy that the incentive to opportunism is the same for large consumers which are committed in long term contracts. This risk of wholesale buyers' opportunism is the most constraining limitation, as it deters producers from signing long-term contracts with them, as emphasized by De Vries and Neuhoff (2004). Or even if long-term fixed-price contracts were signed, they would not provide credible guarantees for the producer investing in generating capacity. Before committing to an investment they must anticipate the possibility of losing revenues if any of the long-term contracts they may sign are challenged, or one of their major clients declares bankruptcy. Thus, they will be reluctant to engage in, and invest on the basis of, any long-term contracts on significant volumes.

#### **4.3. Long term contracting and safeguards to mitigate opportunistic behaviours**

Consequently we will consider the innovative ways to build long term contracts, with first the issue of long term relations between producers and large consumers and second the way of stabilize long term contracting between producers and suppliers. Innovative contracting allows different modes of risk allocations which could decide suppliers to commit. Indexed price contracting, tolling contracts, and option 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.

1. Indexed-price contracts generally index the price of electricity to the cost of another commodity, in particular the cost of the fuel used to generate the electricity. 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 CCGT project, the fuel price risk is allocated to the buyer because the buyer receives a variable-priced product<sup>30</sup>.
2. The so-called tolling agreements whereby the power purchaser delivers fuel to the generator and takes delivery of the resulting kWh more clearly allocated 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<sup>31</sup>. It is noteworthy that these

---

<sup>30</sup> A variant is the "spark-spread contract" which enables the producer to hedge differences between fuel and power prices.

<sup>31</sup> 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).

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.

3. Financial option contracts were a sort of insurance contract against volatile price. They are more favourable to the buyers' interest. Option contract enables them to hedge against high price risk without exposure to the quantity risk that it would have in the first types of contract if the contracted quantity exceeds the amount required to serve its market. In this category contracts for difference with symmetrical options "call" and "put" reflect the mutual incentive of producers and buyers for price insurance<sup>32</sup>. It is noteworthy that such contracts have been made possible by the fact that they benefited from this remaining franchise on which regulated tariffs could pass through the price cost of their contractual purchases to their captive customers.

We now distinguish between the long term contracting options with large consumers (4.3.1) and with suppliers (4.3.2).

#### *4.3.1. Long-term contracting with large consumers*

Three options are of interest in this issue: first the capacity development in joint venture; second, the horizontal arrangements between associations of large consumers and producers; last, the Virtual Power Plant solution.

Large industrial consumers are among the potential counterparties for generators seeking to invest. Rather than develop their own equipment to hedge purchases in the face of erratic short-term price fluctuations, large consumers can seek to obtain more stable terms and avoid movements in wholesale prices with long-term supply contracts. But interests are not completely converging<sup>33</sup>. On the side of the generator to make this kind of contract interesting to invest in a new capacity, it must provide for sufficient volume and time to be associated with the construction cost recovery. Moreover the industrial consumer must be a creditworthy counterpart, in particular with limited risk of relocation or of bankruptcy and disincentives to opportunism. On the side of the industrial consumer there is always a risk to lose the opportunities of electricity purchase at lower price than the contractual one during the stage of low prices on the market. As examples concerning such capacity developments in European countries, electricity companies and large industrial consumers (chemicals, metallurgy) have made joint ventures to develop large CCGT units<sup>34</sup>. They then divide the power between the needs of the industrial partner and sales on the wholesale market. In order to let an important power surplus which is independent of the constraining process need in steam or heat, the equipment is flexible and the electric power capacity is over-dimensioned above the industrial partner's need of power.

---

<sup>32</sup> It has been used as in the British market by the regional electricity companies (REC) and the entrants in the nineties, when the RECs retain a legal franchising on the households segment.

<sup>33</sup> Examples of such long-term contracts associated to large equipment build show that possible conflicts of interests between potential parties could be defused in each context.

<sup>34</sup> Partnerships are based in some cases on valuing a secondary fuel as blast furnace gas. In all the case they are based on the combined production of heat (steam) and power.

Another way for the large consumers to proceed is horizontal arrangements in consumer's cooperative of production or consortium of electricity purchase. 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. A particular arrangement—an electric cooperative in generation owned by several very large consumers (pulp and paper) and local distributors—was already established well before the 1996 market liberalisation reform. 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 euros nuclear reactor of 1700 MW in 2005. The large consumers want to be unaffected by the effects of random hydro inflow situation, future CO<sub>2</sub> 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).

Last solution studied here of long-term arrangements between generators and industrial consumers is based on the same principle of the virtual power plant contract (VPP). This VPP contracts are more flexible because they are not linked with new equipment and the payment may be structured as if the consortium would have to build itself a new plant. In this case, the capacity of which corresponding to the contractual quantity or as if it helps financing this virtual equipment: the consortium pay fixed initial upfront payment at the beginning of the contract and then a fixed price corresponding to the variable costs. A priori this type of arrangement could be applied either to indistinct purchase of electricity or to finance a new one with a generation cooperative, but the time span of the commitment tends to be inferior to the cost recovery period of capital intensive equipment. We can refer to the French example of a cooperative for long-term purchases created in 2006 by the seven largest consumers (under the name of Exeltium) to acquire blocks of a fixed amount of electricity (35 TWh/year) at a the cost-price of nuclear production (i.e., near the cost of generation of large capital intensive equipments not exposed to CO<sub>2</sub> cost) in the framework of one or several tendered contracts covering 15 to 20 years.<sup>36</sup> A similar arrangement exists in Belgium under the name of Blue Sky.

Competition policy principles are respected if the consumers group does not cover an important share of the industrial demand and if selection between producers is made by auctioning. It is noteworthy that a generator may find it beneficial to bid with a contract price below the anticipated market price and sign that type of contract to supply purchasers whose

---

<sup>36</sup>In the case of the accepted bid after auction in 2006, the price offered by the chosen producer (38 €/MWh) for a first contract of 18 TWh per year (in fact, this is the French historic operator) corresponds to the complete cost of generation by existing nuclear reactors at their replacement cost if they would be re-built in the same industrial and regulatory conditions than before. Let us notice that the consortium has to finance the first payment which covers the large upfront cost of virtual equipment by borrowing.

The type of arrangement presents a financing advantage for the contractors in the sense that lenders agreed to lend money to the consortium with high gearing, deconsolidated and non-recourse debt for the members of the consortium.

consumption profile is constant throughout the year and uncorrelated with that of other consumer types. However to avoid opportunism of some members of the consortium in case of unanticipated downturn of the market price under the contractual price, very precise rules govern these types of consortia to prevent strategies of opportunistic exit in the event of a downturn in the short-term market<sup>37</sup>.

Whatever it could be, contractual solutions involving large industrial customers that are designed to collateralize and secure investments in generation by market producers cannot be the principal means of developing generation capacity. But they are of interest to very large consumers who represent less than a fifth of consumption in mature economies.

#### 4.3.2. Long term contracting with suppliers

The conditions of suppliers' commitment in long term PPA: their need of a base of core consumers. In the event that the market is completely open to competition with market rules that eliminate switching costs, retailers 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<sup>38</sup> if they do not follow the price downturns on the wholesale price. But their loss of revenues exposes them to bankruptcy. Even with indexed price contract, risks exist that electricity price downturn is more important than the contractual price decrease. So as said, anticipating opportunism of suppliers, producers hesitate to sign PPAs and investors to lend money with these PPAs as collateral. They need creditworthy purchasers as shown the attitude of lenders who accept now project financing in the USA only if the IPP has a PPA with a historic supplier which has still a regulated monopoly segment (Chao et al, 2008).

But there are disagreements around the conclusion that complete retail competition precludes the signing of long term contracts. The IEA report on conditions of generation investment (IEA, 2007) and Littlechild (2002) argue against this analysis. For the first one, 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. For the latter author, "*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 is that suppliers who wish to sign long term contracts have to back their own judgement rather than pass the risks to consumers; this is likely to improve the quality of decision making*" (Littlechild, 2002). In another words as a financial company which makes fixed interest rates mortgages available while short run rates vary, a supplier transforms short term forward contracts at fixed price in the retail to long term forward contracts in power purchase with producers, provided that it could renegotiate the contractual retail price when retail contracts are ended up in relation to change in wholesale spot price. In the real world suppliers do not exactly develop in this direction.

- *The complementarities between long term contracts and a sticky retail segment*

---

<sup>37</sup> Exit is only allowed to accommodate a modification to the industrial strategy as off shoring, or bankruptcy.

<sup>38</sup> who could directly purchase from the wholesale market

In the real world, the different types of consumers do not react in the same way to price signals, and most of them are quite risk adverse. That means that there is on one side a real risk of customers switching in case of price downturn, in particular from the side of industrial consumers and in some markets from active household consumers if the regulatory and structural conditions of retail competition favour aggressive commercial strategies. The competition is quite different between most of the American liberalized ones and the most active European ones in which high cumulated rates of switching (i.e. the total of switching since the openness of the markets) are observable when effective unbundling, historical supplier's brand changes and lowering switching costs have been realised by the regulator<sup>39</sup>.

In the more general case, in the other US and European markets, on the households and commercial customers segments, there are a number of inactive customers which are pasted to their original 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; In this perspective, Chao, Oren and Wilson (2008) who in the past have promoted the most de-integrated market design in their numerous theoretical works, now consider that "*a basic lesson of liberalized electricity markets is that customers (on the households segments) are deeply adverse to price volatility and to continually monitor and control their consumption. (...) There is a continuous role for (historic suppliers) in providing intertemporal smoothing of retail prices*", as did formerly the cost-of-service regulated utility. In another words, 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 can pass through major part of their sourcing risks on them. And it converges with the producers' interest to meet suppliers able to commit in long term purchase contracts at fixed price.

To go further in this direction, the historic supplier must retain, either *de jure* or *de facto*, a significant segment of its clientele that is either captive or quasi-captive. Either the historic suppliers may legally retain their resale monopoly on part of the market (the segment of small consumers in their distribution area) or, after a complete opening of retail to competition, the retail market reform remains incomplete and leaves the supplier a significant base of "sticky" customers. Both of these conditions would enable them to pass the cost differential of the purchase contract over the wholesale market in their retail prices.

This situation appears to be the solution for curtailing opportunism risk of the suppliers who might enter into long-term contracts, provided that regulation of retail supply lets such imperfect competition situation. It must be underlined that it essentially concerns only the historic suppliers. 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. Chao, Oren and Wilson (2008) stress these complementarities when they conclude (p.30): "*The role of (historic suppliers) could be ideally complementary of those of lowering*

---

<sup>39</sup> : In 2005, 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%.

*capital cost (for generation investment) when they sign long term contracts with IPP or invest in generation”.*

- *Backing the contractual credibility of the suppliers to a consumer franchise*

Newbery (2002) and Green (2004) who usually defends the value of market principles for wholesale exchange develop a stronger position. They advocate retaining consumer franchise and reverting to monopoly in retail supply to households, in order to ensure a stable customer base and facilitate investment. They argue that the complete opening of retail to competition does not induce any improvement in short-term efficiency, since wholesale price movements are not reactively transmitted to retail prices, and competition is only exercised on the already reduced margins of supply. While total retail competition extends risk quantity for the intermediary and contribute to hamper their commitment in investment.

But a new problem will be raised for the regulator. If a partial monopoly is maintained by new franchise for small consumers, the challenge is to ensure that local monopolies have sufficiently strong incentives to negotiate low prices with generators. This can work in two ways: regulating by either comparing across distributors (yardstick competition) or by tendering long-term contracts (Green, 2004). But if the sector is quite fragmented in distribution and supply, regulation could be complex and information costly, as stressed by Littlechild (2006)<sup>40</sup>. He notices that a disadvantage of retail monopoly is that utilities and regulators who do not have to test their judgements 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. They can nevertheless force customers to be associated to such contracts and bear the resulting costs and risks.

In such situations some authors consider that the control problem could be solved by auctioning the long term contracts of suppliers with partial franchise in order to benefit from the pressures of market mechanisms. 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. Let us note however that the complexity of the supplier's regulation in the *half-slave half-free* situation is not only the lot of the supplier's partial franchise. In the former case of no legal monopoly in distribution but stickiness of consumers to historic suppliers, the regulator needs also to ensure that suppliers who are strong in the mass market segment do not exaggerate the transfer of costs across market segments. In these two contexts of either imperfect competition in the retail supply with large core consumers or partial franchise, experience shows that suppliers do not hesitate to sign long term contracts as well as shorter term ones in different markets: Britain, Germany, Norway, New Zealand, Sweden the Netherlands (see box 3) and several States in the USA, even if volumes are small.

---

<sup>40</sup> The regulator would have to define a future path of evolution of spot prices and forward price and to refer to a benchmark of purchase strategy by the historic suppliers, to assess the different risks and allocate them between producers, supplier's and consumers.

(Conclusion to be developed) So the combination of the four premises of the pure market model, which determine the ability of the market players to invest in generation in a timely way and with technological choices converging towards the optimal mix, is not confirmed in the real world.

## **5. Opening the range of vertical arrangements : towards re-integration?**

Long term contracting between new generators and suppliers which could commit thanks to the guarantee offered by their core customers is not the unique solution. Partial or complete vertical re-integration is another option of hedging for the IPP for securing investment in generation by allowing off-taken quantities and sales prices of the new productions to be guaranteed and by passing the fuel risk on to the internal buyer.<sup>41</sup> So it is for the pure suppliers to hedge part of its sourcing. This leads to analyse in a second stage the fitness of vertical industrial organisation based upon existing generators with a historically grown portfolio of various technologies and a developed set of customer relations, with constraints of investment in a variety of generation technologies.

### **5.1. Vertical integration of production and supply: an efficient alternative to long term contracts**

Given the alternatives between long-term contracts and vertical integration, the quest for vertical integration between generation and supply can be understood, from the two respective perspectives of the electricity producer and the electricity supplier, as a strategy for controlling risks along the value chain, some stages of which are highly capital intensive. In particular the incentive to adopt vertically integrated arrangement is increased in countries with fluid competition on the retail market, in a context where risk management is difficult for the pure suppliers. In the case of vertical integration, the vertically integrated generator controls the risks associated with asymmetrical changes in profit margins at each stage under the effect of market prices fluctuations. That which is lost by one unit is recuperated by another. In the perspective of the integrated supplier, this one stabilizes and secures also the terms of its wholesale purchases, even if it does not control its risks in resale.

In case of price downturn, face to the risk of massive customers switching the trading and marketing division of an integrated firm has not the same incentive to opportunism, provided that the wholesale price will not established below the fuel cost of new equipments (In this case it is the managers of the company which decide to mothballed the equipment in case of long depression of market price). While an independent supplier committed in a long term contract at fixed price or even at indexed price will be tempted to do it whatever the threshold of profitability of the producer, the trading department of any (quasi-)integrated electricity company looks only for opportunity of some short term arbitrages.

---

<sup>41</sup> 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 an synthesis, see R. Michaels, 2006; Mansour, 2005 )

In parallel when a supplier is committed with a producer on long term, fixed-price fixed-quantity contract, indexed-price contract, tolling contract or option contract represent different ways to share profit and risk between a developing generation business and a pure supply business on a cyclical market and in a moving environment in fuel prices. But other elements –transactions costs, complexity, risk of market power – appear to give more decisive advantage to partial or complete vertical re-integration.

First in the generator's perspective, the overall advantage goes to vertical integration. The long-term contract allows the sharing of investment risks (construction, fuel price, market price, quantity between different parties), while under vertical integration all of them would be borne by a single firm. For the suppliers in quest of efficient sourcing, they get also advantage in partial or total vertical integration in their risk management for hedging their purchases, given that they are committed in retail sales with a set of forward contracts at fixed price (mainly flat price for a season or a year). Consequently there are transactions costs savings, with regard both to negotiating the contract and monitoring contract performance (amending clauses, renegotiating, etc.).

Second, the model of the merchant plant which is now amended and associated to the signing of long term contracts before the equipment build is also associated with project financing agreements with very high transactions costs, owing to the high number of contracts required between the various parties. In the vertical integration scenario, the inherent guarantees to the vertical arrangement suffice to obtain corporate finance arrangement which is intrinsically generated low transaction costs.

Symmetrically from the supplier's perspective, complexity and risk management gives also some advantages to a partial vertical integration for some physical hedging upon a sourcing strategy only based on long term contracts with new or existing producers. In a long term arrangement supplier-new producer, there is a clear opposition between its need of volume flexibility and the generator's need of off-take guarantee. In its sourcing strategy, suppliers develop a portfolio of one/two year contracts of energy block purchases and monthly/weekly contracts of energy peak, but they have a permanent need of volume adjustments by purchases on the day-ahead, or by real time re-sales in case of temporary over-contracting. This creates a fundamental risk for the supplier that it cannot hedge on the forward market, given its random profile. Neither has it transfers this risk on its customers, given the rigid characters of the sale contracts. Consequently suppliers have interest to make up their hedging strategy by contracts of different time-spans and by some physical hedging by buying or installing flexible generation equipment such as CCGTs in particular for their sourcing during peak and mid-load hours in the week<sup>42</sup>. In another word the supply business is at higher risk business subject to the normal bankruptcy risk faced by companies in

---

<sup>42</sup> The example of Centrica's strategy of sourcing for its electricity sales in its development strategy of dual fuel supply after 1998 is interesting in this respect. 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. This suggests that for a pure electricity supplier, vertical integration presents a necessary complement for risk management to long term and short term contracts.

competitive markets. The risk management advantages of generation and retail integration are very important, such that stand-alone retail electricity companies have struggled.

## **5.2. Combining generation portfolio, customers portfolio and vertical arrangement**

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, as point by Chao, Oren , Wilson (2008). Moreover the company has generally a wide and developed set of customer relations. And usually large-sized, predominantly integrated firms are able to capture various efficiency gains in risk management when investing in generation, especially by controlling construction costs and the capital cost. To sum up advantages that their structure and their size present for risk management in generation investment, they are the following:

First they possess a diversified portfolio of generating equipment, giving them a greater capacity to spread the operating risk attributable to the volatility of input prices (fuels, CO2 permits), as well as market risk. The possibility to produce in different markets, underlying to their large size, reduce also the risks of individual investment on a market.

Second their size<sup>43</sup> allows them to mobilise important capital resource in equity and debt to finance large and capital intensive project in coal generation<sup>44</sup> with a cost of €1 billion or nuclear project with a cost of €2 billion. Since they benefit from a large and diversified asset base, they are able to obtain loans under corporate financing arrangements and consequently, owing to a normal debt-equity ratio (50/50) and good ratings, save on capital costs and risk premium. Lenders are attracted by diversified portfolio of assets, and are more reluctant to lend to merchant plants, even large (Lacy, 2006).

Third large size is also an advantage in the supply business, in which the risk exposure is generally correlated to the size of the business. A large supplier could benefit from its large-size portfolio of contracts as a hedge, via risk aggregation on wide scale. Moreover, if they benefit from a position of historic supplier on their home-market, vertical integration in their home-based market gives them another advantage to make consumers bear part of investment risks in this market.

Fourth the biggest among them have ample expertise in project management, allowing them to control the engineering costs of large equipment and have bargaining power in their dealings with the manufacturer's oligopoly. They could also have quite favourable long term contracts for their fuel purchase, in particular if they are also diversified in the midstream gas business.

---

<sup>43</sup> let us say, € 30 billion of turnover for the top en American companies to 70 billions of turnover for the biggest European companies

<sup>44</sup> Clean coal or IGCC.

These different advantages help them to invest not only in two hundred millions € in CCGT project, but ten to twenty times more in one capital intensive project as a nuclear plant with corporate financing and a normal capital cost.

## **6. Conclusion**

Not one 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. The theoretical market model features market failure 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. Regulating competition by the quest for the maximum transparent market rules for all stages of the electric industry, including the retail market, tend to hamper investments in generation by restricting possibilities of long term contracting and efficient allocation of investment risks on consumers.

Analysis of the way of securing investments in generation by vertical arrangements entered into by new generators (entrants, pure producers) and large purchasers (suppliers or consumers) suggests that regulatory adjustments for allowing credible commitments by generators' counterpart may prove theoretically justified. Vertical integration between generation and supply business, as well as generation asset portfolio present both some advantages in terms of transaction costs and risk management in this respect. Finally large size of vertical and horizontally integrated companies appears to be an economic advantage to manage investment risks at low capital cost.

However discussion should have to be raised about the drawbacks of these different arrangements on the effectiveness of competition and its imperfection with increased risk of market power exercise. Vertical arrangements typically hamper competition by limiting entries. So it is for large size of vertical and horizontal companies when horizontal concentration in their home market is quite high. Indeed barriers to entries and risk of abuse of market power could balance the social benefits coming from the larger capacity to invest in capital intensive generation equipments by controlling costs and risks. This issue of market concentration must be balanced with the issue of investment in generation. In particular, if the complexity of liberalized electricity industry leads to opt for these institutional arrangements and industrial organisation to preserve the long term social efficiency, ensuring the stability of this model must force regulators and competition authorities to consolidate their market monitoring.

## **References**

Averch & Johnson 1962 Behaviour of the Firm under Regulatory Constraint *American Economic Review* 52, pp1052-69.

Besser J. G., Farr J. and Tierrey S., 2002. "The political economy of long term generation adequacy: why an ICAP mechanism is needed as part of standard market design ?" *The Electricity Journal*, August/Sept., vol 15, n°17.

Bohn R.E., Golub B.W., Tabors R.D., Schweppe F.C., 1982 , “Deregulating the generation of electricity through the creation of spot markets for bulk power”, *The Energy Journal*, vol , n° , p.71- .

Bolinger, M., Wiser, R., Golove W., “Accounting for fuel price risk when comparing renewable to gas-fired generation: the role of forward natural gas prices,” *Energy Policy*, 2004.

Borenstein J. et Bushnell J., 2000, “Electricity restructuring: deregulation or reregulation ?”, in *Regulation*, summer, vol 23, n°2.

Bouttes J.P. et Trochet J.M., 2002, *Marché de gros et bourses électriques en Europe et aux Etats-Unis*, Présentation aux Conférences Jules Dupuits, Paris, Décembre 2002

Bouttes J.P., 2005, Sécurité d’approvisionnements et investissements dans l’électricité, *Revue de l’Energie*, Juillet-Août 2005, p.229-238

Bushnell J., Mansour E. , Saravia C. , 2005, *Vertical arrangements , Market Structure, and competition: an analysis of restructured U.S. electricity markets*, Working Paper CSEM, University of California.

Chao H.P. et Huntington H. ed, 1998, *Designing market electricity markets*, Boston (Mas.): Kluwer.

Chao H.-P., Oren S., and Wilson R., 2008, “Reevaluation of Vertical Integration and Unbundling in Restructured Electricity Markets” in F. P. Sioshansi ed., *Competitive Electricity Markets: Design, Implementation, and Performance*, London, Elsevier, Chapter 1, p.27-65.

Chao H.P., Oren S., Wilson R. (2005), *Restructured electricity markets: reevaluation of vertical integration and unbudling*, Harvard Electricity Policy Group, Harvard.

Crampes C., Tirole J.(2004). *Marché électrique et investissement en capacité de production*, Working Paper EDF-IDEI, HR-19/04/029/B, 102 p.

De Vries L. & Haakvoort, 2003, CESP Working Paper

De Vries L. & Neuhoff K., 2004, *Investment Incentives for investment in electricity generation*, Cambridge Working Paper in Economics, CMI Working paper 42.

De Vries L., 2007, Generation adequacy: Helping the market to do its job, *Utilities Policy*,

Defeuilley, C et Meunier, G (2006), *"La gestion du risque d'une commodité non stockable : les limites d'une couverture financière"*, *Economie et Société*, série Economie de l’énergie, n ° 10-11/2006, p.1619-1640.

Esty, B. C. (2004). *Modern Project Finance*. New York: John Wiley and Sons.

European Commission DG Comp., 2007, Preliminary report,

European Commission, DG TREN, 2005b, *Implementing the internal energy market, Fourth benchmarking report*, Brussels, European Commission.

Finon D., 2006, Incentives to invest in liberalised electricity industries in the North and South. Differences in the need for suitable institutional arrangements, *Energy Policy*, Vol.34, n°5, p.601-618

Finon D., Pignon V., 2006, « Electricité et fourniture de long terme; La recherché d’instruments règlementaires respectueux du marché électrique », *Economies et Sociétés*, (série Economie de l’Energie), Vol.10, novembre (Working Paper LARSEN 02-2006)

Ford A. 1999, “Cycles in market electricity market”, *Energy Policy*, vol 27, n° , p.637-658.

- Green R., 2001, "Markets for electricity in Europe", *Oxford Review of Economic Policy*, vol 17, n°3.
- Green R., 2004, *Retail competition and electricity contracts*, CMI working Paper 33, Cambridge.
- Green R., 2006, investment and generation capacity, in F. Lévêque ed., XXXX, Chap. 2, p. 21-53.
- Green, R. and McDaniel, T. (1998), 'Competition in Electricity Supply: Will '1998' Be Worth It?', *Fiscal Studies*, Vol. 19 (3), pp. 273-293.  
<http://ec.europa.eu/comm/competition/sectors/energy/inquiry/index.html#study>
- Hugues W.R. et Parece A., 2002, "The economics of price spikes in deregulated power markets", *The Electricity Journal*, July, p.31-44.
- Hunt S. et Shuttleworth, G., 1997, *Competition and Choice in Electricity*, New York, John Wiley Publishers
- Hunt S., 2002, *Making competition work in electricity*, New York, John Wiley Publishers
- IEA, 2003, *Power generation investment in electricity markets*, Paris, OECD
- IEA, 2005, *Lessons from liberalised electricity markets*, Paris, OECD
- IEA, 2007, *Tackling investment challenges in power generation*, Paris, OECD
- Joskow P., 2000, Why Do We Need Electricity Retailers? Or Can You Get It Cheaper Wholesale? <http://econ-www.mit.edu/files/1127>
- Joskow P. et Tirole J., 2004, *Reliability and Market Markets*, Working paper CEEPR-MIT
- Joskow P., 1997, "Restructuring, competition and regulatory reform in the U.S. Electricity Sector", *Journal of Economic Perspectives*, Vol 11, n°3 (summer), p.119-138.
- Joskow P., 2006, *Market electricity markets and investment in new generating capacity*. Working Paper CEEPR-MIT 06-009, April. Published in Helm D. dir. (2007) *The New Energy Paradigm*, Oxford University Press, 2007
- Lacy B. (2006), « Nuclear investment : performance and opportunity », *World Nuclear Association Annual Symposium 2006*.
- Littlechild, S., 2006, "Competition and contracts in the Nordic residential electricity markets", *Utilities Policy* 14
- Littlechild, S.C. (2002), Competition in Retail Electricity Supply, *Journal des Economistes et des Etudes Humaines*, Vol.12 (2/3), June/September, pp.379-402. Available as CMI Electricity Project Working Paper, No.09/2002.
- Mansour E. (2003) *Vertical integration in restructuring electricity markets: measuring market efficiency and firm conduct*, Yale School of management, Working paper series ES, n° 32
- Michaels R.J.(2006) Vertical integration and the restructuring of the US electricity industry, *Policy Analysis*, n°572, p.1-31.
- Newbery D., 1998, "Competition, contracts and entry in the electricity spot market, *Rand Journal of Economics*, vol 29, n°4, Winter.
- Newbery D.M.2000 *Privatisation Restructuring, and Regulation of Network Utilities* The MIT Press, Cambridge, Massachusetts, London England.
- Newbery D., 2001, *Issues and options for restructuring the Electric supply industry*, Cambridge University, Working Paper, Department of Applied Economics

- Newbery D., 2002, *Regulatory challenges to European electricity liberalisation*. CMI Working Paper 12
- Oren S., 2003, *Ensuring generation adequacy in market electricity markets*, Working Paper UCEI, EPE 007,
- Perry M., 1989, Vertical Integration, in *Handbook of Industrial Organization*, p.185-255
- Posner, R. 1974, *Antitrust law: an economic perspective*. Chicago:University of Chicago Press
- Ramos-Real F.J., Cost functions and the electricity industry. A contribution to the debate on deregulation. *Energy Policy*, Vol.33.
- Read J., 2004, *Re-verticalizing electricity*”, Harvard Electricity Policy Group, Working Paper
- Roques F., Newbery D., Nuttall, W., 2006, Valuing portfolio diversification for a utility: Application to a Nuclear Power Investment when Fuel, Electricity, and Carbon Prices are Uncertain, *The Energy Journal*
- Salinger M., Vertical mergers and market foreclosure, *Quarterly Journal of Economics*, Vol.103
- Scherer F.M., Ross D., 1990, *Industrial market structure and economic performance*, Houghton Mifflin,
- Shuttleworth G. 2002, “Hot topics in European Electricity: what is relevant and what isn't?”, *The Electricity Journal*, October
- Stoft S., 2002, *Power System Economics, Designing Market for Electricity*. New York, Wiley IEEE
- Vasquez C., Perez-Ariaga I. et al., 2001, A market approach to long-term security of supply, *IEEE transactions on Power Systems*, Vol. 25, n°2, p. 349-357.
- Waddam Price et Wilson, 2007
- Williamson O. E. 1975, *Markets and Hierarchies : Analysis and Antitrust Implications. A Study in the Economics of Internal Organization*, Free Press.
- Williamson O. E. 1985, *The Economic Institutions of Capitalism. Firms, Markets, Relational Contracting*, Free Press.
- Williamson O. E. 1996, *The Mechanisms of Governance*, New York : Oxford University Press.
- Wilson R., 1998, *Efficiency consideration in designing electricity Markets*. Report to the Competition bureau of Industry, Canada.
- Wilson R., 2002, “Architecture of Power Markets”. *Econometrica*, Vol 70, n°4, July, p.1299-1340.