What limits for VRES integration in grids?

What limits to the Integration of Variable and Intermittent Renewable Energies into Electricity Grids and consequences?

A study by Georges Sapy – Translated into English by Elisabeth Huffer – May 2024

Executive Summary

Since Nikola Tesla's invention of the three-phase alternator in 1891, AC grids have spread throughout the world. Until the end of the last century, only alternators, driven by turbines (hydraulic, steam or gas) or by diesel generators have powered these grids. Once coupled to a grid, they have the fundamental property of operating together perfectly synchronously, thus defining the common frequency **f** of the grid at all times. They also provide the grid with the mechanical inertia of their rotors, which is essential to stabilize the frequency and dampen its variations.

However, in the early 2000s, the growing concern with global warming led to using wind energy, via wind turbines, and solar energy, mainly photovoltaic, both because they could produce electricity without emitting CO2 during operation, and because they were considered to have very significant growth potential. **Nonetheless, the growing integration of these electricity sources, which are by nature variable and intermittent, has a profound impact on grid operation, for two reasons:**

* <u>One reason is linked to their variability</u>: their variation is rarely correlated with demand; it is in fact cumulative with that of consumption, leading to an overall variability far greater than that of demand alone, as soon as their integration ratio in the grid becomes significant. In order to maintain the balance between generation and demand at all times, an absolute necessity, backup resources have to be provided, the most important of which are energy storage and de-storage facilities and, above all, power modulation from dispatchable generation means. **This is a first cause limiting the integration of variable and intermittent electricity, because of: the physical scale of the palliative means to be implemented; the feasibility of large-scale energy storage and de-storage facilities, such as PHES (pumped hydroelectric energy storage) installations; and, finally, associated investment costs.**

* <u>A technical reason</u>: these sources of electricity are not coupled to the grid synchronously as are alternators, but via power electronic inverters. This is a necessity for photovoltaic panels, which naturally produce direct current that has to be transformed into 50 Hz alternating current thanks to inverters, to feed it into the grid. It is a chosen option for modern, high-power wind turbines: in order to optimally harness the variable power of the wind, they have to operate at variable speed. The alternator they drive does not, then, deliver 50 Hz current, so it cannot be connected directly ito the grid. A complex electronic circuitry is used to convert the variable-frequency alternating current produced by the alternator into direct current via a rectifier, and then back into alternating current, at 50 Hz, via an inverter connected to the grid.

In both cases, they interface with the grid via electronic means (power inverters), which have very different properties to alternators: **they cannot to date "form" the grid in terms of frequency f and voltage U** (they need an already-formed grid in which to inject their power), and they obviously **cannot bring any mechanical inertia to the grid.**

It is thus easy to understand that as we progressively replace dispatchable generation coupled to the grid via alternators, with wind and/or photovoltaic generation coupled via electronic inverters, we weaken the grid's ability to form its frequency f and voltage U, as well as its indispensable inertia, because there comes a time when the number of alternators is no longer sufficient to perform these two vital functions reliably. This is the second reason that limits the possible integration ratio of variable and intermittent electricity.

What do we know to date of the limits for the integration of variable and intermittent electricity in grids? Two very solid references can be cited:

* <u>The first reference is the study published in June 2015 by EDF R&D</u> [1]. It covers the Europe-wide grid up to 2030 and is based on some 30 years of historical weather and demand data. **It concludes, subject to a few additional second-order factors, that it is possible to achieve a variable and intermittent electricity integration ratio of around 40% in mean annual value, rising to around 70% in instantaneous values under**

the favorable conditions of a heavily loaded grid (transporting large power), therefore comprising a large number of alternators and rotating receivers (motors) coupled to the grid.

The profound reason for these results is that, under these conditions, the network constantly remains "formed" by a sufficient number of alternators and retains sufficient inertia. It thus remains in the familiar pattern of historical grid operation.

As a matter of fact, this is still the case today for the European grid, with a variable and intermittent electricity integration ratio that does not exceed around 30% in mean annual value, still well below the 40% limit established in the aforementioned study.

* The second reference is the joint RTE - IEA study of January 2021 **[2]**, which states: ***"Four sets of strict technical conditions will have to be met to allow, with assured security of supply, the integration of a very large proportion of variable renewable energies into a large-scale power system, such as that of France [...] There is no demonstration of the feasibility of a very extensive integration of variable renewable energies such as wind and photovoltaic power into a large-scale power system"***.

Where do we stand three years later with these ***"Four sets of technical conditions"? "Their feasibility is not guaranteed today",*** writes RTE soberly without being more explicit in its ***Bilan prévisionnel 2023-2025*** published at the end of 2023.

These conditions are complemented by alerts published by ENTSO-E (which groups together all the European transmission system operators, RTE's counterparts). This concerns the **risks associated with a reduction in the European grid's inertia due to the planned reduction in the number of synchronous machines** (**[3]** and **[4]**).

Neither RTE and IEA nor ENTSO-E give precise figures for the ratios involved for the variable and intermittent electricity integration, but they are described as a "very large proportion" or "very substantial", obviously well in excess of 40% on annual average. In other words, in the cases considered above, the grid is *a priori* in a situation where **it is no longer predominantly "formed" by alternators. This means moving into an unknown operating zone, devoid, as yet, of theoretically validated references or, more importantly, of experience on actual networks.**

This is of **major strategic importance. Indeed:**

- In the long term, if it is confirmed that it is impossible to operate grids with very large variable and intermittent electricity ratios, which seems very likely according to present knowledge, the illusion of "100% renewable" will crumble definitively for those who set store by this idealized solution;

- In the short and medium term, these considerations are already guiding decisions in view of the long time frame (several decades) over which electrical infrastructures develop. From this point of view, 2040-2050 is already tomorrow. And as these infrastructures are classified as "vitally important" (at least in France), they can only be planned on the basis of tried-and-tested technologies. Looking to hypothetical radical innovations in this field would be an extremely risky wager.

As a result, to date it seems very risky, to say the least, to consider an integration ratio significantly greater than 40% on annual average. All the more so as **achieving this ratio in an electricity mix that will have to be totally decarbonated by 2050 will be far from easy: the remaining 60% of carbon-free electricity will have to be mainly generated by dispatchable means.** There are few possible ways of doing this. The aforementioned EDF R&D study projected a 20% share of hydropower and biomass by 2030. However, as electricity consumption is set to increase sharply between 2030 and 2050, this proportion will mechanically decrease, given that the potential for expanding these two energy sources is limited. They could represent only around 10% in order of magnitude by 2050, in France. **The remaining 50% would then have to be generated with carbon-free means.** But how?

This study takes the EDF R&D study as its base and applies it to two 950 TWh/year mixes. One is more or less consistent in 2045 with the approach taken by Germany, which rejects nuclear power and relies on a mix with a very large wind and photovoltaic power generation ratio. The other is consistent in 2050 with the approach taken by France, which has made the nuclear option a long-term one. Nuclear power would then have to supply at least 50% of the country's annual electricity, and if possible, more, in order to limit the disadvantages of large variable and intermittent electricity ratios (according to several studies, there is a major economic benefit in not exceeding about 30%).

The main results of the simulations for these two mixes are summarized below:

* For the German **"100% renewable"** mix, several possibilities are to be examined:

- A purely **"100% renewable"** scheme (plan A), which would imply successfully operating a grid predominantly "formed" and driven by electronically coupled means (inverters), with very few residual synchronous machines. This has to be ruled out because **to date nothing guarantees that such a scheme would be viable. It would be a very risky GAMBLE on the technical viability of the power system.**

- A first alternative (Plan B) would be to artificially create a dispatchable production system based on the storage of very large quantities of carbon-free hydrogen, which is then used as needed in "hydrogen-compatible" dispatchable thermal power plants, such as combined-cycle power plants (CCGT) and open cycle combustion turbines (OCCT). This scheme will work (we are back to a familiar electrical system, mostly "formed" by synchronous machines). But **it would entail enormous energy losses,** which would have to be offset by **exorbitant physical dimensions in wind and photovoltaic means, as well as in electrolysers**. This would clearly raise **the question of how realistic their sizing and associated costs would be**. **It is thus a GAMBLE on the ability to produce AND to import colossal quantities of carbon-free hydrogen**: imports of over **500 TWh/year** of this gas would be required. Germany, which has realized that it will not be able to produce all the hydrogen it needs, is planning to import quantities of this order of magnitude, according to ref. **[5]**.

- A second alternative (Plan C) would be to **continue using gas** (the vast majority of which is fossil, given the quantities required) and to **decarbonate the associated power generation through carbon capture and storage (CCS).** But the considerable energy consumption and technical and economic uncertainties of this technology, which is still at the stage of its first industrial projects with no real feedback from experience, as well as the CO2 transport networks and the storage capacities to be created, at unknown cost, make embarking on this path difficult, bearing in mind that **over 200 Mt of CO2,** an extremely large quantity, would have to be captured and stored **annually**. **Now, it is a GAMBLE on the scale of CCS facilities that would have to be implemented and, ultimately, on the decarbonation of the mix in the event of their physical inadequacy, the easy and inexpensive way out being to not decarbonate everything... But that would be catastrophic for the climate.**

All in all, the impossibilities and major uncertainties raised by plans A, B and C show that **producing 950 TWh/year of decarbonated electricity with limited hydropower and without nuclear power, the only energy source that is decarbonated, dispatchable and capable of producing large quantities of electricity at a competitive price, is extremely dubious, difficult, and costly.**

* Regarding the French **"majority nuclear"** mix, its technical feasibility has been tested.

But this does not mean that it will be easy to produce 950 TWh/year decarbonated electricity in France in 2050, with **a mix comprising at least 50% nuclear power, i.e., a minimum installed nuclear capacity of 76 GW. It would be highly desirable to push beyond 76 GW in order to limit the disadvantages of large variable and intermittent electricity integration ratios.** **Moreover, this objective can be achieved only** **both by extending the operation of the majority of the current reactors to 70/80 years and by building at least 14 EPR2s, and more, if possible, by 2050.**

The challenge here is essentially an **industrial** one, but the task is immense and set to extend well beyond 2050 with the decommissioning of existing reactors that will eventually have to be replaced and the emergence of FNR reactors so as to use at best uranium's energy potential.

These are the conditions that will have to be met for us to have sufficient decarbonated electricity at the time scale considered.

Supporting Study

1 – Reminder of current grid frequency-power control methods

2 – Today's more or less established physical limits to the integration of variable and intermittent RESs.

3 – Is it possible to push much beyond the conclusions of the 2015 EDF R&D study?

- The technical challenges of electronic coupling to the grid
- Will it be possible to handle the very large amplitude variations of wind and photovoltaic power?

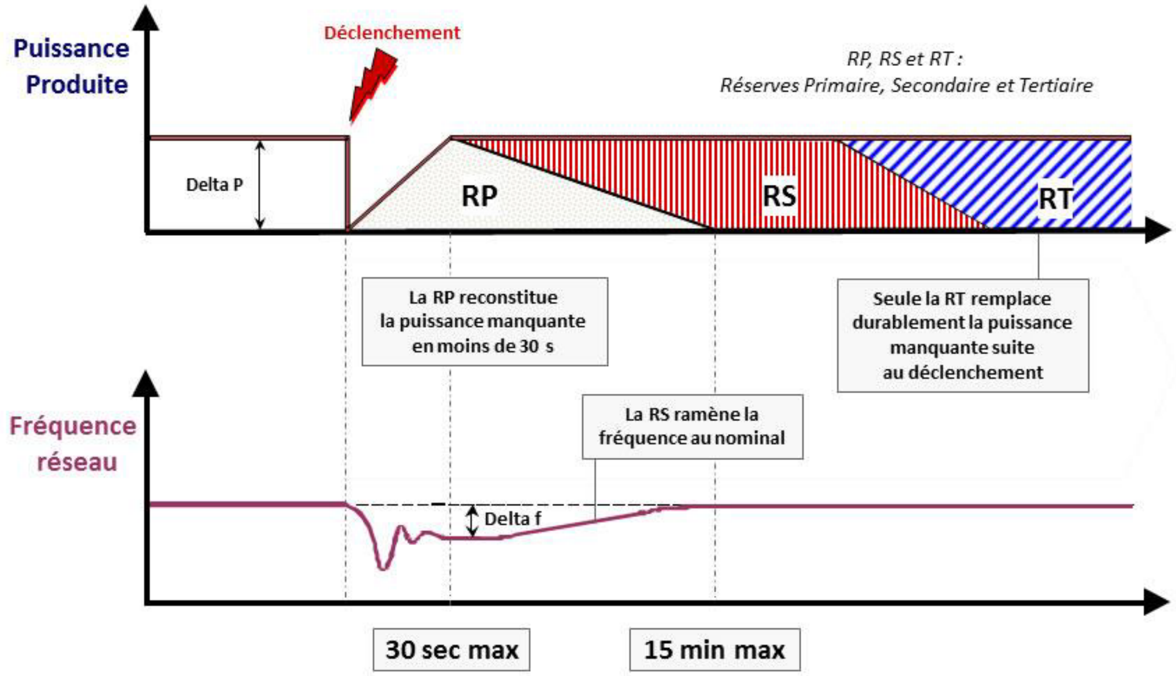
4 – Comparing two antithetical power mixes: "100% renewable" versus "predominantly nuclear".

- Sizing the mixes needed
- Rough estimate of electricity production costs

5 – Summary and conclusions

1 – Reminder of current grid frequency-power control methods

Since **the production-demand balance of a power system must be ensured at all times** in order to keep the frequency within very narrow limits (<< ± 1%), disturbances due to on-going demand variations have long had to be compensated by means based on three types of **"power reserves"** that are activated successively: Primary [RP], Secondary [RS] and Tertiary [RT] reserves, whose workings are illustrated in the **following diagrams:**



The management principles of these reserves and their main characteristics are summarized below according to ENTSO-E common rules at the European level:

* Primary Reserve [RP]: its purpose is to restore the **missing ΔP** (Delta P) as quickly as possible in the wake of an incident. This responsibility is **shared by all of the interconnected European countries.** On the European continental synchronous plate to which France belongs, the **reference ΔP loss** considered is 3,000 MW (in fact, the simultaneous loss of 2 N4 reactors, the most powerful on the European grid to date). France's share is around 600 MW, which must be injected within less than 30 sec.

This reserve is obtained by operating an adequate number of synchronous generators at a maximum of 98% of their rated power Pn, so that they can quickly modulate their power by ±2%.

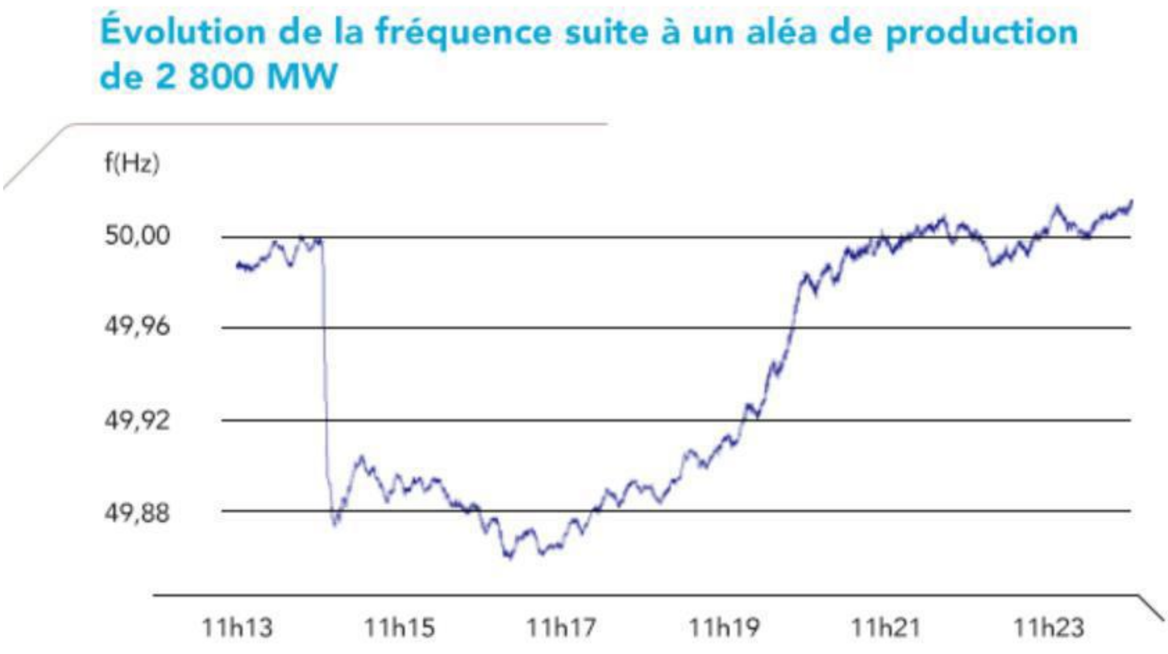
The power is injected according to a proportional feed-in formula of the type: $\Delta P = - K \times \Delta f$. This is a **totally automatic and purely local** control system (acting at the level of each generating unit that participates in the adjustment), which is very simple, but does not allow **Δf** (Delta f) to be brought back to 0 (since ΔP decreases as Δf decreases, it would take an infinite amount of time to get back to 50 Hz). Note that the sub-frequency after a power loss incident is **common to all countries on the interconnected European plate**.

* Secondary reserve [RS]: its purpose is precisely to **restore the frequency value to 50 Hz**. To achieve this, power is injected according to a proportional/integral formula of the type: $\Delta P = -[K1 \times \Delta f + K2 \times \int \Delta f]$. **It too is automatic, but it is triggered remotely via a national signal "N" issued by RTE**, whose value lies within a ± 1 range. The [RS] kicks in after 30 s, and should reach its maximum value of around 1,200 MW in France in no more than 15 minutes. It also serves to **reconstitute the primary reserve** [RP]. The [RS] is obtained by operating a sufficient number of synchronous generators at a maximum of 95% of their rated power Pn, so that they can quickly modulate their power by ±5%. Some units, particularly nuclear plants, can combine [RP] and [RS]. They then operate at a maximum of 93% of their rated power Pn, so that they can modulate their power by ± 7%.

Very important point: the **responsibility** for bringing the **European grid frequency back to 50 Hz** is no longer shared, but **is borne by the country that has suffered the power loss.** If the country does not have the necessary generation capacity, it must **import the necessary power** from neighboring countries at cost until the frequency is restored to 50 Hz.

* Tertiary reserve [RT]: this allows to **restore the [RS]** in order to cope with a new incident. To do so, (in France) it must be able to inject around 1,500 MW into the French national grid within less than 30 minutes, of which 1,000 MW in less than 15 minutes. This reserve is not managed automatically, but via human intervention. Finally, [RS] + [RT] are dimensioned so as to be able to restore the loss of the largest generator on the grid within less than 15 minutes. Given the short mobilization times of the [RT], most of it has to be comprised of **"rotating reserves"** with the capacity to ramp up quickly enough. But this also depends on the state of the network, hydraulic reserves, etc., with technical and economic optimization being carried out on an ongoing basis.

A real example of frequency variation is shown in **figure 1** below in the wake of a 2,800MW power loss:



This example shows a first *fmin* after about 10 s (Δf max ≈ - 140 mHz) and good performance of the [RP] and [RS], with a rapid frequency upswing due to the [RS] and a recovery of the nominal frequency after about 7 min << 15 min specified.

Physically, *fmin* is reached after around 10 seconds thanks to the grid's considerable inertia. The interpretation of the subsequent evolution is complex, with a first upswing resulting from the initial effects of the primary response [RP], superimposed on the natural oscillation of the frequency's ascent. Then, there is probably a second oscillation on which [RP] and [RS] superimpose themselves, the evolution finally becoming quite clear with [RS] contributing alone.

Note that bringing the frequency of the synchronous plate of the interconnected European grid back to 50 Hz (± ε due to small permanent fluctuations) implies physically **restoring the nominal kinetic energy of all the synchronous generators coupled to it.**

* Finally, in addition to the three reserves mentioned above, which enable the management of **incidents due to the loss of generation means**, there is a need for **power modulation**: **"load following"**, i.e. the permanent adaptation of power to demand variations in the short and very short term. This "load following", was formerly limited to counterbalancing demand variations. It is becoming more and more demanding insofar as **it must also, and above all, compensate for variations in wind and photovoltaic power, whose amplitudes are far greater than those of demand alone, and involve much steeper hourly power gradients.** This is one of the increasingly important challenges which, in the absence of mass energy storage capacities, places massive pressure on dispatchable facilities. With the existing installed capacity of wind power (≈ 26 GW) and PV (≈ 17.5 GW) alone, modulation requirements are currently around 10 to 12 GW, and can reach up to 20 GW, within a few hours.

To ensure these modulations, flexible hydraulic and gas facilities are called on first, but their amplitudes are small, and only the nuclear fleet is capable of ensuring modulations of the aforementioned magnitude, using the deep modulation capacities of the reactors; their amplitude can reach 80% of Pn in 30 minutes (passage from 100% to 20% Pn in 30 minutes with a possible return to Pn, at the same speed if necessary, after 2 hours' intermediate stabilization). Virtually the entire nuclear fleet can be managed in this way, except for the four 900 MW Bugey reactors that are not equipped with "gray rods" and the four N4 reactors, which were not equipped with the control mode that enables this flexibility. They can still contribute but they are not as flexible.

Innovations in [RP] and [RS] technologies and management (Source: EDF)

* Moving towards primary frequency-power control based on electro-chemical batteries

This innovation is expected to be in use on the French grid within the next few years, **600 MW** of batteries being sufficient to ensure the function. It is already partially implemented on some grids abroad, notably in the UK. Using batteries offers several advantages:

- The grid frequency fluctuates constantly around 50 Hz. This places an unnecessary burden on the turbogenerators that constitute the [RP], whereas a battery operating continuously in charge-discharge mode responds more easily and more rapidly;

- Indeed, battery response times are much shorter (in the order of a second) than those of electro-mechanical turbogenerators (several seconds). This means that the [RP] can be injected much more rapidly, limiting the frequency dip and rectifying its value more quickly (see § 2 below);

- Freeing the turbogenerators from the [RP] allows a **permanent 600 MW gain of** mainly nuclear generation. This represents more than 5 TWh/year.

* Moving towards a differentiation of the generators that participate in the secondary reserve [RS] helping to cut costs and reduce CO2 emissions.

Until now, the national signal "N" issued by RTE to activate the secondary reserve [RS] was the same for all participating generators. Since mid-November 2023, RTE has been issuing a different signal, depending on the **usage value of the units**. Gas is more expensive than nuclear: it is reduced earlier and increased later. Hydropower from dams is involved also for the same reasons.

Thus, **on average, nuclear power will produce more**, because it will receive a higher "N" signal than gas, which will produce less, and the use of dams will be better managed. This is more economical for the producer, and therefore for the power system and at the end for the customer. And it is virtuous for CO2 emissions.

At the outset, all the nuclear units are valued identically, and they receive the same "N" signal. Once experience will have been acquired, particularly concerning the management of the reactor cores, the nuclear units may receive different "N" signals, depending on the fuel savings required to optimize future scheduling, in winter for example.

2 – Today’s more or less established physical limits to the integration of variable and intermittent RESs.

As pointed out in §1 above, keeping grid frequency variations within a very narrow range (<< ± 1%) **conditions on the first-order their overall operational security,** since excessive frequency deviations (beyond ± 0.8 Hz, the ENTSO-E safety limit, to give an idea) can lead to widespread or even generalized failure (blackout) if they are not brought under control very quickly.

The EDF R&D study referred to in the summary **is fully in line with current operating and security rules in limiting the overall integration ratio of variable and intermittent electricity to 40% on annual average.** It also shows that the **maximum instantaneous integration ratio** is highly variable and, on the first-order, **depends on the inertia of the grid**, itself a **function of grid load**. This ratio is limited to around **25%** for a lightly-loaded grid, with few coupled turbo-generators and few rotating receivers, which also contribute their inertia **provided they are coupled directly to the grid** and not via inverters. These are used increasingly to facilitate their start-up and to optimize their speed so as to save energy.

Conversely, it can reach around **70%** when the grid is heavily loaded, i.e. with many coupled turbo generators and many directly coupled rotating receivers.

This result is tied to the crucial importance of **grid inertia** in ensuring grid stability: ENTSO-E has estimated at around **150 GW the minimum turbo generator power** that needs to be **coupled** to the synchronous grid of the European continental plate to guarantee its stability. As an indication, since the French grid represents around 17% of the aforementioned plate, its share of inertia contribution is of the order of 150 x 0.17 ≈ **25 GW minimum**. Note, however, that thanks to the interconnections, a given country can have less inertia than its quota in % if neighboring countries have more than theirs, as long as the criterion is globally met for the European plate. Individual compliance with the quota is, however, an advantage **in the event of network separation**, a rare but formidable occurrence.

Among the other findings of the EDF R&D study, note in summary that reaching a **40% integration ratio of variable and intermittent sources** on an annual average implies additional second-order conditions, including:

* Implement limited means of energy storage/de-storage and demand withdrawal and/or postponement.

* Having variable and intermittent sources contribute to "system services" (in particular frequency control and participation in reserves). But these contributions remain very limited and temporary, since the **possible contributions to power increases are unpredictable** (they can be thwarted by a temporary and unpredictable drop in wind or sunshine), so that only **power reductions** (by stopping wind turbine or photovoltaic panel production) are truly reliable.

* Be prepared to cope, by as early as 2030, with **power ramps of up to 400 GW** between a sunny and/or windy Sunday and a Monday with very little sun and/or wind, and a sharp demand upturn. Indeed, variations in intermittent generation will become much greater and often much faster than those of demand alone;

* It follows from the above that significant dispatchable power equipment must remain available:

- Either to **compensate for the very large power swings** induced by wind and/or photovoltaic variations, which the **other means considered (storage/de-storage and demand flexibility) will never be able to achieve at scale;**

- Or to be **preemptively started up and coupled to the grid in association with wind and/or photovoltaic production curtailment** so as to maintain grid frequency within security limits, in particular above the grid's minimal security frequency.

Given these different conditions, it is easy to understand that managing the grid’s instantaneous balance will be increasingly complex as the integration ratio of variable and intermittent sources increases, probably calling for **the use of artificial intelligence (AI),** another major development yet to be perfected which harbors new difficulties, and vulnerabilities in terms of cyber risks.

Europe, however, is still far from having reached the stage described in the EDF R&D study. The integration ratio of variable and intermittent sources on the European plate is **close to 30% on annual average**, with a very wide disparity between countries: around 57% in Denmark, 39% in Germany, 38% in

Spain, 34% in the Netherlands, 17% in Italy, 14% in France, 11% in Poland and very low ratios in most other Eastern European countries.

The European power system has yet to experience the real difficulties of integrating 40% variable and intermittent electricity, all the more so since French nuclear power, with its large nuclear units that bring a great deal of inertia to the European grid via its many interconnections, frequently has a stabilizing effect on the frequency of the European synchronous plate. **The difficulties thus remain largely to come, and hence to be discovered**...

However, a European island makes an exception: the island of Ireland, which comprises Northern Ireland (UK) and the Republic of Ireland (EU). For obvious reasons, these two countries have decided to manage their two grids jointly, with a single TSO, EIRGRID GROUP. This grid is only loosely interconnected with the UK grid, via two 0.5 GW DC links (a further 0.7 GW link with Brittany, France is currently under construction). The integration of variable and intermittent sources is thus more difficult than on the highly interconnected European plate, making it a kind of **"advanced laboratory"** for Europe.

EIRGRID GROUP (ref.**[6]**) reports that in 2020/2021 it has reached a wind integration ratio (there is very little photovoltaic power on the island) of around **40% annual average and 70-75% maximum instantaneous value**, roughly in line with the results of the EDF R&D study for the European plate. This result is achieved thanks to two factors:

* Increasingly reliable and precise weather forecasts, which allow to **anticipate wind power production** and take preventive measures such as the preemptive activation of dispatchable equipment;

* The presence of a very large dispatchable fleet (in 2021): in addition to 2.8 GW of coal - and fuel oil - fired facilities, a fleet of 5.8 GW gas-fired CCGTs and OCCTs, whose operation is highly flexible, versus a wind farm of 5.6 GW installed capacity at the same date, all this to satisfy a demand of around 5 GW on average and less than 7 GW at peak. In a nutshell, **EIRGRID GROUP enjoys a practically twofold generating fleet enabling it to adapt very quickly to wind power fluctuations**, these being instantaneous and/or slower but of greater amplitude, reaching 1,000 to 1,500 MW/hour. However, despite the high levels of wind integration announced, **the carbon footprint of this electricity production remained rather mediocre, at around 300 g/kWh, and this doesn't seem to have changed much**.

The EIRGRID GROUP (ref. **[7]**) also announces lofty ambitions for 2030: to achieve an integration ratio of **around 70% on annual average, and 85-95% maximum instantaneous value for 60% of the time**. In-depth studies undertaken by this group with European collaborations – Europe is obviously very interested in the Irish experiment – show, however, that this objective is far from easy to achieve, for numerous reasons detailed below in § 3. In any case, **only feedback from actual grid operation will allow to conclude on the feasibility and the technical and economic viability of such an operation, as well as on its security of supply, an essential feature.**

3 – Is it possible to push much beyond the conclusions of the 2015 EDF R&D study?

Obviously, history did not stop in 2015. In response to the new challenges of integrating growing amounts of variable and intermittent electricity, a number of R&D programs have been launched around the world, more particularly in Europe, notably as part of European cooperative ventures under the aegis of the EU, in which EDF and RTE, as well as laboratories and manufacturers in the French electricity sector, have participated. These projects include:

* **MIGRATE** (ref. **[8]** and **OSMOSE** ref. **[9]**), whose objectives were to study and then test, on small-scale isolated demonstrators, the stability of a grid with a majority share of intermittent electricity, involving a very high proportion of generation resources coupled via power electronic inverters;

* **EU-SysFlex** (ref. **[10]**), whose objective was to study the systemic integration of variable and intermittent sources, together with energy storage/de-storage facilities, production and demand flexibility, etc., and their control by so-called "smart grid" technologies resorting to AI and considering all aspects: technical feasibility, environmental impact (minimizing the CO2 emissions of the selected electricity mix), security of supply, regulatory aspects, costs, market functionality, and so on.

An at least **50% to 55% integration ratio of annual mean production** from variable and intermittent sources has been set for this R&D project.

The results of these projects were published in December 2021. They identify the initial achievements and possible avenues for further development. But it seems that not all the questions have been answered, and further studies and experiments seem imperative **before a possible full-scale deployment on real operational grids**. This would be a very difficult undertaking, given that during such tests it will be essential to guarantee the continuity of supply to consumers with complete security. RTE remains very tight-lipped about this phase, which still seems a long way off...

In short, the **integration into grids of very high levels of variable and intermittent electricity,** whether wind and/or photovoltaic power, has two major consequences:

* It involves a **technological revolution**, wind and photovoltaic power being coupled to the grid via power electronic inverters and not via **synchronous machines** as today. **The consequences are mostly negative, with a few exceptions.**

* The very large amplitude of wind and photovoltaic power variations **deeply destabilize grids** and considerably complicate their physical and economic management.

These two issues are discussed below.

- **The technical challenges of electronic coupling to the grid**

The core machine of today's AC grids is the **three-phase alternator**, invented in 1891 by Nikola Tesla, when working in the USA for George Westinghouse. Since then, they have been constantly improved, until they are now capable of producing extremely high power (up to ≈ 1,800 MW at present), with characteristics that can be described as exceptional as compared to those of electronic inverters:

1 - Alternators can **"form"** a three-phase electrical network in terms of **frequency f and voltage U,** the two main parameters that characterize a grid;

The grid following inverters currently in use don't allow this, as they need an already "formed" grid to inject their power. So-called grid-forming inverters have therefore been invented, with the theoretical capacity to electronically (digitally) reproduce the internal physical laws of alternators. But their **true physical ability to do so has not yet been demonstrated** (see below). What is more, these computerized inverters are inherently **cyber vulnerable**, whereas alternators operating at very high energies according to the laws of electromagnetism are absolutely not (only their command-control links with the outside world can be, but this is true in both cases).

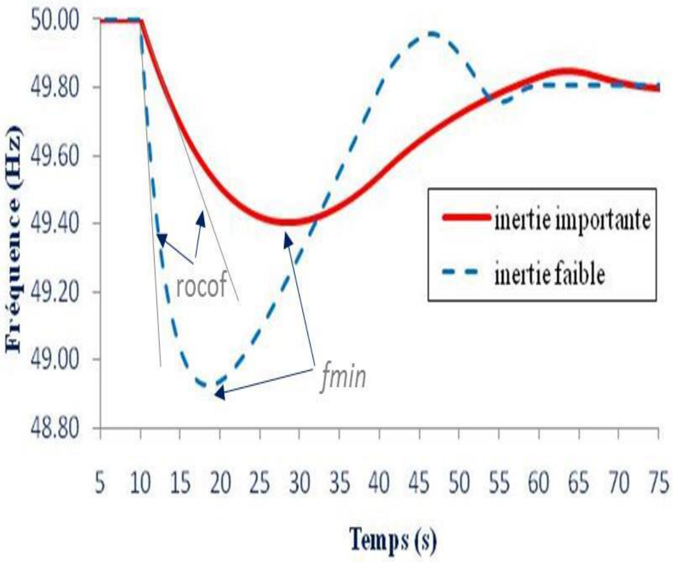
2 - Several alternators coupled in parallel to a given grid operate in a perfectly stable manner if they are fitted with very simple power-frequency regulators applying a law of the form $\Delta P = - K \times \Delta f$ (see § 1). Once they are coupled to the grid, their rotors are all coupled to each other via very powerful electromagnetic torques that allow their rotational speeds to be varied synchronously, i.e. to vary according to the **common frequency of the grid.** This is true regardless of their number (frequency variations propagate across the grid in a fraction (≈ 2/3) of the speed of light in a vacuum: the frequency is thus practically identical everywhere at all times).

As mentioned above, the fact that the so-called grid forming inverters, which are coupled to the grid via purely electronic means, I.e. low-energy means, **do not have the proven capacity to date to be able to operate in parallel and in large numbers on a grid, is a major stumbling block, as it is likely to preclude the operation of grids with a very large ratio of variable and intermittent electricity.**

3 - Alternators have a **high degree of mechanical inertia** (that of their rotor and the turbine that drives it), whose accumulation constitutes the bulk of the **grid's inertia**. This inertia is essential to the grid's stability; also, it provides time for the intervention of the **power-frequency regulators of the turbo-alternators to balance generation and demand at all times**.

The typical impact of inertia on grid frequency transients is illustrated in **Figure 2** below (source: EDF), which shows that the less the inertia, the faster the frequency change, and the deeper the frequency drop in the event of a transient, I.e. the more the system is destabilized.

Note: in this figure, the "rocof" or "rate of change of frequency" is the rate of change of the frequency at the origin of the incident. It is expressed in Hz/s and is **proportional to the power loss and inversely proportional to the residual inertia** of the grid.



To give an idea, the minimum frequency ***fmin*** is reached in 10 to 15 s on the (large) French mainland network, which is strongly interconnected to the European grid, but in well under 5 s on the (small) isolated grids of the DOM-TOM[1] islands, powered by small machines whose rotors have little inertia.

Power electronic inverters obviously have no mechanical inertia. Increasing the proportion of wind and/or photovoltaic power in a grid therefore reduces the number of alternators coupled to it, and consequently its overall inertia. This **increases both the swiftness and the amplitude** of frequency variations, and consequently reduces grid stability and operating security.

EIRGRID GROUP's studies for the Irish grid show that **the rocof must never fall below 1 Hz/s, else the island's grid would become uncontrollable**. The reason for this is easy to understand: there are no known means to compensate for lost power quickly enough to avoid a very rapid and deep frequency drop and a crossing of the low-frequency limit leading to blackout. Not even a [battery + inverter] set that allows injection of the battery's nominal power in ≈ 1 s can do this.

As regards the interconnected synchronous grid of the European plate, studies carried out by ENTSO-E (ref. **[3]** and **[4]**) show that rocofs < 1 Hz/s could be reached in the future **in the event of grid separations within the European synchronous plate**. Such separations could lead to power losses **far greater** than the 3,000 MW of generation losses currently considered (§ 1). **ENTSO-E concludes that it will be essential in the future to increase the inertia of the European grid**, either by keeping turbo-alternators permanently coupled to the grid, or by adding a large number of rotating "**synchronous compensators or condensers**": these machines, which have long been used to regulate grid voltage, are nothing more than alternators coupled to the grid without providing driving torque. **But they do provide rotor inertia**.

In short, **even if this last proven solution exists, the issue of inertia is and will remain a crucial parameter for grids integrating a very high proportion of wind and/or photovoltaic power**.

4 - Alternators also **enjoy a large thermal inertia** due to their electromechanical structure and internal cooling system. This enables them to withstand **very high over-currents** (up to 500 to 600% of rated current) for short moments without damage. Consequently, they **do not have to be disconnected from the grid** in the event of fugitive short-circuits, the most frequent ones on grids. Thus, they **can resume production** as soon as the short-circuit is eliminated, **a major factor in power supply security**.

This is not the case with power electronic inverters, whether "tracking" or "forming", as their electronic components have very little thermal inertia. They are only capable of withstanding over-currents generally between 20% and 80% of their rated current, depending on their design. Moving much further would considerably increase their cost.

1 DOM-TOM: *Départements et Territoires d'Outre-mer* - Overseas departments and territories.

5 - Alternators **produce voltage and current waves with quasi-sinusoidal shapes,** thus **virtually without high-frequency harmonics.**

This is not the case with inverters, whether "tracking" or "forming", insofar as they operate by chopping DC current, producing high-frequency harmonics up to 150 kHz. If not eliminated, these harmonics have deleterious effects on grid hardware and equipment, particularly sensors, but also on consumer equipment. There are, however, simple solutions to their elimination, namely installing so-called "low-pass" filters. These are already used in certain circumstances, but they will have to be generalized as the inverter integration ratio in the grid increases.

6- All in all, the new issues mentioned above, **that result from the electronic couplings required to connect wind and photovoltaic power to the grid**, are far from exhaustive. Many more could be mentioned, such as **the difficulty of providing primary, secondary, and tertiary reserves** (see § 1), as well as **load-following capabilities** that imply storage capacities that can be very substantial.

But there are two issues that stand out as being of crucial importance in **guaranteeing the same quality in the structuring, stability, and security of supply of future grids, as compared to the current situation:**

* The ability to **"form"** future grids in terms of **frequency f** and **voltage U**;

* The need to provide grids with **sufficient inertia**.

The combination of these two conditions currently means keeping a sufficient number of synchronous machines (turbo-alternators and/or synchronous compensators) constantly coupled to the grid.

To understand the reasons for this, consider two clearly different situations:

* The integration ratio of variable and intermittent electricity **does not exceed 40% on annual average,** with instantaneous ratios ranging from a 25% minimum to a 70% maximum, depending on whether the power load on the network is low or high, a case studied in depth by EDF R&D. Under these conditions, the grid remains **constantly formed by the alternators, in a long-established, tried-and-tested scheme with very high reliability and security of supply as is currently the case**.

° The integration ratio of variable and intermittent electricity is **well in excess of 40% on annual average**. This is a **totally new and currently highly uncertain scenario,** that has **not been validated by experience on real grids**. Here, **turbo-alternators are a very small minority** (the only ones left are those which use hydraulic energy or biomass). **These few synchronous means alone become highly insufficient to "form" the grid in terms of frequency f and voltage U.**

This is a **major point of uncertainty,** which is implicit in the joint study by RTE and the IEA of January 2021 **[2]**, which states: ***"Four sets of strict technical conditions will have to be met to allow, with assured security of supply, the integration of a very high proportion of variable renewable energies into a large-scale power system, such as that of France [....] There is no proof that the integration of a very large proportion of variable RES such as wind and photovoltaics into a large-scale electricity system is feasible."***

Three years later, the same uncertainty holds regarding these ***"Four sets of technical conditions": "Their feasibility is not currently guaranteed"***, writes RTE soberly without being more explicit, in its ***Bilan prévisionnel 2023-2025*** published at the end of 2023.

Several prospective hypotheses come forth:

- **Hypothesis 1**: Thanks to future technological advances, **grids can be made to operate stably and securely with a large number of "forming" inverters coupled in parallel with each other and with the residual alternators, and the problem is solved.** It should be noted, however, that since a grid "formed" in this way is **completely unprecedented**, many other surprises should be expected during its tuning, but one thing is certain: given its highly digitized nature, it **would be much more cyber-vulnerable than a grid "formed" by synchronous machines**. This would be a central issue for its operational security, which would have to receive an extremely reliable and robust response in view of the risks involved: a blackout on all or part of the country.

In addition, the grid inertia would have to be increased. This would require the installation of a **very large number of synchronous compensators**, a well-known and proven solution which would also enable the regulation of the grid voltage **U**. And a solution would have to be found for all the other problems mentioned above, and many others not mentioned.

Note: in this hypothesis, a sufficient number of "forming" inverters would be used to "form" the grid, along with, as now, "following" inverters to simply inject power.

- **Hypothesis 2**: It proves **very difficult, if not impossible**, to operate the grid under the conditions outlined in Hypothesis 1 above, and the **only solution is to constantly keep the number of synchronous dispatchable means large enough to "form" the grid.** Yet, to **produce dispatchable carbon-free electricity in very large amounts without resorting to nuclear power,** it is necessary to have **stocks of carbon-free energy accumulated from wind and/or photovoltaic electricity**. The only physical solution known to date on the very large scale required, is to use **carbon-free gas storage, the most obvious one being carbon-free hydrogen.** The latter will then be burnt **on demand** in combined-cycle power plants (CCGTs) for the most part, and in open cycle combustion turbines (OCCTs) to meet the ultra-peaks of demand.

Note: the biomethane solution has not been retained here, as its amounts will be limited and it will probably be much more useful in other applications, such as mobility for instance.

Hypothesis 2, however, entails three additional major consequences:

- In **addition to compensating for the variations and intermittency of wind and photovoltaic generation, the above-mentioned hydrogen-powered dispatchable equipment must also "form" the grid. This function implies the permanent operation of a sufficient number of dispatchable units coupled to the grid, and consequently a permanent consumption of hydrogen**, according to the state of the grid;

- Considerable **hydrogen storage capacities are needed**, including to cope with a sustained lack of wind that can statistically last up to about a fortnight;

- **The production of carbon-free hydrogen from wind and/or photovoltaic electricity needs to be scaled up considerably,** given the **low overall efficiency of the chain of conversions**:

Electricity → Hydrogen → Electricity

This overall efficiency is around 33% if the hydrogen is burned in a high-efficiency combined cycle facility (CCGT), and around 22% if it is burned in an open-cycle combustion turbine (OCCT). This low overall efficiency means that, in the best-case (CCGT), **around 3 kWh of VARIABLE AND INTERMITTENT electricity are consumed, hence have to be produced, to recover... 1 kWh of DISPATCHABLE electricity.**

Based on the criteria of the EDF R&D study, only 40% of the wind and/or photovoltaic electricity produced would be consumed directly. The rest would be used to produce hydrogen to operate dispatchable thermal equipment using this gas, with twice this amount of electricity being lost (2 kWh energy losses per dispatchable kWh produced).

All in all, this hypothesis amounts to artificially **recreating a dispatchable production fleet by storing considerable amounts of hydrogen. This fleet will operate technically in a stable and secure way, but will have to permanently self-consume, in the form of energy losses, around 2/3 of the carbon-free hydrogen it will have previously produced thanks to wind turbines and photovoltaic panels.**

- **Hypothesis 3:** this consists in **doing without hydrogen mass storage, and continuing to use natural gas** (most of which is fossil fuel, given the quantities required) to **run dispatchable thermal power plants, CCGTs and OCCTs,** and to **decarbonate the resulting electricity production through carbon capture and storage (CCS).**

However, this solution presents major difficulties and unknowns: it is very **energy-intensive** (it absorbs the equivalent of around 30% of the dispatchable electricity produced); it is **industrially immature;** it requires very **extensive transport networks** and considerable **deep geological** CO2 storage, which can pose difficult environmental problems; its costs are currently totally unknown.

- **Will it be possible to handle the very large amplitude variations of wind and photovoltaic power?**

This is a major issue considering the projected growth of these energy sources in France and even more so in Europe, with Germany in particular staking everything on renewable energies in the wake of its nuclear phase-out.

✓ **In France**

Recall (§ 1) that power modulation requirements, commonly around 10 to 12 GW, reaching up to 20 GW in a few hours, are already commonly observed with the currently installed wind (≈ 26 GW) and PV (≈ 17.5 GW) capacities as of the end of 2023.

Now, the PPE (multi-annual energy program) currently being drawn up is projecting 58 to 63 GW wind power capacity (onshore and offshore, with 18 GW offshore) by 2035 (i.e. a total wind power almost equal to nuclear capacity at the same date) and 65 to 90 GW for photovoltaics (i.e. up to almost 1.5 times nuclear capacity), for a grand total that could exceed 150 GW. Taking the maximum production potential, this mix could produce a little over 250 TWh/year.

The power transients resulting from these capacities will profoundly alter grid management. An indication of this can be obtained by looking at photovoltaic production, which is easier to analyze. During the period around the summer solstice ± 2 months when the sun is at its highest, with 90 GW installed capacity, production will be able to reach up to approximately 75 GW of electricity on a clear day, at solar meridian time ± 1 to 2 hours. How will this production be used during the summer months, when electricity demand is low, currently around 50 GW on weekdays and down to 40 GW and less on weekends? Several factors must be considered:

* It will be possible to: produce hydrogen; fill the upper basins of PHES facilities; recharge electric vehicles connected to charging stations. However, the grand total of this demand will generally be much less than the 30 to 40 GW of photovoltaic overproduction;

* Exports cannot be counted on too much, as a sunny day in France is likely to spread beyond France's borders to neighboring countries, which will have even larger photovoltaic capacities;

* To operate stably and reliably the grid needs to have a minimum of **coupled** dispatchable means. This is estimated to be **at least 25 GW coupled installed capacity** (see § 2). Indeed, it is sufficient for these means to be **coupled** to provide their inertia, independently of the power they produce. Well, the carbon-free means available include run-of-river hydropower, biomass (and waste) and, above all, the **nuclear power fleet**,' which is **the only means capable of modulating power over wide amplitudes, while gas-fired thermal power, hydroelectric power from dams and PHES facilities are capable of modulating power more rapidly, but over much smaller amplitudes.** The **real power** supplied by these means **may well be slightly less than 25 GW,** but it will anyway reduce the absorption potential of photovoltaic generation.

* All told, **there will definitely be too much photovoltaic electricity at the sunniest hours of the day, and this surplus will have to be curtailed to avoid destabilizing the grid frequency and voltage.** Photovoltaic production will have to "cannibalize" itself...

* Howbeit, when the sun goes down, in the roughly 8 hours between solar noon and nightfall, **the grid will have to absorb a very large power transient**, which will depend on the level of photovoltaic curtailment, but will in any case be **several tens of GW. Only nuclear power will be able to compensate for this transient** by progressively increasing its power until it reaches the power required for the evening and night. And the next morning, it will have to **reduce its power again to make way for the gradual rise of photovoltaic output.** And if the fair weather lasts, nuclear power will have to modulate its output in this way **once a day, every day,** in addition to contributing inertia to the grid.

This indispensable dual role of nuclear power **will logically require that a certain number of reactors operate with deep power modulation, with no temporary shutdowns, even on weekends,** with modalities that will depend on a number of parameters (level of photovoltaic curtailment, power requirements on the grid, etc.). The same problem will arise with wind generation and/or combined photovoltaic + wind generation, which are generally not at their peak at the same time, but whose cumulative output may exceed the maximum photovoltaic output. These situations are much more difficult to analyze, given the much more erratic and sometimes more rapid variations in wind generation. They can be analyzed only with the support of comprehensive statistics based on an hour-by-hour time interval.

In any case, nuclear power will be called upon to balance more and more power variations, and of increasing amplitude, of wind and/or photovoltaic production, and to stabilize the grid through its contribution to inertia, while wind and/or photovoltaic power will have to be **deeply capped at certain times. However, some technical, economic and capability limits to this compensation by nuclear power will**

become self-evident. In particular, the increased flexibility of nuclear power must under no circumstances be detrimental to the extension of reactor life beyond 60 years, a condition of strategic importance if we are to have sufficient nuclear power in 2050 (see § 4 below).

Note: This situation will consequently have a major economic impact on the fundamentals of the electricity system: nuclear power will have to finally be financially compensated in one way or another **for the services it renders** (this is currently not sufficiently the case via the capacity market), and the remuneration of wind and photovoltaic power will have to be profoundly adjusted. This will also have a major impact **on the current rules governing the operation of the electricity market, which will have to be substantially revised** - no mean feat in the European context, especially as these rules will also have a potential impact on future investment choices.

This is a very difficult and long-term undertaking, and one that needs to be properly planned, and this does not seem to be the case at present. Yet the difficulties are set to crescendo between now and 2030, i.e. tomorrow on the scale of the French and European power systems.

✓ **In Germany**

The same problem will arise, but on a much larger scale, for a number of reasons: Germany has very little hydropower and no nuclear power to balance its grid, and it is planning much larger installed capacities in wind and photovoltaic power, according to official German forecasts (EEG 2023 - Source: ref. [11]) summarized in **Table 1** below (installed capacities in GW):

– Source : réf. [11]) résumées dans le **tableau 1** ci-dessous (puissances installées en GW) :

100 % renewable means	Reminder 2022	Planned 2035	Planned 2045
Hydropower (including PHES) + biomass + waste ➔ ≈ **Dispatchable**	≈ 21 (≈ 70 TWh/year)	≈ 21 (≈ 70 TWh/year)	≈ 21 (≈ 70 TWh/year)
Onshore wind	58,1	**157**	**160**
Offshore wind	8,1	**40**	**70**
Solar photovoltaic	67,4	**309**	**400**
Total non-dispatchable	133,6 (x 1)	**506 (x 3,8)**	**630 (x 4,7)**
Actual or estimated production from the mix (**TWh/year**)	**≈ 254** + Other: 317 ➔ **571**	**≈ 745** + Backup H2 (*)	**≈ 960** + Backup H2 (*)

(*) Thermal back-up facilities (CCGTs and OCCTs) running on carbon-free hydrogen, partially in 2035 and totally in 2045, Germany having announced a **totally carbon-free production at that date**. The sizing of these means should ensure that, on the one hand, **the network is "formed" at all times**, and, on the other hand, that **the production-demand balance in terms of power and energy** is maintained in all circumstances (see below).

Several critical operating situations must be analysed for a mix of this type:

* On a very sunny summer day in 2045, the 400 GW of installed photovoltaic capacity could produce up to 350 GW when the sun is at its zenith, while demand is unlikely to exceed around 100 GW. Surpluses could thus reach 250 GW, only part of which could be absorbed by: electrolysers producing carbon-free hydrogen; recharging of PHES facilities and electric vehicles; and possible exports. But the latter will be limited on the one hand by the capacities of the interconnection lines with neighbouring countries, and on the other hand, and above all, by the fact that the neighbours are likely to have plenty of sunshine and, consequently, surplus photovoltaic production at the same time.

The only way to avoid destroying the balance of the European grid (and not just the German one) will be a **considerable curtailment** of photovoltaic production (probably in the range of one to two hundred GW). And if Germany fails to do this, there will be no other solution than to temporarily block interconnections with that country using phase-shifting transformers to protect the balance of our own grid. Other countries will also have to resort to this out of necessity - an ultimate measure currently contrary to the rules governing exchanges between countries - but these will have to evolve if necessary.

But this is not all: the descent of the sun between the meridian hour and nightfall, reaching zero power will result in **an extremely large power transient that will be extremely difficult to control, as only dispatchable hydro and biomass** (≈ 21 GW only) and uncertain, non-dispatchable wind power will then remain. Now, in summer, anticyclone conditions with episodes of very low winds are not uncommon, making the situation even worse. It is possible to assess their potential impact.

According to RTE, **wind power falls below 10% for around 10% of the annual hours, throughout the year.** As for the German TSOs, RTE's counterparts, **in their security of supply studies, they consider they can count on a minimum wind power of 1% onshore and 4% offshore.** Combining the two, we can conclude that wind power is statistically **between 1% and 10% for 10% of the time,** all seasons combined.

Applied to the 160 + 70 = 230 GW of German wind power in 2045, this yields a wind output of around... 4.4 GW to 23 GW during low-wind periods, despite the considerable installed capacity. **The total power of the German renewable mix** during these periods will then be between 21 + 4.4 ≈ **25 GW** and 21 + 23 = **44 GW**, which is far from sufficient to supply the country, despite recourse to PHES and battery de-storage, whose capacities will be depleted in a matter of hours, and demand withdrawal and/or postponement, whose amplitudes are far from sufficient.

It follows that Germany's renewable energy mix will not be able to function at all without extensive use of dispatchable hydrogen-fired thermal plants (CCGTs and OCCTs), including during the summer months, when demand is at its lowest. Several tens of GW of these dispatchable means will have to be activated during summer evenings and nights, depending on the levels of demand and of available wind power.

* Conversely, very cold winter days will be much less problematic in terms of daytime photovoltaic surpluses, as these productions are 4 to 5 times smaller, but **will reinforce the criticality of the passage of long evenings and cold nights in the event of low winds.** Indeed, peak consumption in Germany is estimated at 120 GW in 2030/2035 by the German TSOs and could reach over 150 GW in 2045 according to the German Fraunhofer Institute (ref.**[12]**).

Since the German renewable mix at that date **would deliver only 25 to 44 GW on nights with low winds** (see above), the power deficit would be between ≈ 116 and ≈ 125 GW in the most critical cases, and demand shedding and/or deferral would contribute one to two tens of GW at best. Moreover, **security of supply margins** should be added to the demand considered.

The Fraunhofer Institute thus forecasts a need for around ≈ 63 GW of CCGTs and ≈ 88 GW of OCCTs by 2045 to secure the grid. However, **in line with the decarbonation of its power sector announced by Germany at that date**, **these means should switch to carbon-free hydrogen. Since Germany will not be able to produce enough hydrogen domestically, it is counting on massive imports of carbon-free hydrogen: up to 15.5 Mt of hydrogen in 2050 according to (ref.[5]), representing an energy of around 517 TWh.**

4 – Comparing two antithetical power mixes: "100% renewable" versus "predominantly nuclear"

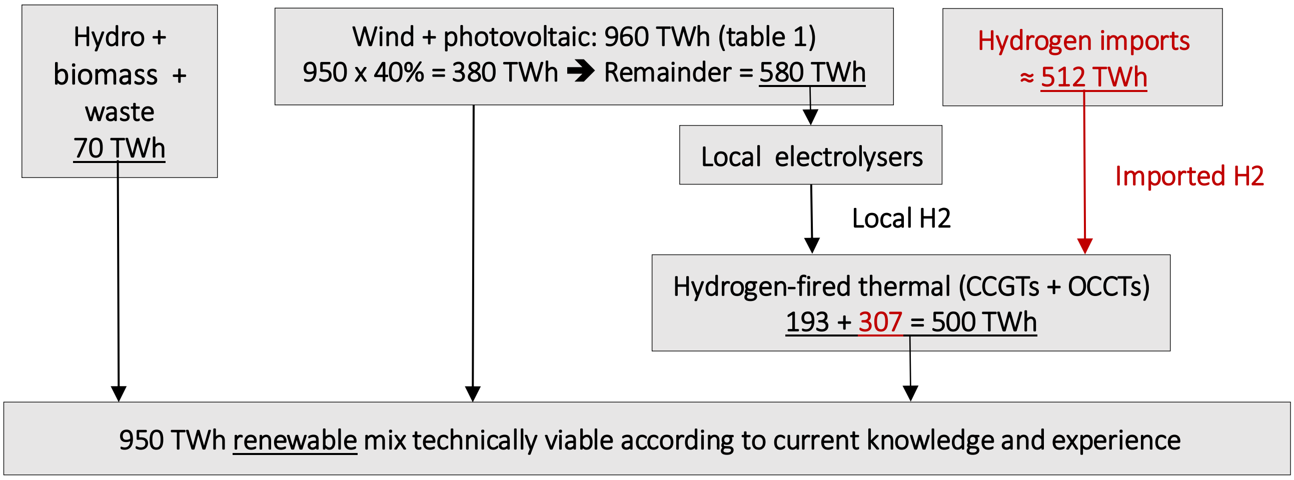
This comparison is based on a 950 TWh total annual electricity production, which roughly corresponds to Germany's forecasts for 2045 and to an **unofficial but realistic** estimate of France's needs for 2050. It is thus based on plausible assumptions and orders of magnitude for the time frames considered.

- **Sizing the mixes needed**
  - ✓ **German "100% renewable" mix**

Here we assume a mix whose operation is **technically proven and certain** (§ 3, hypothesis 2, p. 12). Using the assumptions of the EDF R&D study, with 40% variable and intermittent generation and 60% dispatchable generation, we arrive at the following annual values:

* Directly consumed wind and/or photovoltaic production: 950 x 0.40 = 380 TWh

* **Dispatchable production needed**: 950 x 0.60 = 570 TWh, of which 70 (see Table 1) are provided by hydropower, biomass, and waste. The remaining 500 TWh must be generated by hydrogen-fired thermal power plants, with the hydrogen coming partly from the remaining wind and/or photovoltaic production, and partly from hydrogen imports. In sum, the production of this mix is shown in **figure 3** below:



This diagram highlights the challenge of colossal hydrogen needs:

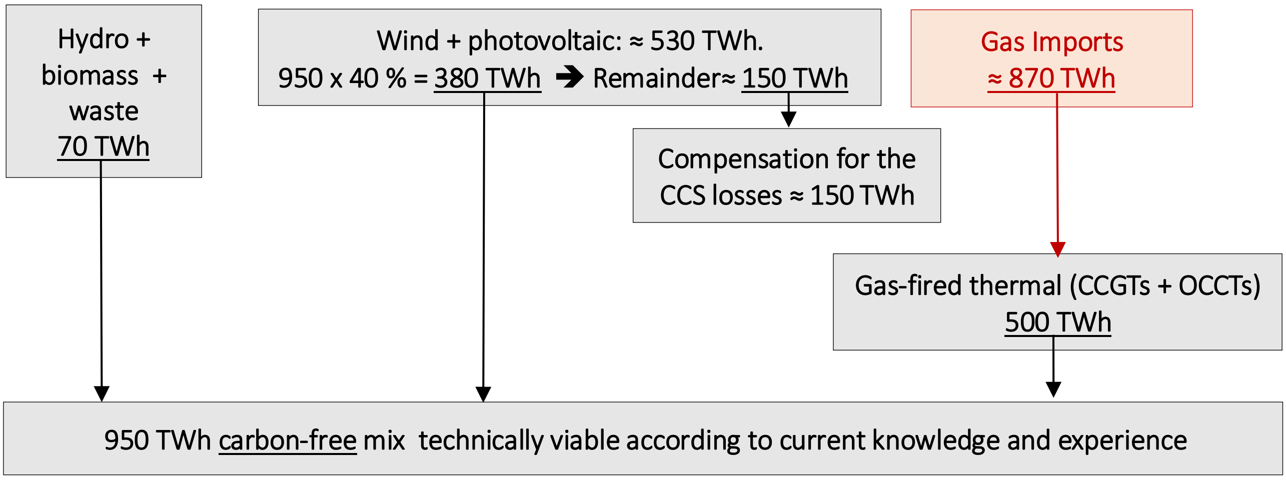
* The 580 TWh of wind and/or photovoltaic electricity used for its production entail an extremely large installed base of electrolysers, whose output will depend on their mean load factor. If we assume it is ≈ 50% due to the variable and intermittent nature of these electricity sources, at least 130 GW of installed electrolysers are necessary;

* But since there will not be enough wind and/or photovoltaic electricity to produce all the hydrogen needed to run the thermal power plants, due to the 33% efficiency of the overall chain of conversions, it will be necessary to resort to imported hydrogen as a supplement. It will be burned with an efficiency of around 60% in a high-performance CCGT;

In short, according to this approach, **in order to have 950 TWh of "100% renewable" electricity, guarantee the balance and security of supply of its grid, and decarbonate its electricity mix, Germany would have to have a considerable installed base of 630 GW of wind and photovoltaic installations, and also import 500 TWh of hydrogen.**

And, as already mentioned above, **according to the Fraunhofer Institute, it would also need a hydrogen-powered fleet of around 63 GW CCGTs and 88 GW OCCTs to cope in all circumstances with grid stability issues and wind and/or photovoltaic production shortfalls.**

Should this **"100% renewable" strategy + massive hydrogen imports** **fail for one reason or another,** Germany would have no alternative but to run its aforementioned CCGTs and OCCTs on **fossil** natural **gas** and resort to **carbon capture and storage (CCS)** (§ 3, hypothesis 3, p. 12) as shown in **figure 4** below:



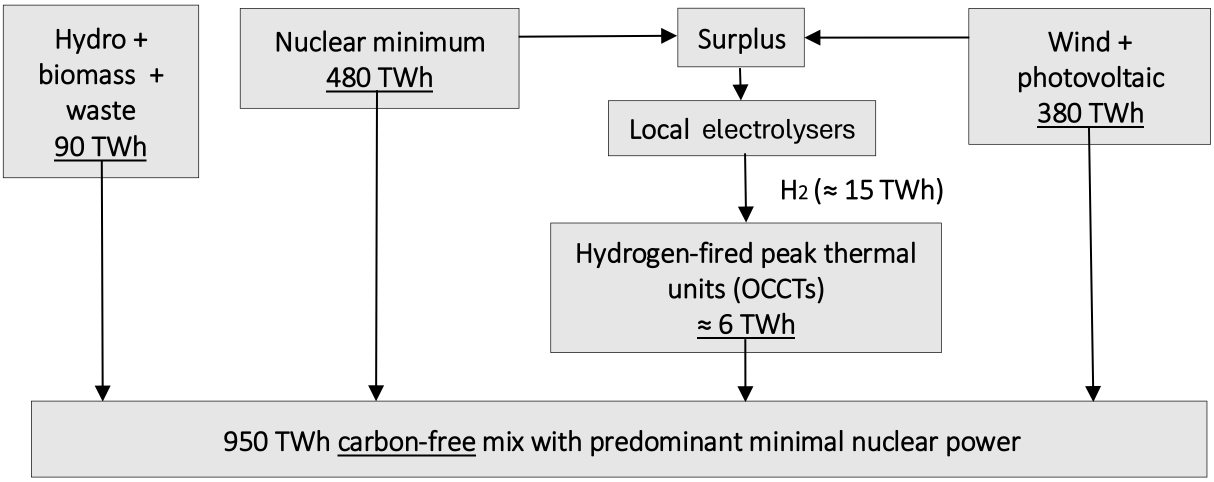
This diagram shows that gas imports would amount to around **870 TWh**, and that wind and photovoltaic production could be reduced to around **530 TWh**. But this solution is neither sustainable in the long term, nor "100% renewable", and to be decarbonated it would require **CCS** to absorb **all the CO2 emitted, i.e. over 200 Mt/year.** This, without considering the uncertainties and difficulties involved in implementing the CCS technology, emphasized in § 3, hypothesis 3, p 12.

✓ **French predominantly nuclear mix**

Predominant here means that **at least 50% of total production** is nuclear-based. Remaining cautious concerning the potential of hydropower or biomass generation in 2050, their extensions being limited, we retain the following annual values: around 75 TWh hydropower and 15 TWh biomass and waste, i.e. a total of ≈ 90 TWh.

In line with the EDF R&D study, to limit wind and/or photovoltaic generation to 40%, i.e. 380 TWh, nuclear power will have to produce at least: 950 - 90 - 380 = 480 TWh. The production of this mix is shown below in **figure 5**.

Note that, in line with the official projections, **no hydrogen imports are contemplated**, as the mix considered is capable of supplying the hydrogen and hydrogen derivatives needed by the rest of the economy (excluding the - very small - energy storage requirements of hydrogen to meet grid needs).



Note that, in line with the official projections, **no hydrogen imports are contemplated**, as the mix considered is capable of supplying the hydrogen and hydrogen derivatives needed by the rest of the economy (excluding the - very small - energy storage requirements of hydrogen to meet grid needs).

To produce 480 TWh nuclear power with some margin, the **installed capacity has to be at least 76 GW**, i.e. around 20% more than today. However, this mix **is not very satisfactory** for at least two reasons:

* It requires a very large wind and/or photovoltaic production of 380 TWh, about 50% more than that forecast by the PPE (multi-annual energy program) (of the order of ≈ 250 TWh, see above, § 3, p.13) while the amplitude of their power variations already raises major compensation difficulties;

* **Its maximum possible power output does not allow it to pass the highest demand peaks**, if, as above, we estimate them at ≈ 150 GW. Indeed, hydropower (including PHESs) with ≈ 18 GW maximum historical power and biomass with today's ≈ 2 GW do not exceed ≈ 20 GW. This could probably be reasonably increased by around 20% by 2050, to ≈ 24 GW. Assuming maximum nuclear power availability during winter demand peaks, i.e. 96% of its 76 GW capacity, nuclear could produce ≈ 73 GW. This yields a total 97 GW dispatchable generation.

Assuming that demand shedding and/or deferral reduces peak demand by around 16 GW (≈ 10 for industry and ≈ 6 for domestic and tertiary buildings, according to RTE), the shortfall would be around 150 - 97 - 16 ≈ 37 GW on windless winter nights. If a safety margin is added, the need would approach 40 GW.

In a carbon-free system, this peak power would logically have to be provided by **hydrogen-fired OCCTs** with operating times of no more than one to two hundred hours per year, as with today's OCCTs. The need for carbon-free hydrogen should therefore be very low, on the order of ≈ 15 TWh per year, but **it will not be non-existent.**

It follows from the above two reasons that it is **highly desirable to push significantly beyond 50% nuclear generation**, bearing in mind that this implies a **twofold industrial challenge**:

*** Extend almost all of the current nuclear fleet to 70 to 80 years operation, in order to have significant nuclear capacity in 2050, while avoiding a very sharp capacity drop in 2050. This is a strategic matter.**

Indeed, 15 GW of the current fleet will reach 60 years of age by 2042, and another 30 GW by 2045. Extending the fleet by **a further 10 to 20 years beyond the age of 60 would enable it to be fully conserved in 2050 and a little beyond**, to give new nuclear power more time to ramp up its capacity;

* **Build sufficient new capacity between now and 2050.** The current outlook is for 14 EPR2 reactors (≈ 23 GW) **commissioned** between 2037 and 2050, i.e. an average of ≈ 1 EPR2 per year over the period. Exceeding this pace is probably conceivable only from 2040 onward. From today's perspective it remains a major industrial challenge that needs to be prepared for now.

All in all, it seems that it will not be easy to push much beyond a target of 63 + 23 = 86 GW by 2050, for an annual production of around 545 TWh and a penetration ratio of around 57%, which would reduce wind and/or photovoltaic production to 315 TWh and bring its penetration ratio down to around 33%.

It also follows that new nuclear facilities will have to be built **well beyond 2050, especially as the current fleet will then have to face imminent declassification. Building new EPR2 nuclear reactors and subsequently their successors, the FNRs (Fast Nuclear Reactors), is thus a very large-scale, long-term industrial project, which will extend well into the second half of this century.**

Note: another reason prompts restricting the integration ratio of wind and/or photovoltaic power: **the extra cost of compensating for their variability and intermittency**. According to the NEA (ref.**[13]**), these additional costs are on the order of under 10 €/MWh for 10% integration, a little over 20 €/MWh for 30%, rising sharply thereafter. **This, irrespective of grid costs, which soar with the multiplication of wind and photovoltaic connections.**

- **Rough estimate of electricity production costs**

It is possible to form an **initial, very approximate idea** of the cost per MWh of these mixes, based on the **average unit production costs** of the various means involved. The following very simplified assumptions are used, bearing in mind that these are **costs and not sale prices.**

* Hydropower, solid biomass and waste: **≈ 60 €/MWh**

* Wind and photovoltaic power, including all farm sizes: **≈ 70 €/MWh**

* Thermal power plants running on carbon-free hydrogen: in its study **energy futures for 2050,** RTE estimates their production costs at around **240 €/MWh** for a CCGT and **350 €/MWh** for a peak-load OCCT, based on an estimated hydrogen cost of around **4€/kg**.

Note: this hydrogen cost is a **very low estimate** for carbon-free hydrogen produced by electrolysis. This is even truer for imported hydrogen, which may be produced at a slightly lower cost in countries with abundant sunshine, but whose cost on arrival will be weighed down by transport and storage costs, for which no reliable references are available at present, but which will certainly be very high given the very great difficulties involved in transporting this gas.

* Nuclear: ≈ **50 €/MWh** for current nuclear and ≈ **85 €/MWh** for new nuclear (EPR2). Considering the weighting of the respective capacities on the order of (63-23) that could occur in 2050, the weighted average comes to:

(50 x 63 + 85 x 23)/86 ≈ **60 €/MWh**

Based on these unit costs, it is then possible to estimate the weighted average costs of the mixes being considered.

- ✓ **German "100% renewable" mix**

This estimate is based on the **only case where cost estimates are available,** namely the hydrogen mix shown in **Figure 3**. Besides, since OCCTs operate only very infrequently throughout the year, for the sake of simplicity, the cost of CCGTs alone will be used.

This gives a weighted average cost of the mix around:

(60 x 70 + 70 x 380 + 240 x 500)/950 ≈ **160 €/MWh**

This is a **very high average production cost**, **despite its being based on a low estimate of the price of carbon-free hydrogen, which is far from being established.** To this we must add the costs of externalities, in particular grid overheads, which are much higher than those of a predominantly nuclear system. Indeed, 630 GW wind and/or photovoltaic power, 130 GW electrolysers and 150 GW hydrogen-fired thermal power plants would have to be connected to the grid, i.e. a total of over 900 GW.

✓ **French predominantly nuclear mix**

In this case, the weighted average cost of the mix is of the order of:

(60 x 90 + 70 x 380 + 60 x 480)/950 ≈ **64 €/MWh**

This cost, **around 60% lower than that of the German mix,** is also associated with **much lower external costs.** For the grid alone, assuming a maximum 33% integration of wind and/or photovoltaic power, only around 313 GW would have to be connected, to which would have to be added 23 GW of new nuclear power, i.e. a total of less than **340 GW. Again, this is around 60% less.**

5 – Summary and conclusions

To answer the question posed in the title of this study, EDF R&D's June 2015 study was used as a reference for several reasons:

* First, it is reference study of widely recognized high-quality including in the USA, where its authors received an Award from the American UVIG (The Utility Variable-Generation Integration Group).

* This study leads to **an easy-to-use global criterion, which implicitly integrates the physical constraints of grid "formation" and the mechanical inertia required for stability** and leads to the conclusion that it is possible to integrate up to **40%** of variable and intermittent electricity in **average annual power on the European continental synchronous plate** (this is the relevant geographical level, as European countries are highly interconnected and form a single grid). This is subject to a number of complementary, limited conditions that do not alter the nature of the power system, which **remains "formed" by synchronous machines in any event. This is a crucial point.**

*** To date, the effective ratio of variable and intermittent electricity on the European plate is around 30%, on annual average. This means that the European plate as a whole is still "formed" by synchronous machines, even if some countries exceed a 40% ratio, and if, accordingly, their grids are more and more disrupted by the ramp-up of wind and photovoltaic capacities. Continental Europe, then, has not yet reached the 40% limit, and the hardest part is yet to come...** (The "small" grid on the island of Ireland, which is relatively isolated from the UK grid and therefore serves as an "advanced laboratory" for Europe, has more or less reached the 40% mark, but under the specific conditions described above in §2, which cannot be generalized to the major European grids).

* Despite the fact that the criterion of a maximum of 40% variable and intermittent electricity **very probably leads to overestimating the need for dispatchable means to stabilize the grid, examination of the physical and economic viability of a "100% renewable" system leaves little doubt that this option is a dead-end regarding both energy and the environment.**

Indeed: **trying to operate grids without sufficient synchronous machines is today an extremely dangerous GAMBLE regarding equipment of vital importance to a modern country;** relying on the extremely large quantities of carbon-free hydrogen that would have to be produced from wind and/or photovoltaic electricity to operate the indispensable dispatchable means comes up against **colossal energy losses.** As for large-scale imports of carbon-free hydrogen, which is currently a trendy topic, they also lead to a new geopolitical dependency, which is certainly different from that of gas, but equally dangerous in the event of a global conflict; finally, using fossil gas in association with carbon capture and storage (CCS) on the very large scale that would be necessary is **extremely risky given the current state of this technology, and would also perpetuate dependency on fossil gas suppliers, and this will not be everlasting either... And in the event of industrial or economic failure, it could result in the absence of decarbonation, a catastrophy for the climate.**

In-depth studies carried out with hourly intervals and considering all the flexibilities mentioned above would probably allow to reduce various constraints, but gaining 10, 20 or even 30% on the dispatchable power requirements needed to guarantee grid operation and ensure the decarbonation of the mix would not fundamentally change the situation, as the orders of magnitude are so large.

The strategic mistake that the European Commission has made, instigated and supported by certain countries, is to have advocated as the ONLY solution the all-renewable option based solely on the mindless growth of wind and photovoltaic power, while at the same time attempting to eliminate nuclear power,

despite the fact that it is the only energy source known to date that is carbon-free, dispatchable and capable of producing electricity in very large amounts at a competitive cost.

This energy policy is heading Europe to disaster... It is urgent to correct it and encourage the development of nuclear power in all countries that wish to do so. Quite simply, the continent's energy future depends on it.

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