D4.2 Quantification of the expected impacts coming from evolutions of RES support schemes and demand flexibility - Intermediate report -

Sophie Dourlens-Quaranta, Eric Peirano, Technofi

September, 2015

Version 1.4

Dissemination level: Public

Agreement n.:	IEE/13/593/SI2.674874
Duration	April 2014 – September 2016
Co-ordinator:	SINTEF Energi AS
Supported by:	Co-funded by the Intelligent Energy Europe Programme of the European Union

DOCUMENT INFORMATION

Deliverable number	D4.2
Deliverable name	Quantification of the expected impacts coming from evolutions of RES support schemes and demand flexibility: Intermediate report
Reviewed by	Andrei Morch, Eline Hegvik, SINTEF Consortium
Date	September 2015
Work Package and Task	WP4, T4.3
Lead Beneficiary for this Deliverable	TECHNOFI

AUTHORS

Name	Organisation	E-mail
Sophie Dourlens-Quaranta	TECHNOFI	sdourlens@symple.eu
Eric Peirano	TECHNOFI	epeirano@symple.eu

CONTRIBUTORS

Name	Organisation	E-mail
Thomas Döring, Manoël Rekinger	EPIA / SOLAR POWER EUROPE	t.doering@solarpowereurope.org
Giorgio Corbetta	EWEA	Giorgio.Corbetta@ewea.org
Adrien Atayi	RTE	adrien.atayi@rte-france.com
Jalal-Edine Zawam	RTE	jalal-edine.zawam@rte-france.com
Bettina Burgholzer	EEG	burgholzer@eeg.tuwien.ac.at
Peter Ahcin	SINTEF	Peter.ahcin@sintef.no

VERSION CONTROL

Version	Date	Author	Description of Changes
V1.0		TECHNOFI	Initial draft
V1.1	[2015-09-02]	TECHNOFI	Incorporation of remarks from RTE and finalization of analyses
V1.2	[2015-09-04]	TECHNOFI	Submission of the draft to Executive Committee
V1.3	[2015-09-07]	TECHNOFI	Incorporation of remarks from EPIA
V1.4	[2015-09-10]	TECHNOFI	Incorporation of remarks following the review by EEG and SINTEF

EXECUTIVE SUMMARY

Introduction

The Work Package 4 (WP4) of the Market4RES project aims at quantifying the impacts of different market architecture options, assuming as an input the generation fleet expected for 2020[1]. The tool used to quantify the impacts of market architecture options is the OPTIMATE prototype simulation platform[2].

The purpose of the present report D4.2 is to present intermediate results of the studies performed with the OPTIMATE tool within the WP4 of Market4RES. Two main studies are being performed:

- Impact on short-term market outcomes of the foreseen evolution in RES support schemes (SS) from Feed-in-Tariffs (FiT) to Price Premium (PP),
- Impact on short-term market outcomes of the development of demand flexibility.

The final report of the studies (deliverable D4.3) is foreseen to be completed in the first quarter of 2016.

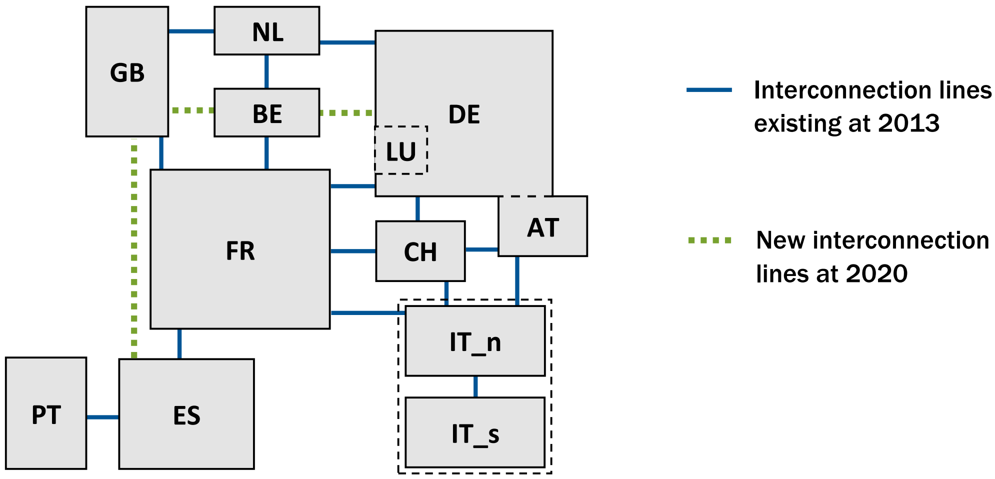
Scenarios underlying the studies

These studies are based on detailed specifications gathered in D4.1 "Specifications of the most adequate options for flexibility markets and RES support schemes to be studied in a cross-border context" [1]. In particular, the above-mentioned market architecture options are studied and compared on the basis of different scenarios, in order to assess the sensitivity of the impacts of each option with regard to the main features of the power system (installed generation capacities, demand level, network capacities, etc.). Therefore, three scenarios are considered within the studies:

- The 2013 scenario, also called reference scenario, mimics the current situation of the power system.
- The 2020 standard scenario mimics the situation of the power system, which can reasonably be expected at 2020. It is based on official publications such as the National Renewable Energy Action Plans (NREAPs) [3], ENTSO-E's Ten-Year Network Development Plan (TYNDP) 2014 [4], ENTSO-E's Scenario Outlook and Adequacy Forecast (SO&AF) 2014-2030 [5], etc.
- The alternative 2020 scenario RES+ is derived from the 2020 standard scenario. RES+ mimics a situation in which RES capacities replace some thermal capacities, the latter being both more flexible, and more costly through an increased CO_2 cost.

[1] It therefore lies in the first Work Stream of the Market4RES project, while the second Work Stream focuses on post 2020 analyses. For more information see www.market4res.eu/.
[2] More information can be found on the OPTIMATE website www.optimate-platform.eu/.

The studies are run over a six-month period allowing to grasp the main seasonal effects (February to July) and a geographical scope covering 11 countries as depicted here below[3].



Configuration of the studies

The following hypotheses have been considered for the study about RES support schemes:

- We have considered that all units built between 2013 and 2020 are subject to a Price Premium (while in real life some will continue to be granted with a Feed-in-Tariff or a similar scheme);
- It has also been assumed that the Feed-in-Tariff contracts for the units already present in the 2013 scenario do not evolve, neither in volume (no consideration of the possible decommissioning of RES units nor of the possible end of some FiT contracts) nor in price (no indexation scheme to the current FiT);
- Price premium at 2020 have been assessed by difference between the levelized costs of electricity (LCOE) at 2020 for each technology, as considered by the IEA, and the average market price at 2020 as calculated by OPTIMATE, considering also an acceptable profit for RES producers.

Regarding demand flexibility development, it is modelled as follows within OPTIMATE:

- A flexible proportion of demand can be voluntarily shed when prices reach a certain level;
- No demand shift is modelled, which means that if peak load is shed, there is no compensation by an increase in electricity consumption during off-peak hours.

[3] See [1] for details about the cross-border lines considered at 2020.

Two variants have been considered:

- "Mid" variant: in this case, 5% of the load is shed when prices reach the 95th centile (in other words, during the 5% of the hours covered by the simulation with the highest prices);
- "High" variant: in this case, 10% of the load is shed when prices reach the 90th centile (in other words, during the 10% of the hours covered by the simulation with the highest prices).

Since no demand shift is modelled, the results of this study will have to be considered with caution.

The market architecture options under study are combined with the different scenarios as follows:

Studies	#	Scenarios	RES SS	Demand flexibility
Default cases	1	2013	None	Low
	2	2020 standard	None	Low
	3	2020 RES+	None	Low
Study on RES support schemes	4	2013	Current RES SS (FiT and/or PP)	Low
	5	2020 standard	Current RES SS (FiT and/or PP) for old, PP for new units	Low
	6	2020 RES+	Current SS (FiT and/or PP) for old, PP for new units	Low
Study on demand flexibility	7a	2013	None	Mid
	7b	2013	None	High
	8a	2020 standard	None	Mid
	8b	2020 standard	None	High
	9a	2020 RES+	None	Mid
	9b	2020 RES+	None	High

Main findings of the studies (intermediate results)

The impact of the evolution in RES support schemes and of the development of demand flexibility are assessed upon five families of indicators:

- Generation mix,
- Costs and profits,

- Market prices,
- Sustainability,
- Cross-border market integration.

Study about the evolution of RES support schemes

Generation mix

- RES support schemes have very little impact on the generation mix: even if support schemes impact the way renewable generation is offered on the market, they hardly have an impact on the merit order curve, and, consequently, on the generation mix.
- However, there is a more significant impact of support schemes on wind and solar generation in Portugal and Spain. This is because these two countries combine the following features: repeated situations with "negative residual load" (generation from non-dispatchable sources high enough to cover the domestic load), and limited cross-border capacities.

Costs and profits

- Within all scenarios, the total RES subsidies outweigh the thermal generation costs incurred in the 11 countries by several billions of euros over the 6-month period despite the gradual move from Feed-in-Tariffs (FiT) to Price Premium (PP).
- Feed-in-Tariffs would remain a major source of revenues for solar producers at 2020.

Market prices

- RES support schemes are responsible for a growing occurrence of negative prices between 2013 and 2020.

Sustainability

- RES support schemes in general and the gradual move from FiT to PP in particular have little impact on the sustainability indicators (CO_2 emissions and share of RES).

Cross-border market integration

- RES support schemes in general and the gradual move from FiT to PP in particular have little impact on cross-border flows, except at the borders of the Iberian Peninsula.
- RES support schemes foreseen at 2020 will cause a major increase in the congestion revenue at the borders of the Iberian Peninsula.

All the analyses foreseen within the WP4 of Market4RES have not been carried out yet. This intermediate report D4.2 will therefore be complemented by further analyses, which will result in the final report D4.3.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF ABBREVIATIONS

ANTARES	A New Tool for Adequacy Reporting of Electric Systems
CHP	Combined Heat and Power
CSP	Concentrated Solar Power
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
FiT	Feed-in-Tariff
LCOE	Levelized Cost of Electricity
NREAPs	National Renewable Energy Action Plans
NTC	Net Transmission Capacity
PP	Price Premium
PV	Photovoltaic
RES	Renewable Energy Sources
RO	Renewable Obligations
RoR	Run-of-river
SO&AF	Scenario Outlook and Adequacy Forecast
SS	Support Scheme
TGC	Tradable Green Certificate
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
WACC	Weighted Average Cost of Capital
WP	Work Package

1 INTRODUCTION

1.1 Role of WP4 in the Market4RES project

The Work Package 4 (WP4) of the Market4RES project aims at quantifying the impacts of different market architecture options, assuming as an input the generation fleet expected for 2020.[4]

The tool used to quantify the impacts of market architecture options is the OPTIMATE prototype simulation platform. This prototype tool was developed during an FP7 project[5] which aimed at developing a numerical test platform to analyse and to validate new market designs which may allow integrating massive flexible generation dispersed in several regional power markets[6]. By using OPTIMATE, different market architecture options can be compared thanks to a set of indicators, while scenarios (installed capacities per energy source, level of peak demand, fuel prices, cross-border capacities…) are considered as input data[7].

1.2 Purpose of this report

The purpose of the present report D4.2 is to present intermediate results of the studies performed with the OPTIMATE tool within the WP4 of Market4RES. Two main studies are being performed:

- Impact on short-term market outcomes of an evolution in RES support schemes (SS);
- Impact on short-term market outcomes of the development of demand flexibility.

These studies are based on detailed specifications gathered in D4.1 "Specifications of the most adequate options for flexibility markets and RES support schemes to be studied in a cross-border context" [1]. This document has been presented at an "expert workshop" organized on the 22nd of May, 2015 in Brussels. Experts have been invited to provide their views upon these specifications both during the workshop and through a written public consultation after the workshop. The final specifications of the studies have therefore slightly evolved compared to the content of D4.1 in order to take into account the inputs coming from experts.

The present report D4.2 will be presented and discussed at a "stakeholder event" in Nice on 16 October 2015. The final report of the studies (deliverable D4.3) is foreseen to be completed by the first quarter of 2016.

All the analyses foreseen within the WP4 of Market4RES have not been carried out yet. This intermediate report D4.2 will therefore be complemented by further analyses, which will result in the final report D4.3.

[4] It therefore lies in the first Work Stream of the Market4RES project, while the second Work Stream focuses on post 2020 analyses. For more information see www.market4res.eu/.
[5] Grant Agreement 239456.
[6] More information can be found on the OPTIMATE website http://optimate-platform.eu/.
[7] It is not the purpose of OPTIMATE to compare the scenarios to each other.

1.3 Structure of this report

This report is structured as follows.

In **Chapter 2**, the methodology used to quantify and compare the impacts of different market architecture options is briefly explained, as well as the market architecture options that are studied within Market4RES WP4 and the three scenarios (2013, 2020 standard and 2020 RES+) built to support the studies. Chapter 2 is actually a rapid summary of D4.1 "Specifications of the most adequate options for flexibility markets and RES support schemes to be studied in a cross-border context" [1]. However, Section 2.5 "Configuration of market architecture options" is new compared to D4.1.

In **Chapter 3**, the default cases for the three scenarios are analysed in detail. For each scenario, several indicators are presented, corresponding to the first family of indicators presented in [1], namely the generation mix indicators. Firstly, global indicators, allowing for rapidly grasping the general functioning of the markets within the default case corresponding to each scenario, are presented in one table; secondly, detailed graphs, per country and per month, are presented to investigate in more detail the features of each scenario.

In **Chapter 4**, the impacts of an evolution in RES support schemes on short-term market outcomes are presented in a quantified manner. Firstly, a table summarizes the impacts of RES support schemes on the global indicators for each of the five families (generation mix, costs and profits, market prices, sustainability, and cross-border market integration), by comparison with the indicators corresponding to the default cases of the three scenarios. Secondly, for each family of indicators, a detailed analysis is conducted.

In **Chapter 5**, the impacts of the development of demand flexibility on short-term market outcomes are presented in a quantified manner. Two different trajectories are studied: one corresponding to a moderate development of demand flexibility, and another corresponding to a large development. Again, a table summarizes the impacts of these two trajectories on the global indicators for each of the five families, by comparison with the indicators corresponding to the default cases of the three scenarios. For each family of indicators, a detailed analysis will be conducted and included in the next deliverable (D4.3).

2 REMINDER ABOUT THE METHODOLOGY USED TO QUANTIFY AND COMPARE THE IMPACTS OF DIFFERENT MARKET ARCHITECTURE OPTIONS

2.1 Overview of the methodology and main modelling hypotheses

2.1.1 The OPTIMATE methodology to compare market architecture options

OPTIMATE is a numerical simulation platform[8] designed to compare wholesale short-term electricity market architecture options integrating massive intermittent electricity generation in Europe, complying with the three EU energy pillars (economic efficiency, climate policy and security of supply). The OPTIMATE prototype platform was developed during an EC-funded FP7 project (2009-2012[9]) under the technical direction of RTE.

The OPTIMATE simulator has been designed rather to give trends in order to ease discussions among electricity stakeholders on system and market design updates, than to lead to absolute results. Consequently, variational studies are conducted: a reference set of designs will be set, leading to the comparison of results based on selected indicators.

In a nutshell, the methodology to compare market architecture options is the sequence of four elements: INPUTS, CORE, OUTPUTS and SCOPE (see Figure *1* below):

1. INPUTS: First of all, **scenarios** are generated. A scenario gathers a set of coherent data describing the initial state of the European power system and consistent with a reference equilibrium of the market. Then, a range of **market architecture options** is set.

2. CORE: The OPTIMATE core then simulates the sequence of actions conducted by market players. It is made of four main processes: Day-Ahead, Intra-Day, Real-Time (including imbalance settlements) and the (feedback) learning-by-doing loop. Each process is made of modules conducting a specific task.

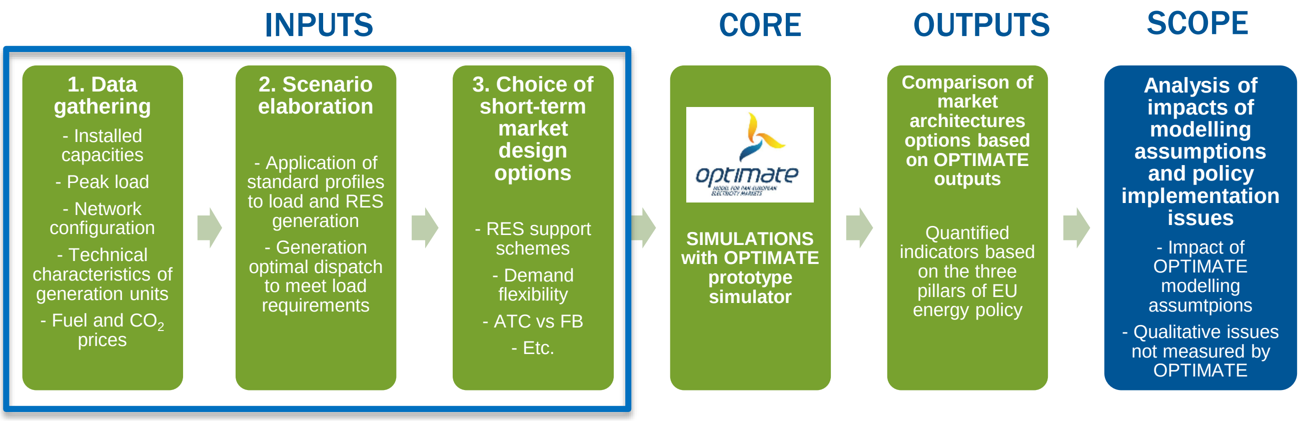
3. OUTPUTS: Once the core simulation is over, outputs are delivered and studied using standard quantified indicators relying on the three pillars of the EU energy policy.

4. SCOPE: Finally the scope of the analysis is taken into account, namely the impacts of OPTIMATE modelling assumptions on the results as well as other qualitative issues not measured by the OPTIMATE simulator.

[8] http://www.optimate-platform.eu/

[9] "An Open Platform to Test Integration in new MArkeT designs of massive intermittent Energy sources dispersed in several regional power markets" (contract no:239456)

Figure 1. *Methodology to compare electricity market architectures*



The report D4.1 "Specifications of the most adequate options for flexibility markets and RES support schemes to be studied in a cross-border context" [1] was focused on the first step of this methodology (INPUTS) and its related tasks, and also provided insights about the indicators to be studied for each set of scenarios and market architecture options.

The present deliverable D4.2 (intermediate report of the studies), as well as the upcoming D4.3 (final report) are focused on the third step of the methodology (OUTPUTS). A fourth deliverable, D4.4 "Recommendations for evolutions in regulatory and remuneration regimes for the involved players to support the most promising instruments at EU and Member State levels" will be built upon the fourth step of the methodology (SCOPE).

2.1.2 Main modelling assumptions of the OPTIMATE prototype simulator

As for all models and simulators, real operations and market behaviours are so complex that simplifying assumptions have to be made. Understanding these assumptions is important when interpreting the results of the studies performed with the OPTIMATE simulator.

The main modelling assumptions made in the OPTIMATE simulator are the following [1]:

- **(almost) Perfect competition:** all market players try to maximise their profits based on price forecast and generation scheduling. They behave as price-takers and do not try to influence the market price through their potentially predominant position on the market. However, at day-ahead they do anticipate on intraday liquidity.[10]
- **Market players behave considering their portfolio.** They are allowed to re-dispatch their day-ahead delivery requirements according to unit commitment considerations of their whole portfolio and also based on their expectations on intraday and balancing prices.
- **Forward contracts are not considered.** All trading and dispatch takes place at day-ahead, intraday and real-time.
- **The shortest time resolution** is 30 minutes.

[10] See chapter 3.2.2. for more details

- **Network limits are never trespassed at real-time.** In case of problems, load or generation curtailment is undertaken.
- **Electric network nodes are aggregated per cluster**. It is assumed that commercial exchanges within a market area occur at the day-ahead stage without internal network constraints. It is possible to define several clusters within a market area as required.
- **Thermal generation is modelled with minimum and maximum load**, start-up costs, gradients, minimum run-time and off-time, planned outage (maintenance) possibility, risk of sudden breakdowns (random variable).
- **Load shedding** is (next to forced curtailment in case of network restrictions) also possible voluntarily in case of high market prices. A given percentage can be shed at a predefined price per cluster.
- **Forecast errors** decrease with time-to-go. Usually, the closer to real-time, the lower the forecast error for generation (i.e. intermittent RES, such as wind energy and solar) and load.
- **TSOs are jointly responsible for congestion management**, with equal allocation of costs and revenues. TSOs can be assigned different levels of risk aversion which will influence their reserve provisions. Each TSO is also responsible for balancing its own control block.

In addition to the above mentioned assumptions, the current version (1.10) of OPTIMATE (used for the Market4RES studies) has the following limitations[11]:

- **Only the day-ahead market process is taken into consideration in the simulations**[12]**;**
- Market design options are exactly the same in all market zones, i.e., market design is fully harmonised, with the exception of RES support schemes and demand flexibility level;
- The average reference water value, which determines the marginal production cost for hydro power plants, is set using the expected marginal production cost[13] and the core simulator updates this value.

Using the day-ahead module alone allows for assessing the overall pattern of the markets (generation mix, cross-border exchanges, etc.), while the intraday and real-time modules would be needed to assess more precisely aspects as imbalance management.

[11] The tool is a prototype which is still under development.

[12] Other modules than the day-ahead one have actually been added into the prototype simulator (intraday and real-time modules), but they have not yet been sufficiently tested to be included into the scope of the Market4RES studies.

[13] Issued from the reference market equilibrium, see next page.

2.2 Day-ahead market architecture options to be studied

Two main aspects of the day-ahead markets are proposed to be the focus of the OPTIMATE studies performed within Market4RES:

- RES support schemes,
- Demand flexibility.

2.2.1 Comparison of RES support schemes

The European Commission's new environmental and energy State Aid Guidelines [2] aim at better integrating renewables into the internal electricity market, through the gradual introduction of market-based mechanisms, reflecting the increasing maturity of RES technologies. Hence, the guidelines envisage:

- the gradual move from Feed-in-Tariffs to Price Premium schemes;
- exposing RES generators to standard balancing responsibilities;
- measures to be put in place in order to ensure that RES producers have no incentive to generate electricity under negative prices.

Therefore, the first goal of this study is to assess *how the gradual move from Feed-in-Tariffs to Price Premium schemes impacts day-ahead market outcomes*.

The options to be studied are the following:

- Feed-in-Tariff (FiT), which guarantees a fixed regulated price per unit of electricity generated (MWh) fed into the grid over a specific time period (whatever the electricity market price) and encompassing a legal requirement that subsidised energy has priority access to the network (priority dispatch). Hence, under the FiT scheme, the remuneration of RES producers is always guaranteed irrespective of the market price in the OPTIMATE model. This means that RES production is integrated as a "must-run". Since within OPTIMATE the whole generation is offered to the day-ahead market, this is modelled as if RES producers submitted bids at the minimum authorised price (i.e. - 500 €/MWh). FiT is the support scheme, which is currently applied in most EU countries, both for wind and for PV. Since in most cases a change in support schemes cannot be retroactive, FiT will continue to be applied to existing RES units for years even if Price Premium schemes are introduced for new units.
- With a Price Premium (PP) scheme, RES producers receive a fixed regulated premium (extra bonus) over the spot electricity market price for the feed-in of renewable energy. They have no priority dispatch. Under this scheme, RES producers have positive income as long as the market price is not more negative than the premium amount. As explained above, price premium is the target set by the new EC State Aid Guidelines.

- No support schemes: studying the impacts of this fictitious[14] option will allow isolating the impacts of RES support schemes on market outcomes. In OPTIMATE, this option is modelled by a price premium at zero applied to 100% of the RES production.

The combination of these options within the different countries, and the values of the different parameters for FiT and PP are detailed in Section 2.5.1 of the present report.

It is worth mentioning that Tradable Green Certificates (TGC), also called Renewable Obligations (RO) cannot be modelled as such within OPTIMATE. This scheme imposes a renewable generation obligation, in most cases, on suppliers to source a certain share of their electricity from renewable energy. Suppliers can comply with the requirement by either producing "green electricity" or by buying renewable energy on the market. Therefore, this scheme can reasonably be approximated by a Price Premium scheme, where the value of the premium corresponds to the average value of the green certificates' price as quoted on the market.

2.2.2 Evaluation of the impacts of the deployment of demand flexibility

Demand response consists in reducing or activating the load level of consumers for some time when the price of electricity reaches a high/low enough level. This reduction/activation can either be directly controlled by the so-called "demand managers" or be left to consumers' decisions, provided that they are informed about the actual price of electricity.

In the OPTIMATE simulator, as a default option, most of the demand is considered inelastic, i.e. voluntary load shedding is not possible. However, demand can be set to have a flexible part (relative to the overall schedule), which can be voluntarily shed when price signals are adequate. For example, when prices are very high, part of the electricity consumption may lead to economic losses for big consumers such as industrial plants, and load units may prefer to decrease their consumption.[15]

Hence, the second goal of this study is to assess *how demand flexibility would impact the day-ahead market outcomes.*

The following options are proposed:

- "Low" load flexibility: as default, demand flexibility is 0%, so that no voluntary load shedding is possible;
- "Mid" and "high" load flexibility: in this case, a certain percentage of the overall load in each market area is willing to shed if the day-ahead market price is above a certain price. The exact values of these parameters considered within the studies are detailed in Section 2.5 of the present report.

[14] This is a purely theoretical case since at least existing renewable plants will be under FiT for several years.

[15] By contrast, as a last resort means of balancing the system, involuntary load shedding, due to scarcity at maximum prices, is applied in the OPTIMATE model whatever the level of load flexibility chosen by the user.

2.3 Elaboration of scenarios to compare market architecture options

The above-mentioned market architecture options are studied and compared on the basis of different scenarios, in order to assess the sensitivity of the impacts of each option with regards to the main features of the power system (installed generation capacities, demand level, network capacities, etc.).

Table 1 below presents the main features of the scenarios being elaborated for the studies in a synthetic and qualitative manner. The detailed description of each scenario can be found in [1].

Table 1. ***Main features of each scenario***

Scenario name	Thermal generation			RES generation	Demand	Transmission network
	Installed capacities	*Flexibility*	*Economic parameters*			
2013 scenario (reference scenario)	Current installed capacities	Current flexibility level	Current CO_2 price and fuel costs	Current installed capacities	Current level of peak demand	Current cross-border capacities
2020 standard scenario	Installed capacities at 2020 as foreseen today	Current flexibility level	Foreseen values at 2020	2020 RES objectives	Level of peak demand at 2020 as foreseen today	2020 cross-border capacities as foreseen today
2020 RES+ scenario	Significant decrease in thermal installed capacities	Higher flexibility of thermal units	Higher CO_2 price (impact on merit order curve)	Additional RES capacities	Level of peak demand at 2020 as foreseen today	2020 cross-border capacities as foreseen today

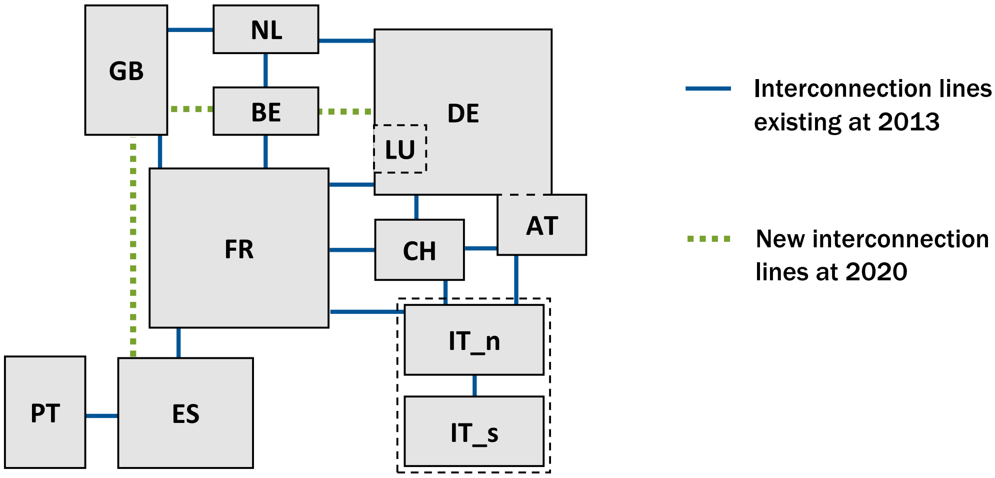
The 2013 scenario, also called reference scenario, mimics the current situation of the power system.

The 2020 standard scenario mimics the situation of the power system which can reasonably be expected at 2020. It is based on official publications such as the National Renewable Energy Action Plans (NREAPs) [3], ENTSO-E's Ten-Year Network Development Plan (TYNDP) 2014 [4], ENTSO-E's Scenario Outlook and Adequacy Forecast (SO&AF) 2014-2030 [5], etc.

The alternative 2020 scenario RES+ is derived from the 2020 standard scenario. RES+ mimics a situation in which RES capacities replace some thermal capacities, the latter being both more flexible and more costly. By contrast with what has been presented in [1] (Table 21), not only the flexibility of coal and gas plants will be improved compared to the 2020 standard scenario, but also the flexibility of nuclear power plants. This has been suggested at the Expert Workshop on 22 may 2015. Quantified elements for adapting the flexibility parameters of nuclear plants within OPTIMATE have been found in [6].

All scenarios are built upon the same geographical scope covering 11 countries as depicted in Figure **2** below (see [1]).

Figure 2. ***Geographical scope of the studies***



2.4 Combining the market architecture options to be studied with the scenarios

For each of the three scenarios defined, a default OPTIMATE case is run: it provides a starting point from which variational studies, covering the two types of defined market architecture options are performed. These default cases are based on the following hypotheses:

- No RES support scheme;
- Low demand flexibility.

Table 2 presents how the parameters of the default cases are modified for each scenario. Initially, 9 OPTIMATE cases were planned to be run, for the two types of market architecture options (see Table 5 in [1]). It was foreseen to run each case over selected periods of the year covering different seasons (for instance one winter month, one summer month and one mid-season month), leading to around 27 case variants.

Compared to [1], two changes have been implemented:

- To grasp the potential seasonal effects of the different market architecture options, while avoiding multiplying the number of cases run with OPTIMATE, each case is run over 6 months, from February to July. This covers 3 different seasons, and a proxy of the different indicators at yearly level could be calculated by doubling each indicator corresponding to the period studied[16];

[16] Obviously doubling the indicators corresponding to the 6-month period studied allows getting only a proxy of the yearly value of the indicators: as an example, consumption peaks potentially occurring in December are not taken into account.

- Following the expert workshop and the public consultation, it is proposed to run two different variants for demand flexibility, mimicking respectively a moderate development (“mid” variant) and a rapid development (“high” variant) of load flexibility.

Table 2. *Proposed combinations of scenarios and market architecture options*

Studies	#	Scenarios	RES SS	Demand flexibility
Default cases	1	2013	None	Low
	2	2020 standard	None	Low
	3	2020 RES+	None	Low
Study on RES support schemes	4	2013	Current RES SS (FiT and/or PP)	Low
	5	2020 standard	Current RES SS (FiT and/or PP) for old, PP for new units	Low
	6	2020 RES+	Current RES SS (FiT and/or PP) for old, PP for new units	Low
Study on demand flexibility	7a	2013	None	Mid
	7b	2013	None	High
	8a	2020 standard	None	Mid
	8b	2020 standard	None	High
	9a	2020 RES+	None	Mid
	9b	2020 RES+	None	High

Other possible combinations of scenarios and market architecture options could be considered. For instance, depending on the results of the studies on load flexibility and RES support schemes, studying the combination of high load flexibility with different RES support schemes could be of interest.

2.5 Configuration of market architecture options

2.5.1 Configuration of RES support schemes

To implement the methodology previously described, precise values have to be defined for wind and solar support schemes:

- Proportion of installed capacities under Feed-in-Tariff (FiT), and average value of the FiT in each country;
- Proportion of installed capacities under Price Premium (PP), and average value of the PP.

Assessing these four values per country, per type of energy source (wind and PV) and per time horizon (2013 and 2020) requires several hypotheses and simplifications; for example the different tariffs applied to the different categories of capacities (onshore / offshore for wind, ground-mounted / roof top for PV) are approximated by one single value.

Assessment of current RES support schemes (2013 scenario)

Regarding the support schemes applied to PV generation, calculating the average support is very complex because market segmentation differs in the different countries, and support has changed from one year to another. With the support of SolarPower Europe, it has therefore been decided to consider an average feed-in-tariff in all countries of 250 €/MWh. Only in Germany a significant share of PV installed capacities is supported by a price premium scheme (4375 MW[17], i.e. 12% of total installed capacities). The premium is at about 107 €/MWh (average value taking account of all market segments, from residential to ground-mounted installations). Table ***3*** below shows the values that are being considered in the studies.

Table 3. *Current (simplified) support schemes for PV generation*

	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH
Percentage of PV generation sold under feed-in tariff	100%	100%	100%	88%	100%	100%	100%	100%	100%	100%
PV Feed-in tariff average value (€/MWh)	250	250	250	250	250	250	250	250	250	250
Percentage of PV generation sold under premium prices	0%	0%	0%	12%	0%	0%	0%	0%	0%	0%
PV premium average price (€/MWh)	-	-	-	107	-	-	-	-	-	-

Assessment by TECHNOFI and SolarPower Europe

[17] See www.germanenergyblog.de/?p=17680 and www.netztransparenz.de.

The support schemes currently applied to installed capacities of wind have kindly been provided by EWEA. Simplifications have been applied to the initial input data: for example, Tradable Green Certificates (TGC) are approximated with a Price Premium; for offshore and onshore PPs and FiTs, average values, weighted by the installed capacities, are calculated. The result of these adaptations is presented in ***Table 4*** below.

Table 4. *Current (simplified) support schemes for wind generation*

	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH
Percentage of wind generation sold under feed-in tariff	100%	0%	100%	0%	0%	100%	0%	100%	100%	100%
Wind Feed-in tariff average value (€/MWh)	94	-	82	-	-	122	-	74	81	146
Percentage of wind generation sold under premium prices	0%	100%	0%	100%	100%	0%	100%	0%	0%	0%
Wind premium average price (€/MWh)	-	82	-	93	85	-	98	-	-	-

Source: EWEA – Calculations: TECHNOFI

Assessment of future RES support schemes (2020 scenarios)

For assessing the RES support schemes at 2020, we need again to simplify the problem:

- Firstly, we consider that the support schemes for the units already present in the 2013 scenario do not evolve: we apply no indexation scheme to the current FiT, and we neglect the possible decommissioning of RES units as well as the possible end of some FiT contracts;
- Secondly, we consider that all units built between 2013 and 2020 are subject to a Price Premium, as foreseen in [2].

For solar generation, to assess the PP at 2020, the below-mentioned method is applied following the advice of SolarPower Europe:

- The levelized cost of electricity (LCOE)[18] at 2020 displayed in the IEA Technology Roadmap [7] (Tables 4 and 5) is considered as the best estimate for the 2020 solar production costs[19];

[18] The LCOE represents the present value of the total cost (overnight capital cost, fuel cost, fixed and variable O&M costs, and financing costs) of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments, given an assumed utilisation, and expressed in terms of real money to remove inflation.

[19] It is an advice from SolarPower Europe to consider this value. It has been calculated as the average between the projections for LCOE for new-built rooftop PV systems and for new-built utility-scale PV plants. For both, the IEA considers a weighted average cost of capital (WACC) of 8%. Actual LCOE might be lower with lower WACC.

- To the LCOE is added an acceptable profit for RES producers: 7% is considered;
- The PP is obtained by difference between the average market price at 2020 calculated without any support scheme (default cases for the 2020 standard and RES+ scenarios) and the LCOE, taking account of the 7% profit for RES producers.

The PP values which are obtained thanks to this method are presented in ***Table 5*** (2020 standard scenario) and ***Table 6*** (2020 RES+ scenario). They are applied to new solar capacities, both for PV and Concentrated Solar Power (CSP) units.

Table 5. ***Assessment of support schemes for solar generation for the 2020 standard scenario***

	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH
Percentage of solar generation sold under feed-in tariff	30%	76%	45%	59%	34%	72%	25%	23%	44%	31%
PV Feed-in tariff average value (€/MWh)	250	250	250	250	250	250	250	250	250	250
Percentage of solar generation sold under premium prices	70%	24%	55%	41%	66%	28%	75%	77%	56%	69%
PV premium average price (€/MWh)	84	84	105	84	83	75	83	108	108	85

Source: IEA – Calculations by TECHNOFI with the support of SolarPower Europe

Table 6. ***Assessment of support schemes for solar generation for the 2020 RES+ scenario***

	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH
Percentage of solar generation sold under feed-in tariff	18%	62%	29%	44%	20%	56%	15%	13%	28%	18%
PV Feed-in tariff average value (€/MWh)	250	250	250	250	250	250	250	250	250	250
Percentage of solar generation sold under premium prices	82%	38%	71%	56%	80%	44%	85%	87%	72%	82%
PV premium average price (€/MWh)	71	73	101	71	71	68	71	102	100	72

Source: IEA – Calculations by TECHNOFI with the support of SolarPower Europe

For wind, the reasoning is the same. However, the IEA Technology Roadmap for Wind Power [8] does not provide values as detailed as the PV Roadmap. However, in a presentation related to this Roadmap [9], low and high values for LCOE are provided, both for offshore and onshore wind units.

Based on this input, average LCOE values have been calculated for onshore and offshore wind, and have been applied in the different countries depending on the proportion of onshore and offshore wind capacities set within each of the two 2020 scenarios. The average PP values which are obtained thanks to this method are presented in ***Table 7*** (2020 standard scenario) and ***Table 8*** (2020 RES+ scenario).

Regarding the 2020 RES+ scenario, it can be noted that in countries where no offshore wind is to be installed, the PP for wind is very low (because the average LCOE for onshore wind is quite close to the average market price).

Table 7. ***Assessment of support schemes for wind generation for the 2020 standard scenario***

	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH
Percentage of wind generation sold under feed-in tariff	50%	0%	41%	0%	0%	71%	0%	83%	88%	5%
Wind Feed-in tariff average value (€/MWh)	94	-	82	-	-	122	-	74	81	146
Percentage of wind generation sold under premium prices	50%	100%	59%	100%	100%	29%	100%	17%	12%	95%
Wind premium average price (€/MWh)	19	51	48	41	74	10	50	44	43	20

Source: IEA – Calculations by TECHNOFI

Table 8. ***Assessment of support schemes for wind generation for the 2020 RES+ scenario***

	AT	BE	FR	DE	GB	IT	NL	PT	ES	CH
Percentage of wind generation sold under feed-in tariff	33%	0%	26%	0%	0%	55%	0%	70%	79%	3%
Wind Feed-in tariff average value (€/MWh)	94	-	82	-	-	122	-	74	81	146
Percentage of wind generation sold under premium prices	67%	100%	74%	100%	100%	45%	100%	30%	21%	97%
Wind premium average price (€/MWh)	6	40	43	28	61	3	38	38	35	7

Source: IEA – Calculations by TECHNOFI

2.5.2 Configuration of demand flexibility

Within OPTIMATE, demand flexibility is modelled as follows:

- A flexible proportion of demand can be voluntarily shed when prices reach a certain level;
- No demand shift is modelled, which means that if peak load is shed, there is no compensation by an increase in electricity consumption during off-peak hours.

The following configuration is adopted for the “mid” and “high” variants:

- **Mid**: in this case, **5%** of the load is shed when prices reach the **95th centile** (in other words, during the 5% of the hours covered by the simulation with the highest prices);
- **High**: in this case, **10%** of the load is shed when prices reach the **90th** centile (in other words, during the 10% of the hours covered by the simulation with the highest prices).

Since no demand shift is modelled, the results of this study will have to be considered with caution.

3 BRIEF ANALYSIS OF THE DEFAULT CASES

In the default cases corresponding to each of the three scenarios, it is supposed that no support schemes are applied and that there is no demand flexibility, as indicated in Table *2* (page 22).

Some indicators corresponding to these default cases are presented in this chapter to illustrate the general functioning of the markets under the 3 different scenarios. They are focused on the first category of indicators amongst the five categories presented in [1] (Tables 1, 2 and 3):

- Generation mix,
- Costs and profits,
- Market prices,
- Sustainability,
- Cross-border market integration.

Actually, for the first category of indicators, namely the generation mix indicators, several indicators are calculated and presented:

- Firstly, global indicators, allowing for rapidly grasping the main features of each scenario over the 6-month period studied, are presented in one table;
- Secondly, detailed graphs, per country and per month, are presented to investigate in more detail the features of the default case corresponding to each scenario.

Then, for the studies about RES support schemes and demand flexibility, the impact of the changes in market design on the indicators covering the five categories is presented in chapters 4 and 5.

3.1 2013 scenario

3.1.1 Generation mix global indicators

The global indicators about the generation mix for the default case for the 2013 scenario are presented in Table *9* below. These values are calculated as follows:

- **Generation** from each type of energy source, as well as **load**, is the sum over all the hours of the period studied (6 months) of the day-ahead clearing quantities corresponding to each type of generation units and to load. Generation from RES takes into account not only wind and solar generation, but also hydro dams and "must-run" generation[20].
- The **score for negative residual load** is the average value, over all countries, of the number of hours during which residual load is negative: this means that domestic load is covered by non-dispatchable generation (must-run, solar and wind).

[20] As explained in [1], "must-run" refers to the production that runs independently from the market: it gathers the run-of-river generation and the "thermal must-run" mainly consisting in Combined Heat and Power units (CHPs).

Table 9. *Generation mix global indicators (2013 scenario, default case)*

	Global indicators (absolute values over 6 months)
Generation from RES	443 TWh
Wind	72 TWh
Solar	50 TWh
Other RES	322 TWh
Generation from nuclear	386 TWh
Generation from fossil fuels	371 TWh
Coal	321 TWh
Gas	51 TWh
Oil	0.017 TWh
Total load	1,200 TWh
Score for negative residual load	252 h

It can be observed that oil generation is lower than what is measured in real-life. This is because only the day-ahead module of OPTIMATE is considered for the studies: in real-life, oil units significantly intervene in shorter-term markets such as intraday and balancing.

3.1.2 Generation mix detailed indicators

Figure *3* below shows for each country, the production per energy source during the 6-month period covered by the studies (the number above each bar represents the total production).

Figure 3. *Total production per energy source and per country (2013 scenario, default case)*

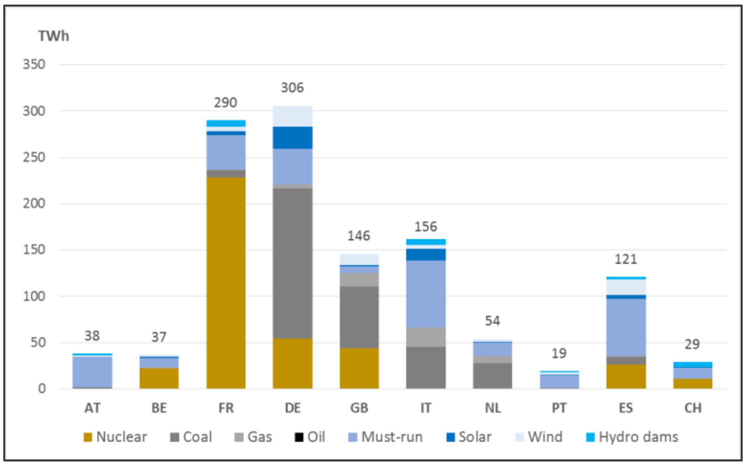


Figure 4[21] below shows the hourly production (per energy source) and load within each country. Overall it shows a "normal" behaviour of the markets, corresponding in general to what can be observed in real life. Within each market, domestic load does not always match the production, which is a normal situation corresponding to the existence of cross-border exchanges.

[21] Note that the graduation on the vertical axis of the ten graphs is adapted to the scale of each market.

Figure 4. *Hourly production and load per country, in MW (2013 scenario, default case)*

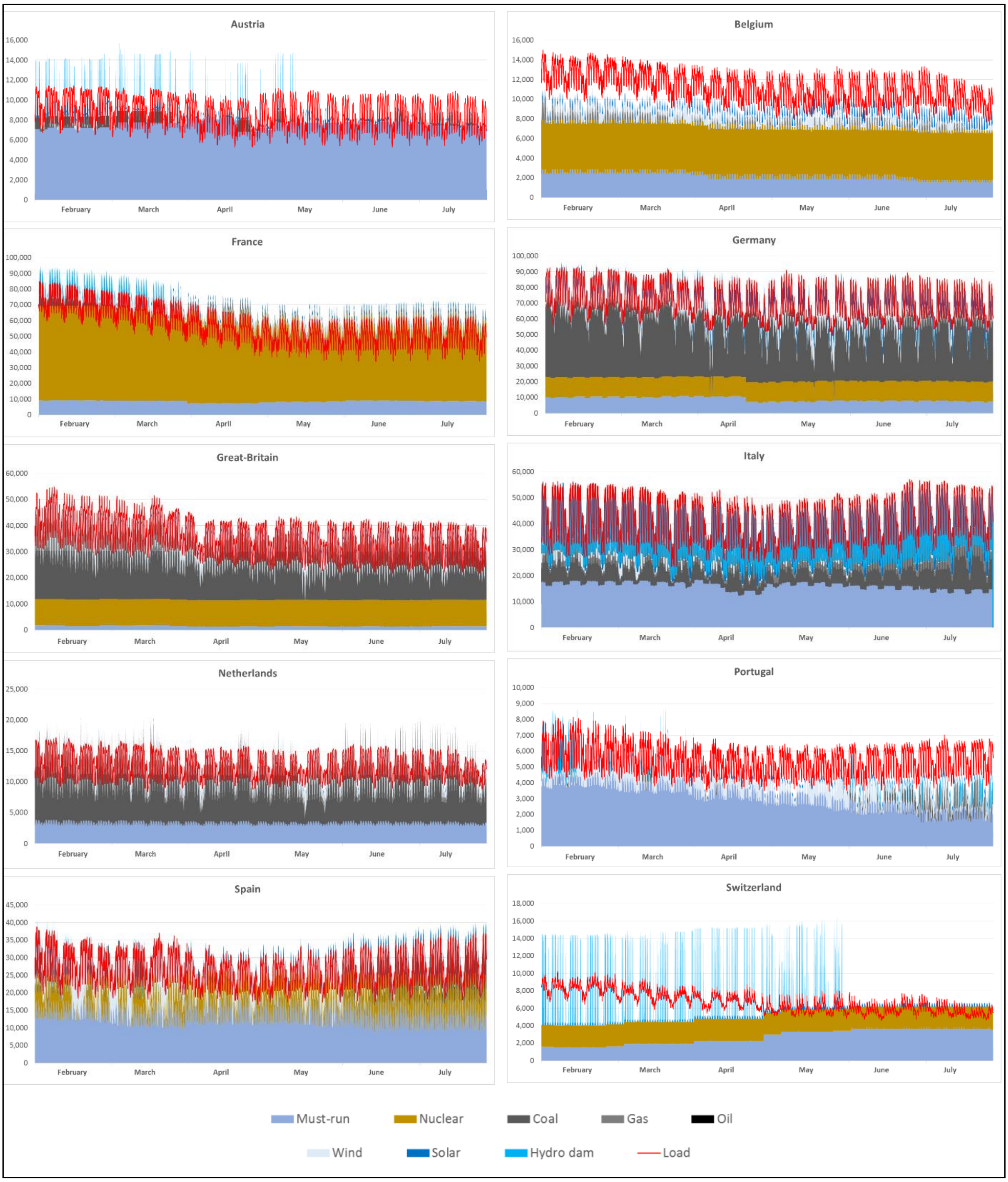
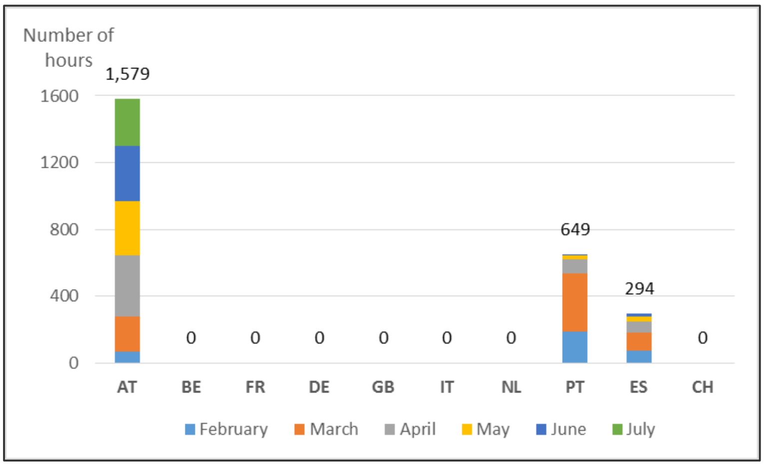


Figure 5 shows the number of hours, for each country and each month, during which domestic load is covered by the domestic generation from non-dispatchable sources (must-run, wind and solar). In other words, it is the number of hours with negative "residual load". When such situation occurs in one country, it must export to neighbouring countries the non-dispatchable generation which exceeds the domestic consumption to the extent allowed by the cross-border interconnection capacities; if those are congested, the non-dispatchable generation in excess must be curtailed.

Within the 2013 scenario, this situation occurs in Austria, mainly in spring, due to run-of-river (RoR) generation, and in Spain and Portugal, mainly during winter months, due to wind generation.

Figure 5. ***Number of hours, per country and per month, with negative residual load (2013 scenario, default case)***



3.2 2020 standard scenario

3.2.1 Generation mix global indicators

As for the 2013 scenario, global indicators and detailed graphs are presented to illustrate the general functioning of the markets ("generation mix indicators") for the default case for the 2020 standard scenario (no support schemes, no demand flexibility). The definition of each indicator is not repeated here: please refer to Section 3.1 if needed. Rather, a short analysis of the evolution of each indicator compared to the 2013 scenario is provided.

Within Table ***10*** the global indicators about the generation mix for the 2020 standard scenario (default case) are to be compared to the indicators presented in Table ***9*** (page 29) for the 2013 scenario. The variation is indicated in italic, between brackets.

Table 10. *Generation mix global indicators (2020 standard scenario, default case)*

	Global indicators (absolute values over 6 months)
Generation from RES	570 TWh *(+29%)*
Wind	151 TWh *(+112%)*
Solar	79 TWh *(+60%)*
Other RES	340 TWh *(+6%)*
Generation from nuclear	398 TWh *(+3%)*
Generation from fossil fuels	291 TWh *(-22%)*
Coal	234 TWh *(-27%)*
Gas	55 TWh *(+9%)*
Oil	1.6 TWh *(+9172%)*
Total load	1,257 TWh *(+5%)*
Score for negative residual load	280 h *(+11%)*

By construction of the 2020 standard scenario, generation from RES is much higher than in the 2013 scenario (+29%). This is mainly due to the development of wind and solar capacities, both in terms of installed capacities and of efficiency (see [1], section 4.4.2). Generation from coal is lower by 27%, which is due to the lower installed capacities of coal units in the 2020 standard scenario, to the higher CO_2 price considered in this scenario and to the fact that RES generation replaces, to a certain extent, coal-based generation. It is worth mentioning that gas- and oil-based production significantly increases.

Total load increases by 5%, which is a direct consequence of the peak load increase considered in the 2020 standard scenario. Despite this increase, domestic load is more often covered by RES generation, with an increase of the corresponding score by 11%.

3.2.2 Generation mix detailed indicators

Figure 6, Figure ***8*** and ***Figure 7*** shall be regarded in comparison with ***Figure 3***, ***Figure 4*** and ***Figure 5***. Regarding the total production per energy source and per country during the 6-month period covered by the studies (***Figure 6***), it can be noted that the production increases in some countries (AT, BE, FR, IT, PT, ES, CH) while in others the production decreases (DE, GB, NL). The decrease is mainly due to the diminution of coal-based production.

Figure 6. *Total production per energy source and per country (2020 standard scenario, default case)*

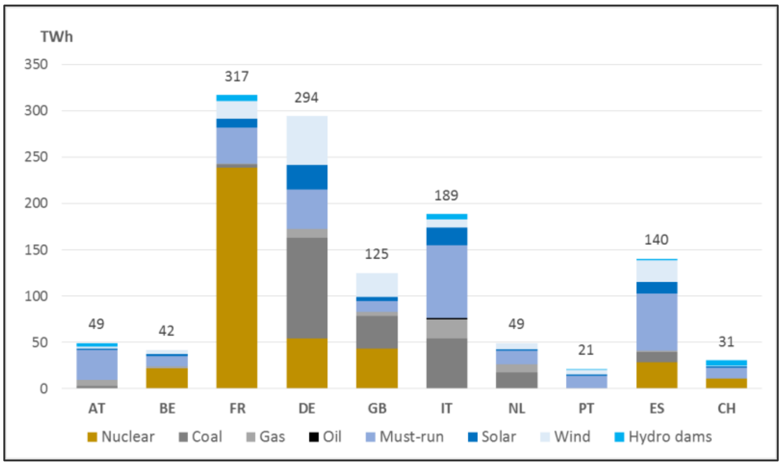
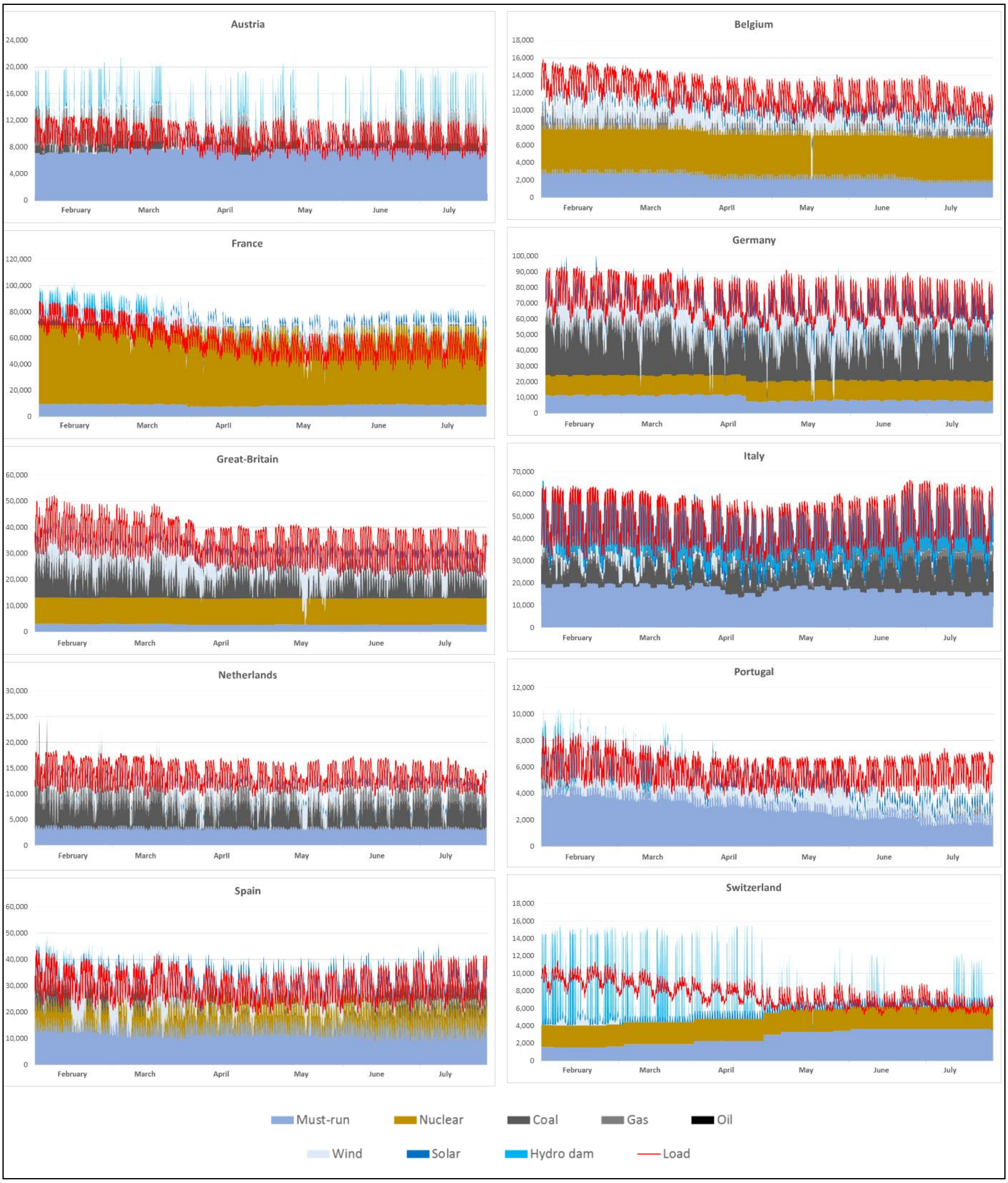


Figure 7. *Hourly production and load per country, in MW (2020 standard scenario, default case)*



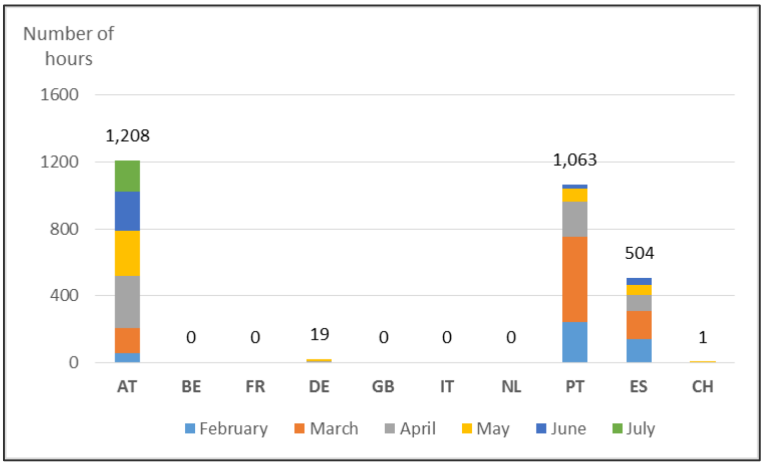
An interesting point in the hourly production per country (***Figure 7***[22]) is the fact that the thermal base load production (nuclear and coal), within the countries equipped with such capacities (BE, FR, DE, GB, NL, ES) needs to be curtailed, during off-peak hours and/or high RES production, which was not the case within the 2013 scenario. It must be reminded here that the present studies are focused on the day-ahead stage of the markets: in real-life, these non-flexible units will probably revise their position at the intraday stage or face imbalance penalties, rather than decreasing their production for a few hours, which is technically difficult and economically inefficient.

It can also be noted that Austria and Switzerland would export their hydro dam production not only during winter and spring as within the 2013 scenario, but also during summer.

Regarding the number of hours during which residual load is negative (Figure ***8***), we notice that, compared to 2013, there are some differences:

- The situation would still occur in Portugal and Spain (still during winter months, mainly), and to a higher extent;
- The situation would still occur in Austria, but to a lower extent. This is due to the level of load which is expected to increase by 10% in Austria between 2013 and 2020: as a consequence, there would be less hours during which load would be low enough to be covered by non-dispatchable generation;
- The situation would occur for a few hours in Germany, and for one hour in Switzerland.

Figure 8. ***Number of hours, per country and per month, with negative residual load (2020 standard scenario, default case)***



[22] Note that the graduation on the vertical axis of the ten graphs is adapted to the scale of each market.

3.3 2020 RES+ scenario

3.3.1 Generation mix global indicators

Again, global indicators and detailed graphs are presented to illustrate the general functioning of the markets ("generation mix indicators") for the default case for the 2020 RES+ scenario (no support schemes, no demand flexibility). The definition of each indicator is not repeated here: please refer to Section 3.1 if needed. Rather, a short analysis of the evolution of each indicator compared to the 2020 standard scenario is provided.

Within Table ***11*** the global indicators about the generation mix for the 2020 RES+ scenario (default case) are to be compared with the indicators presented in Table ***10*** for the 2020 standard scenario (page 32). The variation is indicated in italic, between brackets.

Table 11. ***Generation mix global indicators (2020 RES+ scenario, default case)***

	Global indicators (absolute values over 6 months)
Generation from RES	674TWh *(+18%)*
Wind	208 TWh *(+37%)*
Solar	112 TWh *(+42%)*
Other RES	354 TWh *(+4%)*
Generation from nuclear	335 TWh *(-16%)*
Generation from fossil fuels	246 TWh *(-15%)*
Coal	134 TWh *(-43%)*
Gas	112 TWh *(+102%)*
Oil	0.002 TWh *(-99.9%)*
Total load	1255 TWh *(0%)*
Score for negative residual load	457 h *(+63%)*

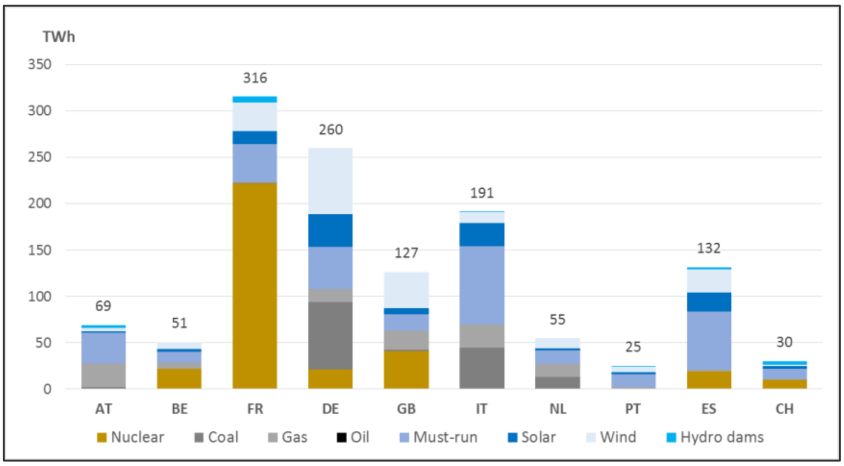
By construction, the consumption is the same in both scenarios (1,255 TWh), and the installed capacities defined in the 2020 RES+ scenario lead to an increase in RES and gas generation, and a decrease in nuclear, coal and oil generation.

3.3.2 Generation mix detailed indicators

Figure ***9***, ***Figure 10*** and Figure ***11*** shall be regarded in comparison with Figure ***6***, ***Figure 7*** and Figure ***8.***

What can be noticed in Figure ***9*** is the significant decrease in the total production from Germany, due in particular to the decrease in German coal and nuclear production. In other countries, the total production over the 6 months studied either increases (AT, BE, NL, PT, ES) or is quite stable (FR, GB, IT, CH).

Figure 9. ***Total production per energy source and per country (2020 RES+ scenario, default case)***



The global decrease in German production can also be observed on ***Figure 10***[23]. It can also be noticed regarding Germany that the nuclear and coal generation, as fixed by the day-ahead market, would become very unstable due to the very high wind and solar production.

In addition, despite this overall decrease, Germany would repeatedly face situations with huge wind and solar penetration leading the global production to exceed load by tens of gigawatts.

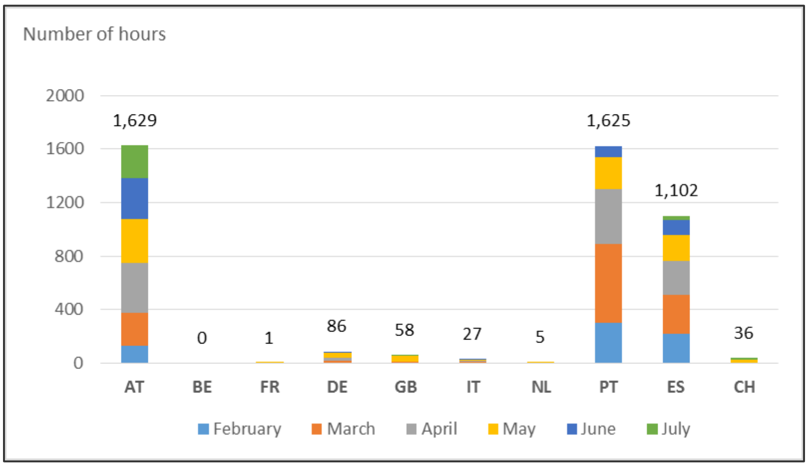
Figure 10 also shows the significant decrease in nuclear production in Spain.

Figure ***11*** shows that within this 2020 RES+ scenario the number of hours during which non-dispatchable generation (must-run, wind and solar) covers domestic load increases in all countries in which this situation also occurs under the 2020 standard scenario (AT, DE, PT, ES, CH). The situation also occurs in countries which were not impacted under the 2020 standard scenario (GB, IT, NL, and FR for only one hour). It can also be noted that the distribution along the year of these hours is more balanced in Spain and in Portugal than it was in the other scenarios (it can be observed during the mid-season months).

[23] Note that the graduation on the vertical axis of the ten graphs is adapted to the scale of each market.

Figure 10. *Hourly production and load per country, in MW (2020 RES+ scenario, default case)*

Figure 11. ***Number of hours, per country and per month, with negative residual load (2020 RES+ scenario, default case)***



4 IMPACT OF RES SUPPORT SCHEMES

In this chapter, the impact of the RES support schemes, as currently in place (2013 scenario) and as foreseen in 2020 (2020 standard and RES+ scenarios) are assessed by comparison with default cases where no support schemes are applied. This assessment is performed for the five families of indicators previously introduced:

- Generation mix,
- Costs and profits,
- Market prices,
- Sustainability,
- Cross-border market integration.

4.1 Quantitative evaluation of RES support schemes on the generation mix

4.1.1 Generation mix global indicators

Table ***12*** shows the impact of the studied RES support schemes on the generation mix global indicators, compared to the default cases (no support schemes), for the three scenarios.

Table 12. *Impact of RES SS on the generation mix global indicators (compared to the default cases)*

	2013 scenario		2020 standard scenario		2020 RES+ scenario	
	With current RES SS	*Variation / default case*	With foreseen RES SS	*Variation / default case*	With foreseen RES SS	*Variation / default case*
Generation from RES	444 TWh	*+0.25%*	571 TWh	*+0.18%*	676 TWh	*+0.29%*
Wind	73 TWh	*+1.78%*	153 TWh	*+0.72%*	210 TWh	*+0.88%*
Solar	50 TWh	*+0.61%*	79 TWh	*+0.26%*	113 TWh	*+0.59%*
Other RES	321 TWh	*-0.1%*	340 TWh	*-0.1%*	354 TWh	*-0.2%*
Generation from nuclear	386 TWh	*+0.07%*	398 TWh	*+0.01%*	335 TWh	*-0.08%*
Generation from fossil fuels	371 TWh	*-0.16%*	290 TWh	*-0.13%*	246 TWh	*-0.05%*
Coal	320 TWh	*-0.14%*	233 TWh	*-0.14%*	134 TWh	*-0.05%*
Gas	51 TWh	*-0.27%*	55 TWh	*-0.06%*	112 TWh	*-0.06%*
Oil[24]	0.016 TWh	*-5.91%*	1.6 TWh	*-0.0001%*	0.002 TWh	*0%*
Total load	1,201 TWh	*+0.07%*	1258 TWh	*+0.06%*	1,256 TWh	*+0.12%*
Score for negative residual load	251 h	*-0.48%*	159 h	*+2.65%*	462 h	*+1.14%*

[24] As already observed in the previous chapter, figures for oil generation are not significant since only the day-ahead module of OPTIMATE is considered for the studies: in real-life, oil units significantly intervene in shorter-term markets such as intraday and balancing.

It can be observed that RES support schemes have very little impact on the generation mix: even if support schemes impact the way renewable generation is offered on the market, they hardly have an impact on the merit order curve, and, consequently, on the generation mix.

However, a closer look to detailed indicators shows that there is a more significant impact of support schemes on:

- wind and solar generation in Portugal and Spain,
- coal generation in France.

These two impacts are analysed within the next sections.

4.1.2 Focus on the wind and solar production in Portugal and Spain

Table ***13*** shows the impact of RES support schemes on wind and solar generation in Portugal and Spain, and the number of hours with negative residual load in these countries. This impact is significant within the three scenarios.

Table 13. *Impact of RES SS on wind and solar production in Portugal and Spain*

	2013 scenario		2020 standard scenario		2020 RES+ scenario	
	With current RES SS	***Variation / default case***	**With foreseen RES SS**	***Variation / default case***	**With foreseen RES SS**	***Variation / default case***
Wind production						
Portugal	3.7 TWh	*+7.0%*	5.4 TWh	*+5.9%*	6.1 TWh	*+9.0%*
Spain	18.1 TWh	*+6.0%*	23.9 TWh	*+3.1%*	26.3 TWh	*+4.3%*
Solar production						
Portugal	0.31 TWh	*+2.1%*	1.4 TWh	*+1.2%*	2.4 TWh	*+3.2%*
Spain	4.2 TWh	*+3.1%*	13.3 TWh	*+0.9%*	20,3 TWh	*+1.8%*
Number of hours with negative residual load						
Portugal	652 h	*+0.5%*	1,083 h	*+1.9%*	1,638 h	*+0.8%*
Spain	279 h	*-5.1%*	526 h	*+4.4%*	1,135 h	*+3.0%*

Table ***13*** must be considered in relation with Figure ***5***, Figure ***8*** and Figure ***11*** regarding the number of hours during which domestic load is covered by non-dispatchable generation (in other words, the number of hours during which the so-called “residual load” is negative).

In Portugal and Spain indeed, during a significant number of hours, generation from must-run, wind and solar sources is high enough to cover the domestic load and the exports towards neighbouring countries.

- With no support schemes, generation from wind, solar and must-run is offered on the market at a zero price: when it is so high (and load is so low) that it needs to be curtailed, the curtailment is performed uniformly on these three types of energy sources.

- By contrast, when RES support schemes are applied for wind and solar generation, these are offered on the market at a negative price[25], while must-run is still offered at a zero price. By consequence, when a curtailment needs to be performed, the merit order implies that only must-run is curtailed. In that case, wind and solar generation are higher compared to the situation with no support schemes.

In our case, this phenomenon has a bigger impact on the wind production than on the solar production, because during daylight (when solar units produce) load is in general high and residual load is not often negative during these hours.

RES curtailment occur in real life in Spain, as described in the Market4RES deliverable "Report on the empirical case study analyses emphasising the challenges in the very short-term, short-term and long-term electricity markets in Europe with high shares of RES-E penetration" (see [10], case study 3).

It could be questioned why support schemes do not impact the wind and solar production in Austria since this country is also significantly concerned with negative residual load (within the 2013 and 2020 RES+ scenarios). It is actually related to the exporting capacities of Austria, which are very high compared to the ones of Portugal and Spain. In fact, Austria and Germany form a single price area: between these two countries, there is no limitation of cross-border exchanges. Therefore, Austria can more easily export its non-dispatchable generation in excess and avoid curtailing it, by contrast with Spain and Portugal which form an electric peninsula with limited cross-border capacities.

4.1.3 Focus on the coal production in France

Table ***14*** shows how RES support schemes impact the production from each type of energy source. Within the first two scenarios, with RES support schemes, some coal generation (and to a lower extent, some gas generation) is replaced by nuclear generation: around 450 GWh for the 2013 scenario, 300 GWh for the 2020 standard scenario.

---

[25] Negative prices are actually not allowed on the Iberian market, while OPTIMATE has been configured for Market4RES with a minimum allowed price at -500 €/MWh. However, the existence of Feed-in-Tariffs with priority dispatch, presently implemented in Portugal and Spain, can be modelled as if the supported generation was offered at a negative price.

Table 14. *Impact of RES SS on the generation mix in France (in GWh)*

	2013			2020 standard			2020 RES+		
	Default Case	With current RES SS	*variation*	Default Case	With foreseen RES SS	*variation*	Default Case	With foreseen RES SS	*variation*
Must run	37,419	37,427	*+0.02%*	39,014	39,005	*-0.02%*	40,427	40,405	*-0.05%*
Wind	5,322	5,323	*+0.02%*	19,640	19,686	*+0.24%*	31,143	31,235	*+0.29%*
Solar	3,722	3,724	*+0.04%*	8,955	8,998	*+0.48%*	14,040	14,099	*+0.42%*
Nuclear	**228,219**	**228,673**	***+0.20%***	**238,379**	**238,682**	***+0.13%***	**221,970**	**221,884**	***-0.04%***
Coal	**7,963**	**7,519**	***-5.57%***	**3,934**	**3,625**	***-7.84%***	**371**	**364**	***-1.74%***
Gas	**561**	**552**	***-1.52%***	**1,005**	**989**	***-1.57%***	**1,445**	**1,429**	***-1.09%***
Hydro dams	6,687	6,683	*-0.07%*	6,357	6,353	*-0.07%*	6,195	6,199	*+0.06%*
Total production	289,893	289,893	*+0.00%*	317,274	317,330	*+0.02%*	315,582	315,606	*+0.01%*
Consumption	247,150	247,201	*+0.02%*	254,545	254,634	*+0.03%*	254,115	254,288	*+0.07%*
Exports	42,743	42,692	*-0.12%*	62,729	62,696	*-0.05%*	61,468	61,318	*-0.24%*

This needs to be further investigated:
A detailed analysis will be carried out and results will be included in D4.3.

4.2 Quantitative evaluation of RES support schemes on costs and profits

4.2.1 Costs and profits' global indicators

The following global indicators are monitored to assess the impact of RES support schemes on costs and profits:

- The **total generation costs** are the sum of two components:
  - The **thermal generation costs**, which are the sum, over all hours and all market areas, of the short-term costs for generating electricity at each hour and within each market. Long-term, fixed costs (investments) are not considered. For a given set of installed capacities, RES generation has therefore no impact on this indicator. For thermal generation[26], short-term generation costs include fuel, CO_2 and start-up costs.
  - The **RES subsidies** which are the sum, over all hours and all market areas, of the revenues earned by wind and solar producers through RES support schemes (feed-in-tariff and/or price premium)[27].

[26] Thermal « must-run » generation units such as CHPs are not taken into account in the calculation of generation costs, because in that case electricity is considered as a secondary product of heat generation.
[27] To be fair regarding the global cost of the FiT, the market value of the corresponding generation is deducted from the gross FiT subsidies, as explained on the next pages.

- The **producer revenue** is the sum, over all hours and all market areas, of the product of the hourly volume sold by each producer by the market price. For **wind** and **solar** producers, the revenues from the RES support schemes (not applicable within the default case) are also taken into account. For **thermal** producers (nuclear, coal, gas and oil), the difference between the revenues and the generation costs corresponds to the surplus of these producers.
- The **producer revenue per MWh generated** is, for each type of producers, the average value, over all hours and all market areas, of the previous indicator (producer revenues in M€) divided by the volume of electricity generated by this type of producers.

Table ***15*** shows the impact of the studied RES support schemes on the costs and profits' global indicators, compared to the default cases (no support schemes), for the three scenarios.

It is obvious that RES support schemes have the most significant impact on the indicators of this family. The wind and solar producers' revenues are logically very much impacted by the RES subsidies.

Table 15. ***Impact of RES SS on the costs and profits' global indicators (compared to the default cases)***

	2013 scenario	2020 standard scenario	2020 RES+ scenario
	With current RES SS	With foreseen RES SS	With foreseen RES SS
Total generation costs	+104%	+112%	+128%
Thermal generation costs	+0.2%	-0.02%	-0.08%
RES subsidies	+17,045 M€	+20,588 M€	+25,665 M€
Total producer revenues	+38%	+34%	+29%
Wind	+255%	+126%	+98%
Solar	+605%	+327%	+245%
Other RES	-5%	-3%	-4%
Thermal	+0.46%	-0.02%	-0.33%
Producer revenues per MWh generated	+31%	+30%	+26%
Wind	+242%	+179%	+140%
Solar	+599%	+421%	+367%
Other RES	-5%	-3%	-3%
Thermal	+0.86 %	+0.09%	-0.18%
Consumer surplus	+0.09%	+0.01%	+0.01%

4.2.2 Focus on the generation costs and RES subsidies

Figure 12 allows comparing the thermal generation costs to the total amount of RES subsidies (Feed-in-Tariffs and Price Premiums, Solar and Wind), for the three scenarios, over the 6-month period and for all countries included in the geographical scope under consideration.

Figure 13 shows how the RES subsidies are distributed between wind and solar capacities on the one hand, Feed-in-Tariffs and Price Premium on the other hand.

Figure 12. *Thermal generation costs and RES subsidies over 6 months*

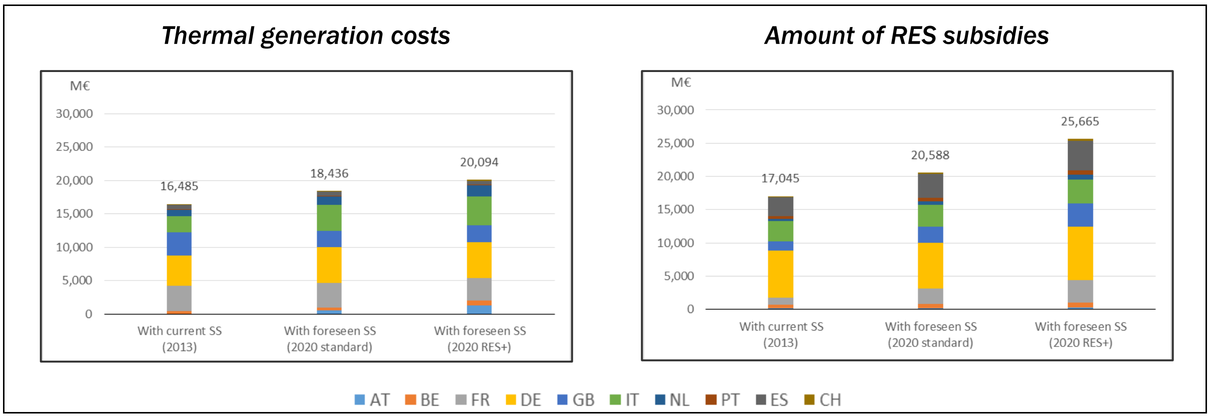
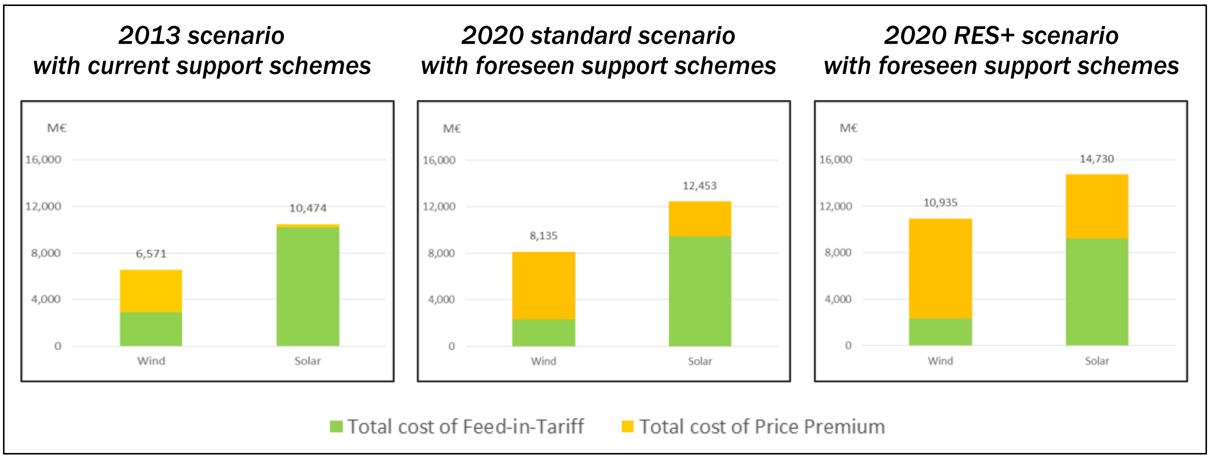


Figure 13. *Amount of (net) RES subsidies per type of support scheme, over 6 months*



The total cost of Feed-in-Tariff (FiT) has been calculated as the difference between the "gross FiT subsidies" and the market value of the corresponding generation:

- By construction, the gross FiT subsidies are stable from 2013 to 2020, because we have considered that the RES capacities currently supported through Feed-in-Tariffs would still be at 2020, since FiT contracts generally run for years[28].
- To be fair regarding the global cost of the FiT, the market value of the corresponding generation must be deducted from the gross FiT subsidies. In other words, the party that pays out the FiT to the RES generators, also collects revenues from their production (either directly on the market, or indirectly through consumers served by this production).

[28] However, this hypothesis may be too conservative compared to reality since the FiT contracts of RES units installed in the 90's or the beginning of the 2000's may be terminated at 2020, and some units may be decommissioned.

Within all scenarios, the total RES subsidies outweigh the thermal generation costs incurred in the 11 countries by several billions of euros over the 6-month period.

It can also be observed that both thermal generation costs and RES subsidies would constantly grow. It must however be noted that the 2020 scenarios have been built under the hypothesis of an increase in fuel and CO_2 prices (see [1], Table 18). This explains, at least partly, the increase in thermal generation costs.

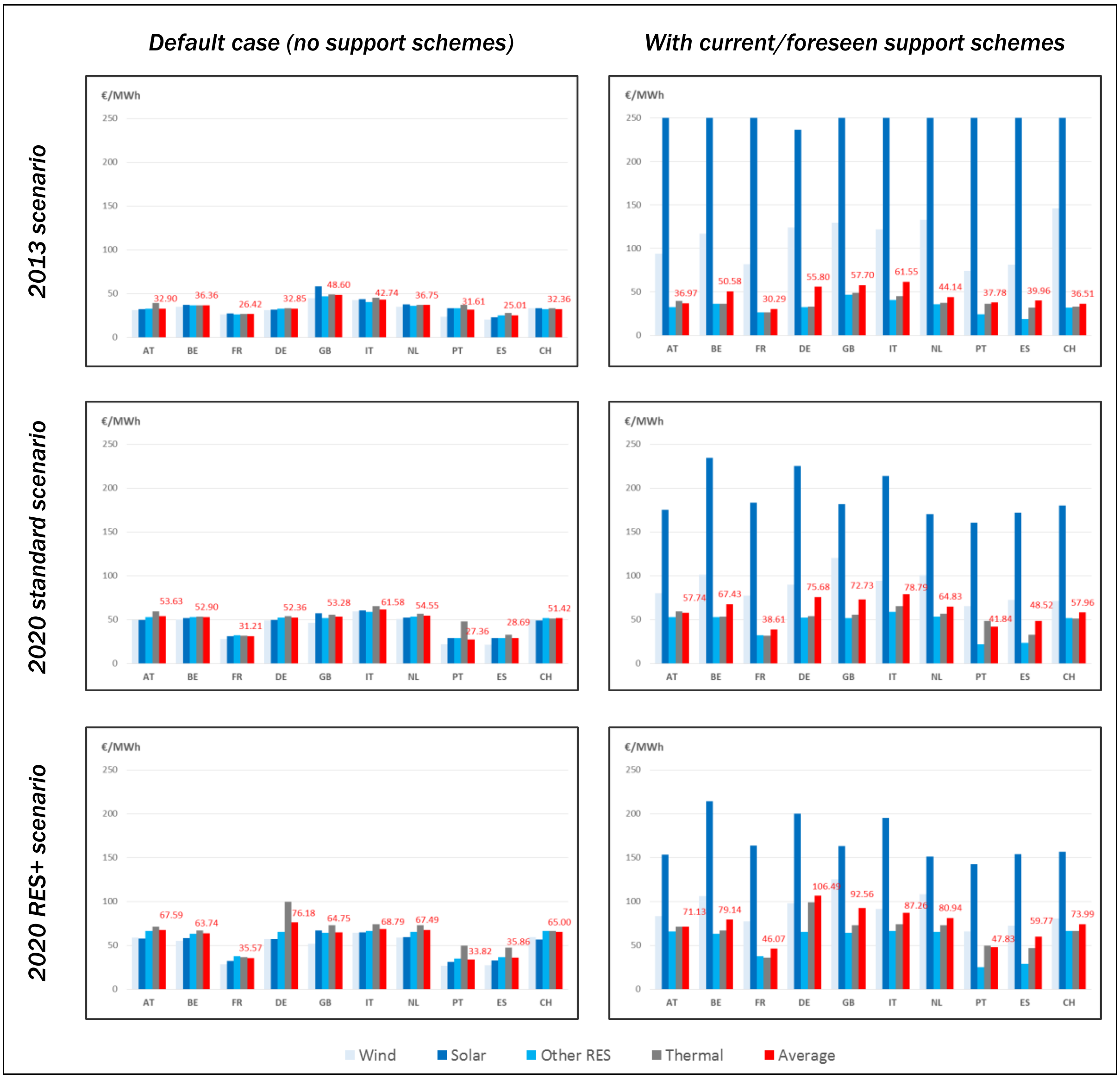
4.2.3 Focus on producers' revenues per type of energy source and per country

Figure 14 shows the average revenues of the different type of producers per MWh generated.

Within the default cases (no support schemes applied – left-hand column in ***Figure 14***), the revenues of each type of producers per MWh generated are quite close to each other: they are indeed related to market prices only. They are however not exactly at the same level, since some generation sources correspond in general to peak hours (with high prices) while others are baseload. It can be observed that with a growing penetration of RES (from the 2013 scenario to the 2020 RES+ scenario), the revenues from the market of thermal producers become higher than the ones of RES producers, because thermal units would decreasingly run during off-peak hours.

Regarding the impact of support schemes (right-hand column in ***Figure 14***), the most striking impact concerns the revenues of solar producers: within the 2013 scenario, they would be aligned at 250 €/MWh, which corresponds to the solar FiT uniformly applied to simplify the situation (see section 2.5.1, Table ***3***): in real life, the revenues of solar producers within the different countries would probably be much more diverse. In general, with a growing RES penetration and a decreasing support, the revenues of wind and solar producers would become closer to the average producers revenues.

Figure 14. ***Average producers revenues per MWh generated, per type of energy source and per country (2013 scenario)***



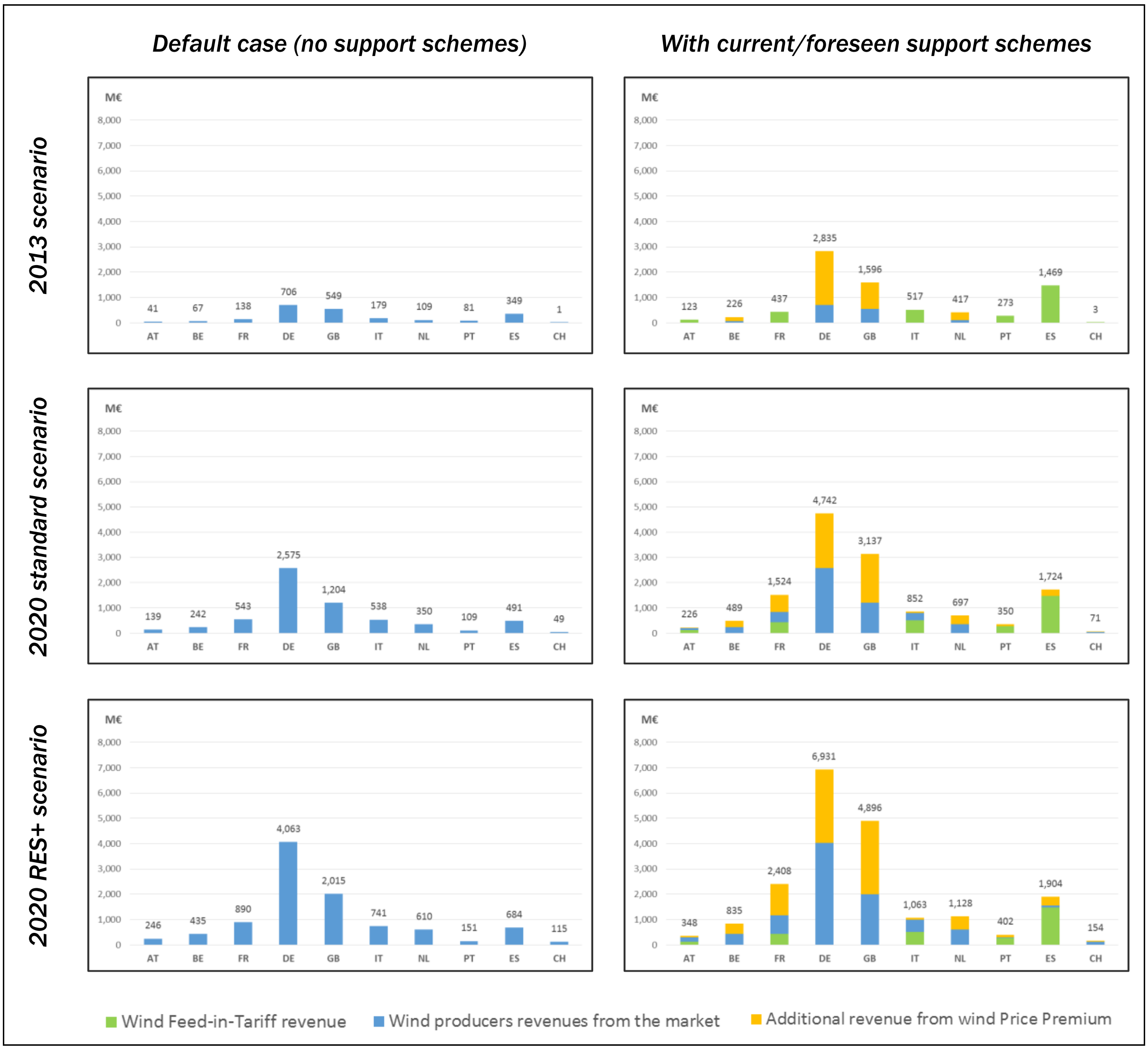
4.2.4 Focus on the breakdown of wind producers' revenues per country

Figure 15 shows the revenues of wind producers per country, over 6 months.

The left-hand column of ***Figure 15*** Figure 15 shows these revenues within the default case for each scenario (no support schemes). For all the countries studied, revenues from the market of wind producers increase with the level of RES penetration (from the 2013 scenario to the 2020 standard scenario and the 2020 RES+ scenario).

The right-hand column of ***Figure 15*** shows how revenues of wind producers are built upon the revenues from the support schemes and, where price premium (PP) is applied at least partly, the revenues from the market. Regarding Portugal and Spain, it can be observed that the main source of revenues of wind producers at 2020 would remain the feed-in-tariffs.

Figure 15. ***Wind producers' revenues per country, over 6 months***

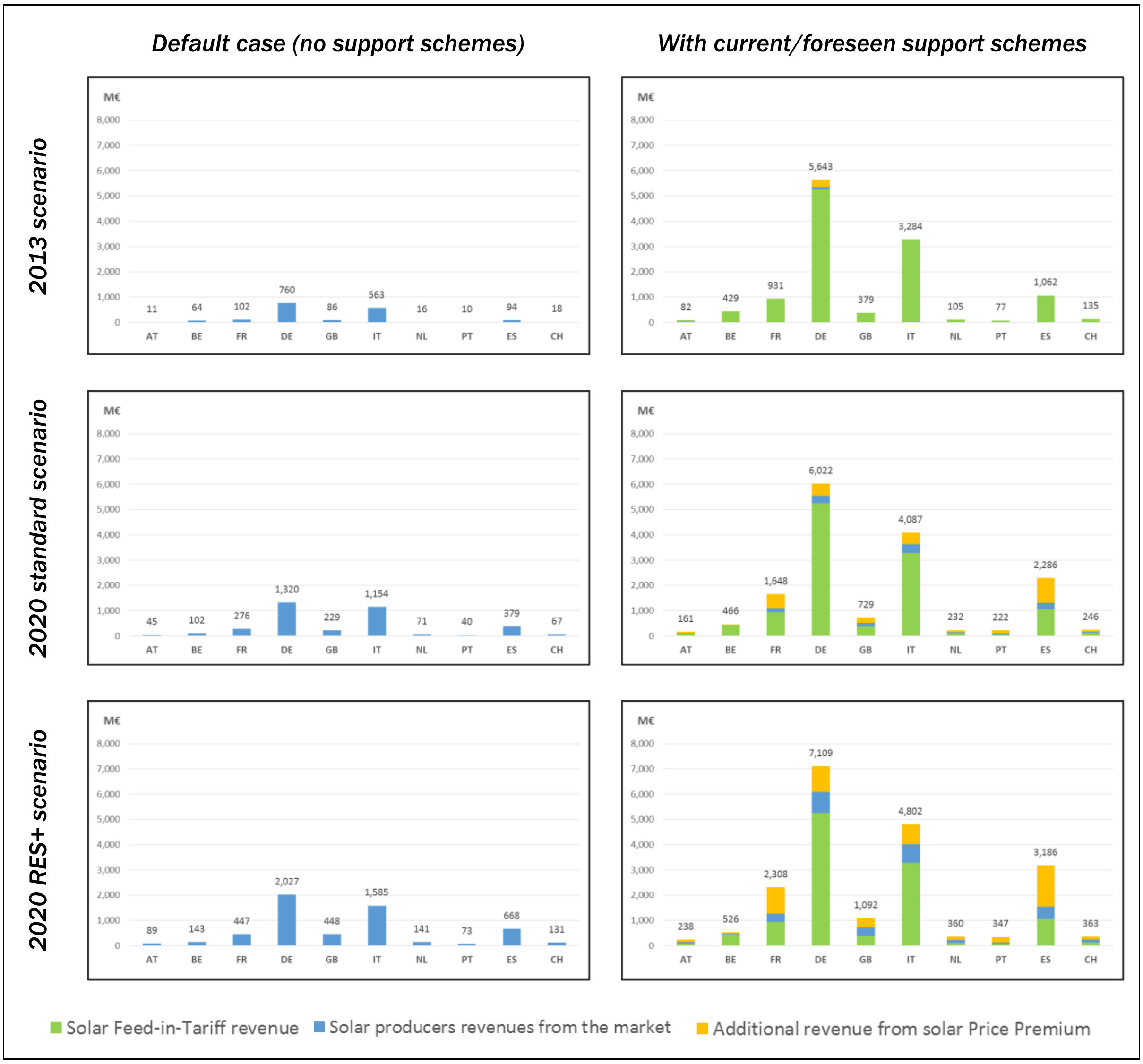


4.2.5 Focus on the breakdown of solar producers' revenues per country

Figure 16 shows the revenues of solar producers per country, over 6 months.

In some countries (BE, DE, IT), FIT would remain the main source of revenue of solar producers at 2020, included within the 2020 RES+ scenario.

Figure 16. *Solar producers' revenues per country, over 6 months*



4.3 Quantitative evaluation of RES support schemes on market prices

4.3.1 Market prices' global indicators

The following global indicators are monitored to assess the impact of RES support schemes on market prices:

- The **average market price** is the weighted average, over all hours and all market areas, of the hourly prices. The weights are the volumes of electricity traded within each market.
- The **occurrence of negative prices** is the sum of the number of hours during which negative prices occur of all market areas.

- The **average daily spread** is a measure of the magnitude of the prices within each day: it is the average, over all days and all market areas, of the difference between the maximum price of the day within a given market area and the minimum price of the same day within the same market area. For example, if for a given day and a given market area the hourly prices lie between 25 €/MWh and 45 €/MWh, then the daily spread is 20 €/MWh.

Table ***16*** shows the impact of the studied RES support schemes on the market prices' global indicators, compared to the default cases (no support schemes), for the three scenarios.

Table 16. ***Impact of RES SS on the market prices' global indicators (compared to the default cases)***

	2013 scenario	2020 standard scenario	2020 RES+ scenario
	With current RES SS	With foreseen RES SS	With foreseen RES SS
Average market price	-3%	-2%	-2%
Occurrence of negative prices	+701	+684	+1,356
Average daily spread	+75%	+18%	+11%

The impact of RES support schemes on average market prices is quite stable over the three scenarios: compared to the default cases, support schemes cause a decrease in average market prices of 2 to 3%. On the other hand, support schemes are responsible for a significant occurrence of negative prices: from around 700 occurrences within the 2013 and 2020 standard scenarios, and the double within the 2020 RES+ scenario. The average daily spread (magnitude of the market prices within a day) is also very much impacted by RES support schemes, mainly within the 2013 scenario.

4.3.2 Focus on the distribution of market prices and occurrence of negative prices

Figure 17 shows the distribution of prices within each market area[29].

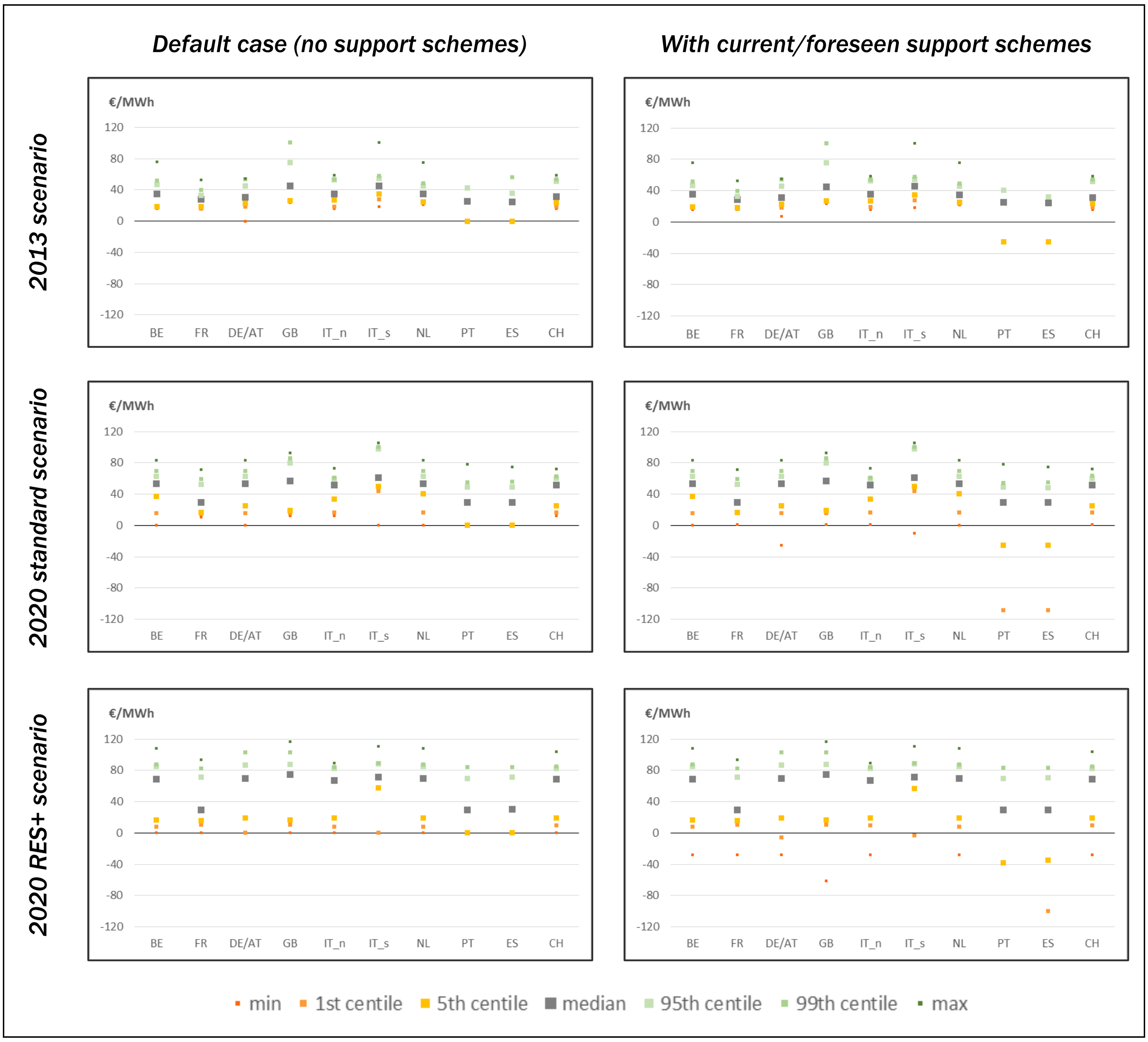
Within all scenarios, it can be observed that RES support schemes are responsible for the occurrence of negative prices (within the default cases, minimum prices never go below zero).

Within the 2013 scenario, negative prices occur only in Spain and Portugal. As already explained in section 4.1.2, in these two countries, there are many hours during which generation from must-run, wind and solar sources is high enough to cover the domestic load (including exports). When RES support schemes are applied for wind and solar generation, these are offered (within the OPTIMATE model) at a negative price, which causes the negative market prices observed within ***Figure 17***. In real-life, negative prices are actually not allowed on the Iberian market, while OPTIMATE has been configured for Market4RES with a minimum allowed price at -500 €/MWh

[29] All graphs have the same scale, from -120€/MWh to +120 €/MWh. In some cases, the prices considered are out of scale.

applied within all market areas (as it is the case in real life for the CWE markets). Actually, in Spain, RES curtailments need to be applied to address the issue (see [10], case study 3).

Figure 17. ***Price distribution per market area: minimum price, 1st and 5th price centiles, median price, 95th and 99th price centiles, and maximum price***

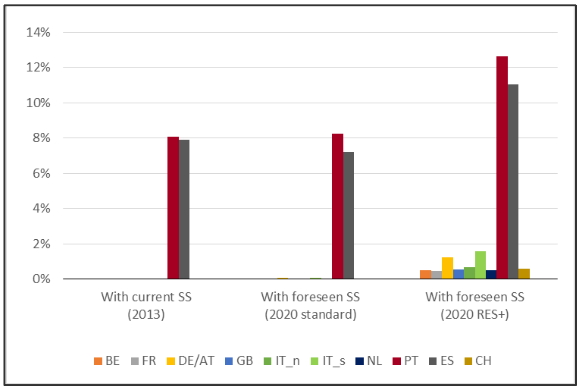


In real life, negative prices also occur at least in Germany, France, Belgium and the Netherlands (see [10], case study 2). The occurrence of negative prices highly depends on the load and RES profiles, since negative prices correspond in general to hours combining very low load and high RES penetration. The load and RES profiles embedded within OPTIMATE seem not to include such situations for the 2013 scenario – except for Portugal and Spain.

Within the 2020 standard scenario, negative prices would also occur in Germany/Austria, and surprisingly in Southern Italy, but infrequently (during less than 1% of the time: the first centile of prices would remain positive). In other market areas (FR, GB, IT_n, CH), support schemes would make the minimum market price hit zero while it would be positive with no support schemes.

Within the 2020 RES+ scenario, even with no support schemes the price within every market area would hit zero at least one time (BE, FR, GB, IT_n, NL, CH), during at least 1% of the time (DE/AT, IT_s) or at least 5% of the time (PT, ES). With the foreseen support schemes, negative prices would occur in every market areas, as shown by ***Figure 18***.

Figure 18. ***Occurrence of negative prices when RES support schemes are applied***



4.3.3 Focus on the average daily spread

The average daily spread (magnitude of the market prices within a day) is significantly impacted by RES support schemes, mainly within the 2013 scenario. Actually, it is due to two reasons:

- The existence of negative prices due to RES support schemes, mainly in Portugal in Spain, as presented in the previous section;
- Price peaks in Spain.

The existence of these price peaks needs to be further investigated:
A detailed analysis will be carried out and results will be included in D4.3.

4.4 Quantitative evaluation of RES support schemes on sustainability

4.4.1 Sustainability global indicators

The following global indicators are monitored to assess the impact of RES support schemes on the electricity system sustainability:

- The **RES share** is the sum of the energy generated from RES sources (wind, solar, must-run and hydro dams) over all hours and all countries, divided by the total load. Since it counts the thermal must-run, which does not count only purely renewable sources, it is higher than the figures usually published. What is important here is not the absolute value of this figure but the relative impact that the market design options will have on it.

- The **total CO_2 emissions** are the sum over all hours and all countries of the CO_2 emissions observed at each hour and within each country.
- The **average CO_2 emissions compared to the energy generated** is the average, over all countries, of the total CO_2 emissions within each country divided by the total energy generated within the same country.

Table ***17*** shows the impact of the studied RES support schemes on the sustainability global indicators, compared to the default cases (no support schemes), for the three scenarios.

Table 17. ***Impact of RES SS on the sustainability global indicators (compared to the default cases)***

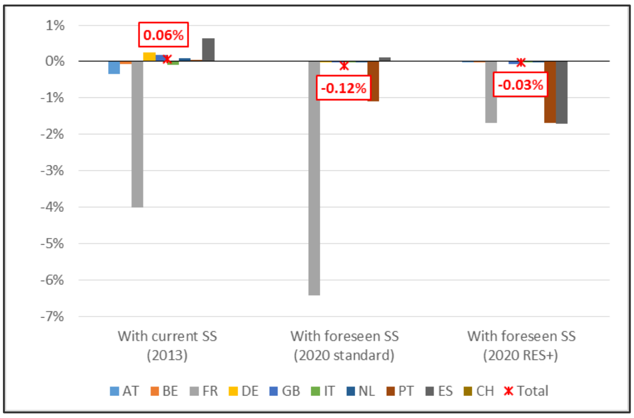
	2013 scenario	2020 standard scenario	2020 RES+ scenario
	With current RES SS	With foreseen RES SS	With foreseen RES SS
RES share	+0.2%	+0.1%	+0.2%
Wind	+1.7%	+0.7%	+0.8%
Solar	+0.5%	+0.2%	+0.5%
Total CO_2 emissions	+0.06%	-0.12%	-0.03%
Average CO_2 emissions compared to energy generated	+0.02%	-0.09%	-0.12%

The little impact of RES support schemes on sustainability indicators is a direct consequence of their little impact on the generation mix (see section 4.1). However, a closer look to indicators detailed per country shows that there is a more significant impact of support schemes on CO_2 emissions in France. This is analysed in the next section.

4.4.2 Focus on the CO_2 emissions in France

Figure 19 shows how support schemes impact the CO_2 emissions per country.

Figure 19. ***Variation in CO_2 emissions compared to default cases, per country***



The biggest impact concerns France, within the 2013 and 2020 standard scenarios. It is a direct consequence of the switch between coal and nuclear production (between 300 and 450 GWh over 6 months), as described in section 4.1.3.

This will be further investigated in D4.3.

4.5 Quantitative evaluation of RES support schemes on cross-border market integration

4.5.1 Cross-border market integration global indicators

The following global indicators are monitored to assess the impact of RES support schemes on cross-border market integration:

- The **cumulated average net cross-border flow** is the sum, over all borders, of the absolute average value, over all hours, of the net cross-border flow. This indicator is a measure of the intensity of cross-border flows during the period studied.
- The **interconnection utilisation score**[30] is the average, over all borders, of the average ratio over all hours between the net cross-border flow and the net transfer capacity (NTC) in the direction of the net flow. It is a measure of the saturation of the existing cross-border infrastructures.
- The **price convergence score**[31] is the average, over all borders, of the proportion of time during which there is no price differential at the border. It is a measure of market integration.
- The **average price differential magnitude** is the average value, over all hours, of the difference between the maximum price reached at a given hour, whatever the corresponding market area is, and the minimum price reached at the same hour. In other words, it is the average hourly spread between the prices of the most expensive and the cheapest market. It is another measure of market integration, providing a quantification of the extent to which prices are diverging within the studied geographical scope.
- The **total congestion revenue** is the sum, over all hours and all borders, of the hourly net cross-border flow realized at each border multiplied by the price differential at this border.

Table 18 shows the impact of the studied RES support schemes on the cross-border market integration global indicators, compared to the default cases (no support schemes), for the three scenarios.

There is a significant impact of RES support schemes on the price differentials and on the congestion revenue, logically derived from the impact on market prices in general.

On the other hand, the little impact of RES support schemes on cross-border flows and interconnection utilisation score is, again, a direct consequence of their little impact on the generation mix (see section 4.1). However, there are significant differences border per border.

These different aspects are analysed within the next sections.

[30] It is expressed as a score out of 100 rather than a percentage, because averaging percentages would not be mathematically correct.
[31] Same comment.

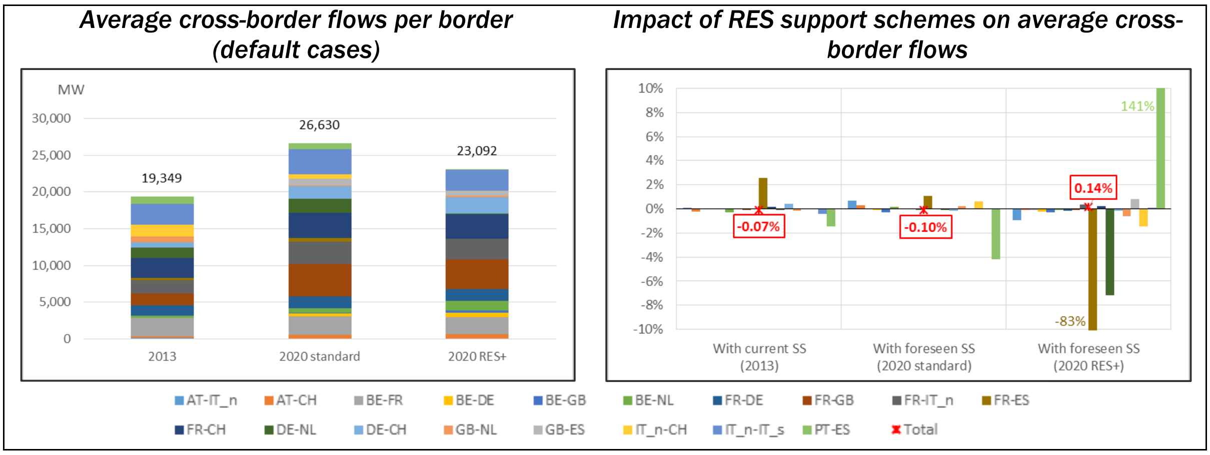
Table 18. *Impact of RES SS on the cross-border market integration global indicators (compared to the default cases)*

	2013 scenario	2020 standard scenario	2020 RES+ scenario
	With current RES SS	With foreseen RES SS	With foreseen RES SS
Cumulated average net cross-border flow	-0.07%	-0.10%	+0.14%
Interconnection utilisation score	+0.14%	+0.09%	+0.38%
Price convergence score	-0.36%	-0.09%	-0.87%
Average price differential magnitude	+46%	+14%	+16%
Total congestion revenue	+7.6%	+6.9%	+7.7%

4.5.2 Focus on the cross-border flows per border

The cumulated cross-border flows and the impact of RES support schemes on these default cross-border flows per border are presented in ***Figure 20***.

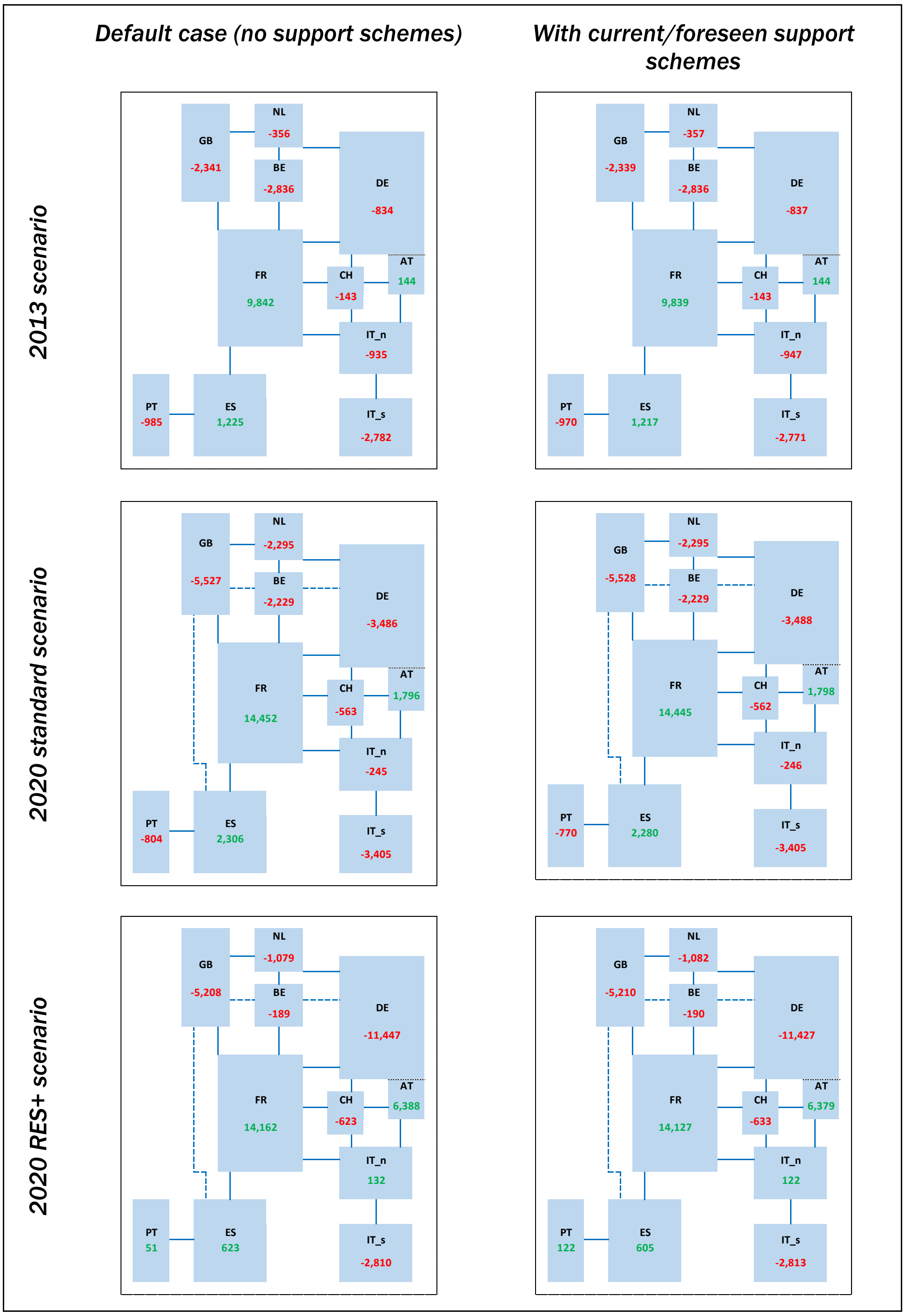
Figure 20. ***Average absolute cross-border flows per border (default cases), and impact of RES support schemes on these flows***



The main impacts of RES support schemes on cross-border flows concern the Iberian Peninsula (border between Portugal and Spain, France and Spain, and at 2020 Great-Britain and Spain).

However, these impacts are not high enough to change the direction of the flows at these borders, as illustrated by ***Figure 21*** which shows that the "exporting status" of each area is unchanged (green = average exports in MW, red = average imports in MW).

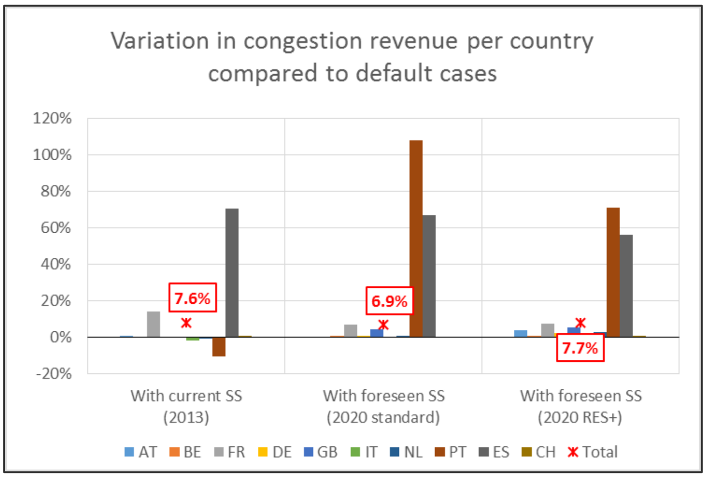
Figure 21. *Average electricity balance per area, over 6 months*



4.5.3 Focus on the congestion revenue per border

The impact of RES support schemes both on the price differentials and on the cross-border power flows at the Iberian borders makes logically the congestion revenue within this area impacted by RES support schemes, as shown by *Figure 22*. This includes Portugal, Spain, France, and as from 2020 Great-Britain. In particular, RES support schemes cause the doubling of the congestion revenue in Portugal.

Figure 22. ***Impact of RES support schemes on the congestion revenue per country***



5 COMPARISON OF DIFFERENT DEMAND FLEXIBILITY LEVELS

5.1 Quantitative evaluation of demand flexibility development on the generation mix

5.1.1 Generation mix global indicators

Table ***19*** shows the impact of the studied demand flexibility options on the generation mix global indicators, compared to the default cases (no demand flexibility), for the three scenarios.

Table 19. ***Impact of demand flexibility development on the generation mix global indicators (compared to the default cases)***

	2013 scenario		2020 standard scenario		2020 RES+ scenario	
	MidFlex *(Variation / default case)*	**HighFlex** *(Variation / default case)*	**MidFlex** *(Variation / default case)*	**HighFlex** *(Variation / default case)*	**MidFlex** *(Variation / default case)*	**HighFlex** *(Variation / default case)*
Generation from RES	**439 TWh** *(-0.8%)*	**435 TWh** *(-1.7%)*	**563 TWh** *(-1.3%)*	**556 TWh** *(-2.5%)*	**668 TWh** *(-1.0%)*	**661 TWh** *(-2.0%)*
Wind	**71 TWh** *(-0.7%)*	**70 TWh** *(-1.6%)*	**151 TWh** *(-0.3%)*	**150 TWh** *(-0.8%)*	**207 TWh** *(-0.5%)*	**206 TWh** *(-1.1%)*
Solar	**49 TWh** *(-0.1%)*	**49 TWh** *(-0.2%)*	**79 TWh** *(-0.2%)*	**79 TWh** *(-0.4%)*	**112 TWh** *(-0.3%)*	**111 TWh** *(-0.8%)*
Other RES	**319 TWh** *(-0.9%)*	**316 TWh** *(-1.9%)*	**333 TWh** *(-1.9%)*	**327 TWh** *(-3.7%)*	**349 TWh** *(-1.5%)*	**344 TWh** *(-2.9%)*
Generation from nuclear	**376 TWh** *(-2.6%)*	**363 TWh** *(-5.8%)*	**387 TWh** *(-2.7%)*	**374 TWh** *(-6%)*	**321** *(-4.1%)*	**306 TWh** *(-9%)*
Generation from fossil fuels	**326 TWh** *(-12%)*	**283 TWh** *(-24%)*	**245 TWh** *(-15.9%)*	**202 TWh** *(-30%)*	**206 TWh** *(-16.2%)*	**169 TWh** *(-31%)*
Coal	**287 TWh** *(-11%)*	**253 TWh** *(-21%)*	**204** *(-12.6%)*	**173 TWh** *(-26%)*	**116 TWh** *(-13.0%)*	**99 TWh** *(-26%)*
Gas	**39 TWh** *(-23%)*	**30 TWh** *(-40%)*	**40 TWh** *(-28.3%)*	**29 TWh** *(-47%)*	**90 TWh** *(-20.0%)*	**70 TWh** *(-37%)*
Oil	**0.001 TWh** *(-96%)*	**0**	**0.67 TWh** *(-56.9%)*	**0.04 TWh** *(-97%)*	**0.001 TWh** *(-50%)*	**0**
Total load	**1,141** *(-4.9%)*	**1,082 TWh** *(-9.8%)*	**1,194 TWh** *(-5.0%)*	**1,132 TWh** *(-10%)*	**1,195 TWh** *(-4.8%)*	**1,135 TWh** *(-9.5%)*
Score for negative residual load	**413 h** *(+64%)*	**480 h** *(+90%)*	**349 h** *(+25%)*	**430 h** *(+54%)*	**547 h** *(+20%)*	**643 h** *(+41%)*

5.1.2 Detailed analysis of generation mix indicators

The detailed analysis will be carried out later on and results will be included in D4.3.

5.2 Quantitative evaluation of demand flexibility development on costs and profits

5.2.1 Costs and profits global indicators

Table *20* shows the impact of the studied demand flexibility options on the costs and profits' global indicators, compared to the default cases (no demand flexibility), for the three scenarios.

Table 20. *Impact of demand flexibility development on the costs and profits' global indicators (compared to the default cases)*

	2013 scenario		2020 standard scenario		2020 RES+ scenario	
	MidFlex	HighFlex	MidFlex	HighFlex	MidFlex	HighFlex
Thermal generation costs	-10%	-20%	-14%	-25%	-15%	-28%
Total producer revenues	-13%	-23%	-13%	-24%	-16%	-27%
Wind	-10%	-17%	-8%	-16%	-40%	-48%
Solar	-8%	-14%	-8%	-15%	-8%	-16%
Other RES	-10%	-17%	-9%	-18%	-10%	-18%
Thermal	-15%	-27%	-16%	-29%	-15%	-29%
Producer revenues per MWh generated	-10%	-17%	-7%	-14%	-10%	-17%
Wind	-9%	-15%	-7%	-15%	-17%	-25%
Solar	-10%	-16%	-8%	-15%	-8%	-16%
Other RES	-11%	-17%	-7%	-14%	-8%	-16%
Thermal	-9%	-15%	-7%	-16%	-5%	-9%
Consumer surplus	-0.9%	-4.1%	-0.9%	-4.1%	-1%	-3.8%

5.2.2 Detailed analysis of costs and profits indicators

The detailed analysis will be carried out later on and results will be included in D4.3.

5.3 Quantitative evaluation of demand flexibility development on market prices

5.3.1 Market prices' global indicators

Table *21* shows the impact of the studied demand flexibility options on the market prices' global indicators, compared to the default cases (no demand flexibility), for the three scenarios.

Table 21. *Impact of demand flexibility development on the market prices' global indicators (compared to the default cases)*

	2013 scenario		2020 standard scenario		2020 RES+ scenario	
	MidFlex	HighFlex	MidFlex	HighFlex	MidFlex	HighFlex
Average market price	-8%	-14%	-7%	-14%	-8%	-15%
Occurrence of negative prices	0	0	0	0	0	0
Average daily spread	-39%	-47%	-30%	-33%	-9%	-20%

5.3.2 Detailed analysis of market prices indicators

The detailed analysis will be carried out later on and results will be included in D4.3.

5.4 Quantitative evaluation of demand flexibility development on sustainability

5.4.1 Sustainability global indicators

Table ***22*** shows the impact of the studied demand flexibility options on the sustainability global indicators, compared to the default cases (no demand flexibility), for the three scenarios.

Table 22. ***Impact of demand flexibility development on the sustainability global indicators (compared to the default cases)***

	2013 scenario		2020 standard scenario		2020 RES+ scenario	
	MidFlex	HighFlex	MidFlex	HighFlex	MidFlex	HighFlex
RES share	+4%	+9%	+4%	+8%	+4%	+8%
Wind	+4%	+9%	+5%	+10%	+5%	+9%
Solar	+5%	+9%	+5%	+11%	+5%	+10%
Total CO_2 emissions	-11%	-22%	-13%	-27%	-14%	-28%
Average CO_2 emissions compared to energy generated	-7%	-14%	-10%	-21%	-10%	-20%

5.4.2 Detailed analysis of sustainability indicators

The detailed analysis will be carried out later on and results will be included in D4.3.

5.5 Quantitative evaluation of demand flexibility development on cross-border market integration

5.5.1 Cross-border market integration global indicators

Table ***23*** shows the impact of the studied demand flexibility options on the cross-border market integration global indicators, compared to the default cases, for the three scenarios.

Table 23. *Impact of demand flexibility development on the cross-border market integration global indicators (compared to the default cases)*

	2013 scenario		2020 standard scenario		2020 RES+ scenario	
	MidFlex	**HighFlex**	**MidFlex**	**HighFlex**	**MidFlex**	**HighFlex**
Cumulated average net cross-border flow	+0.4%	+2%	+1%	+1.5%	+2%	+3%
Interconnection utilisation score	-0.3%	-1.4%	-0.6%	-1.0%	-0.2%	+0.3%
Price convergence score	+1%	+7%	+1%	+3%	-2%	-2%
Average price differential magnitude	-24%	-27%	-8%	-13%	-4%	-8%
Total congestion revenue	-14%	-20%	+1%	-1%	+3%	+3%

5.5.2 Detailed analysis of cross-border market integration indicators

The detailed analysis will be carried out later on and results will be included in D4.3.

6 REFERENCES

[1] Market4RES, deliverable D4.1 "Specifications of the most adequate options for flexibility markets and RES support schemes to be studied in a cross-border context"

[2] Communication from the Commission, "Guidelines on State aid for environmental protection and energy 2014-2020", 2014/C 200/01, 15 July 2014

[3] European Commission, "National Renewable Energy Action Plans (NREAPs)"

[4] ENTSO-E, "Ten Year Network Development Plan (TYNDP) 2014", 31 October 2014

[5] ENTSO-E "Scenario outlook and adequacy forecast 2014-2030" (SO&AF 2014-2030), report and dataset, 2 June 2014

[6] Nuclear Energy Agency "Technical and Economic Aspects of Load Following with Nuclear Power Plants", June 2011

[7] International Energy Agency, Technology Roadmap, Solar Photovoltaic Energy, 2014 edition

[8] International Energy Agency, Technology Roadmap, Wind Energy, 2013 edition

[9] International Energy Agency, "Launch of the IEA Technology Roadmap for Wind Power 2013 Edition", October 2013

[10] Market4RES, deliverable D2.3 "Report on the empirical case study analyses emphasising the challenges in the very short-term, short-term and long-term electricity markets in Europe with high shares of RES-E penetration"