



WHOLESALE ELECTRICITY PRICE PROJECTIONS FOR FRANCE

An ILEX Energy Report to Endesa France
November 2007 edition



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EXECUTIVE SUMMARY

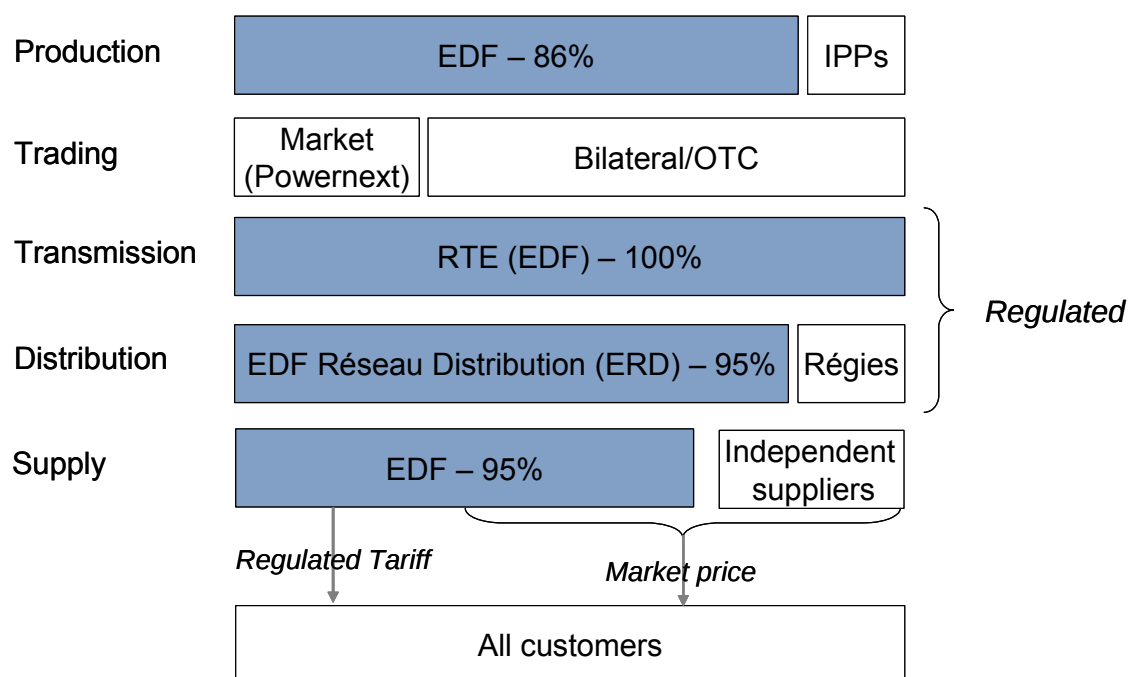
Pöyry Energy Consulting has been commissioned by Endesa France to provide an independent market report and analysis of the French market. We have used our *EurECa* model, which projects output and cross-border flows for twenty-five European countries, taking account of flows from a further six neighbouring countries to project wholesale electricity prices and spark-spreads for the period 2007–2030.

Overview of the French electricity market

In 2006, electricity consumption in France was 470TWh, and peak demand reached 86.3GW. This consumption was met through domestic production of 549TWh, exports of 90.6TWh and imports of 27.3TWh. Nuclear contributed 55% of the generation capacity and 78% of the electricity produced in France, with the remainder of generation mainly made-up of hydro (11%) and thermal generation (10%).

The French electricity market is dominated by the former monopoly EDF (Electricité de France) at all levels of the supply chain. Figure 1 shows the structure of the French electricity market together with EDF's share in the generation, transmission, distribution and supply sectors. The other major players in the generation market include Suez-Gaz de France, Endesa France, the CNR, and Poweo from 2009 onwards.

Figure 1 – French electricity market structure



Source: Pöyry Energy Consulting Analysis

Since 1999, the high-voltage transmission grid has been controlled and operated by Réseau de Transport d'Electricité (RTE), a ring-fenced subsidiary of EDF and about 95% of the distribution network is controlled by EDF Réseau de Distribution (ERD).

The Commission de Régulation de l'Energie (CRE) is the French energy regulator and was created in March 2000. Its main mission is to oversee third party access (TPA) to the RTE grid and distribution networks and to determine tariffs for TPA. Its other responsibilities include protecting captive customers, investment planning for transmission and distribution (T&D), licensing new entrants and ensuring that public service obligations are respected.

Electricity is traded in France using either over-the-counter transactions which are characterised by bilateral contracts, or via the Powernext exchange on which both spot (i.e. for the next day) and forwards (i.e. relating to long-term contracts to be fulfilled at a future date in up to several years' time) are traded. Around 80% of volumes actually delivered are traded Over the Counter, 15% are Powernext Day-ahead and 5% Powernext Futures. Most spot products are traded through Powernext, whilst most baseload products are OTC transactions.

Wholesale electricity price projections

We have used our modelling expertise to create four internally consistent scenarios that we feel span the range of long-term wholesale prices within France, with the aim of examining the effect on prices of a number of key drivers:

- fuel prices (coal, oil and gas);
- gas market liberalisation;
- CO₂ price assumptions;
- electricity demand;
- new power station construction and plant retirements; and
- costs and performance of new entrants.

These four scenarios can be summarised as follows, and as in Table 1 below:

- **High.** The High price scenario examines the effect of high fuel prices, driven primarily by crude oil prices staying high and reaching \$95/bbl by 2030 in real terms. The high oil prices in turn drive up gas prices through indexation. We also assume that electricity demand growth will be relatively high with limited new renewables build leading to high levels of new thermal plant construction, and new nuclear reactors after 2021.
- **Central oil-indexed.** In the Central oil-indexed scenario, we assume that demand and supply remain matched and gas prices remain indexed to our central oil price projections of \$50-60/bbl in the medium to long term as liberalisation throughout Europe either does not occur, or does not break the contractual linkages between oil and gas.
- **Central oil de-linked.** As in the Central oil-indexed scenario demand and supply remain matched but under this scenario North West European gas prices break the link with oil and fall to our central projections of long-run marginal costs of supply. As gas prices fall, gas fired new entry becomes increasingly competitive in France.
- **Low.** In the Low scenario, low demand for electricity is combined with a relatively high system margin and low fuel prices as we assume that gas prices break the link with oil, causing them to fall to the long-run marginal cost of supply. Low demand growth combined with high renewables build means that the quantity of thermal plant built under this scenario is low.

A summary of the different wholesale price projection scenarios is presented in Table 1.

Table 1 – Summary of scenarios

	Demand	New conventional build	Value of capacity	Fuel prices
High	High	High due to low renewables growth	High from 2010	High
Central oil-indexed	Central	Intermediate with central renewables growth	High from 2011	Central with oil-indexed gas prices
Central oil de-linked	Central	Intermediate with central renewables growth	High from 2011	Central with oil de-linked gas prices
Low	Low	Low thermal build, with high renewables growth	Low until 2014 then increasing to high by 2017 and for the rest of modelled period	Low

Source: Pöry Energy Consulting

We have considered scenarios with a value of carbon in the French market. We use a range of different carbon values owing to the uncertainty of the price of carbon allowances in the Emissions Trading Schemes. Our projections for the final year of Phase I (2005–2007), Phase II (2008–2012) and future phases are presented in Table 2.

Table 2 – Pöry assumptions for the value of carbon (€/tCO₂)

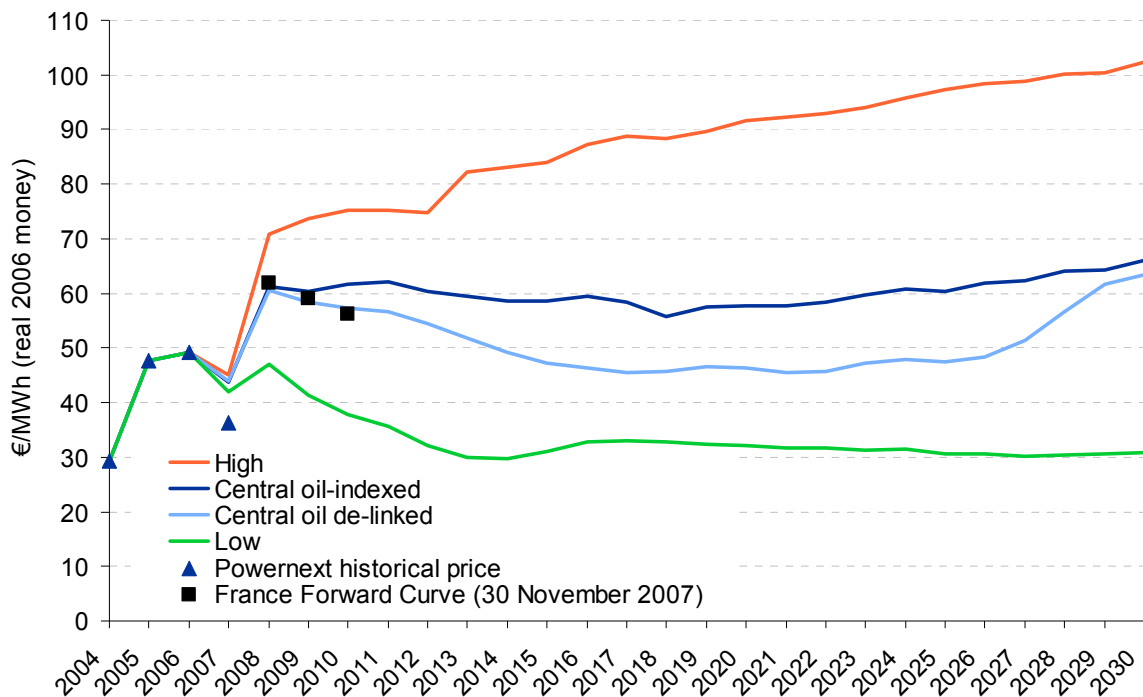
	Phase I	Phase II	Phases beyond 2012
High	1	30	40
Central	1	20	20
Low	1	10	10

Source: Pöry Energy Consulting

Projections

The results of the four scenarios with a value of carbon are summarised in Figure 2 and Table 3 and are discussed in further detail in the following sections. Figure 2 also shows the current forward curve, which we use as a rough comparator against our projections. Forward prices are continually changing, and are based on a low level of liquidity. For 2007 to 2010, our Central scenarios are close to the forward curve as at the end of November 2007.

Figure 2 – Wholesale electricity price projections for France including a value of carbon (€/MWh, real 2006 money)



Source: Pöyry Energy Consulting Analysis

High with carbon

In our High with carbon scenario, the two most important drivers of high electricity prices are high demand and high fuel prices, with gas fired generation generally expensive relative to coal fired generation.

High oil prices (of around \$90/bbl) and the continuation of oil-indexation across NWE leads to gas prices of around €34/MWh. With ARA coal at around \$77/tonne and carbon prices rising to €30/tCO₂ for Phase II and €40/tCO₂ for Phase III and beyond we project high wholesale electricity prices of around €70/MWh in the initial years. Given relatively high demand growth and the need for new capacity, the value of capacity remains high throughout. In the outer years, wholesale electricity prices rise in line with increasing gas prices, remaining at the top of our new entrant bands and reaching €100/MWh by 2028.

Central oil-indexed with carbon

Our Central oil-indexed projection sees new entry commissioning from 2009 with the value of capacity high from 2011 throughout to support the new plant coming on. Prices remain at new entrant levels throughout with new entry coming on-line in all years.

Overall, prices rise quickly from a low of €44/MWh in 2007 to €61/MWh by 2008 and then remain around the €60/MWh level for the majority of the modelled period. In the outer years, electricity prices start to move upwards in line with a rise in gas prices during this period.

Central oil de-linked with carbon

Our Central oil de-linked scenario sees new entry commissioning from 2009 similar to the Central oil-indexed scenario, but due to the lower gas prices, new build is mainly composed of CCGT capacity in Europe, given that coal new entrants cannot compete at this significantly lower wholesale electricity price.

Overall, prices rise quickly from a low of €44/MWh in 2007 to €61/MWh by 2008 and then start to fall to a low of €45/MWh as gas, coal and oil prices fall to their long-term equilibrium. Wholesale prices then remain around this level until 2026, when they start rising again following the increase in gas prices.

Low with carbon

The key drivers for the Low scenario are low demand, high renewables and low fuel prices. The relatively high system margin leads to a low value of capacity until 2014. In later years, the value of capacity rises to ensure that the mix of new entrant CCGT is able to fully recover their fixed and variable costs. We do not project any generic CCGT plant coming on line before 2021 in the Low scenario.

In the Low scenario, gas prices fully de-index from oil by 2010 and fall to low levels of €8/MWh. This decline in gas prices, combined with coal prices falling to \$32/tonne by 2030 and oil prices at \$35/bbl, leads to the wholesale electricity prices gradually falling to €31/MWh by 2030.

Table 3 – Wholesale electricity price projections for France including a value of carbon (€/MWh, real 2006 money)

	High	Central oil-indexed	Central oil de-linked	Low
2007	45.01	43.80	43.88	42.08
2008	70.94	61.19	60.67	47.04
2009	73.79	60.29	58.44	41.42
2010	75.32	61.62	57.38	37.93
2011	75.20	62.14	56.60	35.62
2012	74.72	60.35	54.37	32.10
2013	82.23	59.46	51.80	29.89
2014	83.15	58.63	49.30	29.70
2015	83.95	58.62	47.17	31.16
2016	87.21	59.41	46.39	32.72
2017	88.68	58.46	45.58	33.02
2018	88.25	55.87	45.62	32.70
2019	89.74	57.45	46.66	32.38
2020	91.71	57.66	46.27	32.18
2021	92.20	57.81	45.44	31.79
2022	92.92	58.32	45.77	31.78
2023	93.93	59.73	47.23	31.30
2024	95.72	60.90	47.81	31.48
2025	97.23	60.29	47.56	30.52
2026	98.50	61.98	48.40	30.54
2027	98.80	62.37	51.31	30.22
2028	100.13	64.06	56.70	30.36
2029	100.42	64.32	61.69	30.53
2030	102.27	65.94	63.36	30.81

Source: Pöyry Energy Consulting Analysis

1. INTRODUCTION

1.1 Content of this report

This independent report presents Pöyry's analysis of the wholesale prices for the French electricity market. The projections cover the period 2007–2030, based on our detailed modelling of the fundamentals of supply and demand in France and in Europe. We have combined several assumptions to create four main market scenarios for our price projections.

The remainder of this report is structured as follows:

- Chapter 2 describes the main characteristics of the French electricity market;
- Chapter 3 presents the French policy for supporting the uptake of renewable generation technologies;
- Chapter 4 describes and presents the inputs to our wholesale electricity price projections, which also includes setting out our gas price projections;
- Chapter 5 explains how we combine our input assumptions to develop our price projection scenarios and presents our final wholesale electricity price projections;
- Annex A explains how our European electricity market model, EurECa, operates;
- Annex B provides two worked examples for calculating the potential value of a renewable wind development in France.

1.2 ILEX Energy Reports

ILEX Energy Reports provide detailed descriptions of European energy markets coupled with market-leading price projections for wholesale electricity, gas, carbon and green certificates. ILEX Energy Reports and price projections are currently available for the:

- electricity and/or gas markets in the following countries' markets:
 - Belgium
 - Bulgaria
 - France
 - Germany
 - Great Britain
 - Greece
 - Ireland
 - Italy
 - the Netherlands
 - Poland
 - Romania
 - South East Europe
 - Spain
 - Switzerland
 - Turkey
- renewables markets in:
 - Italy
 - Poland
 - Spain
 - United Kingdom
- The biofuels market in Europe.

ILEX Energy Reports are produced by Pöyry Energy Consulting, formerly known as ILEX Energy Consulting.

In addition to ILEX Energy Reports, Pöyry also produces a number of other reports, including electricity reports for Norway, Sweden and Finland, a renewables report for Sweden, and a report of the EU Emissions Trading Scheme with carbon price projections.

1.3 Pöyry Energy Consulting

Pöyry Energy Consulting is Europe's leading energy consultancy providing strategic, commercial, regulatory and policy advice to Europe's energy markets. Part of Pöyry Plc, the global engineering and consulting firm, Pöyry Energy Consulting merges the expertise of ILEX Energy Consulting, ECON and Convergence Utility Consultants with the management consulting arms of Electrowatt-Ekono and Verbundplan. Our team of 250 energy specialists, located across 14 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.

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1.4 Conventions

All monetary values quoted in this report are in Euros in real 2006 prices, unless otherwise stated. Annual data relates to calendar years running from 1 January to 31 December, unless explicitly defined otherwise.

2. BACKGROUND TO THE FRENCH ELECTRICITY MARKET

In this chapter we provide a background to the French electricity market covering the following key topics:

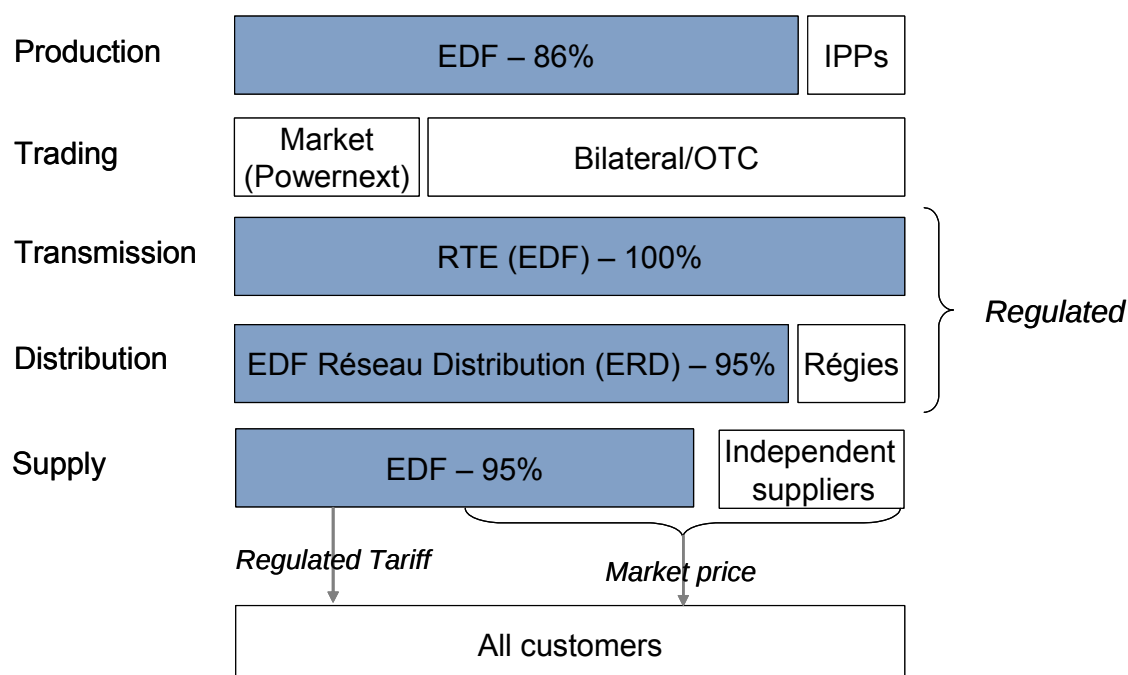
- market structure;
- the major players in the electricity generation, transmission and supply sectors;
- physical characteristics of the French market, including total capacity and demand levels;
- the different trading arrangements used to sell and purchase power;
- economic and environmental regulation; and
- a description of how France has implemented the European Union Emissions Trading Scheme into national policy.

2.1 Current Industry Structure

2.1.1 Overview of the French Electricity market

The French electricity market is dominated by the former monopoly EDF (Electricité de France) at all levels of supply chain. Figure 3 shows the structure of the French electricity market along with EDF's share: generation, transmission, distribution and supply sectors. These areas are described in detail in the following sections.

Figure 3 – French electricity market structure



Source: Pöyry Energy Consulting Analysis

2.1.2 Liberalisation and market opening

The French Government implemented the EU Electricity Directive¹ through the Electricity Law in 2000². The main provisions of the Electricity Law are:

- the establishment of an independent regulatory commission, the Commission de Régulation de l'Energie (CRE);
- Third Party Access (TPA) to transmission and distribution networks for eligible customers;
- TPA tariffs set by the French Ministry of the Economy, Finance and Industry (MINEFI) in consultation with CRE;
- generators, including foreign companies, are allowed to build new generation plants subject to government authorisations;
- MINEFI issues calls for tender based on periodic reviews of capacity requirements; and
- MINEFI oversees the long term planning and investment in the transmission grid (RTE).

Liberalisation has been completed in several phases, as regards to “eligible” customers who can choose their own supplier:

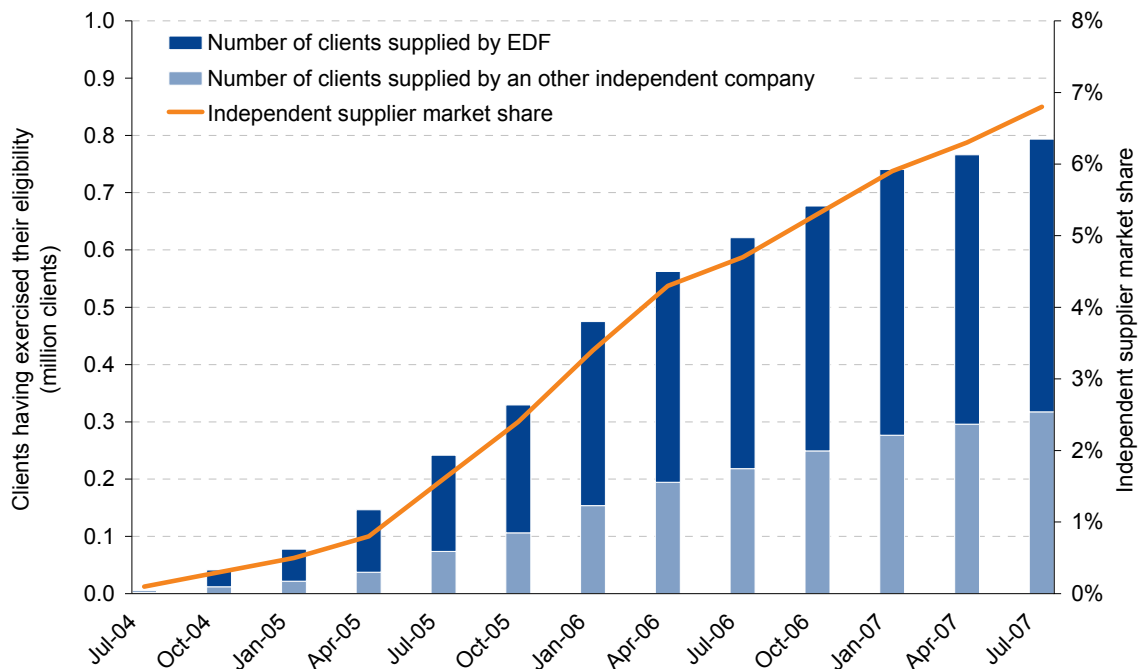
- June 2000, any site consuming more than 16GWh of electricity annually;
- February 2003, any site consuming more than 7GWh;
- July 2004, any non-domestic consumer, consuming approximately 295TWh p.a.; and
- July 2007, any domestic consumer, consuming approximately 135TWh per annum.

Eligible sites have not necessarily exercised their eligibility. For those customers who have not, the tariff they are charged is still regulated. For those customers that have exercised their eligibility, they either have not changed suppliers so far and do not pay regulated tariffs; or they have switched suppliers. Figure 4 shows the switching rate in the French market for non-domestic customers.

¹ ‘Common rules for an internal market in electricity’. Electricity Directive 96/92/EC.

² Law n° 2000-108, 10 February 2000.

Figure 4 – Non-domestic client switching to market prices



Source: CRE

In 2005, a significant number of industrial customers switched to non-regulated contracts linked to market prices supplied both by EDF and other independent suppliers. In 2006, market prices increased significantly whilst regulated tariffs remained mainly driven by the cost of nuclear and therefore remained fairly stable. This caused a lack of competitiveness for those customers exposed to the market price, especially large intensive energy users.

In response to this, the French government introduced a law in December 2006³ which set up a transitional two-year period during which industrial sites that had exercised their eligibility could take advantage of an intermediate tariff. The tariff, known as “tarif de retour”, or TaRTAM, was calculated as a fixed 10 to 23 per cent increase on the regulated tariff, depending on the consumption characteristics of the customer⁴. The impact of this law was minor in terms of the number of client switching back to the regulated tariff: only 3,000 clients decided to take advantage of this offer. The law, however, may have had a much greater impact on market prices, in the sense that they have been associated with a permanent option, with a significant price risk.

Liberalisation has been coolly received by residential customers so far. Poweo, one of the new entrants in the French market, is expected to only acquire around 10,000 customers by the end of 2007 rather than the 100,000 they initially expected⁵. These results were attributed to several factors, including the call from the influential consumer

³ Law 2006-1537, 7 December 2006, article 15.

⁴ Decree of the 3 January 2007.

⁵ ‘Ouverture des marchés de l’énergie: Poweo rate la première marche’. Les Echos, 18 September 2007.

association “UFC – Que Choisir” to stick with regulated tariffs that will not rise above inflation before 2010. At the end of the third quarter 2007, only 6,100 households had switched to non-regulated tariffs, of which 1,000 had kept with their historical supplier⁶.

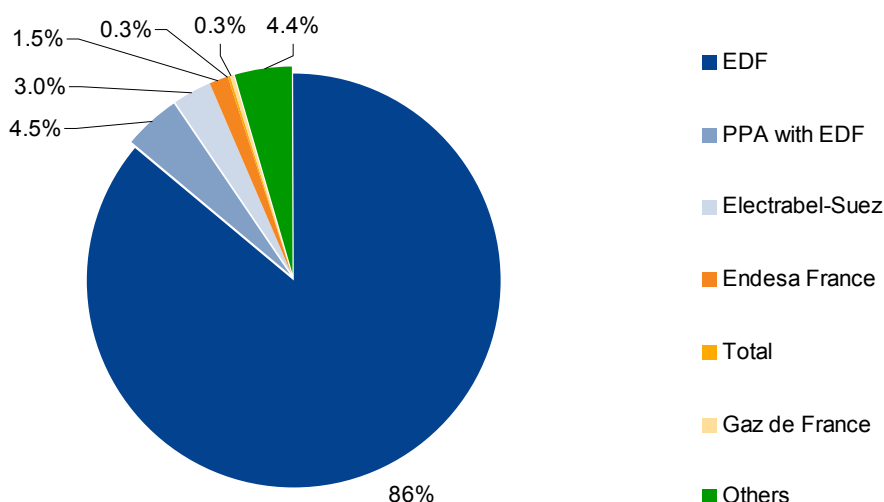
France's parliament voted in December 2007 the right of “reversibility” between regulated and non-regulated tariffs for electricity to all households. This amendment has to be ratified by the French Senate and may be enforced from the beginning of 2008. This reversibility is limited to domestic electricity consumers, before July 2010⁷.

2.2 Structure of Generation, Supply and Transmission

2.2.1 Generation companies

Electricité de France (EDF), the 85% state owned utility, currently dominates the French electricity market at every stage of the supply chain. In 2006, EDF produced around 86% of the 549TWh of electricity in France, and owns around the same share of the 116GW total of capacity. In addition, 4.5% of the generation capacity is directly bought by EDF through compulsory Power Purchase Agreements (PPA)⁸.

Figure 5 – Generation market share in 2006



Source: CRE

2.2.1.1 Electricité de France (EDF)

EDF is Europe's biggest power utility and became a limited company – ‘Société anonyme’ – in 2004. 12.7% of EDF shares were sold on the Paris stock market in a move that reportedly valued EDF at €55bn. By November 2007, this figure raised up to €153bn (+50% since the beginning of the year).

⁶ ‘Observatoire des marchés de l’électricité et du gaz – troisième trimestre’. CRE, 4 December 2007.

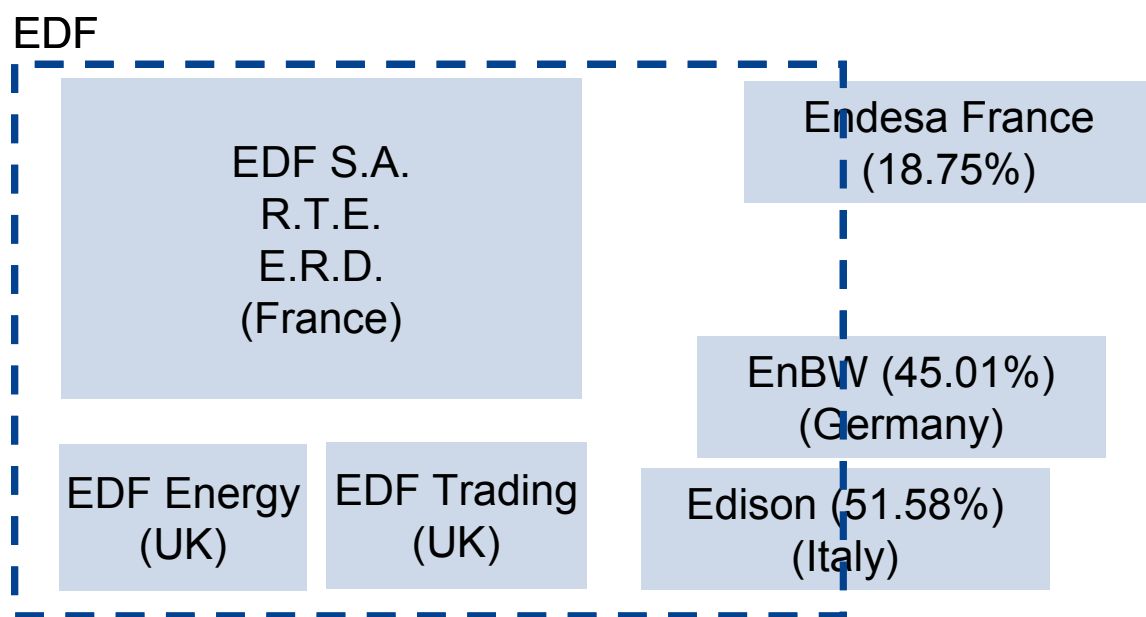
⁷ ‘French energy bill catalyze market opening: Poweo’. Platts, 14 December 2007.

⁸ CRE, Rapport d’activité 2006.

At the end of November 2007, the French government sold 2.47% of its shares in EDF for which it received €3.7bn, which brought the State's participation to around 84.8%. The current law allows the government to reduce its stake down to 70%⁹.

EDF group is active in all of Europe, and is a major player in the markets of France, the United Kingdom, Germany and Italy, as shown in Figure 6. EDF is also involved in power generation in other European countries and in the rest of the world, including Asia and the United States. EDF has recently focused its activities in Europe by selling its shares in Latin America, but is still looking for opportunities for power generation in China and in the United States. EDF is also diversifying its portfolio by investing in renewable energy and gas market. EDF net sales in 2006 were €58.9bn (€31.9bn for France), with 37.8 millions customers (28.2m in France).

Figure 6 – Main EDF ownership in North West Europe



Source: Pöyry Energy Consulting Analysis

EDF owns around 128GW of capacity in the world (99GW in France), including 58 nuclear reactors accounting for 63.3GW, and an EPR under construction in Flamanville. EDF is also investing in fossil-fired plants in order to increase French peak capacity, including the recommissioning of four oil-fired plants 2.6GW of capacity, and the development of 500MW of combustion turbines. EDF is also carrying out a refurbishment program of hydro power plants and investing in wind power in Europe via projects conducted by its subsidiary EDF Energies Nouvelles.

2.2.1.2 Gaz de France – SUEZ

Suez has a share in two nuclear plants in France: Tricastin and Chooz; which amounts to a total of 1.1GW. Suez owns 49.98% of the CNR (see 2.2.1.4) and 99.6% of SHEM and bought a majority stake in the French wind company “La Compagnie du Vent”, which has

⁹ ‘La vente de titres EDF rapporte bien moins que prévu à l’Etat’. Les Echos, 4 December 2007.

148MW of wind capacity in operation or at the final stage of construction, and an additional portfolio of 6.5GW of projects under development¹⁰.

Gaz de France (GdF) owns a 790MW CCGT in France as well as wind and biomass projects. GdF has several development plans, including a 400MW CCGT in Montoir-de-Bretagne, due to be on line in 2009, and a 200MW CCGT to be commissioned in Saint-Brieuc by 2010. Suez and GdF also formed a Joint Venture to build three gas combined cycles in Fos-Sur-Mer, two 425MW units and a smaller 65MW unit.

On 3 September 2007, Suez and Gaz de France finally agreed on the terms of the merger of their two companies, creating the third biggest utility in Europe with a market capitalisation of over €90bn. The merger will become effective from mid-2008, with the French state continues to hold a significant 35% share of capital in the new company in an attempt to protect national interests.¹¹

2.2.1.3 Endesa France (formerly SNET)

Endesa France is the third largest power company in France (on the basis of installed capacity), with 2.5GW currently on-line producing around 8TWh per annum. 65% is owned by the Spanish electricity utility Endesa, 16.25% owned by the national coal-mining company Charbonnage de France (CDF), and 18.75% by EDF. These plants are due to be transferred to E.ON following a deal between E.ON, Endesa and ENEL.

Endesa France has authorization to proceed with CCGTs at Emile Huchet (800MW) and Hornaing (400MW). CCGT proposals are being lined up for its other established sites at Lacq (800MW), Lucy (400MW) and Provence (400MW)¹².

2.2.1.4 Compagnie Nationale du Rhône (CNR)

CNR owns about 3GW of hydro capacity from installations along the river Rhône, whose generation level is fairly unpredictable, but has an average annual production of approximately 16TWh. Electrabel-SUEZ owns just under 50% of CNR, 30% is owned by Caisse des Dépôts et Consignations (CDC), and a number of local authorities make up the remainder¹³.

2.2.1.5 Poweo

Poweo is one of the major new entrants in the French market, with plans to develop 2.8GW of electricity capacity by 2012. Its first plant, a 412MW CCGT in Pont-Sur-Sambre, is under construction and is due to come on line in the beginning of 2009. Poweo also plans to have a portfolio of around 600MW of renewable electricity capacity by 2012.

In January 2007, Poweo signed a swap deal with EDF for 160MW of its CCGT capacity in Pont-Sur-Sambre and 160MW of baseload nuclear capacity from EDF, for a 15 year period¹⁴.

¹⁰ 'Suez buys into French wind boom'. Power In Europe, 3 December 2007.

¹¹ 'Gaz de France et Suez espèrent finaliser leur rapprochement dans les dix mois'. Les Echos, 4 September 2007.

¹² Platts Power in Europe, Issue 505.

¹³ CNR website.

¹⁴ Poweo website, presentation to investors updated in September 2007.

2.2.2 *Transmission*

2.2.2.1 *Transmission networks*

The transmission network is made up of several tiers: a national grid where electricity is transmitted at 400kV (which is interconnected with neighbouring countries) and a set of regional networks ranging from 225kV down to 63kV. The transmission network has a total length of about 100,000km.

2.2.2.2 *Ownership structure*

Since 1999, the high-voltage transmission grid has been controlled and operated by Réseau de Transport d'Electricité (RTE), a ring-fenced subsidiary of EDF, and in September 2005, RTE became a separate limited company. Some small sections of the transmission grid are owned by other companies, such as the national railway company SNCF. Following the adoption of EDF's status change¹⁵, RTE owns all public networks of 50kV and above.

2.2.2.3 *TPA and unbundling arrangements for connection and access*

Both transmission and distribution networks must offer Third Party Access (TPA) to eligible customers. There are currently four tariff levels depending on the voltage involved. Each tariff level comprises capacity and commodity charges that vary with the season and the time of the day. These tariffs can be found on the CRE website¹⁶. The existence of recent IPP entry that required line upgrades suggests that RTE is sticking with TPA arrangements although costs (especially when new HV lines are required) can be significant.

2.2.2.4 *New/planned infrastructure*

A new high voltage line for the EPR nuclear plant at Flamanville in Normandy is at the public consultation stage. Other large grid reinforcement programs are mainly based in the south of the country to prepare the system for the planned development of CCGT plant and the closure of the power-hungry Tricastin uranium enrichment plans. However these reinforcements are not going as quickly as planned and the technical performance of the system in the medium term still raises concerns¹⁷. Moves to enhance the interconnector capacity with Spain have been in discussion for a while but do not appear to be progressing quickly.

2.2.3 *Distribution and supply*

Within France, distribution grids are defined as any transmission lines with voltage below 63kV.

About 95% of the distribution network is controlled by EDF Réseau de Distribution (ERD), under concession agreements from local authorities. The rest is controlled by the so-called régies, which are usually municipal utilities operating in medium-size towns or rural areas. The six largest of these companies are Electricité de Strasbourg, Gaz et

¹⁵ Decree 2004-1224 17 November 2004.

¹⁶ www.cre.fr – 'Accès aux réseaux'.

¹⁷ Source: Platts Power in Europe, Issue 507.

Electricité de Grenoble (GEG), Régie du SIEDS, Usine d'Electricité de Metz (UEM), SICAIE de l'Oise and Sorégies.

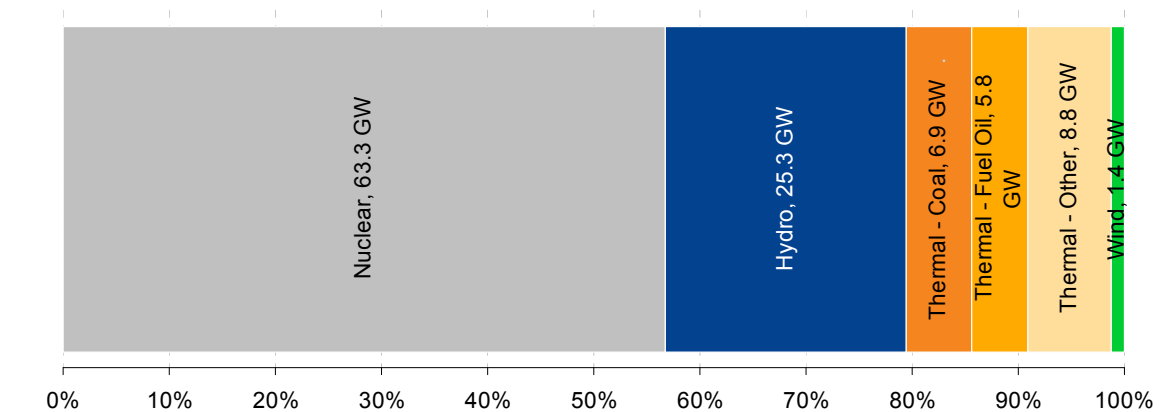
2.3 Physical characteristics

2.3.1 Generation

The total installed generation capacity was 115.4GW at the beginning of 2007, with 111.6GW effectively available for production.

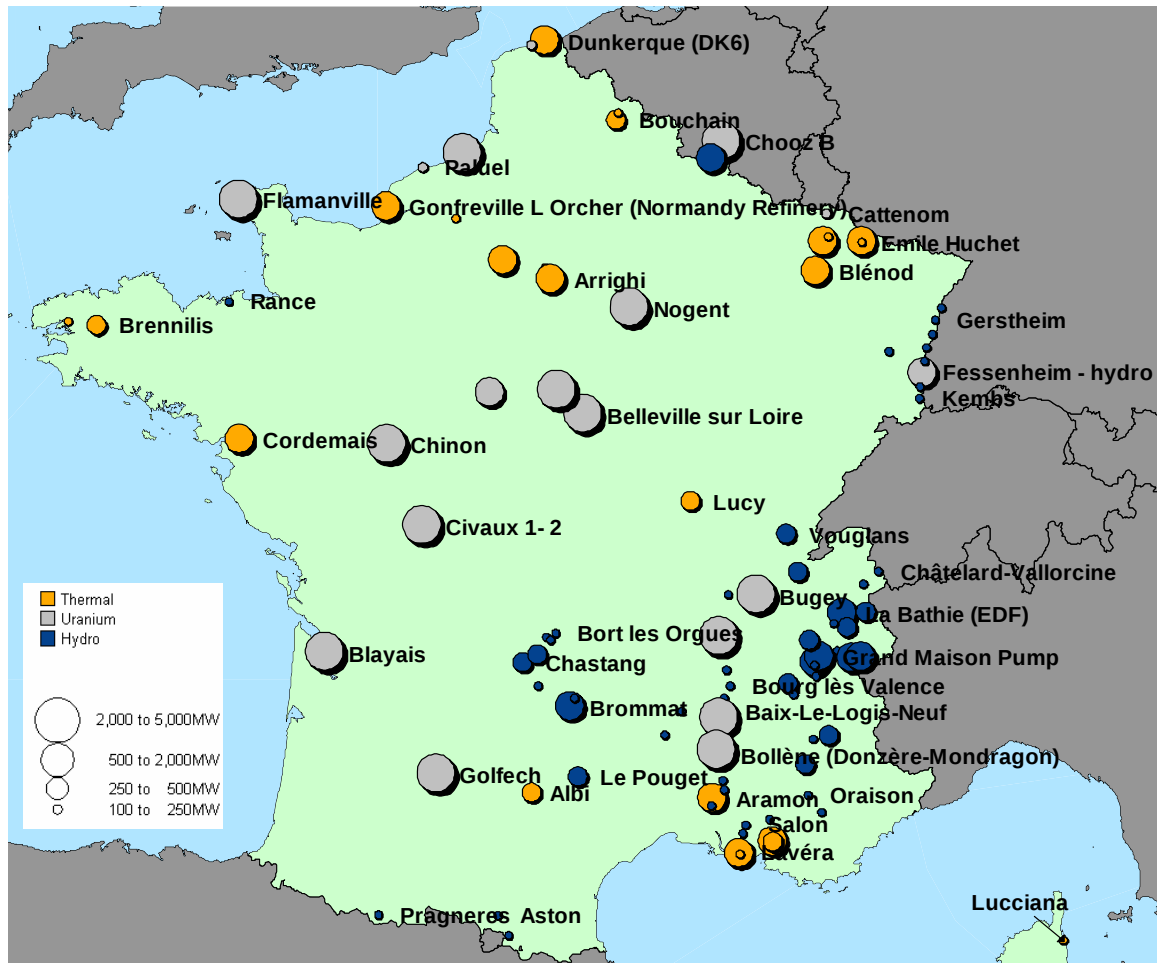
Since the first oil shock of 1973, France has pursued an active policy of achieving a large degree of energy self-sufficiency through nuclear power, given its lack of domestic energy resources. That choice remains a key consideration that guides French energy policy today. Figure 7 to Figure 9 show the dominance of nuclear in the current fuel mix. Whilst nuclear capacity represents around 55% of the generation capacity, it made up 78.1% of the 549TWh produced in France in 2006. Hydro (11.1%), thermal generation (10.4%) and wind (0.4%) made up the remainder of the electricity generated in 2006.

Figure 7 – Proportion of installed capacity in France by fuel type, in GW



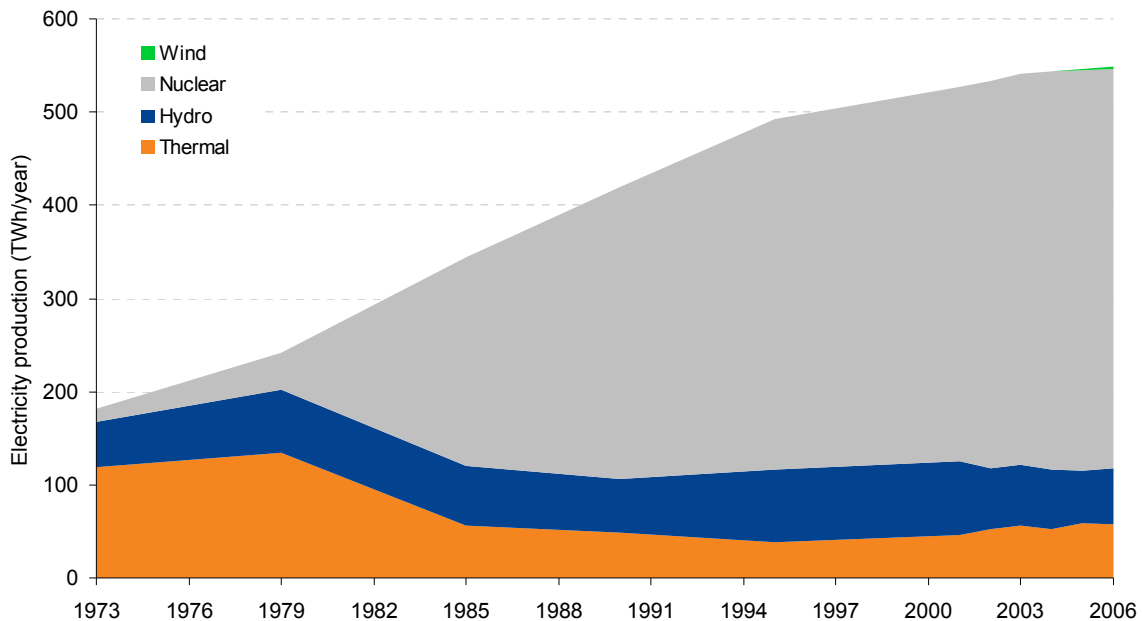
Source: RTE

Figure 8 – Centralised generation with capacity above 100MW in France



Source: Platts PowerVision

Figure 9 – Electricity generation by fuel, in TWh/year



Source: DGEMP

2.3.1.1 Nuclear

French nuclear power stations are mainly Pressurised Water Reactors (PWR), built between 1977 and 1999, with each plant characterised by a size of 0.9GW, 1.3GW or 1.5GW. The minimum lifetime of the French nuclear power stations is forty years, but this lifetime is likely to be extended for at least part of the nuclear fleet¹⁸.

EDF plans to increase by 6-7% the capacity of the 1.3GW-type reactors. This would provide an annual additional production of around 15TWh, compared with an annual production of 13TWh for the new EPR reactor in Flamanville¹⁹.

Nuclear availability in France was around 80% in 2007, the lowest in the past eight years and much lower than for its competitors in Europe or in the United States, due to unexpected outages and maintenance periods taking longer than expected²⁰. EDF's target for nuclear availability is currently 84%.

2.3.1.2 Centralised thermal generation

In 2007, there was 14.7GW of available centralised thermal generation in France, and an additional 2GW of fuel oil power station will be de-mothballed in 2008. The total is made-up of 6.9GW of coal generation and 5.8GW of fuel-oil fired generation, with the remainder being mainly gas and biomass.

¹⁸ 'Bilan Prévisionnel de l'équilibre offre-demande d'électricité en France'. RTE, July 2007.

¹⁹ 'EDF et Suez s'opposent sur la construction d'un deuxième EPR'. Les Echos, 30 November 2007.

²⁰ 'L'arrêt de plusieurs centrales nucléaires oblige EDF à se fournir massivement à l'étranger'. Les Echos, 26 November 2007

The Large Combustion Plant Directive (LCPD)²¹ sets new limits on SO₂ and NO_x from 1st January 2008. A number of different options exist for coal and oil plant, one of which is to 'opt-out' by agreeing to limit power station operating hours and close before 2016. The LCPD is therefore likely to restrict generation from the opted-out coal plant to a lower level than would otherwise be the case, which will have a consequent effect on the rest of the merit order. In France, the LCPD will limit the total operation of 4.4GW of thermal capacity to 20,000 hours between 2008 and 2015.

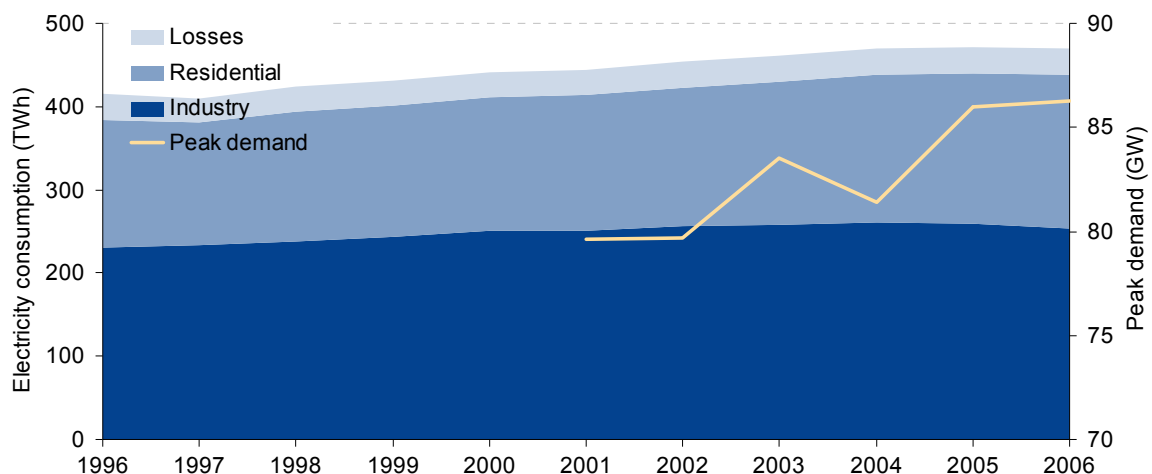
2.3.1.3 CHP

At the beginning of 2007, there was 4.7GW of Combined Heat and Power (CHP) capacity on the French market. The majority of these CHP plants sell their electricity to EDF through a purchase obligation and a feed-in tariff set-up in standard agreements called "97-01" and "99-02". Most of these contract are set to expire between 2010 and 2014 and CHP plants will either have to sell their heat and electricity to the market (plants > 12MWe, around half of the CHPs) or undertake some renovations to benefit from the new feed-in tariff from EDF (plants < 12MWe) detailed in section 3.1.2.

2.3.2 Demand

In 2006, total electricity consumption was 470TWh, falling 0.3% between 2005 and 2006. This reduction was mainly due to a 2.2% fall in medium and large industry electricity consumption, whilst consumption of the residential and commercial sector grew by 2.5%. Peak demand reached 86.3GW in winter 2005-2006 and remained at this level for winter 2006-2007²². The evolution of demand by sector and peak demand is shown in Figure 10 and Figure 11.

Figure 10 – Electricity consumption in France over the last ten years

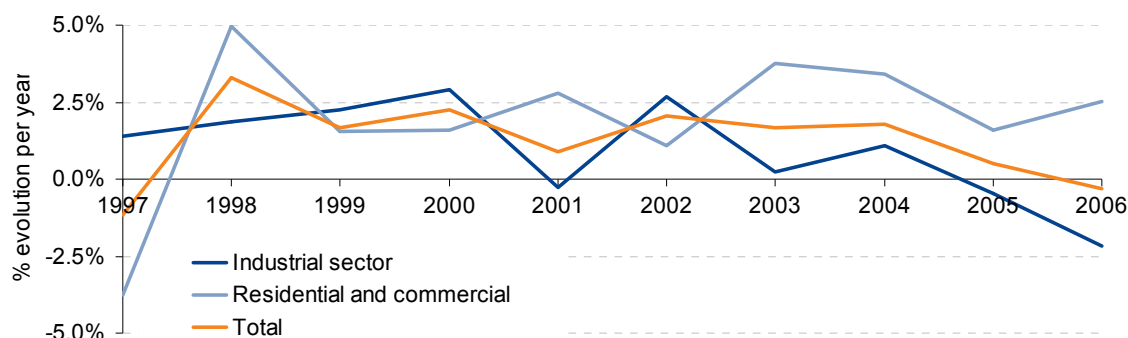


Source: RTE

²¹ Directive 2001/80/EC.

²² Source: RTE "Statistiques de l'Energie Electrique en France", June 2007.

Figure 11 – Evolution of electricity consumption by sector in France



Source: RTE

2.3.3 Interconnection

Due to the low marginal cost and the large amount of generation from nuclear plant on the system, France is the largest exporter of electricity in Europe and is a net electricity exporter (on a contractual basis) to all neighbouring countries except Germany. France mainly exports its baseload power and imports during peak time, due to higher costs for peak power in France than in the neighbouring countries, especially Germany.

As shown in Table 4, exports have remained fairly stable in the last three years, whilst imports decreased in 2006. Further mid-merit and peaking capacity is being deployed in France, both by EDF and new entrants, and we could see imports reducing over time. Due to low nuclear availability in 2007, imports are likely to be higher and exports lower than last year²⁰.

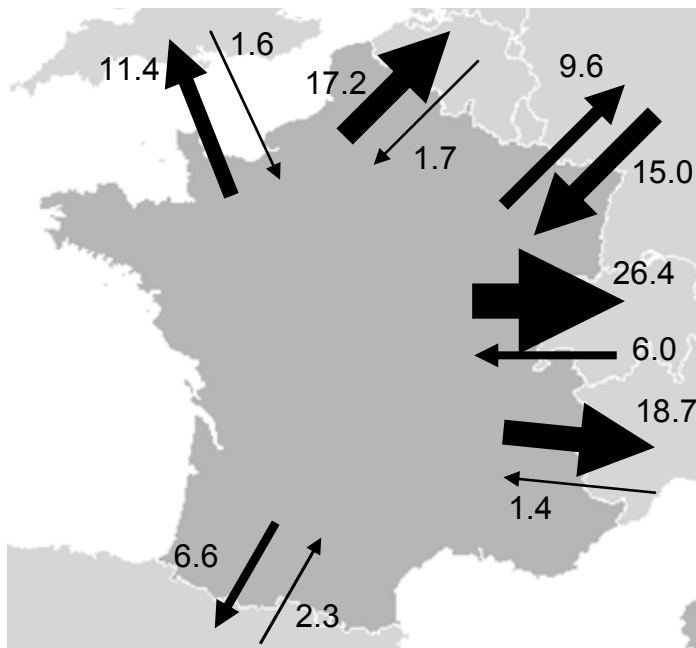
It should be noted that contractual exchanges are significantly different from physical flows at the French border. For example, France imported 15TWh from Germany on a contractual basis, whereas the physical flow from Germany to France is 0.8TWh²³.

Table 4 – Historical evolution of contractual exchanges (TWh)

	Germany	Belgium	Switzerland	Italy	UK	Spain	Balance
2003	4.7	11.4	19.9	21.4	2.4	5.9	65.7
2004	-8.2	12.9	21.2	21.4	9.5	6.0	62.8
2005	-9.5	11.4	20.7	19.4	10.5	6.2	58.7
2006	-5.4	15.4	20.9	17.4	9.8	5.1	63.1

Source: RTE statistics

²³ Pöyry's modelling described in chapters 4 is based on physical flows.

Figure 12 – Contractual exchanges with neighbouring countries in 2006

Source: RTE statistics

2.4 Market operation and Trading

2.4.1 Market Structure

In addition to owning the transmission network and 95% of the distribution network, EDF produces and sells most of the electricity in France. The very high level of vertical integration of the French market can be seen in Figure 13. The consequence is that EDF largely circumnavigates the wholesale market by selling the electricity it produces directly to end-consumers. As a result, only about 20% of injections onto the system are traded on the wholesale market and less than 10% of sales to end-users.

As EDF does not participate significantly in the market, exchanges are not concentrated and the HHI²⁴ sits around 400 and 900 for the wholesale market. For comparison, the HHI is around 9,000 for production in France, and in the region of 4,500 for production excluding EDF²⁵, which means that the remainder of electricity generation is also very concentrated.

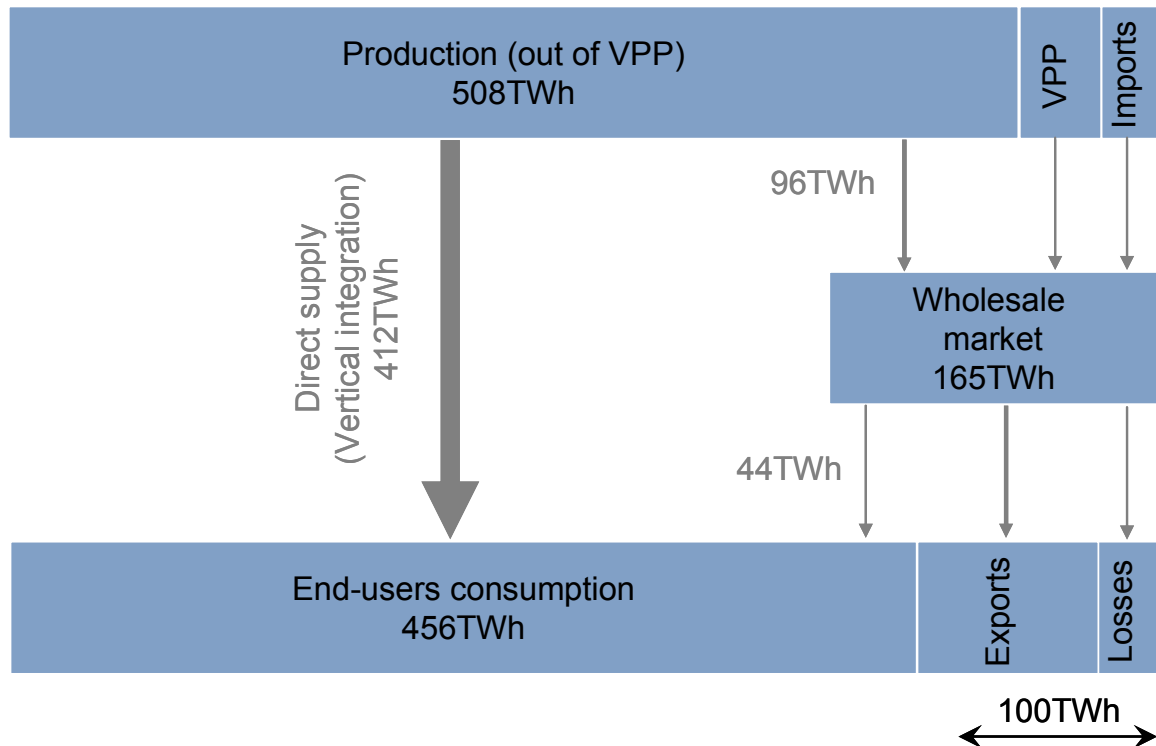
Electricity is traded in France using either over-the-counter transactions which are characterised by bilateral contracts, or via the Pownext exchange on which both spot (i.e. for the next day) and forwards (i.e. relating to long-term contracts to be fulfilled at a future date in up to several years' time) products are traded.

²⁴ The Herfindahl-Hirschmann Index (HHI) determines market concentration by computing the sum of the squared market share of each competitor. In a "perfect monopoly," in which one firm supplies 100 percent of the market, the maximum value of the HHI is at the maximum level of 10,000 (100 times 100). Markets with an HHI value below 1000 (e.g., 10 firms, each with a 10-percent market share) are presumed to be un-concentrated, while markets with an HHI of 1800 or more are considered to be highly concentrated.

Around 80% of volumes actually delivered are traded Over the Counter, 15% are Powernext Day-ahead and 5% Powernext Futures. Most spot products are traded through Powernext, whilst most baseload products are OTC transactions²⁵.

RTE and ERD, the transmission and distribution network, have to buy their losses in a transparent and non discriminatory way. Therefore, they organise call for tenders on the wholesale market, essentially on Future products. This increases significantly the liquidity of the French market: in 2006, RTE and ERD bought 11.7TWh and 18.4TWh respectively, compared with 44TWh sold to end-users via the wholesale market.

Figure 13 – Structure of the French electricity market



Source: CRE

2.4.2 EDF Virtual Power Plants (VPP)

In 2001, the European commission urged EDF to make accessible some of its generating capacity available to competitors through Virtual Power Plants (VPP) auctions. A VPP contract is equivalent to booking generation capacity. An electricity supplier buys the right to use a power plant through auctions, at a fixed cost in €/MW/year. Over the duration of the contract, the buyer has the right to ask for the actual delivery of power up to the capacity contracted for a variable cost in €/MWh. In the case of nuclear baseload, the latter cost reflects the variable cost of a French baseload nuclear power plant operated by EDF.

For the first five years of the auctions, EDF released 6GW of capacity accounting for some 40TWh of energy. This capacity was made up of 1GW of cogeneration, 1GW of

²⁵ 'Rapport d'activité 2006'. CRE, June 2007.

peak power, and 4GW of baseload power. Contracts have historically lasted from three months to three years, and since September 2006, EDF has auctioned a four-year baseload contract²⁶. Variable prices for the latest auction in December 2007 were €9/MWh and €71/MWh for base and peak power respectively²⁷.

2.4.3 OTC

OTC transactions represent around 80% of wholesale exchanges in France and are mainly baseload products. Actual exchanged volumes are unknown, but volumes of OTC transactions resulting to physical deliveries grew steadily from 4TWh/month in January 2002 to 20TWh/month at the beginning of 2006. This number has appeared relatively stable since then²⁵.

2.4.4 Day-ahead and Future: Powernext market

On 26 November 2001, Powernext, the French power exchange was launched with a single spot price for the wholesale market. In June 2004, Powernext started a forward market as well, selling contracts for the next three months, the next four quarters and the next two years. Powernext Day-Ahead trading has steadily increased since 2004 reaching a daily peak of over 172GWh in March 2007. CRE monitors the Powernext index to prevent misuse and manipulation, as this price is used to set imbalance charges. In June 2005, a carbon market was also opened, with up to 5.9MtCO₂ traded per month in February 2007.

After the launch of two new products in July 2007, the Day-ahead comprises three different elements:

- Day-Ahead Auction: electricity traded on day d for delivery the following day in 24 hourly intervals, auctioned at 11AM;
- Day-Ahead Continuous: electricity traded on day d for delivery the following day on 11 standardised blocks of hours, in continuous trading from 7:30AM to 11:30AM; and
- Day-Ahead Intraday: electricity traded on day d for delivery on the same day or on the following day on 24 individual hours, traded from 7:30AM to 11PM.

Volumes traded in 2006 reached 29TWh, compared with 20TWh in 2005. Powernext prices are influenced by fuel prices, weather conditions and the availability of power plants in France and in the neighbouring countries. Extreme price movements on the Powernext market strongly track extreme temperatures in France. For example, electricity prices spiked in July 2006, due to cooling problems in France, Germany and Italy, or in March 2005 because of the extremely cold weather across Europe. Prices and volumes traded on Powernext Day-ahead are shown in Figure 14.

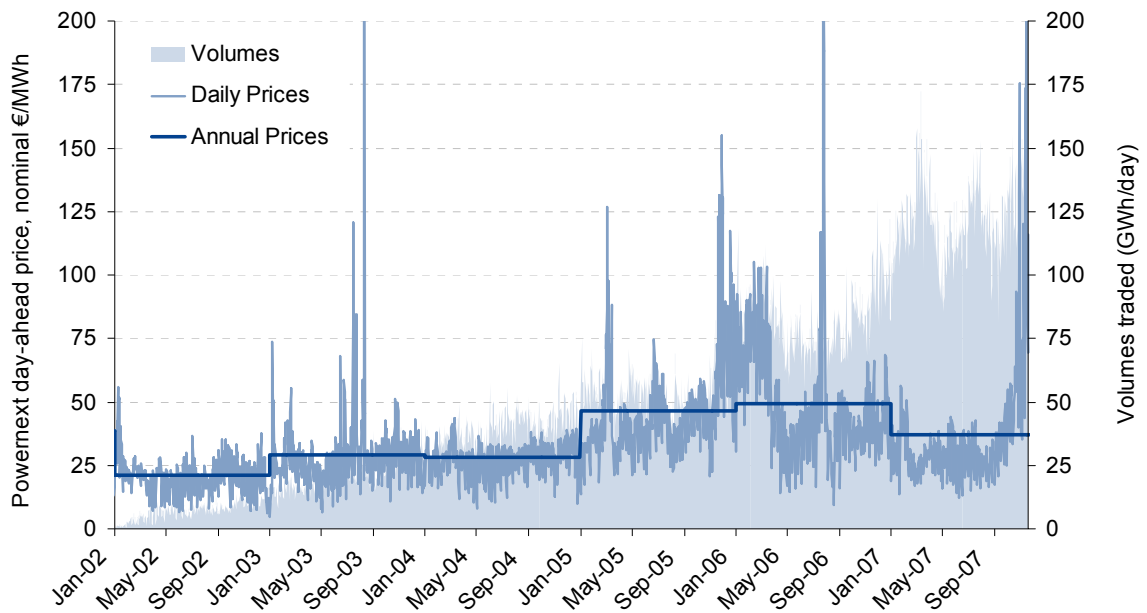
Powernext Futures comprises contracts for Base (24h/24) and Peak (8h-20h) on three different durations:

- monthly contracts, up to three months in advance;
- quarterly contracts, up to four quarters in advance; and
- calendar contracts for the next three years. Prices of calendar contracts are shown in Figure 15.

²⁶ 'Last gasp for protectionism?'. Platts Power In Europe, Issue 505, 16 July 2007.

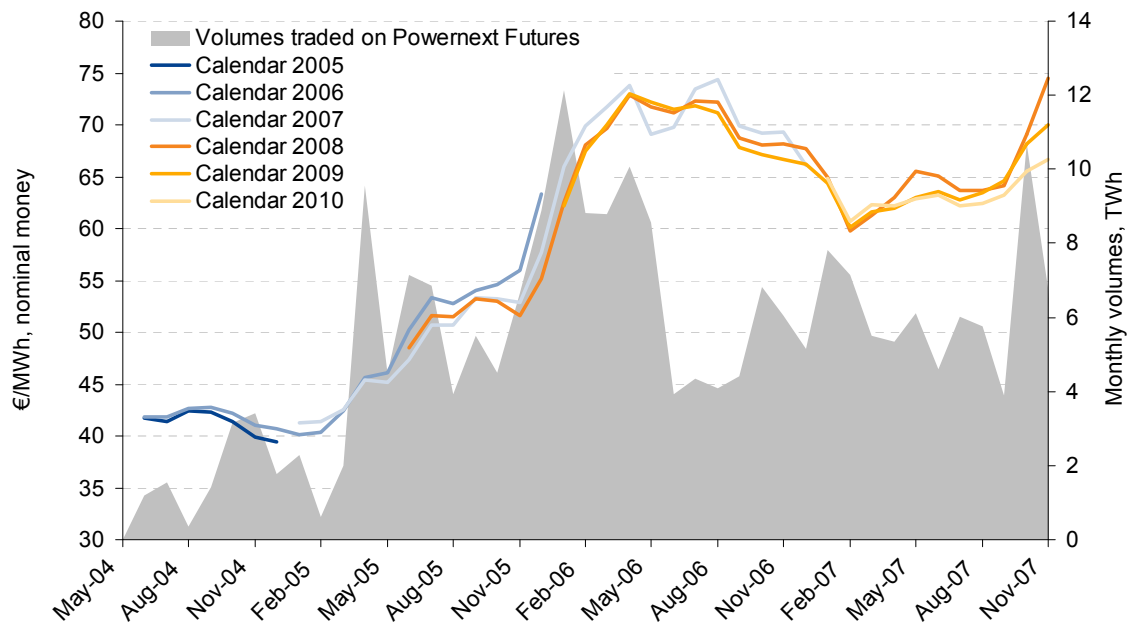
²⁷ EDF.

Figure 14 – Powernext Day-ahead prices and volumes



Source: Powernext

Figure 15 – Calendar contracts monthly prices, and monthly volumes traded on Powernext Futures²⁸



Source: Powernext

²⁸ Volumes include all contracts traded on Powernext Futures.

2.4.5 Market Coupling

2.4.5.1 Tri-lateral coupling

Trilateral Market Coupling was introduced between Belgium, the Netherlands and France on 21 November 2006, which coincided with the launch of Belpex. The consortium responsible for the trilateral coupling consisted of the three TSOs, Elia (Belgium), RTE (France), and TenneT (Netherlands) and the three power exchanges, Belpex (Belgium), Powernext (France) and APX (Netherlands).

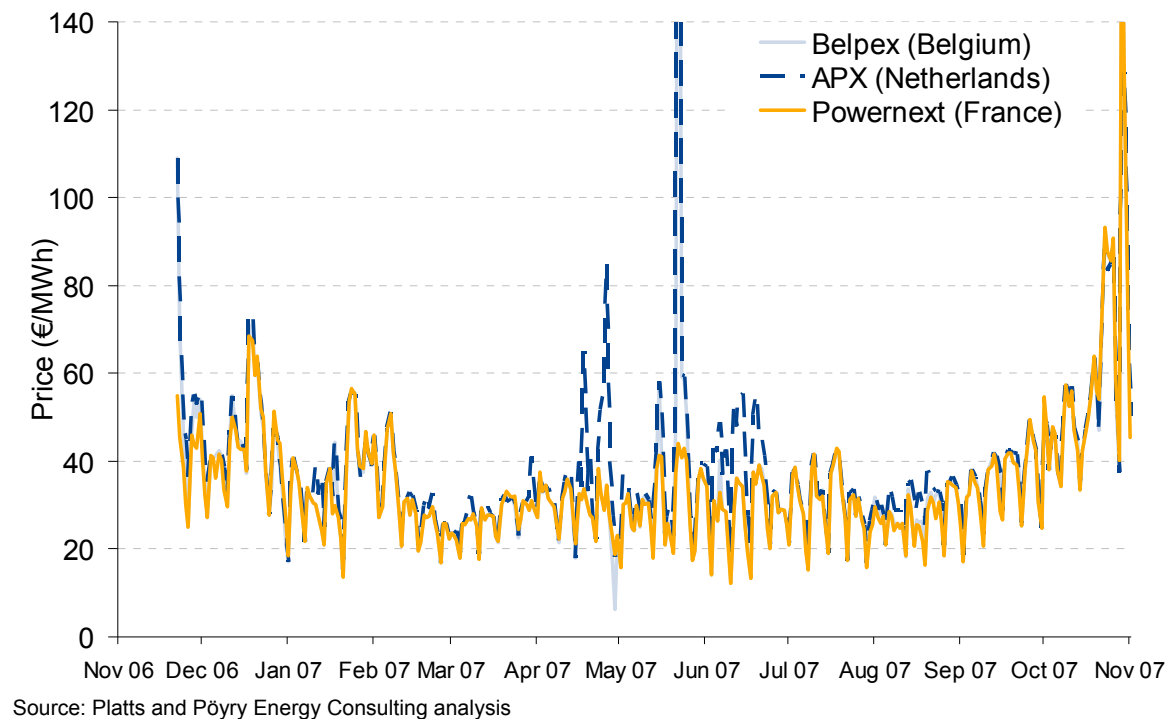
It was intended that market coupling would increase liquidity in day-ahead trading and make optimal use of the interconnection between the countries involved. Before this date, the Day-Ahead markets in each country operated independently, and interconnection capacity between the countries was allocated by means of explicit yearly, monthly and daily auctions. Under the new system, the three markets are treated as one: all bids are aggregated, all offers are aggregated, and the intersection of the resulting supply and demand curves sets the market price. When there is insufficient interconnection capacity to ensure price equality across the three markets, the markets decouple and more than one price emerges.

Market participants submit their purchase or sales orders each morning (at 11.00am Central European Time) for each hour of the following day. At market gate closure, all potential trades are then aggregated by hourly periods and ranked according to price. For each hour, the intersection of the aggregated supply and the aggregated demand curves determines the market results (i.e. the market clearing price and the market clearing volume). After this fixing is performed, the market results are made available to the participants. Contracts are then created which require participants in the three countries to deliver to, or to withdraw, from the network they are connected to the volume of electricity in accordance with their contracts. The market price is identical for all trades in each hour, but will vary depending on the time of the day.

Figure 16 shows the average daily spot prices for the three markets – Belgian, Dutch and French – from 22 November 2006, when coupling was introduced, to beginning of November 2007. During the first year of market coupling, there was a single price for 60% of the traded hours, and a common French-Belgian price 85% of the time²⁹.

²⁹ Press release, Belpex, 21 November 2007.

Figure 16 – Daily average Day-Ahead prices on the APX, Belpex, and Powernext exchanges (€/MWh, nominal prices)



2.4.5.2 Pentalateral Coupling

Following the success of the tri-lateral market coupling, it is anticipated that Germany and Luxembourg will be added to the existing market. A Memorandum of Understanding between governments, regulators, power exchanges, transmission system operators and the electricity associations of Belgium, Luxembourg, the Netherlands, Germany and France was signed in Luxembourg on 6 June 2007. It is expected that a common company will be set up before the end of 2007 to take charge of the process, with a 1 January 2009 target date for initiating the coupled market. The new company is planning to set up new offices in Luxembourg to harmonise the trading platforms and gate closures to ensure optimised use of grid capacity³⁰.

Concerns remain over the interconnector capacity between the five markets and it has been suggested by ERGEG³¹ that current capacities will not allow optimised cross-border trades.

As well as these plans for pentalateral coupling on mainland Europe, it is also expected that the completion of the NorNed interconnector (expected in November 2007) between

³⁰ 'German, French and Benelux TSOs to establish company for market coupling'. Heren EDEM, 11 September 2007.

³¹ The European Regulators' Group for Electricity and Gas (ERGEG), which the European Commission set up on 11 November 2003, is an Advisory Group of independent national regulatory authorities to assist the Commission in consolidating the Internal Market for electricity and gas.

Norway and the Netherlands will allow coupling with the Scandinavian markets. However, because of difficulties in aligning of gate closure times, coupling will not take effect immediately. Explicit auctions will be used as a temporary measure³², and it is hoped that the markets will be coupled from January 2009³³.

2.5 Economic regulation

2.5.1 Recent developments

In order to allow new entrants to supply the French supply market at a tariff that can compete with the EDF regulated level, an anti-trust case in June 2007 ruled that that all new entrants to the French electricity supply market are to be guaranteed electricity at a price that reflects EDF's average production costs. EDF will therefore auction a yearly volume of 10.5TWh, for a price of €36.8/MWh in 2008 and in the region €42/MWh until 2013³⁴. As new entrant CCGTs are likely to have higher production costs than this new 'guaranteed price' this decision will negatively impact independent power producers (IPPs) seeking to arrange contracts with suppliers in the French market.

As shown in Figure 17, electricity tariffs in France are among the lowest in Europe. The issue of regulated tariffs is likely to be one of the major subjects of contentious in the French electricity sector in the coming years, as it is seen by the European Commission both as an indirect state subsidy to French industries and a major hurdle to the development of a competitive French electricity market³⁵.

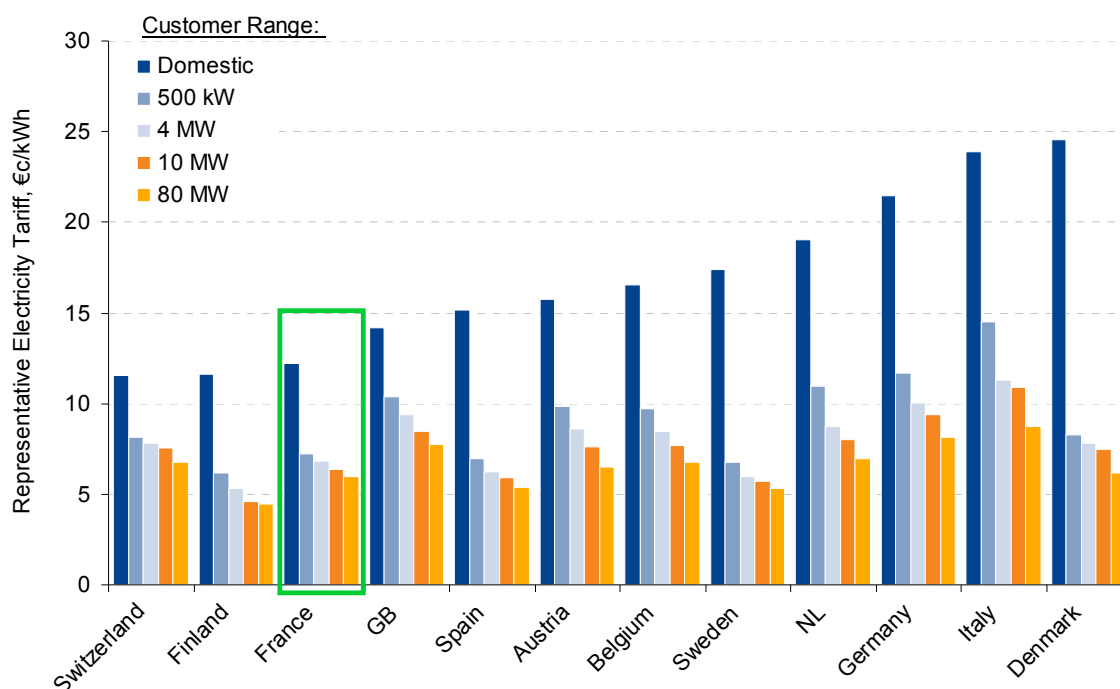
³² 'NorNed Interconnector' on the APX Group website (<http://www.apxgroup.com/index.php?id=184>). Viewed September 2007.

³³ 'Nord Pool CEO regrets coupling delay'. Platts European Power Daily, 24 August 2007.

³⁴ 'EDF contraint de baisser de 29 % ses prix de gros pour stimuler la concurrence'. Les Echos, 11 December 2007.

³⁵ 'ENCe wmsulls case against French fixed tariffs'. Platts European Power Daily, Issue 113, June 13 2007.

Figure 17 – Electricity prices in Europe for different customer types



Source: Energy Advice

2.5.2 Role of the CRE

The Commission de Régulation de l'Energie (CRE) is the French Energy regulator and was created in March 2000. Its main mission is to oversee third party access (TPA) to the RTE grid and distribution networks and to determine tariffs for TPA. Its other responsibilities include some powers in protecting captive customers, investment planning for transmission and distribution (T&D), licensing new entrants and ensuring that public service obligations are respected.

The Ministry of the Economy, Finance and Industry (MINEFI), in conjunction with the regulator, plays an important role in planning future developments in generation and transportation, as well as in setting tariffs.

2.6 Environmental regulation

2.6.1 European Union Emissions Trading Scheme (EU ETS)

Under the Kyoto Protocol of December 1997, France is committed to legally binding targets to limit the emission of a bundle of six greenhouse gases, including carbon dioxide. Collectively, the EU is committed to an 8% reduction in greenhouse gas emissions from 1990 levels by 2008-2012. Based on the burden-sharing agreement between EU Member States, France's national target is to stay at 1990's emission level.

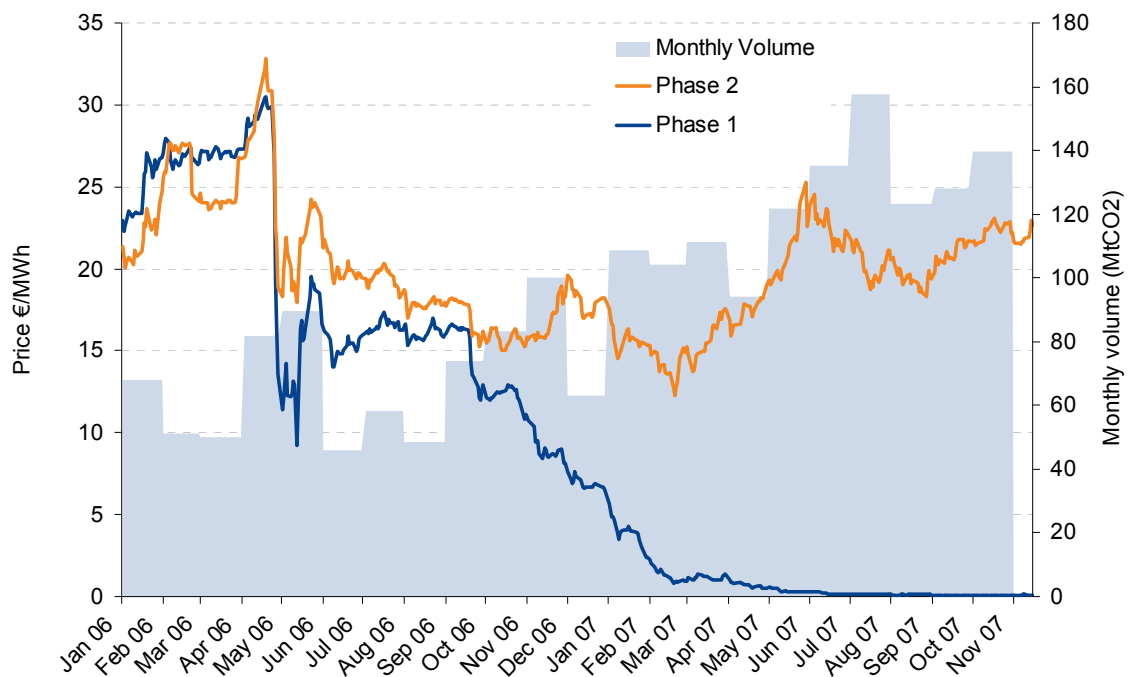
In 2003 the European Commission passed Directive 2003/87/EC, hereafter the Directive, which established the European Union Emissions Trading Scheme (EU ETS) with the objective of helping countries achieve their Kyoto obligations. The EU ETS is a cap and trade scheme, in which Member State define a National Allocation Plan (NAP) that:

- sets the total number of allowances to be issued, referred to as the cap, and
- details how these allowances will be allocated to the installations the Scheme covers.

Figure 18 shows how prices have traded since a month before the inception of the EU ETS on 1 January, for both Phases I (2005-2007) and II (2008-2012).

During the first six months of Phase I, the price of Phase I allowances rose steadily, levelling off at between €20 and €25 per tonne of carbon dioxide (tCO₂) from the middle to the end of 2005. Prices peaked at close to €30/tCO₂ in April 2006. However, information on compliance for the first year of the EU ETS began leaking out in late April 2006. This information suggested that a number of countries would be long in allowances, rather than short as had been expected. Consequently the price of carbon allowances began to fall, dropping to almost €10/tCO₂ per tonne during early May 2006. Prices subsequently recovered during the summer of 2006, only to start falling rapidly during October 2006 to the present levels of around €0.1/tCO₂, once it became clear that emissions under Phase I would not exceed the volume of allowances. Phase II allowances have been trading since 2005. Prices for Phase II have largely remained between €15/tCO₂ and €25/tCO₂ over the trading period, with an average value of €19/tCO₂ over the first eleven months of 2007. Figure 18 also shows how traded volumes have increased steadily over the lifetime of the EU ETS.

Figure 18 – Carbon price and daily traded volumes for the EU ETS 2005-07



Source: Pöyry analysis of data provided by PointCarbon

2.6.1.1 Phase I

The official French National Allocation Plan (NAP), following a number of revisions, was approved by the European Commission on 17 December 2004. For the first phase of the EU ETS, 2005 – 2007, total CO₂ allowances were set at 156.51MtCO₂ per annum, including a 5.69MtCO₂ per annum free reserve for new entrants. This allocation was

originally set at 126.29MtCO₂ (excluding new entrants and the enlarged field, fuel combustion at chemical and agricultural installations) but during the consultation process it was discovered that several installations included in the NAP should actually be omitted. The allocation for the energy sector was set at 66.62 MtCO₂ and industry was set an allocation of 59.67 MtCO₂. The free reserve for new entrants has not changed but the new allocation plan dedicates 123.24 MtCO₂ to the restricted field (58.26 MtCO₂ for industry and 64.98 MtCO₂ for energy) and 27.57 MtCO₂ to enlarged field³⁶.

During the first phase, France was allocated an excess of CO₂ allowances: verified emissions in 2005 were of 131MtCO₂ compared with an allocation of 157MtCO₂³⁷.

2.6.1.2 Phase II

The Phase II NAP for France set the total emissions cap at 138.3mtCO₂, including an allocation of 132.8 million annual allowances to CO₂ emitting installations (with 4 million annual allowances for new entrants), and 5.5 million allowances to plants that emit nitrous oxide, which France brings into the ETS in the second phase. The cap on the use of credits from the Kyoto Protocol's flexible mechanisms is 13.5%, and all allowances will be allocated for free³⁸.

Table 5 indicates the total cap calculation, according to the EC's method.

Table 5 – Carbon Cap calculation method

$$Cap = DE_{2005} \times GR_{05-10} \times CIGR \times (1 - 0.025) + CE + N_2O$$

DE ₂₀₀₅	Declared Emissions in 2005	131.25+0.015
GR ₀₅₋₁₀	Growth Rate (2005-2010)	1.022*1.023*1.021*1.0226*1.0226
CIGR	CO ₂ intensity growth rate in GDP	227.2/254.2
CE	Coverage expansion	5.1
N ₂ O	Opt-in N ₂ O	5.5
TOTAL CAP		138.3

Source: www.ecologie.gouv.fr

Table 6 summarises the allocation for each sector for Phase II, compared with Phase I. It shows how the electricity sector faces a significant reduction in the number of allowances allocated. The NAP states that this is because this sector is less exposed to international competition and is able to pass through costs without having an adverse impact on their competitive position. Plants for the “enlarged field” (meaning combustion higher than 20MW in various sectors) also see their emissions strongly abated.

³⁶ <http://www.ecologie.gouv.fr/IMG/pdf/PNAQ-2.pdf>

³⁷ European Commission, IP/07/415.

³⁸ ‘Échange de quotas d’émission: la Commission approuve le plan national d’allocation de la France pour la période 2008-2012’. European Commission, 26 March 2007.

Allocations by sectors are distributed according to the method advised by the EC on November 2006:

$$Allocation = Production_{2004-2005} \times (1 + AGR_{Production})^5 \times SE_{2004-2005} \times (1 - AIR_{SE})^5$$

With:

- $Production_{2004-2005}$: Average of the production for the sector, for years 2004 and 2005. Recent reference years were taken in order to take into account technical improvements of the sector.
- $AGR_{Production}$: Estimated annual growth rate for coming years, taking into account the five last years and technical elements specific to the sector.
- $SE_{2004-2005}$: Specific emissions of the process for one unit of production, determined on the average of emissions over 2004-2005 for the restricted field.
- AIR_{SE} : Average improvement rate, estimated for the coming years. The eight last years were taken into account, in addition to technical elements specific to the sector.

Table 6 – Comparison of NAP 1 and NAP 2

(MtCO ₂)	NAP 1 (2005-07)	NAP 2 (2008-12)	% NAP2 from NAP1 by sector	% of the total reduction
Urban heating	7.91	5.31	-33%	-9%
Combustion - energy	0.59	0.38	-36%	-1%
Combustion - industry	1.57	1.11	-29%	-2%
Electricity	35.92	27.24	-24%	-31%
Gas transport	0.88	0.84	-4%	0%
Refineries	19.36	15.04	-22%	-15%
Coking plants	0.32	0.25	-22%	0%
Steel	28.71	24.94	-13%	-13%
Cement	14.22	15.34	8%	4%
Lime	3.24	3.18	-2%	0%
Glass	3.98	3.73	-6%	-1%
Ceramics	0.04	0.02	-53%	0%
Tiles and Bricks	1.34	1.12	-16%	-1%
Paper and Pulp	5.16	4.33	-16%	-3%
Enlarged field	27.57	21.3	-23%	-22%
New Entrant Reserve	5.69	4	-30%	-6%
Sub-total	156.5	128.1	-18%	
Coverage expansion NAP2		4.674		
Opt-in N2O		5.5		
TOTAL	156.5	138.3		

Source: Pöyry Energy Consulting and the French Ministry of Ecology

2.6.2 White certificates

The White Certificate scheme, enforced since July 2006, is one of the key new instruments³⁹ aimed at supporting energy efficiency improvements within certain energy-intensive user sectors in France. These certificates are mandatory and tradable, with companies subject to penalties in case of non compliance. This new regulation particularly targets residential and commercial sectors, which have diffuse but significant energy consumption patterns. Energy saving potential is important, but traditional public instruments have proved to be not suitable, inefficient or lacking in public funds. The envisaged advantages of this scheme include:

- economic efficiency, using an instrument adapted to liberalised energy markets;
- the introduction of a direct relationship between obliged parts and the main addressees of the measures, i.e. the households;
- transparency, whereby the energy suppliers can propose measures not yet planned; and
- the provision of new means to finance energy efficiency projects, estimated between €500m and €1000m over three years.

The mandatory targets of the White Certificate scheme requires a saving of 54TWh in final energy consumption for the first three years, with energy efficiency improvements to be undertaken between 2006 to 2008. Within this period, there are no annual deadlines, with compliance only verified at the end of the three years (2008).

The overall target is shared between suppliers who provide electricity, natural gas, LGP, domestic fuel (not for transports) and cooling and heating, and any economic player that can undertake energy efficiency projects and receive White Certificates.

All end-user sectors are eligible. Substitution of fossil energies with renewable energies is eligible, but only in a few select cases, for example heat production and sanitary hot water production. Energy savings linked with the EU ETS scheme are not however eligible for White Certificates.

The type of the eligible projects can be as broad as possible to allow for compliance with target in the most concurrent way. To illustrate, the following projects are eligible:

- substitution with low energy light bulbs;
- loft insulation, use of double glazing;
- installation of heating control mechanisms;
- replacement of domestic appliances with more efficient equipment; and
- replacement of boilers or water heaters by more efficient equipment or thermal renewable energy equipments.

Before the end of the compliance period (2008), the market will reconcile possible lack and excess of titles through a gradual and continuous exchange. Price of transactions will depend on the market but an upper limit is given by the value of the penalty for non-compliance, which is €20/MWh⁴⁰.

³⁹ law n° 2005-781 13 July 2005, enforced since July 2006.

⁴⁰ IEA.

3. RENEWABLE ENERGY IN FRANCE

On the whole, France is seen as being relatively poor in developing renewable generation compared with other European countries, and was considered as “far from commitment” by the European Commission in their recent review⁴¹. For example, France had approximately 1.4GW of installed wind capacity at the end of 2006, which is substantially below their target of 10GW by 2010. Due to their extensive hydroelectric facilities, however, France produces between 11% and 16% of its energy from renewable sources, 12.1% in 2006.

Recently, the situation for wind energy has improved and France was the third largest country in Europe in terms of installed capacity in 2006.

In October 2007, a series of meetings between the State and a number of representatives (Industries, NGOs, consumer associations, etc.) defined a set of measures to promote ecology and sustainable development. On the energy side, the French President concluded the so-called ‘Grenelle de l’Environnement’ announcing that France “will go beyond the target of 20% of energy consumption from renewables by 2020”. The President also announced that research for renewable energy will receive at least as support that received by the nuclear industry.

3.1 Regulatory framework

3.1.1 Directives, Laws and Renewables Targets

The French Government has set an objective, in line with its EU targets⁴², of meeting 21% of national electricity demand by generation from renewables sources by 2010.

With a view to encouraging renewables in France, several measures have been put in place:

- a purchase obligation and associated ‘Feed-in Tariff’;
- tenders for new renewable generation;
- renewable electricity certificates; and
- tax relief for renewable generation.

In order to meet their target of 21% of renewable energy in the generation mix by 2010, France adopted a number of ministerial orders in 2001 and 2002 which set capacity targets for certain technology types. These targets were far from being reached, and have since been superseded by the Plan Climat 2004⁴³, a white paper addressing climate change policy in France which sets out targets for 2010 and a more recent decree signed on 7 July 2006⁴⁴ (PPI Decree).

⁴¹ ‘Report on progress on Renewable energy’. European commission, COM2006-849.

⁴² See Directive 2001/77/EC “On the promotion of Electricity Produced from Renewables Sources in the Internal Electric Market” (27/09/01).

⁴³ Plan Climat 2004. Le Ministre de l’Ecologie et du Développement Durable.

⁴⁴ ‘Arrêté du 7 Juillet 2006 relatif à la programmation pluriannuelle des investissements de production d’électricité’. Ministère de l’Economie, des Finances et de l’Industrie.

Table 7 provides a summary of the targets for the new renewable capacity needed to reach the 10% target by 2010. As a general comment, wind capacity was around 1GW in July 2006, and RTE's central forecast for 2010 is 5GW for installed capacity. This highlights the fact that these targets are far from achievable in the defined timeframe.

Table 7 – French targets for new renewable capacity to be built between July 2006 and 2015.

(MW)	PPI Decree (2007) 2010 target	PPI Decree (2007) 2015 target
Onshore wind	12.5	13.0
Offshore wind	1.0	4.0
Biogas	0.1	0.3
Biowaste	0.2	0.3
Biomass	1.0	2.0
Hydro. wave. tidal	0.5	2.0
PV	0.2	0.5
Geothermal	0.1	0.2
Total	15.6	22.3

Source: PPI decree, 7 July 2006

3.1.2 Purchase obligation and Feed-in tariffs

The primary measure implemented to stimulate renewables is an obligation for EDF and other operating distributors of electricity to purchase renewable generation. Legislation, and associated government orders, from 2000 to 2005⁴⁵ established the obligation, the details of the prices, known as 'Feed-in Tariffs', to be paid and the lengths of the contracts. In 2006, the levels of the feed-in tariffs were significantly increased⁴⁶.

Initially, only renewable plants whose installed capacity was less than or equal to 12MW qualified for the purchase obligation. However, as a result of the 2005 Energy Law⁴⁷, this criterion ceased to apply for wind farms from July 2007 onwards.

Under the purchase obligation, eligible renewable generators are paid a fixed price, for a fixed period, for every kWh of electricity fed into the grid. The 'Feed-in Tariffs', that is prices received, are based on investment costs and operational expenses avoided by buyers and, for certain technologies, a bonus for complying with objectives set by the 2000 Energy Law⁴⁸ in terms of air quality, global warming prevention and technical innovation.

⁴⁵ The obligation was first established by Loi 200-108 (10/02/00) "Loi Relative a la Modernisation et au Developpement du Service Public de L'Electricite" and subsequently modified, most significantly, by Loi 2005-781 (13/07/05) "Programme Fixant Les Orientations de La Politique Energetique", and by Decree 10 July 2006.

⁴⁶ Decree 10 July 2006.

⁴⁷ Law n° 2005-781, 13 July 2005.

⁴⁸ Law n° 2000-108, 10 February 2000.

A decree in July 2006 increased considerably the feed-in tariffs for electricity produced from several renewable sources, including wind and solar PV. A summary of feed-in tariffs is provided in Table 8.

Table 8 – Feed-in tariffs for renewables

Technology	Contract duration	Tariffs €/MWh	Comments
Biogas and landfill gas	15 years	75 - 90	€0-30/MWh Bonus for energy efficiency, €20/MWh Bonus for gasification
Onshore wind	15 years	82 (first 10 years)	€28-82/MWh for following 5 years, depending on load factor
Offshore wind	20 years	130 (first 10 years)	€30-130/MWh for following 10 years, depending on load factor
Solar - mainland	20 years	300	€250/MWh Bonus for integration in an existing building
Solar - overseas	20 years	400	€150/MWh Bonus for integration in an existing building
Geothermal - mainland	15 years	120	€0-30/MWh Bonus for energy efficiency
Geothermal - overseas	15 years	100	€0-30/MWh Bonus for energy efficiency
CHP	12 years	61-91.5	Depends on gas prices, capacity and lifetime
Hydro	20 years	54.9-61	€0-15.2/MWh for generation regularity

Source: DGEMP

Taking the example of an onshore wind farm, the contract under the purchase obligation covers a 15-year duration from commissioning. However, the installation must be on-line within three years from the date of application for the contract. If the site is online after that time, the duration of the contract is reduced by the same delay.

Under the original 2000 Energy Law⁴⁸, a site was able to benefit from a further purchase agreement provided it still met the requirements set in the decree at the end of the term. However, this law was modified by Law 2004-803 (9 August 2004), under which the extension of the purchase obligation beyond 15 years was removed and as such a private power producer may only benefit from EDF's purchase obligation once. Once the contract period is completed, a renewable generator must sell its power on the open market. Therefore, Pöyry assumes that in the absence of significant change in policy, once a PPA has expired a renewable generator will be paid at the prevailing market price.

Onshore and offshore wind, hydro and biomass are seen as key technologies to meet France's renewable electricity production targets, due to their relative maturity.

3.1.3 Call for tender

The second major support mechanism established for renewable energy by the 2000 Energy Law⁴⁸ is the tender process for renewable installations greater than 12MW. The selection criteria for these tenders are the project's economic and technological merits, reliability, respect for the environment, and acceptance by local authorities and

populations. Electricity is bought at a fixed contractual price under a long-term Power Purchase Agreement (PPA) with EDF.

The details of the tenders undertaken to date by the authorities are summarised in Table 9.

Table 9 – Renewables tender

Renewable source	Tendered Capacity (MW)	Publication OJEU ⁴⁹	Capacity approved (MW)	Date Announced
Onshore wind	500	23/04/2004	278	12/12/2005
Offshore wind	500	11/02/2004	100	14/10/2005
Biomass/biogas	200	10/01/2004	216	12/01/2005
Biomass/biogas	300	09/12/2006	⁵⁰	-

Source: Syndicat des énergies renouvelables⁵¹

The results of the onshore wind farm tender were announced on 12 December 2005. In total, only 278MW was approved, though this is thought to be a considerable improvement over the offshore wind tender, which only garnered 100 of the 500MW that was tendered. This low approval rate is thought to be the result of several factors, including the complex tendering procedure, which is insufficiently adapted for the emergence of new technologies.

In addition to the feed-in tariff for biomass and biogas, the French government launched a call for tender in 2004 which targeted the construction of 200 to 400MW of electricity capacity. Over 14 awarded projects (216MW), only 120MW came up to final stage of development. The CRE issued a second call for tender for 300MWe, and around 700MW of capacity has been submitted⁵².

3.1.4 Other schemes

3.1.4.1 Green certificates

Under the 2001 EU Renewable Energy Directive⁵³, Member States were required to put in place certification systems for renewable energy – i.e. administrative systems guaranteeing the ‘origin’ of electricity produced from renewable energy sources – by October 2003.

⁴⁹ Official Journal of the European Union.

⁵⁰ At the time of writing this report, the approval decision was not taken.

⁵¹ ‘Bio-project licences awarded’ Power in Europe, 17 January 2005; Syndicat des énergies renouvelables. Communiqué 13 January 2005; Syndicat des énergies renouvelables. Communiqué 14 September 2005, and; Syndicat des énergies renouvelables. Communiqué 14 November 2005.

⁵² DGEMP.

⁵³ Directive 2001/77/EC.

To meet this requirement, France has put in place a voluntary system of tradable ‘Green Certificates’ as a further means of promoting and supporting renewable energy. These certificates act as ‘certificates of origin’ and, in addition, are tradable.

Green Certificates are issued and administered by “Observ’er”⁵⁴, a member of the Association of Issuing Bodies (AIB)⁵⁵ – the pan-European organisation promoting the standardisation of energy certificate systems. Certificates come in a single denomination with each Certificate corresponding to 1 MWh of energy produced from a renewable source.

Observ’er monitors and reports on the level of activity within the market for Green Certificates. Table 10 shows the traded volume of Green Certificates as reported by Observ’er in September 2007. At that date, 1.17GW of generation was registered by Observ’er, 86% of which was hydro capacity.

Table 10 – Cumulative Trade in Green Certificates

Green Certificates	Number of certificates
Issued	3,451,879
Transferred	599,248
Exported	10,993
Imported	8,343,401
Withdrawn	2,266,584

Source: Observ’er (September 2007)

The value of a Green Certificate is based on the difference between the marginal cost of the electricity produced by the generator holding the Certificate and the wholesale price of electricity. Renewable generators are free to trade their output and their Green Certificates independently of one another. Significantly, however, any renewable generator benefiting from a feed-in tariff under the Purchase Obligation cedes its right to trade Green Certificates.

In France, Green Certificates are used by electricity suppliers who publicise Green Certificates contracts that guarantee a certain amount of electricity from renewable sources. The price of such certificates is usually between 0 and 3 €/MWh, most of the time being around 0.5 €/MWh.

However, there is an important distinction between France’s voluntary system and obligatory certificate trading systems such as the UK’s Renewables Obligation. The French system is not underpinned by a legal requirement on suppliers to source a specified proportion of their energy from accredited renewable generators.

⁵⁴ See www.observ-er.org

⁵⁵ See www.aib-net.org

3.1.4.2 Guarantee of origin

This mechanism was put in place by the 13 July 2005 Law⁴⁷, and elaborated by a decree in 2006⁵⁶. These Guarantee of Origin certificates are issued by RTE, the French TSO, and are applicable to electricity produced from renewable sources or Combined Heat and Power plant (CHP). This Guarantee of Origin scheme is only applicable to producers who don't benefit from the feed-in tariffs described in section 3.1.2.

The price of each certificate comprises a fixed fee for each request of €800 for renewables or €1000 for CHP, and a variable fee of €0.005/MWh.

3.1.4.3 Tax relief

Further support measures apply to generators from renewables and CHP, as introduced by the finance laws between 2000 and 2006. These measures mainly consist of tax relief and exceptional amortization in order to support the generation and consumption of energy from renewables. An example is the acquisition of large renewable electricity generation equipment in French homes that, since January 2005, has been subject to a 40% tax relief on the price of the equipment (up to a maximum of €8000). As of January 2006, the level of tax relief was increased to 50%⁵⁷.

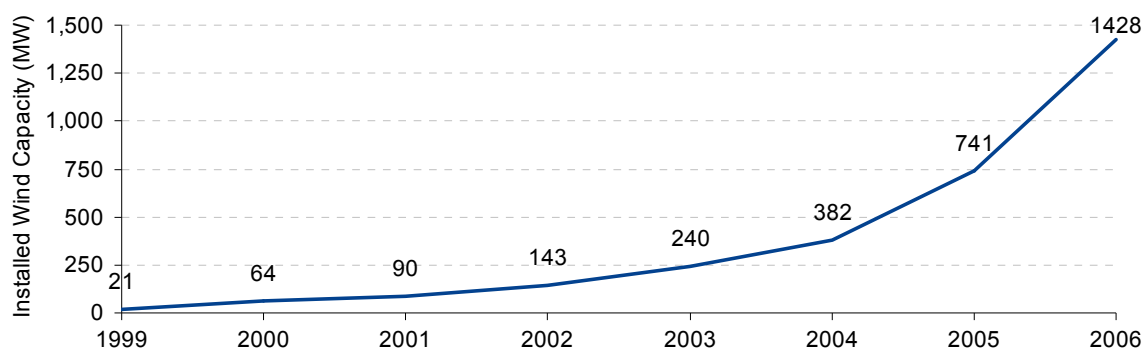
3.2 Renewable technologies

3.2.1 Wind energy

Wind energy is a major renewable generation technology after hydro in France. A graph of installed capacity is provided in Figure 19 and a map of installed capacity by region at the end of 2006 in Figure 20.

France was the third largest country in terms of new wind capacity installed in 2006 (810MW) representing around 11% of new build in Europe in 2006, behind Germany (2,233MW) and Spain (1,587MW).

Figure 19 – Installed wind capacity

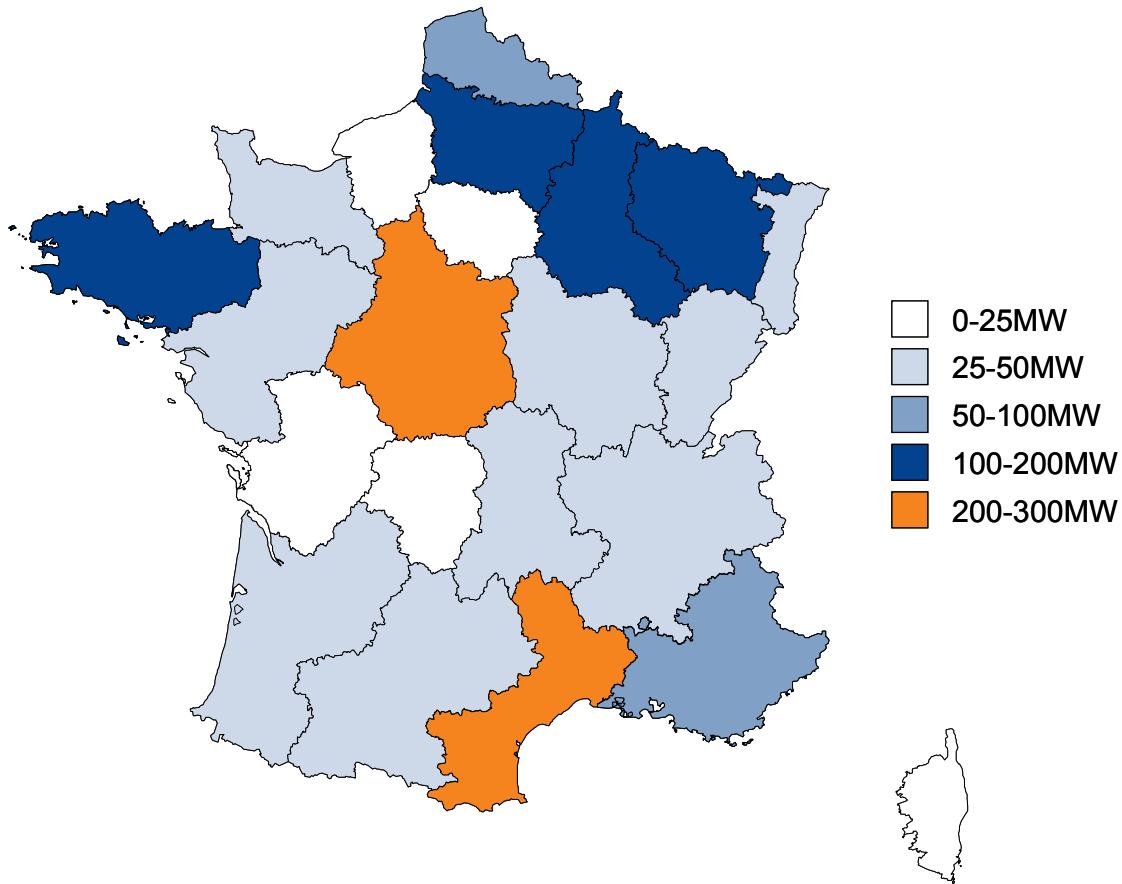


Source: DGEMP

⁵⁶ Decree 2006-1118, 5 September 2006.

⁵⁷ Syndicat des Energies Renouvelables. *Communiqué* 1 Septembre 2005.

Figure 20 – Map of installed wind capacity at the end of 2006



Source: DGEMP

3.2.2 Wind Development Zones (ZDE)

From July 2007 onwards, to qualify for the purchase obligation, wind farms will have to be located in 'Zones de Développement de L'Eolien' (ZDEs), 'wind development zones'.

ZDEs, which will be established at the level of the 'Départements', are to be proposed by 'communes' (the lowest tier of local government in France) and determined by the 'Préfet' (the executive body of the 'Départements'). ZDEs are associated with a surface a location, and a lower and upper bound of allowed capacity.

Once submitted, the Préfet must make a decision on any ZDE proposal within six months of its receipt. During this period, Préfets must consult local environmental authorities and all affected communes.

The Préfet is required to consider ZDEs proposals on the basis of their wind power potential, their connection potential and on the protection of landscapes and historic buildings. In making their decision, the Préfet may reject, approve or approve modified versions of proposed ZDEs. The 2005 Energy Law⁴⁷ leaves open the possibility of modifying ZDEs once established, subject to the same decision-making process as for the establishment of a new ZDE. This may mean that eligibility ceilings (or floors) may be

employed at the regional level⁵⁸. However, whilst Regions are also empowered to identify and zone areas deemed favourable for wind power development in their planning processes⁵⁹, ZDEs explicitly take precedence over any such zones.

The establishment of ZDEs ought to speed up the planning process for wind farm developments located in them. Whilst applications for Construction Permits will continue to be considered on a case-by-case basis, the commonality of some of the criteria for establishing ZDEs and obtaining planning permission for a wind farm should, all other things being equal, ease the process.

According to the first feedback given by the French government, four months before the application of the decree, 18 ZDE were already accepted accounting for a maximum capacity of 602MW. At the end of February 2007, 63 ZDE accounting for 4.1GW were being examined, the maximum capacity for a ZDE was 315MW. 86 additional ZDE were at an earlier stage of proposal. On average, nine weeks are necessary to judge if a ZDE project is receivable, and 22 weeks to examine the case⁶⁰.

3.2.3 Planning and Connection

3.2.3.1 Planning permission

Planning permission is required for wind farms greater than 12m in height. The process has two or three stages, depending on the characteristics of the proposed development. The 2005 Energy Law, as well as introducing the concept of ZDEs, made significant changes to the planning process for wind farms. These changes, like ZDEs, came into effect in July 2007 as shown in Table 11.

Table 11 – Planning requirements

	H < 12m	12m ≤ H ≤ 50m	H > 50m
Connection Agreement	Yes	Yes	Yes
Impact Assessment	No	Yes	Yes
Construction Permit	No	Yes	Yes
Public Inquiry	No	No	Yes

Source: Pöyry Energy Consulting Analysis

The average time it takes to get to obtain a permit for a wind farm in France is stable at 13 months (fastest is four months, slowest 23). One-third of the applications (by capacity) were refused in the year to January 31, 2007. However, the chances of a permit being overturned by court action have dropped from 25% to 14%⁶¹.

3.2.3.2 Connection

Because of the 12MW ceiling for benefiting from the feed-in tariff, which was in place until July 2007, all wind farms have so far been connected to the distribution network (<63kV), mainly owned and managed by EDF Réseau Distribution (ERD). After July 2007, some

⁵⁸ 'French wind at the crossroads', Power in Europe, 18 July 2005.

⁵⁹ Code de l'environnement (Article L553-4).

⁶⁰ Enquête éolien 2007, DGEMP, November 2007.

⁶¹ 'Suez buys into French wind boom'. Platts Power in Europe, 3 December 2007.

wind farms larger than 12MW will be connected to the Transmission Network managed by RTE (see section 2.2.2).

Prices for connecting to the transmission network are calculated using a shallow cost principle, whereby they do not have to pay for any deep reinforcements to the transmission network. For connection to the distribution network, by contrast, generators are charged for any reinforcement of the distribution network.

The time for connecting a wind farm to the distribution grid is quite short when there is spare capacity on the network, but may take up to five years when it is necessary to reinforce the higher voltage network. Poor coordination between the Transmission System Operator RTE and the Distribution System Operator ERD is mentioned as a source of delay.

One major source of dissatisfaction among decentralised generators is that ERD's initial estimates for connection costs (which are non-binding, in the Feasibility Study) are often subject to huge increases later on when the generator receives its PTF (Technical and Financial Proposal). The connection works themselves are subject to auction, and the generator may propose any company to participate in the bid process, provided this company is recognized by ERD. The PTF is binding for all parties, so the DSO does not bear the risk of a possible abandonment of the project, and the producer receives financial compensation in case of delays to the connection works.

On the whole, despite a significant effort from ERD to make the administrative procedures easier and shorter, the bottleneck for renewable projects seems to be the physical connection to the distribution network. The cost of grid access is sometimes excessive, and the administrative burden especially discourages small projects.

3.2.3.3 *Public attitude*

The French public position towards wind energy development is quite ambiguous. On the one hand, surveys show that the vast majority of the French population is favourable to wind energy, whereas, in practice, many associations fight against wind farm projects (25% of the building permits delivered by the public authorities were subject to appeals in the administrative court). The pressure group "Vent de Colère" has mounted several high profile campaigns against proposed developments. In addition, few people agree about the best way to reduce the visual impact of wind turbines. It seems that until recently, small but scattered sites were favoured, whereas now larger sites are gaining preference.

3.2.4 *Feed-in tariff*

This section is elaborated through a worked example, in Annex A.

Initially, only renewable plants whose installed capacity was less than or equal to 12MW qualified for the purchase obligation. The 2005 Energy Law⁶² removed this cap, with effect from July 2007 and the only conditions to benefit from the feed-in tariff for a wind farm is now to be located in a ZDE. This changes the Government's approach to wind farm development, as the 12MW maximum threshold was intended to foster small installations, whereby the removal of this cap is likely to encourage larger wind farm developments.

⁶² Law n° 2005-781, 13 July 2005.

However this change is only applicable to mainland France. The 12MW cap is to remain in force for Corsica, overseas départements and the islands of Mayotte and Saint-Pierre et Miquelon.

The 2006 decree dealing with wind energy provides that, for new installations, each MWh is bought at a price of €82/MWh during the first ten years of the 15-year purchase contract (onshore), and at €130/MWh during the first ten years of the 20-year purchase contract (offshore). For the end of the contract, a new off-take price is set, taking into account effective generation level (i.e. load factor) measured over the first 10 years. The tariff range is between €28/MWh and €82/MWh onshore, and between €30/MWh and €130/MWh offshore, as shown in Table 12 and Table 13. This tariff range, by taking into consideration the wind quality, is designed to ensure that each wind-farm can earn approximately the same amount of money.

These tariffs apply for mainland France. For Overseas Departments (DOM, Saint-Pierre-et-Miquelon and Mayotte), the feed-in tariff is €110/MWh.

Table 12 – Tariffs for onshore wind energy (T) – nominal €/MWh (excluding VAT)

Reference load factor	First 10 years	Next 5 years
Less than 2400 hours	82	82
2400 – 2800 hours	82	Linear interpolation
2800 hours	82	68
2800 - 3600 hours	82	Linear interpolation
More than 3600 hours	82	28

Source: Journal Officiel, 26 July 2006

Table 13 – Tariffs for offshore wind energy (T) – nominal €/MWh (excluding VAT)

Reference load factor	First 10 years	Next 10 years
Less than 2800 hours	130	130
2800 – 3200 hours	130	Linear interpolation
3200 hours	130	90
3200 - 3900 hours	130	Linear interpolation
More than 3900 hours	130	30

Source: Journal Officiel, 26 July 2006

The tariffs presented in Table 12 and Table 13 have additional escalation factors, which will result in the tariffs being revised at the following times:

- at the time of application for the PPA; and
- for each year of the contract.

At the time of application the reference tariffs (T), as shown in Table 12 and Table 13, are adjusted by a **K** coefficient:

- if applied to after 31 December 2007, the reference tariff is adjusted downwards by a 2% discount rate running from 2008: $0.98^{(a-2007)}$; and

- upwards by wage index (WI^{63}) and production price index (PI^{63}) movement since July 2006:

$$- \left(0.5 \times \frac{WIa}{WI'06} + 0.5 \times \frac{PIa}{PI'06} \right)$$

- where 'a' is the year of application.

Therefore, the reference tariffs, both the initial and post-10 year tariff, at the **year of application** for the PPA, can be calculated as:

$$- PPATariff = T \times K$$

$$- \text{where } K = 0.98^{(a-2007)} \times \left(0.5 \times \frac{WIa}{WI'06} + 0.5 \times \frac{PIa}{PI'06} \right)$$

PPA Tariff, depending on the year of application, is shown in Table 14⁶⁴.

Table 14 – Base Tariff calculation, depending on the application year, in €/MWh

Application year	Base tariff in Nominal money	Base Tariff in real 2006 money
2006	82.0	82.0
2007	83.4	81.8
2008	84.4	81.1

Source: Pöyry Energy Consulting Analysis

Tariffs are also indexed annually on 1st November by the application of a coefficient **L** so that:

$$- Tariff = PPATariff \times L$$

$$- \text{where: } L = 0.4 + 0.4 \frac{WIC}{WIS} + 0.2 \frac{PIC}{PIS}$$

- where c is the current year and s is the year the PPA was signed.

A PPA contract for onshore wind lasts for fifteen years whilst that for an offshore wind farm lasts for twenty years. However, the installation must be on-line within 3 years from the date of application for the contract. If the site is online after that time, the duration of the contract is reduced by the duration of the delay (beginning by the first 10-year phase).

⁶³ WI and PI are translations of respectively ICHTTS1 ("identifiant" n° 0630215) and PPEI ("identifiant" n° 0850418) that are published on the INSEE website (www.indices.insee.fr).

⁶⁴ The Base Tariff in real 2006 money is calculated with an inflation adjustment between 2006 and the year of application for the PPA.

Table 15 – Summary of tariff calculations for onshore and offshore wind farms

PPA tariff computation		Yearly actualisation	
2006 (decree)	Year of application	Year of PPA signature	Current year
<i>WI'06</i>	<i>WIa</i>	<i>WIs</i>	<i>Wlc</i>
<i>PI'06</i>	<i>PIa</i>	<i>PIs</i>	<i>PIc</i>
$PPATariff = T \times K$		$Tariff = PPATariff \times L$	
$K = 0.98^{(a-2007)} \times \left(0.5 \times \frac{WIa}{WI'06} + 0.5 \times \frac{PIa}{PI'06} \right)$		$L = 0.4 + 0.4 \frac{Wlc}{WIs} + 0.2 \frac{PIc}{PIs}$	

a= year of application, T=Tariffs as presented in Table 12 and Table 13

Source: Journal Officiel 26 July 2006 and Pöyry Energy Consulting

A private power producer can only benefit from EDF's purchase obligation once. A generator can opt-out from the feed-in tariff but will not be allowed to return once opted out. Once the 15 year (or 20 year) period is completed, the onshore (or offshore) generator must sell their power into the market.

A wind farm which has already produced electricity in a commercial contract and has never benefited from EDF's purchase obligation may also benefit from a contract as defined above, adjusted downward by an S coefficient:

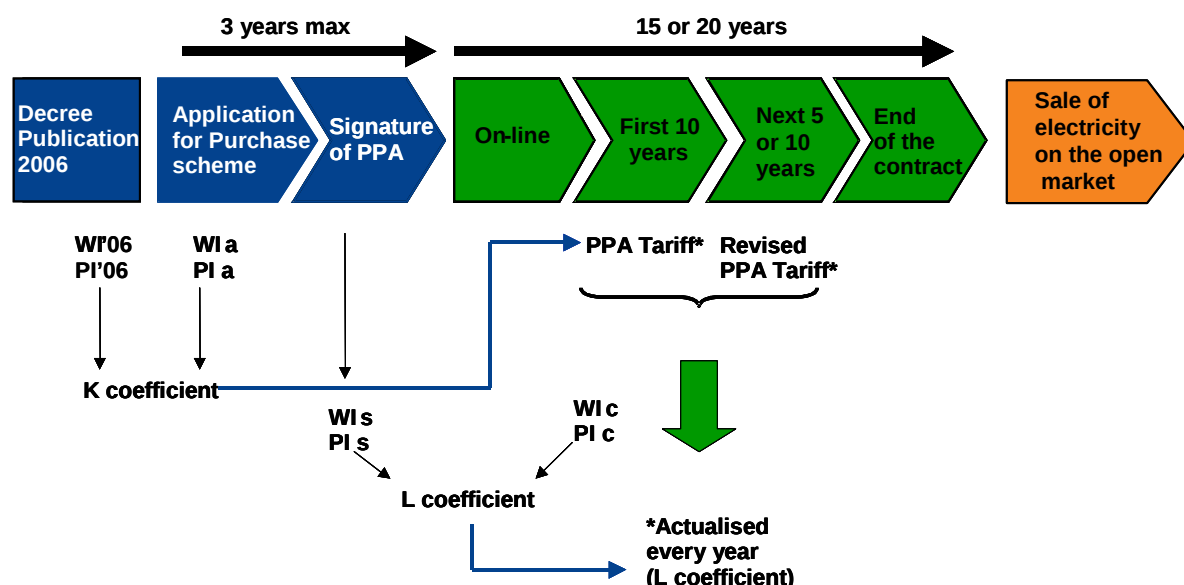
$$S = (15 / N) / 15 \text{ if } N < 15 \text{ years}$$

$$S = 1 / 15 \text{ if } N \geq 15 \text{ years}$$

where N is the number of years between commercial commissioning and PPA agreement.

An overview of the process is provided in Figure 21.

Figure 21 – PPA Process



Source: Pöyry Energy Consulting

3.2.5 Hydro and other technologies

3.2.5.1 Hydro

France has a significant proportion of its electricity coming from hydroelectric dams (25GW, for an average annual production of 70TWh). No new major facilities have been built in the past 20 years and the average age of hydro facilities is around fifty years. A recent report revealed by the press said that EDF's hydro dams were in relatively bad conditions. EDF will invest €500m in the next five years to maintain its current hydro facility production⁶⁵.

Further developments are considered in order to reach its target of renewable electricity production. Table 16 shows the potential development of hydroelectricity⁶⁶.

Table 16 – Potential for development of hydro by 2015

	New projects			Optimisation of existing installations	Total
	<100kW	<4.5MW	20-50MW		
Power (MW)	600	500	475	300	1875
Energy (TWh/year)	1	1.7	1.9	2	6.6

Source: MINEFI

⁶⁵ 'Barrages vétustes : EDF promet d'investir 500 millions d'euros'. Les Echos, 23 February 2007.

⁶⁶ 'Rapport sur les perspectives de développement de la production hydroélectrique en France'. MINEFI, March 2006.

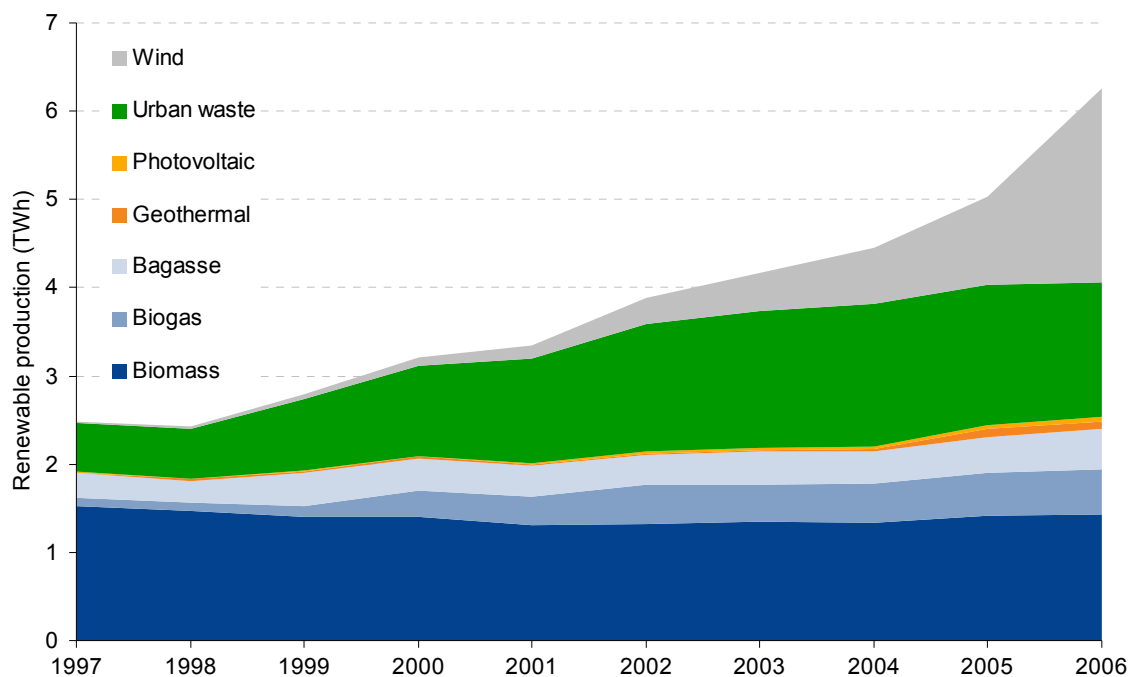
It is also estimated that an additional 0.4TWh could be produced with the exploitation of minimum flows downstream from the hydroelectric dams themselves, and that there is an additional potential development of pumped-storage hydroelectricity of 2GW.

Some of the long-term arrangements for the operation of hydroelectric facilities will expire in the coming years and these will be renewed through fair and transparent competition. According to EDF, the average remaining duration of these arrangements is 22 years, and 20% of the hydro capacity will have its permit renewed by 2020.

3.2.5.2 Other renewable technologies

Figure 22 shows that the only significant growth in renewable electricity generation from 1997 has been in Urban Waste and Wind technologies. France is likely to have more biomass electricity production in the coming years, due to the outcome of call for tenders described in section 3.1.3.

Figure 22 – French renewables' output, excluding hydro (TWh)



Source: Platts with French Industry Ministry data

4. PROJECTING WHOLESALE ELECTRICITY PRICES – INPUT ASSUMPTIONS

Wholesale price projections are produced using Pöyry's *EurECa* model, which projects electricity prices, output and cross-border flows for twenty five European countries, taking account of flows from a further six neighbouring countries. An explanation of the design and operation of *EurECa* is provided in Annex A. This chapter provides a summary description of core assumptions used for input to derive our electricity price projections. These assumptions may be classified under the following headings:

- economic assumptions;
- fuel prices (coal, gas and oil) and carbon prices;
- electricity demand; and
- new power station construction.

Table 17 provides a summary of the main assumptions used for each of the scenarios. We assume low renewables build in the High wholesale price scenario (and high renewables build in the Low wholesale price scenario). The following sections provide further detail on each of the modelled inputs.

Table 17 – Main assumptions in Pöyry's electricity price scenarios

Electricity price scenario	Fuel prices	Demand growth	New conventionnal build	New renewable build
High	High	High	High	Low
Central oil-indexed	Central with oil-indexed gas prices	Central	Central	Central
Central oil-delinked	Central with oil-delinked gas prices	Central	Central	Central
Low	Low	Low	Low	High

Source: Pöyry Energy Consulting

4.1 Economic assumptions

We are using the real 2006 exchange rates and inflation rates as shown in Table 18, as supplied by Royal Bank of Scotland. We hold both the inflation rates in all three areas and the nominal exchange rates constant from 2008 onwards. This drives the movements in real exchange rates seen in Table 18.

Table 18 – Real exchange rates in 2006 money and Inflation rates

	Real Exchange rates in 2006 money			Inflation rates		
	US\$ per €	US\$ per GB£	GB£ per €	US	UK	Euro-zone
2007	1.28	1.88	0.68	2.3%	2.5%	2.0%
2008	1.34	1.88	0.71	2.6%	2.3%	2.0%
2009	1.33	1.87	0.71	2.6%	2.3%	2.0%
2010	1.32	1.87	0.71	2.6%	2.3%	2.0%
2011	1.32	1.86	0.71	2.6%	2.3%	2.0%
2012	1.31	1.86	0.71	2.6%	2.3%	2.0%
2013	1.30	1.85	0.70	2.6%	2.3%	2.0%
2014	1.29	1.85	0.70	2.6%	2.3%	2.0%
2015	1.28	1.84	0.70	2.6%	2.3%	2.0%
2016	1.28	1.84	0.70	2.6%	2.3%	2.0%
2017	1.27	1.83	0.70	2.6%	2.3%	2.0%
2018	1.26	1.82	0.69	2.6%	2.3%	2.0%
2019	1.26	1.82	0.69	2.6%	2.3%	2.0%
2020	1.25	1.81	0.69	2.6%	2.3%	2.0%
2021	1.24	1.81	0.69	2.6%	2.3%	2.0%
2022	1.23	1.80	0.69	2.6%	2.3%	2.0%
2023	1.23	1.80	0.68	2.6%	2.3%	2.0%
2024	1.22	1.79	0.68	2.6%	2.3%	2.0%
2025	1.21	1.79	0.68	2.6%	2.3%	2.0%
2026	1.20	1.78	0.68	2.6%	2.3%	2.0%
2027	1.20	1.78	0.68	2.6%	2.3%	2.0%
2028	1.19	1.77	0.67	2.6%	2.3%	2.0%
2029	1.18	1.77	0.67	2.6%	2.3%	2.0%
2030	1.18	1.76	0.67	2.6%	2.3%	2.0%

Source: Royal Bank of Scotland (RBS)

4.2 Fuel prices

Table 20 to Table 23 provide details of the fuel prices used in the model with regard to French price projections. All figures are for fuel delivered at the power station in €/GJ (of gross, or high calorific value) on a variable cost basis. Prices for fuel delivered at the power plant include transport costs and taxes.

The Central scenario contains two gas price projections, one with oil-gas indexation and one where oil and gas de-link gradually between now and 2015. This reflects our two central views on the European gas market depending on the rate of liberalisation, and hence the de-linking of gas prices from their historic indexation to oil.

All fuel prices are reported on a gross calorific value basis. We assume the following calorific values in our modelling as detailed in Table 19.

Table 19 – Calorific value of fuels (gross)

Fuel	Calorific Value
Coal	26.38GJ/tonne
Heavy Fuel Oil (HSFO) and Light Fuel Oil (LSFO)	43.20GJ/tonne
Gasoil	45.60GJ/tonne
Gas	0.0381GJ/cubic metre

Source: Pöyry Energy Consulting

Table 20 – High delivered fuel prices (gross €/GJ, real 2006 money)

€/GJ	Inland Coal	Coastal Coal	LSFO	Gas	Gasoil
2007	2.63	2.54	6.28	4.54	11.30
2008	2.87	2.78	6.91	6.48	12.37
2009	2.82	2.72	6.84	7.26	12.27
2010	2.76	2.66	6.80	7.01	12.20
2011	2.70	2.61	6.82	6.93	12.24
2012	2.64	2.55	6.86	6.78	12.31
2013	2.65	2.56	6.90	6.79	12.38
2014	2.66	2.57	6.94	7.07	12.45
2015	2.68	2.59	6.98	7.37	12.52
2016	2.69	2.60	7.02	7.63	12.59
2017	2.71	2.61	7.06	7.78	12.67
2018	2.72	2.63	7.27	7.78	13.03
2019	2.73	2.64	7.47	8.05	13.36
2020	2.75	2.66	7.66	8.28	13.69
2021	2.77	2.67	7.80	8.44	13.92
2022	2.78	2.69	7.90	8.58	14.10
2023	2.80	2.70	8.05	8.71	14.35
2024	2.81	2.72	8.19	8.84	14.60
2025	2.83	2.73	8.34	8.99	14.84
2026	2.84	2.75	8.48	9.15	15.09
2027	2.86	2.76	8.63	9.32	15.35
2028	2.87	2.78	8.78	9.47	15.60
2029	2.89	2.79	8.93	9.60	15.86
2030	2.90	2.81	9.08	9.63	16.12

HSFO – High sulphur fuel oil

LSFO – Low sulphur fuel oil

Source: Pöyry Energy Consulting

Table 21 – Central oil-indexed delivered fuel prices (gross €/GJ, real 2006 money)

€/GJ	Inland Coal	Coastal Coal	LSFO	Gas	Gasoil
2007	2.59	2.50	5.82	4.53	10.52
2008	2.73	2.64	6.04	6.25	10.91
2009	2.60	2.51	5.99	6.52	10.83
2010	2.47	2.38	5.95	6.29	10.77
2011	2.33	2.24	5.81	5.99	10.53
2012	2.20	2.11	5.58	5.74	10.16
2013	2.06	1.97	5.36	5.56	9.79
2014	1.92	1.83	5.12	5.42	9.40
2015	1.93	1.84	4.89	5.30	9.01
2016	1.94	1.85	4.65	5.32	8.61
2017	1.94	1.85	4.41	5.20	8.22
2018	1.95	1.86	4.51	5.00	8.39
2019	1.96	1.87	4.59	5.05	8.52
2020	1.97	1.88	4.63	5.16	8.59
2021	1.98	1.89	4.71	5.22	8.74
2022	1.99	1.90	4.79	5.31	8.88
2023	2.00	1.91	4.95	5.43	9.15
2024	2.01	1.92	5.04	5.57	9.30
2025	2.02	1.93	5.13	5.68	9.46
2026	2.03	1.94	5.22	5.84	9.62
2027	2.04	1.95	5.30	6.03	9.75
2028	2.05	1.96	5.37	6.23	9.88
2029	2.06	1.97	5.44	6.31	10.01
2030	2.07	1.98	5.52	6.33	10.14

HSFO – High sulphur fuel oil

LSFO – Low sulphur fuel oil

Source: Pöyry Energy Consulting

Table 22 – Central oil de-linked delivered fuel prices (gross €/GJ, real 2006 money)

€/GJ	Inland Coal	Coastal Coal	LSFO	Gas	Gasoil
2007	2.59	2.50	5.82	4.52	10.52
2008	2.73	2.64	6.04	6.16	10.91
2009	2.60	2.51	5.99	6.06	10.83
2010	2.47	2.38	5.95	5.40	10.77
2011	2.33	2.24	5.81	4.67	10.53
2012	2.20	2.11	5.58	4.26	10.16
2013	2.06	1.97	5.36	3.76	9.79
2014	1.92	1.83	5.12	3.45	9.40
2015	1.93	1.84	4.89	3.15	9.01
2016	1.94	1.85	4.65	3.06	8.61
2017	1.94	1.85	4.41	3.17	8.22
2018	1.95	1.86	4.51	3.20	8.39
2019	1.96	1.87	4.59	3.34	8.52
2020	1.97	1.88	4.63	3.33	8.59
2021	1.98	1.89	4.71	3.26	8.74
2022	1.99	1.90	4.79	3.32	8.88
2023	2.00	1.91	4.95	3.49	9.15
2024	2.01	1.92	5.04	3.61	9.30
2025	2.02	1.93	5.13	3.72	9.46
2026	2.03	1.94	5.22	3.80	9.62
2027	2.04	1.95	5.30	4.26	9.75
2028	2.05	1.96	5.37	4.99	9.88
2029	2.06	1.97	5.44	5.86	10.01
2030	2.07	1.98	5.52	5.88	10.14

HSFO – High sulphur fuel oil

LSFO – Low sulphur fuel oil

Source: Pöyry Energy Consulting

Table 23 – Low delivered fuel prices (gross €/GJ, real 2006 money)

€/GJ	Inland Coal	Coastal Coal	LSFO	Gas	Gasoil
2007	2.48	2.39	5.36	4.44	9.75
2008	2.31	2.21	5.18	5.44	9.46
2009	2.01	1.92	5.13	4.71	9.39
2010	1.91	1.82	5.10	4.06	9.34
2011	1.82	1.73	4.91	3.28	9.03
2012	1.72	1.63	4.61	2.76	8.53
2013	1.70	1.61	4.31	2.38	8.02
2014	1.68	1.59	4.00	2.40	7.51
2015	1.67	1.57	3.69	2.43	6.99
2016	1.65	1.55	3.37	2.49	6.46
2017	1.63	1.54	3.05	2.49	5.93
2018	1.61	1.52	3.11	2.43	6.04
2019	1.60	1.51	3.13	2.40	6.08
2020	1.58	1.49	3.16	2.34	6.13
2021	1.57	1.48	3.19	2.29	6.18
2022	1.56	1.46	3.22	2.27	6.24
2023	1.54	1.45	3.25	2.25	6.30
2024	1.53	1.44	3.29	2.23	6.36
2025	1.52	1.42	3.32	2.21	6.42
2026	1.50	1.41	3.35	2.19	6.48
2027	1.49	1.40	3.38	2.20	6.54
2028	1.48	1.38	3.42	2.19	6.60
2029	1.46	1.37	3.45	2.21	6.66
2030	1.45	1.36	3.48	2.19	6.72

HSFO – High sulphur fuel oil

LSFO – Low sulphur fuel oil

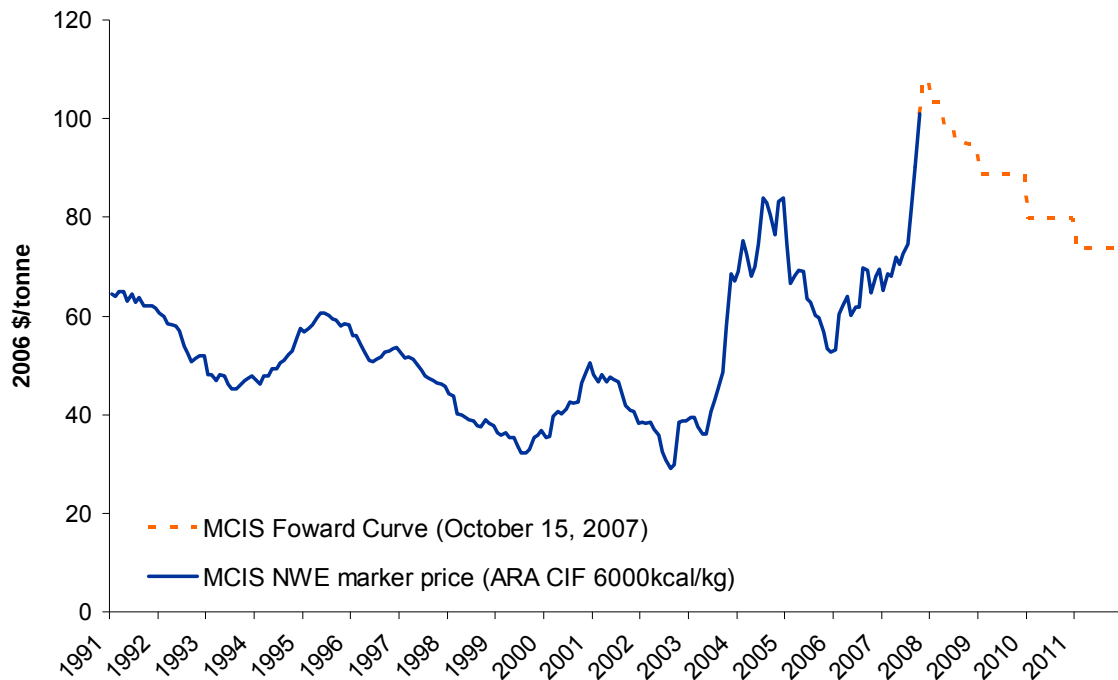
Source: Pöyry Energy Consulting

4.3 Coal

4.3.1 International coal market – recent history

Figure 23 illustrates the price of coal traded at ports in North West Europe (NWE) as reported by McCloskeys Coal Information Service (MCIS).

Figure 23 – MCIS NWE marker price (ARA CIF 6000kcal/kg NAR)



Source: McCloskeys Coal Information Service (MCIS).

In 2002, prices declined but then bottomed out on account of consolidation of the mining industry. An increasingly concentrated ownership in traditional coal exporting countries to Europe under 'the big four' producers, namely BHP Billiton, Rio Tinto, Xstrata and Anglo, led to lower growth in production and a shortage of new mines and infrastructure developments outside of China.

The flattening out of coal prices continued into the first half of 2003, with ARA prices trading around US\$37/tonne in nominal terms. However, in the latter half of 2003, prices rose substantially in both the spot and forward markets with trades for the Calendar '04 product being reported at around the US\$50/tonne level.

Increasing demand for coal, especially in China and other parts of Asia, and constraints on the worldwide shipping capability of dry bulk goods, ensured that European coal prices continued to rise rapidly with spot prices reaching about \$80/tonne by the middle of 2004. The second half of 2004 saw prices levelling off, before falling in 2005 to around \$50/tonne, largely due to a decrease in shipping rates caused by a temporary slowdown in Chinese steel production, as well as a significant increase in supply from Russia and Indonesia.

During 2006 and the first half of 2007 prices started to rise again, with consistent increases taking the ARA coal price to around \$70/tonne. However in the third quarter of 2007 a very sharp increase took McCloskey's NWE marker price above \$100/tonne for the first time.

The main reason cited for the strength of steam coal prices in recent years is tightness in the freight market. Chinese steelmakers continue to increase production levels and hence their coking coal import demand is high. This in turn has an impact on the availability and cost of freight for steam coal transportation.

There has also been a delay in the building of new bulk-carriers, owing to ship-builders currently being busy on both double-hulled tankers for the oil industry and a new generation of container ships. Commentators on the international coal market have previously suggested that even with high freight costs the freight market will take a number of years to catch up with demand.

This analysis can be observed in the movement of freight forward prices. Recent freight prices for transporting coal between Richard's Bay (South Africa) and North West Europe have been over \$40/tonne. This compares to a price that was closer to \$10 in 2005 and even was as low as \$5/tonne back in 2002 (for most of the 1990s, \$5/tonne was a typical level for freight prices.)

As well as the rise in freight prices, additional upward pressure on ARA coal prices comes from restrictions in port capacity for exporting coal from Australia, the unpredictable amount of Chinese steam coal that becomes available for export, and the increased imports required by India, that diverts South African coal that might otherwise be destined for Europe.

4.3.2 *International steam coal price projections*

Our projections for steam coal delivered to France are based on our current projections for coal prices at Amsterdam Rotterdam Antwerp (ARA) and are applicable to both domestic and international delivered coal prices to the power station. These prices are calculated from our world steam coal model that looks at future steam coal supply and demand on a worldwide basis.

Figure 24 and Table 24 present the Pöyry projections for CIF ARA prices in real 2006 money.

4.3.2.1 *Central case*

The Central case assumes an adequate supply of coal to Europe with increasing production in coal exporting countries (Australia, Colombia, and Indonesia) to counteract diminishing indigenous production in European countries. The price of coal trends towards the long run marginal cost (LRMC) of coal production and shipping. This gives an ARA price of around \$52/tonne in real terms by 2014 and remains at this level for the remainder of the projected period i.e. out to 2030.

4.3.2.2 *Low case*

The Low case assumes productivity gains in coal production costs and a faster increase of coal production in low cost countries compared to the Central Scenario. A lower oil price also decreases the fuel price for the transportation of coal. This case tends towards an ARA price of \$39/tonne in real terms by 2020 and \$33/tonne by 2030.

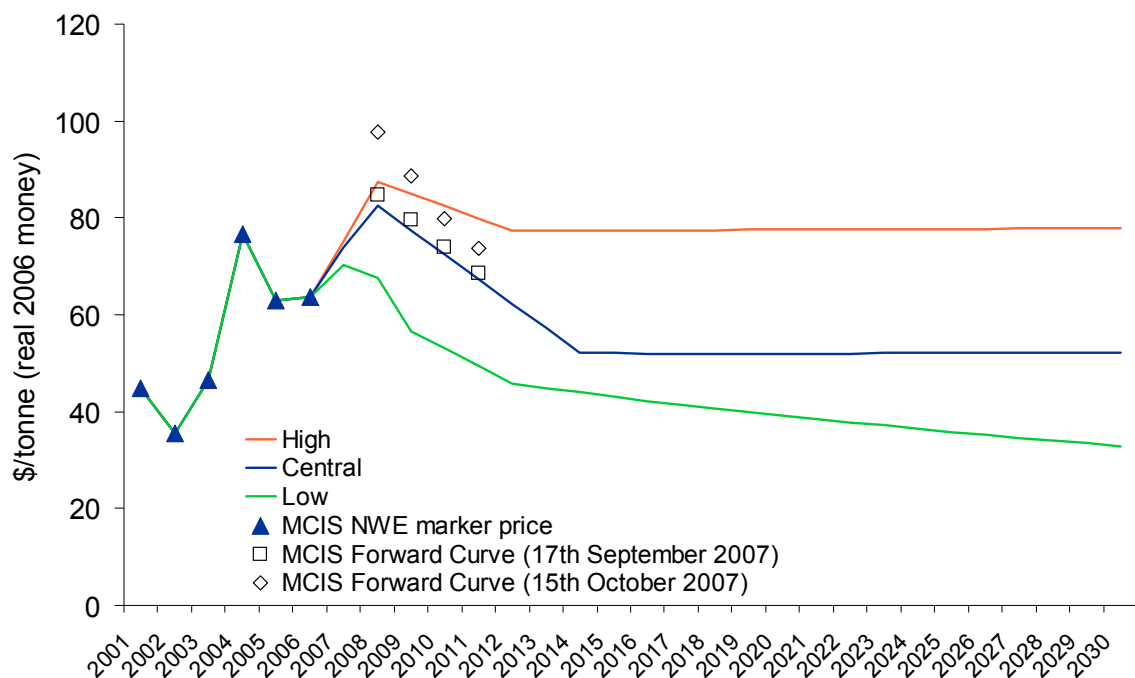
4.3.2.3 *High case*

The High case assumes higher estimates of the LRMC in coal exporting countries, an increased investment cost for mine capacity expansion, and a higher fuel price for the transportation of coal. The ARA price in this case reaches \$77/tonne by 2012 in real terms and remains at this level for the remainder of the projected period i.e. out to 2030.

4.3.2.4 Short-term price projections

The Pöyry steam coal price projections are based on fundamentals of supply and demand using a world coal model. However it can often take many years for the international coal market to respond to price signals and provide increased supply. Therefore short term prices (2-3 years) are based on recent forward market prices for coal⁶⁷. This approach is likely to give a more accurate reflection of near term prices. The first couple of weeks in October 2007 have seen further significant rises in coal forward prices. Forward prices from the 17th September and 15th October are shown against the Pöyry price projections in Figure 24, and show how the 2008 ARA forward price has increased to 98 \$/tonne in real 2006 money. This price for 2008 is higher than our High scenario, but we believe this is a temporary spike in the forward market, and is unlikely to be sustained over the coming year.

Figure 24 – Coal price (CIF ARA) projections (\$/tonne, real 2006 money)



Source: Pöyry Energy Consulting

⁶⁷ The short term prices are based on forward prices from McCloskeys API2 index. An average forward price for the 4 weeks from 20/08/07 to 14/09/2007 has been used to calculate the 2008 coal price projection. The prices for 2009 to 2011 come from interpolation between this price and our long term projections.

Table 24 – Coal price (CIF ARA) projections (\$/tonne, real 2006 money)

\$/tonne	High	Central	Low	Forward*
2007	75.22	73.97	70.22	
2008	87.50	82.50	67.50	84.77
2009	84.98	77.45	56.66	79.58
2010	82.47	72.40	53.05	73.94
2011	79.95	67.35	49.43	68.45
2012	77.43	62.29	45.82	
2013	77.43	57.24	44.90	
2014	77.43	52.19	44.00	
2015	77.43	52.12	43.11	
2016	77.43	52.03	42.23	
2017	77.43	51.96	41.37	
2018	77.48	51.97	40.64	
2019	77.53	51.99	39.92	
2020	77.57	51.99	39.21	
2021	77.60	52.01	38.51	
2022	77.62	52.02	37.83	
2023	77.64	52.06	37.17	
2024	77.67	52.08	36.51	
2025	77.70	52.10	35.88	
2026	77.73	52.12	35.24	
2027	77.76	52.13	34.63	
2028	77.79	52.14	34.03	
2029	77.81	52.16	33.44	
2030	77.84	52.16	32.86	

* Forward curve as of 17th September 2007 as reported by McCloskey's Coal OTC update

These prices are based on a calorific value of 6000kg/kcal CIF net as received (NAR) consistent with API#2.

Source: Pöry Energy Consulting

4.3.3 Delivery costs for coal

For coal we have assumed a delivery cost of \$14/tonne (2006 money) which is equivalent to €0.4/GJ.

4.4 Oil

The direct relevance of oil prices to our projections of electricity prices is through oil indexation in gas prices and the possible use of oil products in power stations. The prices for these oil products – low sulphur fuel oil (LSFO) and gasoil⁶⁸ – are projected through applying parameters from the historic relationship between these products and Brent crude oil to our projections for Brent crude prices. This section outlines the approach we take to project prices for Brent crude, LSFO, HSFO and gasoil. It begins with an overview of the types of oil available, then outlines the movement in crude prices, and finally discusses the projections of Brent crude, LSFO, HSFO and gasoil prices.

⁶⁸ Gasoil is also called medium distillate oil (MDO).

4.4.1 Types of oil

There is a large variety of crude oils, each with its own characteristics, such as thickness, level of acidity and sulphur content. Thicker oils require more processing to turn them into valuable products such as gasoline (petrol) and kerosene. Sulphur needs to be extracted during the refining process, to attain environmental standards and limit the corrosive effects on the refining facilities, so more effort is required to remove sulphur from crude with high sulphur content, known as sour, than from those with low sulphur content, known as sweet.

The benchmark light sweet crude in Europe is Brent, which comes from the North Sea. In the US the light sweet benchmark is West Texas Intermediate (WTI). These crude oils are extensively traded and attract a price premium above other heavier and sourer types of crude.

The types of oil and sources used in this analysis are:

- historical prices for Brent, gasoil, HSFO and LSFO from the International Energy Agency (IEA);
- short term futures Brent prices from the Intercontinental Exchange (ICE)⁶⁹; and
- long term price projections for Imported Low Sulphur Light Crude Oil (ILSLCO) from the Energy Information Administration (EIA).

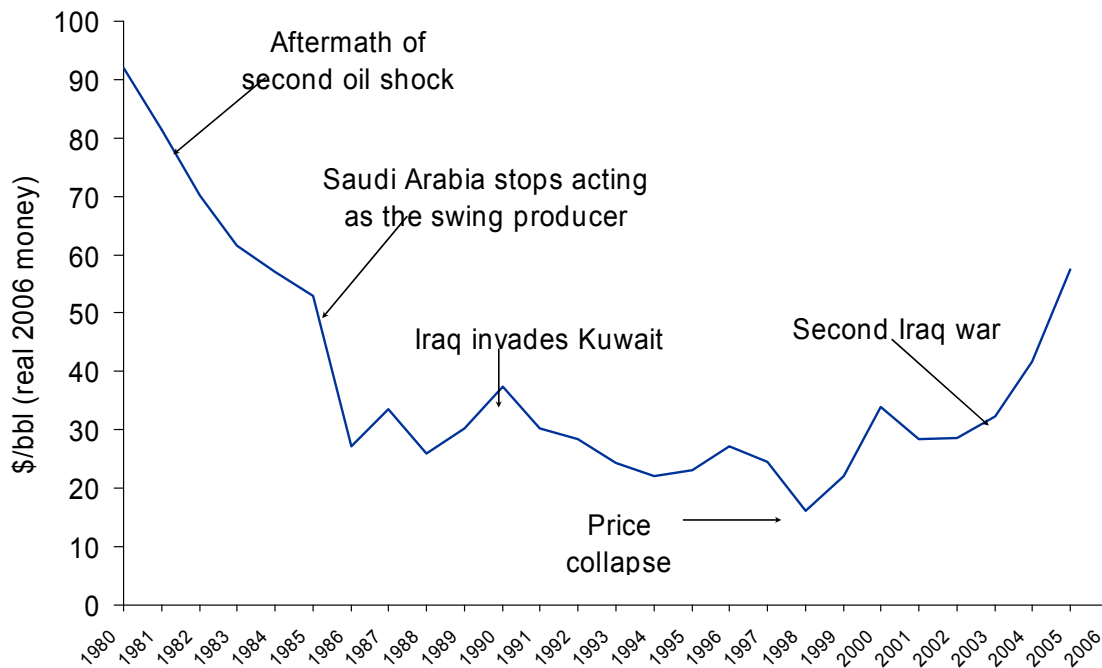
4.4.2 Movement in crude prices

Crude oil prices move in response to a range of factors, including changes in:

- the supply of crude oil, such as a change in OPEC production quotas or disruptions to operations;
- the demand for crude oil, which can be due to changes in economic growth or weather patterns; and
- expectations of risk, particularly arising from conflicts.

Figure 25 shows the history of Brent Crude prices since 1980, which is briefly discussed in the following sections.

⁶⁹ The ICE was formerly known as the International Petroleum Exchange (IPE).

Figure 25 – History of annual Brent Crude prices (\$/bbl, real 2006 money)

Source: IEA

4.4.2.1 Prices between 1980 and 2000

Crude oil prices in 1980 reached historically high levels, following the

- oil embargo of the early 1970's, resulting in a net loss of four million barrel per day;
- Iranian Revolution, resulting in the loss of two to two and a half million barrels per day; and
- Iraq and Iran war, by the end of 1980 world production was 10% lower than in 1979.

The higher oil prices encouraged higher energy efficiency and exploration in non OPEC countries. These developments along with a global recession led to a fall in the demand for crude. OPEC sought to stabilise prices through reducing quotas, but these moves proved unsuccessful, with several OPEC countries exceeding their quotas. In 1985 Saudi Arabia ceased to act as the swing producer and increased production, leading to a collapse in crude prices.

During the late 1980's OPEC had difficulties in setting and enforcing the production quotas of its members. The price of crude spiked following Iraq's invasion of Kuwait and the subsequent war. Following the conclusion of the conflict, crude oil prices continued to decline, and in 1994 they were at the lowest level since 1973 in real terms.

Strong economic growth in the US and Asia Pacific region during the 1990's led to an increase in the demand for oil. This came to an abrupt end with the Asian financial crises in 1997, after which demand in Asia declined. Rather than decrease production, OPEC increased production at the end of 1997 and beginning of 1998, which combined with the lower demand resulted in a collapse in the price. Subsequently OPEC sought, with some success, to reduce output, leading to a recovery in prices.

4.4.2.2 Price between 2000 and 2005

In 2000 the global economic growth continued to bolster demand, and OPEC production increased. At the same time, increased production from Russia began to be felt in the market. During 2001 the US economy began to slow and OPEC sought to reduce production. The terrorist attack of 11 September 2001 led to a significant drop in the price of crude, and OPEC and Russia cut production, leading to a recovery of prices during 2002.

From 2002 crude oil prices began to increase significantly, reaching a level in real terms not seen since the early 1980's. Key drivers behind this increase included:

- the Petróleos de Venezuela, S.A. (PDVSA) strike during 2002, which substantially reduced output from Venezuela;
- the Iraq War starting in 2003;
- disruption to production in Nigeria; and
- increased global demand, particularly from China.

Tight capacity led to prices becoming volatile, which was exacerbated through the loss of productive capacity in the Gulf of Mexico, due to hurricanes, and the difficulties the Russian oil major Yukos experienced.

Price continued to rise during 2005, mainly due to:

- cold weather in the northern hemisphere at the beginning and end of the year,
- loss of production capacity in the Gulf of Mexico following hurricanes Katrina and Rita,
- a persistent demand in Asia;
- supply disruptions in Nigeria; and
- political tension over Iran's nuclear programme.

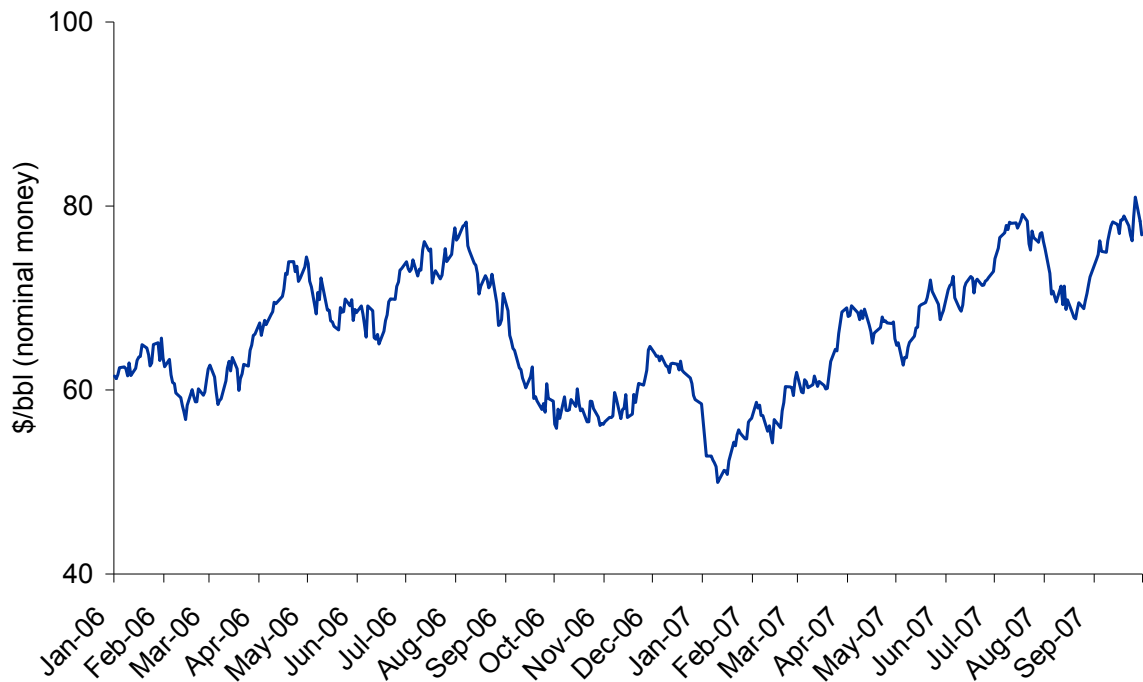
Mitigating factors include an OPEC decision to boost oil flows and the shutdown of refining capacity in the southern US due to damage from Hurricanes Katrina and Rita. Overall the price of Brent rose from \$45/bbl in January 2005 to \$57/bbl in December 2005.

4.4.2.3 Latest developments and future outlook

Figure 26 shows the daily spot price for Brent crude price levels since January 2006. The key drivers behind the movements in prices during 2006 have been:

- the continuing political uncertainty over Iran;
- high demand for gasoline in the US during the summer;
- the war in Lebanon and its subsequent resolution;
- lower output in Alaska, Iraq, Nigeria and Venezuela;
- continued strong demand from China; and
- falling demand in the US, Mexico, Europe and Japan toward the end of 2006.

Figure 26 – Spot prices for Brent Crude FOB (\$/bbl, nominal money)



Source: EIA

During 2007 the price of Brent has risen significantly, from \$54/bbl in January to \$77/bbl in September. The peaks during 2007 have surpassed those in 2006, with the price of WTI exceeding \$80/bbl for periods of time. Significant drivers have been:

- high demand for gasoline in the US during the summer;
- the disruption to output from the Gulf of Mexico, where despite limited damage from Hurricanes Dean and Felix, output temporarily fell by 425 kb/d;
- uncertainty stemming from changes in lender requirements in the sub prime mortgage market; and
- the continuing political uncertainty over Iran.

In the immediate term expectations are mixed with some commentators, most notably Goldman Sachs, arguing that as demand has remained high and output has fallen, the price of crude could end the year 2007 at \$85/bbl; and that there is a high risk of it exceeding \$90⁷⁰ despite OPEC deciding to increase output by 500 kb/d in September. By contrast others have argued that lower demand for products, low refining margins and the end of the hurricane season will put downward pressure on crude prices.

Adding more uncertainty to the picture, the full implications of the difficulties in the sub prime mortgage market remain unclear. On one hand a higher price for risk may lead to a higher cost of capital resulting in higher prices. Alternatively any dampening of the economy could lead to lower prices.

⁷⁰ "Signs point to quarterly decline in oil", International Herald Tribune, 9th October 2007.

In the longer term there is a range of factors which are likely to support prices remaining high, including:

- declining reserves necessitating more expensive production from deep water regions;
- an aging workforce making it more difficult to find and retain staff; and
- increasing equipment and installation costs.

4.4.3 Pöyry oil price projections

4.4.3.1 Crude oil

Pöyry uses the following two sources to project future Brent oil prices:

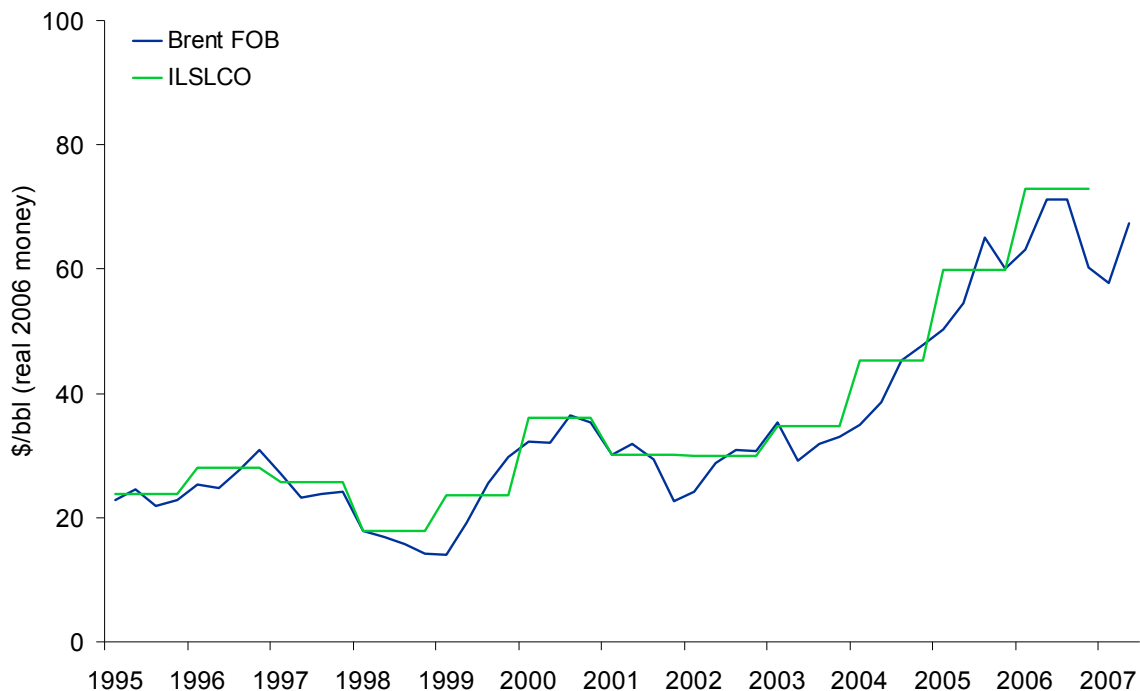
- short term futures prices based on the Intercontinental Exchange (ICE) Brent prices; and
- long term futures prices based on the Energy Information Administration's (EIA) projections for Imported Low Sulphur Light Crude Oil (ILSLCO).

The ICE publishes daily forward prices for Brent crude for each month up to 39 months ahead. The forward prices for the following month cease to be published during the middle of the current month, when the forward prices for the month in 39 months' time starts being published.

We have used the average monthly prices from the forward curves for a 30 day period from mid July 2007 to mid August 2007 to construct a new forward curve. These prices have been used for the short term Central scenario. The short term prices for the High and Low scenarios are calculated by adding or subtracting 15% to the Central scenario prices.

The Energy Information Administration (EIA) is part of the US Department of Energy, and publishes projections until 2030. Figure 27 compares the trend in the annual ILSLCO prices and quarterly Brent crude prices, and illustrates there is a strong relationship between the two series.

Figure 27 – Trends in EIA crude and Brent Crude FOB (\$/bbl, real 2006 money)



Source: EIA, IEA and Pöyry Energy Consulting

We have estimated a regression equation between Brent crude and ILSLCO prices, which yields a R^2 measure-of-fit coefficient of 0.94. The parameters from this equation were applied to the EIA's High, Reference and Low projections of the price for ILSLCO to forecast the High, Central and Low scenario Brent crude prices.

The key difference between the EIA's High, Reference and Low projections is that the:

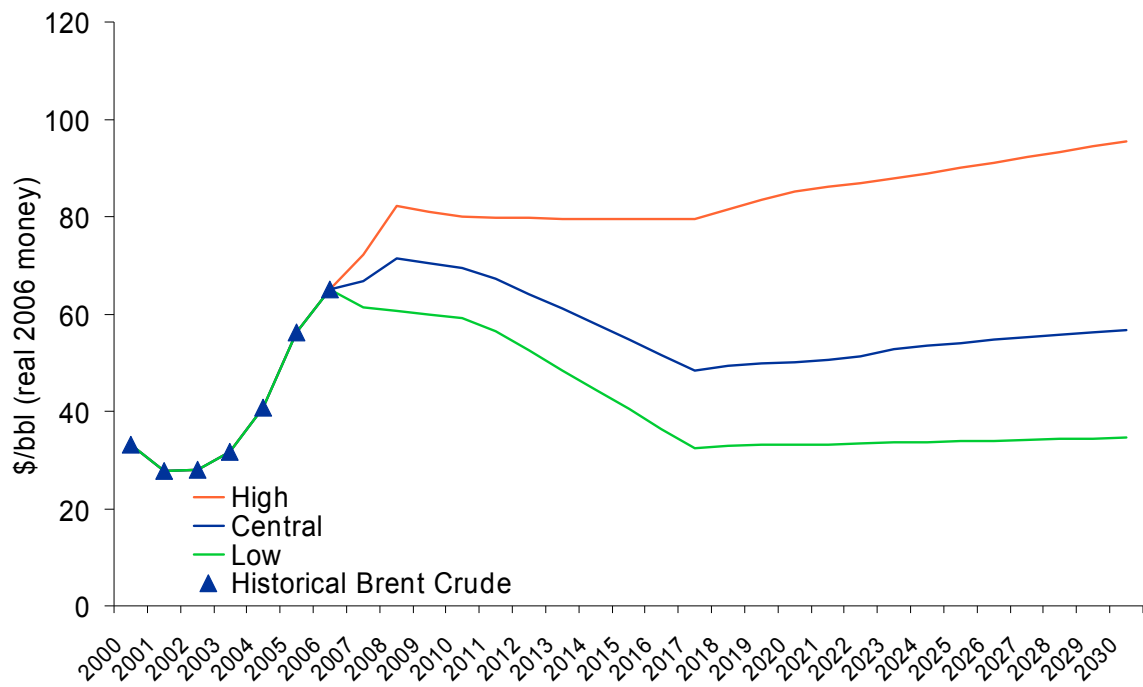
- Reference case uses the US Geological Survey's mean estimate of global oil and gas reserves;
- High price case assumes global reserves are 15% lower, which increases the marginal cost of production leading to higher prices; and
- Low price case assumes global reserves are 15% higher, which reduces the marginal cost of production leading to lower prices.

We consider that prices in the futures markets are a good indicator of short-term price trends but that they become less reliable in the longer term. Consequently our projections for Brent crude are based on:

- an average of ICE futures curves over a 30 day period until the end of 2010;
- an interpolation between the ICE futures curve and the projected prices for Brent using EIA data from the start of 2010 to the end of 2017; and
- the projected prices for Brent using EIA data for 2018 and beyond.

Figure 28 illustrates the historical prices and the three Pöyry projected prices for Brent crude, while Table 25 details the projected Brent crude prices for each case.

Figure 28 – Historic and Pöyry Brent Crude Oil assumptions (\$/bbl, real 2006 money)



Source: IEA, EIA, ICE and Pöyry Energy Consulting analysis

Table 25 – Pöyry Brent Crude Oil assumptions (\$/bbl, real 2006 money)

\$/bbl	High	Central	Low
2007	72.14	66.72	61.29
2008	82.17	71.45	60.73
2009	80.88	70.33	59.78
2010	79.94	69.52	59.09
2011	79.66	67.31	56.39
2012	79.64	64.17	52.40
2013	79.63	61.02	48.40
2014	79.61	57.88	44.41
2015	79.59	54.73	40.41
2016	79.58	51.58	36.42
2017	79.56	48.44	32.43
2018	81.58	49.28	32.95
2019	83.35	49.92	33.01
2020	85.05	50.01	33.06
2021	86.12	50.66	33.20
2022	86.80	51.32	33.35
2023	87.88	52.71	33.50
2024	88.95	53.41	33.64
2025	90.04	54.10	33.80
2026	91.12	54.80	33.95
2027	92.20	55.28	34.09
2028	93.28	55.75	34.25
2029	94.36	56.22	34.40
2030	95.46	56.70	34.55

Source: IEA, EIA, ICE and Pöyry Energy Consulting analysis

4.4.3.2 Oil products

Pöyry projects the wholesale prices for gasoil, Low Sulphur Fuel Oil (LSFO) and High Sulphur Fuel Oil (HSFO). These are based on estimating the historic relationship between the prices for Brent crude and these products, and applying the resulting parameters to our projected High, Central and Low prices for Brent crude to yield our High, Central and Low price projections for each product.

Our analysis shows that there was a change in the relationship between Brent and products from 2004 onwards. This change was a downward shift in the product prices, and coincides with the reduced use of oil products to generate electricity and the introduction of environmental legislation aimed at limiting sulphur emissions. Consequently the data used in the analysis outlined below is from 2004 onwards. Our oil product price projections for each of the three scenarios are shown in Table 20 to Table 23.

4.5 Gas

The Pöyry approach to modelling liberalised gas markets is driven by the underlying economics of supply and demand. The starting point for the French gas price projections is the economic cost of producing and transporting gas across North West Europe.

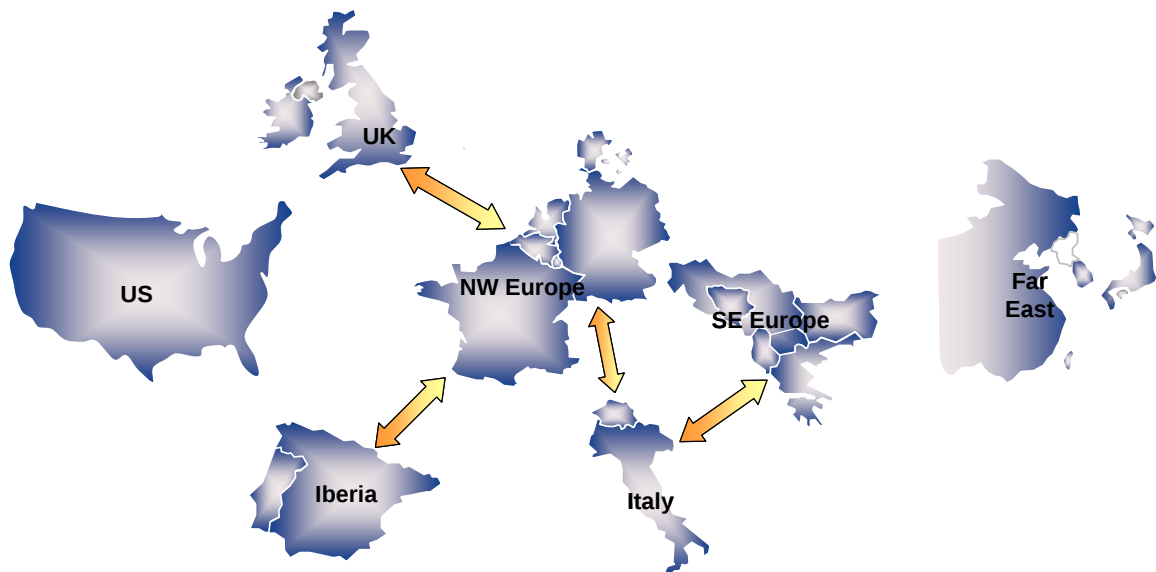
4.5.1 Gas modelling methodology

Gas prices are forecast using our pan-European and US gas model, Pegasus ('Pan-European GAS + US'). The model examines the interaction of supply and demand worldwide on a daily basis. Pipeline imports and interconnections between the UK, Continental NW Europe (NWE), Spain, Italy and South East Europe (SEE) are modelled in detail, alongside all existing and proposed LNG terminals, and their interaction with the global LNG market.

Examining daily demand and supply across these markets gives a high degree of resolution, allowing the model to examine weekday/weekend differences, flows through the interconnectors and gas flows in and out of storage in detail.

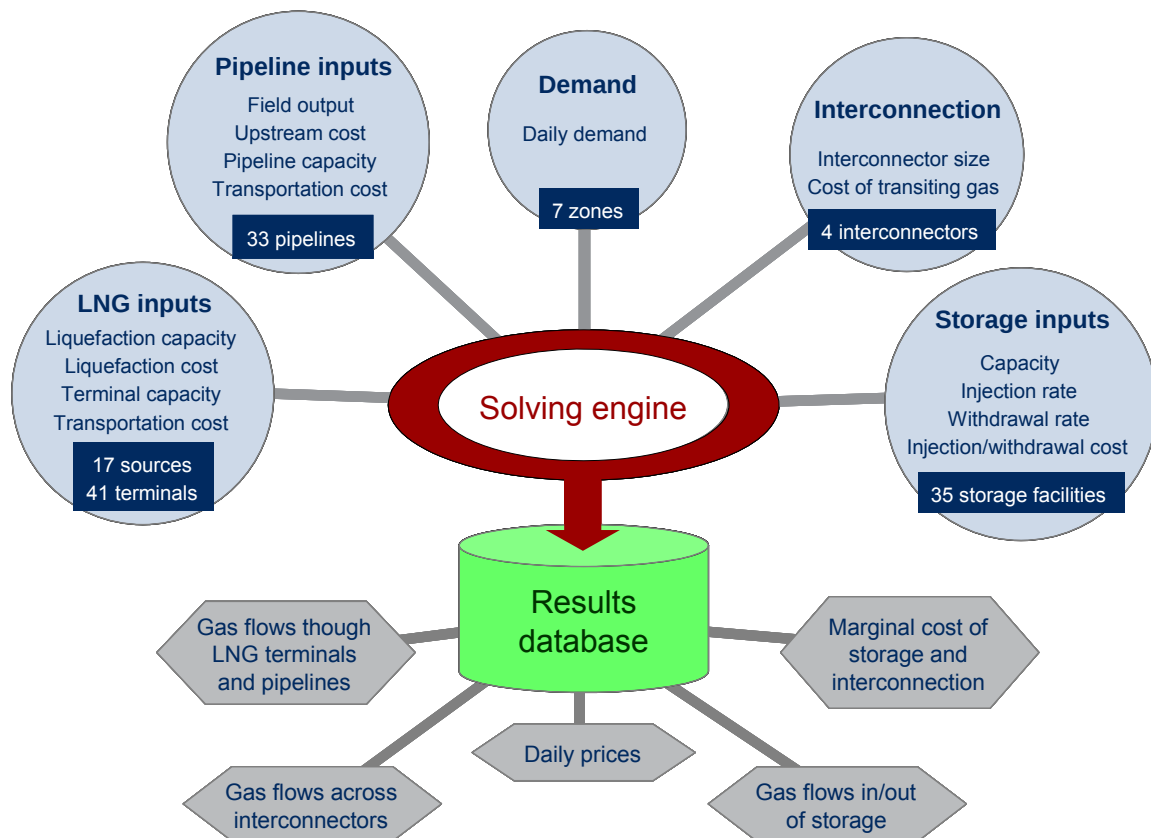
Pegasus itself is comprised of a series of modules. The main solving module is based in XPressMP, a Linear Programming (LP) package, which optimises to find a least-cost solution to supply gas to seven zones over a gas year (see Figure 29). The solution is subject to a series of constraints, such as pipeline or LNG terminal sizes, interconnector capacities and storage injection/withdrawal restrictions.

Figure 29 – Geographic coverage of Pegasus



Source: Pöyry Energy Consulting

Figure 30 – Structure of Pegasus



Source: Pöyry Energy Consulting

The solving module takes input files generated by a series of Excel/VBA modules, which allow a variety of scenarios to be created by changing variables such as supply, demand, costs, storage and interconnectors. The outputs from the model, such as prices and flows of gas, are sent to a database to allow easy extraction of data at either a daily, monthly or annual resolution.

Interconnection through BBL and IUK between the UK and NWE markets is important given the influence of oil-indexed long-term contracts. The optimisation algorithm in Pegasus minimises the cost of supplying gas to both NWE and the UK, subject to both the capacity and the cost of transiting gas across the interconnectors. This tends to lead to imports into the UK during winter to supply the peaky UK winter demand, and exports from the UK during summer. These patterns naturally change over time with differing assumptions on gas cost and new import projects and their location. The daily resolution in the model means that during the shoulder months, the interconnectors 'flip-flop' back and forth between import and export – exactly as we have seen historically.

Modelling storage accurately is key to understanding price formation in the UK and Europe, as it affects both summer and winter prices, along with weekday/weekend prices. Pegasus models each current and forecast UK gas storage field, each with its own injection and withdrawal rates, total storage capacity and cost of injection/withdrawal. The optimisation algorithm used not only means that gas is injected into storage during the summer and withdrawn during the winter, as expected, but also that injection takes place for high cycle facilities during the winter weekends and Christmas periods due to lower demand, as seen in reality.

We also model European and US storage in three generic types – depleted field, salt cavern and LNG. This lower level of detail is sufficient for European storage due to the non-commercial nature and opaqueness of use of much of the storage facilities.

In the new global Pegasus, the worldwide LNG market is modelled. All existing, under construction, proposed and conceptual LNG liquefaction projects worldwide are included under different scenarios, from a total of seventeen countries (or ‘sources’). Similarly all LNG re-gasification terminals worldwide are also modelled. In Europe and the US each terminal is identified separately, except in the longer term when generic LNG terminal capacity may be included in addition. The terminal capacity in the Far East, Canada and South America, and the rest of the World, is grouped within zones.

LNG cargoes can be ‘delivered’ from any source to any LNG terminal. As a result, LNG cargoes can be delivered to different destinations depending on which market is most profitable for a particular cargo – for example, LNG will deliver preferentially to Montoir-de-Bretagne in France or Zeebrugge in Belgium when prices are higher in NW Europe than in the UK. Thus the NW European market is linked to the UK market not just through the interconnectors but also via LNG arbitrage. Furthermore, the interaction with the US and the rest of the Worlds’ LNG markets means that gas markets become linked worldwide based upon supply and demand for LNG.

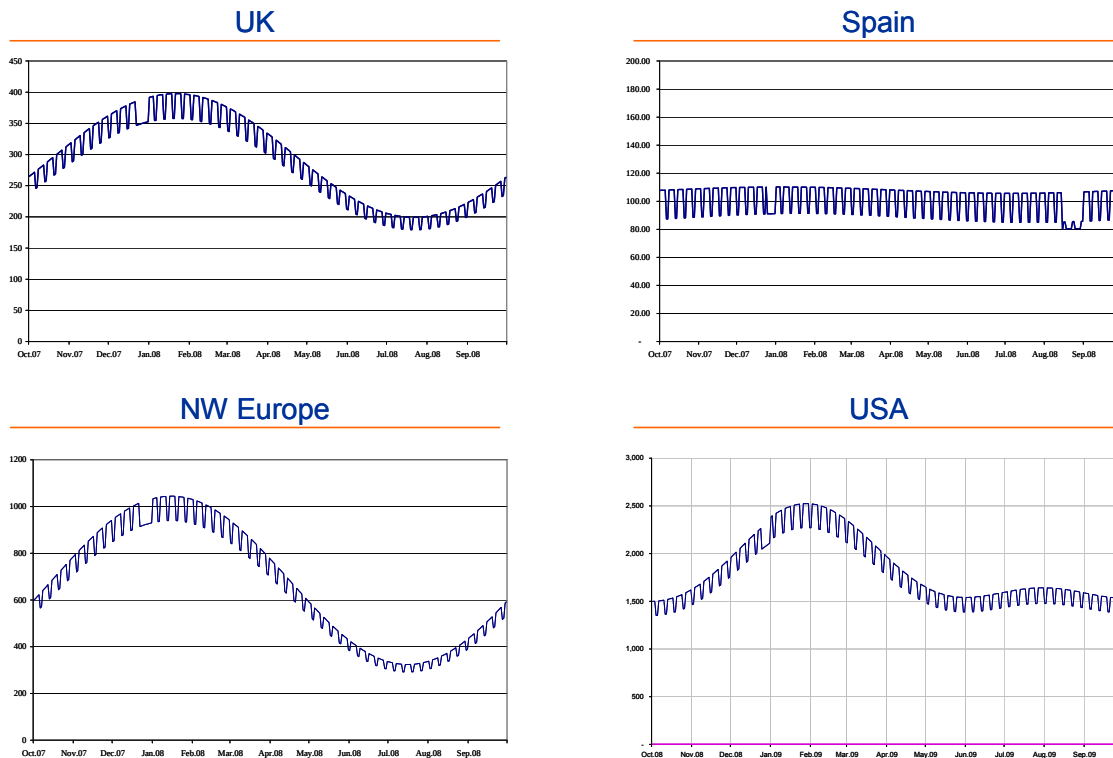
As a core part of our modelling, we carry out iterations with our electricity model to understand the effect of changes in gas price on demand for gas, and changes in demand for gas on price. This iteration between the two models ensures that our assumptions on gas prices and gas demand remain realistic and reflects the elasticity of gas demand given high gas prices.

4.5.2 Modelling assumptions

4.5.2.1 Gas demand

Gas demand is projected through individual forecasts for each zone of domestic, industrial and commercial, power generation and exports/transit gas. We profile the annual gas demand figures for each zone based around a sinusoidal function derived from historical data. The daily gas demand also accounts for the difference in demand between weekday, weekend and the Christmas shutdown period, again based on historical differentials. Four sample curves showing daily demand in the UK, NW Europe, Spain and the US over one year are presented in Figure 31.

Figure 31 – Example of daily gas demand input in four zones



Source: Pöyry Energy Consulting

4.5.2.2 Gas supply and import projects

Indigenous production and pipeline import capacity is forecast based upon market intelligence and information from industry participants.

NWE is modelled as a single zone hence we have grouped BBL and IUK together as a single pipeline, although we generally assume that BBL has only uni-directional capacity (from the Netherlands to the UK). Pegasus also includes interconnections between Spain and NWE, NWE and Italy, SEE and Italy, and SEE and NWE via the proposed Nabucco pipeline.

4.5.2.3 Oil-indexation assumptions

For all scenarios, Pöyry assumes that in early years gas prices on the Continent are heavily influenced by the effect of oil-indexation, particularly gas coming from the FSU. In the Abundant scenario (used for the Low wholesale electricity price scenario), transition to a competitive market, and thus price setting by the marginal player, is assumed to occur in full by 2012. In the 'Balanced oil-gas de-linked' scenario (used in the Central oil de-linked wholesale electricity price scenario), this is assumed to happen in 2015, and in both the 'Balanced: oil-indexation' and the Constrained scenario (used for the Central oil-indexed and High wholesale electricity price scenarios, respectfully) full competition throughout Continental Europe never occurs, and thus gas prices are influenced strongly by oil-indexed contracts.

Under the 'oil-indexed' scenarios – the Balanced: oil-indexation and the Constrained scenarios – the Continental gas supplies from Norway and Russia remain oil-indexed and

these dominate gas prices. UK gas and storage prices are not oil-indexed and are set by the long-run costs. LNG supplies are also set to increase throughout European gas markets and each market must compete for LNG with the rest of the world, making gas price setting much more complex.

The winter gas prices in NW Europe and the UK are largely set by storage cost and availability. Since the previous modelling of the UK and NWE gas markets many more gas storage projects have been proposed and have progressed to a point at which we have included them coming on line in the next ten years or so. This increases storage availability and softens the winter supply-demand balance which has reduced seasonality somewhat and overall annual average prices slightly, under the 'oil-indexed' scenarios.

4.5.2.4 Storage assumptions

Pegasus optimises the use of storage by using it to reduce the overall cost of supplying gas. Thus in the winter, rather than using very expensive sources of gas, or demand-side shedding, the model preferentially withdraws gas from storage when it is optimal to do so. In this case the marginal therm of gas (and hence the marginal price) will come from withdrawing one unit from storage along with the associated injection of one unit at some point in summer, and the corresponding cost of injection and withdrawal. The model assumes that storage is full at the start of the gas year (1 October) and full at the end of the gas year (30 September), and thus must inject any gas withdrawn from storage.

4.5.3 Summary of price projections

The four possible scenarios describe the general levels of supply, demand and transportation capacity for natural gas, and the effect that these levels would have on the price for natural gas. A general overview of each of the four⁷¹ scenarios is as follows.

- **High price:** Demand for gas remains high with limited demand destruction despite high prices and high priced import capacity increasing to cover the shortfall. Market liberalisation on the Continent is limited despite high oil prices between \$80-100/bbl. Therefore gas prices are high and remain indexed to oil and oil products.
- **Central oil-indexed price:** In this scenario, the arrival of new import projects means that there are no supply constraints in the medium term and growth in gas demand is moderate. However, the link between gas prices on the Continent and oil (which are between \$50/bbl and \$60/bbl) remains strong throughout; consequently, gas prices are moderately high.
- **Central de-linked price:** As above, there is no supply constraint in the medium term. Gas prices are assumed to de-link from oil by 2015; consequently, gas prices are moderate and lower than in the oil-indexed scenario. These relatively low prices lead to increased demand and a resulting rise in price during the end of the modelled period (2025 – 2030).
- **Low price:** In this scenario, gas supply is abundant, with production and import capacity in excess of a relatively low demand growth. The oversupply both in the UK and NW Europe means that the Continental market is fully liberalised by 2012. Gas prices are therefore low.

⁷¹ Note we project gas prices under four scenarios, as opposed to the three scenarios we project the prices for other fuels.

Table 26 and Figure 32 shows projections for the wholesale price of gas at a notional balancing point (NBP) in France, based upon the price of gas at a hub in the Netherlands (represented by our NW European prices) plus the transit costs to the NBP in France and an entry charge. France's NBP is also known as PEG (Point d'Echange de Gaz).

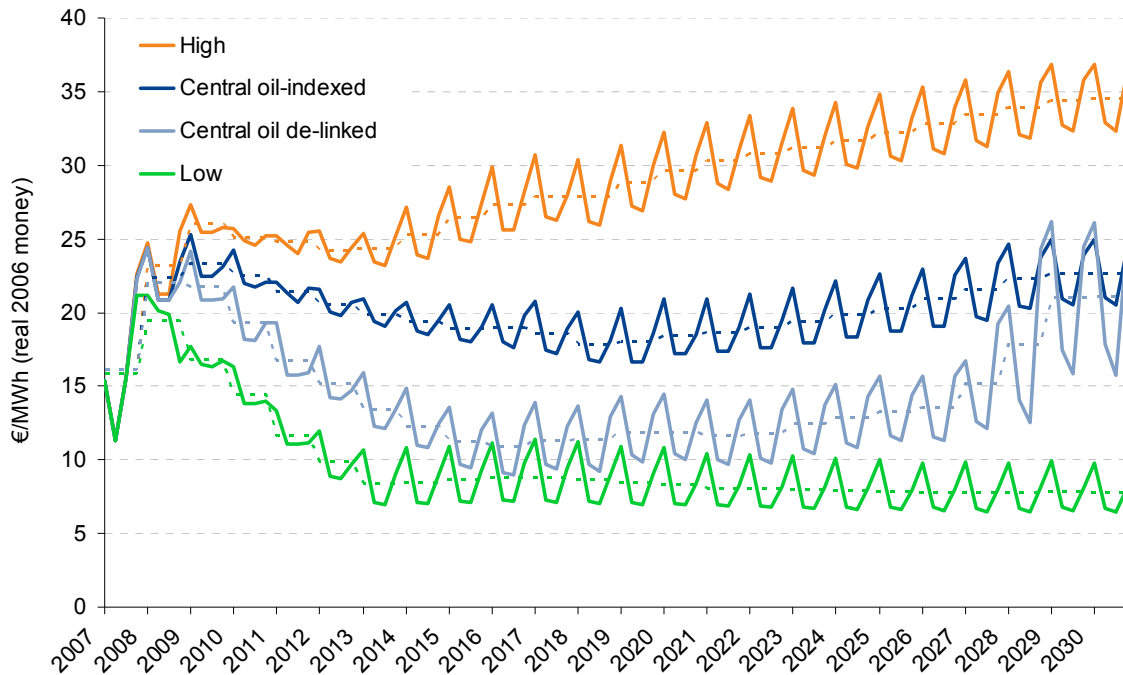
Table 26 – French gas prices at NBP (€/MWh, real 2006 money)

	High	Central Index	Central Delink	Low
2007	16.20	16.15	16.13	15.85
2008	23.17	22.37	22.02	19.45
2009	26.00	23.32	21.68	16.80
2010	25.09	22.51	19.31	14.49
2011	24.80	21.43	16.67	11.66
2012	24.25	20.53	15.18	9.81
2013	24.31	19.87	13.39	8.43
2014	25.32	19.37	12.26	8.50
2015	26.40	18.93	11.19	8.60
2016	27.32	18.99	10.89	8.83
2017	27.86	18.57	11.27	8.81
2018	27.85	17.87	11.36	8.60
2019	28.85	18.04	11.88	8.48
2020	29.67	18.44	11.86	8.27
2021	30.26	18.64	11.59	8.10
2022	30.75	18.97	11.81	8.03
2023	31.21	19.40	12.43	7.96
2024	31.67	19.90	12.84	7.90
2025	32.23	20.31	13.25	7.83
2026	32.78	20.88	13.54	7.75
2027	33.41	21.55	15.19	7.76
2028	33.96	22.28	17.82	7.75
2029	34.42	22.58	20.96	7.80
2030	34.53	22.65	21.03	7.72

Source: Pöry Energy Consulting.

The delivered prices, as compared to prices at the notional balancing point, are not used during the modelling of Pöry electricity price projections (we model the exit charge as being a fixed cost to power stations and as such it is included in our capacity payment). We do however use the full delivered cost of gas when we project our CCGT new entrant costs.

For peaking gas, we assume a peaker would require gas on up to 80 days per annum and have based the cost of winter supply on the cost of a storage service. For France we base the cost on GdF's Lorraine storage (fixed at 77 days) and the cost is around €5/MWh. This would be a premium paid over and above the cost of summer gas to fill storage, and as such we have assumed a lower premium of €3/MWh over the cost of annual baseload gas.

Figure 32 – French seasonal gas price projections (€/MWh, real 2006 money)

Source: Pöyry Energy Consulting.

4.6 EU ETS modelling

The European Union Emissions Trading Scheme (EU ETS) obliges generators to have sufficient carbon allowances to cover the carbon dioxide (CO₂) production. A full description of how this scheme is implemented in France appears in section 2.6.1.

In brief, the two main impacts of the ETS on the electricity sector come from two interrelated factors:

- the price of CO₂; and
- the methodology used by governments to allocate allowances to installations.

The price of CO₂ that emerges as trading continues can have a large impact on electricity prices and generation patterns. This impact can be briefly described as follows:

- As soon as generators need to use up, or purchase, CO₂ allowances as part of their operations, then CO₂ becomes a cost just like any other in their operations (e.g. fuel, labour etc.)
- The cost of CO₂ should therefore form part of the generators' pricing decisions, and the cost at which they offer power into the market. The €/MWh price of a particular generator should increase in line with the cost of CO₂ (in €/tonne) and the amount of CO₂ it emits per MWh of generation. This, in turn, is a function of the carbon intensity of the fuel it burns, and the efficiency of the generator.
- As the cost of CO₂ rises, then generators burning high carbon fuels, and/or relatively inefficient generators, will see their prices rise faster than more carbon-efficient generators.

- This will have two effects:
 - relative positions in the merit order may change; and
 - the market price of electricity will rise in line of the marginal generator.

The outcome on purely economic grounds would involve the extra marginal costs associated with emissions trading being fully passed through to wholesale prices. Even if the bulk of a generator's emissions are covered by free allowances (as in Phase I and Phase II) as per the French National Allocation Plan (NAP), the use of these allowances constitutes an opportunity cost to that generator i.e. the lost opportunity of selling the allowances to another party.

In practice, this full pass-through may not occur whilst the majority of allowances are freely issued, although we have seen that this pass-through is close to 100% to-date for neighbouring markets like Germany. However, a similar outcome, in electricity prices terms, would be observed if we had only partial pass through but higher overall carbon prices. Pöyry projections of carbon price outlined in Table 27 therefore, are actually projections of carbon pass through to wholesale prices rather than the traded value of carbon. These two converge if we have full pass through of carbon costs to wholesale prices.

We use a range of different carbon values owing to the uncertainty of the price of carbon allowances in the market Emissions Trading Scheme. Our projections for the final year of Phase I (2005–2007), Phase II (2008–2012) and future phases are presented in Table 27.

Table 27 – Pöyry assumptions for the value of carbon (€/t CO₂)

	Phase I	Phase II	Phases beyond 2012
High	1	30	40
Central	1	20	20
Low	1	10	10

Source: Pöyry Energy Consulting

4.7 Electricity demand

Our demand projections include demand met by CHP and renewables plant, and are based on demand forecasts for total system demand from the RTE's⁷² Generation Adequacy Report⁷³ for the years 2007-2030. For historical demand data we have also used data recorded by RTE⁷⁴.

RTE shows the level that total and peak demand might be in a number of key years (namely, 2010, 2015 and 2020) for three different scenarios.

⁷² Gestionnaire du Réseau de Transport d'Electricité (RTE) – the French Transmission System Operator.

⁷³ 'Bilan Prévisionnel de l'équilibre offre-demande d'électricité en France'. RTE, June 2007.

⁷⁴ All demand growth figures are weather and load management corrected.

RTE scenarios contain figures for total, average peak and extreme peak system demand. The average peak growth rate shown in Table 28 is the RTE's prediction of the growth rate in a 'normal' year which we apply to a smoothed historical function to obtain an average annual growth rate. The extreme growth rate refers to the Peak in a 1/10 winter and according to the RTE is a probable representation of necessary system margin⁷³. We have used the 'normal' growth rate in our modelling of French peak demand.

Our projections for total system and peak demand are provided in Table 28. These figures have been adjusted to take into account climatic conditions⁷⁵. Table 28 illustrates total system demand and peak system demand for the projected period up to 2030.

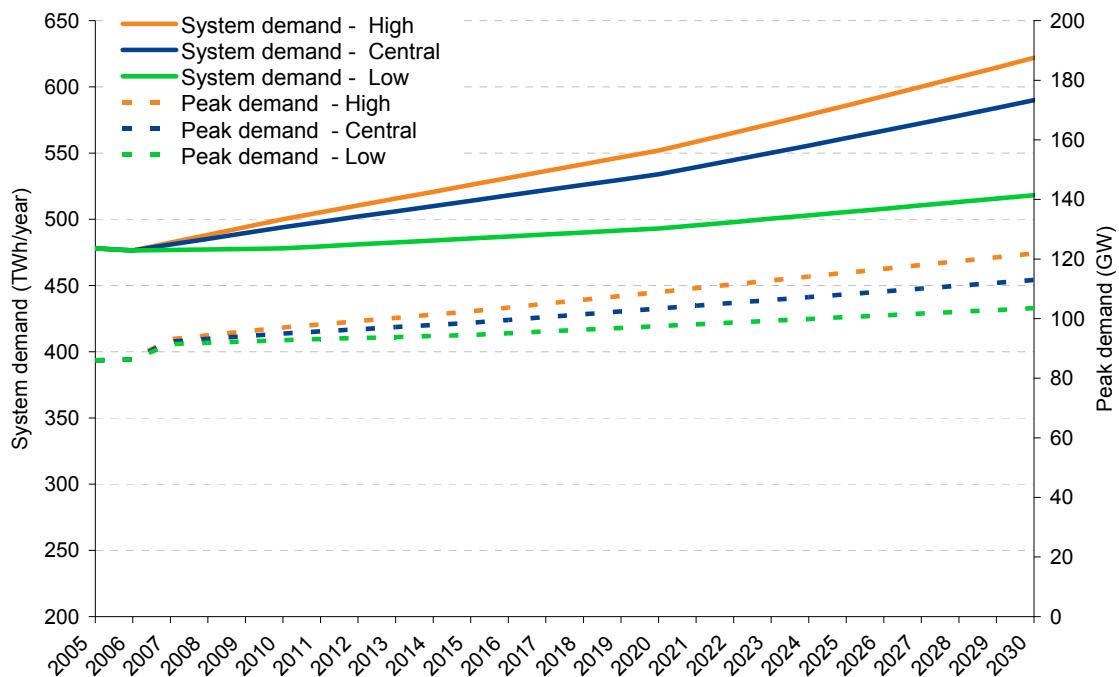
Table 28 – French total system demand (TWh) and maximum peak demand (MW)

	Volume demand (TWh)			Peak demand (MW)		
	High	Central	Low	High	Central	Low
2007	482	481	477	93.1	92.3	91.4
2008	488	485	477	94.4	93.2	91.9
2009	494	490	478	95.7	94.1	92.3
2010	500	494	478	97.0	95.0	92.8
2011	505	498	480	98.1	95.7	93.1
2012	510	502	481	99.2	96.4	93.5
2013	516	506	483	100.2	97.2	93.8
2014	521	510	484	101.3	97.9	94.2
2015	526	514	486	102.4	98.6	94.5
2016	531	518	487	103.7	99.6	95.1
2017	536	522	489	105.0	100.5	95.7
2018	542	526	490	106.3	101.5	96.3
2019	547	530	492	107.6	102.4	96.9
2020	552	534	493	108.9	103.4	97.5
2021	559	539	495	110.2	104.4	98.1
2022	565	545	498	111.5	105.3	98.7
2023	572	550	500	112.8	106.3	99.3
2024	579	556	503	114.1	107.2	99.9
2025	586	561	505	115.4	108.2	100.5
2026	593	567	508	116.7	109.2	101.1
2027	600	573	511	118.0	110.1	101.7
2028	607	578	513	119.3	111.1	102.3
2029	615	584	516	120.6	112.0	102.9
2030	622	590	518	121.9	113.0	103.5

Source: RTE and Pöyry Energy Consulting.

⁷⁵ Weather corrected annual energy values are available from the RTE website. The maximum demands have been adjusted by 1300MW per 1 degree deviation in temperature from 'normal', and then smoothed to remove any year-on-year spikes.

Figure 33 – Historic and projected system demand in France, including demand met from CHP and renewable plant



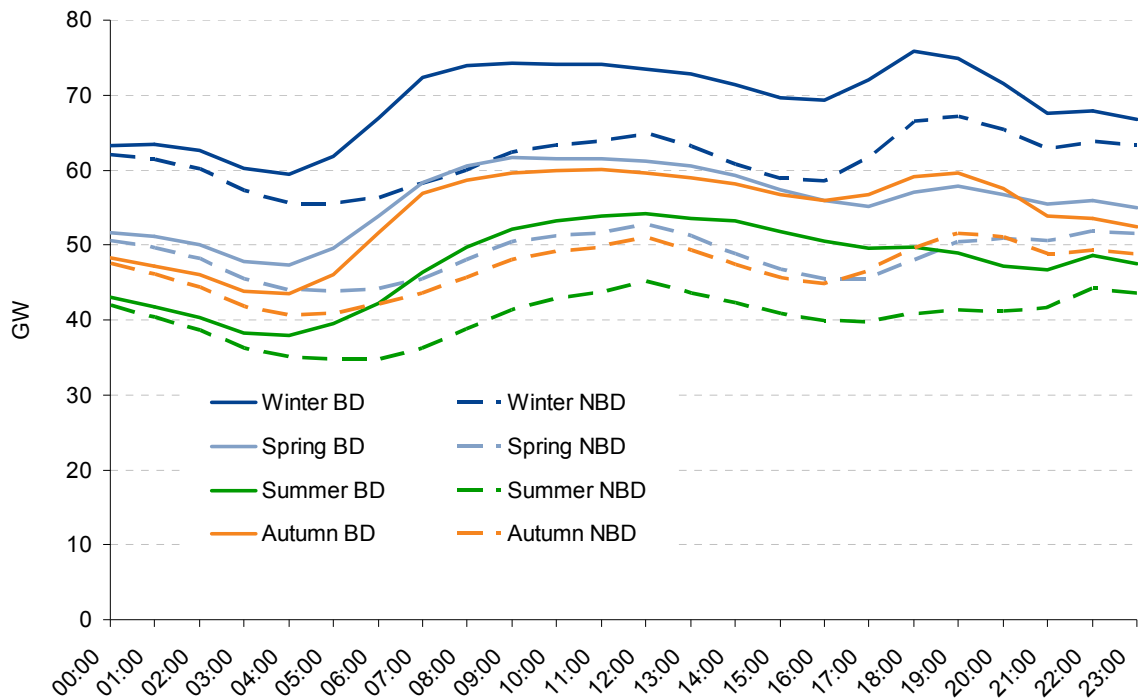
Source: RTE and Pöyry analysis

In our European generation model, *EureECa*, we model 24 sample days – a business day and non-business day for each month. We do not explicitly model the peak day as it is unlikely that the peak days in the different countries will occur simultaneously⁷⁶. New capacity requirements and additions, however, are based on expected peak day maximum demand in each individual country.

The sample day demand profiles are hourly demand values calculated as the average from the years 2000 to 2006, as reported by RTE. Figure 34 shows the shape of the business day (BD) and non-business day (NBD) profiles used for the different seasons.

⁷⁶ Note, however, that we do ensure that there is sufficient capacity on the French system to meet demand, with a suitable reserve margin, on the maximum peak day.

Figure 34 – Demand profile within-day (GW)



Source: RTE, UCTE and Pöyry analysis

4.8 Generation capacity construction and retirement

The status of current plants and future projects, and decommissioning dates, have been taken from a number of sources including Platts PowerVision, company websites as well as Pöyry-based assumptions.

Plant retirements are based on nominal station lives of around 40-50 years for coal plant and 30-years for CCGT. According to Platts⁷⁷ and EDF's Annual Report 2007⁷⁸, EDF and Endesa France have been undertaking a series of investments to modernise their coal plant to enable them to continue running till 2015. We have assumed that some of the newer coal-fired plants will operate beyond 2015. This will require EDF to fit further de-NOx equipment to the power plants to meet the LCPD. Table 29 provides a summary of closure dates that we have assumed for these particular plants.

With respect to Pressurised Water Reactors (PWR) we have assumed a lifetime of 50 years, but since the first one was built in 1977 (Fessenheim), most PWR plant will be running throughout the entirety of the modelled period.

⁷⁷ "Coal-fired competition hots up in France". Platts Power in Europe. Issue 411. 13 October 2003.

⁷⁸ EDF Group Annual Report 2007. EDF.

Table 29 – Assumed closure dates for a number of French coal-fired and oil-fired plants

Plant name	Type	Capacity	Last year of operation
Blénod	Coal	3 x 258	2015
Cordemais	Fuel Oil	693	2013
Cordemais	Coal	2 x 600	2014
La Maxe	Coal	2 x 250	2015
Le Havre	Coal	1 x 250, 2 x 585	2015

Source: Platts and Pöyry Energy Consulting

4.8.1 Projected conventional new entry

Regarding commissioning dates of plant owned by EDF we have used a number of sources. This includes the INSC⁷⁹ database for the commissioning dates of each of the nuclear units, EDF's history for commencement of oil- and coal-fired plants, and Platts Power Station Tracker for new CCGT plants⁸⁰.

Our modelling of plant coming on line have been informed by the dates indicated in Table 30. We have assumed that if they are commissioned, these plants will have efficiencies consistent with other similar types of plant.

We assume that generic new CCGTs, OCGTs and coal-fired plant come on-line as required to ensure that there is adequate supply at all times. We only explicitly include in the model the power plants that are currently under construction, and base our generic new entry assumptions on existing projects, market analysis and RTE's forecasts.

⁷⁹ International Nuclear Safety Centre – operated by Argonne National Laboratory for the US Department of Energy. http://www.insc.anl.gov/pwrmaps/map/world_map.php

⁸⁰ New Power Plant Tracker. Platts Power in Europe. September 2007.

Table 30 – Proposed new plants in France

Status	Location	Type	Capacity	Company	Online Date
Construction	Pont-Sur-Sambre	CCGT	412x1	Poweo	2009
Construction	Fos-sur-Mer	CCGT	480	GdF Suez	2009
Construction	Emile Huchet	CCGT	400x2	Endesa France	2009
Construction	Flamanville	Nuclear	1600	EDF	2012
Approved	Cordemais	Fuel Oil	600	EDF	2007
Approved	Vaires, Vitry	GT	555	EDF	2008
Approved	Hornaing	CCGT	400	Endesa France	2009-10
Approved	Lucy	CCGT	420	Endesa France	2010
Proposed	Montoir	CCGT	400	GdF	2009
Proposed	Bayet	CCGT	400	Atel	End-2009
Proposed	Saint-Brieux	GT	200	GdF	2010
Proposed	Blenod	CCGT	440	EDF	2010
Proposed	Martigues	CCGT	930	EDF	2010
Proposed	Vaires,Monterau	GT	555	EDF	2010
Proposed	Beaucaire	CCGT	800	Poweo	2011
Proposed	Toul	CCGT	400	Poweo	2011
Long-term plans	To be determined		400	Endesa France	
Long-term plans	To be determined		400	Poweo	2011
Long-term plans	Le Havre	Coal	800	Poweo	2012

Source: Platts, press articles

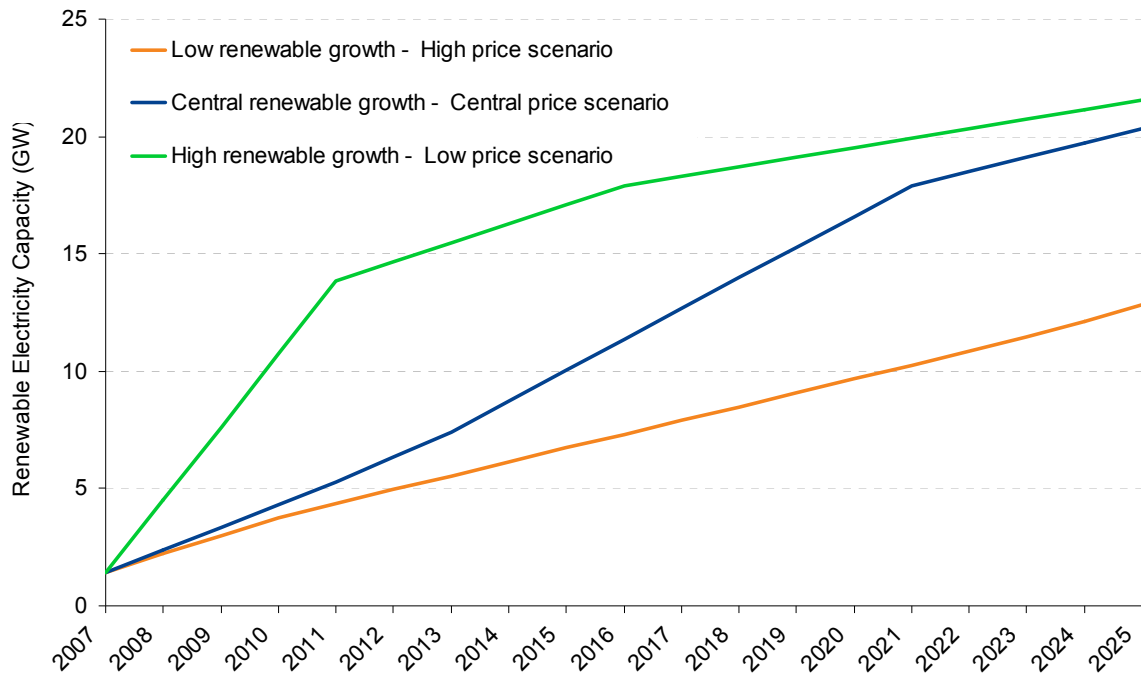
4.8.2 Projected renewable construction

For the purpose of projecting the contribution of renewables in France, we have assumed varying degrees of achieving the capacity targets presented in Table 7 (section 3.1.1) and have also examined both RTE and SER projections to develop a range of scenarios to determine the range of plausible renewable capacity growth over the next decade.

As shown in Figure 35, the High and the Central renewable growth scenarios end-up to approximately the same generation capacity of 20GW, but with a different timing. This is in line with the industry feeling that the PPI objectives for 2010 are unlikely to be met, but that the long-term targets are achievable⁷³. Most of the renewable capacity is made-up of wind, with an increasing proportion of off-shore wind over time.

The renewable scenarios are linked to our demand and capacity scenarios in an inverse relationship; i.e. the low renewable scenario is combined with our high demand and high thermal capacity scenario and so on.

Figure 35 – Renewable capacity projections



Source: Pöyry Energy Consulting Analysis

The generation from each type of renewable technology is calculated based on the assumed load factors shown in Table 31. For the wind plant we assume a flat operating profile over the year – which reflects the fact that wind is intermittent.

Table 31 – Renewables load factor assumptions

Technology	Load Factor
Onshore Wind	25%
Offshore Wind	35%
Biomass	66%
Solar	9%
Geothermal	85%
Other Renewables	52%

Source: Pöyry Energy Consulting Analysis

4.8.3 Interconnectors

France has existing interconnectors with the UK, Spain, Germany, Belgium, Italy and Switzerland. Using information from RTE, we have modelled these interconnectors as shown in Table 32.

In all scenarios, we have modelled increases in interconnection capacity with Spain (in 2010) and Belgium (2008 and 2012).

Table 32 – Seasonal interconnection capacity (GW)

Exports (GW)	UK	Spain	Belgium	Germany	Switzerland	Italy
2007	2.0	0.5	2.2	3.3	2.3	2.7
2008	2.0	0.5	2.5	3.3	2.3	2.7
2009	2.0	0.5	2.5	3.3	2.3	2.7
2010-onward	2.0	1.0	2.5	3.3	2.3	2.7
Import (GW)	UK	Spain	Belgium	Germany	Switzerland	Italy
2007	2.0	1.4	3.2	2.9	3.2	2.7
2008	2.0	1.4	3.5	2.9	3.2	2.7
2009	2.0	1.4	3.5	2.9	3.2	2.7
2010-onward	2.0	1.9	3.5	2.9	3.2	2.7

Source: Pöyry Energy Consulting Analysis, ETSO

4.8.4 Hydro

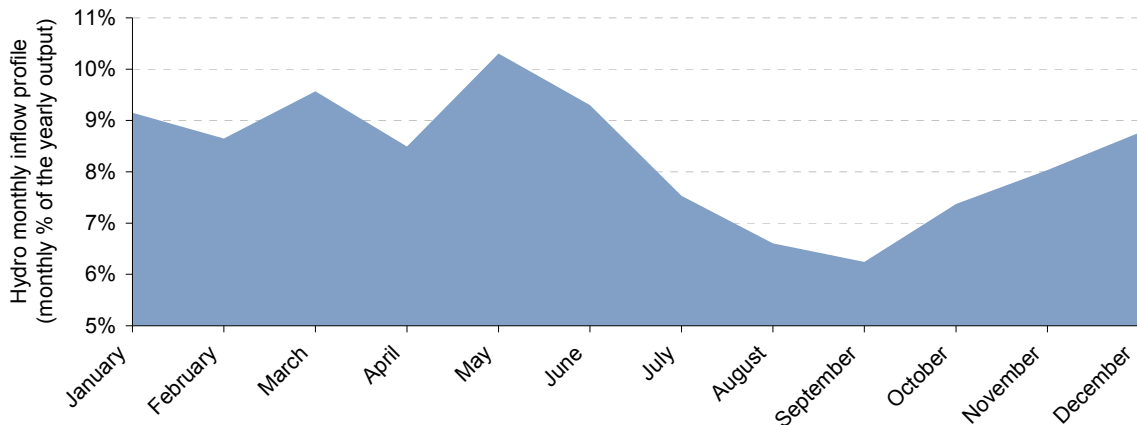
We model non-pumped storage hydro generation in EurECa by optimising its use subject to a number of parameters:

- total hydroelectric capacity and generation are assumed to stay flat at 17.2GW for 66TWh annually;
- the minimum output in any one hour period in each year is 3GW, which is approximately the uncontrollable capacity run-of-river; and
- we assume an inflow profile, which determines the proportion of annual inflow energy into the country's reservoirs each month (see Figure 36).

We have assumed an inflow profile equal to the average historical hydro production in France over the last fifteen years and we allow the model for a limited amount of within-year flexibility. There is a full flexibility of hydro use within-month and within-day, subject to the conditions above.

For modelling of pumped storage, we assume a total of 4.4GW is connected to the French grid.

Figure 36 – Hydro inflow profile (TWh/month)



Source: Pöyry Energy Consulting Analysis

4.8.5 Evolution of Generation capacity between 2007 and 2030: summary

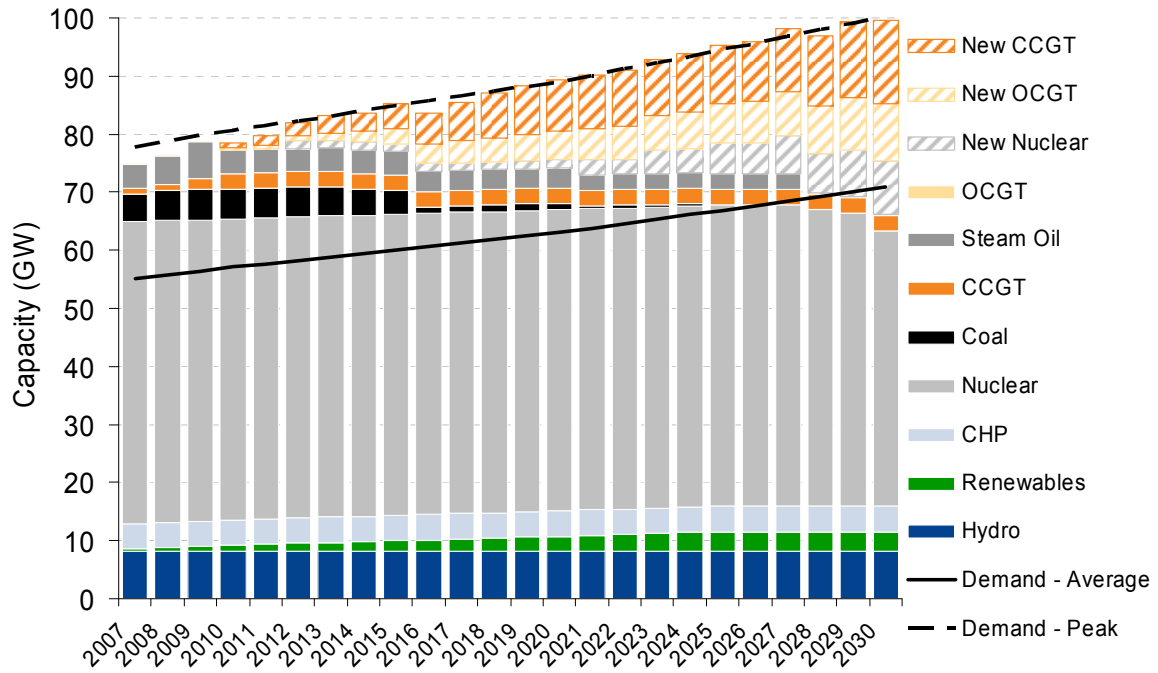
Based on our assumptions regarding total conventional generation, renewable plant, CHP capacity and imports versus our demand projections, we have derived three different capacity scenarios, High, Central and Low.

In the long-term we assume that new capacity will enter the French market to meet the increase in demand. We have assumed a level of generic OCGT and CCGT new entry to ensure that the capacity margin remains adequate at times of maximum summer demand – this is the critical period for the French system due to the large volume of CHP plant that does not run at that time. In addition to the EPR in Flamanville, we see new nuclear plants being built after 2021 in all three scenarios, to a different extent depending on electricity demand growth. We have also included imports (increasing or decreasing) from neighbouring countries over time.

Figure 37 to Figure 39 illustrate how the above assumptions translate into firm capacity⁸¹ at maximum peak by plant type for the High, Central and Low scenarios respectively. Note that imports are not shown in the Figures.

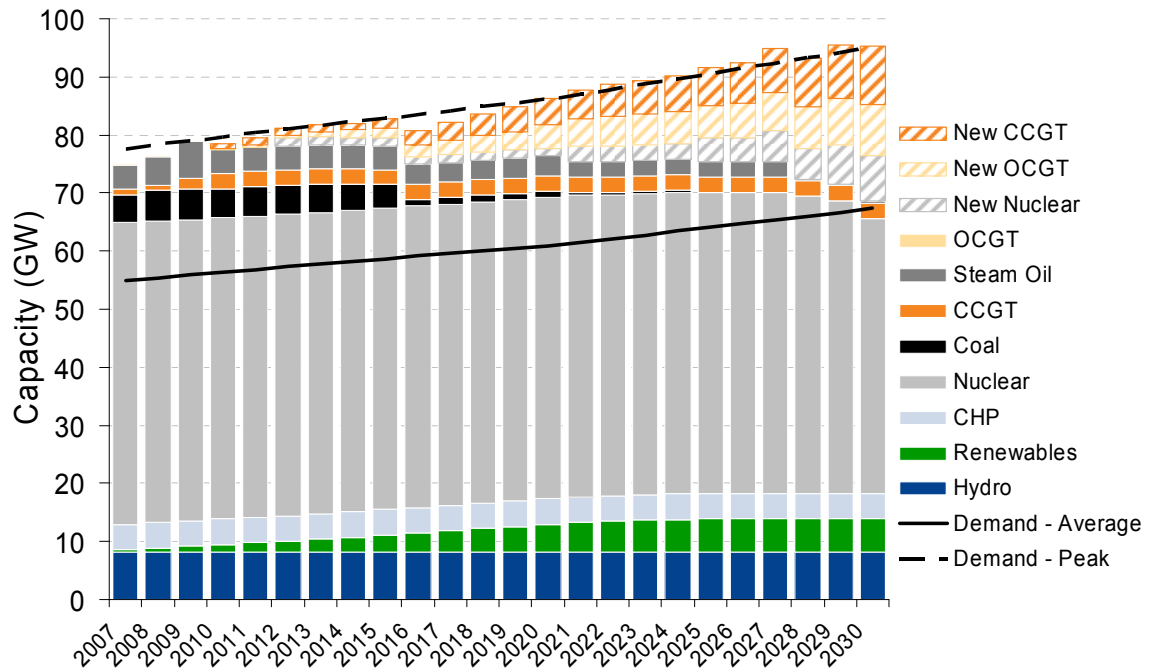
⁸¹ The measure of capacity is 'firm capacity at time of a peak demand', calculated assuming plant availabilities in winter or summer accordingly and a realistic hydro availability. It should be noted that at times of peak demand, a much higher hydro capacity would be available to call upon.

Figure 37 – Firm capacity at maximum peak in the High scenario by plant type



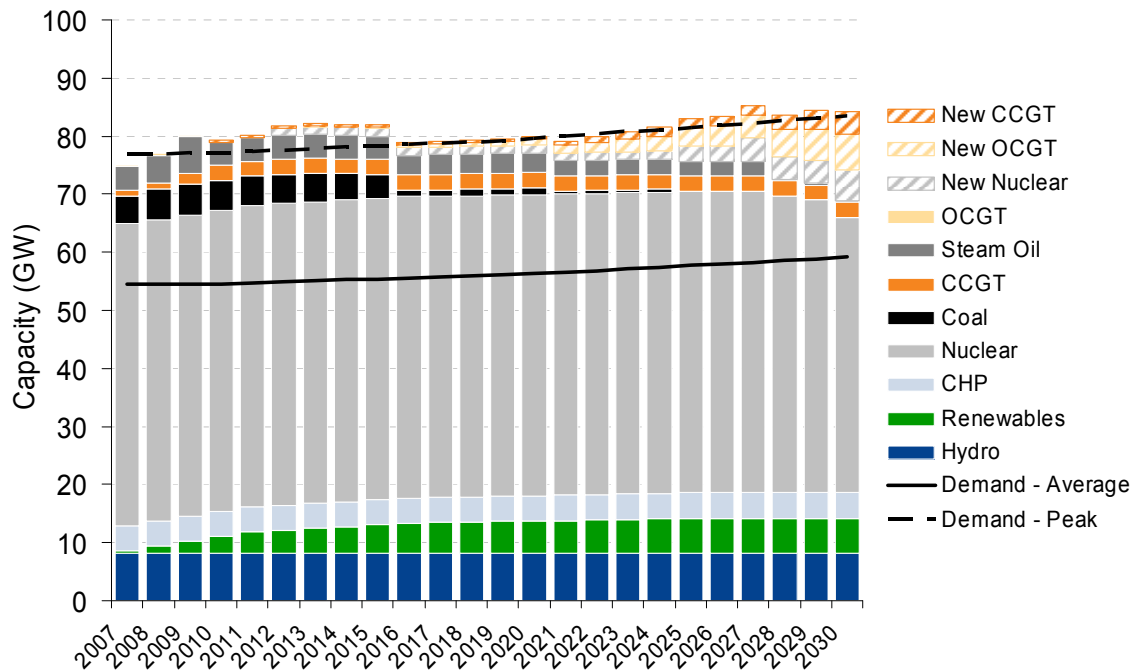
Source: Pöyry Energy Consulting

Figure 38 – Firm capacity at maximum peak in the Central scenario by plant type



Source: Pöyry Energy Consulting

Figure 39 – Firm capacity at maximum peak in the Low scenario by plant type



Source: Pöyry Energy Consulting

4.9 Thermal power station characteristics

4.9.1 Plant efficiency

The plant efficiencies for existing plant have been estimated by comparing the age of the genset with a similar age and type of genset for which we know the efficiency. Some interpolation has been used for those years in which we have no plant of the same age. As a result, the efficiencies vary by genset age and type of plant.

We assume average annual efficiencies for electricity sent-out, net of internal power station consumption, compared with the gross (or higher) calorific value of the fuel to the station. These are known as higher heating value (HHV) efficiencies.

For power stations burning fossil fuel, Pöyry uses an individual efficiency for each and every genset. Those for oil-fired and conventional gas-fired plants are in the approximate range of 30% to 36%. Coal-fired plants (with FGD) have efficiencies of about 33–37%.

Existing gas turbine ‘peakers’ have efficiencies of around 26%.

For new build CCGTs the figure is linked to the date of plant commissioning – as follows:

- commissioned between 2000 and 2009 inclusive: 50%;
- commissioned between 2010 and 2015 inclusive: 52% rising to 55%; and
- commissioned after 2015: 55%.

For new gas-fired OCGTs we assume an efficiency of 35% based on a number of quoted efficiencies for new plant.

4.9.2 Variable other work costs

Variable other works costs (VOWC) cover the non-fuel variable costs that a power station incurs in operation. We have assumed VOWC costs for different plant types as shown in Table 33. With regards to CCGTs we only treat strictly marginal costs as being in VOWC, and capture maintenance costs in station 'fixed costs'.

Table 33 – VOWC (2006 €/MWh)

Plant type	VOWC
Gas Turbine	0.82
Combined Cycle Gas Turbine	0.82
Gas-Fired Steam Cycle	1.15
Oil-Fired Steam Cycle	1.31
Coal-Fired Steam Cycle	1.50
CHP	1.16

Source: Pöyry Energy Consulting

4.9.3 No-load and start-up costs

Information on no-load and start-up costs for existing plant is not readily available. We have used values based on our experience. The level of cost will depend on the actual operation of a particular genset, such as how long it operates for, and to what extent it is part-loaded. Details of these figures are shown in Table 34.

Table 34 – Start-up and No-load energy

Plant type	Start-up energy	No load energy (Gross GJ/hr/GW)	Start-up maintenance cost (€/GW)
Gas Turbine	1,208	80	14,400
Combined Cycle	3,463	857	14,400
CHP	3,463	857	14,400
Conventional Steam Cycle	5,360	846	16,000
Nuclear	0	0	16,000

Source: Pöyry Energy Consulting

4.9.4 Plant availability

The assumptions on availability are shown in Table 35. The availability types indicate which availability pattern each of the plant will follow. The availabilities are calculated for each month, based on a seasonal availability profile where maintenance is concentrated in summer.

These availabilities also take account of temperature effects where these reduce the plants' effective capacity (such as for CCGTs and OCGTs).

Table 35 – Net guaranteed capacity and availability patterns

Plant Type	Winter	Spring/Autumn	Summer	Annual
Combined Cycle	94%	85%	84%	88%
Gas Turbine	95%	95%	90%	94%
Steam cycle (coal-fired) ⁸²	76%	67%	67%	70%
Steam cycle (gas-fired)	95%	87%	80%	88%
Steam cycle (oil-fired)	93%	85%	80%	86%
Nuclear	83%	77%	75%	78%
Onshore wind	24%	24%	24%	24%
Offshore wind	35%	35%	35%	35%
Biomass	66%	66%	66%	66%
Other renewables	52%	52%	52%	52%

Source: Pöry Energy Consulting

4.9.5 CHP

For CHP capacity figures, our analysis draws heavily on data presented in the CEREN report “CHP Statistics and Impacts of the Gas Directive on the Future Development in Europe” dated 21 October 2002. Specifically, much use is made of data in Tables A and B1 of Section 3.12 on France. There has been no significant evolution of capacity in France over the last five years.

The data on efficiencies and fuel consumption in the above report are with respect to ncv – the net, or lower, calorific value of the fuel. Pöry conventionally uses gcv – the gross, or higher, calorific value. We have therefore converted from ncv to gcv throughout, using conventional factors of 0.903 for gas and 0.95 for coal and oil.

4.10 The cost of new entry

In developing our projections of generic new entry we need to ensure that if we assume new entry is required then the wholesale electricity prices need to be consistent with the long-run marginal cost (LRMC) of new entry. We consider two cases for the ‘new entrant’ power station:

- the new entrant is an advanced CCGT, operating at baseload⁸³;

⁸² We have modelled some coal plants with a lower availability because they are contracted with EDF to provide support services and therefore won’t run at their full technical availability.

⁸³ i.e. up to its technical availability.

- the new entrant is an OCGT plant operating as a mid-merit or peaking plant, and in the limit operating only at times of very high demand.

Data for each of these three new 'new entrant' cases are presented in Table 36 and draw upon:

- a wide range of published sources;
- Pöyry's knowledge of actual projects (particularly of CCGTs developed in the UK and elsewhere in Europe); and
- the expertise and experience of engineers within the wider Pöyry Plc.

Corresponding data for a CCGT of current technology is also presented in Table 36.

Table 36 – Pöyry new entry assumptions for France (real 2006 money)

	Current CCGT	Advanced CCGT	Current OCGT
Capital cost (€/kW)	648	648 - 864 ^{84,85}	303
Fixed Other-Works Costs (FOWC) (€/kW)	36 ⁸⁶	32 ⁸⁶	20 ⁸⁷
Variable Other-Works Costs (VOWC)	0.04	0.06	0.72
Efficiency (HHV ⁸⁸)	49%	54%	35% ⁸⁹

Source: Pöyry Energy Consulting

Our experience of the project finance of independent power projects (IPPs) across Europe shows that their projected cash flows for a CCGT under a central view of the future, taken at the time, can be broadly characterised as meeting a 11% rate-of-return (pre-tax, real) over an accounting period of 15 years from commissioning.

Applying these financial criteria to the above data for an advanced CCGT technology⁹⁰ gives the following new entrant formula for the Central scenario:

Advanced CCGT: **$19.15 + 0.6319 \cdot g$ (2006 €/MWh)**

The corresponding formula for a CCGT of current technology is:

⁸⁴ Capital costs for CCGTs range from €648/kW in the Low case to €720/kW in the Central case and €864/kW in the High case.

⁸⁵ This comprises all capital costs to be covered by the financing of the plant except for interest-during construction and debt service reserve.

⁸⁶ Assuming (for the base-load plants) that the costs of scheduled plant overhauls are fixed.

⁸⁷ Assuming (for the peaking plant) that these costs are variable.

⁸⁸ Higher Heating Value.

⁸⁹ At 1000 hours operation per annum.

⁹⁰ Assuming a load factor of 85%, a construction period of 2 years and an operating period of 30 years for the CCGT.

Long-term (post 2010) CCGT: $19.42 + 0.6964 \cdot g$ (2006 €/MWh)

where g is the price of gas, input in €/therm.

We use these formulae to derive our medium-term and long-term new entrant projections. It should be noted that these projections are intended as a guide; for new entry to be economically justifiable we might expect prices to be above these guidelines initially, falling below them by the end of the project lifetime.

Open-cycle gas turbines (OCGTs) are less efficient, but cheaper than CCGTs. As such they can be the most economic option for peaking or mid-merit plants (subject to being able to access sufficiently flexible gas purchase contracts).

If, in the limit, such a plant were not to operate at all, the value of capacity that it would set can be calculated to be €72.27/kW p.a., assuming a construction period of two years and 13% pre-tax, real return over fifteen years after commissioning. On a time-weighted average (TWA) basis this is equivalent to €8.25/MWh, which is used as one indicator of the value of capacity in our price projections in the following section.

5. WHOLESALE ELECTRICITY PRICE PROJECTIONS

This chapter details Pöyry projections for wholesale electricity prices in France for 2007 to 2030. These projections represent the wholesale price at the station gate in France, which is on the grid side of the station transformer, before transmission losses are taken into account.

5.1 Developing our Price Projections

We construct our price projections for each scenario by combining the following components:

- the projected system marginal price; and
- the projected value of capacity.

While there is only a single price per hour in the day-ahead market, i.e. no explicit capacity payment, we model each component separately and combine them together to give the day-ahead wholesale price.

5.1.1 System marginal price

The system marginal price (SMP) is calculated as the variable operating cost (comprising fuel, carbon, other variable, start-up and no-load cost components) of the most expensive plant required to run during each half-hour. The SMP is calculated using Pöyry's *EurECa* model, which projects electricity prices, output and cross-border flows for twenty-five European countries, taking account of flows from a further six neighbouring countries.

5.1.2 Value of capacity

The value of capacity is calculated to ensure that the total revenue a generator would receive from the market is such that the generating plant will be available when required. We have modelled two possible limits of capacity payment, based on the underlying value of generation capacity.

In a medium to long-term equilibrium, the price earned by generators should reflect the cost of efficient new entry, whether or not capacity is priced explicitly (if this were not the case, prices would rise or fall until an equilibrium situation were reached). The value of capacity payments should be broadly in line with the capital and fixed costs (net effective costs – NEC) of a peaking plant (such as an open-cycle gas turbine), which we calculate to be €8.25/MWh (refer to section 4.10). In instances where this level of capacity payment is not sufficient for new entry CCGT and/or coal plant⁹¹ to be brought on, we raise or lower this value of capacity so that total revenue is sufficient to bring new capacity into the market when required.

In the short to medium term, the value of capacity could fall to a level just sufficient to retain existing plant on the system (i.e. to cover the fixed costs of keeping the plant open

⁹¹ Depending on the wholesale electricity price scenario being considered at the time. Most new entry will be in the form of CCGT or coal, because of the lack of a capacity payment mechanism to incentivise peaking plant.

and available to operate, if needed)⁹². We refer to this as the Net Avoidable Fixed Cost (or NAFC) of retaining plant. We use a value equivalent to around €4.35/MWh (averaged across the year)⁹³; we understand that this broad level is reasonable to use in the European context.

5.2 Developing our scenarios

We have used our modelling expertise to create four scenarios that we feel cover a reasonable and internally consistent set of outcomes for wholesale prices within France, with the aim of examining the effect on prices of a number of key drivers:

- fuel prices (coal, oil and gas);
- gas market liberalisation;
- CO₂ prices;
- electricity demand;
- new power station construction and plant retirements; and
- costs and performance of new entrants.

These four scenarios can be summarised as follows, and as in Table 37 below:

- **High.** The High price scenario examines the effect of high fuel prices, driven primarily by crude oil prices staying high and reaching \$95/bbl by 2030 in real terms. The high oil prices in turn drive up gas prices through indexation. We also assume that electricity demand growth will be relatively high with limited new renewables build leading to high levels of new thermal plant construction, and new nuclear reactors after 2021.
- **Central oil-indexed.** In the Central oil-indexed scenario, we assume that demand and supply remain matched and gas prices remain indexed to our central oil price projections of \$50-60/bbl in the medium to long term as liberalisation throughout Europe either does not occur, or does not break the contractual linkages between oil and gas.
- **Central oil de-linked.** As in the Central oil-indexed scenario demand and supply remain matched but under this scenario North West European gas prices break the link with oil and fall to our central projections of long-run marginal costs of supply. As gas prices fall, gas fired new entry becomes increasingly competitive in France.
- **Low.** In the Low scenario, low demand for electricity is combined with a relatively high system margin and low fuel prices as we assume that gas prices break the link with oil, causing them to fall to the long-run marginal cost of supply. Low demand growth combined with high renewables build means that the quantity of thermal plant built under this scenario is low.

⁹² Such a situation could arise where new investment is occurring ahead of need. For example, in England and Wales since 1990 new investment in baseload CCGTs beyond the level necessitated by demand growth and plant retirements has meant that capacity payments to incentivise enough plant to remain on the system have been sufficient to match supply with demand. There has been no necessity for new peaking plant to enter the market.

⁹³ This calculation is based on a fixed cost of around €38/kW p.a which is roughly equivalent to the annual fixed costs of an existing coal plant.

There is no particular reason why, for example, oil prices should be high at the same time as gas prices, once the gas market is liberalised. However, our approach ensures that we capture the full range of plausible price futures; for example, electricity prices would be higher with high gas and high coal prices than with high gas and low coal prices.

Evaluation of all possible combinations of input assumptions would result in a very large number of scenarios. Some of these would be internally-inconsistent. A more practical approach is to select a much smaller number of scenarios, combining internally-consistent combinations of input assumptions, for detailed evaluation.

In examining the economics of specific generation projects, there would be merit in considering a wider range of fuel price combinations. It would also be important to consider an individual plant's position in the merit-order to determine its operating profile and therefore revenues, rather than just assuming the plant will price-take and operate at base-load. For details of our assumptions regarding new entry, refer to section 4.8.

One of the core uncertainties in the future is the effect of the EU ETS (EU Emissions Trading Scheme) and a subsequent value of carbon. To date, the carbon price appears to have had some impact on French electricity prices, but there is still some uncertainty as to how the value of carbon will evolve and the extent it will continue to be passed through to wholesale prices during Phase II and beyond. Our four scenarios examine the impact that different carbon prices may have on the final wholesale electricity price, with pass-through gradually increasing during Phase II. Table 37 summarises our scenario assumptions.

Table 37 – Summary of scenarios

	Demand	New conventional build	Value of capacity	Fuel prices
High	High	High due to low renewables growth	High from 2010	High
Central oil-indexed	Central	Intermediate with central renewables growth	High from 2011	Central with oil-indexed gas prices
Central oil de-linked	Central	Intermediate with central renewables growth	High from 2011	Central with oil de-linked gas prices
Low	Low	Low thermal build, with high renewables growth	Low until 2014 then increasing to high by 2017 and for the rest of modelled period	Low

Source: Pöyry Energy Consulting

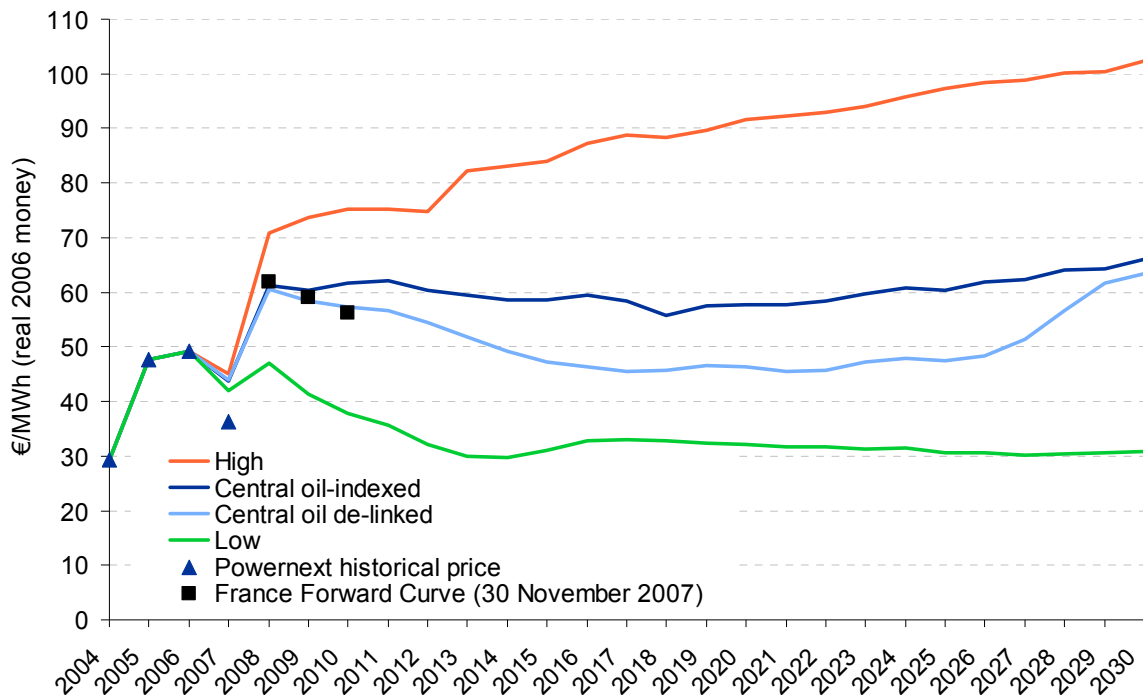
5.3 Projections

The EU ETS and its impact on the French electricity market is considered in more depth in sections 2.6.1 and 4.6. For the purposes of our modelling of prices with a value of carbon, we assume that the full cost of carbon is passed through into electricity prices.

The results of the four scenarios with a value of carbon are summarised in Figure 40 and Table 38 and are discussed in further detail in the following sections. Figure 40 also

shows the current forward curve, which we use as a rough comparator against our projections. Forward prices are continually changing, and are based on a low level of liquidity. Nonetheless, our Central scenarios are in line with the current forward curve.

Figure 40 – Wholesale electricity price projections for France including a value of carbon (€/MWh, real 2006 money)



Source: Pöyry Energy Consulting Analysis

The path of time-weighted average (TWA) price projections are shown in Figure 41 to Figure 44 compared with the new entry cost for CCGTs (see section 4.10). A cost band is shown for new entry; this represents a range of +/-10% about our central view of new entry cost reflecting the natural variation between plants which occurs because of differences in local and plant specific conditions⁹⁴.

We also compare scenarios according to the average load-factor of a generic CCGT new entrant. This analysis has been carried out for a generic new entry CCGT in France between 2010 and 2015, and does not refer to any of the existing projects.

⁹⁴ There is not a single new entry price. Rather, each project has a unique set of cost factors – capital cost, efficiency, fuel contract, transportation charges, connection charges, O&M, etc. – which in our judgement gives a range of +/- 10% about a middle level for the total new entry price.

Table 38 – Wholesale electricity price projections for France including a value of carbon (€/MWh, real 2006 money)

	High	Central Oil-Indexed	Central Oil-delinked	Low
2007	45.01	43.80	43.88	42.08
2008	70.94	61.19	60.67	47.04
2009	73.79	60.29	58.44	41.42
2010	75.32	61.62	57.38	37.93
2011	75.20	62.14	56.60	35.62
2012	74.72	60.35	54.37	32.10
2013	82.23	59.46	51.80	29.89
2014	83.15	58.63	49.30	29.70
2015	83.95	58.62	47.17	31.16
2016	87.21	59.41	46.39	32.72
2017	88.68	58.46	45.58	33.02
2018	88.25	55.87	45.62	32.70
2019	89.74	57.45	46.66	32.38
2020	91.71	57.66	46.27	32.18
2021	92.20	57.81	45.44	31.79
2022	92.92	58.32	45.77	31.78
2023	93.93	59.73	47.23	31.30
2024	95.72	60.90	47.81	31.48
2025	97.23	60.29	47.56	30.52
2026	98.50	61.98	48.40	30.54
2027	98.80	62.37	51.31	30.22
2028	100.13	64.06	56.70	30.36
2029	100.42	64.32	61.69	30.53
2030	102.27	65.94	63.36	30.81

Source: Pöyry Energy Consulting Analysis

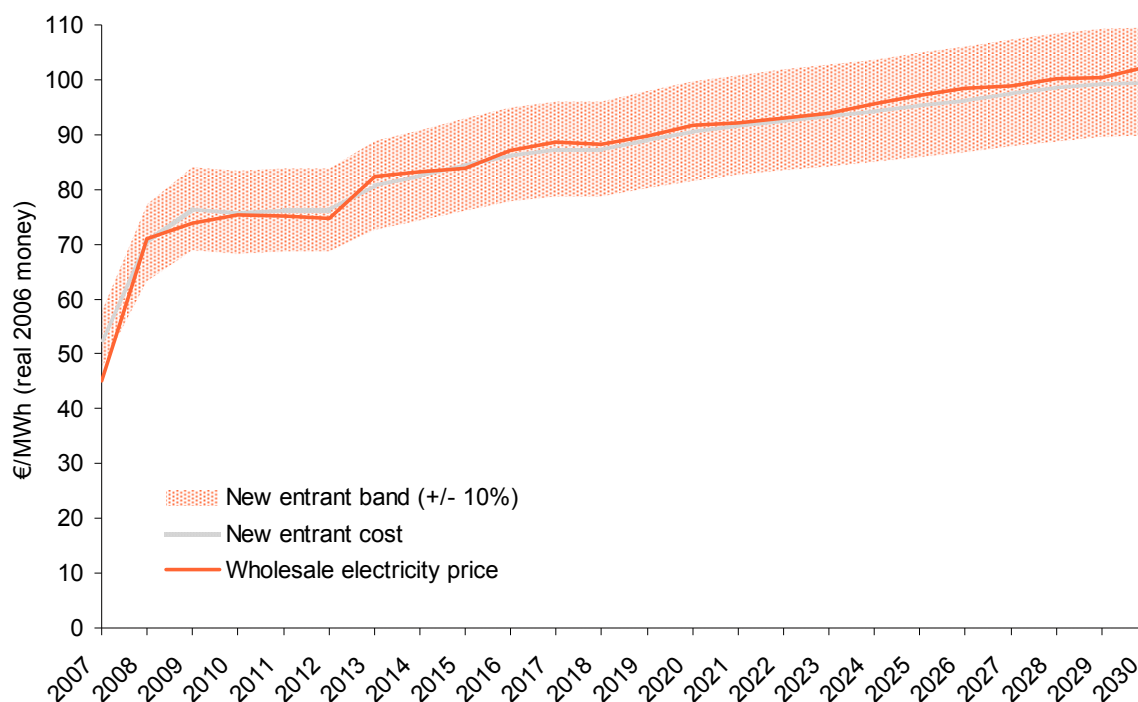
5.3.1 High with carbon

In our High with carbon scenario, the two most important drivers of high electricity prices are high demand and high fuel prices, with gas fired generation generally expensive relative to coal fired generation.

High oil prices (of around \$90/bbl) and the continuation of oil-indexation across NWE leads to gas prices of around €34/MWh. With ARA coal at around \$77/tonne and carbon prices rising to €30/tCO₂ for Phase II and €40/tCO₂ for Phase III and beyond we project high wholesale electricity prices of around €70/MWh in the initial years. Given relatively high demand growth and the need for new capacity, the value of capacity remains high throughout. In the outer years, wholesale electricity prices rise in line with increasing gas prices, remaining at the top of our new entrant bands and reaching €100/MWh by 2028.

CCGTs built between 2010 and 2015 achieve a 70% load factor in the early years after their building, decreasing to around 30% toward the end of the period considered.

Figure 41 – Wholesale prices and CCGT new entry: High scenario with carbon (€/MWh, real 2006 money)



Source: Pöyry Energy Consulting Analysis

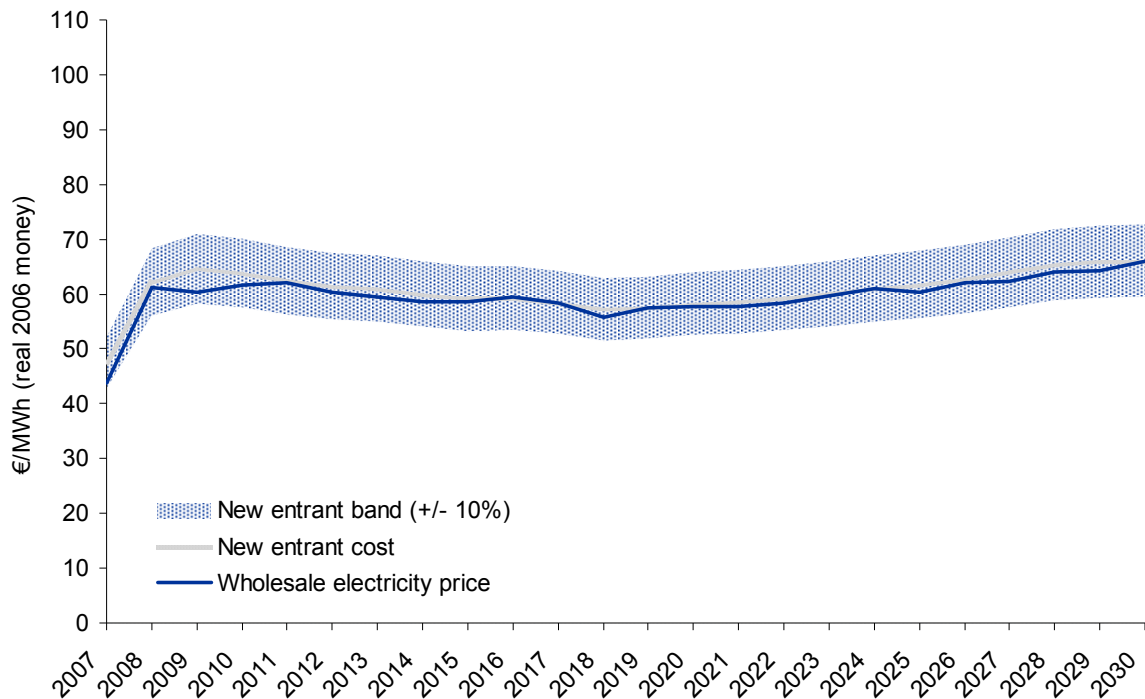
5.3.2 Central oil-indexed with carbon

Our Central oil-indexed projection sees new entry commissioning from 2009 with the value of capacity high from 2011 throughout to support the new plant coming on. Prices remain at new entrant levels throughout with new entry coming on-line in all years.

Overall, prices rise quickly from a low of €44/MWh in 2007 to €61/MWh by 2008 and then remain around the €60/MWh level for the majority of the modelled period. In the outer years, electricity prices start to move upwards in line with a rise in gas prices during this period.

CCGTs achieve load factors from 30% to 50% at the beginning of their life decreasing slowly to low levels, especially after 2025, as newer more efficient CCGTs and new nuclear capacity enter the market.

Figure 42 – Wholesale prices and CCGT new entry: Central oil-indexed scenario with carbon (€/MWh, real 2006 money)



Source: Pöyry Energy Consulting Analysis

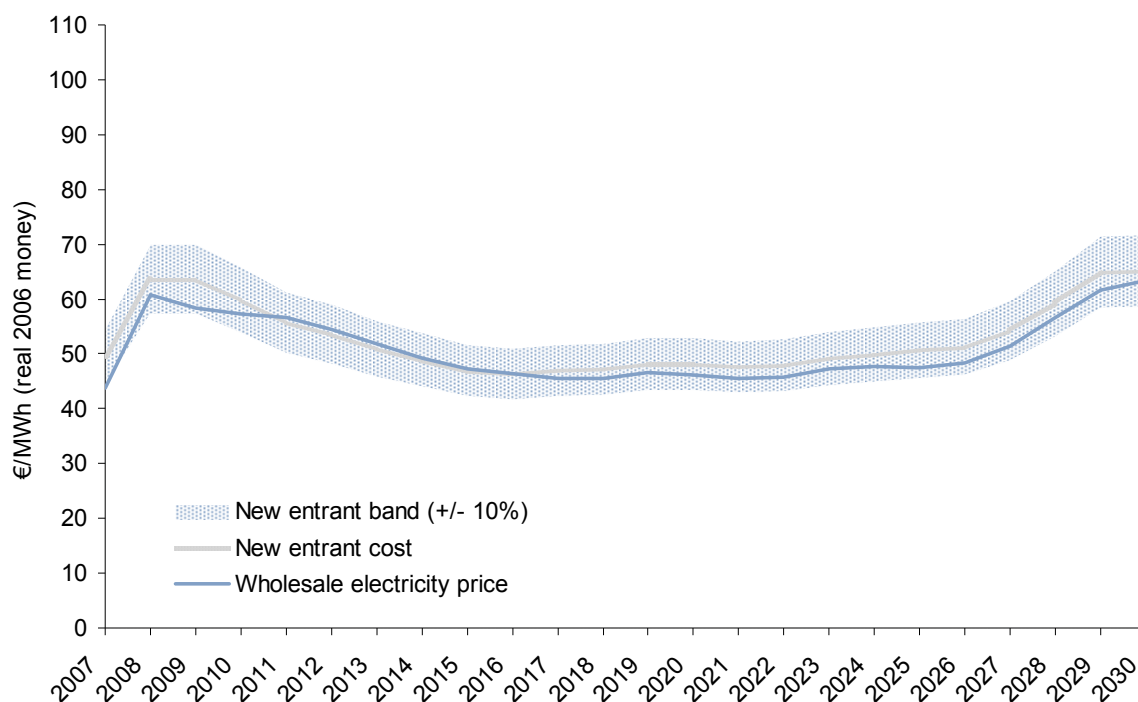
5.3.3 Central oil de-linked with carbon

Our Central oil de-linked scenario sees new entry commissioning from 2009 similar to the Central oil-indexed scenario, but due to the lower gas prices, new build is mainly composed of CCGT capacity in Europe, given that coal new entrants cannot compete at this significantly lower wholesale electricity price.

Overall, prices rise quickly from a low of €44/MWh in 2007 to €61/MWh by 2008 and then start to fall to a low of €45/MWh as gas, coal and oil prices fall to their long-term equilibrium. Wholesale prices then remain around this level until 2026, when they start rising again following the increase in gas prices.

The Central oil de-linked scenario is the most profitable for CCGTs, which run close to baseload levels for around ten years after commissioning. Toward the end of the period, nuclear new entry combined with rising gas prices disadvantage CCGTs and push down load factors.

Figure 43 – Wholesale prices and CCGT new entry: Central oil-delinked scenario with carbon (€/MWh, real 2006 money)



Source: Pöyry Energy Consulting Analysis

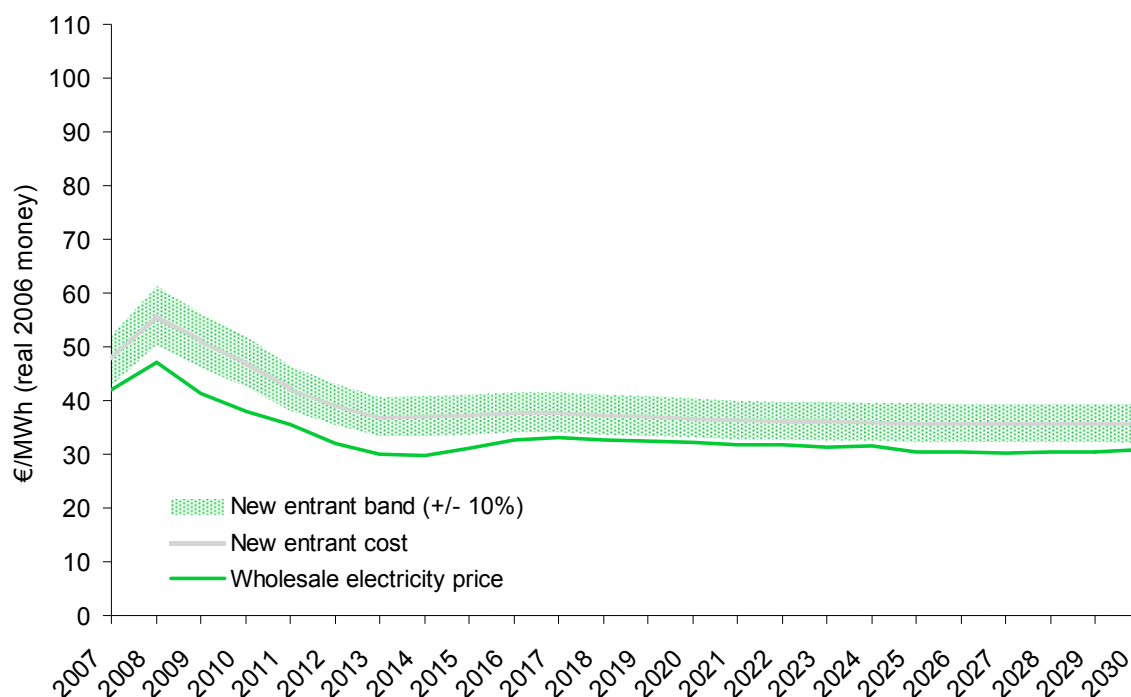
5.3.4 Low with carbon

The key drivers for the Low scenario are low demand, high renewables and low fuel prices. The relatively high system margin leads to a low value of capacity until 2014. In later years, the value of capacity rises to ensure that new entrants in European countries are able to fully recover their fixed and variable costs. There is no conventional new entry in France before 2021 in the Low scenario.

In the Low scenario, gas prices fully de-index from oil by 2010 and fall to low levels of €8/MWh in real terms. This decline in gas prices, combined with coal prices falling to \$32/tonne by 2030 and oil prices at \$35/bbl, leads to the wholesale electricity prices gradually falling to €31/MWh by 2030.

In this scenario, a CCGT commissioned around 2010 would run at a load factor of about 50% for five years and thereafter its load factor would decrease slowly to lower levels.

Figure 44 – Wholesale prices and CCGT new entry: Low scenario with carbon (€/MWh, real 2006 money)



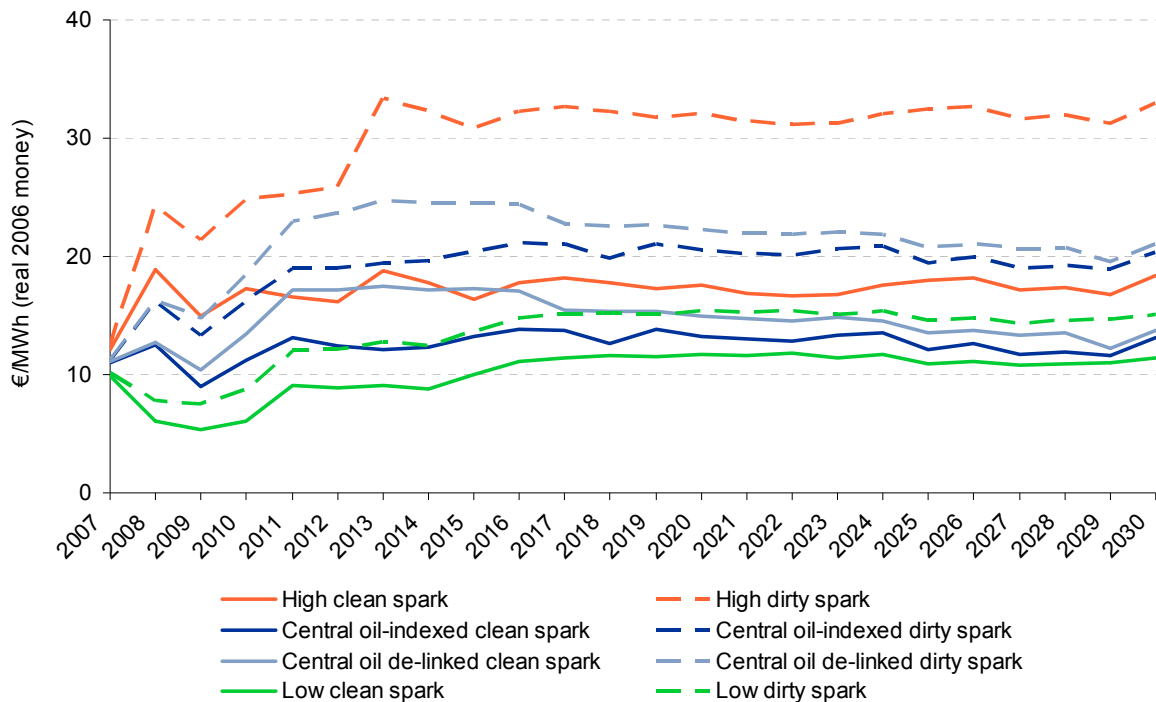
Source: Pöyry Energy Consulting Analysis

5.4 Spark-spreads

For a gas-fired power station, electricity prices only tell half the story. Fuel prices are an important element of total costs. The difference between the power price and the variable production cost of using gas (making an assumption about efficiency – we have chosen 50% HHV here) is termed the spark spread.

In addition to the spark spreads described above (otherwise known as dirty spark spreads), we also show the clean spark spreads which take the full opportunity cost of carbon into account. The clean spark spread is the difference between the power price and the gas plant's carbon-compensated variable fuel costs.

Figure 45 – Projections of French clean and dirty sparks spreads (€/MWh, real 2006 money)



As we have seen in the previous sections, CCGTs in France are unlikely to run baseload, due to the very high proportion of nuclear with a low variable cost. Load factors are generally between 30% and 50% for the Central oil-indexed scenario and around 80% for the Central oil de-linked scenario. The High scenario load factors are also high (close to 80%), whilst the Low scenario load factors are closer to the bottom of the range because there is little need for baseload new entry. Load factors generally decrease towards the end of the modelled period, due to rising gas prices and nuclear new entry. It should be noted that the load factor is heavily influenced by the merit order in neighbouring countries: the relativity between coal and gas generation in Europe significantly changes the running hours of French CCGTs⁹⁵.

As shown in the supply curves, Figure 46 and Figure 47, CCGT is only a marginal technology in France and its load factor may be significantly affected by nuclear availability. If nuclear availability came back to 85%-90% for example (compared with around 80% in 2007), there would be less room for CCGT new entry.

5.5 Supply curves and Price Duration curves

Fundamental to the operation of Pöyry's model, *EurECa*, is the generation of a supply curve for each hour. Rather than showing supply curves for all years across multiple

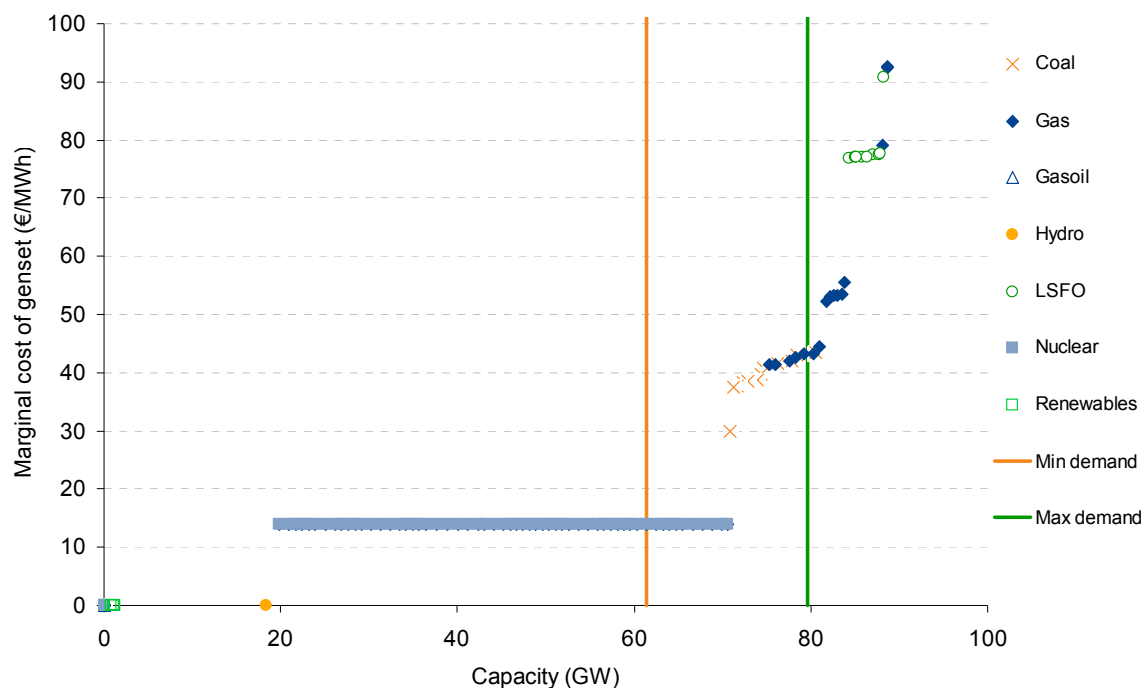
⁹⁵ This analysis has been carried out for a generic new entry CCGT in France and does not refer to any of the existing projects. For any further study on a specific project, using accurate characteristics of the power plant (efficiency, variable other work costs, etc.) is advisable.

scenarios, only the Central oil-indexed scenario supply curves are shown, for a 2010 and 2020 Winter business day as examples.

These supply curves represent only the fuel costs of the plant, and as a result ignore the impact that no-load and start-up costs may have. Furthermore, value of capacity payments are not reflected in the supply curves, which means that the implied prices from the intersection of supply and demand are lower than the final wholesale prices presented above.

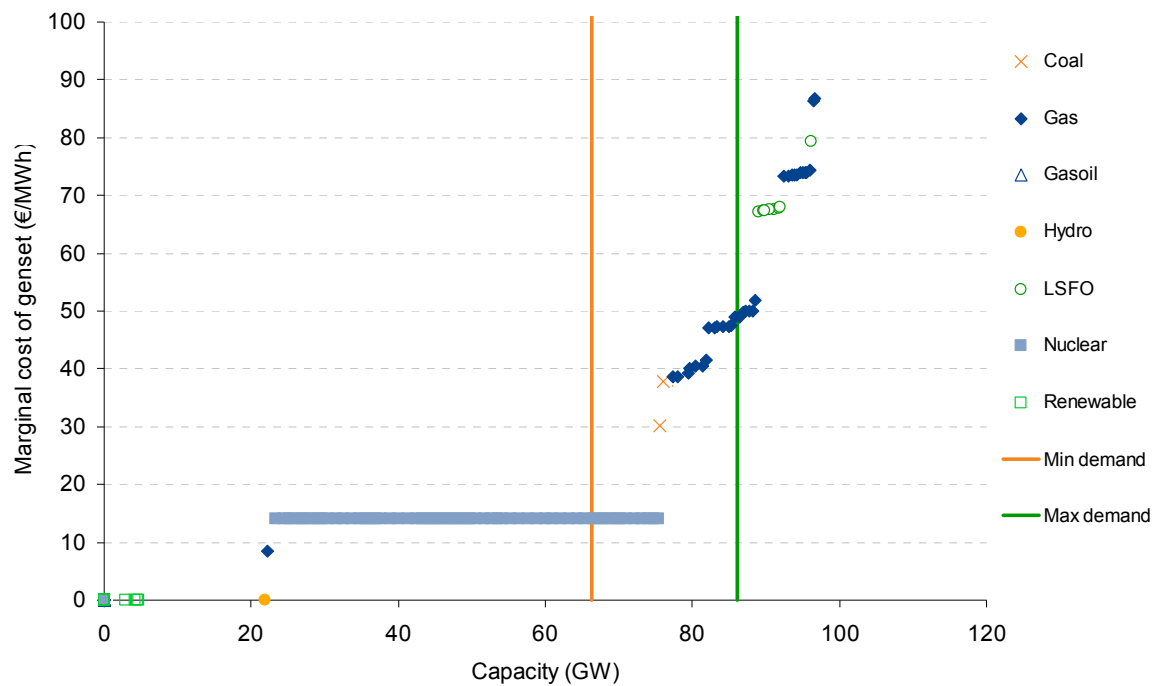
A price duration curve representing the variation of prices during the year is presented in Figure 48.

Figure 46 – Supply curve for Central oil-indexed scenario with carbon for 2010 Winter business day (€/MWh, real 2006 money)



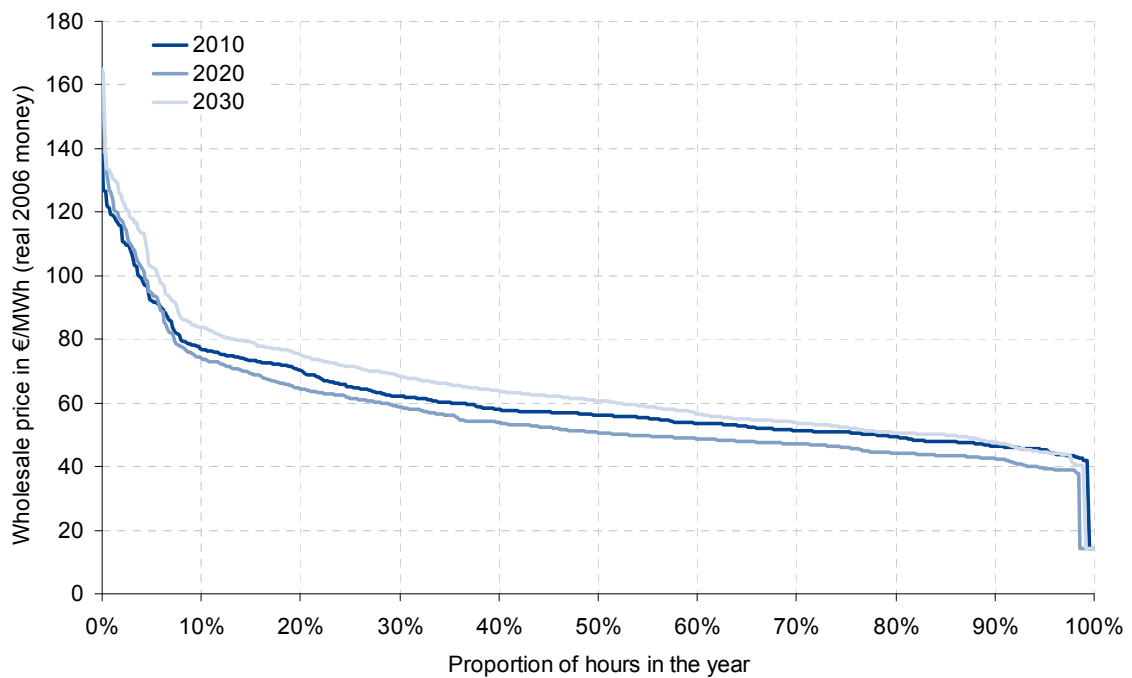
Source: Pöyry Energy Consulting Analysis

Figure 47 – Supply curve for Central oil-indexed scenario with carbon for 2020 Winter business day (€/MWh, real 2006 money)



Source: Pöyry Energy Consulting Analysis

Figure 48 – Price duration curve for the Central oil-indexed scenario (€/MWh)



Source: Pöyry Energy Consulting Analysis

5.6 Concluding comments

These projections are of the underlying level of prices in the market. There may, however, be significant variation of prices about the underlying level, from year to year, driven by factors not modelled here, such as weather, significant plant outages or technical failures. In particular the value of capacity may be much lower than values suggested here in any one year.

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ANNEX A – MODELLING METHODOLOGY

Our electricity model, known as EurECa (European Electricity and Carbon model) is based on linear programming. The model has a database of every medium-large non-hydro genset in (nearly) all of Europe, and we update this database regularly. EurECa can model the whole of Europe or any portion of it. It can be used for projecting both physical behaviour (generator output, fuel use, electricity flows between countries, atmospheric emissions) and economic behaviour (electricity prices and generator revenues).

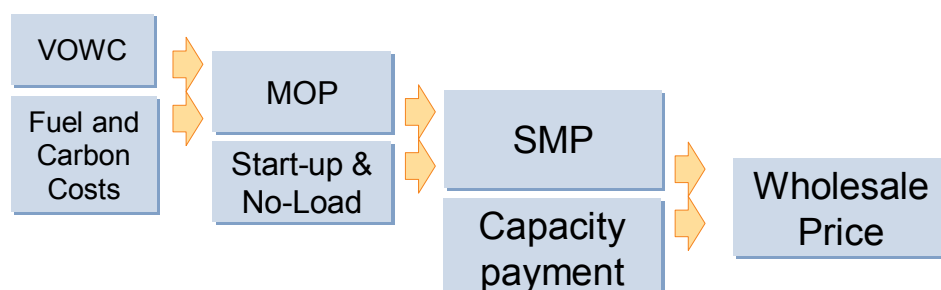
The inputs to the model are the power station database, hydro and pumped storage assumptions, demand assumptions and fuel prices. Twenty-four sample days per year are used to build up hourly results.

EurECa optimises electricity production across Europe by minimising the total variable cost of generation, subject to:

- meeting regional demand on an hourly basis, in each characteristic day;
- hydroelectric reservoir generation constraints in each country;
- pumped storage constraints in each country;
- interconnection constraints between countries or regions;
- pollution constraints (e.g. SO₂ limits under the LCPD);
- commercial constraints (such as take-or-pay levels in fuel contracts);
- heat load requirements at CHP plants; and
- multi-fuel constraints that allow individual stations to switch between fuels.

From this optimisation the model produces a Merit Order Price (MOP) for each country and in each period based on variable costs (fuel costs, carbon costs, and variable other works costs). It then calculates a wholesale electricity price in each country as described in Figure 49. In each country the capacity payment is spread throughout the year as a function of the demand profile, so that it is highest when the demand is highest. (As an alternative, in cases where there is significant historical price data, the capacity element of the wholesale price may be spread on the basis of this historical evidence.)

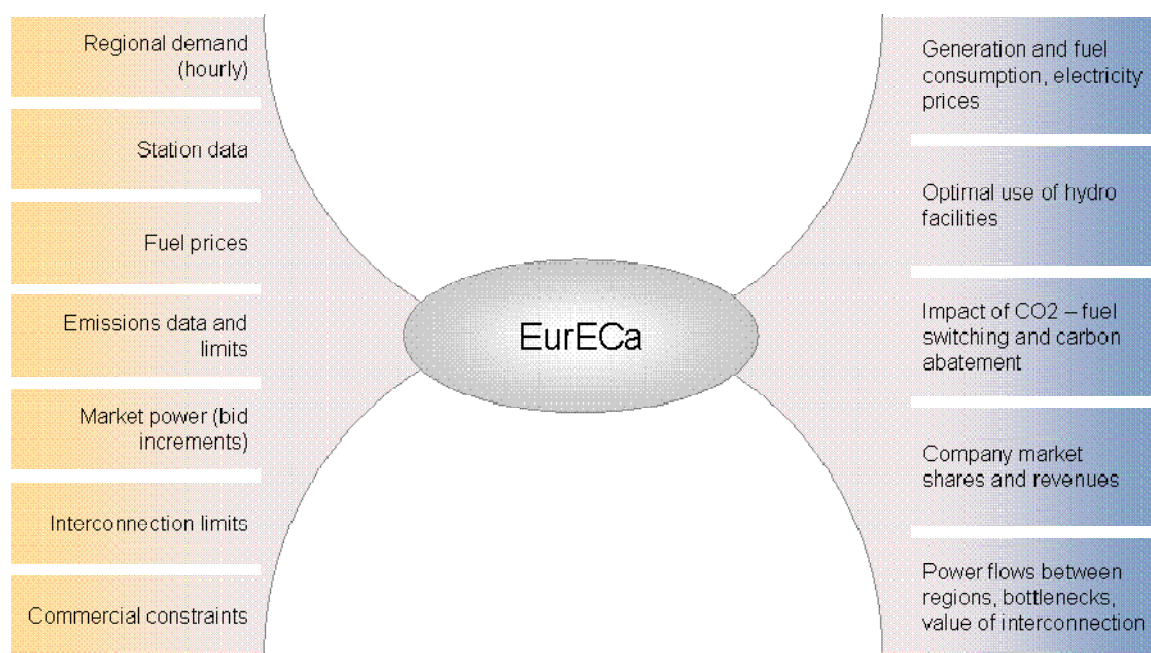
Figure 49 – Calculation of wholesale electricity prices in EurECa



Source: Pöyry Energy Consulting

EurECa may be used not only to estimate future wholesale prices, but also to assess the commercial performance of individual companies or power stations. It can also be used to quantify the utilisation and value of interconnectors. With respect to CO₂, EurECa has been extensively used to develop abatement curves in the EU power sector, and the impact of the ETS on market prices. As well as the carbon intensiveness of each fossil fuel, we take account of the current and future degree of pass-through to electricity prices in each country separately. EurECa is summarised in Figure 50.

Figure 50 – Summary of EurECa – Inputs and Outputs



Source: Pöyry Energy Consulting

ANNEX B – FEED-IN TARIFF TO A WIND FARM

B.1 Introduction

In this Annex, the potential value of renewable energy in France is assessed through worked examples for two wind farms. These examples relate to the present form of support in France, which applies to projects applying for a tariff after 2006. This Annex expands upon the description of the renewable support mechanism provided in Section 3.2.4.

The income to a wind farm comprises of three phases, each of which is explored further below:

- for the first ten years income is based on a base tariff determined by the year in which the project applies for its PPA;
- for the subsequent five years income is based on a tariff determined by the load factor of the windfarm over its first ten years of operation; and
- in all subsequent years the windfarm will not be eligible for any feed-in tariff but may expect to secure an income equal to the wholesale price of electricity in France.

The worked examples are provided for two windfarms, based on the criteria set out in Table 39.

Table 39 – Example wind farms

	Application	Signature	Commissioning	Load factor
Example Windfarm 1	2008	2008	2010	30% (2628h/year)
Example Windfarm 2	2008	2008	2010	25% (2190h/year)

Source: Pöyry Energy Consulting

B.2 Initial Base Tariff to a wind farm

For the first ten years of the contract, the Base Tariff applicable to an individual wind farm is determined by the year of application for the PPA, subject to the windfarm being commissioned within three years of this application date. Whilst the feed-in tariff is determined in nominal money, we have also presented the base tariff in real 2006 money, to be consistent with the rest of this report. The statute sets the base tariff at €82/MWh in 2006, with the value to projects applying in subsequent years being adjusted by Wage and Price production indices. Table 40 shows that the Base Tariff in real 2006 money is €81.1/MWh for the two example windfarms.

Table 40 – Base Tariff calculation, depending on the application year, in €/MWh

Application year	Base tariff in Nominal money	Base Tariff in real 2006 money
2006	82.0	82.0
2007	83.4	81.8
2008	84.4	81.1

Source: Pöyry Energy Consulting Analysis

B.3 Subsequent Base Tariff to a wind farm

For the remaining five years, the Base Tariff is based on the load factor as shown in Table 41.

Table 41 – Base tariff for onshore wind energy – nominal €/MWh

Reference load factor	First 10 years	Next 5 years
Less than 2400 hours (<27.4%)	82	82
2400 – 2800 hours	82	Linear interpolation
2800 hours (32.0%)	82	68
2800 - 3600 hours	82	Linear interpolation
More than 3600 hours (>41.1%)	82	28

Source: Journal Officiel, 26 July 2006

The load factor for Example windfarm 1 is 30%, which means it qualifies for a tariff at a linear interpolation between €68/MWh and €82/MWh for the second period of the PPA, exactly €74.02/MWh. This tariff is then adjusted by Wage and Price production indices which gives a Base Tariff of €76.18/MWh. Example Windfarm 2 has a lower load factor of 25% therefore keeps the same tariff for the second period of the PPA as for the first one, €82/MWh adjusted to €84.4/MWh.

B.4 Calculation of the tariff over time

The annual tariff paid to a wind farm is calculated as the base tariff, subject to a partial inflation adjustment that increases the tariff annually by 60% annual inflation rates⁹⁶, such that the tariff reduces in real terms over the life of the PPA.

Table 42 shows the different steps for the actual income calculations, including the expected tariffs in real 2006 money (assuming annual inflation rates of 2.0% in 2007 and thereafter).

⁹⁶ We assume in this annex that Wage Index (WI) and Price production Index (PI) escalators set out in the statute are equivalent to the annual rate of consumer price inflation.

Table 43 shows the level of income for the two examples, in real 2006 money, which demonstrates the three distinct income phases of the windfarms:

- the first phase of the PPA (for ten years);
- the second phase of the PPA, with a potentially lower tariff (for five years); and
- for the remaining life of the wind farm, the electricity is then sold at the market price.

Table 42 – Detailed actual income for the example windfarm 1 (PPA applied for in 2008, signed in 2008 and a 30% load factor), in €/MWh

€/MWh	Base tariff nominal money	Actual income nominal money	Actual income real 2006 money
2010	84.39	86.60	80.00
2011	84.39	87.64	79.38
2012	84.39	88.69	78.75
2013	84.39	89.75	78.14
2014	84.39	90.83	77.52
2015	84.39	91.92	76.91
2016	84.39	93.02	76.31
2017	84.39	94.14	75.71
2018	84.39	95.27	75.12
2019	84.39	96.41	74.53
2020	76.18	88.07	66.75
2021	76.18	89.13	66.23
2022	76.18	90.20	65.71
2023	76.18	91.28	65.19
2024	76.18	92.38	64.68

Source: Pöyry Energy Consulting Analysis

Table 43 – Actual income for the two example windfarms in €/MWh, in real 2006 money

	Years after commissioning	Example Windfarm 1 (30% load factor)	Example Windfarm 2 (25% load factor)
First Phase of the PPA	2010	80.0	80.0
	2011	79.4	79.4
	2012	78.8	78.8
	2013	78.1	78.1
	2014	77.5	77.5
	2015	76.9	76.9
	2016	76.3	76.3
	2017	75.7	75.7
	2018	75.1	75.1
	2019	74.5	74.5
Second Phase of the PPA	2020	66.7	73.9
	2021	66.2	73.4
	2022	65.7	72.8
	2023	65.2	72.2
	2024	64.7	71.7
	2025 onwards	market price	market price

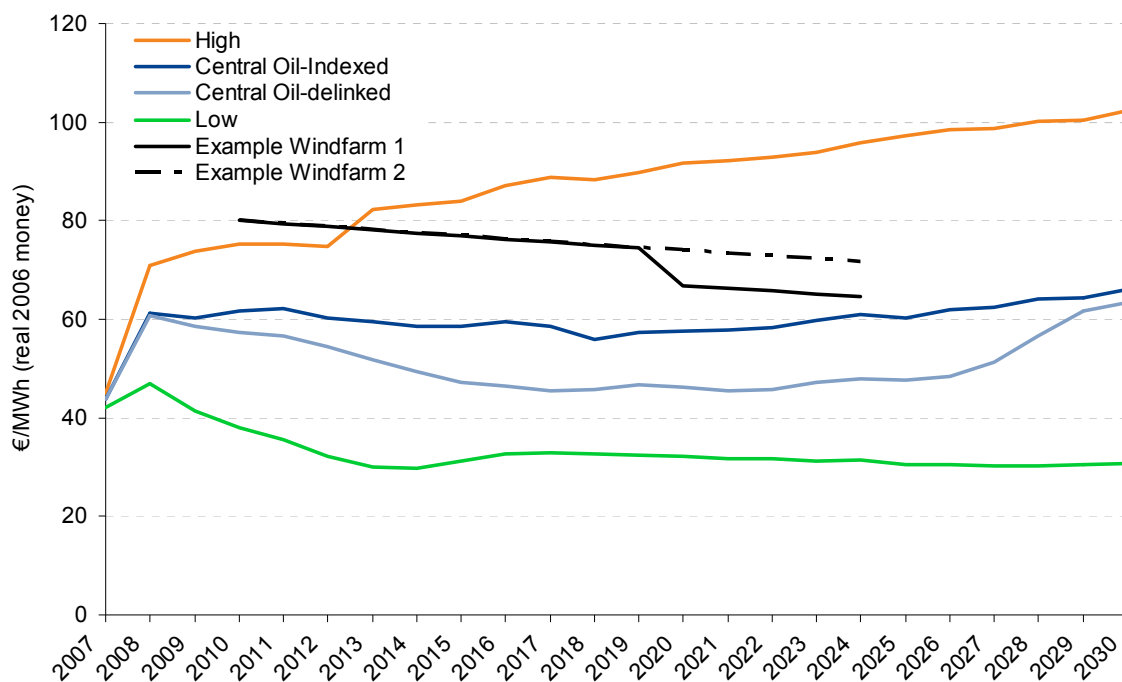
Source: Pöyry Energy Consulting Analysis

B.5 Comparison of feed-in tariffs with electricity price projections

Figure 51 compares our wholesale electricity price projections presented in Chapter 5 with the feed-in tariffs for the two example windfarms as defined in Table 39.

In Figure 51 we assume that the electricity supplier will not opt-out the PPA. However, if the wholesale electricity price is close to the High scenario and the producer is confident that it will be the case for the remainder of the PPA, then they can chose to opt-out the PPA and be paid at the market price.

Figure 51 – Comparison of wholesale electricity price projections with PPA tariffs to example windfarms 1 and 2 (with 30% and 25% load factors, respectively) (€/MWh, in real 2006 money)



Source: Pöyry Energy Consulting Analysis

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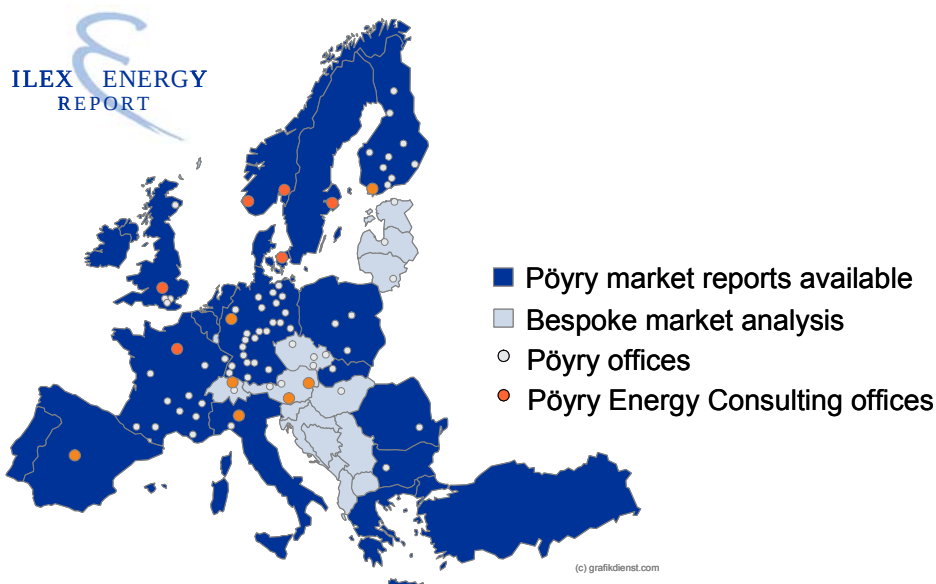
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