« Investment in electricity generation and its determinants »

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Abstract

We begin this paper by abstracting ourselves from some electricity market's characteristics and assuming that there is a competitive energy-only market. The balance of supply and demand in the spot market determines a clearing price, which in turn determines short-run profits for energy. In the long-run equilibrium, investment enters until the point where the expected short-run profit is equal to the fixed costs of marginal capacity. In this simplified case, determinants of investment will be the load-duration curve, the industry's supply curve, VOLL and available technologies. However, current electricity markets have an important market failure – the absence of demand-side response to the energy price. This absence prevents load's willingness to curtail demand to set the price during times of supply scarcity. As a result, the market cannot ration demand by prices and the supply and demand curve will usually fail to intersect. This market failure requires that prices during shortage hours be set administratively. But sometimes the administratively set price caps will not be high enough to cover generators' fixed costs due to some political considerations. This investment incentive problem will in one hand reduce investment and in the other hand undermine electricity system's reliability. Several regulatory policies have been proposed or used to resolve this problem. Four mechanisms from two approaches will be discussed in this paper. All of them could induce the optimal level of installed capacity and reliability by changing the political parameters. But different policies would have different side effects. Anyway, in the case with regulatory policies, the determinants of investment are the load-duration curve, the industry's supply curve, regulatory policies and available technologies.

The objective of this paper is firstly, to build a framework for understanding how the generators make investment decisions in a competitive electricity market and meanwhile to find the determinants of investment decisions. Secondly, to explain the mechanism of several regulatory policies in real electricity market to insure right level of ICap and reliability, and to find the corresponding investment decision determinants.

I. Introduction

After the liberalisation of the electricity sector, especially after the crisis of California in 2001, investment reliability became a big concern of policymakers. Policymakers in many counties are expressing concerns that competitive wholesale electricity markets are not providing appropriate incentives to stimulate "adequate" investment in new generating capacity at the right time, for the right amounts and using the right technologies. That's why, even though in a liberalised market, investment is made by investors and depends on the profit; there continue to be a large number of non-market mechanisms that have been imposed on the emerging competitive generation market to insure investment on generation capacity. These mechanisms include: capacity payment, capacity market and so on.

In some cases these non-market mechanisms could be justified by imperfections in the real electricity market. In particular, market failure caused by non price elasticity of electricity demand; uncertainty of investment caused by the fluctuation of the load-duration curve and lumpiness of electricity generation; generation sector's market power problems and imperfections in mechanisms adopted to mitigate these market power problems.

In this paper, we will explain firstly, because of the large existence of market imperfection, some non-market mechanisms to insure investment on generation in a liberalised market are necessary. Secondly, by constructing a competitive-electricity-market model and extending it in a real market, to explain how the generators make investment decisions in both markets and to find the corresponding determinants of investment decisions. We find at the end that regulatory policies ensure generation investment by changing the regulatory parameters, which are different according to various regulatory policies.

Decisions about electricity generation investment could be divided by two parts: the choice of technology and the choice of capacity. Both of them will be discussed in each investment environment.

We begin section II by abstracting ourselves from some electricity market's imperfections and assuming that there is a competitive energy-only market. Some main assumptions should be mentioned. We assume:

- There is no market failure; demand is sufficiently elastic to clear the market at all times. We know perfectly the value of lost load for any consumer.
- We know the load-duration curve. The investors are risk neutral.
- There is no market power.
- We don't care the (there is no) criteria of reliability.

In such a competitive energy-only market, the equilibrium of supply and demand in the spot market determines a clearing price, which in turn determines short-run profits for energy. In the long-run equilibrium, investment enters until the point where the expected short-run profit is equal to the fixed costs of marginal capacity. In this simplified case, determinants of investment will be the load-duration curve, the industry's supply curve, VOLL and available technologies.

Current electricity markets have several important imperfections: market failure – the absence of demand-side response to the energy price – is the most important one. This absence prevents load's willingness to curtail demand to set the price during times of supply scarcity. As a result, the market cannot ration demand by prices and the supply and demand curve will fail to intersect. This market failure requires that prices during shortage hours be set administratively. But sometimes the administratively set prices will not be high enough to cover generators' fixed costs due to some political considerations. Once the short-run profit is not enough to cover generators' fixed costs, they will not have any incentive to invest. This investment incentive problem will in one hand reduce investment and in the other hand undermine electricity system's reliability. Other market imperfections such as uncertainty and investor's risk aversion, existence of market power will also be discussed in section III.

In section IV, several regulatory policies have been proposed or used to resolve this problem. Four mechanisms from two approaches will be discussed in this paper. All of them could induce the optimal level of installed capacity and reliability. But this does not mean they are all equally desirable. Different policies would have different side effects according to the shape of their profit functions. The shape of profit functions are determined by the political parameters. The side effect includes risks and market power. That is why we say reliability policy should consider risk and market power.

II. Generation investment and its determinants in an ideal competitive electricity market

This section develops a simple market-based model to explain the investment decision process using the assumptions that we made in the introduction. This model has already been discussed by Green (2004). This model finds the optimal level of generation capacity and its types, and explains us how does the market provide it. Note that the discussion will firstly be in terms of the level of capacity, rather than of investment. In an ideal world net investment would equal the difference between the desired level of capacity and the current level.

2.1 – A model of optimal level of generation capacity with a long-run equilibrium in the market

It makes little sense to think of investment without thinking about the overall level of capacity in an industry. We therefore start with a model that develops the optimal level of generation capacity. To simplicity's sake, we will assume that there are just two types of generation capacity available to the industry, peaking plants and base load plants. Just as described in the previous section, peaking plants have relatively low fixed costs per kW of capacity, but relatively high marginal costs per MWh generated. Base load plants, in contrast, have relatively high fixed costs per kW, but lower marginal costs per MWh generated.

Suppose that the costs of the two available technologies, base load plants and peaking plants are showed in Table N°1. Using these, we can draw the total costs curves of different plant types which are presented in Figure N°1.

Table N°1 – costs of available technologies ($)

Technology	Fixed cost per MWh	Variable cost per MWh
Peaking plant	6	30
Base load plant	12	18

Q1. - How can we tell how many hours a year each type of plant operates is optimal?

Figure N°1 – two technologies total costs curves.

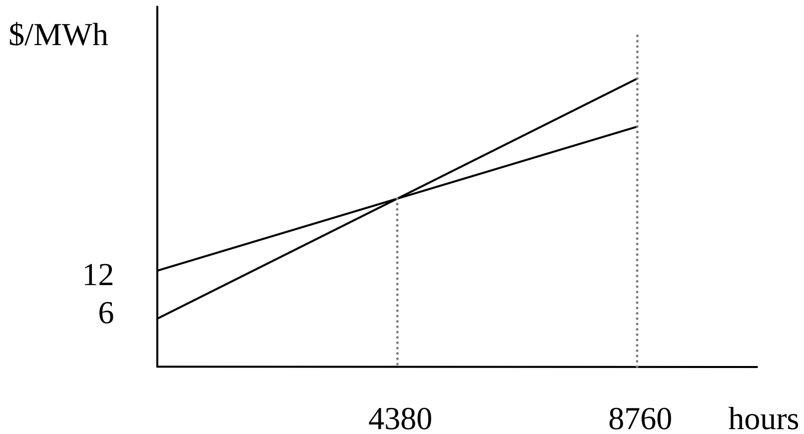
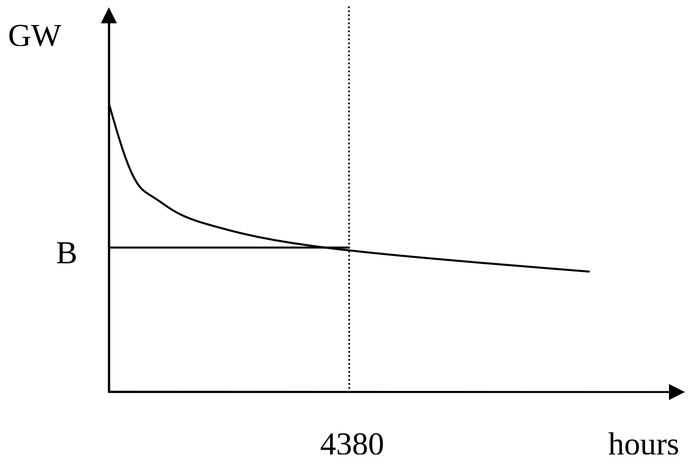


Figure N°1 shows how the total cost of our two types of capacity depend upon the number of hours a year for which the station is operated. The vertical intercept shows the station's fixed costs, while the slope of the line gives the cost per MWh. Given there are 8760 hours per year, if the station is required to run for 4380 hours or less per year, then it is cheaper to use a peaking station, while if it is required to run for more than 4380 hours, then a base load station has lower total costs.

Q2. - How can we tell how many capacity a particular station will be needed to provide?

Figure 2 shows us a load-duration curve. In this curve, the hours of the year are ranked in order of the demand for electricity. So the hours with the highest demand is placed at the left-hand end of the panel, and the hour with the lowest demand at the right-hand end. The vertical axis then shows the demand in that particular hour. The demand during the 4380 highest hour is thus no less than B GW. This therefore implies that if we want base load plant to meet all the demands for electricity that last for 4380 hours or more of the year, then we should ensure that B GW are available.

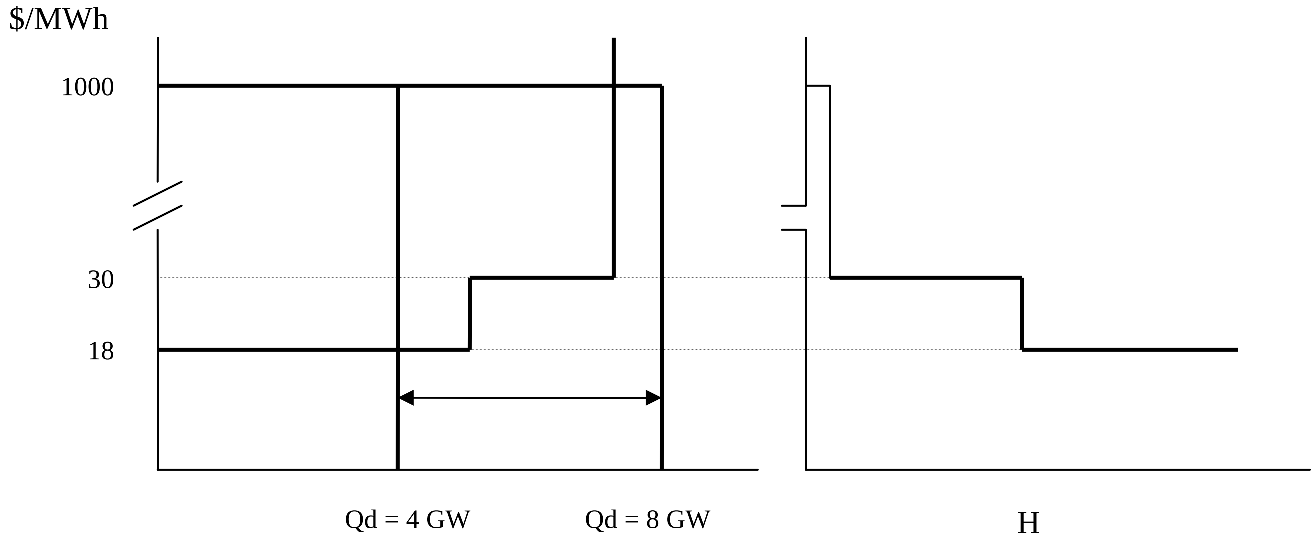
Figure N°2 – load-duration curve shows how many capacity a particular station will be needed.



Q3. - What is the marginal cost of the industry and how the price is determined?

The marginal cost of this industry is given by marginal cost of the two available plants. If the marginal cost of base load plant is equal to 18, then this will be the marginal cost of the industry whenever demand is equal to or less than the capacity of base load plant – assumed to be B GW at the optimal solution. At somewhat higher levels of demand, then the marginal cost will equal 30, the marginal cost of peaking plant.

Figure N°3 – supply and demand for the two-technology model
Figure N°4 – price-duration curve for two-technology example



Based on the marginal cost, we draw the supply curve of this industry and also electricity demand curve in Figure N°3. We assume that the demand shifts in a linear manner at any level from 4 GW to 8 GW, assuming it is not curtailed by a high price. As we discussed in the previous section, we deem that there is little prix-demand elasticity and we draw the demand curves as a vertical line.

As the demand curve moves from 4 GW to 8 GW, the prices change. In Figure 4, the price-duration curve shows us how the prices change with the movement of demand curve. In fact, the price-duration curve is determined by the combined effect of supply and demand curves. Suppose that at the beginning, the demand is 4 GW. The demand curve intersects with the base load plant's supply curve, which then determines the market price in that moment to be equal to the base load plant's marginal cost, 18. As the demand curve moves towards right side, it intersects with the peaking plant's supply curve. Now, the market price is determined by the marginal cost of peaking plant, which is 30. In this case, both the peaking plant and the base load plant receive 30 for their energy, which is higher than the base load plant's marginal cost and can be used to recover its fixed costs. This will be discussed in details later.

The top part of the price-duration curve occurs if available capacity is less than 8 GW. What would happen if capacity was not sufficient to meet the total demand? This depends in part on the details of the market arrangements for the industry (Green, 2004). In the present section, we assume that demand is sufficiently elastic to clear the market at all times as is required for a competitive market. Therefore, once generating capacity is exhausted, demand could be limited by high prices, which is no longer set by generator's marginal cost but by the opportunity cost of a consumer that has decided to reduced its demand. These prices prove to be the case in equilibrium.

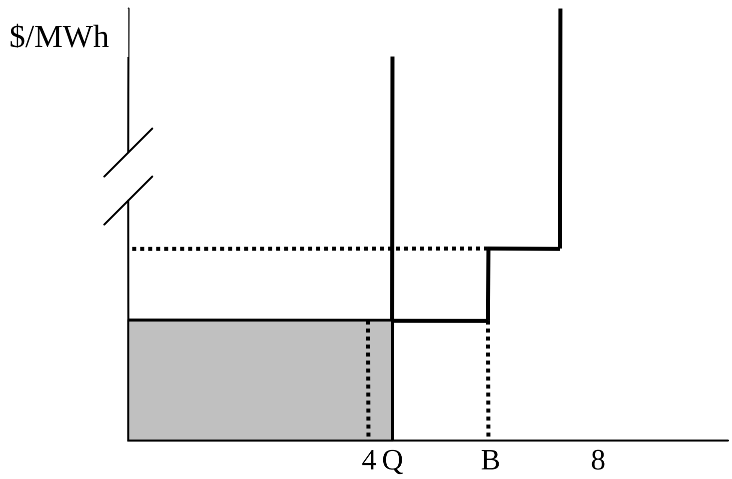
The flat spot at the top the of demand curve in Figure N°3 could be interpreted as a price-capped market. 1000 could be deemed as an equilibrium price. It is not realistic in a competitive market but in this model, it is used only as a simplification that has no impact on the qualitative results. The horizontal portion should be interpreted as demand elasticity that is reflective of the value of power to consumers. They simply do not want any power if it costs more than $1000/MWh.

Q4. - How about the total revenue received by each station and how could each them recover their fixed cost?

For this, we need to return to Figure N°3. We distinguish three situations in which demand can fall into three different regions classified by which plants are marginal. Then, we find the total revenue for each station in any situation respectively.

(1) Demand $\in$ [4 GW, B GW]

Figure N°5 – total revenue of each plant when demand $=Q_1 \in$ [4 GW, B GW]

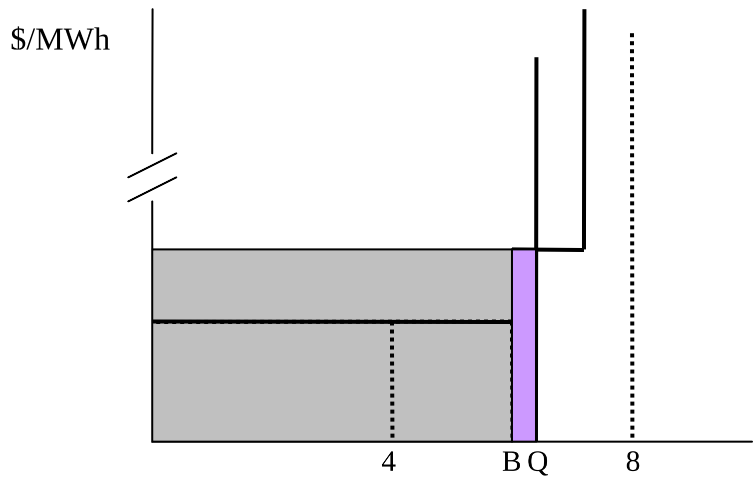


When the demand is between 4 and B GW, the price is equal to the marginal cost of base load plant. The base load plant products as much as the demand, and is paid by his marginal cost to the quantity he products. There is still some spare base load capacity. The peaking load does not product. We define the duration during which the baseload plant is marginal is $D_{baseload}$. Then the total revenue of baseload is Q_1 x 18 x $D_{baseload}$, as showed by the grey area in Figure N°5. This is exact his variable cost. With this base load plant could cover his variable costs but makes no contribution to his fixed costs.

(2) demand $\in$ (B GW, available capacity)

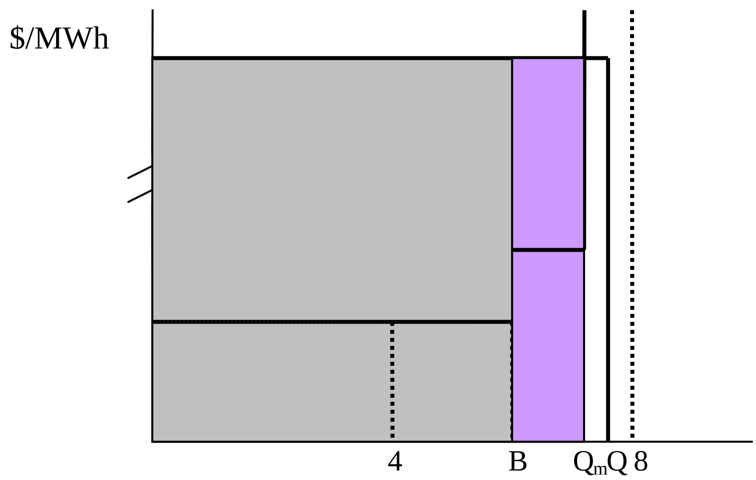
When the demand exceeds B GW and less than the total available capacity, the market price is determined by the peaking plant's marginal cost, which is equal to 30. We define the duration of time when peaker products as D_{peaker}; and the duration during which the price is at the cap is D_{ps}. Then the duration during which peaker plant is marginal is (D_{peaker}-D_{ps}). In this case, the base load plant products as much as possible, B GW. The peaking plant products (Q_2–B) GW. So the total revenue of each plant is respectively, B x 30 x (D_{peaker}-D_{ps}) and (Q_2-B) x 30x (D_{peaker}-D_{ps}), as showed in Figure N°6 by grey area and violet area. In this case, base load plant would make a contribution towards their fixed costs, since the price exceeds his variable costs. The short-run profits, or scarcity rent for base load plant is B x (30-18) x (D_{peaker}-D_{ps}). But peaking plant could just cover his variable costs but makes no contribution to his fixed costs.

Figure N°6 – total revenue of each plant when demand =$Q_2 \in$ (B GW, available capacity)



(3) demand > available capacity

Figure N° 7 – total revenue of each plant when demand =Q_3 > available capacity



Consider the last situation in which the highest level of demand exceeds the available capacity Qm. The capacity of both base load plant and peaking plant are fully used. The market price increases until a very high price, for example $1000, with which we assume that the market is in equilibrium. Similarly, the duration of price spike is defined as D_{ps}. Then the total revenue received by each plant is respectively, B x 1000 x D_{ps} and (Qm-B) x 1000 x D_{ps}, as showed in Figure N°7 by grey area and violet area. The short-run profits for base load plant is B x (1000-18) x D_{ps} and for peaking plant is (Qm-B) x (1000-30) x D_{ps}. In this case, both the base load plant and the peaking plant could make a contribution to their fixed costs.

Q5. – Why the competitive price exactly covers fixed costs?

In a competitive market, if marginal-cost prices did not cover fixed costs, investors would choose to build no more generators. As demand grew and generators wore out, the market would tighten causing price to rise. On the other hand, if marginal-cost prices more than covered fixed costs (which include a normal risk-adjusted rate-of-return on capital), investors would build generation, supply would outstrip demand, and the price would fall. When the market price more than covers fixed costs, price declines; when price fails to cover fixed costs, it increases. Consequently, price converges towards the point at which fixed costs are exactly covered. Once there, it has no inherent tendency to change.

Frequent external disturbances such as changes in demand or the opening of a new plant; push the market out of equilibrium. But investors make their best estimates of what will be needed, and they err on the high side as often as they err on the low side. Although marginal-cost prices do not exactly cover fixed costs at all times, they cover them on average.

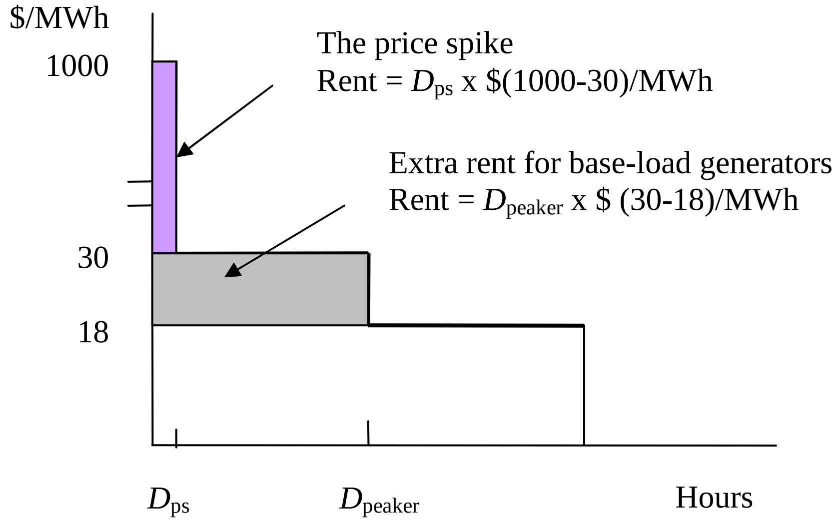
Stoft (2002) draw a conclusion for this discussion: in a long-run competitive equilibrium, generators recover their fixed cost and no more, even though price equals marginal cost (P=MC) at all times and for all generators.

Q6 – What is the competitive solution for each capacity?

We continue to use all of the above assumption to develop the level of each capacity in a competitive market. Determining what generation capacities would be induced by a perfectly competitive market requires the use of the above conclusion: fixed costs are exactly covered in a long-run competitive equilibrium. This means short-run profits (scarcity rents) must exactly equal fixed costs.

From the discussion of total revenue by Q4, we have drawn the price-duration curve for this model. As Figure N°8 shows, if base-load is marginal the market price is 18, the duration of this period is $D_{baseload}$; if peaker is marginal the price is 30, the duration is (D_{peaker}-D_{ps}); and if the marginal unit of load cannot be served, the price rises to the cap at 1000, the corresponding duration is D_{ps}. The price spike is the violet area above 30, and this provides scarcity rent for both generators. It is the only scarcity rent earned by peakers, so their equilibrium condition is: the fixed cost of a peaker equals the price-spike revenue, R_{spike}.

Figure N°8 – using price duration curve to determine short-run profits



Base load plant has two sources of scarcity rent, the price spike and the grey area between 18 and 30, which has duration of D_{peaker}. This observation provides the equilibrium condition for base load plant, which is given as a result in Q7.

The peaker's equilibrium condition implies: $6 = (1000-30) \times D^*_{ps}$,

The base-load equilibrium condition implies: $12 = 6 + (30-18) \times D^*_{peaker}$.

These two equilibrium conditions can be solved for the optimal durations of each plant and D_{ps}, which completely determine the price duration curve and can be used with the load-duration cure to determine the equilibrium capacities of the two technologies. The solution is:

$D_{ps} = 8760 \times 0.62\%$

$D_{peaker} = 8760 \times 50\%$

Base load capacity = 6GW
Peaker capacity = 1975MW

Q7 – the long-run equilibrium conditions

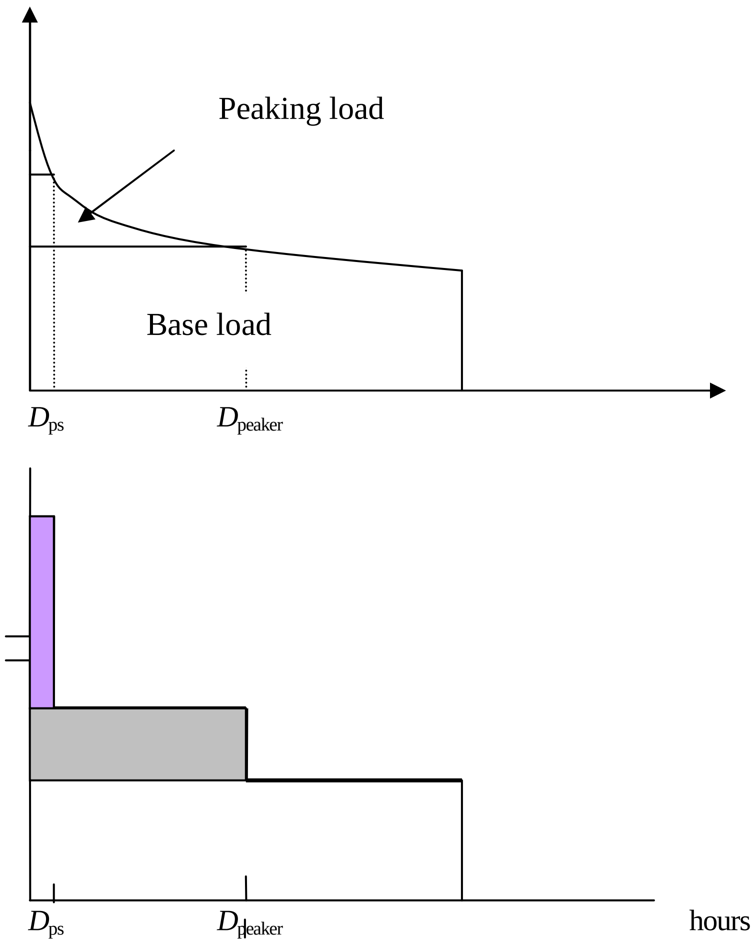
Long-run equilibrium conditions for two technologies: In the long-run, peakers and base load plants must cover their fixed costs from short-run profits (scarcity rents). This implies two equilibrium conditions:

$FC_{peak} = R_{spike}$
$FC_{base} = FC_{peak} + (VC_{peak} – VC_{base})$ x $D*_{peaker}$

Q8. - What would happen if the capacity is in wrong type or in wrong capacity?

What would happen if there is the wrong level, or mix, of capacity? The profitability of peaking plants depends on the total amount of capacity, rather than on the amount of peaking plant in the industry. To see this, I distinguish 6 situations. (1) There is optimal capacity in total, but too little base load. (2) There is optimal capacity in total, but too much base load. (3) There are too much in total, but right base load; (4) there are too much in total, but right peaker. (5) There are too little in total, but right base load; (6) there are too little in total, but right peaker.

Figure N°9 – using the amount of capacity to determine plants' short-run profits



To explain these issues, reminder Figure N°8. It shows us the short-run profits function through the price duration curve. In the case of wrong level or mix of capacity, the three price levels will not change, which remain 18, 30 and 1000. This is because that the price levels depend on the marginal cost of each plant and the VOLL. But the duration of each price level, $D_{baseload}$, $(D_{peaker}-D_{ps})$ and D_{ps}, will change. D_{ps} depends on the total capacity, D_{baseload} depends on the capacity of base load, the correlation between them is positive. D_{peaker} depends on D_{baseload}, given that $D_{\text{baseload}} + D_{\text{peaker}} = 8760$. We can explain this by a combined figure of load-duration curve and the price-duration curve.

That is, as long as there is right total capacity, D_{ps} does not change. When total capacity is more than the optimal level, D_{ps} become shorter; in contrary, when total capacity is too little, D_{ps} become longer. Similarly, whichever the total capacity level is, as long as there is the right level of base load (peaker) capacity, $D_{baseload}$ and D_{peaker} remain unchanged. However, if the base load capacity level is too much (little), D_{peaker} becomes shorter (longer).

From Figure N°8, we know that the profit functions for each plant are respectively:
Extra rent for base-load generators: Rent = D_{peaker} x \$ (30-18)/MWh + D_{ps} x \$(1000-30)/MWh
Extra rent for peaking generators: Rent = D_{ps} x \$(1000-30)/MWh

(1) There is optimal capacity in total, but too little base load.
$\boldsymbol{D_{\text{ps}}}$ remains constant, $\boldsymbol{D_{\text{peaker}}}$ increases. According to the two scarcity rents equations, the scarcity rents for base load plant will increase, while the scarcity rents for peaker remain unchanged.

(2) There is optimal capacity in total, but too much base load.
$\boldsymbol{D_{\text{ps}}}$ remains constant, $\boldsymbol{D_{\text{peaker}}}$ decreases. According to the two scarcity rents equations, the scarcity rents for base load plant will decrease, while the scarcity rents for peaker remain unchanged.

(3) There are too much in total, but right base load and **(5)** there are too little in total, but right base load are two absolute opposite situations. As there are too much (little) in total, $\boldsymbol{D_{\text{ps}}}$ decreases (increases); while there are right level of base load, $\boldsymbol{D_{\text{peaker}}}$ remains unchanged. According to the two scarcity rents equations, the scarcity rents for both plants decrease in (3) and increase in (5). Interestingly, these plants will be making the **same** amount of profit (or loss) per MW.

We can also discuss **(4)** there are too much in total, but right peaker and **(6)** there are too little in total, but right peaker together. As there are too much (little) in total, $\boldsymbol{D_{\text{ps}}}$ decreases (increases); while as there are too much (little) base load, $\boldsymbol{D_{\text{peaker}}}$ decreases (increases). So in (4), both plants will be making losses, but the base load station will make **less** loss per MW than peaking station. In situation (6), both plants will be making profits, but the base load station will make **more** profit per MW than peaking station.

Knowing this, we can sum up the influences of wrong level or mix capacity by Table N°2:

The first two situations show us that the wrong mix of base load and peaking plants does not affect the profitability of peaking plants, as long as the industry has the correct overall level of capacity. If the industry has the wrong level of capacity, however, then the peaking plant's profits will be affected.

Table N°2 – A summary of the influences of wrong level or mix capacity

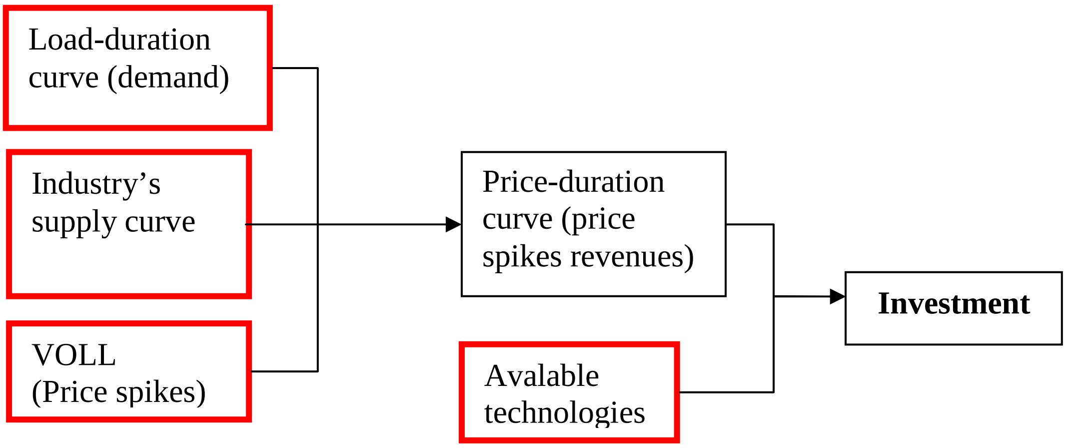
Cases	**Changes of two duration**		**Changes of short-run profits**	
	$\boldsymbol{D_{\text{ps}}}$	$\boldsymbol{D_{\text{peaker}}}$	**For base-load**	**For peaker**
(1) right total, too little base load, too much peaker	———	↑	↑	———
(2) right total, too much base load, too little peaker	———	↓	↓	———
(3) too much total, right base load, too much peaker	↓	———	↓	↓
(4) too much total, too much base load, right peaker	↓	↓	↓	↓
(5) too little total, right base load, too little peaker	↑	———	↑	↑
(6) too little total, too little base load, right peaker	↑	↑	↑	↑

We can summarise the links between the amount of capacity and the profitability of that type of capacity. If there is too much capacity in total, the peaking plants will be making losses, while if there is too little capacity overall, then peaking capacity will be making super-normal profits. In the case of there is too little capacity in total, if we have the right amount of base load capacity, then these stations will be making the **same** amount of profit per MW as peaking stations; if there is too much base load capacity, then the base load station will make **less** profit per MW than peaking stations; if there is too little base load capacity, then these stations will make **more** profit per MW than peaking stations.

2.2 – Determination of investment in a competitive market

From the above discussion, we can draw a conclusion about a series of factors which determine investment step by step. Both the demand and supply condition and the VOLL level determine the generators' actual short-run revenues. Comparing these revenues level with the fixed cost of available technologies, generators make their investment decisions.

Figure N°10 – the determinants of investment



From this figure, we can conclude that in a competitive energy-only electricity market, the initiative (which comes into action by itself, does not depend on the other factors) of influence making a investment decision come from 4 factors, which are famed by the red frames in Figure N° 10:

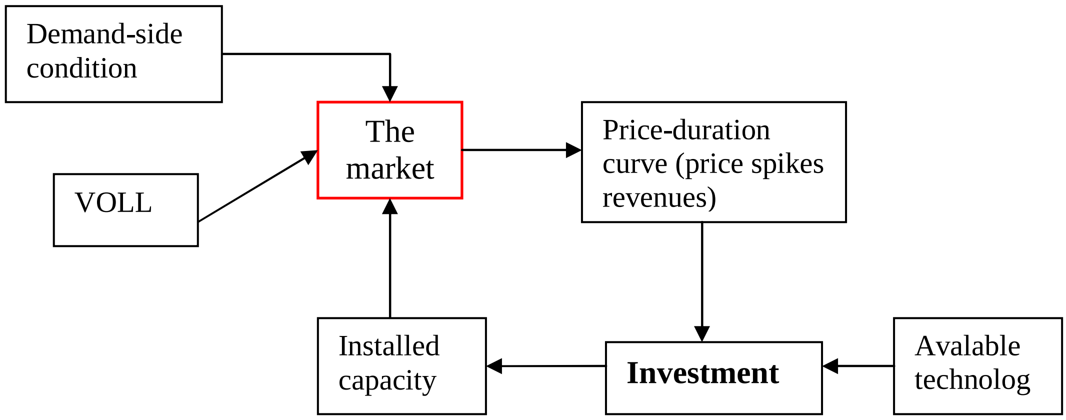
- the demand and its characteristics (load-duration curve)
- Actual technologies and their capacity
- VOLL (what the consumers are will to pay for not be cut off electricity)
- available technologies and their characteristics (marginal costs & fixed costs)

We can conclude that four reasons would induce investment in new capacity. The first is that because of some abnormal reasons, the general demand level increases. The second is due to some changes of actual capacity: either the actual level of capacity is less than the optimal level, or some capacity has reached the end of its physical working life and must be replaced. The third is consumers are willing to pay more than before for not to be cut off electricity, that is VOLL increases. The last reason is because changing relative costs make it economic to replace older capacity with a more efficient station. This could be the result of technological progress.

In this process, it seems that the optimal investment is not useful for the investment decision. In fact, when one invests, although we don't calculate the optimal level of capacity while investing, the difference between this optimal level and the current level of capacity determines generators' price spikes revenues, which then determine investment.

From Figure N°10, we know that, both the demand and supply conditions and VOLL (what the consumers what to pay for not to be cut) act on the market to determine the market's price. These price spikes determine the short-run profits of generators, and the expectations of these profits induce generation investment. Similarly, investment changes the supply-side condition by increasing installed capacity (ICap), which reduces both price and profits. This forms a loop. The choice of technology in this case is also determined by available technologies which is a result of technological progress. This loop is showed in Figure N°11.

Figure N°11 – the structural core of a power market determines investment



III. Imperfections in a real electricity market and implications on investment

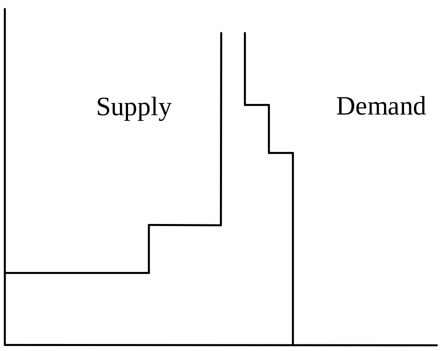
In this section, we relax the assumptions that we made for the second section and discuss some imperfections existing in a real electricity market. All these imperfections could justify the frequent and large use of reliability policy in the world, which will be discussed in the next section.

3.1 – Market failure and no long-run equilibrium

When supply cannot equal demand, the market cannot determine a price. This is a market failure. This failure occurs only for certain combinations of supply, demand curves and load-duration curves, but when it does occur, the market fails; there is no long-run equilibrium. Most current power markets may well satisfy the conditions for this failure.

In the previous section, we analyzed a power market's behaviour with an assumption that demand is sufficiently elastic to clear the market (intersect with supply) at all times. However, in a real electricity market, there is limited elasticity and so the intersection of supply and demand is not guaranteed. Imagine an example of insufficient generating capacity. As price increases toward an equilibrium level, short-run profit will increase. Demand and supply adjust with the price changing, but in a limited scale. Before the supply and demand curve intersect, the adjustment of them stops. These two curves fail to intersect, and this is market failure. Price is pushed toward infinity, but even an infinite price cannot clear the market. Current power markets probably satisfy the conditions required for this failure, which is why they have price caps. This case is showed in Figure N°12.

Figure N°12 – market failure with inelastic demand curve



A less extreme form of the failure may occur. The market clearing price may rise above VOLL before the supply and demand curve intersect. In this case there may be a long-run equilibrium but it would be less efficient than one that caps price at VOLL and sheds load.

With the first failure, the system operator must set price because the market cannot; with the second it should set price because the market sets it at more than power is worth. Price caps have an important influence on the generators' short-run revenues and they will discourage investment.

We can argue that if we set the price cap level at VOLL, then there would not be too much price distortion, as this is proved to be optimal in the simple model of reliability of Stoft (2002). Difficulties to implement VOLL as price cap come from the characteristics of VOLL. It requires a regulatory determination of V_{LL} because the market cannot determine it as described above. Estimation of VOLL is difficult. As we discussed earlier, because most customers do not respond directly to real-time prices, there is almost no market information on the value of lost load, and available estimates are highly inaccurate. Moreover, VOLL is the dramatic variation in values between customers and from one time to another. The effect of the duration of a disconnection on cost is also typically quite nonlinear. Often the first few seconds are the most costly but in other cases costs grow at an increasing rate with the duration of the outage. Because most of these costs involve no market transactions, they are particularly difficult to evaluate. Consequently, VOLL pricing sets a regulated, not a market, price.

Another reason that the policymakers are reluctant to set price cap at VOLL is that the VOLL is very high and the price is volatile. We are not certain about the price spikes and their duration. According to estimation, the VOLL could arrive at $10,000/MWh. It is so high that it brings problems of risk and exercise of market power. The riskiness is not due to the hourly price fluctuations but rather to the annual fluctuations in price-spike revenue. This brings risk to investors because their fixed cost should be covered by the price-spike revenue. Risk to generators makes investing more expensive and discourages investments.

3.2 Uncertainty & Investors' risk aversion

Uncertainty of investment is often caused by the fluctuation of the load-duration curve and lumpiness of electricity generation. Electricity demand fluctuates in a cyclic way during the day, week and year, which then create uncertainty. Two types of demand uncertainty are relevant here. First, the short-term level of demand, relative to its trend, depends on the weather, and the state of any interconnected power system. Second, the trend itself is uncertain, depending on consumers' reactions to prices, the level of economic activity, and technological change. Uncertainty over the trend level of demand creates more problems. If capacity is built to meet a need that does not arise, then prices may be depressed for several years, until demand rises or other plant is retired. The implication of this is that there is some risks faced by generators when taking an investment decision and in most of cases, risks will discourage or delay investment. Generation investment is also characterised by significant lumpiness. That is, investors cannot choose any investment capacity they want. This lumpiness will also result in investment cycle, which is a strong risk faced by investors.

Karsten Neuhoff and Laurens De Vries (2003) show that in the absence of a sufficient volume of long-term contracts or a similar mechanism, spot markets will provide insufficient incentives for investment in generation capacity when investors or final consumers are risk adverse.

3.3 Market Power

We have to talk about the inevitable market power problem. In fact, many price spikes are believed to be the result of market power exercised by generation companies (Wen et al., 2004). As we know, the regulator may impose a price cap on wholesale power prices in order to prevent generators from exercising market power in the wholesale market during peak demand periods.

Thus, if in an energy-only market, the only revenue source for recovery of fixed costs is the price-spike revenue, and we want to rely on these price spikes to reflect short-term supply and demand status and to create market signals for capacity investment, then the use of price cap will impede the price to go up and then reduce the investors' investment incentive.

3.4 Criteria of reliability

In the previous section, we didn't take into account of reliability and we assumed impliedly that, while there may be insufficient resources and rationing, this rationing makes use of all available generation resources. This assumption is a decent approximation for, say, controlled rolling blackouts where the system operator sheds load sequentially to ensure that demand does not exceed available generating capacity. Conceptually, there is a key difference between rolling blackouts in which the system operator sequentially sheds relatively small fractions of total demand to match available supplies in a controlled fashion and a total system collapse in which both demand and generation shuts down over a large area in an uncontrolled fashion. Under a rolling blackout, available generation is extremely valuable (actually, its value is VOLL). By contrast, available plants are almost valueless when the system collapses. To put it differently, there is then an externality imposed by generating plants that initiate the collapse sequence on the other plants that trip out of service as the blackout cascades through the system, that does not exist in an orderly, rolling blackout (Joskow & Tirole, 2004).

It is useful here to relate this economic argument to standard engineering considerations concerning operating reserves. In addition to dispatching generations to supply energy to match demand, system operators schedule additional generating capacity to provide operating reserves. Operating reserves are used to respond to sudden outages of generating plants or transmission lines that are providing supplies of energy to meet demand in real time sufficiently quickly to maintain the frequency, voltage and stability parameters of the network within acceptable ranges.

The possibility of system collapses makes operating reserves a public good. Network users take its reliability as exogenous to their own policy and thus are unwilling to voluntarily contribute to reserves. This has potentially significant implications for investment incentives (Joskow & Tirole, 2004).

3.5 Conclusion

From the discussion of this short section, we can see that several market imperfections exist in a real market. Both these imperfections and the regulation to deal with them could cause investment problems. Consequently, if policymakers had no policy of paying sufficiently high prices for enough hours per year, generators would not have enough short-run profits to cover their fixed costs and would not invest. Thus the market, on its own, would underinvest and reliability would suffer.

IV. Reliability policies induce investment and their mechanisms

In order to induce investment, different regulatory policies have been proposed or being used. In this section, we distinguish two types of approaches: price spikes approach and capacity approach. In price-spike approach, regulatory policy determines the height and duration of price spikes. In fact, price-spike duration is set by short-run engineering considerations, while the height of spikes is typically set by a political process that is concerned mostly with market power. There is only one revenue for generators, which is the revenue comes from the aggregate price spikes. Normally, the price spikes revenues are high enough to cover generators' fixed costs and give them incentive to invest. Conversely, in capacity approach, price caps often limit energy price to increase very high. Sometimes, the price caps are applied to the level of generator's highest bid, which is also peaker's marginal cost. As a result, low price spikes revenue could not cover generators' fixed costs which would discourage investment. In order to obtain the same optimal level of installed capacity, regulatory policies pay for both energy and available capacity to encourage investment.

In this section, we come back to the loop (Figure N°11) that we obtained in section II to form another one integrating the reliability policy. However, the difference between them is that in the new loop, it's not any longer the optimal level of installed capacity determines investment, but the regulatory policies do the job.

Thus, the main objective in this section is to see how different regulatory policies impact on generators' short-run profits (two revenues) by changing political parameters. To compare the different regulatory policies, we will build their profit function. The profit function summarizes the information needed to find the equilibrium ICap level. It takes policy into account and plots expected short-run profits as a function of ICap. It is most convenient to calculate them for the peaker technology (Green, 2004), in which case short-run profit is as the same as price-spike revenue. The equilibrium ICap level occurs at the point on the profit curve where short-run profits just cover the fixed costs of peakers. In price spike approach, there is only energy short-run profit function, but in the capacity approach, there are both energy and capacity short-run profit functions. In both cases, the short-run profit function shows what level of ICap and reliability a given set of policies will produce.

In the end, we will find that many different policies would produce the same optimal level of ICap and reliability, but they have different side effects according to the steepness of their profit functions. A steeper profit function increases risk and facilitates the exercise of market power. By choosing policies that produce low, long-duration price spikes, a flatter profit function can be achieved. That is why we say that reliability policy should consider risk and market power.

4.1 – Price spike pricing approaches and their determinants of investment

In this sub-section, two price spike pricing approaches will be introduced. One is VOLL pricing and the other is operating reserve pricing. Their side affect of reliability policy will be compared in the end.

4.1.1 - VOLL pricing

The minimal price intervention that would produce a reasonable level of reliability is known as VOLL pricing. This has been studied and implemented by Australia's National Electricity Market (NECA, 1999b). This approach recognizes that the system operator must purchase power on the behalf of load when demand exceeds supply and instructs it to pay V_{LL}, the value of additional power to load, whenever some load has been shed (during a partial blackout).

Implementing VOLL pricing requires a regulatory determination of V_{LL} because the market cannot determine it. This value will determine the height of the aggregate price spike, and the duration of the price spike will be determined by the regulator's decision to set this price when, and only when, load has been shed. The Australians estimated V_{LL} to be about $16,000 but set their price limit at only about $10,000. Both the height and average annual duration of the price spikes under V_{LL} pricing are determined by regulatory policy and not by any market mechanism.

4.1.2 – Operating reserves pricing

In the operating reserves pricing approach, both energy and the operating reserves are paid according to the current system operating reserves availability. Engineering suggests appropriate levels for operating reserves, which cover "regulation", spinning reserves and nonspinning reserves which together amount to roughly 10% of load. It makes the operating reserve requirement, OR^R. Instead of waiting until load must be shed to raise price, a shortage of operating reserves is deemed to be sufficient reason to pay whatever is necessary. The market price is set to price cap when operating reserves, OR, fall below the operating reserve requirement, OR^R. This results in high prices whenever demand exceeds about 90% to total available supply. Is this way, this reliability policy determines a much longer duration for price spikes.

Compared with VOLL pricing approach, the price cap is set to a relatively modest level rather than to the extremely high value of VOLL. We will find that this approach is as effective as VOLL pricing to induce optimal investment in generation capacity, and they cause less problems of risks and market power.

4.1.3 – Profit functions and determinants of investment

Profit-driven investment is key to the market equilibrium. In this section, we develop a profit function, which shows us a profit per MW that a generator receives.

A profit function gives expected short-run profits as a function of installed capacity; K. The short-run profit is determined by the price spikes (price-cap) level and the duration of the price spike. This duration is determined from the load-duration curve and the required level of operating reserves, which triggers the price cap. The purpose of constructing the profit function is to understand the feedback loop in Figure N°18 which controls investment and installed capacity. The price-spike revenue is the appropriate summary statistic for market prices. Price-spike revenue encourages investment when and only when it exceeds the fixed costs of a peaker. The other key variable in this feedback loop is installed capacity, K. The profit function connects (short-run) profit to installed capacity.

Under VOLL pricing, the system operator set the spot-market price to V_{LL} when L+g (load and generation outages) exceeds installed capacity K. The total energy produced is paid by V_{LL}. Under operating reserves pricing, the price is set to price cap (which is inferior to V_{LL}) when operating reserves, OR, fall below the operating reserve requirement, OR^R. Different from the VOLL pricing approach, in the operating reserves pricing approach, both the energy produced and the operating reserves are paid by this price cap.

In the model under consideration, demand is not elastic; price spikes are simply a matter of the price being set to the price cap whenever (L+g) exceeds a certain threshold. The number of times this occurs, together with price cap, determines the price-spike revenue.

Suppose that:

The profit function (short-run profit per MW): $SR_\pi(K)$; and

The load-duration function: D(L+g)

The threshold that (L+g) must exceed to cause the system operator to set price to the price cap is $K\text{-}OR^R$, installed capacity minus the operating reserve requirement. Thus, price spikes occur when L+g > $K\text{-}OR^R$. The duration of their occurrence is given by D(L+g), where L+g = $K\text{-} OR^R$. This gives the rule for finding price-spike duration: $D(K\text{-} OR^R)$

Price-spike revenue is simply the duration of the price spike times the difference between the price cap and the variable cost of the peakers. Thus,

$$\mathbf{SR_\pi(K) = D(\mathit{K}\text{-} \mathit{OR}^R) \times (P_{cap} - VC_{peak})} \qquad \textbf{equation 1}$$

From equation 1, we know that the short-run profit function depends on four different values. Two of them are policy parameters, OR^R and P_{cap}, while the third one VC_{peak} is a technology parameter. The last one is the installed capacity, K. Regulators (including system operators and engineers) use the policy parameters, consciously or unconsciously, to control the profit function and thereby control equilibrium installed capacity.

In the case of VOLL pricing, $OR^R = 0$, so price is set to V_{LL} whenever L+g exceeds installed capacity K and load must be shed. Thus, $SR_\pi(K) = D(K) \times (V_{LL} - VC_{peak})$.

This function could be explained as a low ICap level produces shortages and high energy prices which provide a high profit level. When ICap is high, shortages are very infrequent and prices are rarely high. This leads to a low expected annual profit. At some level in between, expected prices are just high enough to produce a profit level that would cover the fixed cost of a new peaker, which is 6$/MWh as the example in the previous section. This is the long-run equilibrium level of ICap, 7.975 MW. As a result, long-run equilibrium installed capacity is determined by the intersection of the profit function and the level of fixed costs.

In the case of operating reserves pricing, short-run profit comes from both energy and reserve. That is: $\mathbf{SR_\pi(K_{energy})} = D(K\text{-} OR^R) \times (P_{cap} - VC_{peak})$ and

$\mathbf{SR_\pi(K_{reserve})} = D(K\text{-} OR^R) \times P_{cap}$, where $P_{cap} < V_{LL}$, in which we ignore the variable cost of reserve.

This function provides a longer duration for price spikes and a modest price cap level. We can adjust the policy parameters OR^R and P_{cap} to make the profit function intersect the level of the fixed cost of a peaker, \$6/MWh, when it reaches an installed capacity of 7975MW. Thus, both pricing policies induce the same equilibrium level of installed capacity.

However, as a result drawn by stoft (2002), VOLL pricing would have more negative side effects. For the same level of year-to-year fluctuation in the load-duration curve, the VOLL pricing profit function will cause more variation in fixed-cost recovery and will increase the exercise of market power.

4.2 – Capacity approaches and their mechanisms

Capacity approaches provide a fundamentally different approach to generation adequacy. Under the price-spike approach, energy (and operating reserves) revenues cover the fixed costs of generators. Under the capacity approaches, energy and capacity revenues together cover the fixed costs of peakers and determine the level of all types of installed generation capacity.

According to these approaches, generation of electricity requires two factors of production: capacity and energy. The amount of energy that can be produced in any given time period is constrained by the available capacity. Regulatory policies pay energy and capacity (whether they get dispatched or not) separately. Then the payment to energy and capacity together induces a long-run equilibrium, in which it should be equal to the peaker's fixed costs. Two capacity mechanisms will be discussed: capacity payment and capacity market.

4.2.1 - Capacity payment

Ensuring generation adequacy through capacity payments has been implemented in the UK (before the new trading arrangements (NETA)), Spain and several Latin American countries such as Argentina, Colombia. We take the UK pool system as an example. In this system, the National Grid Company calculates, on a day-ahead basis, the expected loss-of-load probability (LOLP) for each 30-minuite period. The market price was set as the highest bid unless there was some probability of shortage, in which case the VOLL came into play. There, the LOLP is multiplied by the VOLL to develop a capacity charge, which is added to the system marginal price. It means that the price was the weighted average of the highest bid and the VOLL, weighted by the probability that there would be a shortage: (highest bid) x (1-LOLP) + VOLL x LOLP. This formula also acted as a price cap of VOLL if the system was actually short of power.

Capacity payment approach in this case resembles a lot to the operating reserves pricing approach. They have almost the same mechanism. The difference is just some definitions of political parameters.

4.2.1.1 – Profit function

The profit functions can be calculated from the load duration curve and two policy variables: the price cap (VOLL) and LOLP (technical calculation, a function of available capacity, K). In the model under consideration, demand is not elastic; capacity payment is simply being set to the price cap whenever LOLP is positive. The capacity payment per MW, multiplied by its duration, determines the energy and capacity revenues. The price cap duration could be calculated from the load-duration curve and it is a function of LOLP. It could be represented algebraically as follows:

The price cap duration: D[LOLP(K)]

When LOLP equal to zero, D equals to zero too. When LOLP is positive, D is positive. Thus, capacity payment occurs when there is some possibility of shortage, that is LOLP>0.

Capacity payment revenues are the sum of energy revenue and available capacity revenue in the case when LOLP>0. The energy revenue is simply the duration of the price cap times the difference between the price cap and the variable cost of the peakers. The available capacity revenue is the duration of the price cap times the price cap, in which we ignore the variable cost of capacity. Thus,

$SR_\pi(K_{energy})$ = D[LOLP(K)] **x (price cap – VC_{peak}), and**

$SR_\pi(K_{capacity})$ = D[LOLP(K)] **x price cap, when LOLP>0**

The long-run equilibrium installed capacity take places when the total short-run profit equals to the fixed cost. From this profit function, we know that if the installed capacity falls below the optimal level installed capacity (in which case LOLP is positive), there is a short-run profit for generators. If the installed capacity is superior to the optimal level, the generators earn no profit. Thus, a capacity payment is intended to induce investment when K< optimal K. According to the two profit-function equations, the profit functions depend on four different values. Two of them are policy parameters, VOLL and LOLP, while the third one, VC_{peak} is a technology parameter. The last one is the installed capacity, K. Regulators (including system operators and engineers) use the policy parameters to control the profit function and thereby control equilibrium installed capacity, K^e.

4.2.1.2 – Existing problems and shortcomings

Although this approach could induce investment, there are still some problems:

- The regulated nature of the procedure has created strong disagreements regarding both the total volume of money to be paid to the generators and the allocation of it among the different facilities, especially when there are thermal and hydro units involved. Besides, it is unclear whether the method can effectively enhance the reliability of the system, and dissatisfied consumers argue that they are paying a capacity charge in exchange for nothing.
- Another problem is also the reason why this approach has received little attention in the United States. It is because the capacity charge is too easy to manipulate for companies that own large amounts of generation. They can declare units unavailable in the day-ahead market and then make them available in real time to collect the high-capacity charge caused by the unavailability declarations. This is found in England & Wales electricity market in which gaming for capacity payment was serious.

- Applying this approach need the use of VOLL. Thus we will meet all the difficulties that we should meet while defining and evaluating VOLL.

4.2.2 - Capacity market

Ensuring generation reliability by imposing an installed capacity obligation on load serving entities (LSEs) has been implemented in the eastern pools in the US including PJM, NYPP and New England. All LSEs are required to own, or to have under contract, a certain required capacity. The sum of these is the market's capacity requirement and is typically about 18% greater than annual peak load. A LSE is penalized if it fails to meet its requirement. Capacity markets, which are established to facilitate trading, allow trading of capacity obligations among the LSEs who have already accompanied installed capacity obligations. The basic motivation for the ICAP requirements is similar to the argument in favour of capacity payments. The capacity markets prompted by the obligation provide generators with the opportunity to collect extra revenue for their unutilized reserve generation capacity and provide incentives for the building of reserves beyond the reserves that meet the short term needs for ancillary services.

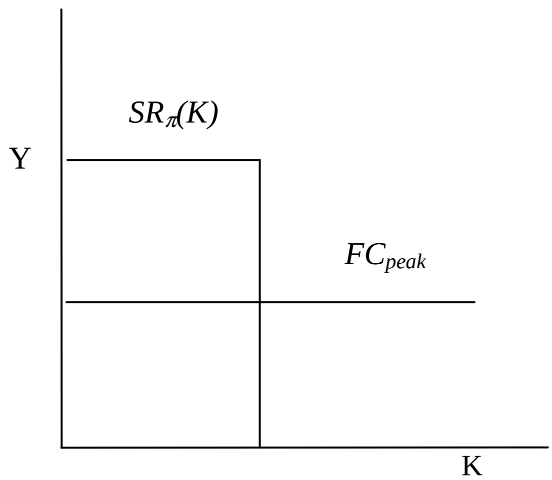
4.2.2.1 – Profit function

An installed capacity requirement produces a very different profit function. The first step toward implementing a capacity requirement is to determine the optimal level of ICap. We set the required level of ICap to the optimal level. When ICap is below the required level, ICap-profits for all generators are set by the ICap-requirement penalty, and when ICap is above the required level, profits are zero. (A small correction should be made for market power.) Capacity requirements easily induce sufficient generation capacity by setting a penalty level that is higher than the cost of new capacity. Adding profit from the energy market to profit from the capacity market produces a total profit function from which an equilibrium value of ICap can be determined.

If there is no market power in an isolated capacity market, the price of capacity will be either zero or equal to the penalty. If total installed capacity, K, is less than required capacity, K^R, the price will equal the penalty, Y. if $K> K^R$, the price should be zero.

A capacity requirement is intended to induce investment when $K< K^R$, and will be successful if Y is greater than the fixed costs of owning a new peaker, FC_{peak}. The profit function is the step function shown in Figure N°13. Unlike the profit function for price spikes, there is no level of ICap for which $SR_\pi(K) = FC_{peak}$; profits are either zero of twice this value. In spite of this, the deterministic equilibrium ICap is the required capacity level ($K^e = K^R$).

Figure N°13 – profit function of capacity in the case of capacity requirement



4.2.2.2 – Existing problems and shortcomings

A capacity requirement produces an easily controlled, low-risk profit function. Capacity requirements are a more direct approach to reliability than assigning high price limits when the system is short of operating reserves. A side effect of the capacity approach is also helpful; it eliminates the need for high energy price spikes to induce investment.

Although in practice, capacity markets are workable, there are problems:

- One of the fundamental problems with capacity markets is that there is disconnect from the energy market. The fundamental relationship between capacity and energy prices in a long run equilibrium is such that the expected social cost of unserved energy as reflected by the energy-only markets prices should equal the marginal cost of incremental capacity. However, the separate capacity markets created for trading reserve capacity requirement set through engineering based methods may produce prices that are not in equilibrium with the energy market prices.
- There are policing and other problems with the sellers of capacity, because it is difficult to produce incentive-compatible capacity market rules. Generators who are being counted as reserve may sell the same capacity in another market if external prices are attractive, meaning it is not available in the first market when a generator outage or other problem arises.
- The reliance of capacity payments and capacity obligations on engineering based calculation has been criticized repeatedly on the grounds that the VOLL used in these calculations is administratively set and has no market base.

4.3 – Reliability policies determine investment and reliability

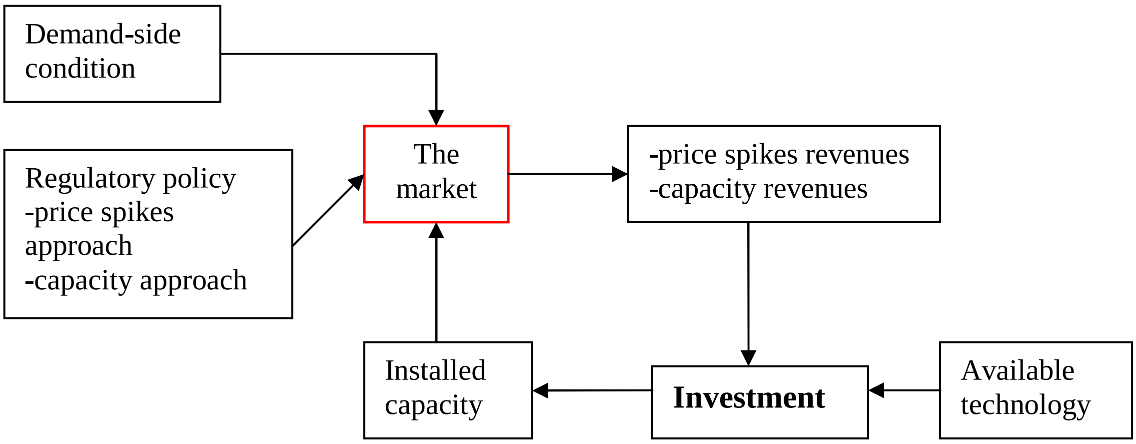
We have discussed several reliability policies used or being used to induce generation investment: four mechanisms from two approaches: price spikes approach and capacity approach. In price-spike approach, regulatory policy determines the height and duration of price spikes. There is only one revenue for generators, which is the revenue of energy (and operating reserves) comes from the aggregate price spikes. Conversely, in capacity approach, price caps often limit energy price to increase very high. As a result, low price spikes revenue could not cover generators' fixed costs and discourage investment. In order to obtain the same optimal level of installed capacity, regulatory policies pay for both dispatched and non-dispatched capacity to encourage investment.

By building profit functions, we compared in the four mechanisms, how ***political parameters*** affect the shape and the equilibrium level of installed capacity of its profit function. More precisely, in VOLL pricing mechanism, policy parameter is the system operator's price limit when load is shed, $\boldsymbol{V_{LL}}$. In operating reserves pricing mechanism, available political parameters are the price limit when operating reserve requirements are not met, ***Pcap*** and the required level of operating reserves, $\boldsymbol{OR^R}$**.** Comparably, in capacity payment approach, ***LOLP***, the technical calculation to evaluate the system's reliability and the system operator's price limit when LOLP is positive, $\boldsymbol{V_{LL}}$, are the political parameters. Finally, in capacity market mechanism, the required level of installed capacity, $\boldsymbol{K^R}$ and the penalty for being short of capacity, ***Y*** determine the profit function.

A new loop similar to the Figure N°11 and integrating the regulatory policies is showed in Figure N°14. In the place of VOLL which determines prices spikes, regulatory policy determines the market's price (energy price and capacity price) when demand, including the regulated demand for operating reserves, exceeds total available capacity. Similarly, these prices determine the short-run profits (prices spikes revenues and/or capacity revenues) of generators, and the expectations of these profits induce generation investment. Investment increases installed capacity (ICap), which reduce both price and profits. This feed back loop, which is controlled by reliability policy, determine the equilibrium level of ICap and thus long-run reliability.

In all of our four mechanisms, we found that the equilibrium value of ICap, K^e, is not automatically the optimal value. Policy must be adjusted so that the profit function of a peaker crosses the profit level (approximately \$6/MWh) required to cover the fixed costs of a peaker at the optimal ICap level. Any profit function that does this, no matter what its shape, will induce the right level of ICap. Thus there are many "optimal" policies to choose from. Although many policies will produce a profit function that determines the correct equilibrium level of installed capacity, but this does not mean they are all equally desirable. The first goal is the correct average level of installed capacity, but that is not the only criterion for a well-functioning power market. If ICap is right on average but fluctuates too dramatically, the excess *unreliability* in years of low ICap will more than offset the excess reliability in years of high ICap. In fact any value of ICap other than the optimal value causes a reduction in net benefit, so no matter what the average value, fluctuations produce a sub-optimal result.

Figure N°14 – the market structure in which regulatory policy determines investment



Moreover, two phenomena other than reliability deserve attention – risk and market power. Even if the ICap were exactly right every year, so that reliability was optimally maintained, profits would fluctuate. If the profit function can be very steep at the equilibrium, any small unexpected increase in demand will cause a large increase in profits. The VOLL pricing policy fits this description. That is, a profit function that is extremely steep encourages the exercise of market power. Withholding 2% has the same impact on profits as a 2% reduction in ICap. So profit functions that are very steep reward withholding most handsomely. Again, the VOLL pricing policy fits this description (Stoft, 2002). Conversely, a flatter (less steep) profit function can be obtained by designing price spikes that are lower and of longer duration. With a flatter profit function, there is less risk and less market power than the case of a steeper one. Operating reserves pricing policy has done this job very well.

Comparing to the capacity approach, price spikes systems have the advantage of sending efficient price signals to the demand side of the market and to expensive existing generators. Price spikes are sensitive to load fluctuations while capacity approach is not. By eliminating this source of risk, the capacity approach makes it easier to control reliability and suppress market power in the energy market.

To conclude, many different policies would produce the same optimal level of ICap and reliability, but they have different side effects according to the shape of their profit functions. The shape of profit functions are purely under political consideration and are determined by the political parameters.

V. Conclusion

This paper tried to find the determinants of electricity production investment. With some strong assumptions, we built a two-technology model in an energy-only market. In this simplified case, determinants of investment will be the load-duration curve, the industry's supply curve, VOLL and available technologies.

However, current electricity markets have some imperfections; these imperfections and imperfections in mechanisms adopted to mitigate these problems cause some investment inventive problems. This investment incentive problem will in one hand reduce investment and in the other hand undermine electricity system's reliability. Thus, several regulatory policies have been proposed or used to resolve this problem. Four mechanisms from two approaches have been discussed in this paper. All of them could induce the optimal level of installed capacity and reliability by changing the political parameters. But different policies would have different side effects. Anyway, in the case with regulatory policies, the determinants of investment are the load-duration curve, the industry's supply curve, regulatory policies and available technologies.

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