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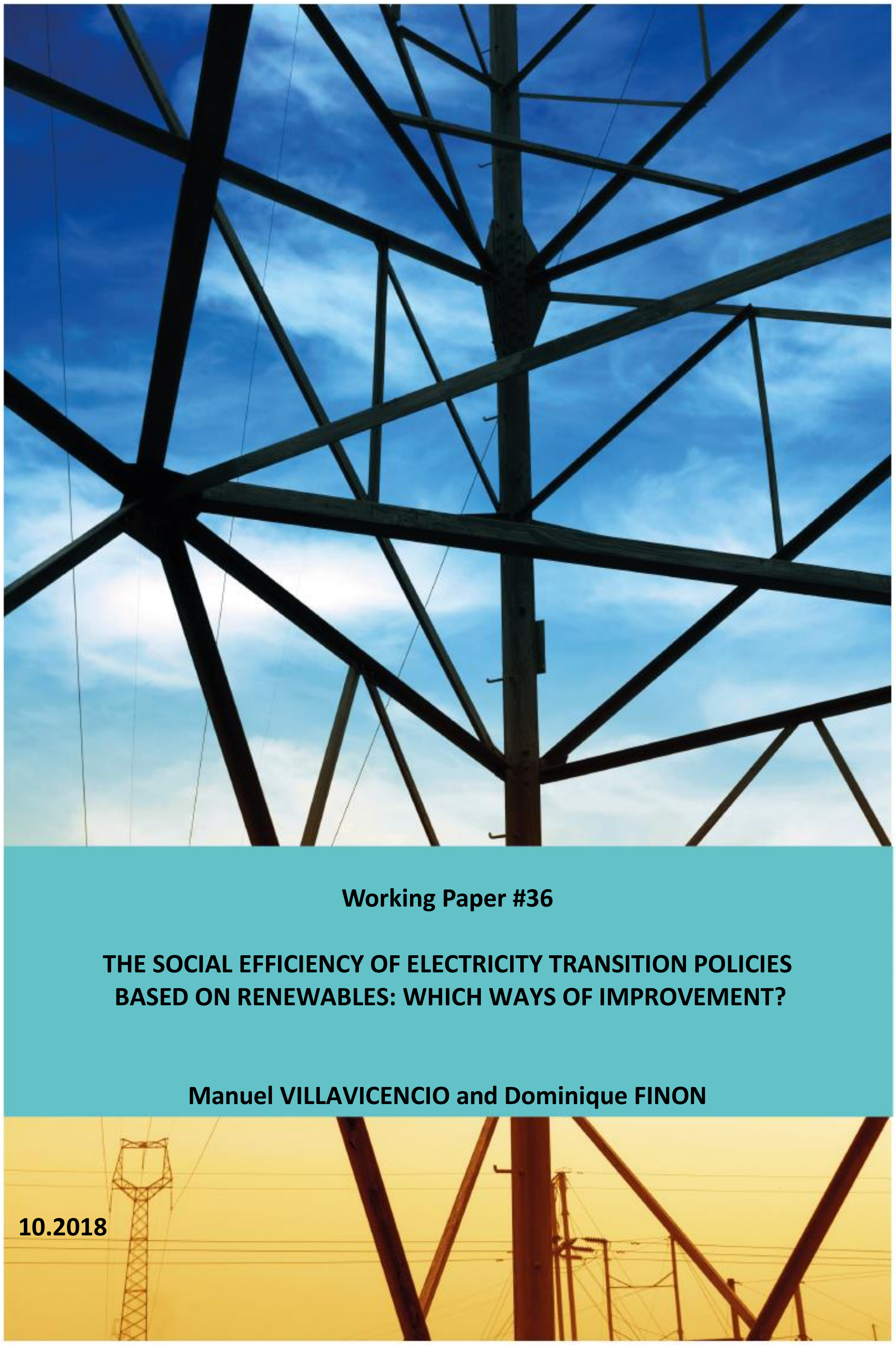

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THE SOCIAL EFFICIENCY OF ELECTRICITY TRANSITION POLICIES BASED ON RENEWABLES: WHICH WAYS OF IMPROVEMENT?

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Abstract

Climate and energy policies use to be embedded in joint packages with seeming coherent goals on which the electricity sector is specifically targeted. However, the complexity of power systems is rarely fully apprehended while setting up such packages, particularly when technical externalities from variable renewable energies (VRE) become widespread and different sources of flexibility need to be considered. We use a detailed model of the French power system under a combination of RE goals and CO_2 caps to seize their interplays and propose a methodology to rank the resulting equilibriums in terms of environmental effectiveness and economic efficiency. We show that: modest levels of VRE develop without subsidies regardless carbon cap level; technical externalities create trade-offs between VRE shares and environmental effectiveness; new flexibility (storage, demand response) may correct or exacerbate these externalities, impacting effectiveness, costs, and coherence of such packages, conducing to a sensitive target hierarchisation and fine-tuning challenge.

Keywords: Electricity, Transition, Planning, Renewables, Flexibility.

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I. INTRODUCTION

Over the past ten years, several European countries, engaged in climate and energy policies as prescribed by the European Union3, have launch official goals promoting renewables energy (RE) sources and CO2 emissions offsets in joint policy packages. The concerns with reducing CO2 emissions exists, but the climate policies struggle to translate into effective implementation (functional emissions cap and trade systems, CO2 taxes), in practice, very few reforms have been made to use direct carbon policy instruments and only indirect instruments are effectively implemented (technology-oriented policies), so this no longer appears as a priority goal. This justifies the showcasing of policies in the power sector targeting ambitious RE development in many countries: 80-100% of total production in 2050, passing by a level of 50% in 2030-2035.

The objective of promoting RE is reinforced by the fact that this responds to other tangible industrial goals (job creation, reinforcing industrial tissue), or moral and cultural positions (energy self-sufficiency, supply decentralization, but also damming up nuclear production, maybe eventually abandoning it, due to technological risks that are perceived as too high). The German case is a good example: after deciding a complete nuclear energy phase-out by 2022, the objective of developing REs at 80-100 % responds to a clear need, especially if confidence is lacking with respect to methods that directly reduce CO2 emissions without limiting fossil fuel generation. Yet it is well worth questioning the environmental effectiveness and economic efficiency of such RE pushing policies targeting very high levels of REs.

The pursuit of this objective through the use of support mechanisms that guarantee the long-term revenues of investors in variable renewables (VREs) forcibly has an opportunity cost, which is that of the de-optimisation of the electricity mix with respect to a second-best optimum that would result from a complete market play or the optimisation of a social planner (equivalent in theory), without any carbon emission constraint nor RE subsidy mechanism. The opportunity cost should grow in function of the level of the RE targeted.

Because of the growing need for fossil fuel technologies as back-up to variable VRE, targeting very high shares of REs (that we will later call the RE obligation) could translate into a lesser effect in CO_2 emissions offset from this policy. This invites us to question the convergence of large-scale RE policies with the limitation of total emissions and recourse to a carbon constraint (ceiling on total emissions), specific to the electricity sector, to correct for eventual divergencies.

The addition of economic instruments for the pursuit of a single objective is criticized in theory as a source in inefficiency with reference to the Tinbergen's golden rule[4] (Tinbergen 1952), according to which, in political economy, the realisation of a given number of objectives requires the utilisation of the same number of instruments, and not more. Any policy that goes around this rule can only present additional cost with respect to a policy that is based on a single instrument. Thus, combining a RE obligation with a carbon constraint leads by definition to third-best optimums of which the results will be distant from the second-best optimums found through the

[3] 20% emissions reduction with respect to 1990, 20% of renewables and 20% energy efficiency.

[4] "Variables are targets, instruments, data, and so on. Relations are structural ones (model) and restrictions. Consistent economic policy requires that the number of instruments equal the number of targets. Otherwise, targets are incompatible or instruments alternative." (Tinbergen 1952).

implementation of direct CO_2 policies like carbon caps, therefore, the results from combining climate - energy policies could be ranked on a hierarchical equilibrium framework.

In terms of climate - energy policy, a couple of instruments promoting electricity technologies that aim to reduce the total emissions necessarily leads to social inefficiency, because it turns its back on the principle of equimarginality between alternative low carbon options. In addition, the complexity introduced by the development of VREs in power systems may not have the effect of leading to a simple (monotonous) reduction of total system emissions. At this stage it is worth taking into consideration what can be brought by new sources of flexibility, different types of electrical storage and demand response (including direct load control), as these can reduce the environmental effects of policies that target high levels of VRE and facilitate its integration into the electrical system. Promoting storage and direct load control can be an important element in policies that prioritize the development of VREs.

Most studies that evaluate climate-energy policies in the power sector concentrate on the feasibility of objectives defined in terms of RE penetration or an energy efficiency goal, off to the side of the primary objective of CO_2 emissions reduction. But they don't question the rationality of these objectives nor their effectiveness in limiting total emissions. Based on the seminal analyses on economic policy developed by Tinberghen (1952) and Thiel (1964), we propose a "proper planning" methodology to design and evaluate energy policies aiming the clean energy transition of the power system with liberalized markets. The methodology consists on finding the best set of instruments (policies and/or incentives) to attain a set of goals (targets) at the lowest cost. In the case of climate-energy policies the targets are commonly defined as CO_2 emissions levels, security of supply compliance and cost affordability, while the policy instruments are the application of reliability standards, CO_2 offsetting policies through "cap and trade" mechanisms or taxes and RE standards. Therefore, the power system can be represented as a partial equilibrium problem formulated as a system cost minimization subject to climate-energy constraints, so targets are obtained from the resulting equilibrium states. When this multi-objective problem solved by prioritizing the CO_2 emissions cap while guaranteeing security of supply, this approach leads to a second-best solution with respect to an unconstrained system. When an additional objective is simultaneously targeted, which is here that of promoting RE shares, the "proper planning" approach must focus on the search for an effective calibration of policies and incentives such that their combination can be the most effective in terms of environmental performance and the closest from the first-best solution. To appropriately evaluate climate – energy policy packages targeting the electricity sector at the horizon of 2050, we use a detailed model of the power system, which is the most straight forward way to seize the complexity introduced by the large-scale development of variable renewable energies (VREs).

The complexity of power systems subject to large-scale deployment of VRE is a major difficulty in sweeping through the different combinations of climate-energy policies to identify hierarchical equilibriums in terms of economic and environmental efficiency. Multiple dependencies and non-linear relations between variables (targets) exist as a result of non-convexities and jointness in the constraints (instruments). Investment choices and market coordination of the operation of different types of technologies to guarantee long-term security of supply and ensure the stability of the system are rendered very complex by the variability of VRE production. The interactions within the operation of different techniques multiply rapidly. Furthermore, the development of

VRE capacity triggers dynamic effects that entail technical externalities[5] and increasing integration costs (Hirth, Ueckerdt, and Edenhofer 2015), effects that are not present with capacities allowing generation on-demand as with fossil and nuclear technologies. When evaluating a climate-energy policy package, all these effects must be resituated in a modelling framework.

Indeed, precision and detail while representing these interactions become an imperative necessity to proceed to rank the hierarchical equilibriums obtained so as to define and calibrate the right set of policy instruments to efficiently achieve the targets while accounting for interdependencies. This is what is pretended with the "proper planning" definition. As D'Haeseleer and al. (2017) judicially underline on the complexity of policies affecting the power system:

"... policy and regulation often have unexpected and, possibly counterproductive effects on overall system performance. It should, therefore, be a part of good policy making to first study the overall system by modeling its different parts, with much emphasis on the interactions among the different subparts as well as among different policies. As the behavior of the system regulated by electricity market will be strongly nonlinear, careful analysis is called for, well beyond the standard isolated "impact assessments". (…) Quick-and-dirty regulation will likely backfire, and even simple, positive-seeming measures may lead to unforeseen side effects because of negative feedback and system interactions".

In the following, in section II, we clarify the structure of the DIFLEXO system optimisation model6 solved on a long-term year (''greenfield'') to represent the French power system of 2050. From there, the paper pursues a three-stage approach. In section III, we first look for the second-best solutions in 2050, under an intensifying carbon constraint (decreasing emission caps). There are tests of each case of the contribution from possible new sources of flexibility and the improvement of the economic efficiency of the system. Then, in section IV, we seek to situate the different equilibriums that result from the combination of these carbon constraints with increasing RE obligations, with respect to those stemming from the previous second-best solutions. The objective is to identify how, for a given RE obligation, we can improve the environmental effectiveness and/or the economic efficiency by playing with emission caps and the recourse to new sources of flexibility. The third stage in section V compares the cost-effectiveness of different combinations of policies. These sweeps through different combinations of policies allow us, in fine in conclusion (section VI), to draw lessons from the climate-energy packages that combine different policy instruments and target multiple-objectives.

II. MODELLING THE COMPLEX ECONOMICS OF AN ELECTRICAL SYSTEM WITH A LARGE SHARE OF RE

In simulating a distant horizon, the objective is to capture the dynamic effects of the entrance of VRE on their economic value as well as the effects of RE production variability on the rest of the system for ensuring complementary production as back-up as well as long-term flexibility services. The detailed modelling framework must also consider the interactions between the transformation factors of the power system under the effect of technical progress through cost

[5] This is, technological externalities in the sense of Scitovski (Keppler and Cometto 2012).
[6] More details on the model can be found in (Villavicencio 2017a, 2017b).

reductions in renewable technologies, promising learning effects in new storage technologies and the perspectives opened by digitalisation in piloting demand.

2.1. The structure of the DIFLEXO model

We use here an optimisation model of investment choices and system operation, which finely represents the system balancing constraints and the reliability requirements that become a bit more crucial in a system with high shares of VRE. Such a model must make it possible to reveal the value of each new capacity different technologies (RE and conventional), storage and demand-response (DR), by valuing the products and services offered by the different units, or required by them to satisfy their balancing obligations, through shadow prices on the constraints of supply – demand hourly energy balancing, reserve scheduling and capacity adequacy requirements.

- **The modelling framework**

The DIFLEXO model is determinist. It is structured in hourly time steps for optimisation over a single year based on annualized investment costs. It rests on a linear programming formulation under the criteria of cost minimisation which covers investment cost, fixed operating costs (including wear and tear costs from multiple cycles of production level rise and fall) and variable costs (fuel, CO_2 emissions). It simultaneously optimises the short-term decisions by representing an economic « *dispatch* » and adding the arbitration decisions permitted by the storage units and direct load control (which shifts demand from peak hours to lower load hours), together with investment decisions on a long-term optimisation by processing a « greenfield » on a theoretical long-term year (2050).

This is a sectorial optimisation model which represents the different electricity markets, the hourly market, the system services market (reserves), and a capacity obligation[7] . One of the qualities of DIFLEXO is to be able to differentiate the exigencies of three different markets: very short-term physical equilibrium (frequency reserve control, then balancing), short-term (hourly wholesale markets) and long-term (capacity adequation), so as to balance each of the three on a price that is aligned with the cost of the marginal resource. (Details on the formalisation of the model are given in Villavicencio (2017c)). It enables us to find the mix of generation and flexibility technologies needed to ensure economic and technical equilibrium by minimising total system costs subject to energy-climate policies.

- **Energy-climate policies**

These policies are formalized under the form of two constraints: a carbon constraint as a total CO_2 emissions cap expressed as a norm of emission per kWh produced (that is called here ''carbon constraint''), and an obligation on the share of RE production in total production. Concretely, the first constraint corresponds to an emissions ceiling that will be imposed on the full system, each producer can freely use all his capacity as long as he respects the ceiling through emissions permit exchanges with his competitors. From this constraint on emissions we can derive the shadow price of carbon that aligns with the marginal cost of emissions reduction of the optimum. It is important to underline that we do not consider the price of carbon emissions *ex-ante*, contrary to what is done in most climate policy models, but rather as an implicit price emanating from the carbon

[7] This is similar to accounting for a capacity remuneration mechanism.

constraint limiting total emissions. Also, this constraint only applies to the power sector to constantly adjust the shadow price of carbon to permit achievement of the emissions limitation objective of this sector as stated on most power sector policy goals. The carbon constraint is formulated in g of CO_2/kWh. While the system optimised without a carbon constraint and without new sources of flexibility emits around 160 g/kWh (190 g/kWh if we use the new sources of flexibility), the first emissions norm considered in the tests is set at 150 g/kWh and goes down to 25g/kWh.

As for the RE policy, which is formulated in terms of a fixed share of RE within total production, this corresponds to an obligation on renewable energy certificates which is imposed on all producers or suppliers, similar to the mechanism that exists in the US under the name of Renewable Portfolio Standards (RPS), or like those of different European countries (Sweden, Belgium, Poland, and, in the recent past, the United Kingdom and Italy).

- **Supply – demand balancing equations for three markets**

On the hourly energy market, market demand is calculated by considering the "residual power demand" (hourly demand reduced by VRE production). This said, the way hourly demand is represented integrates in storage recharging as well as direct load control piloted by aggregators and load shifting due to "real-time pricing" applications. On the markets for balancing and system services, supply is assured by production technologies, storage technology and demand- response capacity (both direct load control and load shifting due to real-time pricing). Each technology of each group is described by its technical constraints and associated costs.

- **Operational constraints**

There are equations that represent the operational constraints of production units: minimum and maximum production levels of a MW of capacity of each technology; ramp-up and ramp-down speeds; frequency regulation services available. It takes into account the new sources of flexibility including storage technologies and active demand management (called DSM or demand-side management here), and also rapid ramp turbines and hydraulic reservoirs used to assure frequency regulation within the operating constraints of each type of technology together with the possible load modulations available from nuclear, CCGT gas and coal stations able to provide adjustment services. The storage technologies are represented with two constraints on their minimum and maximum stock levels and two other constraints on their availability to participate as suppliers of reserve services during their charge or discharge. As for demand – response capacity through load shifting, there is a constraint that limits the duration of the shift, to which is added a constraint on the ulterior reformulation of shifted demand which limits the number of successive demand shifts.

- **Taking new sources of flexibility into account**

To analyse the effect of possible recourse to demand-response and large-sized storage solutions, we compare the optimums obtained without these new sources of flexibility (by considering them ''as if'' they are too expensive so as to arbitrarily remove them from the set of available technologies) with the solutions obtained through the endogenous optimisation of the development of diverse production technologies, storage capacity and demand response solutions. These new sources of flexibility are thus only activated in these tests where we explore what they can bring to the economic integration of VREs into the system. The activation of these techniques implicitly supposes that in the year of optimisation, they will have sufficiently benefitted from learning curve impacts for their development to be included with that of different production techniques. The data on storage costs used for 2050 considers significant technical progress and cost decrease versus the current state, results are contingent on the quality of these expectations.

2.2. Hypotheses and data on mix optimisation under political constraints in 2050

We use a ''greenfield'' optimisation to simulate capacity investments on different power generation technologies, storage and demand control, using as a reference a situation that is close to that of the French electrical system in 2050: very low demand growth through 2050 (a total demand of 510 TWh, including transportation losses), an hourly demand profile taken from actual 2016 demand adjusted for projected growth and including new usage impacts (electric vehicles, heat pumps, etc.), hourly profiles of wind turbine and solar PV production over the year identical to some current profiles (including their random structure), continuation of the nuclear option, possible development of hydraulic reservoirs and hydro pump energy storage, etc.

- **Cost hypothesis for power generation technologies and storage in 2050**

The costs and other technical parameters of different generation technologies are shown in Table 1, while the data on storage technologies and demand-response tools appear in Table 2. We use a discount rate of 7% in the calculation of the different annualized investment costs, which is higher than that used in France for public choices, so as to remain closer to the reality of private investment criteria.

Technologies	***Cost sec of inv.*** [€/kW]	***Expected Life*** [yr]	***O&M^V*** [€/MWh]	***Fuel costs*** [€/MWh]	***Unitary emissions rate*** [t CO_2/MWh]
Nuclear	*3750*	*60*	*2,5*	*7,0*	*0,015*
Coal	*1264*	*40*	*6,9*	*19,8*	*0,96*
Coal FBLwith CCS	*3500*	*40*	*10,0*	*11,2*	*0,13*
Coal PSC with CCS	*2550*	*40*	*3,0*	*19,8*	*0 ,10*
CCGT	*785*	*30*	*4,7*	*51,7*	*0,34*
CCGT with CCS	*1500*	*30*	*4,0*	*51,7*	*0,07*
OCOT	*490*	*30*	*7,3*	*67,3*	*0,67*
OCGT-flexible	*400*	*25*	*6,1*	*51,7*	*0,64*
Reservoirs	*2686*	*80*	*0,0*	*0,0*	*0,01*

Table 1. Cost of conventional production technologies in 2050.
Sources: IEA/NEA (2010, 2015), SETIS (2014)

Technologies	*Investment cost (overnight)* [€/kW]	*Expected life* [yr]	*Annualised fixed cost* [€/kW-yr]
Wind	*1100*	*25*	*96,0*
Solar PV	*710*	*25*	*61,8*

Table 2. **Cost of wind and solar PV in 2050.** Source: **SETIS (2014).**

		CAPEX			*OPEX*	
Technologies	*Acronyms*	*Power conversion system* [€/kW]	*Energy reservoir* [€/kWh]	*Expected Life* [yrs]	*O&M^F* [€/kW]	*O&M^V* [€/kWh]
Lithium ion batteries	*Li-Ion*	*140*	*245,5*	*10*	*2,0*	*2,6*
New pumped storage	*PHS-New*	*1500*	*68*	*60*	*6,0*	*0*
Renovated pumped storage	*PHS-retro*	*400*	*-*	*-*	*22,5*	*0*
Interseasonal H_2 Electrolyser with fuel cell	*H_2-FC*	*2465*	*130*	*8*	*25,0*	*-*
Diabatic compressed air storage	*CAES*	*450*	*26,3*	*55*	*5,9*	*1,2*
Adiabatic compressed air storage	*ACAES*	*679*	*78,8*	*60*	*9,5*	*2,0*

**The cost of direct load control corresponds to estimations for air conditioning, heat pumps (hot and cold) and industrial processes*

Table 3. Costs for storage and demand response in 2050. Source: SETIS (2014), Zerrahn and Schill (2015).

Type	Acronym	Resource availability	Investment cost	O&M^V	Continuous duration	Max hours per day (L_{hpd})	Type of service
		[GW]	[k€/MW/an]	[€/MWh]	[h]	[h]	
ToU tariff	*HC_HP*	*23,4*	*0*	*0*	*0*	*N/A*	*shape*
Household time arbitrage	*LS_hh1*	*10,3*	*16,8*	*0*	*3*	*4*	*shift*
Household dynamic control	*LS_hh2*	*0,8*	*46,2*	*0*	*3*	*4*	
Industry long-term dynamic control	*LS_ind_L1*	*1,2*	*15*	*300*	*108*	*N/A*	
	LS_ind_L2	*0,8*	*30*	*300*	*108*	*N/A*	
	LS_ind_L3	*0,8*	*60*	*300*	*108*	*N/A*	
	LS_ind_L4	*1,0*	*100*	*300*	*108*	*N/A*	
Industry short-term dynamic control	*LS_ind_C1*	*0,6*	*20*	*0*	*1*	*2*	*shift & shimmy*
	LS_ind_C2	*0,4*	*50*	*0*	*1*	*2*	
	LS_ind_C3	*1,0*	*100*	*0*	*1*	*2*	
	LS_ind_C4	*0,3*	*150*	*0*	*1*	*2*	
	LS_ind_C5	*0,1*	*200*	*0*	*1*	*2*	

Table 4. Hypothesis related to DR categories. Source: ADEME (2017) and RTE (2017).

III. THE EFFICIENCY OF ELECTRICITY MIXES OPTIMISED UNDER THE CARBON CONSTRAINT ALONE

We first identify the effects of a carbon constraint on the optimisation of the electricity mix with respect to the first best optimum, by proceeding through a series of optimisations with increasing carbon constraints. In the second stage, we test the possibilities of social efficiency improvements from recourse to new sources of flexibility (storage, demand-response).

3.1. Optimisation without the new sources of flexibility

The 'business-as-usual' (BAU) points in Figure 1 correspond to decentralised equilibrium states obtained under the effect of perfect market plays in the absence of any carbon constraint and represent a "*technology neutral*" energy policy. They correspond to the hypothesis shown above on the costs of each technology, fossil fuel prices and the VRE generation profiles over the year. These points serve as references to identify the evolution of the equilibrium resulting from regulatory interventions that constrain CO_2 so as not to exceed the level of total emissions decided by the government. The curve shown by the dotted line in Figure 1 (left-hand side) represents the optimal capacity investment in VRE for each level of carbon policy after cost minimisation and without new flexibility sources. We first note that the optimal share of VRE in the electrical system comes out at a low level of 11 to 12%, with this share almost exclusively coming from wind turbines.

By reasoning as if all the VRE units entered "through the market" in the power system (i.e. without support mechanisms), the revenues from the new VRE units yield lower economic value in the electricity market on each step for two reasons. First the VRE units require complementary energy production and systems services through flexible units to compensate for their variability and to guarantee systems stability, the so-called system costs which increase in relation to development of VRE capacity, as shown by Keppler and Cometto (2012). Second, the productions of the different wind power units (as for solar PV units) tend to be correlated amongst themselves and each unit lowers the hourly market price when run at the same time as other units of the same type. Over the long run this autocorrelation lowers the value of the MWh's produced with respect to the value of VRE's MWh produced with less VRE penetration. Beyond a certain level (which is 11 to 12% here without new sources of flexibility), the economic value yielded by each supplemental VRE'S MW no longer permits its fixed cost recovery, in particular for investment costs. If the support mechanisms for VRE units (which guarantee their long-term revenue and help to trigger investment) lead us to exceed this level, an opportunity cost will materialise for the full electricity systems with respect to the situation were VRE development is done through market at the optimal level.

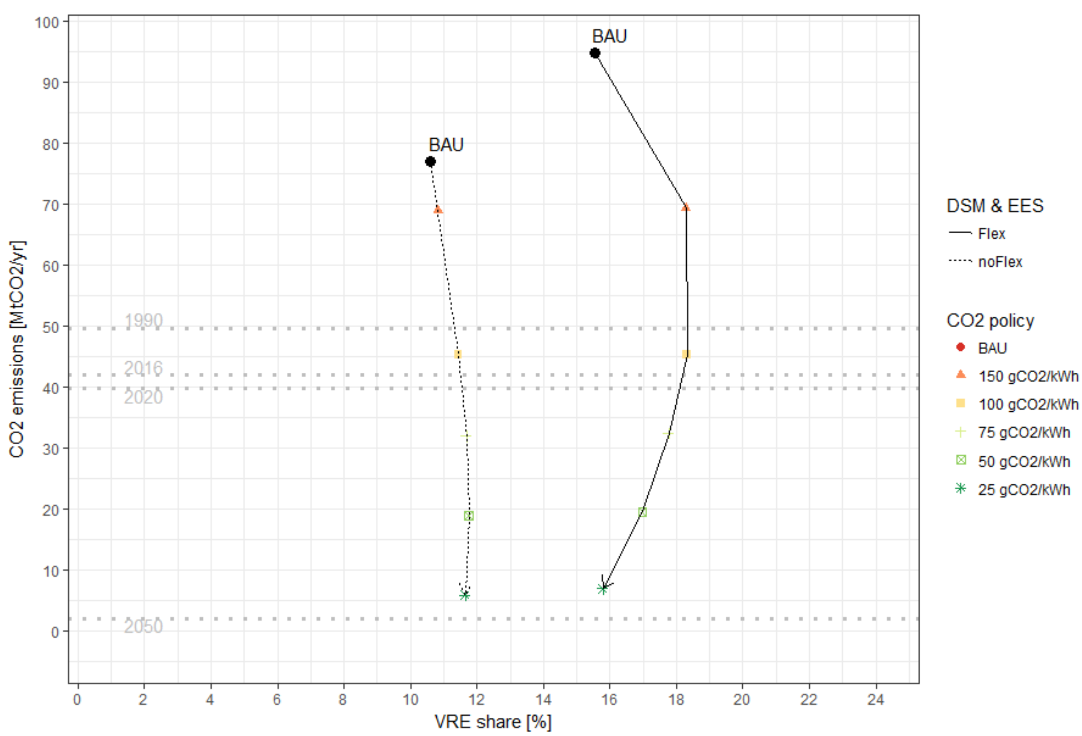

Figure 1. Optimal share of VRE under different CO2 norms and with/without flexibility in 2050

This result is confirmed by many studies based on empirical market data (Fripp and Wiser 2008; Joskow 2011) or very detailed simulations of optimisations through increasing levels of VRE

(Hirth 2013, 2015; Bruninx et al. 2016). They show that the remuneration of electricity produced by VRE from electricity markets alone diminishes significantly with the increase of the share of VRE in electricity production. Hirth (2015, 2016) identifies the optimal share of VRE in a system in different contexts[8], placing it between 10 and 15% in the context where the nuclear option is open at the time of the electricity system set-up and the carbon policy is based on a tax of 30€/tCO_2, which is close to our results.

Note that, in these results, changes in the emissions constraint have little impact on the share of VRE. In Figure 2 (downside part), we see that more restrictive CO_2 emissions policies primarily lower the share of coal and increase the share of nuclear but have little impact on VRE with only a 1% increase in the optimal shares with low emissions constraints (see Figure 1). With stricter levels of emissions constraints, the share of nuclear goes from 72% to 83% (level attained for the CO_2 norms of 50 and 25 g of CO_2 per kWh). This impact is explained by the low availability of VRE and their variability, which gives nuclear plants a significant advantage in terms of economic value of its production and beyond its marginal cost of emissions reduction.

Even with realistic cost prices for nuclear (71 €/kWh, with 3750 €/kW in investment for a discount rate of 7%) and low costs for RE in 2050 (61,8€/kW-yr for solar PV, 96 €/kW-yr for offshore wind), the dispatchable production of nuclear technology has an economic value that is much higher than that of VRE. But recourse to new sources of flexibility, like storage or direct load control, modifies these results, as it enables VRE to yield supplemental economic value by reducing their system costs, as shown by Hirth (2016) and Villavicencio (2017c).

3.2. The effect of recourse to new sources of flexibility

We thus tested the effects of the development of flexibility through storage and demand –response piloting to improve the integration of VREs. If, as we just saw, increasingly severe CO_2 policies don't improve the profitability of VRE units and their optimal systems share, the results show that the possibility of developing new sources of flexibility stimulate the optimal development of VRE. Their penetration rises to a 7% increase, placing the optimal share of VRE between 15 and 17.8%. Indeed, in Figure 1, we see that the optimal share of VRE increases first by 7% for a medium carbon constraint of 100 to 150 g/kWh. But this increase is lower beyond that level, with only a 4% increase for stronger carbon constraints under 75 g/kWh for two indirect reasons. First, new sources of flexibility that can be economically developed are deployed by type with its associated increasing marginal costs and limited resource availability by hypothesis in the model[9]. So, as the first low cost flexibility alternatives are deployed, further flexibility developments come at higher unit cost due to technology shifts, so they show decreasing returns to scale since the least-cost flexibility alternatives becomes exhausted with increasing shares of RE obligations. Second,

[8] These contexts concern the meteorology, the annual load profile, the nuclear option (open or not), the price of carbon (or the carbon constraint), which penalizes fossil generation, and the presence of flexibility sources, in particular hydraulic.

[9] This is the case for demand response applications on the industry and tertiary sector, pumped hydro storage (PHS) and underground compressed air storage (CAES) facilities. Remaining flexibility technologies (see Table 3) are excepted of this resource availability constraint.

beyond the carbon constraint level of 75 g/kWh, the marginal abatement cost of nuclear power is lower than that of VRE plus new flexibility alternative. Furthermore, the recourse to flexible fossil energy sources is no longer possible because their development is quickly limited by the carbon constraint. It follows that the optimal shares of RE are indirectly limited by their integration costs and expressed as flexibility needs RE development. Thus, the optimal share of VRE that rose to 17.8% thanks to possible investment in storage and demand-response falls back to 16% when the emissions constraint becomes more severe.

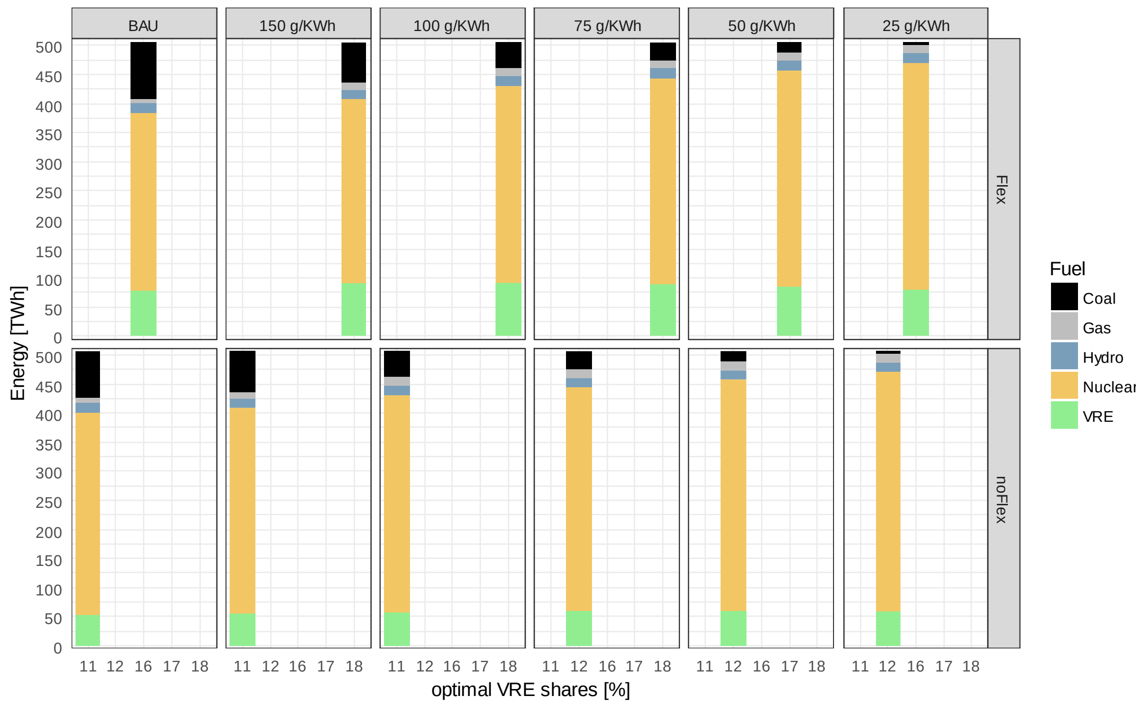

Figure 2. The electricity mixes under different carbon constraints with and without flexibility[10]

We can also note on Figure 2 (upper part) that, without a carbon constraint but with flexibility, we reach a mix structure that includes 12% of fossil energy (with 14% RES, 66% nuclear and 5% hydraulic), while in the same test without new sources of flexibility, the share of production from fossil units is only 8.7 %. This explains why, in Figure 1, the level of total CO_2 emissions in the BAU case with flexibility is higher than that in the BAU case without flexibility. This indicates that the environmental performance of the systems diminishes as we make use of new sources of flexibility, if these performances are not controlled by a carbon constraint (i.e. in the absence of a tight carbon policy). This counter intuitive impact of RE obligation policies will be discussed below.

IV. THE ENVIRONMENTAL PERFORMANCE OF POLICIES THAT MAKE RE A PRIORITY

In this section, we analyse the effects of policies that force increasing levels of VRE entry under different contexts of carbon constraint. As said, the RE policy is formulated as an obligation on the share of RE in total production in 2050 that is superior to the previous optimal shares shown

[10] In the figure, "Flex" stands for the case were new flexibility technologies (Storage and DR) can be optimally deployed, while "noFlex" represents the case where they are not considered among the investment alternatives.

above, with RE including some dispatchable sources – biomass, biogas – at the VRE with variable supply. First, we compare the results of three combinations of RE and carbon policies, on without the RE obligation and the two others with the RE obligation set respectively at 50% and 80%. The place of conventional technologies (nuclear, gas, coal) is determined by their marginal production costs and their technical capabilities for integrating the variability coming from the increasing VRE shares included in the RE obligation, and their relative contribution to total CO_2 emissions. In a second stage, we analyse the effects of recourse to new sources of flexibility on total CO_2 emissions, with all other conditions held equal (RES obligation and carbon constraint); to do this we proceed through the same tests of policy combinations but simultaneously considering investments on power generation capacity and flexibility sources.

4.1. Optimisation under RE obligation constraints without flexibility sources

In Figure 3, we show the curves of total emissions reduction as a function of the required RE share with respect to the optimal BAU scenario, for each level of emissions constraint (150, 100, 75, 50 and 25 gCO_2/kWh). These curves represent the total emissions performance for each equilibrium point associated with a CO_2 constraint and for different levels of RE share obligation[11].

For a given carbon constraint level, the change in the electricity mix under the effect of increasing RE obligation has two different impacts on total emissions. On one hand, as the increase in the RE obligation leads to a reduction in the share of coal production in semi-base periods next to the reduction of nuclear production share, there is a reduction in total emissions. On the other hand, the increasing need for flexible gas production units to cover rises and falls in residual load and the increasing demand of systems services, but also to complete the semi-base supply, drives an increase in emissions. The conjunction of these two impacts logically changes from one RE obligation level to another, experiencing at the beginning of the process a reduction of total emissions as the RE obligation rises, up to a threshold beyond which the net impact turns, when the limitation impact shrinks on one hand side and the second impact drives emissions increase as the RE share continues up on the other hand side.

[11] In figures 3 and 6, we only refer to the share of VRE in the systems. The targets of 50% and 80% RE correspond respectively to 46 et 76% of VRE share, as pilotable RE technologies that can be economically developed first only fill a slot of 4% under the effect of their constraint of resource availability.

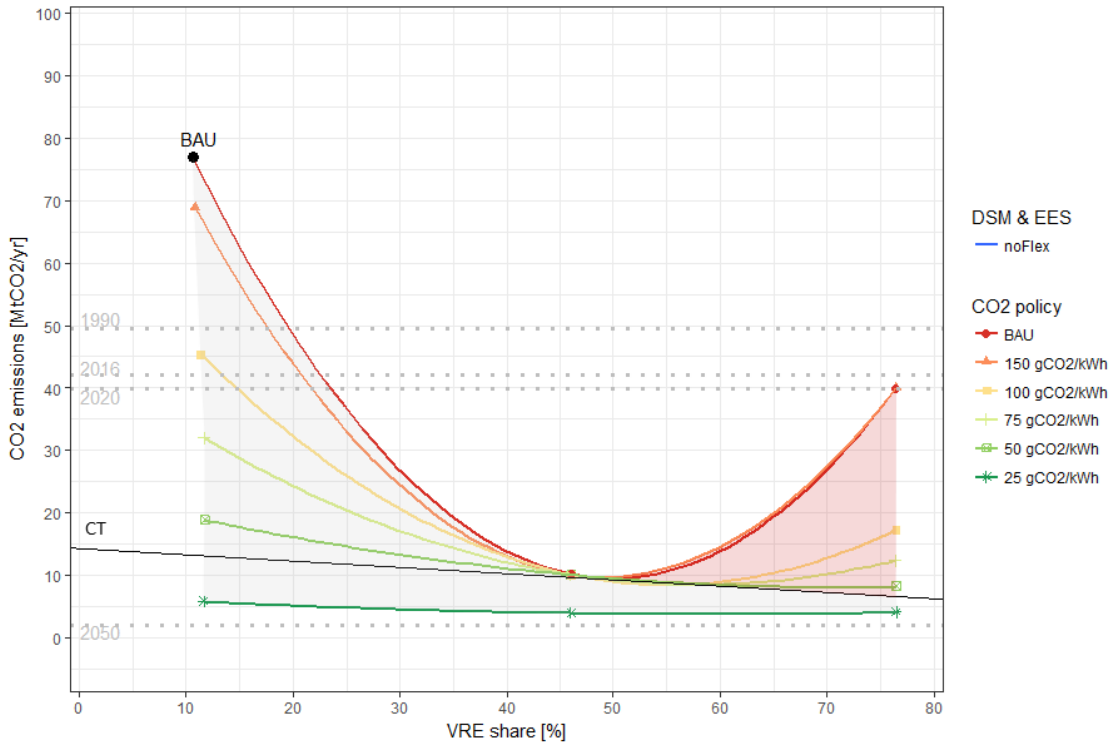

Figure 3. The performance of total emissions reductions under RE obligations in the system without new sources of flexibility

We observe that CO_2 emissions diminish rapidly as the RE obligation rises from 11% to approximately 50%. Between these obligation levels, the first effect, which lowers emissions, is not radically affected by the second impact, which increases emissions. The limitation of total CO_2 emissions reaches a maximum at a VRE obligation of 47% (which corresponds to a RE obligation of 51%). Note that this turning point is the same for all the levels of carbon constraints as defined in emissions per kWh.

The production of fossil fuel technologies (coal, CCGT, OCOT, OCGT), that complement the VRE capacities by replacing the nuclear MW for semi-base and to respond to increased adjustment need for flexible units, can then be developed without penalty from the carbon *shadow price* which would come if the constraint was saturated. This explains why the total emissions are always inferior to the level sought by the government and prices on emission trading systems are near zero when RE shares are forced under unbinding carbon caps (See the split of production technologies in different electricity mixes on Figure 4).

- **The turn-around in the environmental performance of the RE obligation**

The trade-off between the negative and the positive effects of increasing RE shares over CO_2 emissions is evidently the same for all the levels of carbon constraints considered up to the stringent level of 50g/kWh, as this constraint is not sufficiently binding to be saturated before reaching this level. Nevertheless, the trade-off turns around at about this level when the RE share rises beyond 51%, as the constraint comes into play. Beyond the carbon constraint level of 50 g/kWh, the curves become weakly concave and no longer show the impact of lowering total emissions as the RE share rises beyond the threshold of 51% RE (with the VRE share at 47%). As the more severe carbon constraint saturates, rendering the price signal from carbon effective, via the dual pricing of the carbon constraint that increases the marginal cost of MWh from fossil generation. This modifies the way that nuclear MW are replaced by combination of RE and fossil units (coal, gas) as the RE obligation increases, leading to lower productions from coal and more production from gas in the case where new flexibilities technologies are no considered ("noFlex" case presented in Figures 3 and 4), and from storage and demand response when flexibility sources are considered ("Flex" case presented in Figures 5 and 6), for each increment in the RE obligation above that level.

- **Combinations of policies that become convergent**

The common tangent of curves with carbon constraints above 50g/kWh from Figure 3 provides additional information: it defines a frontier between two zones of policy combinations for CO_2 and REs. Beyond the common tangent, simultaneously adding a carbon constraint and enforcing RE shares in climate-energy policies is superfluous. The zone below the common tangent is where the combination of two policies is reinforced, with the carbon constraint allowing limitation of the rise in total emissions as we move from one RE obligation level to another. This links up with the results of Delarue and Van den Bergh (2016) in their exercise of testing different combinations of RE obligation and exchangeable CO_2 quotas mechanism in the electrical sector where they show that high levels of carbon constraint are required to trigger and effect in systems subject to high RE obligations.

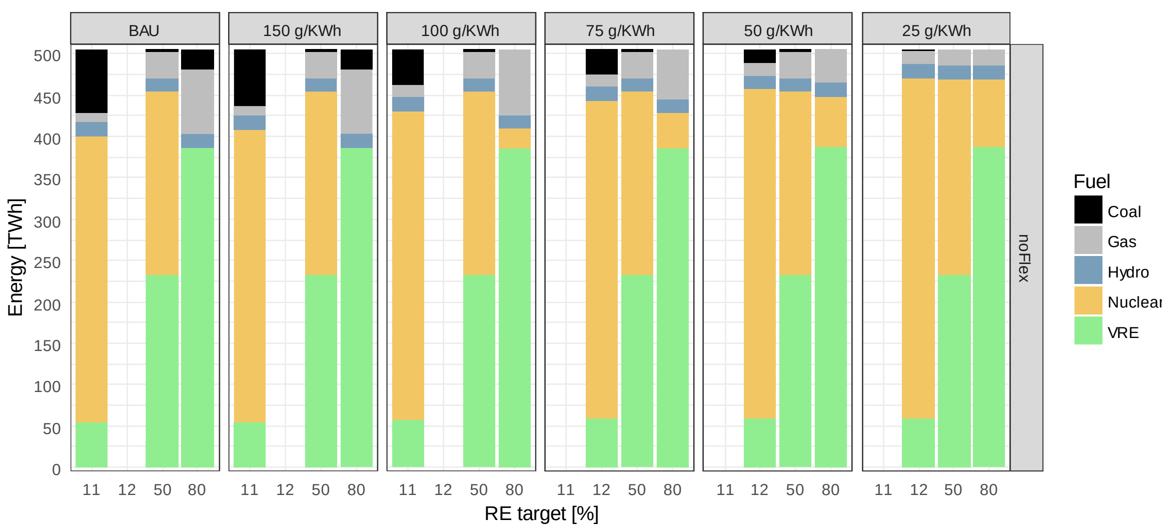

Figure 4. Influence of the RE obligation on electricity mix without new sources of flexibility

In summary, reinforcing the RE obligation does not always converge with the objective of limiting total emissions, particularly when we this policy instrument is implemented under a loose carbon constraint. Only by applying a tight carbon constraint it may play its limitative role when the RE obligation goes above a threshold, so as to permit the growth of the RE obligation to lead to an overall limit in the growth of total emissions. Poorly calibrated policies have the unexpected impact of generating lower emissions offsets when the RE obligation is placed at a very high level. This invites us to question what new sources of flexibility can do to improve the environmental performance of different combinations of policies, while waiting to see if they limit the implementation cost from these policies.

4.2. The effects of recourse to new sources of flexibility

A priori, it is expected that considering a capacity mix composed by power generation units and new sources of flexibility (storage, demand-response) should lead to better environmental performance, at the same level of RE development, as they reduce the frequency of recourse to the back-up of gas and coal units. In fact, the introduction of them leads to higher emissions for the same RE obligations for the cases with a loose carbon constraint which is not binding. However, flexibility does change the situation in the resultant mix with a combination of policies when carbon policies are binding, so increasing the coherence between them since higher CO_2 offsets might be obtained with higher VRE shares (see Figure 6).

- **Higher carbon emissions for the same RE obligation**

In comparing electricity mixes between the cases with and without flexibility in Figures 3 and 6, we see that the use of competitive flexibility sources allows better economic integration of VRE, for which the share goes from 5% to 7% depending on the carbon constraint level, as well as for the BAU case without RE obligation. However, flexibility doesn't lead to reduced CO_2 emissions for emissions norms of 75 g/kWh or less beyond the threshold of 51% RE (corresponding to 47% VRE). We see this in Figure 6 compared to the Figure 3 with the upwards shift of the emissions as a function of the share of VRE for these carbon constraints.

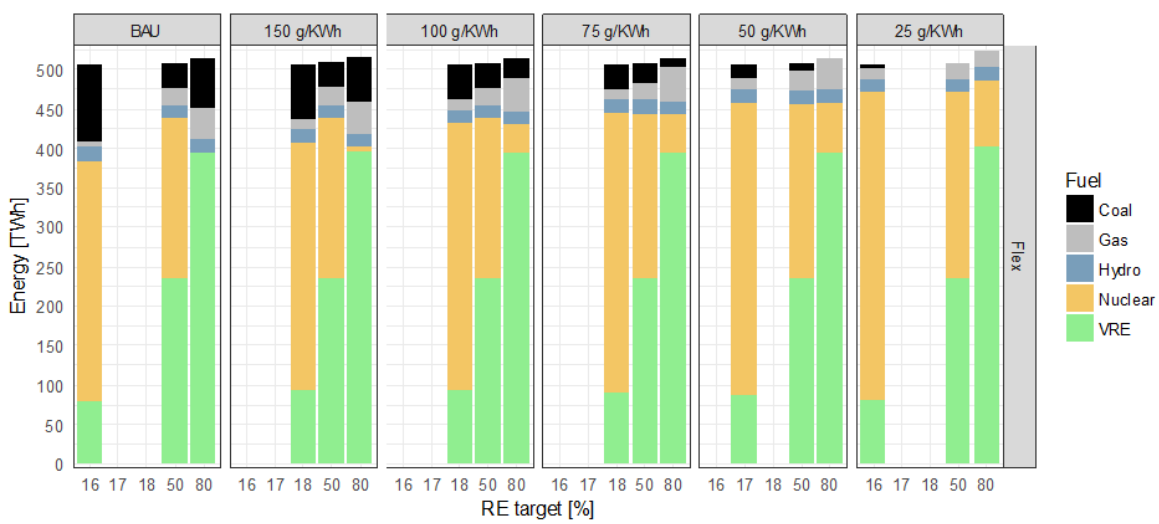

Figure 5. Evolution of the electricity mix with increasing RE obligations and new sources of flexibility

This effect results from the fact that flexibility allows for intertemporal arbitrage based on the hourly prices of electricity, which leads to stocking energy produced by base and semi-base generation at times of strong VRE production during which prices are low, to re-inject it into the system during hours of lower VRE production during which the prices are higher. This leads to an increase in the capacity factors of low short-run marginal cost (SRMC) technologies and a decrease in that of high SRMC plants, in particular gas fuelled power plants. In parallel, storage and demand-response ensure a large part of the systems services that were provided by flexible gas units in cases without flexibility sources. Furthermore, by improving the load factor of semi-base units and limiting the number of their operating cycles, storage makes possible operating cost economies by reducing the cost of power ramp-ups and the wear and tear on these stations[12].

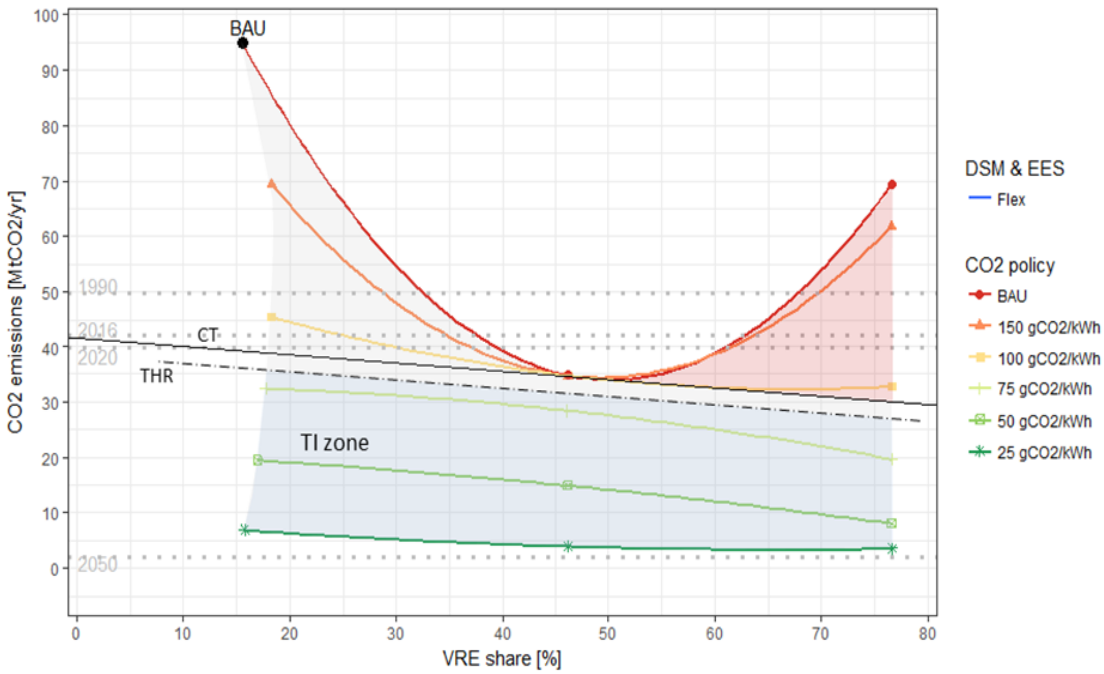

Figure 6. The performance of total emissions for increasing RE obligation levels in systems with new sources of flexibility

- **Improving the coherence of implementing joint policies**

The lack of convergence of policy combinations with the objective of limiting emissions increases with the use of storage and demand-response, because CO_2 emissions are not penalized by the *shadow price* of carbon since the carbon constraint is not saturated. But they converge more rapidly with this objective than in the former cases without new sources of flexibility when the carbon constraint becomes more severe at norms below 90g/kWh, as seen by the higher position of the common tangent in Figure 6 related to the same tangent in the Figure 3. In the group of policy combinations with severe CO_2 norms for which the equilibrium points are situated under the tangent, flexibility makes it possible to modify the way nuclear is replaced by VRE and completed by fossil generation, compared to the cases without flexibility previously presented.

In the cases without flexibility, the rebound of total emissions for the RE obligations above 51% was explained by a growing replacement of nuclear production by a triplet of VREs, gas and coal, for emissions norms above 40 g/kWh. This occurs because, without an active carbon constraint,

[12] In the BAU test with a norm of 100 g/tCO₂ and without a RE obligation, the effect of storage is clearly seen in the higher production share of coal units in cases with flexibility with respect to cases without flexibility (12% in place of 7%).

coal units can develop to cover semi-base demand without an economic penalty from the shadow price of carbon. However, in cases with flexibility, this rebound, which only occurs for looser CO_2 constraints (above 90 g/kWh), operates differently. For combinations in which the loose CO_2 constraint remains inactive, coal units find operating space more easily than gas units compared to the case without flexibility. This happens because the arbitrage options from storage permits better usage of coal production units as well, time arbitrage comparatively increase their capacity factors compared to that of gas.

Concerning the greater number of coherent combinations of policies with the upward displacement of all the test curves with flexibility (compared to the tests without flexibility shown in Figure 3), this displacement is inversely proportional to the level of the CO_2 constraint in combinations with an increasing RE obligation represented by these curves. However, the curves associated with carbon constraints of 75 g/kWh, 50 g/kWh and 25 g/kWh, situated below the common tangent of the higher curves, don't show a rebound from the effect of limiting total emissions, contrary to combinations with loose carbon constraints above 90 g/kWh. In these cases, when flexibility is included, the carbon constraint somewhat limits recourse to coal plants, which the presence of the storage option has rendered more economical than a semi-peak supplier (gas) than in cases without storage and DR.

V. THE COST-EFFECTIVENESS OF DIFFERENT COMBINATIONS OF RE OBLIGATIONS AND CARBON CONSTRAINTS

The priority given to the objective of promoting RE based on the pursuit of multiple finalities leaves CO_2 cap instruments, the principal instrument of carbon policy in the electricity sector, stuck in the middle. But the third-best optimum forcibly has a higher cost than that of the second-best optimum reachable from a simple policy that directly targets CO_2 emission levels. The intervention of a RE policy displaces the equilibrium of the system to sub-optimal states, which enforces an opportunity cost. Faced with the choice of giving priority to the RE objective, we must seek out the combination of policies that is most acceptable in terms of environmental performance and additional costs with respect to the second-best optimum.

The calibration of two instruments used conjointly is delicate as certain policy combinations, which don't necessarily lead to the best possible total emissions limitation, forcibly have higher costs than the simple policy based on carbon constraint alone. We must therefore seek to identify combinations that lead to positive results with respect to the central objective of limiting total emissions while keeping the opportunity cost at an acceptable level.

Figure 7 presents the results of each policy combination in terms of total emissions cap and additional cost with respect to the BAU case. The curves correspond to policy combinations for each level of carbon constraint with increasing RE obligations. Each curve draws together the different points which link the level of total emissions reduction (in %) on the y-axis with the additional cost of each policy combination for these same cases on the x-axis. They are constructed for three points: without a RE policy, with a RE obligation at 50%, and with a RE obligation at

80%[13]. We first consider cases without flexibility (represented by the dotted line curves), then we compare them with those with flexibility (curves drawn in solid lines).

- **The cost-effectiveness of policy combinations in systems without flexibility**

We note first that for a RE obligation of 50%, the cost increase in the two types of cases (with respect to the BAU case without a RE obligation) remains modest regardless the level of the carbon constraint: around 12.5% for cases without flexibility and 5% for those with flexibility. This is no longer the case with a RE obligation at 80%; in which case the cost overruns are up at 48% without flexibility as it is necessary to impose severe emissions norms as to bring the environmental performance to the level of that with the 50% RE obligation.

In all three of the curves corresponding to emissions norms above 50 g/kWh, the growth of the RE obligation beyond 50% reduces the emissions limitation (versus cases up to 50%) while the additional cost logically rises. But the counter effect of the environmental performance is progressively depreciated as the carbon constraint becomes more severe. In combinations with a carbon constraint at 100g/kWh, moving from a RE obligation of 50% to 80% drags the total emissions limitation down from 90% to 81%, while the additional cost, which is at 15% for the 50% RE obligation, moves up to 34% at the 80% RE obligation level.

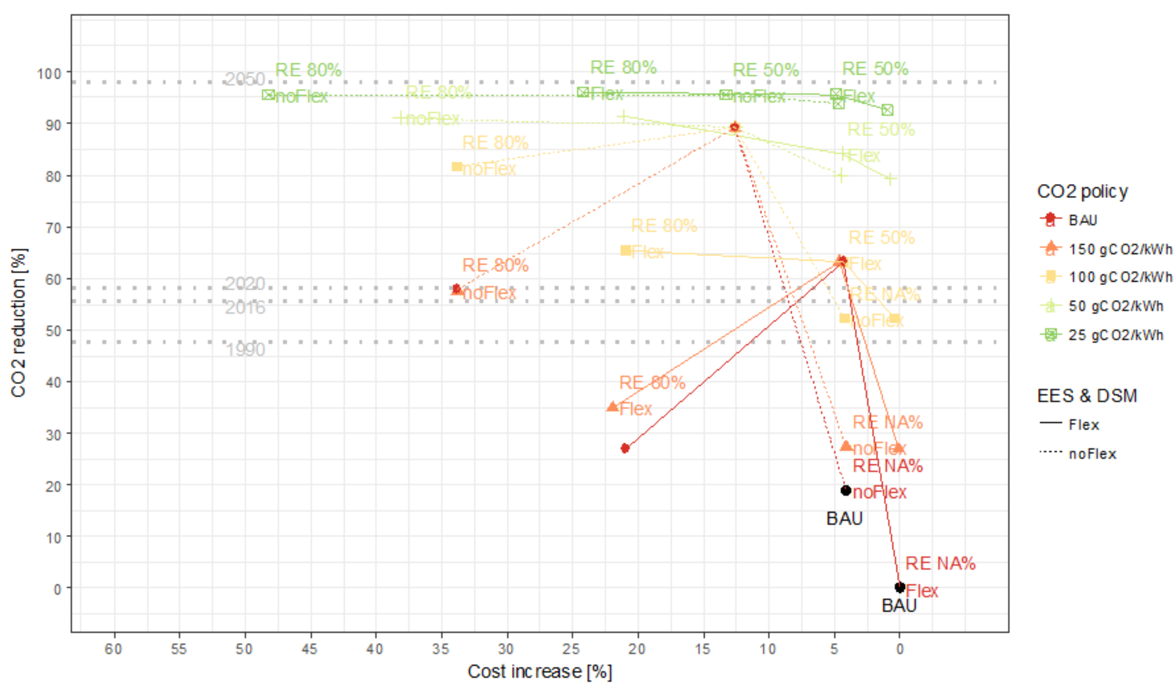

Figure 7. Performances of policy combinations in systems without and with flexibility

In the second set of curves at the top of Figure 7, we observe that there is no longer a rebound on total emission with respect to the BAU case without RE obligation when the obligation rises from

[13] Remember that the emissions level is at 160 g/kWh in the BAU case without flexibility, and at 190 g/kWh with flexibility.

50 to 80%. But costs go up more with this rise of obligation than in the preceding case. Indeed, in tests with a carbon constraint of 50 g/kWh, the additional cost goes from 12% to 35% as the RE obligation moves from 50% to 80%. In tests with a carbon constraint at 25 g/kWh, the additional cost moves from 13% to 48% for this same transition passage. The policy combinations with RE obligations between 51% and 80% thus have an additional cost that becomes increasingly higher if we want to maintain the environmental performance that we achieved at lower RE obligation levels. The impact of these policy combinations on the total cost analysed as a ratio of the total emissions reduction in the BAU case is thus neither monotonous nor linear.

- **The cost-effectiveness of policy combinations in systems with flexibility**

In Figure 7, each of the curves is drawn in double, the first in the context of a system without new sources of flexibility and the second in the context of a system with flexibility. This presentation makes it possible to see how new sources of flexibility effect and improve the performances of two combined policies. In Figure 7, for the same carbon constraint level, we see a displacement of the ''no flex'' curve to the right (with respect to the ''flex'' curve). This signifies lower additional costs, all other things being equal. With a carbon constraint at 50 g/kWh, the additional cost of a RE obligation of 50%, which is 12,5% in the case without flexibility, goes down to 5 % if flexibility source can develop.

More generally, while the additional costs attached to the RE obligations are between 5% and 48% in systems without flexibility, the possibility of recourse to flexibility narrows this range to 2% to 25%. So, flexibility tends to reduce environmental performance for policy combinations as the emission caps are unbinding but at the same time it limits the additional cost of RE integration, all other things being equal. New sources of flexibility allow cost reduction in the integration of production variability as VRE are added to the system. Storage should then be mobilised to reduce costs particularly when tight carbon constraints are used to limit the environmental performance degradation brought on by the intrinsic variability contained in the RE obligation. This might be interpreted as the technical externalities of VREs.

VI. DISCUSSION AND CONCLUSIONS

In order to appropriately evaluate energy transition policies at a 2050 horizon in the electricity sector, we used here a detailed model of the power system to track down unexpected effects from the complex interactions between policies targeting the large-scale development of RE technologies, CO_2 reduction targets, and the possible recourse to new sources of flexibility to diminish VRE integration costs. Different types of unexpected effects appeared.

- *In the different second-best optimums, the optimal part of RE in the electricity mix remains low while that of nuclear remains high, without influence from the carbon constraint level.*

The optimal share of non-subsidised VREs in a system without a carbon constraint is around 11% with flexibility and 17% without flexibility. But, the RE share doesn't go up under the effect of increasingly sever carbon constraints, even for very high levels. Nuclear has an economic advantage over VREs because it is available on-demand; the growth of the carbon constraint just leads us to replace coal by nuclear, bringing the total share of nuclear from 72% to 83% of total production.

- *Setting a RE target beyond this optimal share forcibly has a higher cost than a CO2 policy directly capping total emissions in volume.*

The cost-effectiveness analyses show that this additional cost is 10% for RE obligations at 50% but rises to 47% for RE shares of 80%. This suggests that policies which target the share of RE at below 51% to contain the nuclear shares at 45% or lower, could easily attain societal acceptance, especially as these are the levels at which the CO_2 emissions are the lowest among the different policy combinations.

- *Very high RE obligations have lower environmental performance.*

These results show that the effect of the total emissions limitation goes down beyond a RE obligation level of 51%, for all carbon constraint levels above 50 g/kWh without new sources of flexibility and 75 gCO_2/kWh with flexibility. Beyond these level, further reinforcement of the RE obligation no longer converge with the objective of reducing total emissions. This is the case for those policies targeting an 80% RE shares. Moving from a 50% to an 80% RE obligation only leads to a total emission rebound. However, this effect can be countered by strengthening the carbon constraint to push high RE shares, in particular the 80% policy, to be as effective in environmental performance as the 50% RE policy but inducing high system costs in exchange. For a norm of 50 g/kWh, the additional cost is 13 % if RE share is forced up to 50 % and 45% if forced up to 80%, for identical total emissions performance.

- *These new sources of flexibility (storage, demand-response) improve the economic efficiency of policies based principally on the RE obligation, but not forcibly those based on environmental performance.*

The results show that, as soon as we consider new sources of flexibility, they develop: first through demand-response alternatives, followed by storage from the 30-35% RE share level onwards, because these technologies make it possible to reduce the cost of integrating VRE into the system. In both cases of ambitious RE policies, the new sources of flexibility have a major impact on limiting the additional cost of the total pushing REs. But the improvement in economic efficiency of the policies implemented is accompanied by a diminished environmental performance for RE obligations over 50%. In practice, the time arbitration capabilities of storage and demand response, which improves the economics of fossil technologies as semi-base suppliers, may bring on additional emissions depending on the composition of the electricity mix. At the same time, by reducing the additional cost through better economic integration of VRE into the system, flexibility plays in favour of ambitious RE policies by diminishing their opportunity cost. We can observe, for example, that in the case of an 80% RE obligation, the extra cost is only 23% in place of 48% without flexibility. For less ambitious RE obligations, we observe a reduction of 50-60% of their opportunity cost with respect to cases without flexibility (for example for the 50% RE obligation, the opportunity cost which is 13 % of the total cost of the BAU case, is reduced to 5 %).

Thus, policy measures to promote storage technologies to lower costs through learning by doing, and to be rewarded under broader regulatory frameworks would be quite pertinent to decide. This could be done through long-term contracts that guarantee the revenues of investors in storage units, as is currently done for RE technologies and generation capacity under adequacy requirements.

- *For policies targeting REs at the 80% level, it should be sought out the best combination of measures including a carbon constraint and storage promotion to attain a precise emissions limitation objective with limited additional cost.*

The results show that it is necessary to have recourse to very severe carbon constraints (below 50g/kWh) without flexibility, a bit less with flexibility (below 75g/kWh) so as not to have a lowering of the total emissions limitation with respect to combination including a 50% RE obligation. Furthermore, the important cost overruns appear if very high shares of RE are implemented with a severe carbon constraint so as not to degrade the environmental performance. This additional cost rises to 32-38% for a carbon constraint at 50-100 g/kWh, and to 47% for a carbon constraint at 25g/kWh. In such cases, recourse to flexibility improves both performances. Thus, for a carbon constraint at 25g/kWh, the possibility moves the cost overruns from 48% to around 23% relative to the BAU. On the environmental performance side, thanks to flexibility, performance doesn't go down when we pass from a RE target of 50 to 80% as long as the carbon norm is under 100 g/kWh.

The case of policies targeting of RE shares is of practical interest for defining an energy transition strategy as it allows achieving significative CO2 reductions under unbinding carbon policies, or equivalently, under emission trading system with very low-price levels. At this RE share, CO_2 offsets are obtained with still moderate cost overruns. The analysis of cost effectiveness shows that the cost overruns does not exceed 12.5% in systems without flexibility, and 5% with flexibility. At the same time, this RE shares induce a CO_2 offset of between 85% and 90% of total emissions relative to BAU (with and without flexibility). This suggests that policies that target RE shares under 51% to contain the nuclear development and that promote new sources of flexibility could easily gain societal acceptance while remaining effective at CO_2 emissions reduction without a direct emissions reduction policy.

In conclusion, in countries that prioritise large-scale REs development in their climate policy package, the calibration of policies and measure of this package is delicate as we want to ensure convergence between the RE policy and the decarbonisation objectives without distancing ourselves from economic efficiency in the market-based electricity sector. This is the reason why, in power systems for which the technical and economic coordination is rendered quite complex by the large-scale development of VRE with associated technical externalities, it is crucial to be able to quantitatively understand the links between co-existing climate-energy policies. Detailed modelling these interactions is the only mean able to sweep through the different policy options to yield a well-informed definition of objectives and policy tools for the low carbon transition. More generally, the debate on the low carbon transition must be founded on a solid scientific base that allows the use of the economically rational approach necessary to effectively think through this transition.

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APPENDIX: EVOLUTION OF OPTIMAL ELECTRICITY MIX UNDER INCREASING RE OBLIGATIONS

We are looking here at electricity mixes emanating from different levels of RE obligations constrained at a given level of CO_2 so as to explain the evolution of total emissions performance from one RE obligation to another. In Figure 4, we present the results in terms of mix for five levels of carbon constraint and for three RE policies: 80% RE share, 50% RE share, and no RE obligation. Let's consider first the case of a carbon constraint of 50 g/kWh compared with the BAU case without a carbon constraint so as to identify the mix evolution as a function of the change in obligation share. In these tests without carbon constraint and without flexibility (BAU test)[14], we note that:

- the "natural" development of REN by the market leads to a share of 11%, with nuclear at 72%, coal at 15% while gas and hydraulic reservoirs (with +5% for system flexibility) are respectively at 3% and 5%;
- with a RE obligation at 50%, the share of nuclear goes down to 46% and that of coal to 1%, while gas goes up to 4%, leading to a significant reduction in total emissions from the preceding BAU (10 Mt in place of 78 Mt) (Figure 3);
- with a RE obligation at 80%, nuclear doesn't develop at all, and the share of remaining production goes up to 5% for coal (semi-base) and 10% for gas to ensure flexibility and contribute to semi-base supply. CO_2 emissions can't help but go up from the preceding case in this situation (40Mt in place 11 Mt) (Figure 3).

In the tests with a carbon constraint of 50 g/kWh and an increasing RE obligation, we see that:

- the "natural" development of renewables by the market leads to a 12% RE share (1% more that the BAU from above), nuclear goes up to 83 % (11% more than in the BAU above), while coal goes down from 15% to 2% and gas and reservoirs remain at identical levels (respectively 3% and 5%); this translate to an inferior total emissions level (19 Mt in place of 78 Mt in the BAU without a carbon constraint) (Figure 3);
- with a RE obligation at 50% and the same carbon constraint, the share of nuclear is reduced to 45.5 %, coal almost disappears at only 1%, while the share of gas goes up to 8%. It follows that the total emissions go down versus the case without the carbon constraint (10 Mt in place of the 19 Mt in the preceding case). However, this emissions level is the same as that we reached without the carbon constraint, but with the same RE obligation (Figure 3);
- with a RE obligation at 80% and the same emissions constraint, the share of nuclear goes down to 8%, while the share of gas to ensure flexibility and part of the semi base supply goes up to 10%. However, coal stays under 1% and doesn't make a comeback here as happened in the 80% RE case without carbon constraint above (with coal at 5%). It follows that total emissions are slightly greater than for the 50% case (10.3 Mt in place of 10 Mt), but lower than the test at 80% without the carbon constraint at 40 MT (Figure 3).

[14] Hydraulic reservoirs represent a 4% share in the REN base for all these tests.