New challenges for French energy policy

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France now faces three new challenges in implementing its energy policy.

It needs to move away from carbon-based fossil fuels in order to meet the target of carbon neutrality by 2050, and this will involve raising the price of carbon. Secondly, it needs to invest massively in electricity generation to meet the growing demand for electricity as a result of the electrification of energy uses, and this requires investment in dispatchable, low-carbon nuclear power. Finally, France must rise to the challenge of large-scale storage and retrieval of renewable energies, and look at the extent to which electric mobility can contribute to this.

We also need to rethink the way the electricity markets operate if we are to ensure that these challenges are financed.

The 2015 law on the "energy transition for green growth" (TECV) set the goal of achieving "carbon neutrality" by 2050. by 2050, which means we need to significantly reduce greenhouse gas (GHG) emissions, particularly CO_2 emissions. This means rapidly reducing energy consumption in the two main sectors that consume carbon-based energy: buildings and transport [1]. Another objective of the 2015 law is to reduce the proportion of nuclear power to 50% by 2035, compared with almost 72% in 2019. This requires a substantial increase in the share of renewable energies (RE) in electricity production. Of the 56 nuclear reactors still in operation in 2020, after the closure of the two Fessenheim reactors, twelve should still be closed (decision abandoned in 2023). The others will be extended, and a project to build six new reactors is under study (these reactors should replace decommissioned reactors).

In 2019, the residential-tertiary sector (mainly buildings) accounted for 46% of final energy consumption in France, compared with 32% for transport and 19% for industry (the remaining 3% mainly concerns agriculture). Refined petroleum products still account for 44% of France's final energy consumption, compared with 25% for electricity, 19% for natural gas, 10% for biomass, wood and waste, and just 2% for coal.

It should be noted that the public authorities are encouraging the development of electric mobility and the gradual banning of gas heating in new buildings, so that electrical uses are set to grow massively, especially as the increased use of digital technology accentuates the phenomenon. As a result, final energy consumption is set to fall, but electricity 's share of that consumption is set to rise. Electricity consumption is therefore expected to rise by at least 30% between now and 2050.

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One of the 70 Toyota i-Roads in front of its electric charging point in Grenoble.

The massive growth in electricity use associated with the move away from fossil fuels means that we need to ensure that the electricity mix can meet consumer needs in the future. Investing in electricity generation, particularly new nuclear reactors, and developing electricity networks to absorb this growing production of nuclear and renewable electricity is a major challenge, given both the financial requirements and the time needed to implement these massive investments.

The challenge of phasing out fossil fuels

At the December 2015 Paris climate conference, the European Union committed to reducing its GHG emissions by 40% by 2030 compared to 1990 levels. The target has since been revised upwards by the Member States, who have agreed on a new emissions reduction target of 55% by 2030. Raising Europe's climate ambitions is a significant milestone on the road to carbon neutrality by 2050, which will require accelerating the continent's withdrawal from fossil fuels. To achieve this, the European Commission is betting on strengthening its carbon market, which is the main tool in the EU's decarbonisation policy. It announced a series of measures to this end when it presented the "Fit for 55" legislative package in July 2021, the most emblematic of which is the introduction of a carbon adjustment mechanism at Europe's borders. Under this mechanism, which should be operational by 2026, the CO_2 cost of imported products would be aligned with that borne by European producers. This reduces the exposure of energy-intensive sectors to the risk of "carbon leakage", which should eventually make it possible to abolish the subsidies granted to these sectors in the form of free allowances. In this way, the Commission can ensure that efforts to reduce CO_2 emissions in Europe do not result in an increase in the carbon footprint. At the same time, the scope of the carbon market should be extended to include emissions from maritime and road transport, as well as those from the heating of buildings, which until now have been exempt.

We can therefore expect a high carbon price in Europe in the future, which will encourage investment in low-carbon energies and energy efficiency. The rise in the price of carbon will be accompanied by the relocation of certain activities, such as the steel industry, and the emergence of new green industries for the production of cement, hydrogen and batteries. At the same time, the cost of using fossil fuels is set to rise, putting a strain on the profitability of the most energy-intensive industries and increasing the risk of stranded assets, i.e. costs that cannot be recovered as the price of carbon rises. Europe must send a clear signal

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to investors through its green taxonomy project, so as to direct funding towards activities that will accelerate the phase-out of fossil fuels. However, there are divisions among the Member States, with some wanting to be able to label investments in fossil gas, while others are opposed to including nuclear power - which does not emit CO_2 - in the taxonomy of green assets. A compromise has been reached that will enable both energies to gain access to preferential financing.

In 2019, fossil fuels (coal, oil and gas) will still account for 72% of the final energy consumed in the European Union and around 65% in France. There is certainly a paradox in seeing hydrocarbon-importing countries encouraging producers to invest more in order to produce more, with the aim of bringing down prices on world markets, while at the same time declaring their desire to do without these hydrocarbons in the long term. This reflects a schizophrenic behaviour between short-term concerns ("the end of the month") and long-term concerns ("the end of the world").

Generally speaking, decarbonisation policies in the energy sector will result in higher energy prices for end consumers. The rise in CO_2 prices and the inclusion in the carbon market of emissions linked to fuels for road transport and fuel oil for heating will weigh on consumers' energy bills, with the risk of increasing fuel poverty. As the yellow waistcoat crisis in France has reminded us, environmental taxes are generally anti-distributive and tend to weigh more heavily on low-income households, who are often heated by oil, and whose energy costs account for a much higher proportion of their income than affluent households. We therefore need to ensure that these households are protected, as they should not have to undergo the energy transition or bear the brunt of its costs. The proceeds from the auctioning of quotas should be used to strengthen existing redistribution schemes, such as the energy voucher, which does not cover mobility, and to enable low-income households to finance insulation work or the purchase of less polluting vehicles [2].

The challenge of investment in electricity generation

France's electricity mix is already largely decarbonised (93%), and the priority is not to substitute decarbonised renewable energies for decarbonised nuclear power, even if the objectives of the PPE (Pluriannual Energy Programme) law are to increase the proportion of renewable energies in the electricity mix to 50% by 2035 and to reduce the proportion of decarbonised nuclear power to 50%. The electricity grid needs dispatchable power plants, i.e. plants that follow the load curve in real time and maintain the frequency at 50 Hz. Following the load curve means that the power injected upstream into the grid must, in real time, be equal to the power subscribed downstream by consumers. Electricity cannot currently be stored, at least on a large scale and under acceptable economic conditions. Only nuclear and hydroelectric dam power stations are both dispatchable (on given time scales) and decarbonised, while gas- and coal-fired power stations are dispatchable but carbon-intensive. Renewable energies such as photovoltaics and wind power are decarbonised, but not dispatchable. In the latter case, it is demand that has to adapt to supply and not the other way round, which is not always possible, nor desirable either. If, at certain times of the year, a lot of renewable (and therefore non-dispatchable) "unavoidable" electricity is injected because there is a lot of wind or a lot of sun but, at the same time, electricity demand is low, this injection poses a problem and needs to be stored, which is not easy today on a large scale, otherwise it will lead to negative prices on the wholesale market, as we saw on several occasions in France between 2010 and 2020. The producer has to pay to get rid of this product, which has become cumbersome.

Conversely, when demand for electricity is high, particularly in winter due to heating needs, and at the same time the availability of wind and solar power is low due to the absence of wind or sun, prices tend to soar on the wholesale electricity market, which has an impact on the price paid by the end consumer. At the end of 2021, a combination of unfavourable factors across Europe led to a very sharp rise in prices on the wholesale electricity market. Prices peaked at 6pm on 21 December 2021, when they reached €620 per MWh, compared with between €40 and €60 per MWh a few months earlier. The price (including tax) paid by a domestic consumer supplied by EDF at the regulated sales tariff (TRV) is around €200 per MWh, and this price includes not only the cost of producing and supplying the electricity, but also the cost of the electricity itself (around 33% of the price including VAT), but also the cost of tolls for access to the RTE and Enedis transmission and distribution-networks (32%) and taxes (35%). Some suppliers are therefore obliged to buy the electricity they sell to their customers on the wholesale market at a very high price. Either they pass on the increase to consumers, at the risk of them changing supplier and

"The energy transition will be accompanied by a growing electrification of uses, particularly in mobility, but also as a result of the development of connected objects."

reverting to the regulated tariff, or they incur losses that could lead to bankruptcy, as has happened to several suppliers in Europe.

The dizzying rise in the price of gas on the international market is the main reason for this rise in wholesale electricity prices, although it is not the only reason. The rise in the price of carbon (€80 per tonne of CO_2 by the end of 2021), the low load factor of wind power in Europe, the closure of many coal-fired power stations in Germany and the lower availability of French nuclear power are also to blame. The electricity market operates like all competitive markets: the price is set on the basis of limit price auctions, which means that the operating cost (marginal cost) of the marginal plant sets the price for all the plants taking part in the auctions. As gas-fired power stations are for the most part the marginal power stations in Europe, the ones that are called on at times when demand is high, and as all the European markets are interconnected, the increase in the price of gas, which accounts for most of the operating costs of a gas-fired power station, largely explains the rise in the price of electricity [3]. Some therefore want to reform the market by changing the auction system, others want to limit the role of the market by favouring long-term contracts, and many recognise that we need to invest massively in dispatchable nuclear power stations to limit the weight of gas-fired power stations in the merit order mechanism. At the very least, we need to stop closing nuclear power plants that are likely to fail in the future.

A study by France Stratégie [4] shows that, on the basis of cautious assumptions in terms of the availability of the various power plants and relative stability in electricity demand, France could experience serious risks of a blackout from 2030-2035, with peak demand exceeding available power, at least if the closure of twelve new nuclear reactors is maintained in accordance with the provisions of the PPE law. On the other hand, there is a risk that we will be faced with wind and solar "fatal" electricity that is far greater than the power demand at off-peak times, which will raise the question of how to use these surpluses. Will it be possible to transform them all into "green" hydrogen by electrolysis of water, which involves separating water into its two components, hydrogen and oxygen? Storage capacity using batteries or PSH (Pumped-Storage Hydro) is clearly insufficient.

The energy transition will be accompanied by a growing electrification of uses, particularly in mobility but also as a result of the development of connected objects, as confirmed by the recent RTE study [5]. Under the optimistic assumption adopted by RTE. Final energy consumption in France will fall from 1600 TWh in 2019 to 930 TWh in 2050, which requires major energy efficiency efforts, the share of electricity would rise from around 25% in 2020 to almost 55% in 2050. Electricity grids, which will have to manage millions of injection and extraction points in real time, will need to rely on digital platforms to arbitrate between electricity production, consumption and storage, thanks in particular to quantum technologies.

Investing in electricity generation is a priority, and relaunching a nuclear programme involves studying new financing mechanisms such as the "Contracts for Difference" chosen by the UK for the Hinkley Point project. The investor signs a contract with the government guaranteeing that, for a good part of the plant's operating life, the kWh produced will be remunerated at a price sufficient to ensure the profitability of the operation. Under this system, the producer sells its electricity on the wholesale market. If the wholesale price is lower than the guaranteed price, he receives a top-up payment from the government, and if the wholesale price is higher than the guaranteed price, he pays the government the difference. However, the guaranteed price at the outset must not be too far removed from the trend in prices observed on the market.

The challenge of large-scale storage and retrieval of renewable energies

The penetration of wind power and photovoltaics has been greatly facilitated by the introduction of highly remunerative feed-in tariffs across Europe. This off-market electricity is fed into the grid at zero marginal cost. These renewable energies are not sensitive to the wholesale market price, and they recover their fixed costs *via* feed-in tariffs set by regulation (electricity consumers *via* the CSPE, contribution to the public electricity service, which has merged with the TICFE, and consumers of petroleum products *via* part of the TICPE, domestic tax on the consumption of energy products). It is true that the fall in the cost of renewable energies, achieved through mass production on a global scale, and the sharp rise in the cost of fossil fuels mean that the subsidies granted *via* feed-in tariffs are less and less necessary. These subsidies nevertheless remain in the form of bonuses, a variable remuneration supplement designed to encourage "decarbonised" energy . However, the costs incurred by this injection must be taken into account, particularly those linked to intermittency and the costs of reinforcing the networks [6, 7].

In anticipation of the growing use of this type of energy, we are now looking at large-scale storage when production exceeds requirements, with a mechanism for releasing it when necessary, particularly at peak times. In the short term (day-to-day), we can envisage storing some of this electricity in batteries; but in the medium term (a few days or even a few weeks), we need to go down the "power-to-gas" route , which involves producing hydrogen *through* the electrolysis of water using this surplus electricity, and then storing the hydrogen produced or combining it with CO_2 to produce methane. But this solution, although attractive, is not yet profitable with the "power-to-gas" and then "gas-to-power" systems, which compromises the introduction of large-scale storage in the short or medium term [8].

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➲ LARGE-SCALE DEVELOPMENT OF ELECTRIC VEHICLES

A major thrust of European energy policies, particularly in France, is the large-scale development of electric vehicles (which will eventually be autonomous). While it is conceivable that the introduction of electric mobility could help to alleviate some of the constraints on renewable energies, we must not underestimate the impact this will have on the demand for electrical power on the grid if a large fleet of vehicles has to be recharged.
A few questions remain unanswered.

If all cars were electric, how much additional electricity generation would be needed in France to maintain current levels of traffic?
France's final energy consumption of petroleum products in the transport sector is around 45.4 Mtoe. The efficiency of an internal combustion engine (transformation of thermal energy into mechanical energy) is in the range (15 - 30%); therefore the mechanical energy used to drive vehicles is in the range 7 - 14 Mtoe. This energy corresponds to 80 - 160 TWh.
Electrifying transport would require a further 100 TWh.

If all cars are electric, what is the total electrical charge that will be stored in all their batteries at any given time?
The French fleet comprises 30 million vehicles; if we replace all these vehicles with electric vehicles equipped with a 52 kWh battery (the battery in Renault's Zoé), then this fleet has a total maximum storage capacity of 1500 GWh. This is a low figure, because the Zoé's battery is small compared with the 100 kWh of a Tesla Model S. It's worth remembering that the car fleet stores between 1 and 2 TWh. Total French electricity production in 2019 was 538 TWh.
An electric car fleet therefore stores around one to two days' electricity production.

What are the constraints on charging cars?
If we charge a Zoé on a domestic socket (10 A), it takes 32 hours to fully charge it for a power demand of 2.3 kW, i.e. 10 A x 230 V (table 1). If all the cars charge at the same time, assuming a slow charge, they will draw 69 GW, compared with the 61.4 GW of nuclear capacity installed in France (since the closure of Fessenheim). If they are in fast-charging mode (43 kW), they will require 1.2 TW of power. This corresponds to twelve times the maximum power demand on the French grid (100.5 GW on 7 February 2012 at 19:00), which is hardly realistic.
An electric vehicle fleet necessarily means that the grid operator controls the charging regime for electric vehicles.

How does the storage needed for "all electric" compare with that needed to smooth out fluctuations in renewable energy?
An electric car can only make economic sense if it is used, because a significant amount of money is tied up in its battery. Batteries generally withstand 1000 - 2000 charge-discharge cycles (many developments are underway to increase this number of cycles). Assuming that the network could discharge and charge the batteries as it sees fit (which is neither technically nor sociologically obvious), it is unlikely that this margin would be more than 20% of the nominal value (the vehicle is charged to 90% of the nominal load and is discharged to 80% in the event of peak consumption and is charged to 100% in the event of under-consumption or peak production from renewable energy sources), i.e. a storage capacity of 100 to 200 GWh. In theory, this amount of available storage would make it possible to offset peaks in renewable energy production and peaks in household consumption. However, this finding needs to be put into perspective:
1- we need to find an economic model that is collectively acceptable (fair compensation for the vehicle owner);
2- This storage capacity is only good for 24 hours, because the next day another day begins;
3- the grid must be able to cope with the intermittent nature of renewable energies.
Car batteries can help to absorb peaks in the production of renewable energies, by eliminating peaks in production imposed by current weather conditions. Rather than injecting this surplus electricity at a negative price, it can be stored in this way.

Is it conceivable that car batteries could be used for a second life, for seasonal storage and peak shaving?
Given the large number of batteries in the car fleet and the fact that they can be used for a limited number of cycles with a loss of capacity compatible with their use, it can be estimated that a car fleet will scrap a nominal capacity of 200 GWh of batteries per year (1/5 of storage). As these batteries are old, their capacity can be considered to be halved, i.e. 100 GWh for an average life of 5 years. This total cumulative capacity of 500 GWh over 5 years is close to France's daily consumption and could resolve the short-term component of the problem of the intermittent nature of renewable energies. The technical and economic model for the second life of batteries in electricity storage remains to be demonstrated: compatibility and availability of BMS (battery management system), infrastructure, maintenance, etc.

Type of charging point or socket	Charging power	For 395 km
10 A domestic socket	2.3 kW	32 h
16 A reinforced domestic socket	3.7 kW	19 h
Domestic/public charging point	7.4 kW	9 h 30
Public charging point	11 kW	6 h
Public charging point	22 kW	3 h
Fast charging point	50 kW	1 h 30

Table **1. Maximum charging time for a Renault Zoe E-tech 100% electric car charged under various conditions.** 52 kWh battery. Range: up to 395 km.
(2023 data. Source: Renault website)

“Many scientific and technological hurdles remain to be overcome...”

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All these issues will be discussed in the fourth part of this issue. Finally, the absence of large-scale storage and the reduction in centralised, demand-responsive generation may lead to high volatility in energy pricing [9].

As the potential of PSH is limited for geological reasons, other solutions must be sought. Research is being carried out to develop new storage techniques or improve the efficiency of batteries. Lithium batteries are currently the best small-scale storage solution, but there is a risk that this resource will run out very quickly. To store two days' worth of electricity in France, for example, we would need 360 000 tonnes of lithium using current technology, according to a study by Ancre (Alliance nationale de coordination de la recherche pour l'énergie). Yet world production of lithium does not exceed 40 000 tonnes a year... We can certainly think of fuel cells: water is electrolysed locally and then hydrogen is used to do the reverse operation. However, the widespread use of this technology is hampered by the availability of platinum. Hopes are pinned on new batteries, particularly solid-state batteries.

A major challenge on a European scale is the large-scale development of electric vehicles (see box on page 34).

Conclusion

To achieve carbon neutrality by 2050, we need to invest massively in energy technologies that respect the climate and the environment, while ensuring that energy is accessible to as many people as possible and available for the success of public policies (health, food, transport, etc.). Many scientific and technological hurdles remain to be overcome, and this will require sustained investment in fundamental, technological and industrial research.

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