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Assessment of the Contribution of Power-To-Hydrogen to the Flexibility of the Future European Energy System

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Abstract

The European Commission is planning to become climate-neutral by 2050. At the power sector level, this implies turning to renewable sources such as PV panels and wind turbines. However, the intermittence of variable renewable sources is making this task more complex and putting at risk the power sector security of supply. Coupling sectors is a solution to that problem. In particular, power-to-hydrogen is getting more and more attention. This is about using electricity when it is abundant to synthesize hydrogen which can then be used for various purposes. The first goal of this work was to add the power-to-hydrogen sector into the unit-commitment and power dispatch model Dispa-SET. The second objective was to soft-link Dispa-SET with the long-term investment model JRC-EU-TIMES and investigate the benefits of this sector in terms of curtailment, total costs, CO_2 emissions, etc.
The linking between JRC-EU-TIMES and Dispa-SET allowed to observe the importance of power-to-hydrogen in using the extra renewable production and avoiding curtailment. Indeed, 20% of the total renewable production is used to produce hydrogen. This highlights the importance of sector coupling in future energy systems. Moreover, the results showed that hydrogen storage is not seasonal. Finally, the importance of validating system feasibility provided by long-term planing models was demonstrated as TIMES overestimates renewable production by 15% compared to Dispa-SET.

Nomenclature

Abbreviation	**Description**
BATs	Batteries
BEVs	Battery Electric Vehicles
CAPEX	Capital expenses
CCU	Carbon Capture and Utilization
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
DAC	Direct Air Capture
DSM	Demand Side Management
EFOH	Equivalent Full Operating Hours
Elyser	Electrolyser
ESOM	Energy System Optimization Model
FC	Fuel cell
FCEV	Fuel cell Electric Vehicle
HDAM	hydro dams
NTC	Net Transfer Capacity
PEM	Proton Exchange Membrane
P2G	Power to gas
P2L	Power to Liquid
PtL	Power to Liquid
PV	Photo-voltaic
RES	Renewable Energy Sources
SOC	State of Charge
UCM	Unit-Commitment and power dispatch model

Part I

Introduction

Global warming is becoming an increasing concern around the world. Extreme weather events such as forest fires, flash floods and typhoons have been multiplying in recent years. In 2018, temperatures above the Arctic Circle were 5°C above ordinary [1]. The vulnerable communities are the most threatened but climate change is impacting everyone.
This is why the European commission has been building a strong plan aiming at becoming climate-neutral by 2050. The main goal is to keep global warming well below 2°C. At the power sector level, this implies turning to renewable sources such as PV panels and wind turbines.
However, what is called the intermittence of variable renewable sources is making this task more complex and putting at risk the power sector security of supply. Different solutions exist, and it is likely that a mix of them will allow us to succeed in the energy transition. A first key to solve the problem is to increase power transmission capacities across countries. Secondly, more flexibility can be obtained by coupling different energy sectors. It has been widely proven that coupling the power sector with the transport and heating sectors could have a large impact on decreasing emissions ([2], [3]). Increasing storage capacities such as pumped hydro storage and developing demand side management are other key aspects.

Another solution that is attracting more and more attention is the Power-to-Hydrogen sector. It is part of what is called Power-to-X (P2X) which indicates transforming electricity into another energy vector. The concept of Power-to-Hydrogen, also called Power-to-gas (P2G), is about using electricity when the production from renewable sources is high to synthesize hydrogen from water. This hydrogen can then act as a coupling commodity and be consumed in sectors such as transport, heating or industry, or it can be stored and be consumed by fuel cells to produce electricity when needed. Hydrogen can also be combined with CO_2 to produce methane, what is called methanation, or produce synthetic chemicals and fuels (called electro-fuels). This last process is named Power-to-Liquid (PtL or P2L). Those fuels can also be directly produced from CO_2 and electricity, which is more efficient than producing hydrogen in the first place. Many variants of the system described hereabove exist. For instance, the CO_2 needed for P2L could come from Carbon Capture but also from biomass gasification. If electrolysers are considered today as a mature technology, P2L is still in its infancy. In order for power-to-hydrogen to become competitive, its efficiency should be increased.

P2G and P2L have many interesting features. The biggest advantage is that hydrogen can be used in a wide range of applications, which is an interesting flexibility option since future energy systems will be closely interlinked. Hydrogen, methane and liquid fuels are also much easier to store than electricity. Moreover, PtL could be the solution to decarbonize the part of the transport sector that cannot be electrified, such as heavy trucks and planes. Another attracting feature is that with large capacities, electrolysers are able to reduce curtailment.

1. State of the art

One of the first descriptions of P2G dates back to 1999 [4]. Hashimoto et al. presented a circular use of CO_2 thanks to seawater electrolysis with solar energy, methanation and carbon capture in industrial plants [5]. Since then, a growing interest in P2G has led to numerous pilot plants all around the world [6]. The size of those plants ranges between lab scale test units, couple of kW, and a utility scale unit, few MW, such as the 6 MWe plant built in Werlte, Germany.
Götz et al. [4] and Schiebahn et al. [7] provide a description of P2G possibilities as well as technical data. They point out that power-to-gas provides a good interconnection with the heat sector since methanation is a very exothermic process. Schiebahn et al. also list the requirements electrolysers need in power-to-gas applications. Those include high efficiency, long lifetime, low investments, ability to deal with fluctuating renewable power, low minimal load and high output pressure. Sterner et al. [8] show that synthetic methane and energy network development are key elements for reaching 100% renewable energy supply structures. Parra et al. [9] also estimate that power-to-hydrogen and power-to-methane will play a key role for the energy transition. Bolat and Thiel [10] provide a very complete description and review of literature on techno-economic description of the hydrogen supply chain. Steward et al. [11] study the interest in hydrogen electrolysers powered by PV energy for load levelling and vehicle refuelling. Also many roadmaps have been published on the topic, studying the introduction of a hydrogen economy in large spatial scale (e.g. [12] in Europe) or in smaller regions, such as [13] for Flanders, Belgium. Different studies also found out that electrolysers and fuel cells could be key players of ancillary markets due to their fast regulation ([14], [15], [16]).

Many energy modeling tools now include P2G and P2L, and the modeling possibilites are wide. Berger et al. [17] proposed an investment model which considers only electricity and gas sectors. Storage technologies such as pumped-hydro, batteries, hydrogen and methane sinks are included. Results demonstrates that if battery content is very dynamic with short term periodic variations, H_2 and CH_4 storage dynamics show that the former would be used for short term to medium term storage whereas the latter is more event-driven, meaning that it discharges in short period of time but not often.

PyPSA is a complete European sector-coupled investment and dispatch model [18]. It considers in a detailed way the transport, heating and electricity sectors and their interactions through for instance Battery Electric Vehicles (BEVS), Fuel Cell Electric Vehicle (FCEVs), combined cycles, heat pumps or electrolysis and methanation. The power-to-gas sector consists of hydrogen electrolysers, hydrogen fuel cells, hydrogen storage and methanation units. The CO_2 that is needed for producing methane is obtained by direct air capture which decreases the efficiency of methanation from 60% to 40%. Results show that methanation allows to decrease total system costs for a certain level of CO_2 emissions. However, long term district heating storage and high shares of BEVs-V2G are even more beneficial and their introduction decrease the need for power-to-methane. Concerning hydrogen, FCEVs are competitive in few cases.

EnergyPLAN is another European-level energy model, focussing on operation only [19]. The goal is to reach a 100% renewable energy system by 2050. To do so, 9 steps (scenarios) are created and installed capacities are associated. Power-to-gas and Power-to-liquid are modelled. Fifty percent of the needed CO_2 comes from biomass and the other part is supposed to be issued from carbon capture in industry. Here power-to-methane allows to complete the decrease of CO_2 emissions from 80% to 100% and is therefore the last step to reach a complete renewable system. The scenario including this possibility leads to an increased primary energy consumption compared to other scenarios (due to bad efficiencies of P2G) and it is the most expensive. However, the authors emphasize that power-to-gas leads to more investment-based costs which are likely to create many local jobs in Europe. This could therefore be offsetting the additional energy costs. Moreover, no fossil fuels would be bought outside Europe anymore.

Balmorel is an investment model that optimizes social welfare. Their modeling of the P2G sector does not include methanation. Jensen et al. [20] observes that hydrogen has a strengthened role when less bio-energy is assumed available.

METIS simulates both energy systems and energy markets for electricity, gas and heat [21]. In [22], a scenario with full carbon neutrality by 2050 is studied. Main conclusions are first that the main sources of flexibility would be cross-border capacities, storages such as pumped-hydro (where possible) and demand-side management. Moreover, Power-to-X are useful to adapt to the residual load, depending on the energy mix of each country. If large hydrogen storage capacities are available, it is found that water electrolysers would be widely used. However, methanation could only be economically relevant in countries with particularly low power prices.

Finally, JRC-EU-TIMES is a widely used European long-term investment model, using linear optimisation. The description of the energy model is very detailed including many sectors. Also hydrogen sector is very complete, including centralised and decentralised hydrogen production technologies (from fossil fuels, biomass and electrolysers) and many delivery pathways. Blending of H_2 in the natural gas grid is included as well as fuel cells for power production, fuel cell vehicles, hydrogen delivery for industries, methanation and PtL possibilities ([23], [24], [25]). Simulations on the hydrogen sector showed that electrolysers can decrease greatly renewable curtailment. Hydrogen could also play a significant role in sectors such as the industrial and transport ones. However, the large-scale development of stationary fuel cells still requires considerable cost improvements. In [25], a study of the potential of hydrogen and PtL in low-carbon Europe is realised. In their simulations, uses of hydrogen increases compared to today. Demand for hydrogen also depends on development of PtL, which is supposed to grow only if carbon storage is not possible and under strict CO_2 targets. In this case, PtL could meet 60 to 90% demand in aviation and up to 60% of diesel demand. According to TIMES, the preferred energy carrier for transport should be electricity, with a contribution of hydrogen in applications that cannot be electrified. Power-to-methane is represented by methanation of hydrogen and upgraded biogas (addition of H_2) [24]. The needed CO_2 comes from carbon capture in industry, power plants, biogas, hydrogen or from the atmosphere directly. After simulation, it comes out that power-to-methane is present in scenarios with at least 95% CO_2 reduction by 2050, no CO_2 underground storage and low CAPEX. Other factors that increase its use are, among others, limited biomass potential, low PtL performance and use of power-to-methane waste heat in order to increase the efficiency of the process.

The first goal of this work is to add the power-to-hydrogen sector into the unit-commitment and power dispatch model Dispa-SET. The second objective is to soft-link Dispa-SET with the long-term investment model JRC-EU-TIMES and investigate the benefits of this sector in terms of curtailment, total costs, CO_2 emissions, etc.

2. Framework

After the introduction, the second section will address the methodology. The two models will be presented as well as the coupling techniques. Then the implementation of the power-to-hydrogen sector into the power dispatch model will be described. Finally, the input data of the simulations and the different scenarios will be introduced.

Section IV will discuss the results of the simulations and compare the different scenarios. There will also be a discussion about the difference of results between the two models.

Section V will resume the main conclusions of this work.

Part II
Methods

This section starts with a description of Dispa-SET. Then JRC-EU-TIMES is presented followed by an introduction to model soft-linking and how it is applied here. The two last parts consist of a detailed presentation of the modeling of the power-to-hydrogen sector in Dispa-SET and of the scenarios that will be studied in the results section .

1. Dispa-SET model

1.1. Introduction

Dispa-SET is an open-source short-term unit-commitment and power dispatch model (UCM) mainly developed by the Joint Research Centre of the EU Commission. It minimizes the total production cost of energy during a certain period while observing different demands and constraints that will be detailed later. The model also includes different flexibility options such as hydro pumped storage, hydro dams (HDAM), batteries, BEVs, Thermal Heat Storage (TES) and Demand Side Management (DSM). Moreover, not only the power sector is modelled. The heat sector is included as well as part of the transport sector.

Dispa-SET was already used in many scientific works. For instance, Beltramo et al. [26] assessed the influence of BEVs charging demands in the Dutch energy system at the country level. Quoilin, Nijs, and Zucker [27] and Pavičević et al. [28] focused on model coupling between JRC-EU-TIMES and Dispa-SET. Pavičević et al. [29] compared different model formulations considering the Balkan countries and Jiménez Navarro et al. [30] investigated the possible benefits of the combination of CHP plants and thermal storage in energy systems.

The model is expressed as a Mixed-Integer Linear Program (MILP) but can also be simplified into a Linear Program (LP). The integer variables are the commitment status of the units. The preprocessing of the Database is performed in `Python` and the optimisation in `GAMS`[1]. All codes can be found in an open-source `Github` repository[2].

The next sections have been inspired by the official Dispa-SET documentation. This can be found online[3] or in the 2017 JRC technical report [31].

[1] https://www.gams.com/
[2] Dispa-SET repository
[3] Dispa-SET Documentation

1.2. Features

Dispa-SET offer many possibilities, and its main features are:

- Minimum and maximum power for each unit
- Power plant constraints: minimum power, ramping limits, minimum up/down times, start-up, no-load costs
- Outages (forced and planned) for each units
- Reserves (spinning & non-spinning) up and down
- Load Shedding
- Curtailment
- Storage technologies
- Non-dispatchable units (e.g. wind turbines, run-of-river, etc.)
- Multi-nodes with capacity constraints on the lines (congestion)
- Constraints on the targets for renewables and/or CO_2 emissions
- CHP power plants and thermal storage
- Power-to-heat (heat pump, electrical heater) and thermal storage
- Demand Side Management-ready demand
- Integrated mid-term scheduling and short-term optimal dispatch
- Different model formulations and levels of clustering complexity generated from the same dataset.

Corresponding equations can be found in Annex A. The demand is assumed to be inelastic to the price signal. The MILP objective function is therefore the total generation cost over the optimization period.

1.3. Input Data

Technologies
The Dispa-SET input distinguishes between the technologies defined in Tab 1. The VRES column indicates the variable renewable technologies and the Storage column indicates the technologies which can accumulate energy.

Table 1: Dispa-SET technologies

Technology	Description	VRES	Storage
COMC	Combined cycle	N	N
GTUR	Gas turbine	N	N
HDAM	Conventional hydro dam	N	Y
HROR	Hydro run-of-river	Y	N
HPHS	Pumped hydro storage	N	Y
ICEN	Internal combustion engine	N	N
PHOT	Solar photovoltaic	Y	N
STUR	Steam turbine	N	N
WTOF	Offshore wind turbine	Y	N
WTON	Onshore wind turbine	Y	N
CAES	Compressed air energy storage	N	Y
BATS	Stationary batteries	N	Y
BEVS	Battery-powered electric vehicles	N	Y
THMS	Thermal storage	N	Y
P2GS	Power-to-gas storage	N	Y
P2HT	Power-to-heat	N	Y
SCSP	Concentrated solar power	Y	Y

Fuels

Dispa-SET only considers most commonly used fuel types. Those are: biomass (BIO), gas (GAS), geothermal heat (GEO), coal (HRD), hydrogen (HYD), lignite (LIG), nuclear energy (NUC), petroleum (OIL), solar energy (SUN), wind energy (WIN), biogas (BIO) and water energy (WAT). Different fuels may be used to power a given technology, e.g. steam turbines may be fired with many different fuel types.

Demand

Electricity demand is given per zone. Heat demand time series are needed where CHP or P2HT plants are used. In the current formulation, each CHP/P2HT unit covers a heat load. In other words, one power plant is connected to a single district heating network.

Zones

In this study, each zone correspond to one European country. The United Kingdom, Norway and Switzerland have been added to the list of the simulated countries whereas Malta and Cyprus have been removed. The ISO 3166-1 standard has been adopted to describe each country at the NUTS1 level (except for Greece and the United Kingdom, for which the abbreviations EL and UK are used according to EU Interinstitutional style guide). The list of countries is defined as:

TABLE 2: List of included countries and their abbreviations

Code	Country	Code	Country
AT	Austria	IE	Ireland
BE	Belgium	IT	Italy
BG	Bulgaria	LT	Lituania
CH	Switzerland	LU	Luxembourg
CZ	Czech Republic	LV	Latvia
DE	Germany	NL	Netherlands
DK	Denmark	NO	Norway
EE	Estonia	PL	Poland
EL	Greece	PT	Portugal
ES	Spain	RO	Romania
FI	Finland	SE	Sweden
FR	France	SI	Slovenia
HR	Croatia	SK	Slovakia
HU	Hungary	UK	United Kingdom

TABLE 3: Common parameters

Description	Field name	Units
Unit name	Unit	-
Power Capacity (for one unit)	PowerCapacity	MW
Number of units	Nunits	-
Technology	Technology	-
Primary fuel	Fuel	-
Zone	Zone	-
Efficiency	Efficiency	%
Efficiency at minimum load	MinEfficiency	%
CO_2 intensity	CO2Intensity	t_{CO2}/MWh
Minimum load	PartLoadMin	%
Ramp up rate	RampUpRate	%/min
Ramp down rate	RampDownRate	%/min
Start-up time	StartUPTime	h
Minimum up time	MinUpTime	h
Minimum down time	MinDownTime	h
No load cost	NoLoadCost	EUR/h
Start-up cost	StartUpCost	EUR
Ramping cost	RampingCost	EUR/MWh

Power Plants data

Technical and operational parameters of the power plants are defined by the fields included in TAB 3.

Some parameters are only defined for units equipped with storage. Those are presented in TAB 4. Discharging efficiency and maximum discharging power are assigned to the common fields "Efficiency" and "PowerCapacity".

The parameters related to CHP and P2H units can be found in Annex A.

TABLE 4: Parameters for storage units

Description	Field name	Units
Storage capacity	STOCapacity	MWh
Self-discharge rate	STOSelfDischarge	%/d
Maximum charging power	STOMaxChargingPower	MW
Charging efficiency	STOChargingEfficiency	%

Renewable generation

Variable renewable generation is either fed to the grid or curtailed. The time-dependent generation of these technologies must be provided as an exogenous time series in the form of an “availability factor”. Non-renewable technologies are assigned an availability factor of 1.

Storage and hydro data

Storage units are an extension of the regular units, including additional constraints and parameters. Some other parameters must be introduced in the form of time series. Those are described hereunder.

It should be noted that the nomenclature adopted for the modeling of storage units refers to the characteristics of hydro units with water reservoirs. However, these parameters (e.g. inflows, level) can easily be transposed to the case of alternative storage units such as batteries or BEVS.

Inflows: The Inflows are defined as the contribution of exogenous sources to the level (or state of charge) or the reservoir. They are expressed in MWh of potential energy. The input to dispaset is defined as “StorageInflow”. This can represent the contribution of a river in the case of a hydro dam.

Outflows: The Outflows are represented in Dispa-SET by the parameter "StorageOutflow". These represent predefined fluxes of energy going out of the storage unit without producing power. This could be due to environmental regulations in case of hydro units.

Storage Level: Because emptying the storage has a zero marginal cost, a non-constrained optimization tends to leave the storage completely empty at the end of the optimisation horizon. For that reason, a minimum storage level is imposed at the last hour of each horizon. In Dispa-SET, a typical optimisation horizon is a few days. The model is therefore not capable of optimising the storage level e.g. for seasonal variations. The minimum storage level at the last hour is therefore an exogenous input. It can be selected from a historical level or obtained from a long-term scheduling optimization, which is called Mid-term scheduling (see SECTION 1.4.2.).

Variable capacity storage: In special cases, it might be necessary to simulate a storage unit whose capacity varies in time. A typical example is the simulation of the storage capacity provided by electric vehicles: depending on the time of the day, the connected battery capacity varies. This special case can be simulated using the “AvailabilityFactor” input. In the case of a storage unit, it allows to reduce the available capacity by a factor varying from 0 to 1.

Other storage units
Other storage units include batteries (BATS) and electric vehicles with vehicle-to-grid capabilities. For both, the parameters "StorageInflow" and "StorageOutflow" are set to 0 all the time.

Interconnections
Two cases should be distinguished when considering interconnections:

- Interconnections occuring between the simulated zones
- Interconnections occuring between the simulated zones and the Rest of the World (RoW)

These two cases are addressed by two different datasets described hereunder.

Net transfer capacities: Dispa-SET models the internal exchanges between countries (or zones) using a commercial net transfer capacity (NTC).

Historical physical flows: In Dispa-SET, the flows between internal zones and the rest of the world cannot be modelled endogenously. They must be provided as exogenous inputs.

Fuel prices
Fuel prices are defined as inputs and can vary both geographically and in time.

1.4. Model Description

The model is expressed as a MILP or LP problem and implemented in `GAMS`. The binary variables are the commitment status of each unit. An exhaustive list of the sets, parameters and variables used in the model can be found in Annex A.

1.4.1. Optimisation model

The aim of this model is to represent with a high level of detail the short-term operation of large-scale power systems solving the so-called unit commitment problem. To that aim the system is considered managed by a central operator with full information on the technical and economic data of the generation units, the demands in each node, and the transmission network.

The unit commitment problem considered in this report is a simplified instance of the problem faced by the operator in charge of clearing the competitive bids of the participants into a wholesale day-ahead power market. In the present formulation the demand side is an aggregated input for each node, while the transmission network is modelled as a transport problem between the nodes (that is, the problem is network-constrained but the model does not include the calculation of the optimal power flows).

The unit commitment problem consists of two parts: i) scheduling the start-up, operation, and shut down of the available generation units, and ii) allocating (for each period of the simulation horizon of the model) the total power demand among the available generation units in such a way that the overall power system costs is minimized. The first part of the problem, the unit scheduling during several periods of time, requires the use of binary variables in order to represent the start-up and shut down decisions, as well as the consideration of constraints linking the commitment status of the units in different periods. The second part of the problem is the so-called economic dispatch problem, which determines the continuous output of each and every generation unit in the system. Therefore, given all the features of the problem mentioned above, it can be naturally formulated as a mixed-integer linear program (MILP). However, the problem can also be relaxed to a linear program (LP).

Since the goal is to model a large European interconnected power system, a tight and compact formulation has been implemented, in order to simultaneously reduce the region where the solver searches for the solution and increase the speed at which the solver carries out that search. Tightness refers to the distance between the relaxed and integer solutions of the MILP and therefore defines the search space to be explored by the solver, while compactness is related to the amount of data to be processed by the solver and thus determines the speed at which the solver searches for the optimum. Usually tightness is increased by adding new constraints, but that also increases the size of the problem (decreases compactness), so both goals contradict each other and a trade-off must be found.

Objective function

The goal of the unit commitment problem is to minimize the total power system cost, which is defined as the sum of different cost items:

$$\begin{aligned}
\min\Big[&\sum_{u,i} CostFixed_u \cdot Committed_{u,i} \cdot TimeStep \\
&+ \sum_{u,i} (CostStartUpH_{u,i} + CostShutDownH_{u,i}) \\
&+ \sum_{u,i} (CostRampUpH_{u,i} + CostRampDownH_{u,i}) \\
&+ \sum_{u,i} CostVariable_{u,i} \cdot Power_{u,i} \cdot TimeStep \\
&+ \sum_{l,i} PriceTransmission_{l,i} \cdot Flow_{l,i} \cdot TimeStep \\
&+ \sum_{n,i} CostLoadShedding_{i,n} \cdot ShedLoad_{i,n} \cdot TimeStep \\
&+ \sum_{th,i} CostHeatSlack_{th,i} \cdot HeatSlack_{th,i} \cdot TimeStep) \\
&+ \sum_{chp,i} CostVariable_{chp,i} \cdot CHPPowerLossFactor_{chp} \cdot Heat_{chp,i} \cdot TimeStep) \\
&+ \sum_{i,n} VOLL_{Power} \cdot (LL_{MaxPower,i,n} + LL_{MinPower,i,n}) \cdot TimeStep \\
&+ \sum_{i,n} 0.8 \cdot VOLL_{Reserve} \cdot (LL_{2U,i,n} + LL_{2D,i,n} + LL_{3U,i,n}) \cdot TimeStep \\
&+ \sum_{u,i} 0.7 \cdot VOLL_{Ramp} \cdot (LL_{RampUp,u,i} + LL_{RampDown,u,i}) \cdot TimeStep \\
&+ \sum_{s,i} CostOfSpillage \cdot spillage_{s,i} \\
&+ \sum_{s} WaterValue \cdot WaterSlack_s\Big]
\end{aligned} \tag{1.1}$$

where the sets u, i, l and n respectively represents the power generation units, the simulated hours, the interconnection lines between zones and the zones. s, th and chp represents the storage technologies (without heat units), thermal units and combined cycles units.

The costs can be broken down as:

- Fixed costs: depending on whether the unit is on or off.
- Variable costs: stemming from the power output of the units.
- Start-up costs: due to the start-up of a unit.
- Shut-down costs: due to the shut-down of a unit.
- Ramp-up: emerging from the ramping up of a unit.
- Ramp-down: emerging from the ramping down of a unit.
- Load shed: due to necessary load shedding.

- Transmission: depending of the flow transmitted through the lines.
- Loss of load: power exceeding the demand or not matching it, ramping and reserve.
- spillage: due to spillage in storage.
- Water : cost of water coming from unsatisfied water level at the end of the optimization period.

The model considers the possibility of voluntary load shedding resulting from contractual arrangements between generators and consumers. Additionally, in order to facilitate tracking and debugging of errors, the model also considers some variables representing the capacity that the system is not able to provide when the minimum/maximum power, reserve, or ramping constraints are reached. These lost loads (LL) are a very expensive last resort of the system used when there is no other choice available. The different lost loads are assigned very high values (with respect to any other costs). This allows running the simulation without infeasibilities, thus helping to detect the origin of the loss of load. In a normal run of the model, without errors, all these variables are expected to be equal to zero.

For compactness purposes, all other equations than the ones related to demand and storage units have been moved to Annex A. Storage equations are the ones that are going to be modified in the scope of adding the hydrogen sector.

Day-ahead energy balance

The main constraint to be met is the supply-demand balance, for each period and each zone, in the day-ahead market. According to this restriction, the sum of all the power produced by all the units present in the node (including the power generated by the storage units), the power injected from neighbouring nodes ($Flow$) is equal to the load in that node, plus the power consumed for energy storage ($PowerConsumption$ and $StorageInput$), minus the load interrupted (LL) and the load shed ($ShedLoad$).

$$\begin{aligned}\sum_u (Power_{u,i} \cdot Location_{u,n}) + \sum_l (Flow_{l,i} \cdot LineNode_{l,n}) & \\ = Demand_{DA,n,h} & \\ + \sum_s \left(StorageInput_{s,h} \cdot Location_{s,n}\right) & \\ - ShedLoad_{n,i} & \\ + \sum_{p2h} PowerConsumption_{p2h,i} \cdot Location_{p2h,n} & \\ - LL_{MaxPower\,n,i} + LL_{MinPower\,n,i} & \end{aligned} \tag{1.2}$$

Storage-related constraints
Generation units with energy storage capabilities (large hydro reservoirs, pumped hydro storage units, batteries or BEVS) must meet additional restrictions related to the amount of energy stored. Storage units are considered to be subjected to the same constraints as non-storage power plants. In addition to those constraints, storage-specific restrictions are added for the set of storage units (i.e. a subset of all units). These restrictions include the storage capacity, inflow, outflow, charging, charging capacity, charge/discharge efficiencies, etc. Discharging is considered as the standard operation mode and is therefore linked to the *Power* variable, common to all units. Storage units are modelled as in FIG 1. Spillage has the same meaning as curtailment has for RES, that is wasting energy.

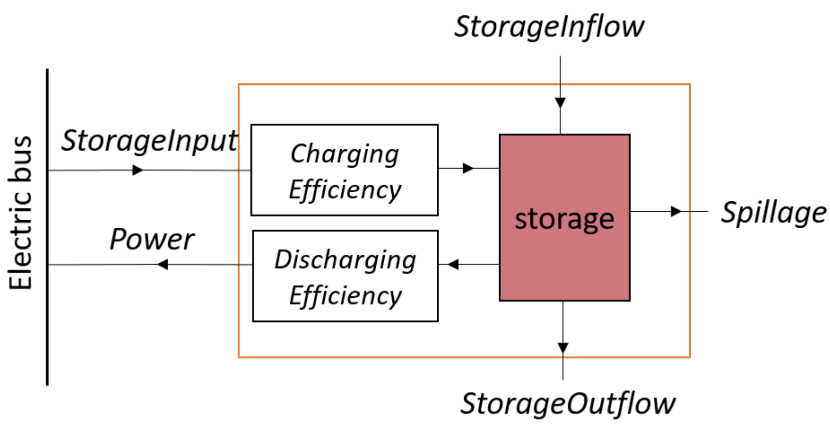


FIGURE 1: Model of storage units

The first constraint imposes that the energy stored by a given unit is bounded by a minimum value:

$$StorageMinimum_s \leq StorageLevel_{s,i} \cdot Nunits_s \tag{1.3}$$

In the case of a storage unit, the availability factor applies to the charging/discharging power, but also to the storage capacity. The storage level is thus limited by:

$$StorageLevel_{s,i} \leq StorageCapacity_s \cdot AvailabilityFactor_{s,i} \cdot Nunits_s \tag{1.4}$$

The energy added to the storage unit is limited by the charging capacity. Charging is allowed only if the unit is not producing (discharging) at the same time (i.e. if *Committed*, corresponding to the normal mode, is equal to 0).

$$StorageInput_{s,i} \leq StorageChargingCapacity_s \cdot (Nunits_s - Committed_{s,i}) \tag{1.5}$$

$$\tag{1.6}$$

Discharge is limited by the level of charge of the storage unit:

$$\frac{Power_{i,s} \cdot TimeStep}{StorageDischargeEfficiency_s} - StorageInflow_{s,i} \cdot Nunits_s \cdot TimeStep \leq StorageLevel_{s,i-1} \tag{1.7}$$

It is worthwhile to note that $StorageInflow$ must be multiplied by the number of units because they are defined for a single storage unit. On the contrary $StorageLevel$, $Spillage$ and $Power$ are defined for all units of the same plant.

Charge is limited by the level of charge of the storage unit:

$$\begin{aligned} StorageInput_{s,i} \cdot StorageChargingEfficiency_{s} \cdot TimeStep \\ -StorageOutflow_{s,i} \cdot Nunits_{s} \cdot TimeStep \\ \leq StorageCapacity_{s} \cdot Nunits_{s} \cdot AvailabilityFactor_{s,i} \\ -StorageLevel_{s,i-1} \end{aligned} \tag{1.8}$$

Besides, the energy stored during a period is given by the energy stored in the previous period, net of charges and discharges:

$$\begin{aligned} StorageLevel_{s,i-1} + StorageInflow_{s,i} \cdot Nunits_{s} \cdot TimeStep \\ +StorageInput_{s,i} \cdot StorageChargingEfficiency_{s} \cdot TimeStep \\ = StorageLevel_{s,i-1} + StorageOutflow_{s,i} \cdot Nunits_{s} \cdot TimeStep \\ +Spillage_{wat,i} + \frac{Power_{s,i} \cdot TimeStep}{StorageDischargeEfficiency_{s}} \end{aligned} \tag{1.9}$$

Some storage units are equipped with large reservoirs, whose capacity at full load might be longer than the optimisation horizon. Therefore, a minimum level constraint is required for the last hour of the optimisation, which otherwise would systematically tend to empty the reservoir as much a possible. An exogenous minimum profile is thus provided and the following constraint is applied:

$$StorageLevel_{s,N} \geq StorageFinalMin_{s} + WaterSlack \tag{1.10}$$

where N is the last period of the optimization horizon, $StorageFinalMin$ is a non-dimensional minimum storage level provided as an exogenous input and $WaterSlack$ is a variable defining the unsatified storage level. The price associated to that missing energy is very high.

1.4.2. Mid-Term-Scheduling (MTS)

As will be explained in more details hereunder, MTS computes to pre-defined storage levels during the whole year based on a simplified set of equations and linear optimisation. In this configuration, all equations concerning unit commitment are not considered and the binary variables $Committed$, $StartUp$ and $ShutDown$ are defined as linear. The following constraints are therefore ignored:

- The committment equations
- The minimum Up and Down times equations
- The Ramp up and Ramp down limitation equations

1.5. Rolling Horizon

The mathematical problem described in the previous sections could in principle be solved for a whole year split into time steps, but with all likelihood the problem would become extremely demanding in computational terms when attempting to solve the model with a realistically sized dataset. Therefore, the problem is split into smaller optimization problems that are run recursively throughout the year.

Fig 2 shows an example of such approach, in which the optimization horizon consists of two days, including a look-ahead (or overlap) period of one day. The initial values of the optimization for day j are the final values of the optimization of the previous day. The look-ahead period is modelled to avoid issues related to the end of the optimization period such as emptying the hydro reservoirs, or starting low-cost but non-flexible power plants. In this case, the optimization is performed over 48 hours, but only the first 24 hours are conserved. The optimization horizon and overlap period can be adjusted.

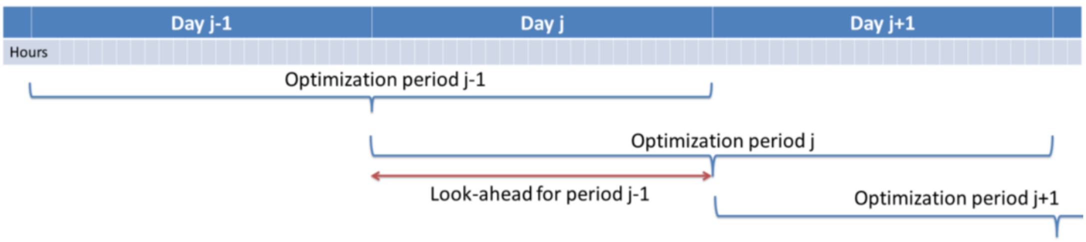


Figure 2: Representation of the simulation horizon

1.6. Mid-Term Scheduling

As discussed in previous sections the simulations depends on exogenous storage level profiles.

In many cases, collecting accurate and reliable historical storage levels and profiles in form of hourly timeseries might be a difficult or close to impossible task. In future scenarios storage levels are usually forecasted based on the historical data. The lack of such data also impacts the accurate modelling of such scenarios. In systems with high shares of hydro dams (HDAM) and pumped hydro storage (HPHS) units, such as Norway and Albania, this might have a huge impact on the overall results of the simulation.

In order to avoid this, Dispa-SET's Mid Term Scheduling (MTS) module allows perfect foresight and allocation of storage resources for the whole optimization period and not only for the tactical horizon of each optimization step. This module enables quick calculation (later also referring as allocation) of reservoir levels which are then used as guidance curves (minimum level constraints) at the end of each rolling horizon. Therefore, MTS is applied during preprocessing. It allows to define the parameter $StorageProfile$ for the storage units that require MTS before running the main simulation. Most of the time, MTS is run for all zones simultaneously but it can also run for each zone individually. MTS can be applied with any TimeStep but a TimeStep of 24 hours is well adapted since the simulation is applied during the whole year.

2. JRC-EU-TIMES model

The power plants capacities in Dispa-SET database need to be fixed beforehand. Those capacities come from another energy model: JRC-EU-TIMES.

JRC-EU-TIMES is a European long-term Energy System Optimization Model (ESOM) developed by the Joint Research Center of the European Union. As such, it forecasts capacity expansion and computes the investment and operation costs while minimizing total system cost via linear programming on a multi-year horizon. The main goal of JRC-EU-TIMES is to analyse the future potential and interactions of energy technologies in order to give recommendations on European energy policies. This includes making estimations of the best shares of flexibility options (storage technologies, power-to-X, demand side management) needed to cope with systems including a lot of Renewable Energy Sources (RES).

While both the supply and demand sides are included in the model, the following seven sectors are represented: primary energy supply, power generation, industry, residential, commercial, agriculture and transport [32]. The model calculates prices endogenously, based on supply and demand curves.

The model includes EU and neighbouring countries, each of them representing a node, and carries out simulations from 2005 to 2050. Given the complexity of the model and the large covered timespan, each year is divided in 12 representative time-slices. Those represent a mean day, night and peak demand for each season. This approximation has important consequences when energy systems with large shares of RES are modelled. Indeed, the reduced number of time slices decreases the insights on the variability of renewable production.

2.1. Hydrogen sector

The hydrogen sector in JRC-EU-TIMES is divided into production, storage, delivery and end use. Many hydrogen fabrication processes are included, varying from technology (electrolysis, reforming, gasification), fuel (electricity, methane, biomass) and size (centralised or decentralised). Storage can be underground or in tanks. Concerning delivery, blending in the natural gas grid, liquefaction and ship transports among others are possibilities. Hydrogen is used in the residential sector to supply part of the space heating, in the industry sector (mainly steel), for transport and synthetic fuel synthesis (P2L), such as methanol or diesel. If the hydrogen has been blended in the natural gas grid (up to 15% concentration), it is used for the same applications as methane.

3. Unidirectional soft-linking

Despite the complexity of JRC-EU-TIMES, the time step of long term investment models does not allow to completely appreciate the real needs for flexibility ([33], [34]). Also some technical constraints such as start-up times or minimum running times cannot be included. On the other side, an operational and economic dispatch model such as Dispa-SET having a small time step, a large covered area and unit commitment constraints is too complex to also include investments and a long simulated period. This is why most of the time that kind of model only runs a few days long simulations. This does not allow long-term investment previsions.

Therefore, it is interesting to link the two kinds of model. This action is called *soft-linking* [35]. It allows to take advantage of the long-term investment strategy of the ESOM as well as the short time step of the operational model. For instance, bidirectional linking of TIMES and EnergyPLAN in [36] allowed to invest in more diversified resources and technologies since the production of RES was badly estimated by TIMES only.

This relation can be unidirectional, meaning that some outputs from the ESOM are once included as inputs in the operational model. In this work, JRC-EU-TIMES and Dispa-SET are unidirectionally linked. The other possibility, more complex, is bidirectional soft-linking. This involves iterations between the two models.

As said, some results from TIMES are used as inputs in Dispa-SET. Those variables consist of:

- The available technologies and their installed capacities. Those technologies are related to power, heat and hydrogen generation as well as storage.
- The annual demands per country related to power, heat, transport and hydrogen.
- Carbon emission and commodity prices.

Pavičević et al. [28] present some of the techniques that were implemented within the scope of linking the two models.

Fig 3 represents the block diagram of the relation between TIMES, Dispa-SET and the different data sources used. Some outputs from JRC-EU-TIMES are given as annual values and need to be processed as hourly profiles. This is done in the Soft-linking toolbox. Other inputs such as availability factors (needed for RES, BEVS, etc.), river inflows and outside temperatures are assumed similar to historical values from 2016. NTCs values are based on the e-Highway 2050 project. Those data, together with the power plant portfolio constitute the Dispa-SET Database. At that point 2 Dispa-SET simulations are performed. First, the Mid-Term Scheduling allows to computes storage levels and P2L demand profiles (see section 2.1.4.). Then the second simulation gives the final results. Those include the economic dispatch throughout the year, curtailment, total cost, CO_2 emissions, etc.

The coupling methodology applied here is inspired by Blanco Reaño [33]. It consists of the following steps:

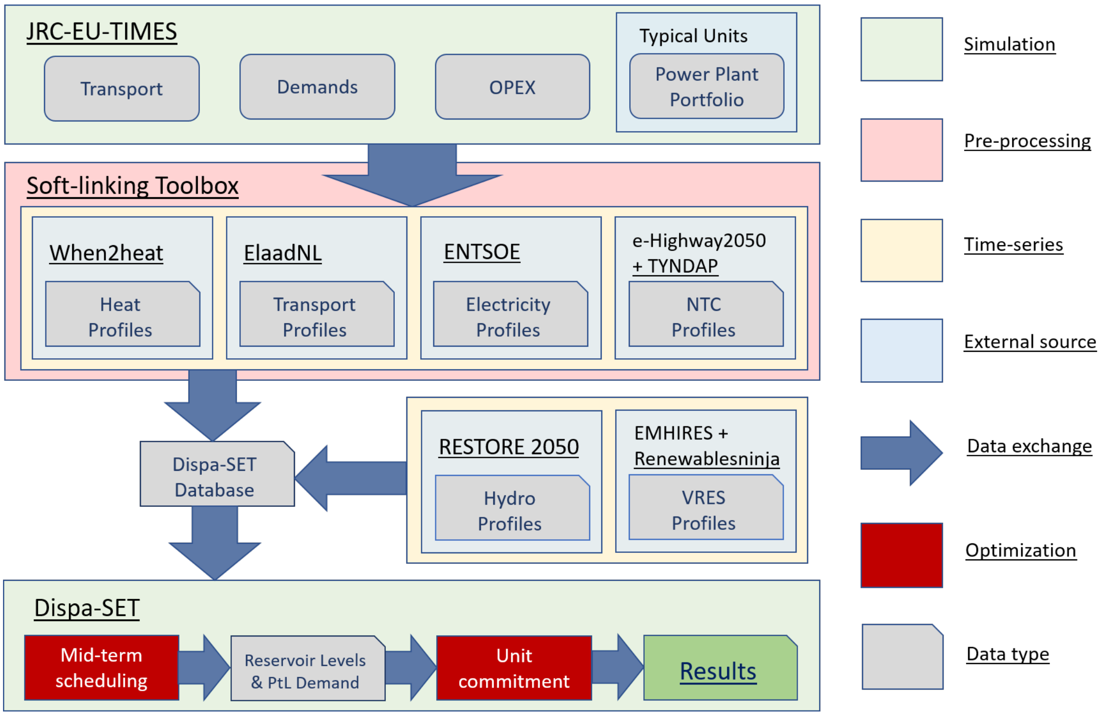


Figure 3: Explanatory block diagram of the model coupling. This figure has been taken from [28] and slightly modified.

1. Recover the output data of the TIMES simulation and put them in the right format to enter Dispa-SET.
2. Run Dispa-SET with the new database.
3. Identify lost loads and excessive shed loads. Compute the maximum of those values in each zone and add the same amount of capacity in the form of combined cycle gas turbines. This step is necessary because long term planning models usually over-estimate RES production and therefore under size the thermal capacity needed to avoid lost loads.
4. Run Dispa-SET again and analyse the results.

3.1. JRC-EU-TIMES Scenario

TIMES has a large panel of scenarios. CO_2 target, expected development rate of technologies and biomass potential are a few examples of what differentiate them. The selected scenario for this study is called NearZeroCarbon. It includes a high penetration of VRES and an ambitious CO_2 reduction target of 95% by 2050 compared to 1990 levels. Carbon Capture and Storage (CCS) is allowed but power plants equipped with CCS only constitute around one ninth of total thermal plants capacity. Both the 95% CO_2 target and the limited amount of units with CCS have a positive impact on the P2G sector development [25]. The first one because it increases the share of VRES and therefore the need for technologies able to absorb the over-production when needed. The second because producing e-fuels requires carbon capture, which helps decreasing CO_2 emissions. CCS has the same effect and its extensive use decreases the need of developing PtL. The year 2050 is studied. The high resulting capacity of electrolysers allows to better observe the role of P2G.

4. P2G sector in Dispa-SET

This section describes how the power-to-hydrogen sector was included into Dispa-SET model.

4.1. Acquisition of the data from JRC-EU-TIMES

First, output data from JRC-EU-TIMES were gathered. During this research, it appeared that capacity of methanation units was 0 in the NearZeroCarbon scenario. Indeed, a lot of conditions are needed to make them profitable. For instance, CO_2 reduction must be 95% and higher, there must be no possible storage of CO_2 (which could be due to low social acceptance), the CAPEX of this technology needs to decrease more than basic expectations, etc.
In this study, H_2 is produced by electrolysers connected to the power grid. Two types are particularly promising: Alkaline electrolysers and Proton Exchange Membrane (PEM) electrolysers. In both case, the chemical reaction transforms water into hydrogen and oxygen:

$$H_2O \quad \rightarrow \quad H_2 + \frac{1}{2} O_2 \tag{4.1}$$

This reaction is not spontaneous and needs electricity to take place.

Alkaline electrolysis is a mature technology [7]. They are currently cheaper than PEM and can reach higher sizes. However, PEM electrolysers also have some advantages including higher output pressure and good flexibility (lower part load minimum and faster working point changes).

The hydrogen produced by the electrolysers is stored before being used to satisfy the demand or before producing electricity through fuel cells (FC). Those are performing the reverse reaction than electrolysers and produce water and power from hydrogen and oxygen. In TIMES, only PEM fuel cells are considered. They run on 100 kW_{H2} based units.

In order to simplify the model, the end uses of hydrogen are simply represented by an exogenous hydrogen demand without interactions with other sectors. This is why not all hydrogen end uses from TIMES are included in Dispa-SET. The demand related to industry, transport and fuel synthesis has been taken into account, but the hydrogen used for space heating and blending in the natural gas grid in TIMES was not accounted for.

Hydrogen demand is first expressed as an hourly flat demand that derives from a total yearly demand per country from JRC-EU-TIMES. In a second time, advantage is taken from the flexibility that P2L can bring. Indeed, P2L needs hydrogen but this demand can be shifted in time since liquid fuels are easy to store and there already exist today big storage capacities. Hydrogen demand is therefore divided in two parts: a rigid demand that needs to be satisfied at all time, and the P2L demand. Mid-term-scheduling allows to determine the best P2L demand profile throughout the year, as will be explained in section 4.2.

The needed data were therefore: the installed electrolysers, storage units and fuel cells capacities and the H_2 demand in each zone.

4.2. Integration into Dispa-SET

The modelling of the hydrogen sector is represented in Fig 4. Electrolysers, storage and fuel cells are considered as one unit and modelled similarly as other storage units. The storage inflows and outflows are defined as null at all times. *StorageOutput* represents the hydrogen that goes out of the storage to satisfy the demand. This demand is made up of the rigid H_2 demand (*H2Demand*) and the demand linked to P2L. The variable *StorageSlack* is needed to avoid infeasibilities in the model in case there is not enough energy to fulfil hydrogen demand and a cost is associated with it. It will also be used in the scenario to assess if hydrogen production cost of electrolysers is competitive

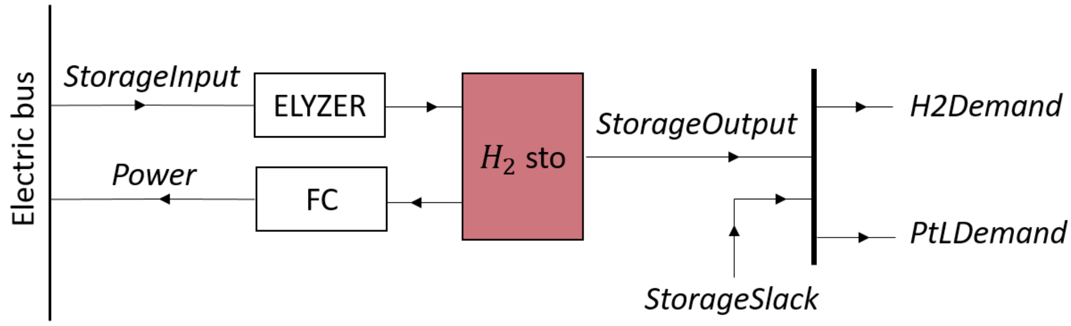


Figure 4: Model of the hydrogen sector in Dispa-SET

In a pratical point of view, a new set was created. $p2h2$ represents all P2G units and is part of the set s, meaning that all equations related to storage units also apply to $p2h2$ units. Eq 1.1 representing the total production cost therefore becomes:

$$
\begin{aligned}
\min \Big[& \sum_{u,i} CostFixed_u \cdot Committed_{u,i} \cdot TimeStep \\
& + \sum_{u,i} (CostStartUpH_{u,i} + CostShutDownH_{u,i}) \\
& + \sum_{u,i} (CostRampUpH_{u,i} + CostRampDownH_{u,i}) \\
& + \sum_{u,i} CostVariable_{u,i} \cdot Power_{u,i} \cdot TimeStep \\
& + \sum_{l,i} PriceTransmission_{l,i} \cdot Flow_{l,i} \cdot TimeStep \\
& + \sum_{n,i} CostLoadShedding_{i,n} \cdot ShedLoad_{i,n} \cdot TimeStep \\
& + \sum_{th,i} CostHeatSlack_{th,i} \cdot HeatSlack_{th,i} \cdot TimeStep \\
& + \sum_{\mathbf{p2h2,i}} \mathbf{CostH2Slack_{p2h2,i} \cdot StorageSlack_{p2h2,i} \cdot TimeStep} \\
& + \sum_{chp,i} CostVariable_{chp,i} \cdot CHPPowerLossFactor_{chp} \cdot Heat_{chp,i} \cdot TimeStep \\
& + \sum_{i,n} VOLL_{Power} \cdot (LL_{MaxPower,i,n} + LL_{MinPower,i,n}) \cdot TimeStep
\end{aligned}
$$

$$
\begin{aligned}
&+\sum_{i,n} 0.8 \cdot VOLL_{Reserve} \cdot (LL_{2U,i,n} + LL_{2D,i,n} + LL_{3U,i,n}) \cdot TimeStep \\
&+\sum_{u,i} 0.7 \cdot VOLL_{Ramp} \cdot (LL_{RampUp,u,i} + LL_{RampDown,u,i}) \cdot TimeStep \\
&+\sum_{s,i} CostOfSpillage \cdot spillage_{s,i} \\
&+\sum_{s,i} WaterValue \cdot WaterSlack_{s}\Big]
\end{aligned} \tag{4.2}
$$

Storage equations that are related for instance, to limits on storage level or limits on charging/discharging capacity, remain unchanged for $p2h2$ units. However, the equations related to storage balance need to be slightly modified. Eq 1.8 bounding the charging capacity is transformed as:

$$
\begin{aligned}
StorageInput_{s,i} \cdot StorageChargingEfficiency_{s} \cdot TimeStep \\
-StorageOutflow_{s,i} \cdot Nunits_{s} \cdot TimeStep \\
-\mathbf{H2Output_{p2h2,i}} \cdot \mathbf{TimeStep} \\
\leq StorageCapacity_{s} \cdot AvailabilityFactor_{s,i} \cdot Nunits_{s} \\
-StorageLevel_{s,i-1}
\end{aligned} \tag{4.3}
$$

Eq 1.9 is now:

$$
\begin{aligned}
StorageLevel_{s,i-1} + StorageInflow_{s,i} \cdot Nunits_{s} \cdot TimeStep \\
+StorageInput_{s,i} \cdot StorageChargingEfficiency_{s} \cdot TimeStep \\
= StorageLevel_{s,i} + StorageOutflow_{s,i} \cdot Nunits_{s} \cdot TimeStep \\
+Spillage_{wat,i} + \frac{Power_{s,i} \cdot TimeStep}{StorageDischargeEfficiency_{s}} \\
+\mathbf{H2Output_{p2h2,i}} \cdot \mathbf{TimeStep}
\end{aligned} \tag{4.4}
$$

A new equation related to H_2 demand needs to be introduced:

$$
\begin{aligned}
H2Demand_{p2h2,i} + PtLDemand_{p2h2,i} \\
= H2Output_{p2h2,i} + StorageSlack_{p2h2,i}
\end{aligned} \tag{4.5}
$$

P2L demand is assigned by the mid-term scheduling. It is first defined as a flat demand at each hour but mid-term scheduling allows to take advantage of the easy storage of liquid fuels. Therefore, it allows the demand to vary during the year by ensuring that the total yearly demand remains the same. This is done thanks to the following equation, that is only activated during MTS:

$$
\sum_{i} PtLDemandInput_{p2h2,i} = \sum_{i} PtLDemand_{p2h2,i} \tag{4.6}
$$

where *PtLDemandInput* is the flat demand coming from the Database and *PtLDemand* is the demand used in the previous equations. *PtLDemand* is bounded by the next equation, also only activated in MTS mode:

$$
PtLDemand_{p2h2,i} \leq MaxCapacityPtL_{p2h2} \tag{4.7}
$$

where *MaxCapacityPtL* is the sum of the capacity given by TIMES to produce liquid fuels. It is the sum of the capacity to produce methanol and the capacity to produce Diesel in each country.
After the MTS, the P2L demand profile computed (*PtLDemand*) is assigned by the preprocessing to the parameter *PtLDemandInput*. A last equation is needed to ensure that *PtLDemand* during the final simulation is equal to *PtLDemandInput*:

$$PtLDemand_{p2h2,i} = PtLDemandInput_{p2h2,i} \tag{4.8}$$

This equation is only activated when MTS mode is off.

Part III
Scenarios

1. Definition of the scenarios

Four scenarios are studied. They are presented in the next sections.

1.1. CHEAPSLACK

This scenario studies the competitiveness of electrolysers to produce hydrogen. Therefore, the hydrogen slack represents hydrogen supplied by other means. Today, around half of the hydrogen produced worldwide comes from methane steam reforming. This is why it has been chosen to associate the slack to methane reforming units with carbon capture in this scenario. These units are not present in the TIMES scenario, as was showed by FIG 6.

A cost needs to be associated to the slack. According to Bolat and Thiel [10], the mean cost of producing hydrogen from methane is around 63.5 EUR/MWh. Adding CCS can increase the cost up to 40 %. To that amount, the price of emitting the CO_2 present in methane should be added. Soltani, Rosen, and Dincer [37] state that 210 kg of CO_2 are emitted per MWh of hydrogen produced. It is considered that CCS allows to capture 90 % of the emitted CO_2. The cost of the hydrogen produced by methane reforming should therefore be computed as:

$$63.5 \times 1.4 + 0.021 \times \text{Cost } CO_2 \tag{1.1}$$

Since CO_2 costs are not taken into account (which will be explained in SECTION 2.4.), a price of 88 EUR/MWh is used in this scenario.

1.2. H2FLEX

H2FLEX is the main scenario. It includes the full modeling of the P2G sector (just as CHEAPSLACK). It also has a higher cost for the hydrogen slack to promote usage of electrolysers. The slack does not represent methane steam reforming in this scenario and is only present to avoid infeasibilities in the modeling. Its price is set to the maximum price to prevent electricity from thermal power plants to directly enter electrolysers. This is the case if:

$$\frac{\text{Cost}_{\text{gas}}}{\epsilon_{\text{gas}} \times \epsilon_{\text{electrlysers}}} < \text{Cost H2 Slack} \tag{1.2}$$

considering that gas combined cycles form the main part of thermal power plants. This gives a price of 160 EUR/MWh.
Preventing thermal plants from producing at the same time as electrolysers aims at forcing the system to produce *green* hydrogen. This is the case when hydrogen is produced from renewable energy. If thermal energy was partly used to produce H_2, the hydrogen would be calle *blue*. This would be of no interest since the efficiency of methane steam reforming is around 70% [10] which is better than the efficiency of a gas combined cycle multiplied by the one of electrolysers.

1.3. No_PtL

Third scenario seeks to investigate the benefits of the PtL planning in the mid-term-scheduling simulation. This simulation therefore gives information on the modeling methodology and not on the benefits of P2G or on the functioning of the energy system. As a reminder, the PtL planning during MTS takes into consideration the storage capacities of e-fuels and optimizes the PtL related hydrogen demand shape. In this scenario, this possibility is removed and the whole hydrogen demand is expressed as flat during the year.

1.4. NOH2STO

In this last scenario, the hydrogen storage capacities are set equal to 0 in order to evaluate the benefits of those capacities.

1.5. Summary

The analysis of the results will be made in 3 steps. First, CHEAPSLACK and H2FLEX results will be compared to assess the influence of the slack cost. Then, H2FLEX, No_PtL and NOH2STO results are commented. Finally, some Dispa-SET and TIMES results are compared. The scenarios characteristics are summarised in TAB 5.

TABLE 5: Definition of the scenarios

Scenario	Cost H2 Slack		PtL	H2 storage
	88 EUR/MWh	160 EUR/MWh		
CHEAPSLACK	✓		✓	✓
H2FLEX		✓	✓	✓
No_PtL		✓		✓
NOH2STO		✓	✓	

2. Database

The database was completely renewed in the scope of this work. The functions and data needed to create it can been found in an open-source `Github` repository[4]. The database includes the following data:

- The power plant portfolio for each country and the characteristics of the power plants (efficiency, ramp-up rate,...);
- the hourly day-ahead load for each country;
- the hourly heat demand for each country;
- the hourly availability factors per technology and per country;
- the hourly temperatures per country;
- the Net Transfer Capacities (NTC) between countries;
- the hourly hydrogen rigid and flexible (P2L) demands per country;
- the maximum capacities of P2L per country.

[4] Dispa-set SideTools repository

2.1. P2G capacities

2.1.1. Electrolysers

According to TIMES, there is more than 3,800 GW of electrolyser capacity in Europe, which indicates that this scenario relies a lot on hydrogen. The projected electrolysers capacity in each country in 2050 is represented in Fig 5. As can be directly observed, electrolysers consist almost exclusively of Alkaline type. Moreover, Italy has the biggest capacity on its territory, with more than 707 GW of installed power. In comparison, there is around 660 GW of PV panels and less than 100 GW of wind turbines onshore in Italy. Power-to-hydrogen does not seem interesting in all European countries, with some of them having very small or null electrolyser capacity.

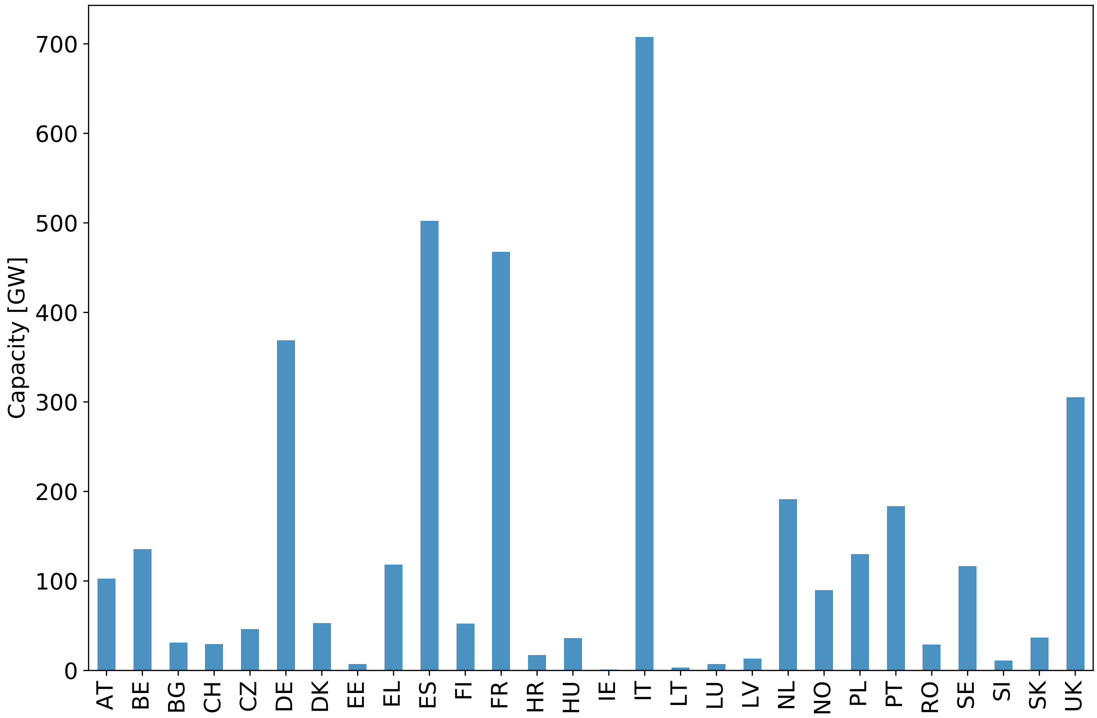


Figure 5: Installed capacity of electrolysers per country

Fig 6 justifies the fact that electrolysers are the only hydrogen production units taken into account in Dispa-SET. As can be observed, even though methane steam reforming is the only production possibility in 2030, electrolysers overtake it by far in 2050.

2.1.2. Fuel cells

Fuel cells capacities can be found in Fig 7.
A first observation is that the United Kingdom and Italy are the countries with the highest installed FC capacities. However, those have a very different order of magnitude compared to electrolysers. Italy has almost 20 times less FC capacity, which shows that hydrogen is mostly not used as electrical storage but more as a coupling commodity. Some countries also have a null capacity. This is the case of Belgium, Luxembourg and Slovenia.

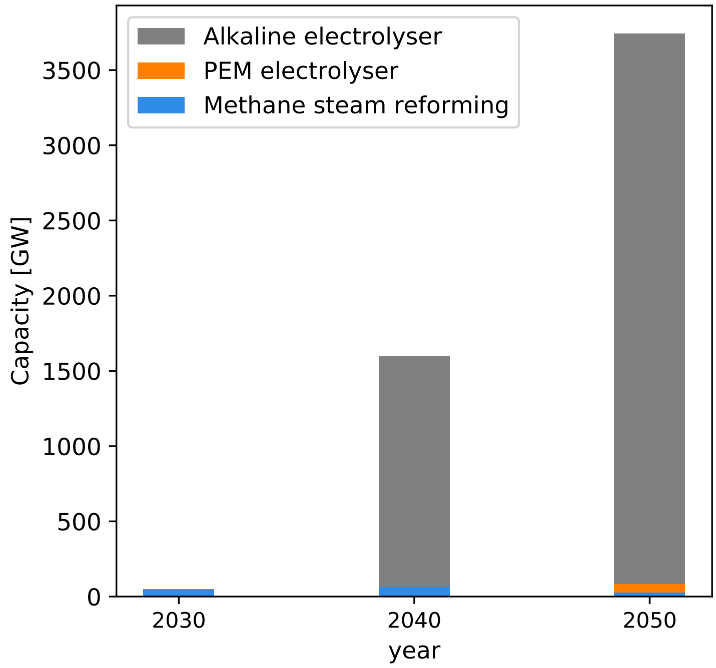


FIGURE 6: Evolution of the capacities of the main hydrogen production processes. Capacities are are provided at EU level.

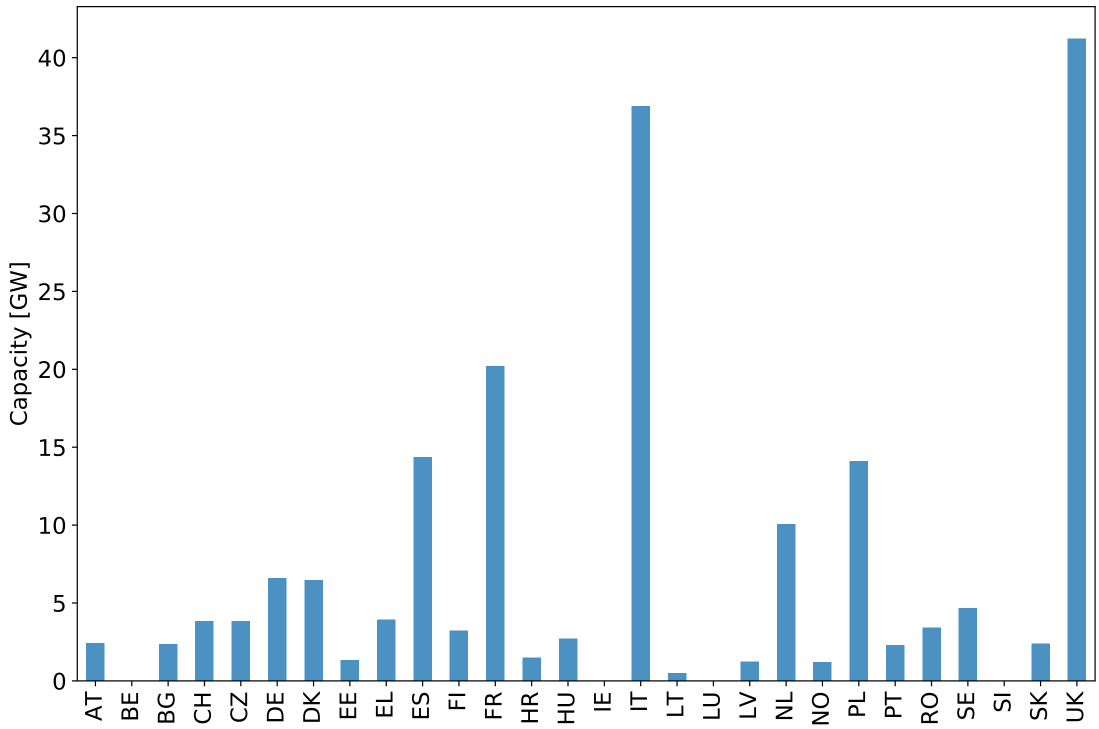


FIGURE 7: Installed capacity of fuel cells per country

2.1.3. Storage infrastructures

Hydrogen is supposed to be stored mainly in centralised hydrogen gas tanks. Less than a hundredth of the storage capacity consists of underground storage and less than a thousandth of distributed tanks. Underground storage is almost exclusively located in Germany. Hydrogen storage capacities are displayed in FIG 8. The storage capacity to electrolyser capacity ratio is 1 h for global EU capacities. This means that electrolysers are able to fill hydrogen storage in 1 h only.

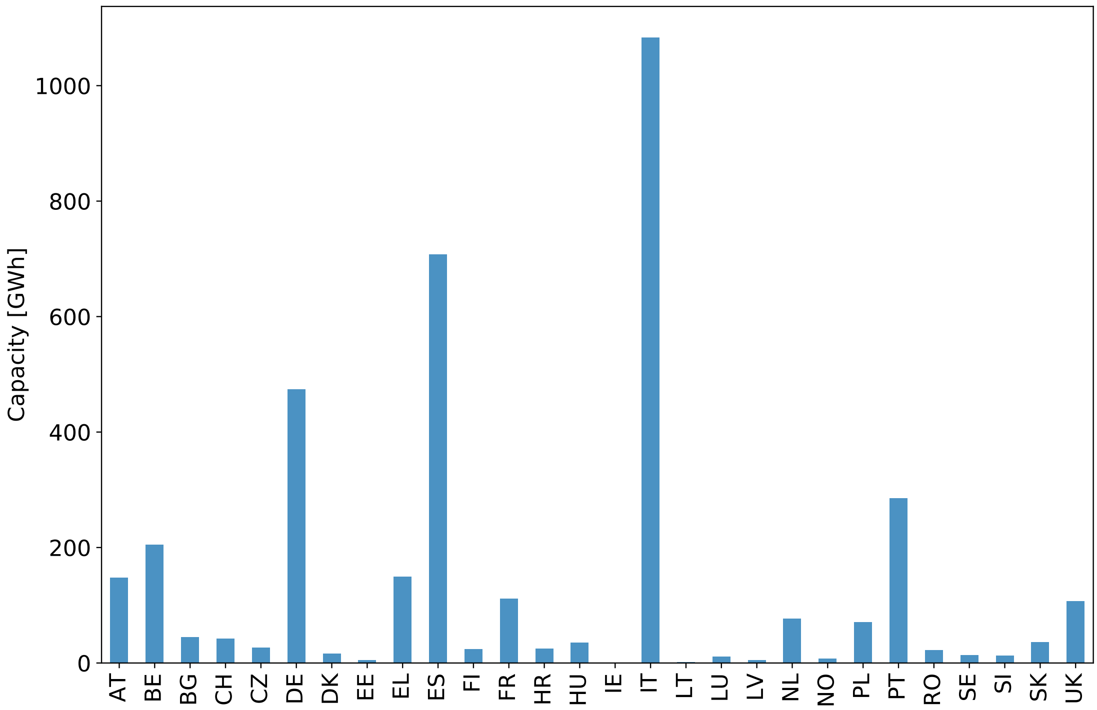


FIGURE 8: Installed H_2 storage capacity per country

2.1.4. H_2 Demand

The annual demand used for hydrogen in the NearZeroCarbon scenario amounts to 10,750 PJ. Around two fifth of this hydrogen is used to produce e-fuels.

2.2. Installed capacities

The generation installed capacities disaggregated by fuel type are presented in FIG 9. A first observation is that the greatest part of those capacities consists of renewable technologies or storage. It can also be seen that a non negligible capacity of gas combined cycles had to be added in the second step of the soft-linking process to avoid lost loads, indicating a sub-investment in conventional technologies in TIMES. Another solution could have been to increase the RES and storage capacities. This is in agreement with Pina, Silva, and Ferrão [36], that observes that long-term models over-estimate the energy production from renewable sources, therefore under-estimating the need for storage or back-up thermal plants.

The storage capacities are represented in FIG 10, where it is clear that hydro technologies and in particular hydro dams are the main storage possibilities in Europe. The northern part of Europe (Norway and Sweden) provides the biggest hydro storage capacities. Countries with no hydro dams possibilities such as Denmark or Belgium have very few storage capacities and rely on flexibility from neighbouring countries.

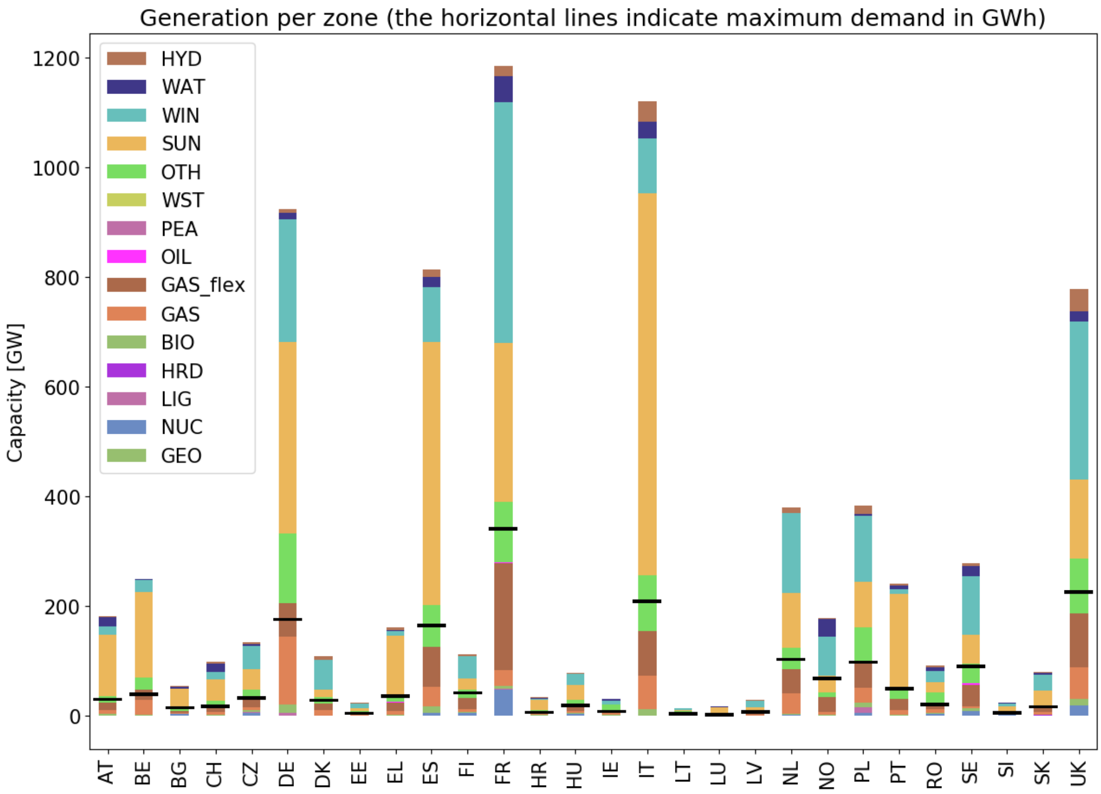


FIGURE 9: Installed capacities according to the fuel type. *GAS_flex* represents the additional capacity of *GAS_COMC* that had to be added to avoid lost loads. *OTH* represents electricity storage technologies (BEVS and BATS).

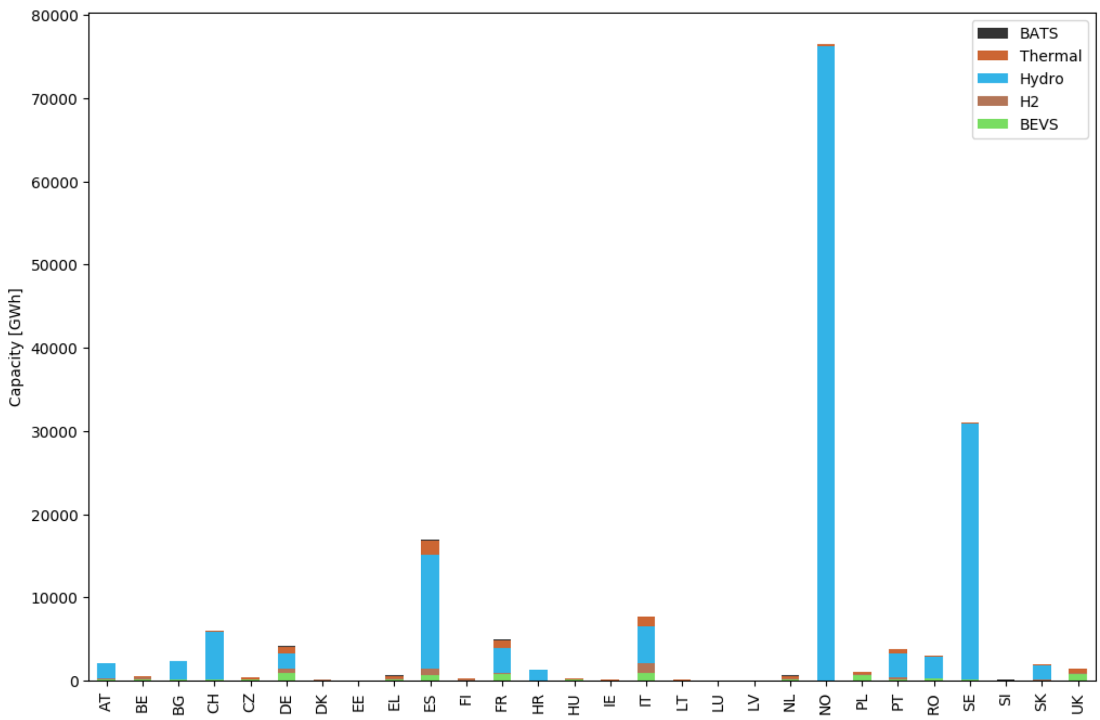


FIGURE 10: Installed storage capacities.

2.3. NTC

The transmission capacities have been taken from the project e-Highway 2050. Tab 6 shows the most important capacities. A complete description of interconnections can be found in Annex B. Transmission costs and losses are assumed null.

Table 6: Main transmission capacities

Interconnection	Capacity [GW]
AT -> IT	9.9
BE -> DE	6
BE -> NL	12.4
BE -> UK	6
DE -> AT	15.5
DE -> NO	10.4
DE -> PL	12
DE -> SE	16.2
ES -> FR	19
ES -> PT	7.2
FR -> BE	7.3
FR -> CH	7.3
FR -> DE	9.1
FR -> UK	16.4
IT -> EL	9.5
NL -> NO	14.7
NO -> UK	6.4
PL -> LT	9

2.4. Commodities price

The cost of commodities can be found in Tab 7. They are used to compute the variable costs of the power plants.

Table 7: Commodities price.

Name	Price EUR/MWh
Nuclear	4
Black coal	20
Gas	60
Fuel-oil	78
Biomass	30
Lignite	15

For such a scenario with high CO_2 reduction target in TIMES, a high CO_2 emission cost around 350 EUR/t can be expected. Taking into account the entirety of this cost into the marginal price of generators could excessively skew the optimisation results. This is why it has been decided not to take those costs into account. The reality will probably lie between including the whole CO_2 cost into marginal price of generators and taking a null cost for CO_2.

2.5. Heat slack

For computational reasons, a cost for back-up heat need to be defined. It is set to 100 EUR/MWh. This is taking into account that this heat is supposed to be provided by old gas units still available but that possibility should be used as little as possible.

2.6. Typical units

Technical and operational characteristic of individual fuel - technology combinations is presented in TAB 8. The column "Power" refers to the power capacity of 1 unit of that type. If the capacity of the power plant is higher, a number of units greater than 1 is assigned, meaning that 1 power plant can have many units. If there is no power defined in the table, the number of units is always set to 1.

TABLE 8: Typical characteristics of the units

Fuel	**Technology**	**Power**	**Efficiency**	**Min up time**	**Min down time**	**Ramp rate**	**Start up cost**	**No load cost**	**Ramping cost**	**Part load min**	**Start-up time**	**CO_2 intensity**
-	-	MW	-	h	h	%/min	EUR/MW	EUR/MW	EUR/MW	-	h	t/MWh
BIO	COMC	420	0.51	3	3	0.07	55	2.9	0.25	0.06	1	0.21
BIO	GTUR	64	0.33	1	1	0.17	25	2.9	0.25	0.2	0.17	0.32
BIO	ICEN	25	0.36	1	1	0.04	24	0	0.63	0.25	1	0.27
BIO	STUR	180	0.40	4	6	0.02	120	12.5	1.3	0.4	1	0.42
GAS	COMC	420	0.51	3	3	0.07	55	2.9	0.25	0.06	1	0.36
GAS	COMC_CCS	750	0.43	3	3	0.07	55	2.9	0.25	0.06	1	0.04
GAS	GTUR	64	0.33	1	1	0.17	25	2.9	0.25	0.2	0.17	0.68
GAS	ICEN	10	0.36	0	0	1.0	0	0	0	0.30	0	0.01
GAS	STUR	120	0.37	1	1	0.02	25	2.90	0.25	0.40	0.17	0.53
GEO	STUR	40	0.1	2	2	0.02	0	0	0	0	0	0
HRD	COMC	500	0.31	1	1	0.01	720.36	3.1	1.8	0.2	1	0.04
HRD	STUR	764	0.42	6	6	0.04	65	12.5	1.8	0.2	2	0.47
HRD	STUR	500	0.31	1	1	0.01	519.80	3.1	1.8	0.2	1	0.87
LIG	STUR	604	0.40	8	8	0.01	65	8	2.20	0.43	7	1.15
NUC	STUR	1008	0.34	24	24	0.05	300	12.5	2.2	0.25	12	0
OIL	GTUR	70	0.33	0	0	0.17	0	0	0	0.20	0.17	10.8
OIL	STUR	386	0.33	5	5	0.02	120	0	1.80	0.40	1	0.72
OTH	BATS		0.89	0	0	1	0	0	0	0	0	0
OTH	BEVS		0.94	0	0	1	0	0	0	0	0	0
OTH	P2HT		1.0	0	0	1	0	0	0	0	0	0
OTH	STUR	70	0.33	0	0	0.17	0	0	0	0.2	0.17	0.8
PEA	STUR	25	0.4	4	6	0.02	120	12.5	1.3	0.4	1	0
SUN	SCSP	150	1	2	2	0.02	0	0	0	0	0	0
WAT	HDAM		0.89	0	0	1	0	0	0	0	0	0
WAT	HPHS		0.89	0	0	1	0	0	0	0	0	0
WST	ICEN	45	0.42	1	1	0.04	24	0	0.63	0.25	1	0.27
WST	STUR	48	0.20	5	5	0.02	65	0	1.8	0.4	1	0
HYD	P2GS		0.46	0	0	1	0	0	0	0	0	0

More parameters are associated to storage units, linked to the efficiency of storage. Those are presented in TAB 9. All efficiencies except those related to heat storage come from JRC-EU-TIMES database [38].

Table 9: Additional parameters linked to storage units

Technology -	Self discharge %/day	Charging efficiency -
P2HT	3	1
CHP	3	1
SCSP	3	1
P2GS	0	0.72
HDAM	0	0.89
HPHS	0	0.89
BEVS	0	0.94
BATS	0	0.89

2.7. Load shedding

Load shedding is permitted. At most 25% of the load can be shedded for a price of 400 EUR/MWh.

2.8. Horizon length

The horizon length of the simulations is 2 days and the look ahead period is 1 day. It means that each simulation lasts for 3 days and that the last day is then disregarded.

2.9. Exchanges outside Europe

The simulated countries are exchanging power through transmission lines together but exchanges with the rest of the world are not considered.

Part IV
Results

The results from the 4 scenarios (CHEAPSLACK, H2FLEX, No_PtL and NOH2STO) are presented in this section. Each simulation took between 13 and 20 h to run on a 64 GB 8-CPU cluster node [5].

1. CHEAPSLACK and H2FLEX

This part analyses the 2 scenarios CHEAPSLACK and H2FLEX, whose difference is the price of hydrogen slack.

1.1. Hydrogen demand satisfaction

Fig 11 shows the part of the hydrogen demand that is supplied by the electrolysers and the one that needs to be covered by the slack for both scenarios. The slack produces hydrogen whenever cheap renewable energy is already used for other purposes or there is too few of it; or when the slack price is too competitive.

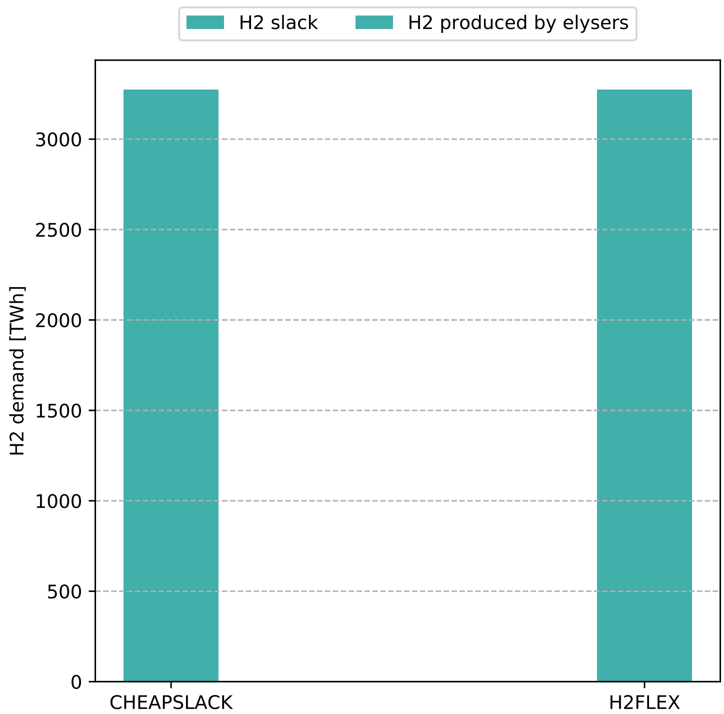


Figure 11: Repartition of the production of hydrogen from the system and from the slack

It can be observed that the slack is still producing the biggest part of the demand, even when its price is 160 EUR/MWh. This high price forces the system to produce 1000 TWh, which is less than one third of the demand. CHEAPSLACK has half less hydrogen produced by the electrolysers.
The next comparisons will investigate the reason behind this difference of production.

[5] http://www.ceci-hpc.be/clusters.html

1.2. Curtailment

The total curtailment compared to the total and peak renewable production is represented in FIG 12. Curtailment is very small. It seems that the difference between the scenarios may only be explained by solver precision. This had to be relaxed so that objective function falls within 5% to take into account the complexity of the model. Since curtailment is very small, there is no real opportunity of producing more hydrogen from renewable sources, whatever the slack cost.

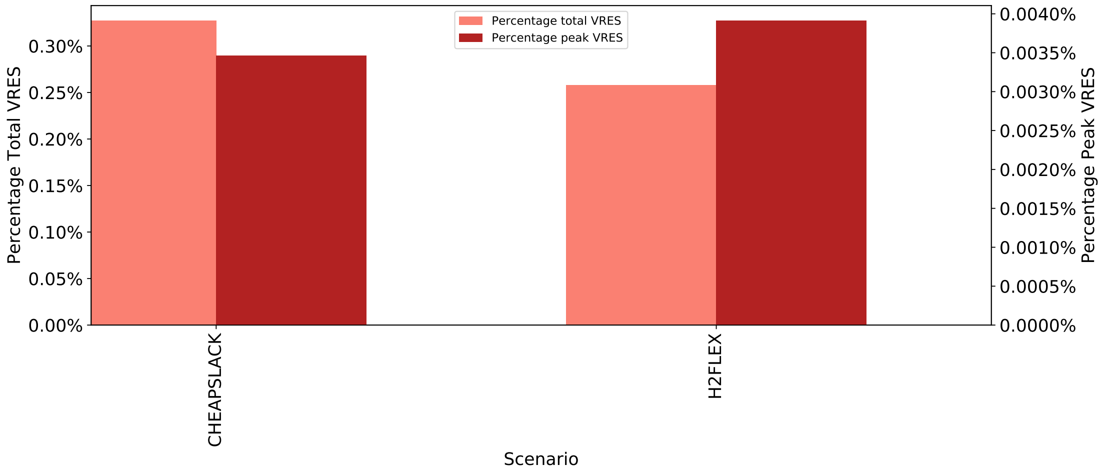


FIGURE 12: Total curtailment in both scenarios

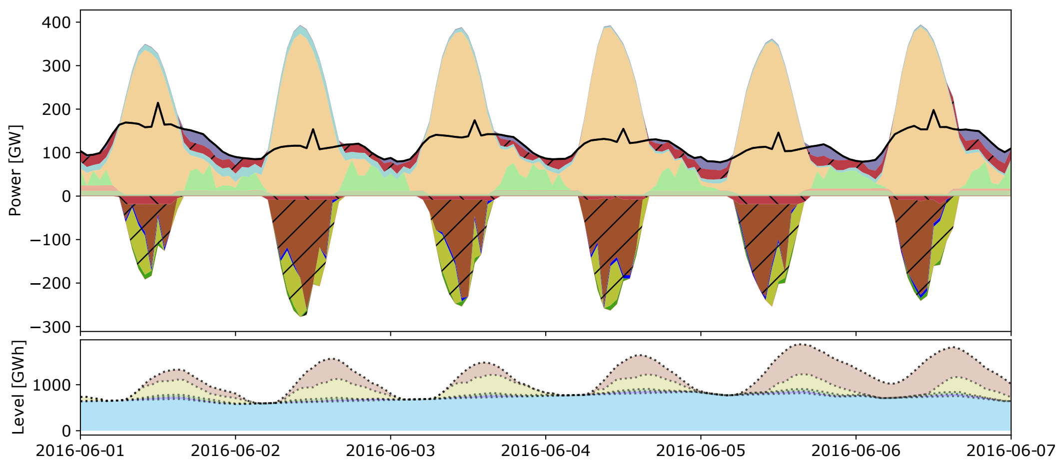
1.3. Power dispatch

Power dispatch plots of a selected week in June are represented in FIG 13a and 13b. In the reservoirs level plots, the hydrogen storage is discharging without producing power since it satisfies the demand.

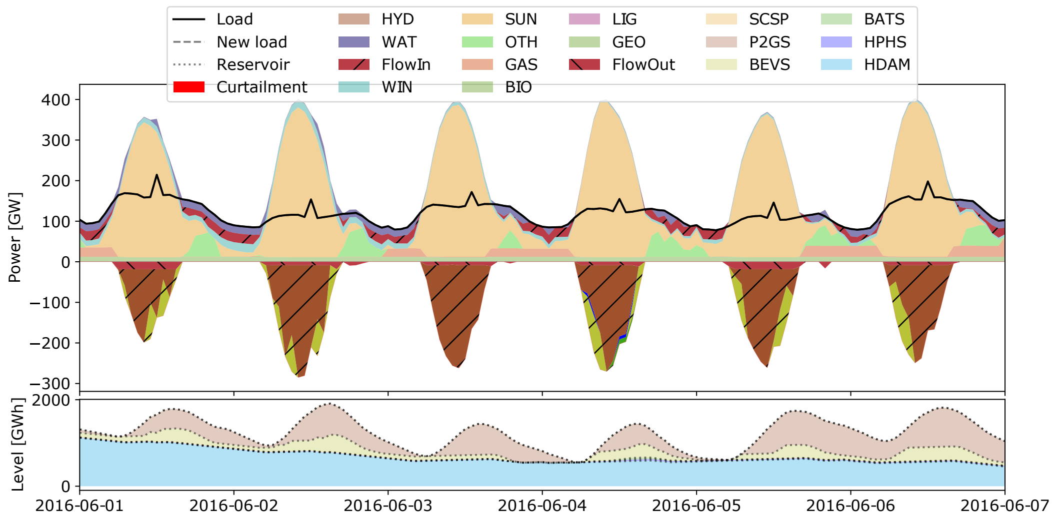
A first observation is that, despite a very sunny week, no curtailment is to be observed. Comparing both scenarios, it can be seen that CHEAPSLACK is producing less hydrogen, storing more energy in batteries and BEVS. This energy allows then to reduce gas turbines production when the load exceeds the renewable production.
In other words, increasing the cost of the slack results in more hydrogen produced by the electrolysers. However, it also increases the gas consumption since less renewable energy is stored to later satisfy the demand when there is a lack of renewable production.

1.4. Generation breakdown

The power generation of each fuel is represented in FIG 14. As expected, gas is producing more in the H2FLEX scenario to offset hydrogen production. On the other hand, batteries and BEVS are producing more in the CHEAPSLACK scenario. H2FLEX has a greater total power generation than CHEAPSLACK due to the additional hydrogen production. This also means better sector coupling because more electricity is used to produce hydrogen in H2SLACK than in



(a) CHEAPSLACK



(b) H2FLEX

Figure 13: Power dispatch and reservoir levels of a selected week in Italy in June. Negative values in the dispatch plot indicate exported power or power going into storage.

CHEAPSLACK. A last remark is that despite a certain capacity of fuel cells, very little hydrogen is used to produce electricity. This makes sense since electrolysers are not producing enough hydrogen to satisfy the demand, and efficiency of fuel cells is only 46%.

1.5. Electrolysers operation

Section 2.1.1. showed that there is around 3,800 GW capacity of electrolysers in this scenario. Compared to the 1000 TWh of hydrogen production in H2FLEX scenario, this gives a global capacity factor of around 3%, or an Equivalent Full Operating Hours (EFOH) of 263 h. This variable with marginal price of electricity is very important to determine if electrolysers can be profitable. The EFOH per country are represented in Fig 15.

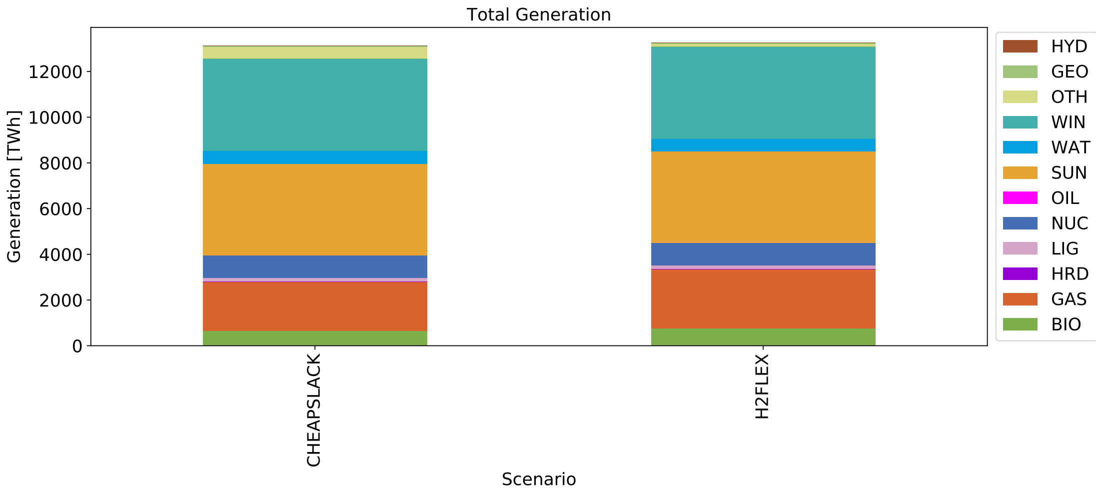


Figure 14: Generation breakdown by fuel type for both scenarios.

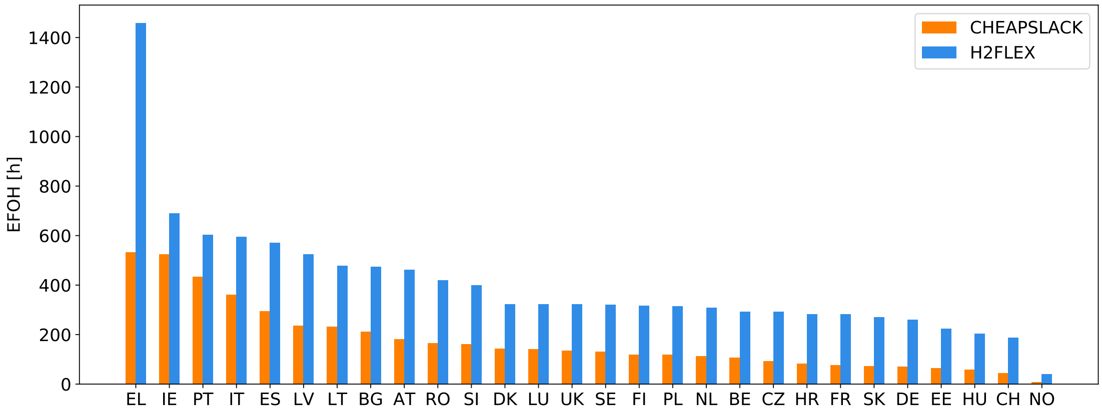


Figure 15: EFOH per country and per scenario.

As is represented in the figure, the EFOH are highly dependant of the simulation parameters, namely the price of H_2 Slack. If the slack was not included in the simulation or had a very high price, the EFOH would be higher. However, they would produce hydrogen from electricity produced by thermal plants, whereas for now, electrolysers only produce with RES electricity and a very small amount from biomass CHP plants because their marginal cost is smaller than the slack cost in both scenarios.
A possibility to have green hydrogen and satisfy the whole demand of this TIMES scenario is to increase the RES capacity. Installing more gas turbines with CCS or methane reforming units with CCS would also allow to produce hydrogen without emitting CO_2. The advantage of producing hydrogen via electrolysers is that it allows Europe to be less dependant on fuels importation.

1.6. CO_2 emissions

CO_2 emissions are given in Fig 16. H2FLEX is producing more CO_2 because of the additional gas production and because the hydrogen slack was assumed to be equipped with CCS. If those back-up units are not equipped with CCS, then H2FLEX would be the scenario emitting less CO_2.

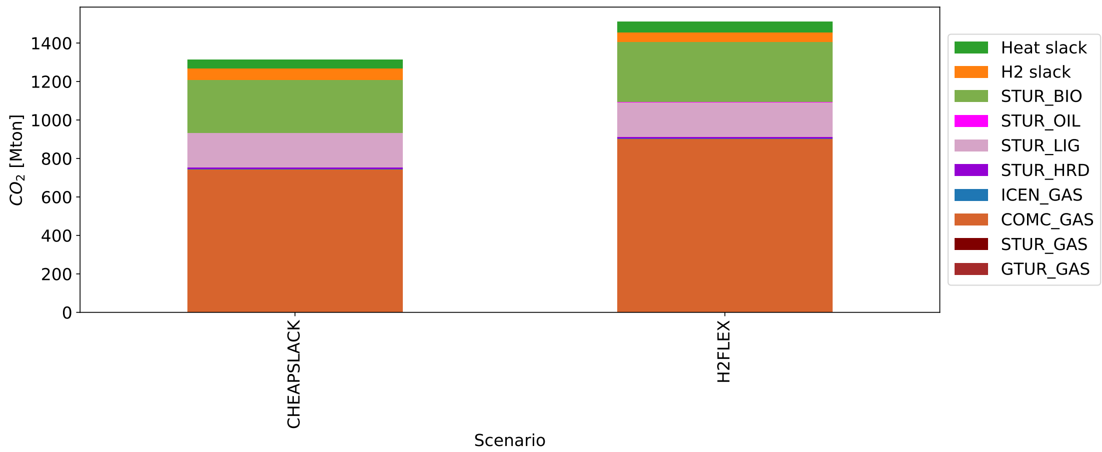


FIGURE 16: Total CO_2 emission per scenario.

1.7. Shadow prices

The last part of this section is the comparison of the shadow prices of both scenarios in FIG 17 and 18. In CHEAPSLACK scenario, electrolysers are producing only when marginal price is under the price of hydrogen slack times the efficiency of electrolysers, which gives:

$$88 \times 0.72 = 63.4 \text{ EUR/MWh}$$

In H2SLACK, electrolysers are producing when marginal cost is under $160 \times 0.72 = 115$ EUR/MWh. Therefore, whenever prices in CHEAPSLACK scenario are between those 2 values, they increase to 115 in H2SLACK. This illustrates how much influence electrolysers can have on the demand and on the market prices. It is also worth noticing that introducing electrolysers in power system implies less volatile prices and a higher average price of electricity, which could act as an incentive for investors to invest in renewable generation. Countries like Portugal that have prices often under 63.4 EUR/MWh keep their low prices in both scenarios because it indicates that at those time intervals the hydrogen demand is satisfied.

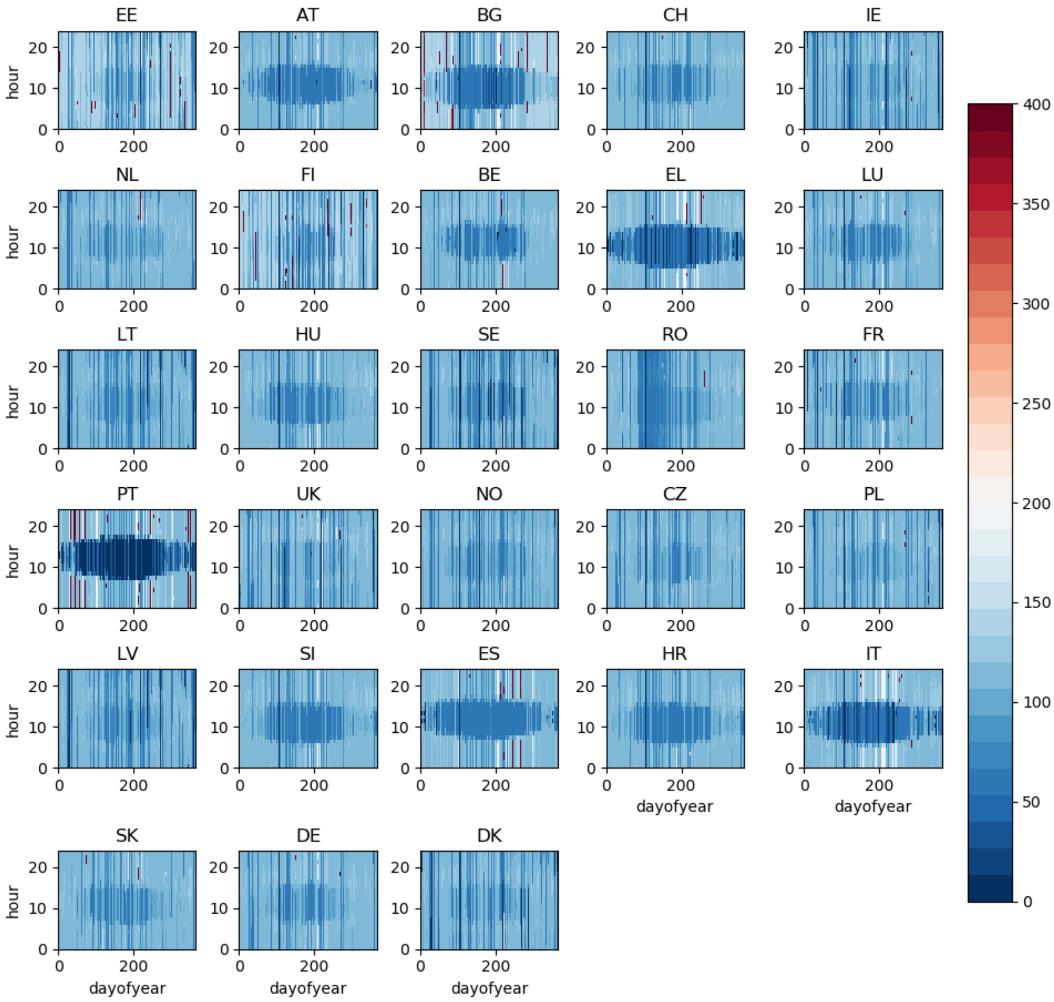


FIGURE 17: Marginal price of electricity at each hour of the year for CHEAPSLACK scenario.

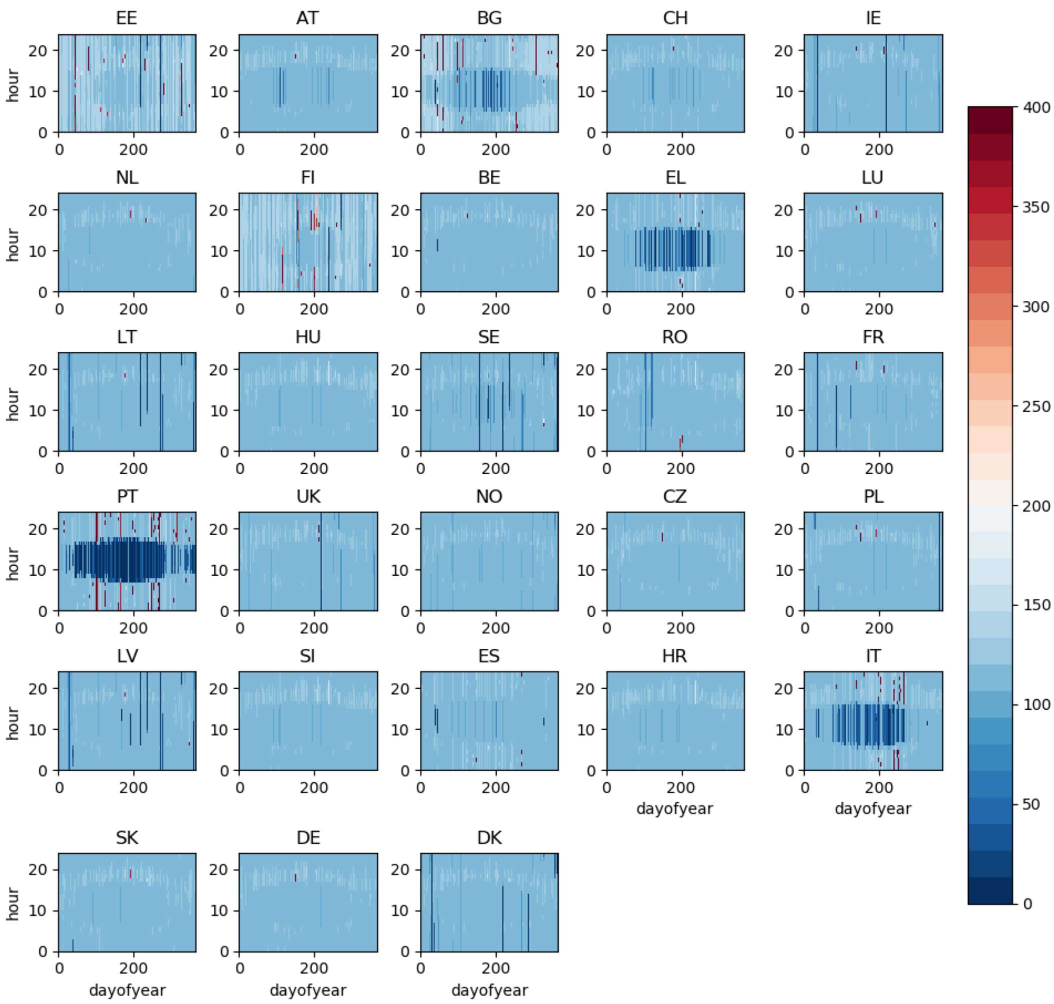


FIGURE 18: Marginal price of electricity at each hour of the year for H2FLEX scenario.

2. H2FLEX, No_PtL and NOH2STO

This section seeks to first understand the interest of the PtL part of the simulation. The only difference between H2FLEX and No_PtL can be found at the modelling level: in H2FLEX, the profile of hydrogen demand linked to PtL is shaped during MTS whereas it is fixed flat in advance in No_PtL. The second goal is to evaluate the role of hydrogen storage.

2.1. Hydrogen demand satisfaction

First of all, the part of the hydrogen demand that is satisfied by the system and by the slack is represented in Fig 19. H2FLEX produces slightly more hydrogen than No_PtL but the difference only amounts to 4 TWh. This figure indicates that hydrogen storage has a certain impact since H2FLEX produces 300 extra hydrogen TWh compared to NOH2STO. However, no storage capacity still allows to produce 60% of H2FLEX hydrogen production which is not negligible.

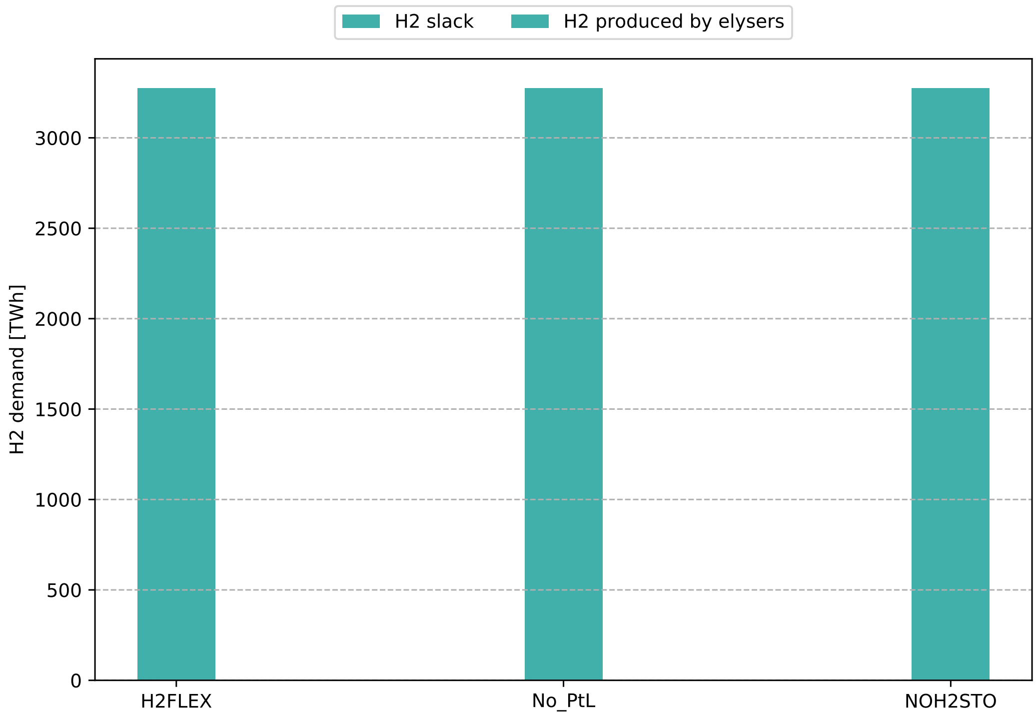


Figure 19: Repartition of the production of hydrogen from the system and from the slack

2.2. Curtailment

Curtailment is represented in Fig 20. Even though No_PtL does not produce significantly less H_2 than H2FLEX, it has almost double curtailment. This implies that PtL planification has a real modelling interest. However, this modelling could be improved. Indeed, MTS has a 24-hour time step. The PtL demand is therefore given per day and is then applied at the same level all day. This is not efficient in countries with a lot of solar energy, as the sun is not shining all day.

Since hydrogen storage capacities are not very high, it might be more beneficial to shape the PtL demand given by the MTS to follow solar production profile in countries depending on solar energy.
As expected, there is much more curtailment in NOH2STO scenario. This curtailment is limited by a higher use of BEVS and BATS in this last scenario than in the 2 others even though the storage capacities of electrical storage technologies are quite limited. As for CHEAPSLACK, this energy allows later to use less gas when RES production is small or equal to 0.

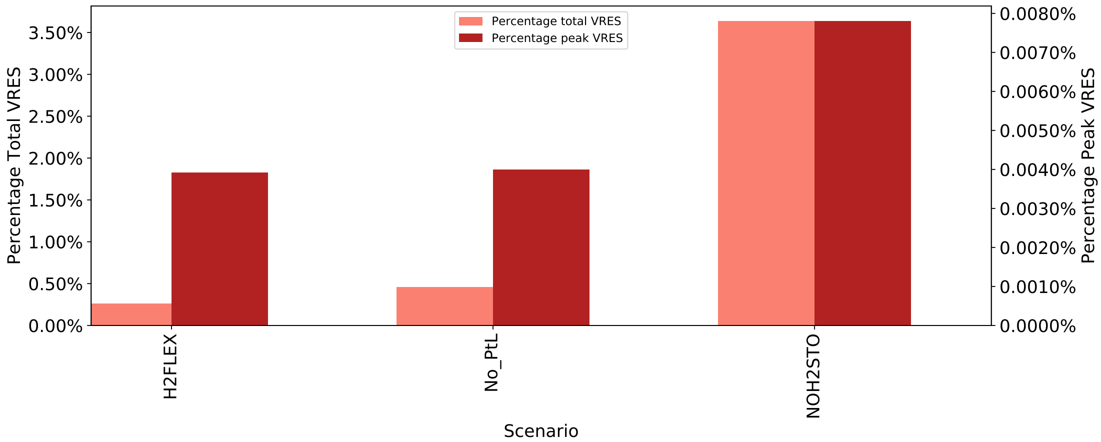


FIGURE 20: Total curtailment for all scenarios

2.3. Electrolysers operation

The EFOH per country is represented for the three scenarios in FIG 21. It can be observed that H2FLEX does not always have higher EFOH than No_PtL. This can be particularly observed in countries whose main RES in sun such as Greece (EL), Slovenia (SI), Spain (ES) or Austria (AT).
EFOH in NOH2STO is generally smaller, especially in countries with high storage capacities. There is almost no difference between H2FLEX and NOH2STO in Ireland (IE) because this country has only 480 MWh of H_2 storage.

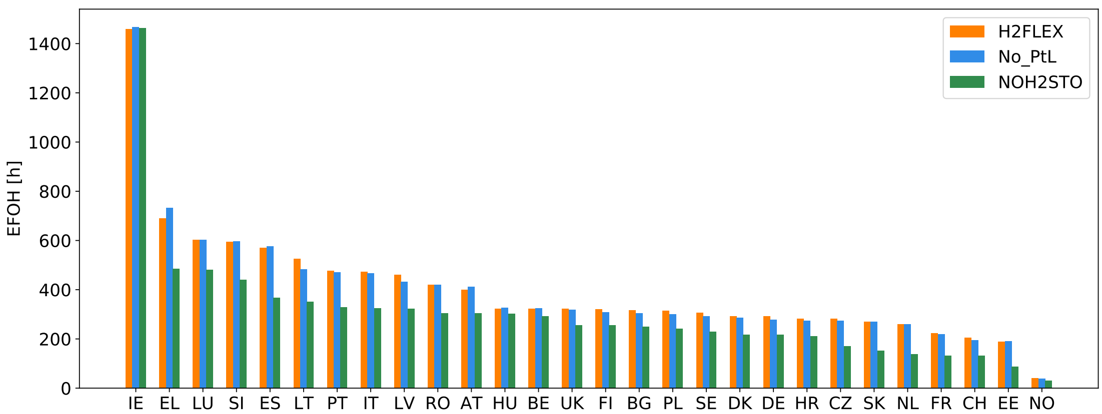


FIGURE 21: EFOH per country for each scenario.

2.4. Storage technologies dynamics

This section is not comparing the different scenarios but observes the storage dynamics. For that purpose, H2FLEX results are described. The State Of Charge (SOC) of 3 storage technologies is compared for Italy and the United Kingdom. Those countries have been chosen because Italy mainly relies on sun production whereas more energy is produced from wind in the UK. Therefore, Italy has to cope with a RES production that peaks around midday but is null at night and the UK deal with a VRES production that can be very high at night. Also the sun produces more during the summer which is not the case of wind.

2.4.1. Italy

The SOC of batteries, H_2 storage and HDAM in Italy is represented in Fig 22. The batteries have a dynamic behaviour all year, even though their activity is limited since the scenario is using a lot of hydrogen. H_2 storage is more full during the summer, which makes sense since Italy mainly relies on solar energy. Its behaviour is also very dynamic as it charges and discharges very often. Finally, the hydro dams acts as the seasonal storage technology. It is also interesting to notice that none of those storage has been oversized. They are probably not undersized either since the curtailment is very small.

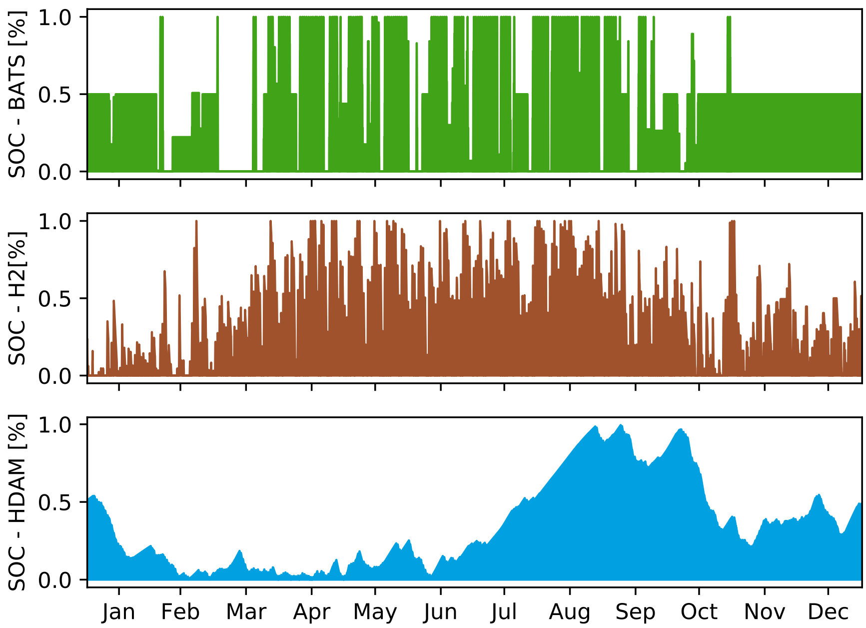


Figure 22: Evolution of the state of charge of batteries, H_2 storage and hydro dams in Italy during the year.

2.4.2. The United Kingdom

The same study is applied to the UK. Fig 23 shows that batteries have the same behaviour as in Italy. However, the hydrogen storage content acts differently since wind is blowing all year and especially more in the winter. Since the capacity of hydro dams in the UK is very restricted, it does not have a seasonal profile and acts more as what is expected for short term storage.

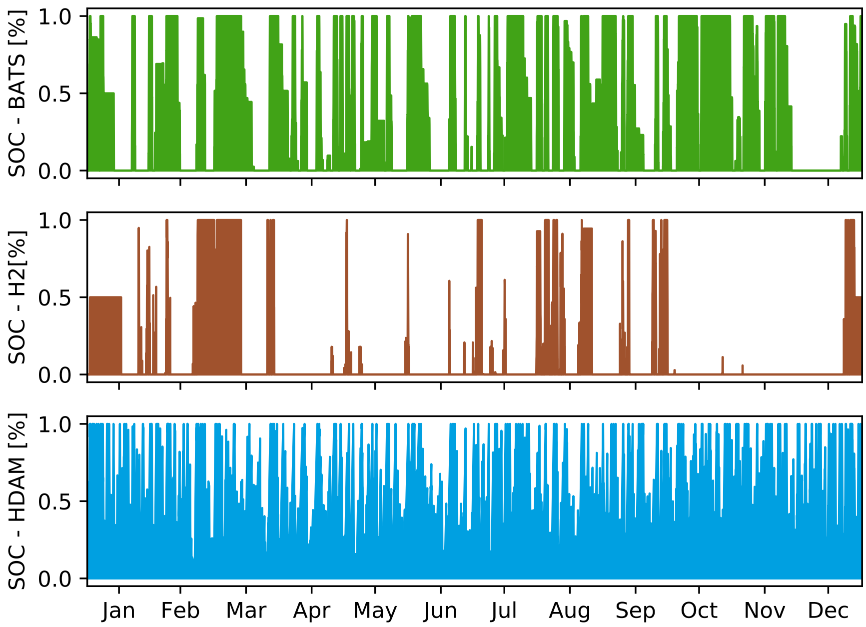


FIGURE 23: Evolution of the state of charge of batteries, H_2 storage and hydro dams in the United Kingdom during the year.

3. TIMES vs. Dispa-SET

It was concluded hereabove that TIMES was overestimating RES production compared to Dispa-SET simulations which led to a lack of renewable energy for hydrogen production in Dispa-SET results. In order to validate this assumption, renewable production in TIMES scenario and in Dispa-SET are compared inFIG 24. As expected, Dispa-SET has a smaller VRES generation than TIMES. The difference is small regarding solar production but is significant when looking at wind production or even water production. The higher production from fuel cells in TIMES was expected since there is less renewable production available for hydrogen in Dispa-SET simulation.

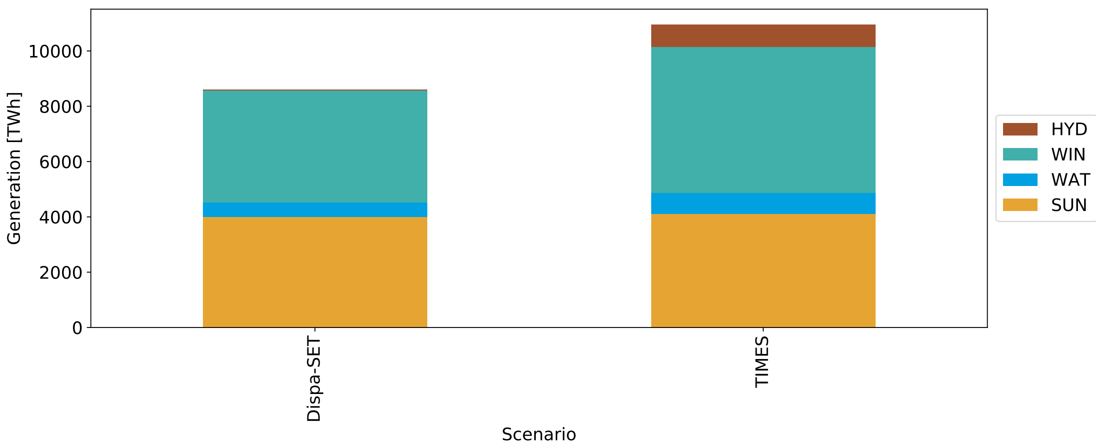


FIGURE 24: Comparison between renewable generation in Dispa-SET (with the H2FLEX scenario) and JRC-EU-TIMES.

Since the biggest difference can be observed for wind, this production had been differentiated by country to look from where the difference can come from. The capacity factors for both scenarios are represented in Fig 25. Capacity factors in Dispa-SET are almost always smaller than the ones in TIMES. The difference can be easily explained due to the fact that Dispa-SET uses historical capacity factors for renewable production and inflows in run-off-rivers and HDAM and TIMES uses standard capacity factors and only simulates 12 time-slices per year.

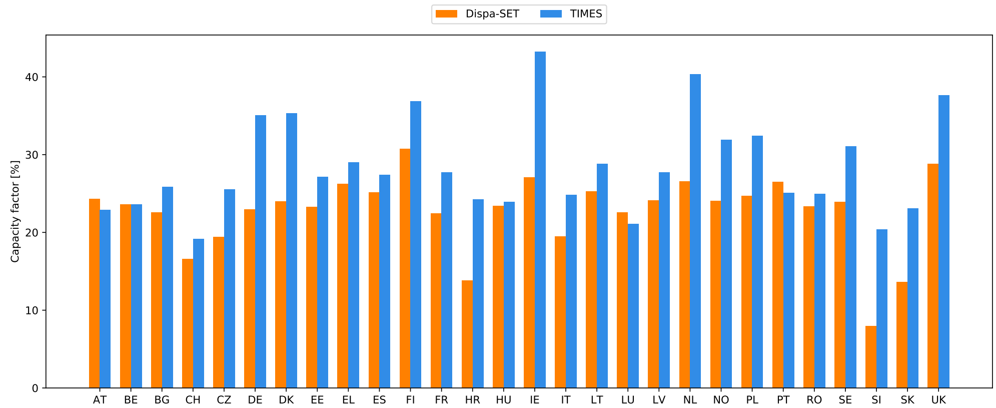


Figure 25: Comparison between renewable wind generation in Dispa-SET (with the H2FLEX scenario) and JRC-EU-TIMES.

3.0.1. Electrolyser capacity

Fig 26 compares the installed capacity of electrolysers in each country and their maximum utilisation. It seems that the electrolysers are over-sized. However, the hydrogen demand has been assumed partly flat, partly shaped in MTS which can be improved and could bring a large error margin. Moreover, the VRES production is different in the 2 scenarios and this also has a big influence on this graph.

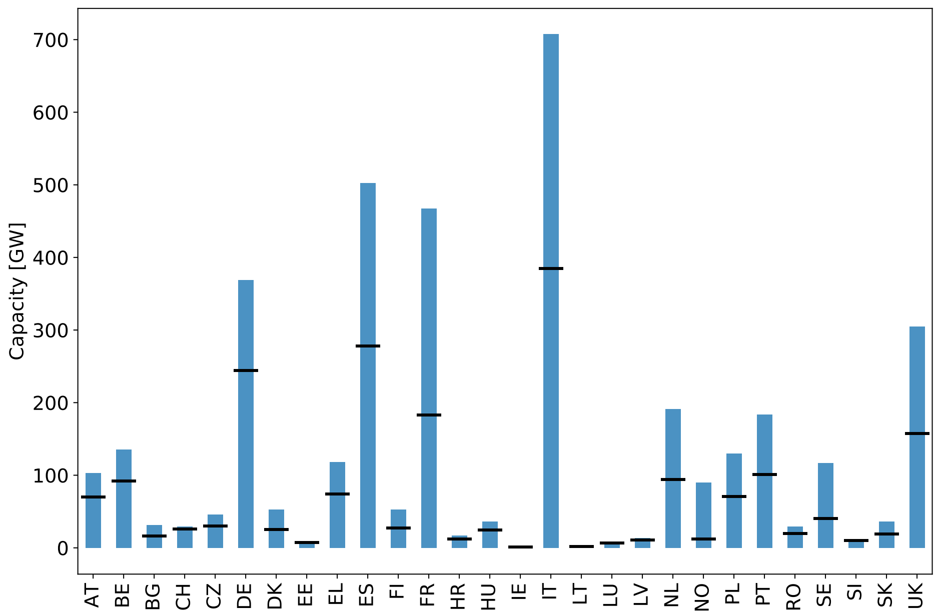


Figure 26: Electrolyser capacities in each country. The horizontal line indicates the peak hydrogen production in Dispa-SET simulations, in GWh.

Part V
Conclusion

The goal of this work was to assess the contribution of the power-to-hydrogen sector in increasing the flexibility of highly coupled energy systems. To do so, Dispa-SET, a highly detailed unit commitment and power dispatch model, was soft-linked with JRC-EU-TIMES, a European long-term investment model. A scenario from TIMES with large shares of VRES was selected. Dispa-SET was extended by adding the equations related to power-to-gas. Also the hydrogen demand for power-to-liquid was taken into account, which gave more flexibility related to liquid fuels storage. An alternative to electrolysers was included, representing methane steam reforming, to determine if electrolysers were able to produce hydrogen at a competitive price and in order to avoid infeasibilities. Four scenarios, CHEAPSLACK, H2FLEX, No_PtL and NOH2STO were studied by varying the price of the hydrogen slack, the power-to-liquid implementation and the hydrogen storage size.

The simulations directly indicate a lack of renewable generation, because renewable generation in TIMES was, due to simplified input assumptions, overestimated by 15% compared to Dispa-SET results. Therefore, the system was not able to produce the right amount of hydrogen to satisfy the demand. On the other hand, TIMES was under estimating the capacity of thermal generation needed to guarantee the security of supply at each hour of the year. Another interesting conclusion is that the RES curtailment in the system was very small, equal to 0.26% of total RES production for H2FLEX scenario, and that was due to the hydrogen sector and to the large electrolysers capacity. Indeed, in this scenario almost 20% of the total renewable production is consumed by electrolysers. Moreover, they have a large influence on the market price by flattening its volatility and increasing it when there are large shares of renewable production. For instance, the average market price in the UK increased by 11% in H2FLEX scenario compared to CHEAPSLACK scenario, due to the additional hydrogen production. On the other hand, the standard deviation of marginal prices during the year decreased by 41% in H2FLEX due to electrolysers consumption.

The proposed modelling framework also allowed validation of the PtL sector modeling since it allows to almost reduce curtailment by 50% and produce more hydrogen with that energy. Hydrogen storage is not seasonal due to its relatively small capacity. In most countries it can provide around 1 hour of storage capacity. In all scenarios, similar H_2 storage behaviour was observed. It often fills completely when there is too much renewable production and empties shortly afterwards to satisfy hydrogen demand.

The uni-directional soft-linking between JRC-EU-TIMES and Dispa-SET provided useful insights regarding the importance of the power-to-gas sector in using the extra renewable production and reducing the curtailment. This shows the importance of sector coupling in future energy systems. The results also show the importance of validating system feasibility provided by long-term planing models.

The future step of this study would be the introduction of feedback loops which would result in bidirectional soft linking between Dispa-SET and TIMES reducing the error and increasing the accuracy of the outputs. The second step would be to refine the carbon cycle implementation in Dispa-SET in order to have a more precise estimation of carbon emission and check that the carbon goal is well achieved. That would for instance require taking into account the carbon needed to synthesize the e-fuels.

Annex

Annex A: Detailed description of Dispa-SET equations

Power plants data: additional information

Input data related to CHP units can be found in TAB 10.

TABLE 10: Parameters for chp units

Description	Field name	Units
CHP Type	CHPType	-
Power-to-heat ratio	CHPPowerToHeat	-
Power Loss factor	CHPPowerLossFactor	-
Maximum heat production	CHPMaxHeat	MW_{th}
Capacity of heat Storage	STOCapacity	MW_{th}
Self-discharge rate	STOSelfDischarge	%/d

Parameters related to power-to-heat (P2HT) units, including heat pumps and electrical heaters, are identified in TAB 11. Electrical heaters can be simulated by setting the nominal COP to 1 and the temperature coefficients to 0. Moreover, the two coefficients a and b aim at correcting the COP for the ambient temperatures. They are calculated as follows:

$$COP = COP_{nom} + coef_a \cdot (T - T_{nom}) + coef_b \cdot (T - T_{nom})^2 \tag{0.1}$$

where T is the atmospheric temperature at each time step.

TABLE 11: Parameters for P2HT units

Description	Field name	Units
Nominal coefficient of performance	COP	-
Nominal temperature	Tnominal	°C
First coefficient	coef_COP_a	-
Second coefficient	coef_COP_b	-
Capacity of heat Storage	STOCapacity	MWh_{th}
% of storage heat losses per day	STOSelfDischarge	%

Power plant outages

In the current version, Dispa-SET does not distinguish planned outages from unplanned outages. They are characterized for each unit by the "OutageFactor" parameter. This parameter varies from 0 (no outage) to 1 (full outage). The available unit power is thus given by its nominal capacity multiplied by (1-OutageFactor).

Optimisation sets, parameters and variables

The sets, parameters and variables used in the modeling are presented.

Sets

Table 12: Sets

Name	Description
au	All units
f	Fuel types
h	Hours
i(h)	Time step in the current optimization horizon
l	Transmission lines between nodes
mk	{DA: Day-Ahead, 2U: Reserve up, 2D: Reserve Down, Flex: flexibility}
n	Zones within each country (currently one zone, or node, per country)
p	Pollutants
p2h(au)	Power to heat units
t	Power generation technologies
th(au)	Units with thermal storage
tr(t)	Renewable power generation technologies
u(au)	Generation units (all units minus P2HT units)
s(u)	Storage units (including hydro reservoirs)
chp(u)	CHP units
wat(s)	Hydro storage technologies
z(h)	Subset of every simulated hour

Parameters

Table 13: Parameters

Name	Units	Description
AvailabilityFactor(u,h)	%	Percentage of nominal capacity available
CHPPowerLossFactor(u)	%	Power loss when generating heat
CHPPowerToHeat(u)	%	Nominal power-to-heat factor
CHPMaxHeat(chp)	MW	Maximum heat capacity of chp plant
CHPType	-	CHP Type
CommittedInitial(u)	-	Initial commitment status
CostFixed(u)	EUR/h	Fixed costs
CostLoadShedding(n,h)	EUR/MWh	Shedding costs
CostRampDown(u)	EUR/MW	Ramp-down costs
CostRampUp(u)	EUR/MW	Ramp-up costs
CostShutDown(u)	EUR/u	Shut-down costs for one unit
CostStartUp(u)	EUR/u	Start-up costs for one unit
CostVariable(u,h)	EUR/MWh	Variable costs
CostHeatSlack(th,h)	EUR/MWh	Cost of supplying heat via other means
CostH2Slack(p2h2,h)	EUR/MWh	Cost of supplying H2 by other means
Curtailment(n)	-	Curtailment {binary: 1 allowed}
Demand(mk,n,h)	MW	Hourly demand in each zone
Efficiency(p2h,h)	%	Power plant efficiency
EmissionMaximum(n,p)	tP	Emission limit per zone for pollutant p
EmissionRate(u,p)	tP/MWh	Emission rate of pollutant p from unit u
FlowMaximum(l,h)	MW	Maximum flow in line
FlowMinimum(l,h)	MW	Minimum flow in line
Fuel(u,f)	-	Fuel type used by unit u {binary: 1 u uses f}
HeatDemand(au,h)	MWh/u	Heat demand profile for chp units

Table 13 Continued from previous page

Name	Units	Description
K_QuickStart(n)	-	Part of the reserve that can be provided by offline quickstart units
LineNode(l,n)	-	Line-zone incidence matrix {-1,+1}
LoadShedding(n,h)	MW	Load that may be shed per zone in 1 hour
Location(au,n)	-	Location {binary: 1 u located in n}
LPFormulation	-	Defines the equation that will be present: 1 for LP and 0 for MIP
Markup	EUR/MW	Markup
MTS	-	Defines the equation that will be present: 1 for MidTermScheduling, 0 for normal optimization
Nunits(u)	-	Number of units inside the cluster
OutageFactor(u,h)	%	Outage factor (100 % = full outage) per hour
PartLoadMin(u)	%	Percentage of minimum nominal capacity
PowerCapacity(au)	MW/u	Installed capacity
PowerInitial(u)	MW/u	Power output before initial period
PowerMinStable(au)	MW/u	Minimum power for stable generation
PowerMustRun(u)	MW	Minimum power output
PriceTransmission(l,h)	EUR/MWh	Price of transmission between zones
QuickStartPower(u,h)	MW/h/u	Available max capacity for tertiary reserve
RampDownMaximum(u)	MW/h/u	Ramp down limit
RampShutDownMaximum(u,h)	MW/h/u	Shut-down ramp limit
RampStartUpMaximum(u,h)	MW/h/u	Start-up ramp limit
RampUpMaximum(u)	MW/h/u	Ramp up limit
Reserve(t)	-	Reserve provider {binary}
StorageCapacity(au)	MWh/u	Storage capacity (reservoirs)
StorageChargingCapacity(au)	MW/u	Maximum charging capacity
StorageChargingEfficiency(au)	%	Charging efficiency
StorageDischargeEfficiency(au)	%	Discharge efficiency
StorageInflow(u,h)	MWh/u	Storage inflows
StorageInitial(au)	MWh	Storage level before initial period
StorageMinimum(au)	MWh/u	Minimum storage level
StorageOutflow(u,h)	MWh/u	Storage outflows (spills)
StorageProfile(u,h)	%	Storage long-term level profile
StorageSelfDischarge(au)	%/day	Self discharge of the storage units
Technology(u,t)	-	Technology type {binary: 1: u belongs to t}
TimeDownMinimum(u)	h	Minimum down time
TimeStep	h	Duration of a timestep of optimization
TimeUpMinimum(u)	h	Minimum up time
VOLL()	EUR/MWh	Value of lost load

NB: When "/u" appears in the units of the parameter, the value is given per unit.

Optimisation variables

Table 14: Continuous variables

Name	Units	Description
Committed(u,h)	-	Unit committed at hour h {1,0}
CostStartUpH(u,h)	EUR	Cost of starting up
CostShutDownH(u,h)	EUR	Cost of shutting down
CostRampUpH(u,h)	EUR	Ramping cost
CostRampDownH(u,h)	EUR	Ramping cost
CurtailedPower(n,h)	MW	Curtailed power at node n

Table 14 Continued from previous page

Name	Units	Description
Flow(l,h)	MW	Flow through lines
Heat(au,h)	MW	Heat output by chp plant
HeatSlack(au,h)	MW	Heat satisfied by other sources
Power(u,h)	MW	Power output
PowerConsumption(p2h,h)	MW	Power consumption by P2H
PowerMaximum(u,h)	MW	Power output
PowerMinimum(u,h)	MW	Power output
Reserve_2U(u,h)	MW	Spinning reserve up
Reserve_2D(u,h)	MW	Spinning reserve down
Reserve_3U(u,h)	MW	Non spinning quick start reserve up
ShedLoad(n,h)	MW	Shed load
StorageInput(au,h)	MWh	Charging input for storage units
StorageLevel(au,h)	MWh	Storage level of charge
StorageSlack(s,i)	MWh	Unsatisfied storage level
Spillage(s,h)	MWh	Spillage from water reservoirs
SystemCost(h)	EUR	Total system cost
LL_MaxPower(n,h)	MW	Deficit in terms of maximum power
LL_RampUp(u,h)	MW	Deficit in terms of ramping up for each plant
LL_RampDown(u,h)	MW	Deficit in terms of ramping down
LL_MinPower(n,h)	MW	Power exceeding the demand
LL_2U(n,h)	MW	Deficit in reserve up
LL_3U(n,h)	MW	Deficit in reserve up - non spinning
LL_2D(n,h)	MW	Deficit in reserve down
WaterSlack(s)	MWh	Unsatisfied water level at end of optimization period

Table 15: Integer variables

Name	Units	Description
Committed(u,h)	-	Number of unit committed at hour h {1 0} or integer
StartUp(u,h)	-	Number of unit startups at hour h {1 0} or integer
ShutDown(u,h)	-	Number of unit shutdowns at hour h {1 0} or integer

Optimisation model: presentation of missing equations

Storage equations are not represented here since they can be found in the main text.

The variable production costs (in EUR/MWh), are determined by fuel and emission prices corrected by the efficiency (which is considered to be constant for all levels of output in this version of the model) and the emission rate of the unit (equation):

$$\begin{aligned} CostVariable_{u,h} =& Markup_{u,h} + \sum_{n,f} \left(\frac{Fuel_{u,f} \cdot FuelPrice_{n,f,h} \cdot Location_{u,n}}{Efficiency_u} \right) \\ & + \sum_{p} \left(EmissionRate_{u,p} \cdot PermitPrice_p \right) \end{aligned} \tag{0.2}$$

The variable cost includes an additional mark-up parameter that can be used for calibration and validation purposes. For now, only CO_2 emissions are taken into account.

Dispa-SET uses a 3 integers formulations of the up/down status of all units. According to this formulation, the number of start-ups and shut-downs at each time step is computed by:

$$Committed_{u,i} - Committed_{u,i-1} = StartUp_{u,i} - ShutDown_{u,i} \tag{0.3}$$

The start-up and shut-down costs are positive variables, calculated from the number of startups/shutdowns at each time step:

$$CostStartUp_{u,i} = CostStartUp_{u} \cdot StartUp_{u,i} \tag{0.4}$$

$$CostShutDown_{u,i} = CostShutDown_{u} \cdot ShutDown_{u,i} \tag{0.5}$$

Renewable units are enforced commited when the availability factor is non null and the outage factor is not 1 and decommited in the other case.

Ramping costs are defined as positive variables (i.e. negative costs are not allowed) and are computed with the following equations:

$$\begin{aligned} CostRampUp_{u,i} &\geq CostRampUp_{u} \cdot (Power_{u,i} - Power_{u,i-1}) \\ CostRampDown_{u,i} &\geq CostRampDown_{u} \cdot (Power_{u,i-1} - Power_{u,i}) \end{aligned} \tag{0.6}$$

It should be noted that in case of start-up and shut-down, the ramping costs are added to the objective function. Using start-up, shut-down and ramping costs at the same time should therefore be performed with care.

In the current formulation, all other costs (fixed and variable costs, transmission costs, load shedding costs) are considered as exogenous parameters.

Reserve constraints

Besides the production/demand balance, the reserve requirements (upwards and downwards) in each node must be met as well. In Dispa-SET, three types of reserve requirements are taken into account:

- Upward secondary reserve (2U): reserve that can only be covered by spinning units
- Downward secondary reserve (2D): reserve that can only be covered by spinning units
- Upward tertiary reserve (3U): reserve that can be covered either by spinning units or by quick-start offline units

The secondary reserve capability of committed units is limited by the capacity margin between current and maximum power output:

$$\begin{aligned} Reserve_{2U\,u,i} \leq & PowerCapacity_{u} \cdot AvailabilityFactor_{u,i} \cdot (1 - OutageFactor_{u,i}) \cdot Committed_{u,i} \\ & - Power_{u,i} \end{aligned} \tag{0.7}$$

The same applies to the downwards secondary reserve capability, with an additional term to take into account the downward reserve capability of storage units:

$$\begin{aligned} Reserve_{2D\,u,i} \leq\ & Power_{u,i} - PowerMustRun_{u,i} \cdot Committed_{u,i} \\ & + (StorageChargingCapacity_u \cdot Nunits_u - StorageInput_{u,i}) \end{aligned} \tag{0.8}$$

The quick start (non-spining) reserve capability is given by:

$$Reserve_{3U\,u,i} \leq (Nunits_u - Committed_{u,i}) \cdot QuickStartPower_{u,i} \cdot TimeStep \tag{0.9}$$

The secondary reserve demand should be fulfilled at all times by all the plants allowed to participate in the reserve market:

$$\begin{aligned} Demand_{2U,n,h} \leq & \sum_{u,t} \left(Reserve_{2U\,u,i} \cdot Technology_{u,t} \cdot Reserve_t \cdot Location_{u,n}\right) \\ & + LL_{2U\,n,i} \end{aligned} \tag{0.10}$$

The same equation applies to downward reserve requirements (2D).

The tertiary reserve can also be provided by non-spinning units. The inequality is thus transformed into:

$$\begin{aligned} Demand_{3U,n,h} \leq & \sum_{u,t} [(Reserve_{2U\,u,i} + Reserve_{3U\,u,i}) \cdot Technology_{u,t} \cdot Reserve_t \cdot Location_{u,n}] \\ & + LL_{3U\,n,i} \end{aligned} \tag{0.11}$$

The reserve requirements are defined by the users. In case no input is provided a default formula is used to evaluate the needs for secondary reserves as a function of the maximum expected load for each day. The default formula is described by:

$$Demand_{2U,n,i} = \sqrt{10 \cdot \max_h (Demand_{DA,n,h}) + 150^2} - 150 \tag{0.12}$$

Downward reserves are defined as 50% of the upward margin:

$$Demand_{2D,n,h} = 0.5 \cdot Demand_{2U,n,h} \tag{0.13}$$

Power output bounds

The minimum power output is determined by the must-run or stable generation level of the unit if it is committed:

$$PowerMustRun_{u,i} \cdot Committed_{u,i} \leq Power_{u,i} \tag{0.14}$$

In the particular case of CHP unit (extration type or power-to-heat type), the minimum power is defined for for a heat demand equal to zero. If the unit produces heat, the minimum power must be reduced according to the power loss factor and the previous equation is replaced by:

$$\begin{aligned} PowerMustRun_{chp,i} \cdot Committed_{chp,i} - StorageInput_{chp,i} \cdot CHPPowerLossFactor_u \\ \leq Power_{chp,i} \end{aligned} \tag{0.15}$$

The power output is limited by the available capacity, if the unit is committed:

$$\begin{aligned} & \mathit{PowerCapacity}_u \cdot \mathit{AvailabilityFactor}_{u,i} \cdot (1 - \mathit{OutageFactor}_{u,i}) \cdot \mathit{Committed}_{u,i} \\ & \qquad \geq \mathit{Power}_{u,i} \end{aligned} \tag{0.16}$$

The availability factor is used for renewable technologies to set the maximum time-dependent generation level. It is set to one for the traditional power plants. The outage factor accounts for the share of unavailable power due to planned or unplanned outages.

Ramping constraints
Each unit is characterized by a maximum ramp-up and ramp-down capability. This is translated into the following inequality for the case of ramping up:

$$\begin{aligned} \mathit{Power}_{u,i} - \mathit{Power}_{u,i-1} \leq & (\mathit{Committed}_{u,i} - \mathit{StartUp}_{u,i}) \cdot \mathit{RampUpMaximum}_u \cdot \mathit{TimeStep} \\ & + \mathit{StartUp}_{u,i} \cdot \mathit{RampStartUpMaximum}_u \cdot \mathit{TimeStep} \\ & - \mathit{ShutDown}_{u,i} \cdot \mathit{PowerMustRun}_{u,i} \\ & + LL_{\mathit{RampUp}_{u,i}} \end{aligned} \tag{0.17}$$

and for the case of ramping down:

$$\begin{aligned} \mathit{Power}_{u,i-1} - \mathit{Power}_{u,i} \leq & (\mathit{Committed}_{u,i} - \mathit{ShutDown}_{u,i}) \cdot \mathit{RampDownMaximum}_u \cdot \mathit{TimeStep} \\ & + \mathit{ShutDown}_{u,i} \cdot \mathit{RampShutDownMaximum}_u \cdot \mathit{TimeStep} \\ & - \mathit{StartUp}_{u,i} \cdot \mathit{PowerMustRun}_{u,i} + LL_{\mathit{RampDown}_{u,i}} \end{aligned} \tag{0.18}$$

Note that this formulation is valid for both the clustered formulation and the binary formulation. In the latter case (there is only one unit u), if the unit remains committed, the inequality simplifies into:

$$\mathit{Power}_{u,i} - \mathit{Power}_{u,i-1} \leq \mathit{RampUpMaximum}_u \cdot \mathit{TimeStep} + LL_{\mathit{RampUp}_{u,i}} \tag{0.19}$$

If the unit has just been committed, the inequality becomes:

$$\mathit{Power}_{u,i} - \mathit{Power}_{u,i-1} \leq \mathit{RampStartUpMaximum}_u \cdot \mathit{TimeStep} + LL_{\mathit{RampUp}_{u,i}} \tag{0.20}$$

And if the unit has just been stopped:

$$\mathit{Power}_{u,i} - \mathit{Power}_{u,i-1} \leq -\mathit{PowerMustRun}_{u,i} + LL_{\mathit{RampUp}_{u,i}} \tag{0.21}$$

Minimum up and down times

The operation of the generation units is also limited as well by the amount of time the unit has been running or stopped. In order to avoid excessive ageing of the generators, or because of their physical characteristics, once a unit is started up, it cannot be shut down immediately. Reciprocally, if the unit is shut down it may not be started immediately.

To model this in MILP, the number of startups/shutdowns in the last N hours must be limited, N being the minimum up or down time. For the minimum up time, the number of startups during this period cannot be higher than the number of currently committed units:

$$\sum_{ii=i-\frac{TimeUpMinimum_u}{TimeStep}}^{i} StartUp_{u,ii} \leq Committed_{u,i} \tag{0.22}$$

i.e. the currently committed units are not allowed to have performed multiple on/off cycles between the optimization time minus TimeUpMinimum and the optimization time. The implied number of periods is computed by the ratio of TimeUpMinimum and TimeStep. If TimeUpMinimum is not a multiple of TimeStep, their fraction is rounded upwards. In case of a binary formulation (Nunits=1), if the unit is ON at time i, only one startup is allowed in the last TimeUpMinimum periods. If the unit is OFF at time i, no startup is allowed.

A similar inequality can be written for the minimum down time:

$$\sum_{ii=i-\frac{TimeDownMinimum_u}{TimeStep}}^{i} ShutDown_{u,ii} \leq Nunits_u - Committed_{u,i} \tag{0.23}$$

Heat production constraints (CHP plants only)

In Dispa-SET Power plants can be indicated as CHP satisfying one heat demand. Heat Demand can be covered either by a CHP plant or by alternative heat supply options (Heat Slack), which is represented in FIG 27.

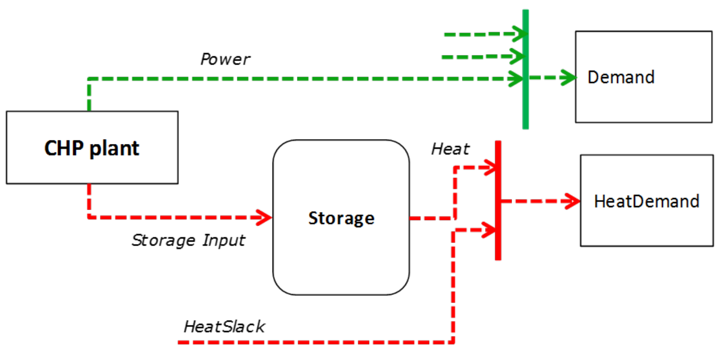


FIGURE 27: Representation of CHP flows

The following two heat balance constraints are used for any CHP and P2H plant types.

$$\begin{aligned} Heat(th,i) + HeatSlack(th,i) = HeatDemand(th,i) \\ StorageInput_{chp,i} \leq CHPMaxHeat_{chp} \cdot Nunits_{chp} \end{aligned} \tag{0.24}$$

The constraints between heat and power production differ for each plant design and explained within the following subsections.
Steam plants with Backpressure turbine: This options includes steam-turbine based power plants with a backpressure turbine. The feasible operating region is between AB on FIG 28. The slope of the line is the heat to power ratio:

$$Power_{chp,i} = StorageInput_{chp,i} \cdot CHPPowerToHeat_{chp} \tag{0.25}$$

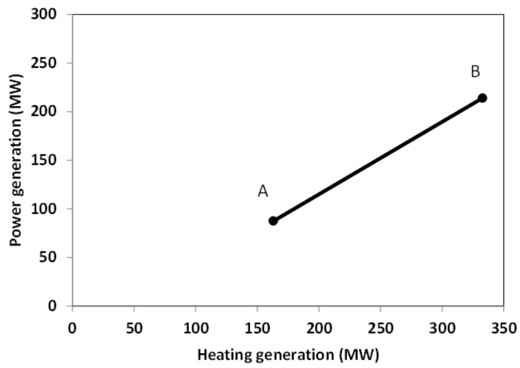


FIGURE 28: Backpressure turbine feasible region

Steam plants with Extraction/condensing turbine: This options includes steam-turbine based power plants with an extraction/condensing turbine. The feasible operating region is within ABCDE as represented in FIG 29. The vertical dotted line BC corresponds to the minimum condensation line (as defined by CHPMaxHeat). The slope of the DC line is the heat to power ratio and the slope of the AB line is the inverse of the power penalty ratio. The contraints applied on the output power of those units are represented by EQ 0.26 to 0.28.

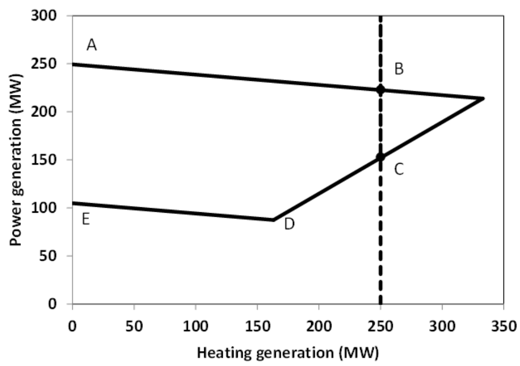


FIGURE 29: Extraction turbine feasible region

$$Power_{chp,i} \geq StorageInput_{chp,i} \cdot CHPPowerToHeat_{chp} \tag{0.26}$$

$$\begin{aligned} Power_{chp,i} \leq\ & PowerCapacity_{chp} \cdot Nunits \\ & - StorageInput_{chp,i} \cdot CHPPowerLossFactor_{chp} \end{aligned} \tag{0.27}$$

$$
\begin{aligned}
Power_{chp,i} \geq\ & PowerMustRun_{chp,i} \\
& - StorageInput_{chp,i} \cdot CHPPowerLossFactor_{chp}
\end{aligned} \tag{0.28}
$$

Power plant coupled with any power to heat option: This option includes power plants coupled with resistance heater or heat pumps. The feasible operating region is between ABCD in Fig 30. The slope of the AB and CD line is the inverse of the COP or efficiency. The vertical dotted line corresponds to the heat pump (or resistance heater) thermal capacity (as defined by CHPMaxHeat). The constraints applied on the output power can be found in Eq 0.29 and 0.30.

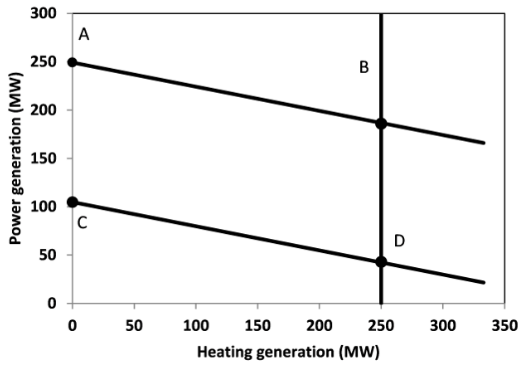


Figure 30: Feasible region of P2H units

$$
Power_{chp,i} \leq PowerCapacity_{chp} - StorageInput_{chp,i} \cdot CHPPowerLossFactor_{chp} \tag{0.29}
$$

$$
Power_{chp,i} \geq PowerMustRun_{chp,i} - StorageInput_{chp,i} \cdot CHPPowerLossFactor_{chp} \tag{0.30}
$$

Heat Storage: Heat storage is modeled in a similar way as electric storage. Heat storage balance is expressed as:

$$
\begin{aligned}
StorageLevel_{th,i-1} + StorageInput_{th,i} \cdot TimeStep = & \qquad (0.31)\\
StorageLevel_{th,i} + Heat_{th,i} \cdot TimeStep & \qquad (0.32)\\
+StorageSelfDischarge_{th} \cdot StorageLevel_{th,i} \cdot TimeStep/24 & \qquad (0.33)\\
& \qquad (0.34)
\end{aligned}
$$

Storage level must be above a minimum and below storage capacity:

$$
StorageMinimum_{th} \cdot Nunits_{th} \leq StorageLevel_{chp,i} \leq StorageCapacity_{th} \cdot Nunits_{th} \tag{0.35}
$$

Network-related constraints

The flow of power between nodes is limited by the capacities of the transmission lines:

$$
\begin{aligned}
Flow_{l,i} \geq FlowMinimum_{l,i} & \qquad (0.36)\\
Flow_{l,i} \leq FlowMaximum_{l,i} & \qquad (0.37)\\
& \qquad (0.38)
\end{aligned}
$$

In this model a simple Net Transfer Capacity (NTC) between countries approach is followed. No DC power flow or Locational Marginal Pricing (LMP) model is implemented.

Load shedding

If load shedding is allowed in a node, the amount of shed load is limited by the shedding capacity contracted on that particular node (e.g. through interruptible industrial contracts)

$$ShedLoad_{n,i} \leq LoadShedding_{n,i} \tag{0.39}$$

Annex B: Transmission capacities

TABLE 16: Transmission capacities

Interconnection	Capacity [GW]	Interconnection	Capacity [GW]
AT -> CH	2.5	HU -> SK	2
AT -> CZ	1	IE -> FR	2
AT -> DE	7.5	IE -> FR	0.7
AT -> HU	1.2	IE -> UK	1.7
AT -> IT	9.9	IT -> AT	1.7
AT -> SI	1.2	IT -> CH	3.65
BE -> DE	6	IT -> EL	9.5
BE -> FR	2.8	IT -> FR	2.2
BE -> LU	1.08	IT -> SI	1.2
BE -> NL	12.4	LT -> LV	5.1
BE -> UK	6	LT -> PL	1
BG -> EL	2.4	LT -> SE	0.7
BG -> RO	1.4	LU -> BE	0.7
CH -> AT	2.2	LU -> DE	2.3
CH -> DE	5	LV -> EE	1.6
CH -> FR	2.8	LV -> LT	1.9
CH -> IT	5.9	NL -> BE	2.4
CZ -> AT	1.2	NL -> DE	5
CZ -> DE	2.6	NL -> NO	14.7
CZ -> PL	2.8	NL -> UK	1
CZ -> SK	2.1	NO -> DE	1.4
DE -> AT	15.5	NO -> DK	1.7
DE -> BE	1	NO -> FI	0.1
DE -> CZ	2	NO -> NL	0.7
DE -> DK	4.6	NO -> SE	3.695
DE -> FR	4.1	NO -> UK	6.4
DE -> LU	2.3	PL -> CZ	1.8
DE -> NL	5	PL -> DE	3
DE -> NO	10.4	PL -> LT	9
DE -> PL	12	PL -> SE	0.6
DE -> SE	16.2	PL -> SK	0.99
DK -> NL	0.7	PT -> ES	3.2
DK -> NO	1.7	RO -> BG	1.5
DK -> NL	0.7	RO -> HU	1.4
DK -> SE	2.44	SE -> DE	1.2
DK -> UK	1.4	SE -> DK	2.04
EE -> FI	5	SE -> SI	3.15
EE -> LV	5.6	SE -> LT	0.7
EL -> BG	0.4	SE -> NO	3.995
EL -> IT	0.5	SE -> PL	0.6
ES -> FR	19	SI -> AT	1.2
ES -> PT	7.2	SI -> HR	1.5
ES -> UK	1	SI -> HU	2
FI -> EE	1	SI -> IT	2.4
FI -> NO	0.1	SK -> CZ	1.1
FI -> SE	3.15	SK -> HU	2
FR -> BE	7.3	SK -> PL	0.99

Table 16 Continued from previous page

Interconnection	Capacity [GW]	Interconnection	Capacity [GW]
FR -> CH	7.3	UK -> BE	2
FR -> DE	9.1	UK -> DK	1.4
FR -> IE	5.7	UK -> ES	1
FR -> IT	4.35	UK -> FR	5.4
FR -> LU	0.51	UK -> IE	5.7
FR -> UK	16.4	UK -> NL	1
HU -> AT	0.8	UK -> NO	1.4
HU -> RO	3.3	HU -> SI	1.7

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