Modelling Hydropower in detail to assess its contribution to flexibility services in the European power system

Master thesis in Energy Science
by **Andrés Sánchez Pérez**

Student

Andres Sanchez Perez

Student number: 5566118

a.sanchezperez@students.uu.nl

Supervisor

dr. ir. Machteld van den Broek

m.a.vandenbroek@uu.nl

Second reader

Prof. dr. Gert Jan Kramer

g.j.kramer@uu.nl

Master Programme: Energy Science, System Analysis track

Course Title: ENSM-Master's thesis (GEO-2510), 30ECTS

Acknowledgments

To my supervisor Machteld van den Broek for providing valuable feedback and guidance for the writing of this report. To William Zappa for contributing with his advice. Special thanks for Sylvain Quoilin for answering endless questions and helping me getting the model started.

To my parents for their patience, unconditional support and encouragement. To my brother for his helpful reviewing work and company.

Table of Contents

Summary

Decarbonizing the energy mix is a promising strategy to mitigate climate change and reach long term emission reduction targets. Intermittent renewable energy sources (iRES) such as solar PV and wind (offshore and onshore) are expected to have a vital role in future low carbon energy systems. As the share of iRES increases, so do the flexibility requirements from complementary technologies to ensure system adequacy. Hydropower is regarded as a key contributor for system adequacy by providing flexibility and the full range of ancillary services.

This study assesses the effects of different yearly water inflows (rainfall years) on the ability of hydropower to generate and store electricity in a European low carbon energy system with 59% iRES penetration in the year 2050. This is done using the hourly power system simulation software Dispa-SET developed by the European Commission. Three rainfall years are investigated: a high flow year, an average flow year and a low flow year. Each rainfall year is simulated using short-term and long-term optimization of the storage of the hydropower storage levels, leading to a total of six scenarios. Only the long-term optimization considers seasonal variation of water inflows for the simulation.

Results show that different rainfall years affect electricity production of hydro plants by up to 4%. This translates into a maximum of 7% variation in annual variable production costs. The long-term optimization of reservoir levels results in increased electricity production (1- 2%) and decreased variable costs (5 - 7%), compared to the short-term optimization. Key mechanisms contributing to the results are: (1) a production shift from gas turbines (GT) to pumped hydro storage plants (PHS), storage hydro plant STO) and other power generators, (2) iRES curtailment reduction, (3) storage hydro plant spillage reductions.

Based on this study, hydropower has a key role as a flexibility provider in an energy system with 59% iRES penetration. The different rainfall years have a limited impact on the total hydroelectricity production but they translate into a significant reduction of variable costs in the system. The added value of the long-term optimization lies in providing insight on the potential savings that can be achieved if seasonal variations of water inflows are considered for the dispatch of hydropower plants

Abbreviations

HP: Hydropower

CCS: Carbon Capture & Storage

DR: Demand Response

CAES: Compressed Air Storage

iRES: Intermittent Renewable Energy Sources

RES: Renewable Energy Sources

ROR: Run-of-River hydro plant

GT: Gas Turbine

NGCC: Natural Gas Combined Cycle Plant

Solar PV: Solar Photovoltaic

STO: Storage hydro plant

PHS Pump Hydro Storage

ES: Electricity Storage

JRC: Joint Research Center

GB – United Kingdom + Ireland

FR – France

DE – Germany + Belgium + Luxemburg + Netherlands

ES – Portugal + Spain

IT – Italy + Austria + Switzerland

SH – Simulation horizon

ST – Short term

LT – Long term

UCED: Unit Commitment and Economic Dispatch

Concept definitions

Unit: element of the energy system producing or storing electricity

Availability factor: proportion of the nominal power capacity that can be generated at each hour for a given unit.

Capacity factor: ratio of the net electricity generated by a unit in a year to the energy that could have been generated if the unit had run at continuous full power.

Inflows: contribution of exogenous sources to the level (state of charge) of a reservoir. Only water inflows and electricity inflows are considered for hydropower and demand response respectively.

Simulation horizon: full time length in which the simulation runs over.

Simulation step: length of the time intervals the solver takes to solve the simulation horizon.

Rainfall year: sample year defining the monthly water catchment by the reservoirs. Three are considered:

1. Wet scenario (high flows)
2. Dry scenario (low flows)
3. Average scenario (average flows)

The scenarios are defined by three elements: (1) A rainfall year, (2) A simulation step, (3) A simulation horizon.

Short term (ST) scenarios are defined for the three rainfall years optimized with a simulation step of 5 days and a simulation horizon of 1 year. Three are modelled:

1. 1-year-wet-ST-scenario (wet-ST-scenario)
2. 1-year dry-ST-scenario (dry-ST-scenario)
3. 1-year-average-ST scenario (average-ST-scenario)

Long term (LT) scenarios: defined for the three rainfall years optimized with a simulation step and simulation horizon of 1 year. Three are modelled:

1. 1-year-wet-LT scenario (wet-LT1 scenario)
2. 1-year-dry-LT scenario (dry-LT1 scenario)
3. 1-year-average-LT scenario (average-LT1 scenario)

1 Introduction

1.1 Background

Anthropogenic CO_2 emissions contribute to increasing the global average surface temperature leading to global warming (European commission, 2011). This has been recognized as a threat to the climate system for which mechanisms to reduce such emissions are being set in place (IPCC Working Group 1 et al., 2013).

Decarbonizing the energy mix by including higher shares of intermittent renewable energy sources (iRES) and power plants equipped with Carbon Capture and Storage (CCS) is a promising strategy to mitigate climate change and is regarded as a necessity in order to meet the emission reduction targets[1] set by the European Union (European commission, 2011).

As the penetration of iRES increases in a power system, so does the requirement for operational flexibility and backup generation capacity which requires shifting to a more complex power system (Brouwer, van den Broek, Zappa, Turkenburg, & Faaij, 2016; Kopytko & Perkins, 2011).

Operational flexibility and/or backup generation capacity can be obtained from five different complimentary options: fast responding power plants (usually gas fired plants, but lately also coal fired plants) to adjust quickly to sudden changes in demand, Demand Response (DR) to reduce peak load, storage capacity (e.g. Pumped hydro storage, compressed air energy storage (CAES)), connection to other grid zones to enable import/export of electricity, and curtailment (Brouwer et al., 2016; Gaudard & Romerio, 2014)

How these options will be deployed in a cost-effective way in future low carbon energy systems remains of great interest for energy companies and governments for future planning. In this, hydropower has been recognized as a central player in providing flexibility to the power system, especially due to its low operational cost, reliability and unrivaled fast response time to demand fluctuations (Gaudard & Romerio, 2014; IRENA, 2012).

Hydropower is the most established and long lasting renewable resource for energy production (Twidell & Weir, 2006). In 2016, it was responsible for producing 341TWh of gross electricity in EU-28, which corresponds to 42.9% of its renewable energy and 10.5% of its total gross electricity production (Eurostat, 2017a, 2017b). It is able to provide an important share of ancillary services (AS) including: secondary and tertiary reserves[2], voltage support, load following, compensation for grid losses and black start contributing strongly to the flexibility of the energy system (Gaudard & Romerio, 2014). As a storage technology, it is the most efficient available today, capable of storing electricity for weeks, months and

[1] Such targets consist on reducing the emissions by 20% by year 2020 and by 80% by 2050 (compared to 1990's emissions)

[2] Secondary reserves are available in between 30 secs and 15 min. Tertiary reserves must be available in 15 -30 min. Hydropower is not able to provide primary reserves (available in 0-30 secs) for which fast responding power plants are needed.

even years , and constitutes the only existing economically viable large-scale technology available today (Eurelectric, 2015; IRENA, 2012).

In the context of power system modelling, hydropower requires a detailed treatment including sufficient hydrological data such as water availability, regulations (water required for other purposes such as irrigation, or drinking water, ecological reasons) and plant configurations (Eurelectric, 2015; Huertas-Hernando et al., 2016). There are three reasons for requiring such a detailed approach (Gaudard & Romerio, 2014; Huertas-Hernando et al., 2016; Twidell & Weir, 2006).

1. Water availability is determined by inherently variable rainfall patterns, changing both temporally and spatially.
2. There are technical differences between hydro-power plants (type of turbine, available hydraulic head, storage capacity, efficiency.
3. Generating costs and electricity production are site-specific for which performance data of currently operating plants cannot be extrapolated to other locations.

The combination of these factors causes the characteristics of individual plants to differ from one another (even for the same type of plant), making detailed models of hydro power plants valuable

An example is Gerritsma's model for the European power system that included a database of techno-economical details of installed hydropower plants and an estimation of their corresponding water flows (Gerritsma, 2016). Other models present simpler modelling approaches making use of aggregated data to define plant performance while not taking rainfall patterns or water availability into consideration (Brouwer, van den Broek, Zappa, Turkenburg, & Faaij, 2016; Deml, 2014). Many other examples of modelling techniques for hydropower can be found in Manzano-agugliaro's work (Manzano-agugliaro et al., 2011). A common limitation among these studies is that reservoir levels are not optimized to model seasonal variations accurately because the reservoir levels (if considered) are only optimized for short term scheduling (e.g. 5-10 days). Such approaches limit the potential contribution hydropower could provide to the system by shifting peak loads over longer time scales.

The aim of this research is to assess the contribution that hydropower can provide to the flexibility of the European energy system on a long-term scale, and determine its sensitivity to different rainfall scenarios. The focus is to be able to adequately model hydropower during periods equal to and greater than 1 year, thus enabling the possibility of studying the effects of variable water inflow scenarios in the model predictions.

To achieve this goal, a detailed approach to modelling hydropower – based on the methods developed and data gathered by Gerritsma (Gerritsma, 2016) – is required. Gerritsma's methodology is extended to attain an optimal management of water inflows by allowing an unconstrained optimization of reservoirs water levels during the full simulation periods. With this approach, it is possible to study the effects of seasonal variation of water inflows (using time horizon of one year)

The results show the advantages of smart management of water availability in exploiting the inherent flexibility in the energy system. A direct comparison is presented between typical optimization of reservoir levels with the improved approach in this study for different rainfall scenarios.

The modelling work is done using Dispa-Set 2.1 (Dispa-Set) which is a power system modelling software developed by JRC's Institute of Energy and Transport (Hidalgo Gonzalez, Sylvain, & Zucker, 2014).

Dispa-SET is used since it is free and open-source, which means that there is full disclosure on the calculations take place and that formulas con be modified to meet the user's needs. These advantages are expected to provide insight into the modelling limitations and will help guide further improvements to increase the accuracy of results.

The results of this research should be able to answer the following research question:

1.2 Problem definition

Research question:

> How does the role of hydropower, for both electricity generation and storage in the future European low-carbon power system, depend on different yearly rainfall scenarios?

1.3 Scope

The geographical scope of this research includes the following countries: Austria, Belgium, France, Germany, Ireland, Italy, Luxemburg, Netherlands, Portugal, Spain, Switzerland and the United Kingdom, as in Gerritsma's work (Gerritsma, 2016).

The countries are grouped into 5 regions in the following manner:

- GB – United Kingdom + Ireland
- FR – France
- DE – Germany + Belgium + Luxemburg + Netherlands
- ES – Portugal + Spain
- IT – Italy + Austria + Switzerland

The year of the study is 2050.

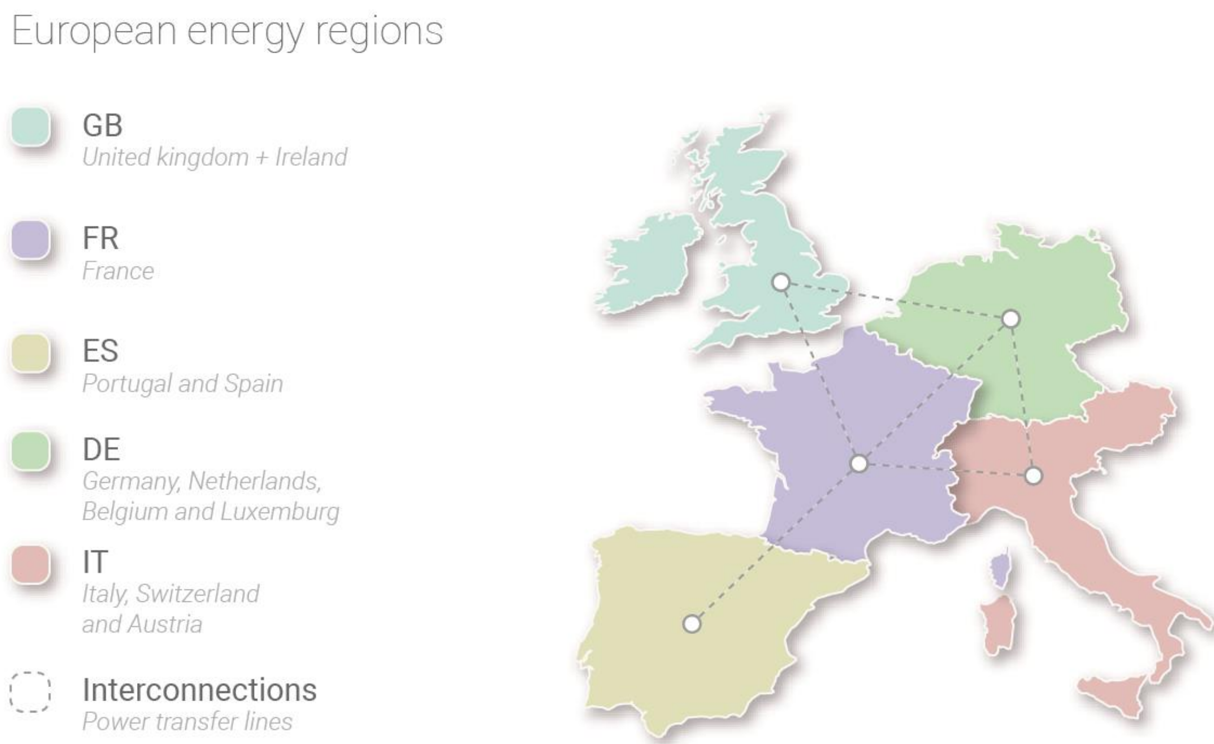

Fig 1. Overview of the regions considered in this study.

1.4 Document Structure

- Chapter 2 explains the methodology followed in this study.
- Chapter 3 presents an overview of the input data required for the simulations.
- Chapter 4 presents the modelling results.
- Chapter 5 consists on the discussion of the results including: limitations of the study, comparison to literature and further research.
- Chapter 6 presents the conclusions.

2 Methods

This study considers a scenario in which a scenario of 80% renewable energy sources (RES) energy system is built. The year 2050 is considered since such system is expected to be realized by then. Five regions in western Europe are included based on their intermittent renewable energy source (iRES) potential (Fig 2.1). Power transmission is considered only between regions and not within those outside the geographical scope of this research.

Two groups of technologies are considered: fossil generators and non-fossil generators. Fossil generators only include: gas turbines (GT) and natural gas combined cycle plants (NGCC). The rest of technologies considered fall into the non-fossil category and include: Solar photovoltaic (Solar PV), wind (onshore and offshore), hydropower, nuclear, geothermal and demand response (DR). Hydropower includes hydro dams (STO), run-of-river plants (ROR) and pumped hydro storage (PHS).

Six scenarios (one-year scenarios) are explored in this thesis: three short-term (ST) scenarios and three long-term (LT) scenarios. Scenarios are defined by three elements: (1) a rainfall year, (2) a simulation horizon, (3) a simulation step.

Rainfall years are sample water inflow years defining the monthly water catchment of the reservoirs and are further explained in section 2.2. Three rainfall years are defined according to their total flows: wet year (high discharge), average year (average discharge) and dry year (low discharge)

Simulation horizon refers to the length of the simulated time-interval and it is set to 1 year for all scenarios explored in this study. Simulation step refers to the time-interval of each step the solver takes to solve the simulation horizon. Two simulation steps are considered in this research: 5-day step for the ST scenarios and 1-year step for the LT scenario. Given three different rainfall years and two different simulation steps, six scenarios are obtained (see Fig 2.1):

(1) Dry ST scenario
(2) Wet ST scenario
(3) Average ST scenario
(4) Dry LT scenario
(5) Wet LT scenario
(6) Average LT scenario

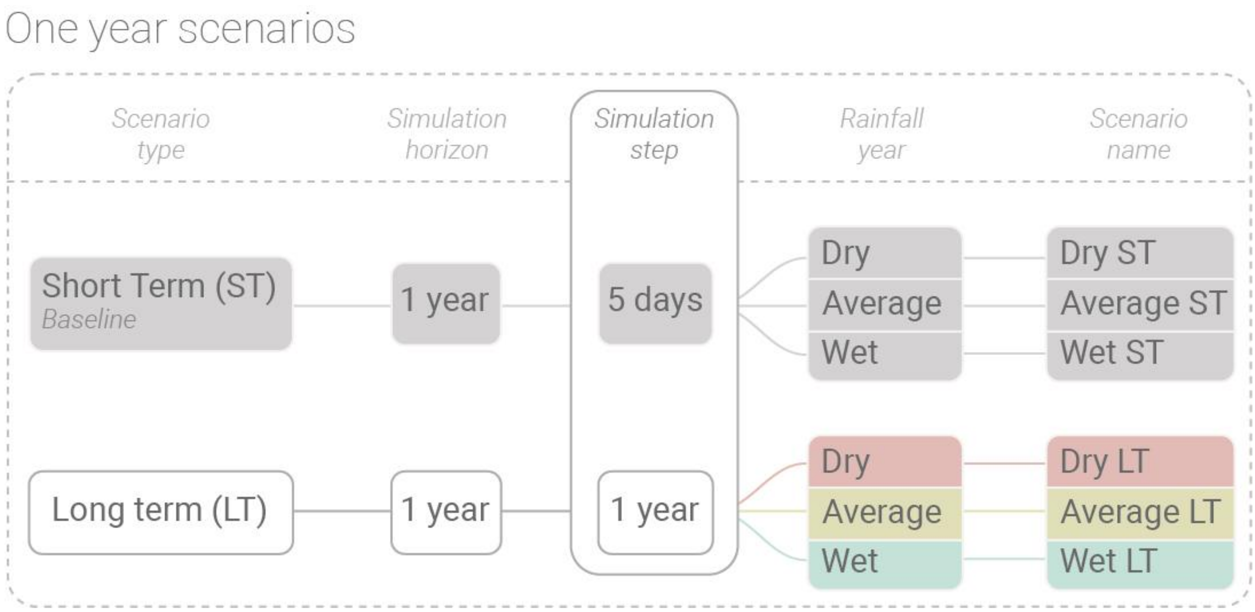

Fig 2.1 Summary of the six one-year scenarios explored in this research.

For all scenarios, Dispa-SET's LP (linear program) formulation[3] is used to optimize the economic dispatch of the power system. The reservoir levels are optimized to include the effects of seasonal variations (LT scenarios) and are compared to a reference scenario (ST scenarios). Optimized reservoir level data is implemented as input for Dispa-SET's MILP (mixed-integer linear program) for future research.

[3] Also called linear relaxation of the original mixed-integer linear program.

The study method consists mainly on four steps (see Fig. 2.2).

- **Step 1**. Define the full energy mix for the 80% RES scenario based on the results found in (Gerritsma, 2016)
- **Step 2**. Define sample rainfall years for hydropower plants: a high flow year (wet scenario), a low flow year (dry scenario) and an average flow year (average scenario)
- **Step 3**. Define Dispa-SET scenarios. Six simulation scenarios are created using two different simulation parameters on each of the rainfall years.
- **Step 4**. Run Dispa-SET using the Linear Program (LP) formulation to obtain results and pre-optimize the reservoir levels (for storage technologies) to be used on Step 5.
- **Step 5** (future research). Run Dispa-SET using the Mixed Integer Linear Program (MILP) formulation to solve the Unit-Commitment and Economic Dispatch (UCED) of the energy system increasing the accuracy of results presented in step 3. The pre-optimized reservoir levels from Step 3 are ready to use as input for this formulation.

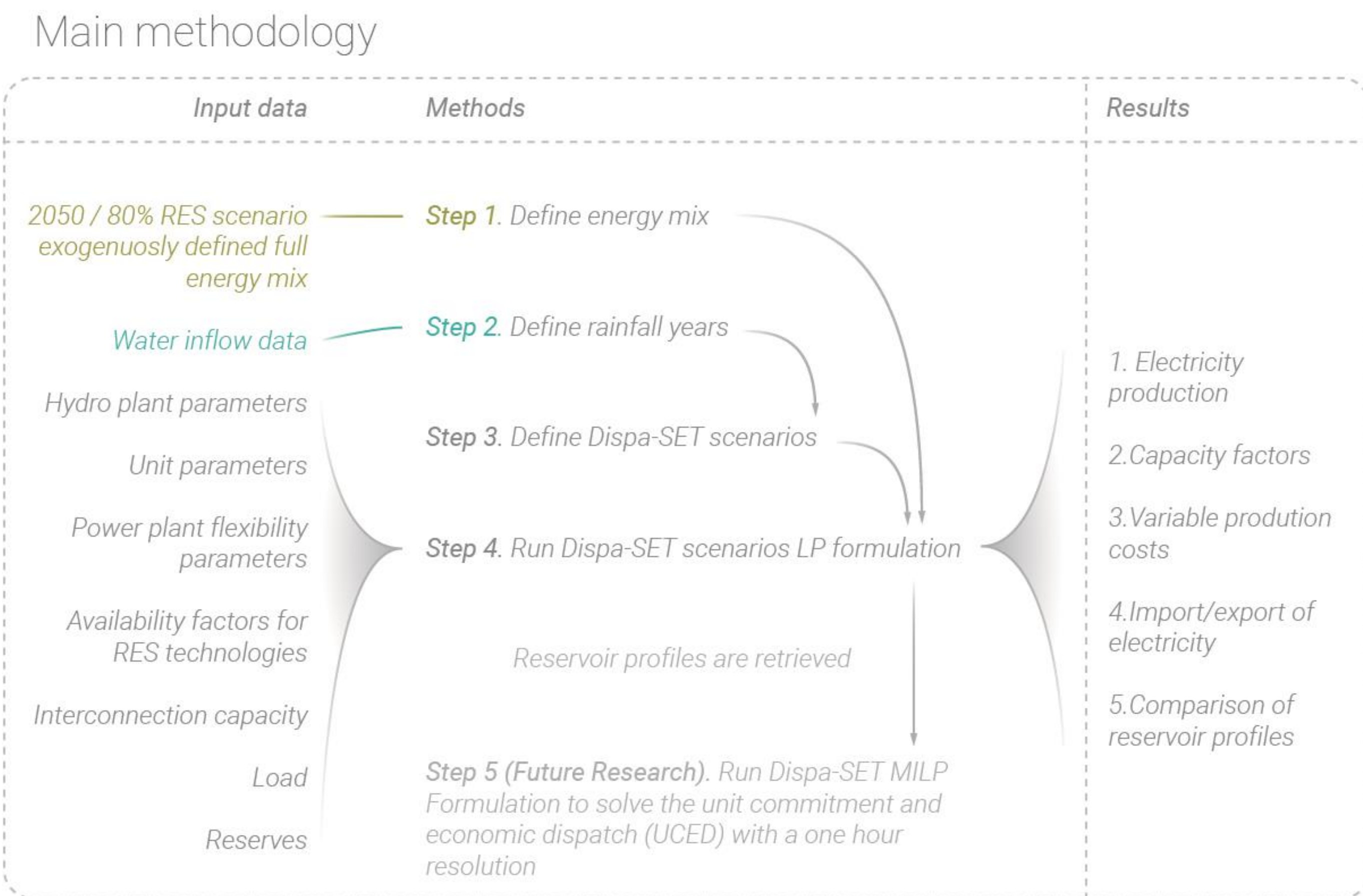

Fig 2.2. Main methodology of this research

2.1 (Step 1). Define energy Mix

The energy mix for the 80% RES scenario used in this research is the result of an optimization done by (Gerritsma, 2016) using the modelling software PLEXOS[4]. PLEXOS's long-term tool was used, which is a MILP tool designed to optimize long term investment decisions. Its objective is to minimize the total fixed and variable costs of building, operating and maintaining units over time scales long time scales (time scale > 1 year), while constrained by emission caps and reliability criteria (Brouwer, van den Broek, Zappa, Turkenburg, & Faaij, 2016). The output of the LT plan of PLEXOS is required because Dispa-SET does not have an equivalent long-term tool. Dispa-SET is only concerned with modelling economic dispatch of pre-defined energy systems. No new units can be built or existing ones modified during the simulations.'

The input for the LT plan was defined as follows (Gerritsma, 2016):

(1) iRES generation capacities for each region are allocated based on the scenarios of the 2050 roadmap study of the European Climate Foundation (ECF, 2010).
(2) Geothermal and hydropower capacity is allocated based in their current potential (Gerritsma, 2016)
(3) The storage technologies considered are Pumped Hydro Storage (PHS) and Hydro Dam (STO)
(4) Demand response (DR)[5] capacity is allocated based on the projections done by (Brouwer, van den Broek, Zappa, Turkenburg, & Faaij, 2016).
(5) No new nuclear capacity can be installed in DE.
(6) Only Gas Turbines (GT) and Natural Gas Combined Cycle plants (NGCC) –with and without carbon capture and storage (CCS) - can be built.
(7) Demand Response (DR) installed capacity is based on an overview of the technical demand response potential in Europe by Gils (Gils, 2014).
(8) Additional input: limited interconnection capacity, balancing reserve requirements and emission constraints.

There are two reasons why only GT's and NGCC's could be built: First, in earlier LT runs neither biothermal plants nor pulverized coal plants (with or without CCS) were built (Gerritsma, 2016). This is a direct result of the cost effectiveness of GT's and NGCC plants (Brouwer, van den Broek, Zappa, Turkenburg, & Faaij, 2016). Second, the capacities of iRES, hydropower and geothermal are already defined exogenously by the 80% scenario and therefore no additional capacity can be built during the run. This represents a limitation of this study since hydropower capacity is expected to be expanded (especially PHS) by 2050 in the future (this is further treated in the discussions section).

The results of the LT plan define the energy portfolio required for the simulations in Dispa-SET. The technologies included are: solar PV, wind (offshore and onshore), hydropower (STO, ROR and PHS),

[4] PLEXOS is a bottom-up modelling tool developed by Energy Exemplar.

[5] Demand response is only used to contribute to provide system adequacy by reducing peak loads of the power system and consequently, the resources required to maintain system adequacy (i.e. GT, NGCC's, PHS).

nuclear, geothermal, GT, NGCC (CCS) and Demand Response. An overview of the LT results is presented in section 3.1.

2.2 (Step 2). Define rainfall years.

Natural water inflow data is required to set rainfall scenarios. The data is obtained from a model developed by David Gernat that takes geographical elevation maps and spatial precipitation data as input, performs precipitation and surface run-off calculations and generates natural inflow data for every pair of coordinates associated with the reservoirs. The results are average natural inflow data for the years 1971-2000, expressed in terms of *monthly* inflows (m3/s). This output is then converted to energy units (MWh)[6] (Gerritsma, 2016).

Three sample years are defined based on the results of a predictive model developed by David Gernat. A low discharge year (dry year) is created by choosing the year with the lowest natural inflow and using the monthly flow data of that year. A high discharge year (wet year) is created by an analogous procedure in which we choose the year with the highest natural inflow. An average year (average year) is defined by averaging the monthly data from the 30-year period mentioned above. E.g. to calculate January for the average scenario, we average all January flow data from those 30 years, and so on for each month of the year.

2.3 (Step 3). Define Dispa-SET scenarios

Six simulation scenarios are defined (Dispa-SET scenarios) and are summarized in Table 2.3. Dispa-SET scenarios are defined by three elements: (1) one of the three rainfall years, (2) a time step and (3) a time horizon. (1) refers to a change on input data while (2) and (3) are changes in the configuration of the LP solver (i.e. simulation parameters).

Simulation horizon (SH) refers to the full length of the simulations which is 1 year for all scenarios. The simulation time step is the length of the 'step' the solver takes to simulate the entire simulation horizon. The time step is commonly used to reduce computational burden by breaking the initial optimization problem into 'n' sub-problems of length equal to SH/n. The subproblems are connected by a recursive algorithm in such a way that the final values found for a given subproblem 'j' must match the initial values for sub-problem 'j+1', and so, continuity is ensured. The drawback of this approach is that the user must define some of such initial and/or final values which adds extra constraints for the formulation.

For generators, the electricity production level at the end of every time step must be equal to the value at the beginning on the next. In the case of storage units such as hydropower, in addition to the production level, the state of charge of the reservoirs must match as well.

---

[6] Conversion from m3/s to MWh assumes a linear relationship between the water volume and the energy content. The effects of differences in hydraulic head are not taken into consideration (Gerritsma, 2016).

For the reservoir levels to be optimized to include the effects of seasonal variations the time step must be set equal to the time horizon (i.e. the optimization problem is not split into smaller problems). This means that the reservoir optimization is not constrained during the entire simulation horizon and the only actual constraints are the physical size of the reservoirs[7]. On the other hand, if the time step is shorter than the time horizon, the solver ensures the water levels return to a user-defined value (50% for this research) at the end of every time step. Thus, seasonal variation can only have modelled with time steps (~ 1 year). Inter-seasonal variation would require even longer time steps (2 years or more).

Each rainfall year is solved twice using different time steps: 5 days (for short term optimization of reservoir levels) and 1-year (for long term optimization of reservoir levels). Scenarios solved with a 5-day simulation step are called short-term (ST) scenarios. Scenarios solved with 1-year simulation step are called long-term (LT) scenarios. A summary of the scenarios explored in this research can be found in Fig 2.1.

2.4 (Step 4). Run Dispa-SET LP solver

The Dispa-SET LP (linear program) solver is used to optimize each Dispa-SET scenario. It minimizes the total generation costs with an hourly resolution under the following constraints: (1) production equals demand, (2) the flexibility constraints (ramp up/ down rates) of units, (3) supply equals demand (4) balancing reserves requirement are met[8]. Results are shown it section 4.

The LP formulation is the linear programming relaxation of the original MILP formulation which means that the following binary variables are not considered:

1. Start-up/shut-down costs (EUR)
2. Minimum up/down times (h)
3. Minimum stable levels (MW)

Since the start-up/shut-down of individual units is no longer considered, all units of similar technology, fuel and region can be aggregated into a single unit at the beginning of the simulation (clustered). This process (further described in Appendix A), reduces the computational burden of the optimization problem to feasible levels for this study since the MILP formulation is not designed to run for long time steps (Hidalgo Gonzalez, Sylvain, & Zucker, 2014)[9].

The simulation results are then compared based on the following indicators:

1. Average costs of electricity production (EUR/MWh)
2. Annual electricity production per technology (TWh)
3. Annual capacity factors per technology (%)
4. Annual electricity curtailment per scenario (TWh)

---

[7] This approach is too demanding for a MILP method to be used, for which the LP is used instead.

[8] Typically, outage factors are also considered but it is not the case in this study.

[9] Typical values for time steps are 5 – 10 days.

5. Comparison of optimized reservoir profiles

The average costs of electricity production (variable costs) are the objective function that Dispa-SET's LP is set to minimize. It consists of the yearly average of all variable production costs and it is the main indicator to judge the performance of scenarios. Indicators (2-4) are provide insights in the differences between scenarios at a technology level. The comparison between reservoir profiles shows the main differences behavior between ST and LT at a reservoir level quantified by the other indicators.

2.4 (Step 5). Run Dispa-SET MILP (future research)

Due to time constraints, step 5 was not brought to completion and therefore results are not presented in this report. In this step, the optimized reservoir levels of the LT scenarios obtained in the previous step are used as input for the MILP solver. The MILP solver is used to optimize unit commitment and economic dispatch (UCED) and, as opposed to the LP solver, it does include the binary variables (start-up/shut-down costs, minimum up/down times and minimum stable levels) increasing accuracy of results.

Six additional (MILP) Dispa-SET scenarios are defined (see Table 2.5). As in the previous step, three are short-term scenarios (ST-MILP scenarios) and three are long term-scenarios (LT-MILP). The ST-MILP scenarios are simple runs using the MILP solver, with a time step of 5 days and a time horizon of 1 year. The LT-MILP scenarios have the same simulation parameters but they differ in that they are fed with the optimized reservoir profiles from previous step. By providing the profiles, the reservoir levels no longer need to return to 50% capacity at the end of every simulation step; instead, they return to the value defined by the profile in at that point in time. This way, the MILP solver can be used to solve long-term optimization problems with short simulation time steps. A comparison of the results from the ST MILP and LT MILP scenarios, the advantages of such an approach can be quantified.

Table 2.1 Summary of the six MILP scenarios explored in this research. Reservoir levels

Dispa-SET scenario	Rainfall year	Time Horizon	Time Step	Pre-optimized reservoir levels (y/n)
Wet-ST-MILP	Wet	1-year	5 days	NO
Dry-ST-MILP	Dry	1-year	5-days	NO
Average-ST-MILP	Average	1-year	5-days	NO
Wet-LT-MILP	Wet	1-year	5-days	YES
Dry-LT-MILP	Dry	1-year	5-days	YES
Average-LT-MILP	Average	1-year	5-days	YES

3 Input Data

This section is concerned with providing an overview of the data used for the simulations.

- Section 3.1 describes the full energy mix used for the simulations.
- Section 3.2 describes hydropower in detailed and introduce the who approaches to model this technology (detailed and lumped).
- Section 3.3 presents the unit techno-economic parameters.
- Section 3.4 Presents the flexibility parameters of power plants and storage units.
- Section 3.5 presents annual average values of the availability factors used to model iRES.
- Section 3.6 presents the interconnection capacity available for electricity transfer between regions.
- Section 3.7 presents statistical indicators of the projected load in the system.
- Section 3.8 describes the balancing reserves calculation to ensure system adequacy.
- Section 3.9 presents an overview of the inflow data used to create the inflow scenarios.

3.1 Overview of Energy Mix for the 80% RES Scenario

The optimized capacities (per region per technology) for the 80% RES scenario can be seen in Table 3.1. This table summarizes the result of the PLEXOS LT plan (in which only GT and NGCC CCS could be built) and forms the energy mix used as input for Dispa-SET. Fig 3.1 graphically depicts the results.

Table 3.1. Input data for Dispa-SET. This table consists on the total installed capacities per region (column) per technology (row) within the geographical scope of the research for year 2050. *Installed capacities are in GW.* WTON: Wind Offshore, WTOF: Wind Offshore, PV: Solar Photovoltaic, Geo: Geothermal, GT: Gas Turbine, NGCC (CCS): Natural Gas Combined Cycle with Carbon Capture and Storage, DR: Demand Response, Hydro: Hydropower (including run-of-river, storage and pumped hydro plants).

		Technology – Installed Capacity in GW								
		Wind Onshore	*Wind Offshore*	*Solar PV*	*Geothermal*	*Nuclear*	*GT*	*NGCC (CCS)*	*DR*	*Hydro*
Region	*GB*	85.0	38.8	17.9	0.5	1.5	66.4	0.0	6.0	5.0
	FR	64.8	9.8	55.4	2.2	24.0	49.3	0.0	7.5	30.6
	DE	117.4	47.9	44.3	1.5	0.0	62.4	15.0	8.9	13.3
	ES	68.8	0.4	72.0	1.5	3.0	27.3	0.0	4.0	25.7
	IT	30.0	0.0	95.7	1.4	12.0	6.0	0.0	5.9	52.4
Totals		366.1	97.0	285.3	7.0	40.5	211.4	15.0	32.3	127.0

The total installed capacity for all technologies and for all regions is 1181.5 GW. Most gas turbines were installed in regions where hydropower is scarce to compensate for the flexibility requirements. IT and ES have the least amount of gas turbines while GB, DE and FR have most of the capacity (84%). NGCC's (15GW) are only installed in DE.

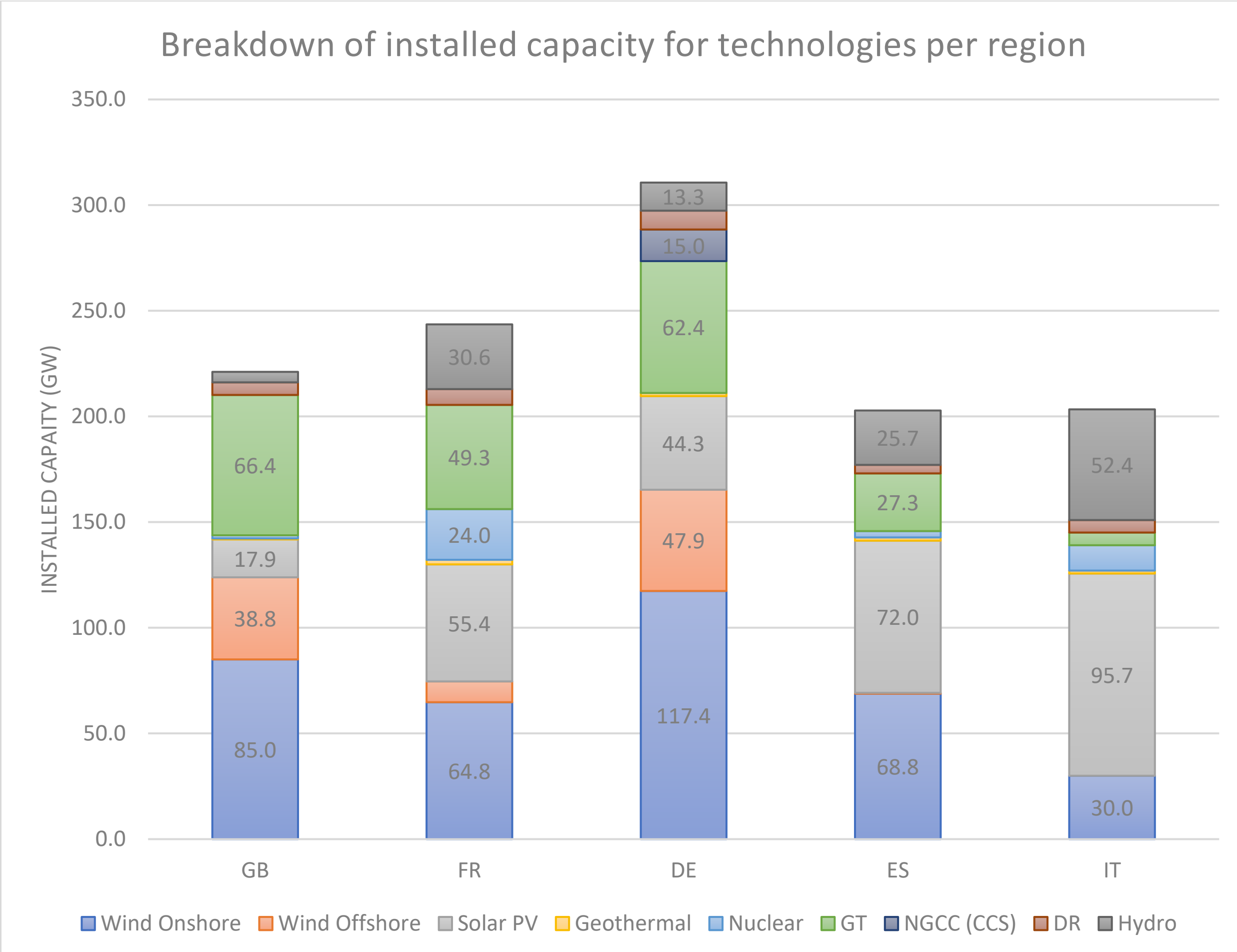

Fig 3.1. Breakdown of installed capacity per technology region. Data values are only shown for capacities greater than 10 GW for readability.

An overview of the energy mix for the entire geographical scope of the research is shown in Fig 3.2. The bulk of energy production is given by iRES, Nuclear, Geothermal, Hydropower (HROR) and NGCC CCS. The peak response options are GT, DR and Hydropower (HPHS). HDAM can provide both bulk production as well as peak response.

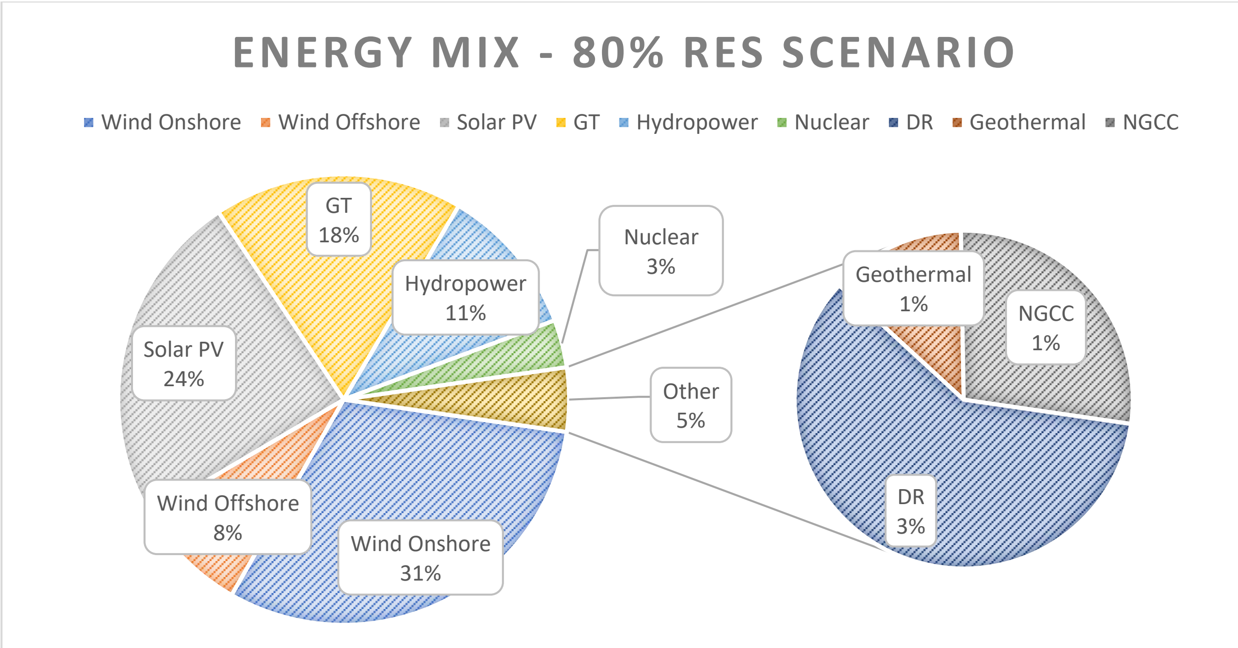

Fig 3.2. Energy Mix of all regions for the 80% iRES Scenario on a capacity basis. Result of the PLEXOS LT plan.

3.2 Hydropower

There are different ways to categorize HP plants (high/low head, capacity, etc.) (Gaudard & Romerio, 2014; IEA, 2012; Twidell & Weir, 2006). In this report, plants are divided in 3 types (IEA, 2012):

- Run-of-River (ROR): it harnesses energy mainly from the natural flow of a river. It can contain a small reservoir or "pondage" to store water for short times, allowing for some flexibility in adapting to the load.
- Dam (STO): stores large amount of water from natural flows to be used when convenient thus providing flexibility to generate electricity on demand. Large reservoirs can store up to years of inflows reducing dependence on the variability of inflows
- Pumped Hydro Storage (PHS): water is pumped from a lower reservoir to an upper reservoir whenever production exceeds consumption. Water can be released later enabling the transfer of energy from off-peak hours to peak hours (demand shift). The profitability of this generator depends on the ratio of electricity prices between off-peak and peak hours, and therefore it can only be efficiently operated at certain when electricity prices are low and high respectively.

ROR and STO plants only differ in the amount of water they can withhold (storage capacity). Both types of power plants are connected to water bodies and flows, but typically, ROR plants have high flows with relatively low storage capacity while STO plants have low flows with high storage capacity. For this analysis, the convention is that STO plants can withhold more than 400hrs of average historical flows while

ROR can only withhold up to 400hrs. *Once categorized, all ROR plants are modelled in Dispa-SET as pure ROR plants, without reservoirs to withhold flows*[10].

No distinction between pondage ROR plants (withhold time < 400hrs) and pure ROR plants is made[11].

Hydropower is modelled using two different approaches (See Fig 3.3):

(1) A detailed approach
(2) A lumped approach

Plants modelled using the detailed approach (referred to as detailed plants) are connected to natural inflows and their individual techno-economic data is known. Their natural inflows vary as they are defined by the rainfall years (see below) which limits their electricity production. Plants modelled using the lumped approach (referred to as lumped plants) are not connected to natural inflows (closed loop systems) and therefore they are not affected by the rainfall years. Instead, they are modelled using average storage sizes, maximum annual capacity factors and aggregated techno-economical parameters.

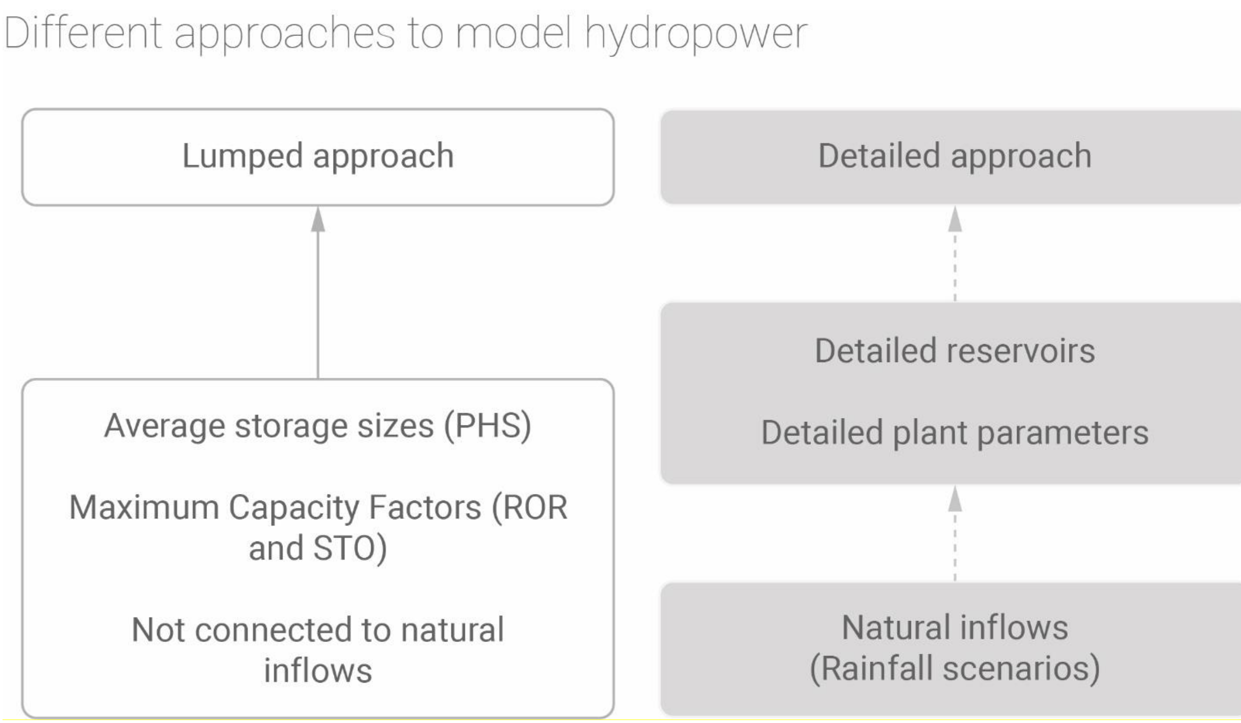

Fig 3.3. Different approaches to model hydropower.

[10] This simplification is done to reduce simulation times significantly.
[11] Details on the categorization process can be found in (Gerritsma, 2016).

3.2.1 Detailed Hydro Plant data

The detailed plants in this research are retrieved from the hydro plant database built by (Gerritsma, 2016). According to this report, 13638 plants lie within the geographical scope of this research covering a total installed capacity of 126.8 GW. To keep simulation times within bounds, only the largest plants (capacity higher than 250 MW) and 4 smaller plants (226-96 MW) with which they shared their reservoir were included since additionally units can increase simulation times considerably.

In total, 68 plants (40.4 GW of installed capacity) are modelled in a detailed way in this study. This capacity represents 32% of the total capacity in the geographical scope of the research. Since Dispa-SET can only model simple configurations (1 plant – 1 reservoirs) these 4 plants were clustered with the plants they shared a reservoir with. This process is treated in Appendix B and results in 64 plants each connected to its own reservoir.

Overall, the total PHS capacity installed (considering all regions) is 35.0 GW[12]. Total non-PHS capacity amounts to 92.0 GW. Figure 3.2 shows the distribution of installed capacities per region. 90.8% of the total ROR installed capacity and 95.5% of the total installed STO capacity are found in the regions ES, IT and FR. Together those regions make up for 93.5% of the total non-PHS installed capacity. PHS capacity is more evenly spread amongst regions, with the highest concentrations in DE and IT.

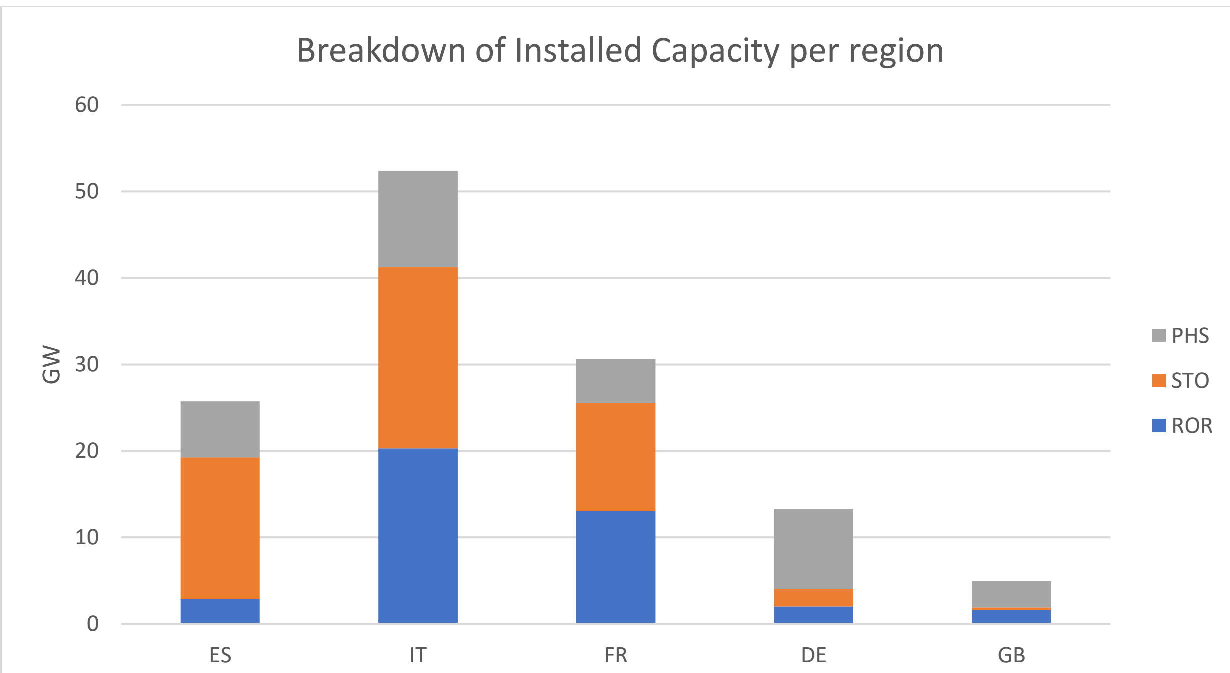

Figure 3.2. Distribution of installed capacities in GW per region. PHS: Pumped Hydro Storage, STO: Storage Hydropower, ROR: Run-of-river plants.

The detailed plants (40.4 GW) are connected to water flows and their electricity production depends on water catchment (see Flow scenarios). These plants are affected directly by rainfall scenarios

---

[12] There is a small discrepancy between this value and the one reported in (Gerritsma, 2016) which is 34.80 GW. It has not been found where the 0.16GW difference is coming from but it is not expected to have a major impact on the results.

as opposed to the rest of the hydropower capacity (86.6 GW – 68% of total hydro capacity) which are modeled with the *lumped approach* as in (Brouwer et al., 2016).

3.2.2 Lumped Hydro Plant Data

As in (Gerritsma, 2016), the lumped hydro plants (plants modelled using the lumped approach) are divided into 5 categories depending on their size (Table 3.2). None of the plants in these 5 categories are connected to natural inflows for which their electricity production is constrained by maximum annual capacity. This is further described in Appendix C. For PHS plants, maximum capacity factors were not imposed since their calculated capacity factors remained at normal values during the simulations.

Table 3.2. Average capacity factor and total installed capacity for the lumped plant categories. Source (Gerritsma, 2016)

Plant category	Capacity (MW)	Capacity Factors	Installed capacity (GW)
Small non-PHS	< = 10 MW	0.465	11.6
Small PHS		-	0.08
Large STO	> 10 MW	0.500	40.1
Large ROR		0.465	40.0
Large PHS		-	34.8

Regarding storage capacity, average storage sizes are used for PHS (Geth, Brijs, Kathan, Driesen, & Belmans, 2015); for STO and ROR the storage size is the average of the storage sizes of the detailed plants. In addition, the maximum energy content of the storage limits both water pumping and discharge. The parameters are available electronically.

3.3. Unit parameters

The parameters of individual units are shown in table 3.3. Installed capacities for all regions are covered by an integer number of these units. The number of generators for the simulations is calculated simply by dividing the installed capacity (taken from the table in Long Term Plan PLEXOS) by the unit capacity per generator. Unit capacities for wind onshore, wind offshore and solar PV are not shown in this table since they are set equal to the total installed capacity for each region. The number of units for iRES technologies is set to 1. Since ramping rates, run-up rates, startup /shut down costs, startup cost, ramp up/down times are all set to 0[13] which makes the modelling of a single unit or several units (assuming equal total capacity) indistinguishable. Build costs are not considered since no new units can be built during the Dispa-SET runs.

[13] iRES technologies ideally would have ramping/run-up/run-down rates and start up/ shut down times different to 0. This is a limitation of this study.

Table 3.3. Techno-economic parameters of individual thermal and iRES power plants for all regions for 2050-2051. Variable production costs are calculated endogenously by Dispa-SET. The rest of the data is taken from (Brouwer, van den Broek, Zappa, Turkenburg, & Faaij, 2016).

Unit	Capacity per unit (MW)	Efficiency (LHV)	Fuel	Fuel Price	Variable Production costs [$€_{2012}$/MWh]
GT	100	42%	Natural Gas	23.4	58.6
NGCC CCS	650	56%	Natural	23.4	41.8
Nuclear Power	1500	33%	Uranium	3.6	10.7
Wind onshore	-	-	-	0	0
Wind offshore	-	-	-	0	0
Solar PV	-	-	-	0	0
Geothermal	25	-	-	0	0
Hydropower	-	87%[14]	-	0	0
Demand Response	1,5	100%	-	0	0

Fixed costs are not taken into consideration since they are assumed to be independent of whether the unit is operational or not. Only variable costs (due to fuel use) are considered which are calculated endogenously by Dispa-SET using Equation 1 which defines the variable production costs in EUR/MWh considering the efficiency of the technology and the costs of fuel. Variable production costs are assumed to be null for iRES, Geothermal and Hydropower and efficiency is not defined for iRES since energy production for these technologies is defined with the projected generation patterns (see section 3.5).

$$Variable\ production\ costs\ \left[\frac{€}{\mathrm{MWh_e}}\right] = \frac{Fuel\ Price[€/\mathrm{MWh_f}]}{Efficiency[MWh_e/MWh_f]} \qquad \text{Equation 1}$$

Demand response is modelled as electric batteries with 100% efficiency both for charging and discharging. The unit parameters are defined as in (Brouwer et al., 2016)

3.4. Power plant flexibility parameters

For dispatchable technologies (GT, NGCC-CCS, and Nuclear) historical capacity factors and installed capacity are also used but only to limit the electricity production. For such technologies, flexibility parameters are used, these are defined in table 3.4.1. No ramping costs are considered in this research, for which costs considered in this research can only come from variable production costs (from fuel use) and startup costs of units.

[14] Charging (for PHS) and discharge efficiency is % for all hydro units lumped and detailed.

Table 3.4.1. Flexibility parameters of dispatchable technologies. Cold and hot start are not considered since they cannot be modelled in Dispa-SET. Warm start is assumed to be the only start available and its defined as a generator starting after being offline for (8 - 48 hrs). Source: (Brouwer et al., 2016).

Technology			Start-up time (hours)	Start-Up cost[15] (€$_{2012}$/MW installed per start)
	Minimum load (% of max capacity)	Ramp rate (%of max capacity/minute)	Warm start	Warm start
Nuclear	20	5	8	46
NGCC CCS	25	9	2	39
GT	20	20	0.25	16

Table 3.4.2. Flexibility parameters for storage units. Sources: (Brouwer, van den Broek, Zappa, Turkenburg, & Faaij, 2016; Eurelectric, 2015)

	Minimum load (% of max capacity)	Ramp rate (%of max capacity/minute)	Start-up time (h)
Hydro (PHS)	0.2	40%	0.1
Demand Response (DR)	0	100%	0

3.5. Availability Factors for iRES

Availability factors are only defined for iRES technologies (wind, solar) and hydro plants without natural inflows (rest-of-plants). For iRES technologies, availability factors are obtained from the projected generation patterns for these technologies (Brouwer et al., 2016), a source the reader is encouraged to revise if more detailed information on the gathered data is required. Data is presented as a time series with an hourly frequency which in only available electronically. Average availability factors are presented in table 3.5

Table 3.5. Average projected availability factors for hydro and iRES technologies for the year 2050. Source: (Brouwer et al., 2016).

Region	GB	FR	DE	ES	IT
Solar PV	12.1%	15.5%	12.8%	20.5%	17.1%
Wind Onshore	24.2%	21.5%	25.3%	22.0%	21.0%
Wind Offshore	38.7%	40.0%	43.5%	-	-

[15] Startup costs include fuel, maintenance, auxiliary power and forced outage costs. They are only considered in the MILP formulation.

3.6 Interconnection Capacity

The interconnection capacity between regions is shown in Table 3.6 below and derived from (Brouwer et al., 2016). Note that interconnection capacity is symmetrical (e.g FR -> DE is equal to DE -> FR) and remain constant throughout the entire simulation period.

Table 3.6. Projected interconnection capacity per region for 2050.

Interconnection capacity in MW	GB	FR	DE	ES	IT
GB	0	12788	4946	0	0
FR	12788	0	19910	27389	13149
DE	4946	19910	0	0	6619
ES	0	27389	0	0	0
IT	0	13149	6619	0	0

3.7 Load

Load data consists on a time series with hourly load data for each considered region for the year 2050. It is based on the 2013 historical patterns reported by ENTSO-E to which a 0.25% yearly increase is applied. Values retrieved from (Brouwer et al., 2016). A summary is shown in Table 3.7. Fig 3.7 depicts the total load on the system for 2050.

Table 3.7. Summary of electricity demand per region in year 2050. Time series is available electronically. (Brouwer et al., 2016)

Region	Annual load (TWh)	Peak load (GW)	Min load (GW)	Average load (GW)
DE	737	113	50	84
GB	377	67	23	43
FR	547	102	33	62
ES	326	52	6	37
IT	478	79	33	55
Total	2465	413	145	281

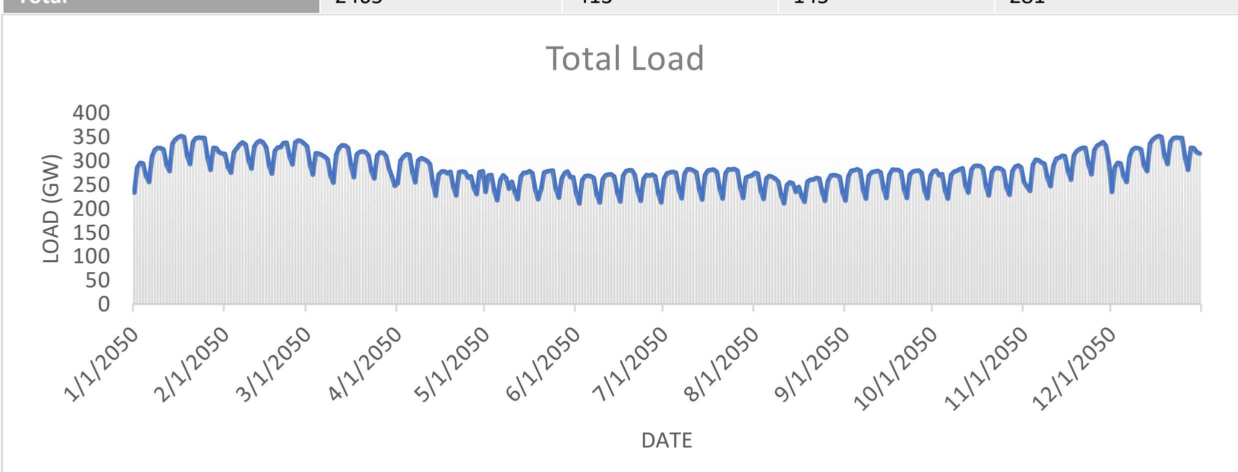

Fig 3.7. Total projected load patterns for 2050.

3.8 Reserves

Reserves are implemented in Dispa-SET as an aggregation of secondary and tertiary reserves. The reserve requirements and the technologies that take part to provide them can be modified to fit the user's needs. Reserves are divided into two kinds within Dispa-SET: upwards and downwards.

The formula used to calculate the capacity allocated to provide reserves is retrieved from ENTSOE (Entso-e, 2009) and depends on the maximum expected load for each day (max demand) of the simulation and its defined as follows for upwards reserves:

$$Reserve_{UP} = \sqrt{10 \times \max(demand) + 150^2 - 150}$$

Downwards reserves are defined as half of the upwards reserves:

$$Reserve_{Down} = 0.5 \times Reserve_{UP}$$

The technologies active in the reserve market are: GT, NGCC, hydro (STO and PHS) and nuclear.

3.9 Inflow data

An overview of the rainfall years can be seen in Fig 3.10. Most important observations are:

(1) September to April are the months with the highest flows for all scenarios. May, June, July and August are the driest months.
(2) The max scenario receives 49% of its yearly flows in the first two months of the year. This amounts to 89% and 164% received on a yearly basis in the average and dry scenarios respectively.
(3) Yearly flows are 21.48 GW, 39.76 GW and 71.94 GW for the dry, average and wet scenarios respectively. Dry scenario represents a decrease of yearly flows of 46% compared to the average scenario, while the wet scenario represents an increase of 81%.
(4) The wet scenario exhibits by far the most variability in monthly inflows (see Table 3.10). Other scenarios receive relatively constant monthly inflows throughout the year.
(5) May and September have inflows higher for the average scenario than for the wet scenario. This is a result of the methods used to obtain the scenarios.

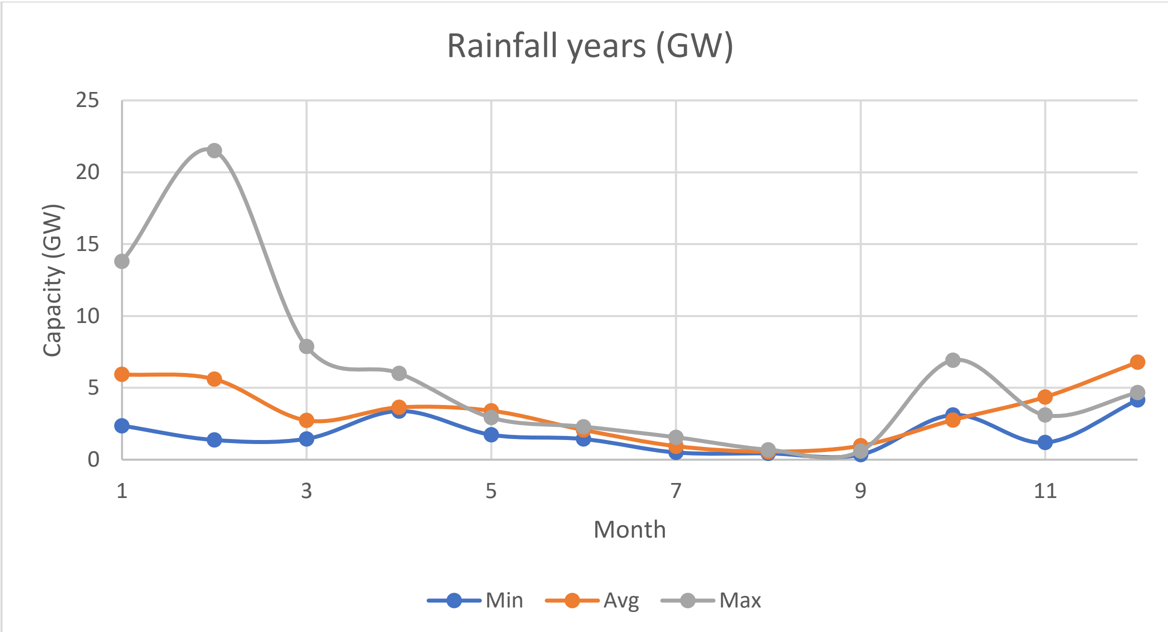

Fig 3.10. Average monthly inflows for the three scenarios defined above: average, wet (max) and dry (min).

Fig 3.11 shows the absolute difference in flows for the wet and dry scenarios compared to the average scenarios. The dry scenario receives less inflow in each of the 12 months than the average scenario. The wet scenario receives considerably higher inflows in the first trimester and October, as opposed to the last two months when the average scenario receives more inflows.

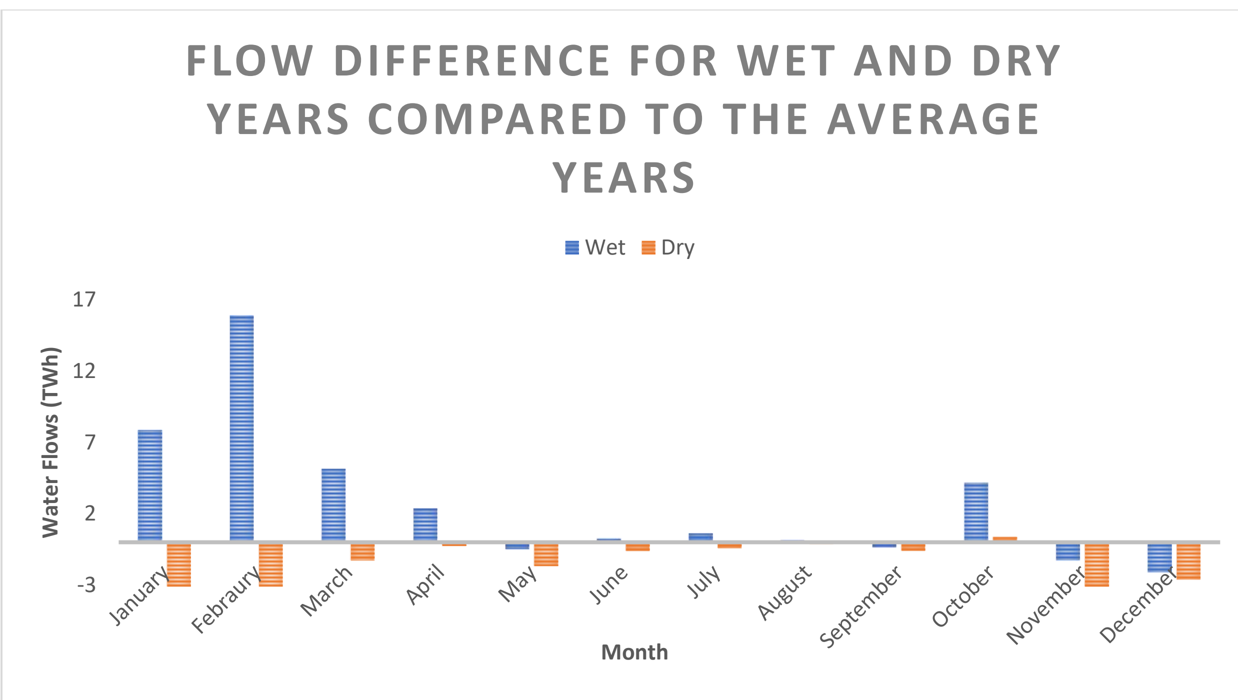

Fig 3.11. Absolute difference in potential electricity from flows (TWh) for the wet and dry scenarios compared to the average scenario for all reservoirs in 2050. Positive flows represent higher flows than the average scenario, negative flows represent lower flows.

4 Results

Section 4.1 presents an overview the total electricity production and average electricity production costs (variable costs) for 2050 for all scenarios. Focus is on ST scenarios and the introduction of the model results. Section 4.2 compares the results of the LT scenarios with respect to the ST scenarios in terms of annual electricity production, annual capacity factors, reservoir level profiles, and total production costs.

4.1 Total energy production – ST Scenarios

This section presents an overview of the total electricity production and variable costs in the ST scenarios. The analysis is divided into five parts. The first part (4.1.1), shows the total production for each scenario. Subsections (4.1.2 -4.1.4) explain the role of separate groups of technologies in the results shown. The groups are (1) Baseload units, (2) Peak response options, (3) Hydropower. Results are explained based on these three indicators:

1. Annual electricity production per technology (TWh)
2. Annual electricity curtailment per scenario (TWh)
3. Annual capacity factors per technology (%)

Subsection (4.1.5) presents total variable costs (EUR/MWh) for all ST scenarios.

4.1.1 Total production

Fig 4.1 shows the annual electricity production per technology for the ST scenarios (left bars). Total production is 2575.0 TWh for the wet ST scenario (highest), 2566.1 TWh for the average ST scenario and 2565.6 TWh for the dry ST scenario (lowest). Total production values do not include electricity consumption for charging PHS and DR which is 109.4 TWh, 100.5 TWh and 100.0 TWh respectively. Considering these values, the net production is 2465.6 TWh for all scenarios.

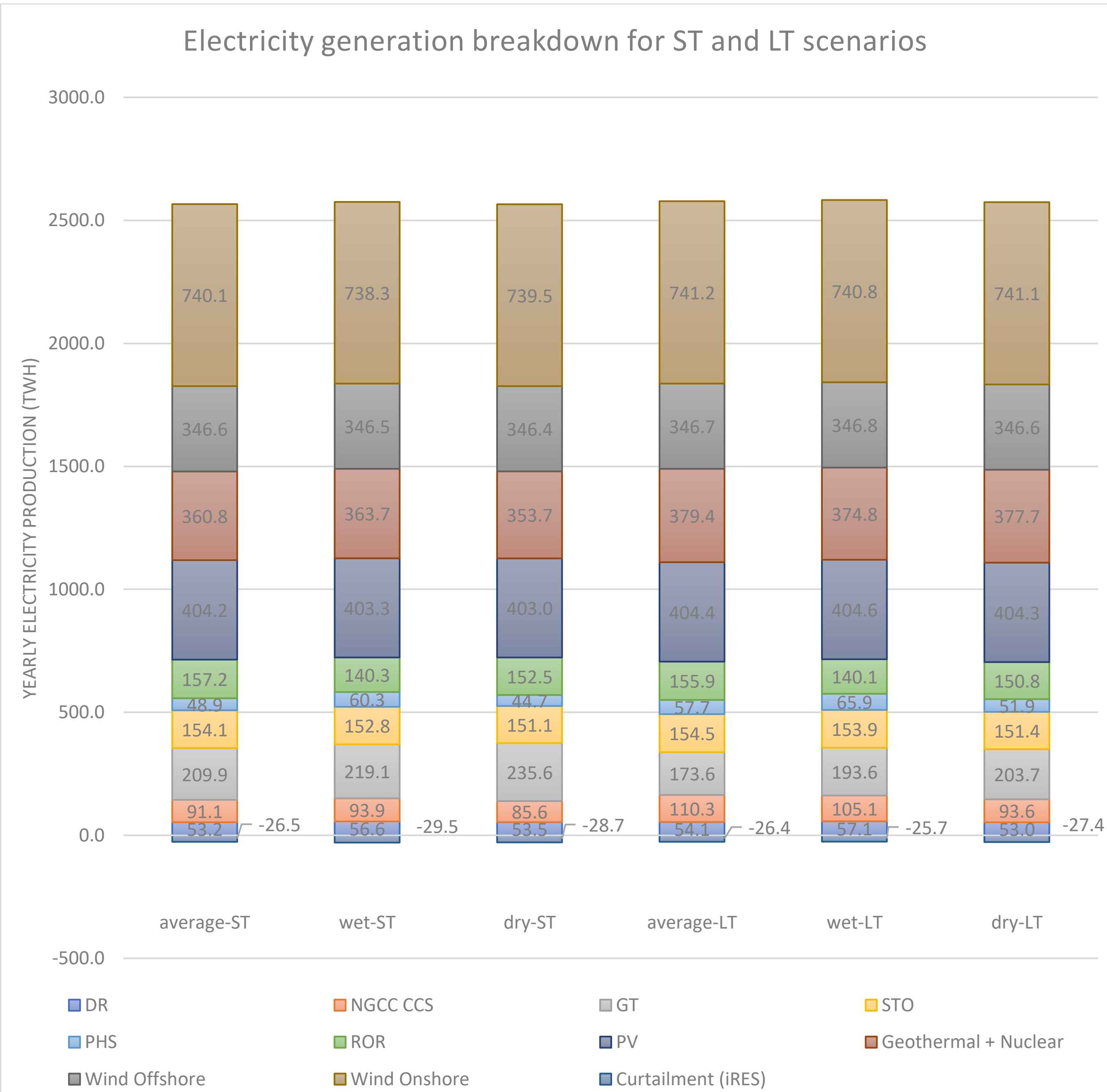

Fig 4.1 Breakdown of electricity generation per technology for ST scenarios (left bars) and LT scenarios (right bars).

4.1.2 Contribution of baseload units

The bulk of electricity production is provided mostly by iRES technologies (58.1 - 57.8 %), nuclear + geothermal (14.0 - 13.7 %)[16] and non-PHS (ROR and STO) hydropower plants (11.8 - 12.1 %) while NGCC (CCS) plants contribute to a lesser extent (3.3 - 3.6 %). The percentages shown are relative to the total electricity production and their range represents the variation between the different ST scenarios. Peak units produce smaller shares of electricity accounting for only 12.2 % to 13 % of the total production. GT's produce more electricity than PHS and DR units combined (67.3 - 70.6% of total production from peak units). PHS and DR provide the remainder production, (16 - 17 %) and (13.4- 18.0 %) respectively.

Regarding iRES technologies, the difference in production between scenarios observed is explained by the electricity curtailed: -26.5 TWh for the average-ST scenario, -29.5 for the wet-ST scenario and -28.7 TWh for the dry-ST scenario. After taking curtailment into account, slight differences (lower than 0.3 TWh) remain which are attributed to the solver resolution.

Nuclear + geothermal produce a large share of the total electricity produced considering their share in the total installed capacity is only 4%. This is a result of high capacity factors (91.6 - 92.7 %) which are possible due to the lack of outage factors (full or partial, planned or unplanned) in the model (Fig 4.2). Capacity factors cannot go to 100% since these technologies are ensuring balancing reserves for the system (see Section 3.8)

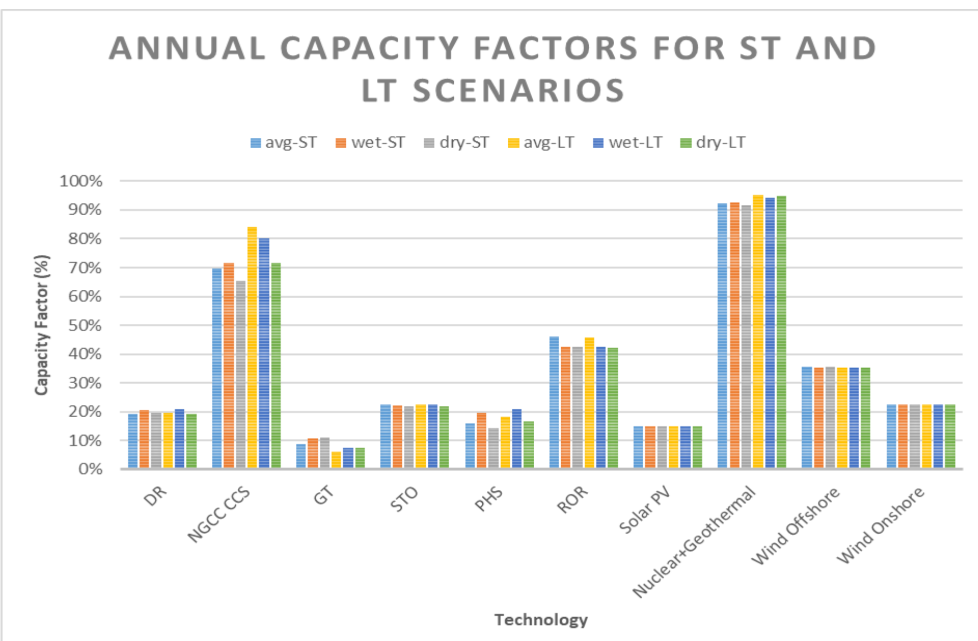

Fig 4.2 Annual capacity factors for ST and LT scenarios for all technologies.

[16] Nuclear and geothermal are shown together since they were clustered during the simulation. However, the results are more representative for nuclear since the installed capacity is nearly six times as much as for geothermal.

4.1.3 Contribution of peak response units

Peak load options exhibit high capacity factors for the different ST scenarios, (8.7 - 11.0% for GT units), (19.4 - 20.6 % for DR units) and (14.4 - 19.6 % for PHS units). Capacity factors of DR units are high since no maximum annual capacity factors are set to constrain their production. However, they can only be charged using electricity produced within the system, since no electricity can be bought from outside the grid of the five regions considered. The same principle applies to PHS units, although these can be charged from water inflows too. High capacity factors for GT's stem from the inability of DR and PHS capacity to cover all flexibility requirements of the system, thus incurring additional fuel-use costs for the system.

4.1.4 Contribution of hydropower

Total production from hydropower units is maximum for the average ST scenario (360.3 TWh), followed by the wet ST scenario (353.5 TWh) and the dry ST scenario (348.3 TWh). The difference is maximum when comparing the average and dry ST scenarios (11.9 TWh) representing a deviation of 3.4% from the average electricity production of the ST scenarios (354.0 TWh). In terms of the total electricity production (based on the average total production of the ST scenarios), this amounts to only 0.05%.

Production of non-PHS units is highest for the average ST scenario (311.4 TWh) and lowest for the wet ST scenario (293.1 TWh). Since the total flows for the wet-ST scenario are by far the highest amongst all ST scenario (81% higher than average ST), this effect is caused by water spillage for ROR plants. This can be observed in the production from ROR plants which is lowest for the wet ST scenario (140.3 TWh) and highest for the average ST scenario (157.2 TWh). The electricity production of STO plants ranges from 154.1 TWh to 151.1 TWh, being highest for the average ST scenario and lowest for the dry ST scenario. The wet ST scenario receives the most inflows, but 5.5 TWh of potential electricity is lost due to spillage for the wet ST scenario[17] decreasing its production to 152.8 TWh.

Regarding STO plants, their contribution to the electricity production for the average ST scenarios is shown in Fig 4.3. This graph exhibits high variability which fits more into the description of a peak load option than a baseload generator. Although the exact role of STO plants is not clarified in this study, the results suggest that in a system with high iRES penetration, STO plants act more as flexibility providers than baseload providers for the system. This observation can be relevant for the design of new STO plants or the upgrade of existing ones since, given a set of inflows and a catchment area, STO plants can be designed to have either: (1) high installed capacities and low capacity factors (to meet demand peaks) or (2) low installed capacities and high capacity factors (to provide baseload production) (IRENA, 2012).

[17] Spillage for other ST scenarios is negligible (lower than 10 MWh) and no spillage for PHS units is observed for any ST scenario.

According to the results shown, STO plants of the first type would have more important roles to play for the future low-carbon energy system.

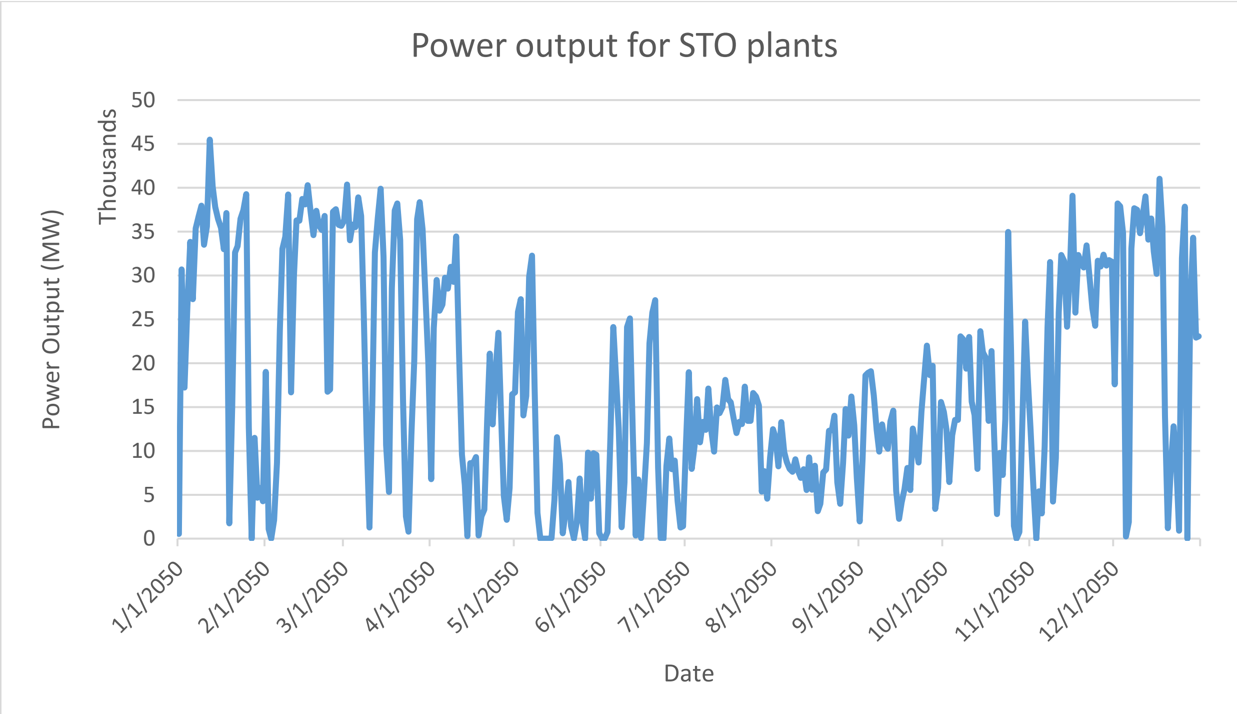

Fig 4.3. Power output from STO plants (45.5 GW) for the average ST scenario.

4.1.5 Average electricity production costs and total energy production

The average costs of electricity production (Fig 4.4) are highest for the dry-ST scenario (8.5 TWh) and lowest for the average-ST scenario (7.9 TWh). The difference in costs (0.6 TWh) represents a relative variation of 7% based on the average costs for the three scenarios (8.2 TWh)

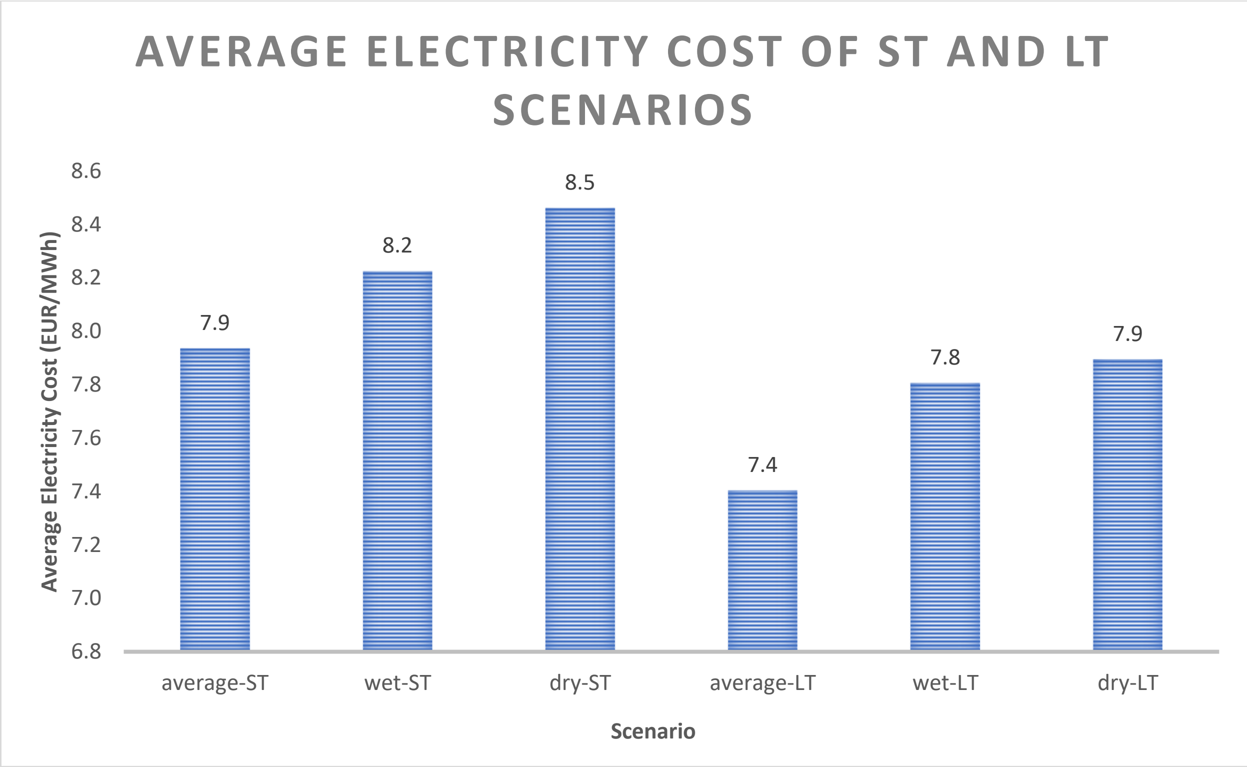

Fig 4.4. Average yearly cost of electricity production for ST and LT scenarios.

A summary of the results of this section:

- Bulk of electricity production is provided by iRES, Nuclear + Geothermal, Hydropower (ROR) and NGCC (CCS)
- Peak load is provided by GT, Hydropower (PHS, STO) and DR.
- Curtailment explains the difference in electricity production from iRES technologies between scenarios.
- Electricity use to charge DR and PHS units explains the difference in electricity production between scenarios
- Change in total electricity production due to the different rainfall years is limited (0.5% of total electricity production).
- Spillage explains the low production levels of hydropower for the wet-ST scenario.
- Best performing scenario is the average ST scenario, having lowest electricity production from fossil plants, lowest curtailment of iRES, lowest production from peak response units, highest production from non-PHS units, ultimately leading to the lower average production costs of all ST scenarios.
- The distribution of water inflows throughout the year plays a key role in the performance of hydropower units.

4.2 Scenario comparison

In this section, the results of the LT scenarios are compared to the ST scenarios based on three criteria: (1) average electricity production costs (EUR/MWh), (2) annual electricity production, (3) total water spillage from STO plants (TWh) and (4) storage level profiles of STO plants. Subsection 4.2.1 makes the comparison using criteria (1-3). Subsection 4.2.2 compares storage profiles and provide insight into the behavior of hydro plants.

4.2.1 Average electricity production costs

The LT scenarios exhibit lower average electricity production costs compared to their respective ST scenarios (Fig 4.4). The cost reduction is highest for the wet LT scenario (0.6 EUR/MWh), followed by the average LT scenario (0.5 EUR/MWh) and the wet LT scenario (0.4 EUR/MWh). In terms of relative (percentile) cost, the average and dry LT scenarios show costs reduction of 6.7%. For the wet LT scenario, the reduction is only 5.1%

The cost reduction achieved in the LT scenarios can be understood in terms of four mechanisms:

1. A load shift from GT's to less expensive baseload generators (NGCC's and Nuclear + Geothermal)
2. A load shift from GT's to less expensive peak load units (PHS mostly and DR)
3. A reduction of water spillage from STO plants.
4. Increased production from hydropower units.

Mechanisms (1-2) seem to exploit the fact that peak demand can be anticipated, for which less expensive (baseload) generators are producing extra electricity to charge PHS and DR beforehand. This results in increased production from NGCC's, Nuclear + Geothermal, PHS[18] and a decrease in production from GT's. This effect can be seen clearly in Fig 4.3 where the change in electricity production for units of LT scenarios, compared to their corresponding ST scenarios is shown. This change is simply defined by subtracting the production of the LT scenarios from the electricity production found for the ST scenarios for each of the rainfall years.

The reduction in electricity production of GT's is highest for the average LT scenario (-36.3 TWh) and lowest for the wet LT scenario (-25.5 TWh). The average LT scenario shifts the highest amount of electricity production from GT's to NGCC's, PHS units and Geothermal Nuclear units. The dry LT scenario has the largest increase in electricity production from Nuclear+Geothermal but it is still below the other scenarios in total production levels for those technologies (Fig 4.1). The wet-LT scenario reduces the least amount production from GT's which explains its cost reduction to be the lowest.

The third mechanism plays a limited role. For the average and dry LT scenarios, the reduction is negligible (lower than 2 MWh), but for the wet LT scenario, spillage is reduced by 1.2 TWh (22%) compared to the ST scenario. This explains the electricity production difference of STO observed in Fig 4.1. The

[18] DR units, although a direct competitor for GT's as peak response option, barely increase their production which means it was already performing at maximum capacity considering the charging/discharging constraints defined in section 4.1.

production differences observed for STO plants, the dry and average LT scenarios compared to their corresponding ST scenarios is not explained by a difference in spillage but by the initial and final values of the reservoir levels in the simulation horizon caused by the look-ahead period (see Appendix A2). The reasons behind the production reduction from ROR plants in the LT scenarios remains unknown. Possibly, water spillage is increased as a substitution of iRES curtailment which is reduced for LT scenarios.

The fourth mechanism is simply an increase in electricity production for hydropower units for all LT scenarios compared to their respective ST scenarios (Fig 4.6). Its calculated as 7.9 TWh, 6.4 TWh and 5.7 TWh for the average, wet and dry rainfall years respectively. This effect is driven by the increased production of HPS plants (8.8 TWh, 5.5 TWh and 7.1 TWh) and damped by the production reduction from ROR plants (Fig 4.5). Overall, an average hydroelectricity production increase of 2% is observed for the LT scenarios, being highest for the average LT scenario (2.2%) and lowest for the dry LT scenario (1.6%). The maximum difference in hydroelectricity production (only considering LT scenarios) is observed between the average and dry LT scenarios and it is 14.1 TWh. This represents a 3.9% deviation from the mean electricity production for LT scenarios, calculated to be 360.7 TWh. Thus, the sensitivity (in terms of hydroelectricity production) to the rainfall years is increased from the 3.4% value found for the ST scenarios to 3.9%

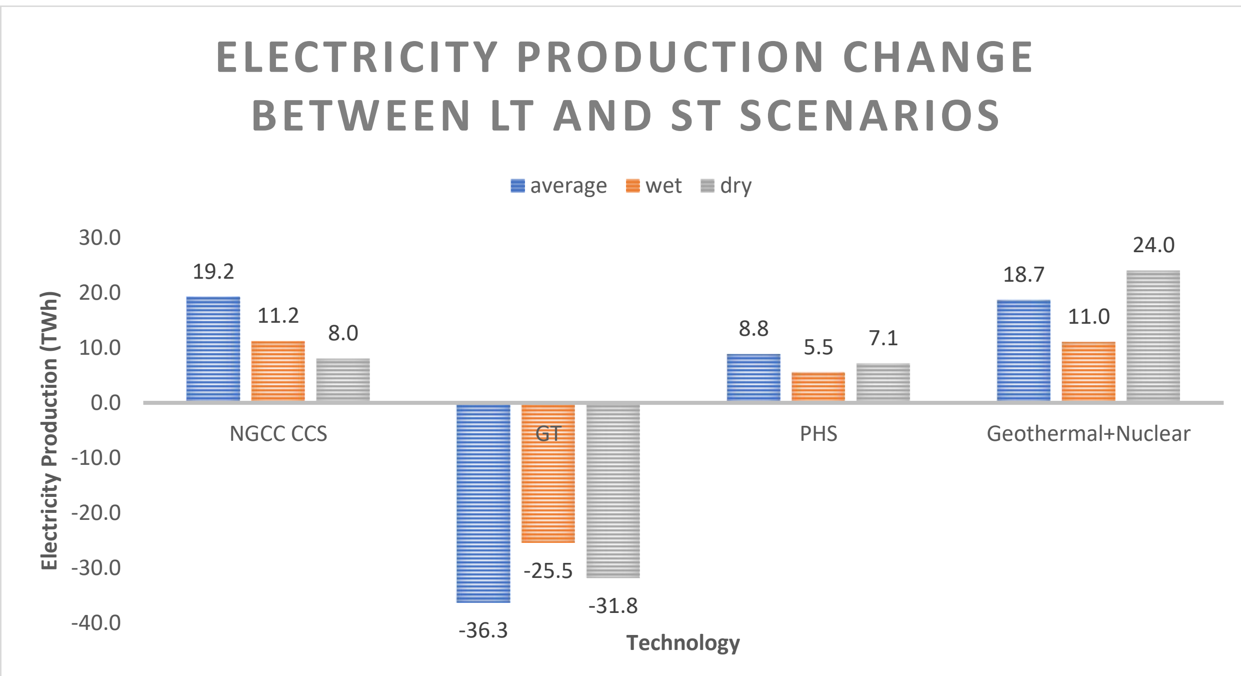

Fig 4.5. Electricity production change for the LT scenarios compared to their corresponding ST scenarios. Only scenarios of the same rainfall year (average, wet and dry) are compared and other technologies (HROR, HDAM, DR) are not included since the changes were negligible.

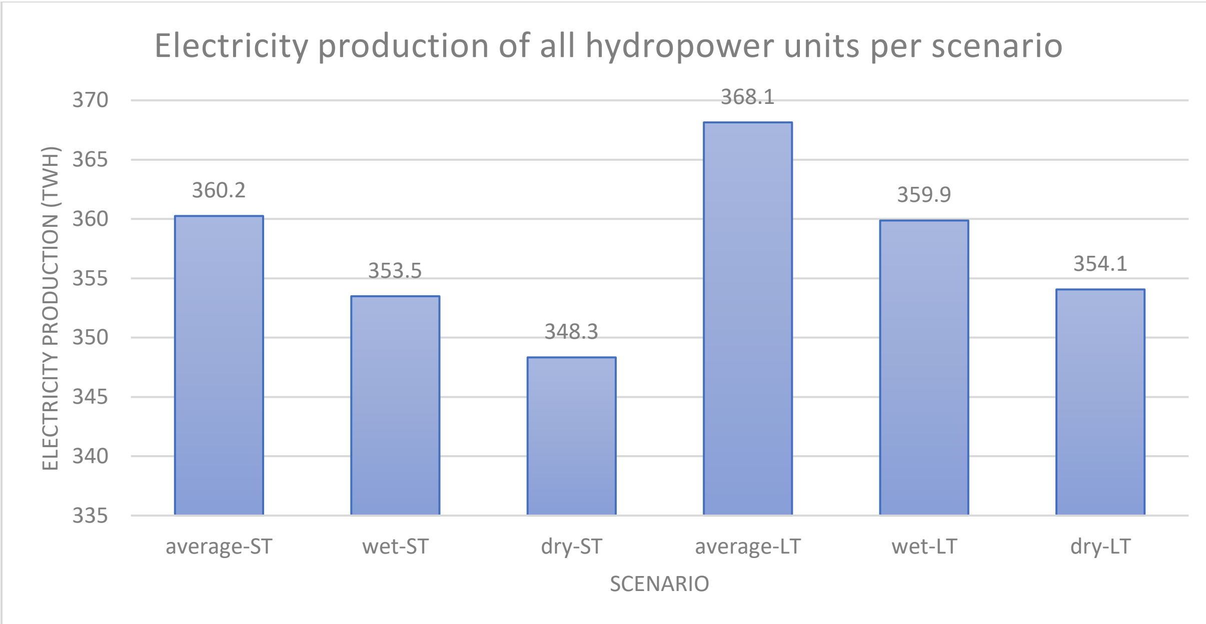

Fig 4.6. Total electricity production from all hydropower plants for each scenario.

From these results, four conclusions can be drawn:

1. The LT modelling approach reduces the overall use of GT's for all LT scenarios. The production is shifted to Nuclear+Geothermal and NGCC's and PHS.
2. The LT modelling approach reduces the average electricity cost since it is driven mostly by the reduction of production from GT's.
3. The LT modelling approach reduces water spillage for STO plants leading to higher availability to provide peak load power.
4. Increased production of hydropower plants in the LT scenarios is driven by the increased production from PHS plants.

4.2.2 Assessment of reservoir profiles

This section presents a comparison between the behavior of the reservoirs during the simulations. The load distribution (Fig 3.7) and the rainfall years (Fig 3.10) which form the basis of the explanations in this section.

Figs 4.5 and 4.6 show the reservoir profiles for the ST scenarios which are obtained by aggregating the storage levels of all PHS and STO plants and normalizing them. The aggregation process consists on adding the hourly storage levels of all plants and results in a time series representing the total amount on electricity stored[19]per unit of time (h). Then, the time series is normalized by dividing all its values by the aggregated storage capacity of all the reservoirs (19.57 TWh). After normalization, reservoir profiles reach

[19] The efficiency of discharge is already included in the reservoir level profiles since it is constant for all plants.

a value of 1 when they are full and a value of 0 when they are empty. The stored electricity at 50% storage capacity equals 9.78 TWh.

For the ST scenarios (Fig 4.7) the levels are fluctuating around 0.5 (50%), a minimum value required for the storage levels at the end of every simulation step. A remarkable point is the peak observed for the wet scenario at the beginning of the year which coincides with the high inflows in those months. The peak lasts for a period slightly shorter than two months and it can happen because the reservoirs are receiving more water than they can turn into electricity. In such a situation, the solver first tries to increase production from STO units[20] which is already at its maximum value after which only two options remain: store or spill water. If there is storage capacity available, the solver will go for the first option. After the high flow months (January, February and to a lesser extend March – see Fig 3.10), the STO units continue to produce electricity until the reservoir levels return to 50% capacity. During the rest of the simulation horizon there is a visible overlap among all the scenarios, especially when the inflows are also overlapping (May to September).

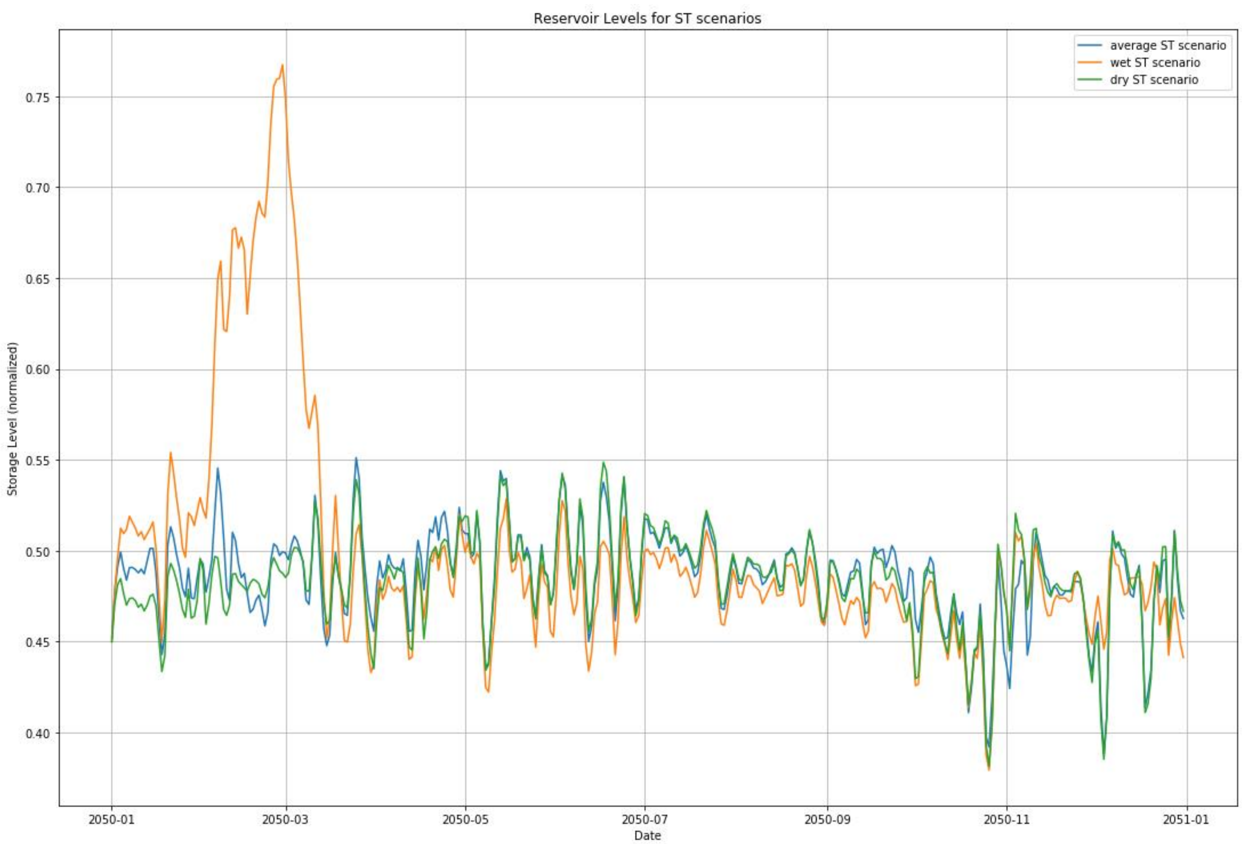

Fig 4.7 Reservoir level profiles for hydro plants for the ST scenarios in 2050.

Fig 4.8 shows normalized reservoir levels for the LT scenarios. A drastically different behavior is observed with respect to the ST scenarios since the storage levels are required to return at 50% storage capacity only at the end of the year. The storage profiles for the average and dry LT scenarios exhibit

[20] Most PHS units return to the 50% since they are connected to very low inflows so this effect is dominated by STO plants.

similar trends throughout the year. The reservoir levels of the wet-LT scenario have a different behavior. The following observations can be made when comparing this results with the inflow scenarios (Fig 3. 10):

1. All LT scenarios reach a full reservoir around the month of July.
2. The dry and average LT scenarios empty their reservoirs around April, fill them completely around July and October. The period from March to November has the lowest flows of the year for those scenarios.
3. The wet-ST scenario profits from the high inflows at the beginning of the year to fill the reservoirs. The last two months (November and December) the reservoir levels drop (inflows are low in those months for this scenario) as opposed to the other scenarios.
4. The wet-ST scenario reservoirs reach their lowest points around February when the flows are high.

The main difference between the wet ST scenario compared to the average and dry ST scenarios is caused due to its high inflows during the first four months of the year. Except for the period between March and July, the wet ST scenario has a similar trend to the other scenarios. This suggests that there is a common trend to all scenarios that optimizes water use.

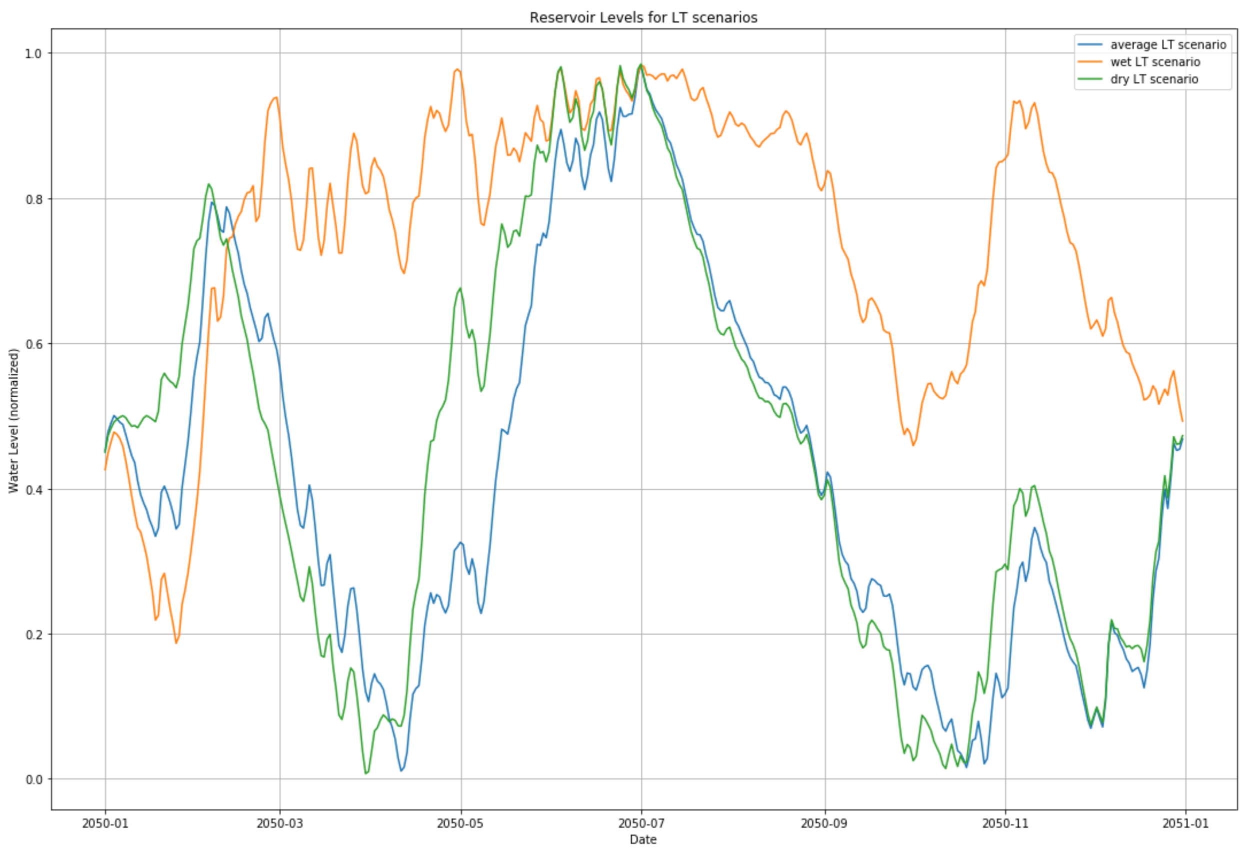

Fig 4.8. Normalized reservoir levels for all hydro plants for the 1-year LT scenarios for 2050. A value of 1 represents a full reservoir, a value of 0 represents an empty one

Regarding the first two observations, they can be explained by the residual load after the power production from iRES technologies has been considered:

$$Residual\ Load\ \ (GW) = Load(GW) - iRES\ Power\ Production\ (GW)$$

The residual load represents the load that needs to be provided by technologies other than iRES and is shown in Fig 4.9. The depression starting on April and reaching is lowest point in July explains the behavior of the reservoir levels on those months (Gig 4.8). It also reflects the fact that demand of electricity rises in winter months compared to summer months.

To explain observations 3 and 4, it seems plausible that the reservoir levels are lowered in the first two months since the residual load is at its peak. The high flows of the wet rainfall year are enough to still refill the reservoirs completely by July, which is not the case for the dry and average ST scenarios if water would have been used at the beginning of the year. Filling the reservoirs by July are the only common point for all three LT scenarios and seems to be central for the optimizations.

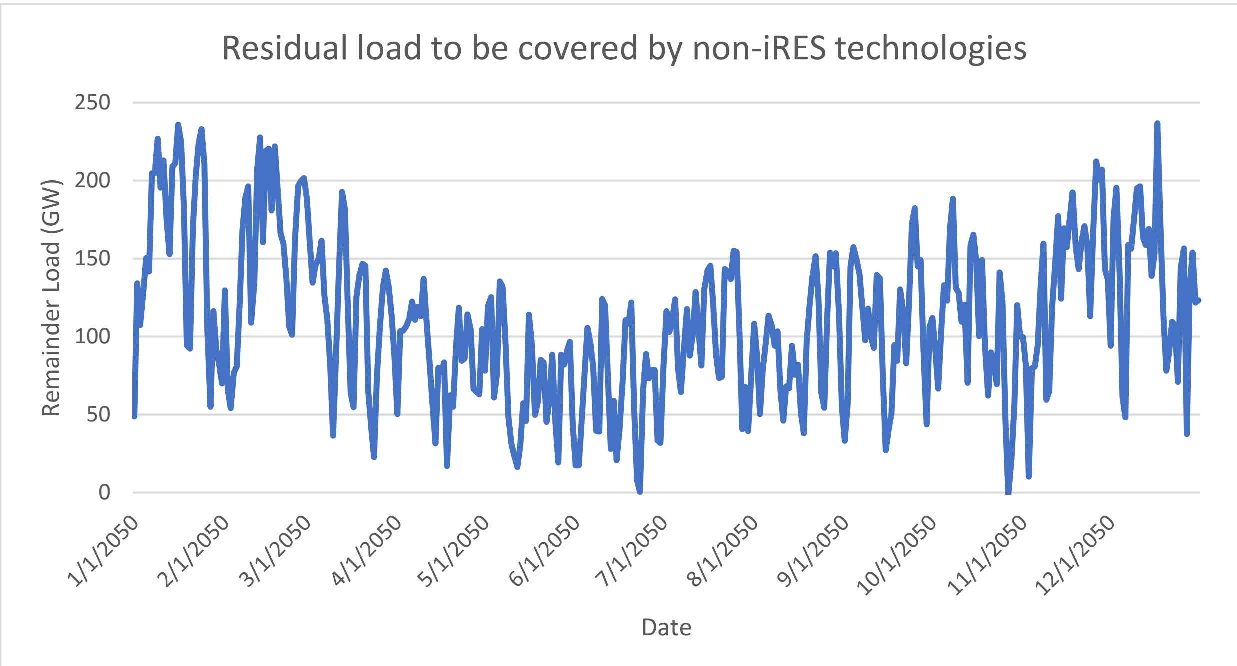

Fig 4.9. Residual load calculated for the average LT scenario.

A summary of the main results of this section:

- The average LT scenario has the lowest average production costs of all LT and ST scenarios.
- Relative cost reductions for the LT scenarios compared to their respective ST scenario range from (5.1% to 7%)
- The average hydroelectricity production is increased by 2% on average in the LT scenarios compared to the ST scenarios.
- Cost reduction is achieved by shifting production away from gas turbines to NGCC plants, Nuclear+Geothermal and PHS.
- The distribution of monthly inflows plays a key role in the electricity production for hydropower plants. The wet LT scenario does not benefit from periods of high flows due to spillage of STO and ROR plants.

- The reservoir levels for all LT scenarios are filled around the month of July. This is caused by lower electricity production demand and sufficient water inflows during summer months.
- The optimized reservoir profiles exhibit similar trends throughout the year for the LT scenarios.

5 Discussion

This chapter is divided into four sections. Section 5.1 deals with the limitations of this study. Limitations are subdivided into data limitations and model limitations. Section 5.2 discusses the model results. Section 5.3 makes a results comparison to validate results. Section 5.4 introduces further research steps.

Some of the limitations are common to other models which this research is based on (Brouwer et al., 2016; Gerritsma, 2016).

5.1 Limitations

5.1.1 Data Limitations

- The Scandinavian region is not considered due to data availability limitations (Gerritsma, 2016). This represents an important limitation since approximately 213 TWh of gross hydroelectricity was produced in this region in 2015, mostly by Norway and Sweden (Eurostat, 2017b). Compared to the total hydroelectricity produced in EU-28 (341 TWh), this corresponds to 62%.
- No additional hydropower capacity was projected to be built by 2050 during the PLEXOS long term planning runs. This approach was chosen to avoid reducing the share of detailed power plants in the simulation to enable a clearer distinction of the flexibility provided by the detailed plants to the overall flexibility provided by lumped hydro plant capacity. However, the projected capacity increase of hydropower is largely focused on emerging technologies for which it is expected to be limited for Europe, achieving (optimistically) a doubling of current capacity by 2050 (IEA, 2012). For PHS however, there is significant potential for existing plants to be optimized and new plants developed to levels above 650TWh a year (Eurelectric, 2015). This model predicts an average production of 55 TWh which is significantly lower.
- Water is only used to produce electricity for which water availability could be being overestimated. Hydropower can provide a variety of services such as irrigation or drinking water (Eurelectric, 2015)
- Climate-change-induced variation in rain fall patterns is expected to affect hydropower generating capacity in the coming years (Lehner, Czisch, & Vassolo, 2005). According to Van Vliet (2013), the overall gross hydropower potential of Europe is expected to decrease by 4-5% for the period 2031-2060 relative to 1971-2000. Although northern countries (Norway, Sweden and Finland) are expected to increase its mean hydropower potential by around 8% or more, strong declines are expected in southern and southeastern countries (Portugal, Spain, France, Italy) in the order of 15% (van Vliet, Vögele, & Rübbelke, 2013). These declines correspond to the regions of ES, FR and IT in the model which concentrate 90% of the overall hydroelectricity production in the model (321 TWh).

- Evaporation losses are not considered and their impact on electricity generation is strongly site-specific with an estimated average of 68 m^3 of evaporated water per GJ of electricity produced, where colder climates benefit from lower evaporation rates (Mekonnen & Hoekstra, 2012).
- Only 32% of the hydropower installed capacity is modelled with the detailed approach for which the effect of the rainfall years is being underestimated.
- DR provided on average 55 TWh of peak response in this study yet its economic potential capacity and costs are uncertain which could have an important impact on the results (Brouwer, van den Broek, Zappa, Turkenburg, & Faaij, 2016)

5.1.2 Modelling-related Limitations

The limitations in this section include those from Dispa-SET and those derived from the modelling approach. They are not separated into distinct categories since some software limitations led to different modelling approaches. Instead, this section is divided into two categories: excluded elements (limitations derived from variables not taken into consideration in the model) and the model limitations (limitations from variables that were taken into consideration)

Excluded elements:

- Efficiency curves are not taken into consideration in Dispa-SET. Efficiency remains the same for all levels of operation for all units which overestimates the performance of GT's, NGCC CSS and nuclear generators (see Appendix F).
- Only electricity market is covered. Heat or cold production are not taken into consideration for which the flexibility that combined heat and power could provide is not included (Nuytten, Claessens, Paredis, Bael, & Six, 2013).
- Total emission constraints (maximum CO2 emissions per year) are not imposed. Dispa-SET's code can be expanded to include this feature but could not be performed due to time constraints.
- Ramp up/down costs are not considered for which variable operational costs of units are being underestimated.
- No outage factors (partial or full) or mean repair times were included due to time constraints. These are estimated as leading to overestimating available flexibility and energy production of all units in the model, particularly allowing the capacity factors of nuclear and geothermal plants to be so high. Average outage factors are estimated to be 9% (including planned and unplanned outages), the mean repair time after an unplanned outage is 50hrs (Brouwer et al., 2016).
- No limits on spillway capacity were imposed for STO and PHS plants overestimating the capacity of hydro plants to deal with high flows potentially decreasing the negative effects of flooding. These effects can limit electricity production and increase operational costs(Kaunda, Kimambo, & Nielsen, 2012).
- Electricity cannot be traded with countries or regions outside the modelled area. Thus, advantages of purchasing/selling electricity are not accounted for.

Model limitations:

- A pre-clustering of detailed hydropower units was carried out to link only one reservoir to each hydro plant as required for Dispa-SET. All the units sharing a head reservoir were aggregated and tail reservoirs were not modelled. This process is expected to have very limited impact on the results since it only applies to 0.5 GW (1.2%) of the capacity installed for detailed plants
- Maximum annual capacity factors cannot be set in Dispa-SET. Important consequences are the high capacity factors of DR (~20%) and nuclear (>90%) which significantly overestimate peak response and baseload capacity availability. ROR plants (detailed and lumped) are modelled as pure ROR plants and therefore they have no storage capacity. This might have had an important impact on the results since about half of the flows (47-51% for the different rainfall years) correspond to ROR plants. The potential flexibility provided from these storages is not included in the modelling and water spillage for ROR plants is overestimated and unaccounted for.
- Artificial flows were used to model lumped plants to set annual capacity factors for ROR and STO plants (see Appendix C). These flows are based on the average rainfall year for all the scenarios for which lumped plants do not play a role in the assessing the impact of rainfall years in the model results. In addition, they could have led to the overestimation of flows for the dry scenarios and the underestimation of flows for the wet scenarios.
- The solutions from the LP solver are used instead of the ones from the MILP solver due to time constraints. Binary variables (start-up/shut down costs, min up/down times and minimum stable levels) are not considered and units of the same technology, region and fuel type are being clustered. Binary variables represent additional constraints to the flexibility of the system for which, if included in the model, fuel costs from generators are expected to be higher. Flexibility provision from these units and storage units (to a lesser extent) should be lower as well. On the other hand, the clustering of units does not decrease the accuracy of results significantly since the binary variables are not being considered. In this case, the modelling of non-detailed plants using clustering is indistinguishable from the normal approach. For detailed plants, this represents a simplification but it is not expected to alter the results significantly since only minimum stable level is different from zero (hydro plants can start-up and shut-down without cost or time penalty) and they can ramp up from 0 to full capacity in a matter of minutes. Regardless of the disadvantages, clustering is a necessity in this study to keep the simulation times at reasonable levels.

5.2. Validation of results

The validation of model results is focused on hydropower and its done by comparing the results of all scenarios with real world data. Two types of results are compared: annual capacity factors and reservoir level profiles.

5.2.1 Validation of total electricity production and capacity factors

The average hydroelectricity production reported in literature for the EU-28 in 2016 is 341 TWh (Eurostat, 2017b).The average value found in this research (considering the different rainfall years) amounts to 357 TWh. This represents a deviation of only 4.6%, which seems plausible.

Table 5 compares the capacity factors found for hydro plants for all scenarios and historic values. The historic values are calculated as averages of the capacity factors found for the detailed plants (Gerritsma, 2016).

Table 5.1. Capacity factors for each hydropower technology for

	ST scenarios	LT scenarios	Historic Value
STO	22 %	22 %	21.8 %
ROR	42 -46 %	42 – 46 %	24.3 %
PHS	14 - 20 %	17 -21 %	13 %

Values found for STO and PHS are very close to the historic values, although capacity factors for hydropower (STO and ROR) are strongly site-specific by which they can range from 25% to 90% (IRENA, 2012). Scenario values for ROR plants are almost double the historic values, however, this model assumes that all water inflows are used for producing electricity which might overestimate the water availability for ROR and STO plants. For PHS units, the values found are higher than the historic values, although still at reasonable levels. These values are expected to increase if the variable costs for DR are properly assessed and included in the model. This, in turn, may also decrease the capacity factors found for DR units.

5.2.2. Validation of storage level profiles

In this section the storage level profiles obtained for the LT scenarios are compared with real water reserve data from France and Spain for the years 2015 and 2016 (Entsoe, 2017; RTE, 2017). Maximum levels of the reservoirs are reached around the middle of the year for all the profiles retrieved for France and Spain. Minimum storage levels in Austria and Switzerland have also been observed to be lower for early spring than the volume available in winter season (Mennel, Tim; Ziegler, Holger; Evert, Michael; Nybo, Agnes; Oberrauch, Felix; Hewicker, 2015) .

An additional comparison is made in terms of its variability, that is, how much the reservoir levels vary from their mean value throughout the year. This is quantified by the relative standard deviation which is simply the standard deviation (STD) of the profile divided by its mean. The relative STD ranges from 5% to 13% for ST scenarios, and from 26% to 62% for LT scenarios. The real water reserves range from 24% to 29% for France and from 16 to 20% for Spain. The real values range between the values found for the ST and LT scenarios. This is expected to a certain extent since the model assumes that the central operator has full information about the parameters of the optimization for the entire year. This is not the case in reality, where future inflows, demand and production from iRES remain uncertain.

5.3. Discussion of results

Results from the ST and LT scenarios indicate that hydropower plays a significant role both for electricity generation and storage on the modelled system. ROR plants provide intermittent electricity production, PHS plants provide peak response almost exclusively and STO plants provide a combination of both. PHS and (to a lesser extent) STO units can directly substitute flexibility provided by GT's or shift peak loads to less flexible units such as Nuclear, Geothermal or NGCC units, in addition to reducing curtailment from iRES technologies. This holds true for all considered scenarios and opens opportunities for the integration of CCS technologies in the grid as substitution of gas turbines, assuming sufficient PHS is provided.

The contribution of PHS to the flexibility of the system has been significantly underestimated in this study. The null variable costs and near 100% efficiencies for DR units favored them to provide flexibility that could have been provided by PHS plants, thus limiting the potential contribution of PHS to the system. This issue can be addressed by setting variable costs for DR for which estimates range from 10 to 2000 EUR/kWh according to Brouwer (2016). On the other hand, results show DR as a key provider of flexibility which is in agreement with literature (NREL, 2012; OECD/IEA, 2014). However, uncertainties about economic potential and costs have been highlighted as an important barrier to determine cost values for DR and true economic potential remains uncertain (Brouwer, van den Broek, Zappa, Turkenburg, & Faaij, 2016).

ROR plants are limited to contribute only to intermittent production as they are modelled as pure ROR plants. This bypasses completely their contribution to the flexibility of the energy system. This issue can be addressed by modelling ROR plants with reservoirs as if they were STO plants (at the expense of increased simulation times). However, if Dispa-SET's LP solver is used and clustered is enabled (as in this study), it should not incur increased simulation times[21].

The average LT scenario (not the wet LT scenario) was found to have the lowest variable costs (7.4 EUR/MWh). This raises questions regarding the importance of the inflow profile in the capacity of the model to shift stored inflows from high flow seasons to low flow seasons. The profile for the wet rainfall year differs drastically from the others and the system does not benefit significantly from the high flows

[21] If the MILP solver is used, increasing the amount of storage units will increase simulation times significantly. This is the reason why ROR plants were modelled as pure ROR plants in the first place.

at the beginning of the year. This point requires clarification in terms of how much of it was caused by the modelling approach for ROR plants and is recommended as further research.

Taking into consideration the effects of seasonal variations (LT scenarios), the variable costs are reduced to a range between 7.4 and 7.9 EUR/MWh, representing a reduction 5.1% to 6.7% from the costs found in the ST scenarios. The results from LT scenarios outline potential savings from smarter water management which justify the integration of predictive flow models into the operation and planning of hydro plants.

The electricity production from STO plants exhibited a high degree of variability in the model, suggesting its contribution to be more as peak response options than as baseload providers for the system. This observation can be relevant for the design of new STO plants, given a set of inflows and a catchment area, STO plants can be designed to have either: (1) high installed capacities and low capacity factors (to meet demand peaks) or (2) low installed capacities and high capacity factors (to provide baseload production) (IRENA, 2012). According to the results shown, STO plants of the first type would have more important roles to play for the future low-carbon energy system, a lesson that needs to be considered for future expansion of hydropower STO capacity.

6 Conclusion

This study assesses the effects of different rainfall years on the ability of hydropower to generate and store electricity in a European low carbon energy system with 59% intermittent renewable energy sources (iRES) penetration projected for 2050. The model set up is based on data collection and modelling methodologies done in previous studies (Brouwer, van den Broek, Zappa, Turkenburg, & Faaij, 2016; Gerritsma, 2016) and it uses the power system modelling software Dispa-SET developed by the Joint Research Center of the European Commission. Dispa-SET is used to minimize the yearly variable system costs by optimizing the economic dispatch of electricity generators and storage units.

The energy mix is defined (on a capacity basis) by 59% iRES (solar photovoltaic, wind offshore and wind offshore) supplemented by gas turbines (18%), hydropower (11%), nuclear (3%), natural gas combined cycle plants (NGCC) with carbon capture and storage (1%), geothermal (1%) and demand response (3%). The total hydropower installed capacity is 127.0 GW consisting of 35.0 GW (28%) of pumped hydro storage (PHS) plants, 42 GW (31%) of run-of-river (ROR) plants and 52.2 GW (41%) of storage (STO) plants. Only 64 plants, making up 40.4 GW (32%) of installed capacity, are modelled in a detailed way (detailed plants) by taking into consideration natural inflow data and individual techno-economic performance parameters. For these plants, water catchment limits electricity production and thus they are affected rainfall years. The rest of the hydropower, covering the remaining 86.4 GW (68%) of installed capacity, is modelled using aggregated performance data and is not connected to natural inflow, remaining unaffected by the rainfall year.

Three rainfall years are defined: a year of high flows (wet year), a year of low flows (dry year) and a year of average flows (average year). Rainfall years are simulated using a short-term and a long-term optimization of the reservoir levels of hydro plants leading to a total of six simulated scenarios. The short-term optimization simplifies the simulation of each rainfall year by simulating time intervals (steps) of 5 days at a time. For each simulation step, the solver cannot anticipate future electricity production or demand shifts and thus the optimization is short sighted. Long-term optimization simulates the full year at once and thus it can include the effects of seasonal variations of water inflows in the simulation.

Results show that rainfall scenarios affect the electricity production of hydro plants by having an impact on the flexibility hydropower can provide to the system. This results in changes on the average production costs, which is quantified by differences in terms of electricity production of hydropower plants (348 to 360 TWh) and variable production costs (7.9 to 8.5 EUR/MWh) found for the short-term scenarios. These differences correspond to a change of 4% in electricity production and a cost difference of up to 7% and they are expected to be even higher if the total installed hydropower capacity (127.0 GW) is modelled in a detailed way.

Taking into consideration the effects of seasonal variations of water levels on the model allows better exploitation of the inherent flexibilities of the energy system. This is observed in the results of the long-term scenarios that show increased electricity production of hydropower plants (354.1 – 368.1 TWh) and reduced variable production system costs (7.4 – 7.9 EUR/MWh). These represent production increases of 1-2% and a cost decreases of 5-7% compared to the values found for the ST scenarios.

Additional effects contributing to these results are: (1) the reduction of spillage reduction from storage hydro plants, (2) curtailment reduction from iRES, (3) electricity production shift from gas turbines towards natural gas combined cycle, nuclear, geothermal and pumped hydro storage.

The average rainfall year resulted in the highest electricity production for hydro plants and lowest variable system costs for both long-term and short-term optimizations. This suggests that water inflow profiles (the distribution of flows throughout the year) have a key role in the performance of hydropower units, a point that requires further research.

Regarding individual hydropower technologies, PHS units can directly substitute gas turbines as peak response options, or they can shift peak load to be covered by less flexible generators which can decrease variable costs. Increased capacity of these units can aid to integrate larger shares of NGCC with carbon capture and storage assisting in the transition to a 100% renewable energy system. STO plants can supplement PHS plants as peak load options in future low carbon energy systems. The flexibility of their design allows the development of new projects to be steered towards addressing demand peaks rather than contributing to baseload production, as required for energy systems with high iRES penetration. ROR plants provide intermittent electricity production. Their role in providing flexibility to the system requires further research since it is not quantified due to the modelling approach used.

Overall, hydropower was found to play a key role in producing and storing electricity to provide flexibility to energy systems with 80% iRES penetration considering rainfall scenarios. The sensitivity of the results to changes in water inflows is expected to be increased if a larger share of the installed hydropower capacity is covered by detailed plants. Results from the long-term scenarios provide insight on the potential savings that can be achieved if seasonal variations of water inflows are considered for the dispatch of hydropower plants.

Further research:

- Use the optimized reservoir levels obtained for the LT scenarios as input for the solver to increase accuracy of results. Described in the methodology (Step 5).
- Model ROR plants as STO plants to quantify their contribution to the flexibility of the energy system. If the same LP solver. If an LP solver is used, the units can be clustered without reducing the accuracy of results or increasing simulation times
- Model consecutive rainfall years to assess the contribution of several years of high or low inflows into the model outcomes
- Explore the effects of the water inflow distribution on the model results. This point can provide insights to optimize storage capacities of hydro plants, another research topic that is central to capture benefits from seasonal variation.
- Expand Dispa-SET's code to include maximum annual capacity factors to ensure the electricity production from generators is within normal levels.
- Expand Dispa-SET's code to include total CO2 emission constraints as this can further limit production from fossil plants and is a requirement to reach emission target goals.

Bibliography

Brouwer, A. S., Van Den Broek, M., Seebregts, A., & Faaij, A. (2015). Operational flexibility and economics of power plants in future low-carbon power systems. *Applied Energy*, *156*, 107–128. https://doi.org/10.1016/j.apenergy.2015.06.065

Brouwer, A. S., van den Broek, M., Zappa, W., Turkenburg, W. C., & Faaij, A. (2016). Least-cost options for integrating intermittent renewables in low-carbon power systems. *Applied Energy*, *161*, 48–74. https://doi.org/10.1016/j.apenergy.2015.09.090

Deml, S. (2014). *The Role of Aggregation in Power System Simulation*. Swiss Federal Institute of Technology (ETH) Zurich.

ECF. (2010). *Roadmap 2050. A practical guide to a propserus low carbon Europe*. Retrieved from http://www.roadmap2050.eu/attachments/files/Volume1_fullreport_PressPack.pdf

Entso-e. (2009). *Continental Europe Operation Handbook, Appendix I, Load-Frequency Control and Performance.* Retrieved from https://www.entsoe.eu/fileadmin/user_upload/_library/publications/entsoe/Operation_Handbook/Policy_1_final.pdf

Entsoe. (2017). Water Reservoirs and Hydro Storage Plants. Retrieved October 10, 2017, from https://transparency.entsoe.eu/generation/r2/waterReservoirsAndHydroStoragePlants/show

Eurelectric. (2015). *Hydropower. Supporting a power system in transition.* Brussels, Belgium. Retrieved from http://www.eurelectric.org/media/180752/hydropower-final-lr-2015-2120-0003-01-e.pdf

European commission. (2011). Roadmap for moving to a low-carbon economy in 2050. *DG Climate Action Portal*, 1–2. Retrieved from http://ec.europa.eu/clima/policies/roadmap/index_en.htm

Eurostat. (2017a). Primary Production of Energy by Resource. Retrieved from http://ec.europa.eu/eurostat/tgm/table.do?tab=table&init=1&language=en&pcode=ten00076&plugin=1

Eurostat. (2017b). Primary Production of Renewable Energy by Type. Retrieved March 2, 2017, from http://ec.europa.eu/eurostat/tgm/refreshTableAction.do?tab=table&plugin=1&pcode=ten00081&language=en

Gaudard, L., & Romerio, F. (2014). The future of hydropower in Europe: Interconnecting climate, markets and policies. *Environmental Science and Policy*, *37*, 172–181. https://doi.org/10.1016/j.envsci.2013.09.008

Gerritsma, M. (2016). *Role of Detailed Hydropower Modelling in Investigating Power System Flexibility*. Utrecht University.

Geth, F., Brijs, T., Kathan, J., Driesen, J., & Belmans, R. (2015). An overview of large-scale stationary electricity storage plants in Europe : Current status and new developments. *Renewable and Sustainable Energy Reviews*, *52*, 1212–1227. https://doi.org/10.1016/j.rser.2015.07.145

Gils, H. C. (2014). Assessment of the theoretical demand response potential in Europe. *Energy*, *67*, 1–18. https://doi.org/10.1016/j.energy.2014.02.019

Hidalgo Gonzalez, I., Sylvain, Q., & Zucker, A. (2014). Dispa-SET 2.0: unit commitment and power dispatch model, 1–26. https://doi.org/10.2790/399921

Huertas-Hernando, D., Farahmand, H., Holttinen, H., Kiviluoma, J., Rinne, E., S??der, L., … Menemenlis, N. (2016). Hydro power flexibility for power systems with variable renewable energy sources: An IEA Task 25 collaboration. *Wiley Interdisciplinary Reviews: Energy and Environment*. https://doi.org/10.1002/wene.220

IEA. (2012). Technology Roadmap. Hydropower. *Oecd/Iea*, 68. https://doi.org/10.1007/SpringerReference_7300

IPCC Working Group 1, I., Stocker, T. F., Qin, D., Plattner, G.-K., Tignor, M., Allen, S. K., … Midgley, P. M. (2013). IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. *IPCC*, *AR5*, 1535.

IRENA. (2012). *Hydropower* (Vol. 1). Bonn, Germany. Retrieved from https://www.irena.org/documentdownloads/publications/re_technologies_cost_analysis-hydropower.pdf

Joint Research Center - European Comission. (2017). Dispa SET's 2.0 online documentation. Retrieved July 20, 2007, from http://dispa-set.readthedocs.io/en/latest/model.html#power-plant-clustering

Kaunda, C. S., Kimambo, C. Z., & Nielsen, T. K. (2012). Hydropower in the Context of Sustainable Energy Supply: A Review of Technologies and Challenges. *ISRN Renewable Energy*, *2012*, 1–15. https://doi.org/10.5402/2012/730631

Kopytko, N., & Perkins, J. (2011). Climate change, nuclear power, and the adaptation-mitigation dilemma. *Energy Policy*, *39*(1), 318–333. https://doi.org/10.1016/j.enpol.2010.09.046

Lehner, B., Czisch, G., & Vassolo, S. (2005). The impact of global change on the hydropower potential of Europe: a model-based analysis. *Energy Policy*, *33*, 839–855. https://doi.org/10.1016/j.enpol.2003.10.018

Manzano-agugliaro, F., Montoya, F. G., Gil, C., Alcayde, A., Gómez, J., & Ba, R. (2011). Optimization methods applied to renewable and sustainable energy : A review, *15*, 1753–1766. https://doi.org/10.1016/j.rser.2010.12.008

Mekonnen, M. M., & Hoekstra, A. Y. (2012). The blue water footprint of electricity from hydropower. *Earth Syst. Sci*, *165194*(10), 179–187. https://doi.org/10.5194/hess-16-179-2012

Mennel, Tim; Ziegler, Holger; Evert, Michael; Nybo, Agnes; Oberrauch, Felix; Hewicker, C. (2015). *The hydropower sector contribution to a sustainable and prosperous Europe*. Bonn.

NREL. (2012). *Renewable Electricity Futures Study: Executive Summary*. Golden Colorado: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/analysis/re_futures/.

Nuytten, T., Claessens, B., Paredis, K., Bael, J. Van, & Six, D. (2013). Flexibility of a combined heat and power system with thermal energy storage for district heating. *Applied Energy*, *104*, 583–591. https://doi.org/10.1016/j.apenergy.2012.11.029

OECD/IEA. (2014). *The Power of Transformation - Wind, Sun and the Economics of Flexible Power Systems*. Paris, France. Retrieved from https://www.iea.org/publications/freepublications/publication/The_power_of_Transformation.pdf

RTE. (2017). France Water Reserves. Retrieved October 11, 2017, from http://clients.rte-france.com/lang/an/visiteurs/vie/prod/stock_hydraulique.jsp

Twidell, J., & Weir, T. (2006). *Renewable Energy Resources*. *Management* (Vol. 532). https://doi.org/10.4324/9780203478721

van Vliet, M. T. H., Vögele, S., & Rübbelke, D. (2013). Water constraints on European power supply under climate change: impacts on electricity prices. *Environmental Research Letters*, *8*, 35010. https://doi.org/10.1088/1748-9326/8/3/035010

Appendix

Appendix A. Dispa-SET runs.

This section is concerned to explain the parameters that were used for the simulation. Section A1 introduces the simulation parameters that control the way the optimization problem is tackled (without altering the input data). Section A2 introduces the simulation scenarios investigated in this report, and explains the exact methodology followed to model long period of times using pre-optimized reservoir levels.

Dispa-SET solves the Unit-Commitment and Economic Dispatch (UCED) using an objective function to minimize the total power system costs in a certain simulation period. These include (start-up costs, shut down costs, fixed costs, variable costs, ramping costs, transmission costs[22] and load shedding costs (Hidalgo Gonzalez, Sylvain, & Zucker, 2014). As opposed to the LT runs, no additional capacity of any type can be added and the model only focuses on the UCED.

Since the input data consists of a mix of binary (start up and shut down decisions) and continuous variables (e.g. production levels), Dispa-SET can formulate UCED mathematical problems as mixed-integer linear program (MILP) or as linear program (LP) if the binary variables are not to be considered.

In addition to the simulation period, three parameters control the way simulations are performed within Dispa-SET(Hidalgo Gonzalez, Sylvain, & Zucker, 2014):

(1) Time horizon or optimization period
(2) Look-ahead period
(3) Clustering method

A.1. Time Horizon

A simulation can be performed in principle for any simulation period (e.g. one year) split into one-hour time steps but the problem could become extremely demanding in terms of computational resources. To avoid this, the problem can be split into smaller optimization sub-problems connected through a recursive algorithm. In this way, solving 'n' small optimization sub-problems can be considerably less time intensive than one full problem.

The chosen time horizon has a special impact for storage units since minimum storage levels must be imposed at the end of every horizon to avoid the emptying of storages. For this study, storage levels must be at 50% capacity at the start and end of every horizon to ensure availability for future periods. As an example, a time horizon of 90 days requires all storage technologies to return to 50% capacity level every 90 days which is not good enough to study seasonal variations.

[22] Transmission costs are no yet fully implemented into the current version of Dispa-SET therefore they are assumed to be zero in this study.

Time horizon represents the amount of time the reservoir levels can change freely before returning to the 50% capacity pre-set value[23]. To assess seasonal variations, a long simulation period (1 year >=) must be selected with an (ideally) equally long-time horizon. Setting a time horizon equal to the simulation period allows a better optimization of the storage levels (at the cost of longer simulation times).

To set realistic time horizons and simulation periods a few run test were carried out. Depending on the CPU processor capacity and the amount of RAM memory available, the simulations times can vary. Still, increasing the time horizon increases the simulation times in a non-linear fashion. With the resources available for this research, a 90-day time horizon resulted to be the maximum manageable using Dispa-SET's MILP solver. Due to this, the reservoir levels were pre-optimized using the Dispa-SET's LP solver before using the MILP solver, which allowed to model longer time horizons. This method, leaves the groundwork needed to simulate long time horizons with Dispa-SET while allowing the reservoir levels to variate.

A.2. Look-ahead period

Look ahead period is an extension of time at the end of every optimization period that overlaps with the next one. As an example, for a given optimization period j-1, the actual period that is simulated equals the optimization period j-1 plus the look ahead period j-1. Later, the results during the look ahead period are discarded but the values connecting the optimization period j-1 and look-ahead period j-1 are used as initial values for the next optimization period j. Fig A2 graphically depicts this process.

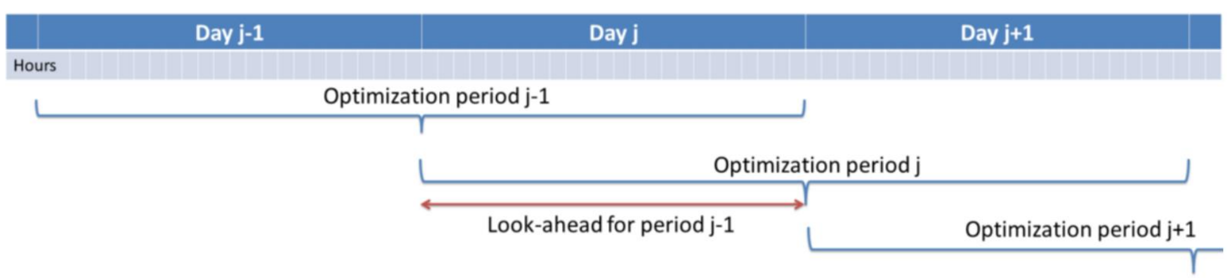

Fig A2. A schematic of the look ahead period. Source (Joint Research Center - European Comission, 2017)

Look ahead period is designed to avoid issues related to the end of simulation period such as emptying reservoirs or starting low-cost but non-flexible power plants. In the case of long simulations, this period should be small, being the minimum one day as it is the case for the simulations in this report.

A.3. Solver Method

[23] Reservoir levels do not have to return to the pre-set value exactly at the end of every time horizon (see look-ahead period)

The first solver method available is the Mixed Integer Linear Programing (MILP). This method is the most detailed within Dispa-SET and solves the UCED problem taking into consideration binary variables (minimum up/down times, sart-up/shut-down costs, minimum stable level) and continuous variables (energy production, storage levels, etc.)

Clustering of units can take place when units have very low power capacity or are very flexible. In such situations, units are merged into a single highly flexible unit with averaged parameters.

Fig A3 shows the parameters for the clustering decisions. Dispa-SET will only cluster units of the same technology (type) yet they must comply to other characteristics: (1) Similar parameters and a minimum stable level close to zero[24], (2) Start-up time less than an hour, (3) power capacity less than 30MW[25]. More information on the clustering method can be found in Dispa SET's online documentation (Joint Research Center - European Comission, 2017).

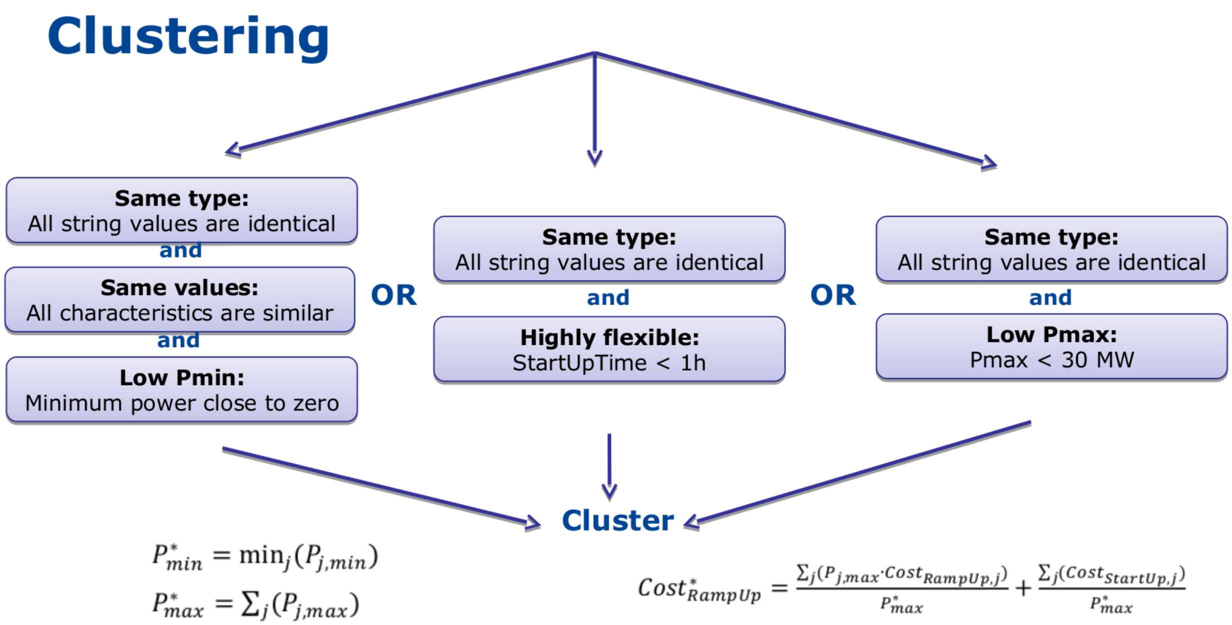

Fig A3. Clustering parameters for Dispa-SET. Source: (Joint Research Center - European Comission, 2017)

The second method available is the LP (clustered) method. The clustering conditions are the same as in the MILP method (see Clustering diagram) but the modelling is simplified to not include binary variables. Explicitly, the following parameters are dropped in this method:

- Minimum up/down times
- Start-up/shut-down costs
- Minimum stable level

[24] How close?

[25] This value is used defined and therefore it can be changed to alter the clustering conditions.

Since the start-up/shut-down and minimum stable level of individual units is no longer considered, a clustered formulation is equivalent to an individual one. Therefore, all units of the same technology, fuel and zone are aggregated.

A more efficient approach is to use the LP formulation is used first, but only to optimize the reservoir levels. The LP formulation drops the binary variables (minimum up and down times, startup costs and minimum stable load) and simplifies greatly the mathematical problem reducing simulation times significantly.

All scenarios are modelled by using the LP (clustering) formulation to optimize the reservoir levels first. The time horizon is set to the same length as the simulation ensuring that the reservoir levels are only forced to start and finish at 50% capacity. At any point between the start and the end of the simulation period, the reservoir levels remain unconstrained.[26] From the LP runs, only the part of the output relative to the storage levels are retrieved. The storage levels have been optimized for each scenario and the rest of the results are discarded.

[26] A minimum reservoir level of 0 is set for all simulations so that the reservoirs can empty themselves at any point between the beginning and the end of the simulation.

Appendix B. Pre-clustering of detailed hydro plant units.

Most hydro plants (ROR and STO) are connected to a single upper reservoir (head storage) and they release the water to a river after passing through the generator. In an equivalent way, PHS plants are typically connected to a single upper reservoir (head storage) but also to a lower reservoir (tail storage) where the water is reserved to be pumped back up at the appropriate time. This is referred to as a simple configuration.

Some plants have more complex configurations in which they can share reservoirs and/or a single reservoir can be connected to more than a single hydro plant. *Dispa-SET can only model the simple configuration* explained above.

Out of the 68 hydro plants, 4 small plants (226 MW to 96 MW) were connected to the remaining 64 large hydro plants (larger than 250 MW) and therefore they had to be included in the database. To be modelled with Dispa-SET they had to be converted to a simple configuration (1 plant – 1 head storage).

This was achieved by clustering the power plants sharing head storage into a single artificial unit[27]in a process that will be referred to as pre-clustering[28]. Such artificial unit is an average of the aggregated plants, having an average of the parameters of the original plants. The parameters that are aggregated and averaged are the following:

- Capacity per unit
- Capacity factor per unit
- Ramp Up/Down rate (as % of total capacity) per unit
- Variable costs per unit
- Pump capacity (as % of total capacity - for PHS) per unit
- Storage size per unit

For any parameter listed above, the formula used (using capacity as an example) is:

$$Capacity\ per\ artificial\ unit = \frac{\sum Number\ of\ Units * Capacity\ per\ unit}{\sum Number\ of\ Units}$$

$$Artificial\ number\ of\ units = \sum Number\ of\ Units$$

The artificial units have a different number of units (artificial number of units) and different parameters (artificial parameters). Therefore, the original plants are discarded and the artificial units take their place for modelling.

64 artificial plants where formed.The artificial units formed were given new names, consisting on the sum of the original names that form the group, separated by a coma.

Three artificial units where formed:

1. Bieudron, Fionnay, Nendaz (STO)

[27] All power plants sharing a head storage belong to the same category (STO, ROR, PHS) therefore the artificial plant also belongs to the same category.
[28] The process is called pre-clustering to distinguish it from the clustering process that takes place within Dispa-SET.

2. Brevieres, Malgovert (STO)
3. La Muela I, La Muela II (PHS)

Since natural water flows are connected to reservoirs (head or tail storages) rather than plants, the grouping process results in 64 plants and 64 flows, which can be modelled in Dispa-SET.

Appendix C. Capacity factors for lumped hydro plants

None of the plants modelled using the simplified approach are connected to natural inflows. Instead, artificial inflows were devised (using the average inflow scenario as basis) to be able to model them as storages with inflows. These artificial flows will be called lumped flows or lumped inflows in the context of this research. Only ROR and STO lumped plants were connected to lumped flows, the storages of lumped PHS plants are assumed to be recharged only by pumping water from their lower reservoir to their upper reservoir.

Typically, yearly maximum capacity factors can be imposed but this option is not available in Dispa-SET. In Dispa-SET maximum capacity factors can be imposed in an hourly basis, however this would limit the response that hydropower can provide during peak loads.

The methodology presented below represents an alternative to simply impose hourly capacity factors to the hydro plants. The idea is creating artificial flows (for each lumped plant) with two characteristics:

(1) The flow profile is set equal to that of the average flows of all detailed plant in the average 1-year scenario
(2) The annual average water inflow of each reservoir equals the annual capacity factor chosen times the capacity of the lumped plant connected to the reservoir.

Regarding (1), the average scenario is chosen since its most representative of a typical rainfall year. Property (2) ensure that the value of the capacity factor of lumped plants is respected while allowing the plants to perform at full capacity at peak loads.

The average inflow scenario is defined by monthly inflows (per plant) expressed in MW. To obtain the profile (a set of the 12 monthly flows following the same shape as the average flow scenario curve), we compute the mean inflow for all 64 plants (k) for each month (j). Following the equation C1 we find the average value of the flow profile for month j:

$$flow_j = \frac{1}{64}\sum_k flow_j^k \qquad \textbf{Equation C1}$$

Note that the sum over k goes from 1 to 64. To fulfill condition (2), the profile must also satisfy equation C2 for each plant and reservoir:

$$\frac{flow_1 + flow_2 + \cdots + flow_3\ [MW]}{Installed\ Capacity\ of\ plant\ [MW]} = Capacity\ Factor\ of\ plant \qquad \textbf{Equation C2}$$

To achieve this, the flow profile is multiplied by a value α (to be found for each lumped plant) such that equation C2 is satisfied. The capacity factor of equation C2 is defined by the values in table C1.

The result can be seen in Fig C1. The blue line represents the approach developed in this section while the orange line represents the approach in which we simply convert the annual maximum capacity factor into monthly (constant) values.

The results are shown as percentages of the maximum capacity of each plant (the actual values used in Dispa-SET are calculated in MW and they are different for each plant). The blue line follows a profile similar to that of natural inflows with higher availability in the months of November, December, January and February, and lower availability in the rest of the year.

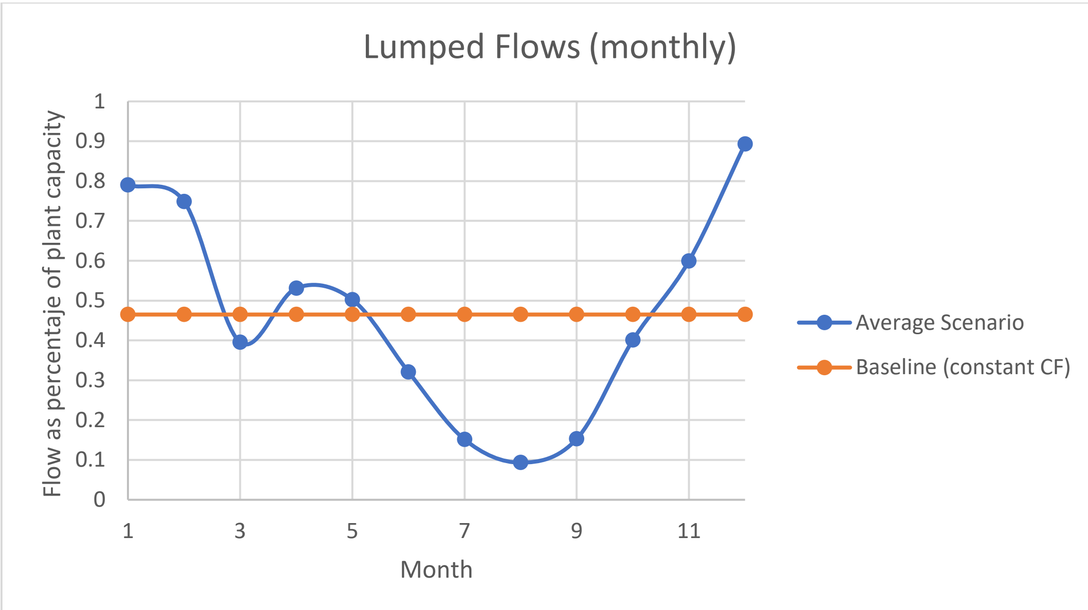

Figure C1. Lumped flows example for an annual capacity factor of 0.465.

Finally, capacity factors are set for each hydro plant category according to Table C1.

Table C1. Average capacity factor per for rest-of-plants. Source (Gerritsma, 2016)

	Capacity Factors
Small non-PHS	0.465
Small PHS	-
Large STO	0.500
Large ROR	0.465
Large PHS	-

Appendix D. Data Tables

This section presents the full database of the units modelled in this study. Fig D1 shows the unit parameters for all technologies other than hydropower, Fig D2 shows all the detailed hydro units and Fig D3 shows all the lumped hydro units.

0	Region	Unit	Nunits	Technology	Fuel	PowerCapacity	Efficiency	MinEfficiency	CO2Intensity	PartLoadMin	RampRate	StartUpTime	MinUpTime	MinDownTime	StartUpCost	STOCapacity	STOMaxChargingPower	STOChargingEfficiency
Units -->	-	-	-	-	-	MW	%	%	tCO2/MWh	%	%	h	h	h	EUR	MWh	MW	%
1	GB	D-Fri - GB	114	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
2	DE	D-Fri - DE	244	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
3	FR	D-Fri - FR	134	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
4	IT	D-Fri - IT	129	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
5	ES	D-Fri - ES	83	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
6	GB	D-Hea - GB	617	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
7	DE	D-Hea - DE	704	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
8	FR	D-Hea - FR	789	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
9	IT	D-Hea - IT	562	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
10	ES	D-Hea - ES	319	DR	-	5	1.00	0.00	0	0	1	0	0	0	0	40	5	1
11	GB	D-T21 - GB	247	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
12	DE	D-T21 - DE	435	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
13	FR	D-T21 - FR	334	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
14	IT	D-T21 - IT	272	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
15	ES	D-T21 - ES	241	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
16	GB	D-T22 - GB	107	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
17	DE	D-T22 - DE	202	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
18	FR	D-T22 - FR	150	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
19	IT	D-T22 - IT	117	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
20	ES	D-T22 - ES	107	DR	-	5	0.99	0.00	0	0	1	0	0	0	0	40	5	1
21	GB	D-Was - GB	535	DR	-	1	0.97	0.00	0	0	1	0	0	0	0	8	1	1
22	DE	D-Was - DE	983	DR	-	1	0.97	0.00	0	0	1	0	0	0	0	8	1	1
23	FR	D-Was - FR	447	DR	-	1	0.97	0.00	0	0	1	0	0	0	0	8	1	1
24	IT	D-Was - IT	509	DR	-	1	0.97	0.00	0	0	1	0	0	0	0	8	1	1
25	ES	D-Was - ES	288	DR	-	1	0.97	0.00	0	0	1	0	0	0	0	8	1	1
26	GB	Geo - GB	18	Geothermal	-	25	0.96	0.83	0	0.2	0.03	0	0	0	975	0	0	0
27	FR	Geo - FR	87	Geothermal	-	25	0.96	0.83	0	0.2	0.03	0	0	0	975	0	0	0
28	DE	Geo - DE	59	Geothermal	-	25	0.96	0.83	0	0.2	0.03	0	0	0	975	0	0	0
29	ES	Geo - ES	61	Geothermal	-	25	0.96	0.83	0	0.2	0.03	0	0	0	975	0	0	0
30	IT	Geo - IT	55	Geothermal	-	25	0.96	0.83	0	0.2	0.03	0	0	0	975	0	0	0
32	DE	NGCC CCS Gas DE	23	NGCC CCS	Gas	650	0.63	0.50	0	0.25	0.045	2	5	1	25350	0	0	0
33	GB	Nuclear - GB	1	Nuclear	Uranium	1500	0.34	0.24	0	0.2	0.025	8	24	24	58500	0	0	0
34	FR	Nuclear - FR	16	Nuclear	Uranium	1500	0.34	0.24	0	0.2	0.025	8	24	24	58500	0	0	0
35	ES	Nuclear - ES	2	Nuclear	Uranium	1500	0.34	0.24	0	0.2	0.025	8	24	24	58500	0	0	0
36	IT	Nuclear - IT	8	Nuclear	Uranium	1500	0.34	0.24	0	0.2	0.025	8	24	24	58500	0	0	0
38	DE	GT - DE	624	GT	Gas	100	0.42	0.25	0.45	0.2	0.1	0.25	0	0	1600	0	0	0
39	GB	GT - GB	664	GT	Gas	100	0.42	0.25	0.45	0.2	0.1	0.25	0	0	1600	0	0	0
40	FR	GT - FR	493	GT	Gas	100	0.42	0.25	0.45	0.2	0.1	0.25	0	0	1600	0	0	0
41	ES	GT - ES	273	GT	Gas	100	0.42	0.25	0.45	0.2	0.1	0.25	0	0	1600	0	0	0
42	IT	GT - IT	60	GT	Gas	100	0.42	0.25	0.45	0.2	0.1	0.25	0	0	1600	0	0	0
43	GB	Solar PV - GB	1	Solar PV	-	17944	1.00	1.00	0	0	1	0	0	0	0	0	0	0
44	FR	Solar PV - FR	1	Solar PV	-	55383	1.00	1.00	0	0	1	0	0	0	0	0	0	0
45	DE	Solar PV - DE	1	Solar PV	-	44306	1.00	1.00	0	0	1	0	0	0	0	0	0	0
46	ES	Solar PV - ES	1	Solar PV	-	71988	1.00	1.00	0	0	1	0	0	0	0	0	0	0
47	IT	Solar PV - IT	1	Solar PV	-	95701	1.00	1.00	0	0	1	0	0	0	0	0	0	0
49	GB	Wind Offshore - GB	1	Wind Offshore	-	38848	1.00	1.00	0	0	1	0	0	0	0	0	0	0
50	FR	Wind Offshore - FR	1	Wind Offshore	-	9827	1.00	1.00	0	0	1	0	0	0	0	0	0	0
51	DE	Wind Offshore - DE	1	Wind Offshore	-	47897	1.00	1.00	0	0	1	0	0	0	0	0	0	0
52	ES	Wind Offshore - ES	1	Wind Offshore	-	396	1.00	1.00	0	0	1	0	0	0	0	0	0	0
54	GB	Wind Onshore - GB	1	Wind Offshore	-	85039	1.00	1.00	0	0	1	0	0	0	0	0	0	0
55	FR	Wind Onshore - FR	1	Wind Offshore	-	64792	1.00	1.00	0	0	1	0	0	0	0	0	0	0
56	DE	Wind Onshore - DE	1	Wind Offshore	-	117435	1.00	1.00	0	0	1	0	0	0	0	0	0	0
57	ES	Wind Onshore - ES	1	Wind Offshore	-	68841	1.00	1.00	0	0	1	0	0	0	0	0	0	0
58	IT	Wind Onshore - IT	1	Wind Offshore	-	29996	1.00	1.00	0	0	1	0	0	0	0	0	0	0

Fig D1. Non-hydropower database.

0	Region	Unit	Nunits	Technolog	Fuel	PowerCapacity	Efficiency	MinEfficiency	CO2Intensity	PartLoadMin	RampRate	StartUpTime	MinUpTime	MinDownTime	StartUpCost	STOCapacity	STOMaxChargingPower	STOChargingEfficiency
Units -->	-	-	-	-	-	MW	%	%	tCO2/MWh	%	%	h	h	h	EUR	MWh	MW	%
60	ES	Aldeadavila	8	PHS	-	155.20	1	1	0	0.2	0.4	0	0	0	0	2337.50	50.00	0.87
61	ES	Almendra dam reservoir	6	PHS	-	135.00	1	1	0	0.2	0.4	0	0	0	0	359251.67	121.33	0.87
62	ES	Alqueva	4	PHS	-	129.80	1	1	0	0.2	0.4	0	0	0	0	1440.00	108.45	0.87
63	ES	Alto Lindoso	2	PHS	-	315.00	1	1	0	0.2	0.4	0	0	0	0	118497.44	315.00	0.87
64	IT	Anapo upper reservoir	4	PHS	-	125.00	1	1	0	0.2	0.4	0	0	0	0	1791.65	150.00	0.87
65	ES	Bemposta	4	ROR	-	107.38	1	1	0	0.2	0.041	0	0	0	0	581.74	0.00	0
66	IT	Grand Dixence reservoir	15	STO	-	129.93	1	1	0	0.2	0.041	0	0	0	0	117618.37	0.00	0
67	IT	Gibidum	3	ROR	-	113.33	1	1	0	0.2	0.041	0	0	0	0	5427.81	0.00	0
68	FR	Chevril	7	STO	-	61.14	1	1	0	0.2	0.041	0	0	0	0	58155.15	0.00	0
69	ES	Cedillo	4	ROR	-	118.25	1	1	0	0.2	0.041	0	0	0	0	6595.97	0.00	0
70	FR	Flumet	2	PHS	-	230.00	1	1	0	0.2	0.4	0	0	0	0	1440.00	240.00	0.87
71	IT	Lago del Chiotas	8	PHS	-	148.00	1	1	0	0.2	0.4	0	0	0	0	2130.00	75.71	0.87
72	FR	Canal Donzere-Mondragon	6	ROR	-	58.00	1	1	0	0.2	0.041	0	0	0	0	1.81	0.00	0
73	DE	Coo 1, Coo 2	6	PHS	-	194.00	1	1	0	0.2	0.4	0	0	0	0	970.00	172.50	0.87
74	GB	Cruachan	4	PHS	-	100.00	1	1	0	0.2	0.4	0	0	0	0	2500.00	100.00	0.87
75	GB	Marchlyn Mawr	6	PHS	-	288.00	1	1	0	0.2	0.4	0	0	0	0	1440.00	275.00	0.87
76	IT	Cesima	4	PHS	-	250.00	1	1	0	0.2	0.4	0	0	0	0	1750.00	257.25	0.87
77	IT	Avio, Benedetto	8	PHS	-	125.00	1	1	0	0.2	0.4	0	0	0	0	611.25	140.00	0.87
78	GB	Stwlan	4	PHS	-	90.00	1	1	0	0.2	0.4	0	0	0	0	325.00	75.00	0.87
79	IT	Koelnbrein	2	PHS	-	60.00	1	1	0	0.2	0.4	0	0	0	0	1450.00	58.00	0.87
80	FR	Genissiat	6	ROR	-	70.00	1	1	0	0.2	0.041	0	0	0	0	1475.74	0.00	0
81	ES	Gento	4	PHS	-	111.50	1	1	0	0.2	0.4	0	0	0	0	225.00	117.00	0.87
82	DE	Goldisthal-oberbecken	4	PHS	-	263.25	1	1	0	0.2	0.4	0	0	0	0	2106.00	263.25	0.87
83	FR	Grand Maison	12	PHS	-	149.17	1	1	0	0.2	0.4	0	0	0	0	2900.00	96.67	0.87
84	IT	Oberaar	4	PHS	-	87.00	1	1	0	0.2	0.4	0	0	0	0	13355.00	88.00	0.87
85	IT	Val Grosina	4	ROR	-	107.00	1	1	0	0.2	0.041	0	0	0	0	416.43	0.00	0
86	IT	Zillergruendel	2	PHS	-	180.00	1	1	0	0.2	0.4	0	0	0	0	5585.00	180.00	0.87
87	IT	Gelmersee	5	STO	-	51.00	1	1	0	0.2	0.041	0	0	0	0	4387.56	0.00	0
88	IT	Gepatsch	5	STO	-	78.40	1	1	0	0.2	0.041	0	0	0	0	55769.61	0.00	0
89	IT	Kops	3	PHS	-	175.00	1	1	0	0.2	0.4	0	0	0	0	780.00	160.00	0.87
90	IT	Finstertal	2	PHS	-	144.50	1	1	0	0.2	0.4	0	0	0	0	1345.00	125.00	0.87
91	FR	Roselend	6	STO	-	91.00	1	1	0	0.2	0.041	0	0	0	0	94538.89	0.00	0
92	ES	Muela upper reservoir	8	PHS	-	185.00	1	1	0	0.2	0.4	0	0	0	0	3062.50	87.94	0.87
93	IT	Mooserboden	4	PHS	-	148.00	1	1	0	0.2	0.4	0	0	0	0	18205.00	151.00	0.87
94	DE	Markersbach-oberbecken	7	PHS	-	149.43	1	1	0	0.2	0.4	0	0	0	0	574.00	149.43	0.87
95	ES	Mequinenza	4	STO	-	81.00	1	1	0	0.2	0.041	0	0	0	0	42530.82	0.00	0
96	ES	Miranda	4	ROR	-	92.38	1	1	0	0.2	0.041	0	0	0	0	212.42	0.00	0
97	FR	Monteynard	4	STO	-	91.00	1	1	0	0.2	0.041	0	0	0	0	19469.33	0.00	0
98	FR	Monnes_l'Etang	4	PHS	-	227.50	1	1	0	0.2	0.4	0	0	0	0	9100.00	217.50	0.87
99	ES	Alcantara	4	STO	-	228.75	1	1	0	0.2	0.041	0	0	0	0	242517.10	0.00	0
100	ES	Picote	4	ROR	-	110.25	1	1	0	0.2	0.041	0	0	0	0	586.33	0.00	0
101	FR	Villefranche-de-Panat	5	PHS	-	88.00	1	1	0	0.2	0.4	0	0	0	0	142.00	6.58	0.87
102	IT	Cancano_San Giacomo	6	STO	-	37.67	1	1	0	0.2	0.041	0	0	0	0	47565.31	0.00	0
103	IT	Lago di Campotosto	3	PHS	-	47.00	1	1	0	0.2	0.4	0	0	0	0	49076.49	47.00	0.87
104	FR	Marquisades	4	PHS	-	180.00	1	1	0	0.2	0.4	0	0	0	0	900.00	180.00	0.87
105	ES	Ribarroja	4	ROR	-	65.70	1	1	0	0.2	0.041	0	0	0	0	3295.80	0.00	0
106	IT	Latschau	5	PHS	-	98.60	1	1	0	0.2	0.4	0	0	0	0	350.00	63.40	0.87
107	IT	Lago Delio	8	PHS	-	130.00	1	1	0	0.2	0.4	0	0	0	0	2210.00	98.00	0.87
108	IT	Galgenbichl	4	PHS	-	182.50	1	1	0	0.2	0.4	0	0	0	0	325.00	72.50	0.87
109	IT	Lago della Rovina	1	PHS	-	133.67	1	1	0	0.2	0.4	0	0	0	0	2000.00	125.00	0.87
110	DE	Eggbergbecken	4	PHS	-	90.00	1	1	0	0.2	0.4	0	0	0	0	516.00	75.00	0.87
111	IT	Lago d'Arno	2	PHS	-	280.00	1	1	0	0.2	0.4	0	0	0	0	65194.18	105.00	0.87
112	IT	Provvidenza	6	PHS	-	74.67	1	1	0	0.2	0.4	0	0	0	0	436.45	74.67	0.87
113	IT	Molveno	15	PHS	-	23.33	1	1	0	0.2	0.4	0	0	0	0	2988.51	23.33	0.87
114	ES	Saucelle	6	ROR	-	87.50	1	1	0	0.2	0.041	0	0	0	0	5925.17	0.00	0
115	FR	Serre-Poncon	4	STO	-	95.00	1	1	0	0.2	0.041	0	0	0	0	95907.12	0.00	0
116	IT	Laengental	2	STO	-	250.00	1	1	0	0.2	0.041	0	0	0	0	4451.40	0.00	0
117	FR	Bissorte	5	PHS	-	149.60	1	1	0	0.2	0.4	0	0	0	0	630.00	126.00	0.87
118	ES	Tajo de la Encantada upper	4	PHS	-	95.00	1	1	0	0.2	0.4	0	0	0	0	250.00	90.00	0.87
119	IT	Limmern	6	PHS	-	73.50	1	1	0	0.2	0.4	0	0	0	0	111.67	23.33	0.87
120	DE	Vianden upper	11	PHS	-	117.82	1	1	0	0.2	0.4	0	0	0	0	471.27	95.45	0.87
121	FR	Le Mont Cenis	2	STO	-	178.50	1	1	0	0.2	0.041	0	0	0	0	344944.67	0.00	0
122	DE	Oberbecken Waldeck II	2	PHS	-	240.00	1	1	0	0.2	0.4	0	0	0	0	1714.00	238.00	0.87
123	DE	Hornbergbecken	4	PHS	-	248.00	1	1	0	0.2	0.4	0	0	0	0	1984.00	250.00	0.87

Fig D2. Detailed hydropower database.

	Region	Unit	Nunits	Technology	Fuel	PowerCapacity	Efficiency	MinEfficiency	CO2Intensity	PartLoadMin	RampRate	StartUpTime	MinUpTime	MinDownTime	StartUpCost	STOCapacity	STOMaxChargingPower	STOChargingEfficiency
Units -->	-	-	-	-	-	MW	%	%	tCO2/MWh	%	%	h	h	h	EUR	MWh	MW	%
124	GB	Large ROR	54	ROR	-	30.20	1	1	0	0.2	0.041	0	0	0	0	0	0.00	0
125	GB	`	246	STO	-	1.21	1	1	0	0.2	0.041	0	0	0	0	44	0.00	0
126	GB	Large PHS	2	PHS	-	274.00	1	1	0	0.2	0.4	0	0	0	0	12800	274.00	0.87
127	FR	Large ROR	159	ROR	-	77.02	1	1	0	0.2	0.041	0	0	0	0	0	0.00	0
128	FR	Large STO	123	STO	-	67.85	1	1	0	0.2	0.041	0	0	0	0	12800	0.00	0
129	FR	Small non-PHS	2301	STO	-	0.92	1	1	0	0.2	0.041	0	0	0	0	44	0.00	0
130	DE	Large ROR	80	ROR	-	25.26	1	1	0	0.2	0.041	0	0	0	0	0	0.00	0
131	DE	Large STO	10	STO	-	25.26	1	1	0	0.2	0.041	0	0	0	0	12800	0.00	0
132	DE	Small non-PHS	426	STO	-	4.22	1	1	0	0.2	0.041	0	0	0	0	44	0.00	0
133	DE	Large PHS	26	PHS	-	108.38	1	1	0	0.2	0.4	0	0	0	0	12800	108.38	0.87
134	DE	Small PHS	6	PHS	-	3.68	1	1	0	0.2	0.4	0	0	0	0	44	3.68	0.87
135	ES	Large ROR	49	ROR	-	7.95	1	1	0	0.2	0.041	0	0	0	0	0	0.00	0
136	ES	Large STO	265	STO	-	48.07	1	1	0	0.2	0.041	0	0	0	0	12800	0.00	0
137	ES	Small non-PHS	4752	STO	-	0.50	1	1	0	0.2	0.041	0	0	0	0	44	0.00	0
138	ES	Large PHS	8	PHS	-	119.15	1	1	0	0.2	0.4	0	0	0	0	12800	119.15	0.87
139	ES	Small PHS	2	PHS	-	5.00	1	1	0	0.2	0.4	0	0	0	0	44	5.00	0.87
140	IT	Large ROR	364	ROR	-	53.69	1	1	0	0.2	0.041	0	0	0	0	0	0.00	0
141	IT	Large STO	280	STO	-	45.02	1	1	0	0.2	0.041	0	0	0	0	12800	0.00	0
142	IT	Small non-PHS	4343	STO	-	1.15	1	1	0	0.2	0.041	0	0	0	0	44	0.00	0
143	IT	Large PHS	62	PHS	-	13.72	1	1	0	0.2	0.4	0	0	0	0	12800	13.72	0.87

Fig D3. Lumped plant database.

Appendix E. Water Reserves

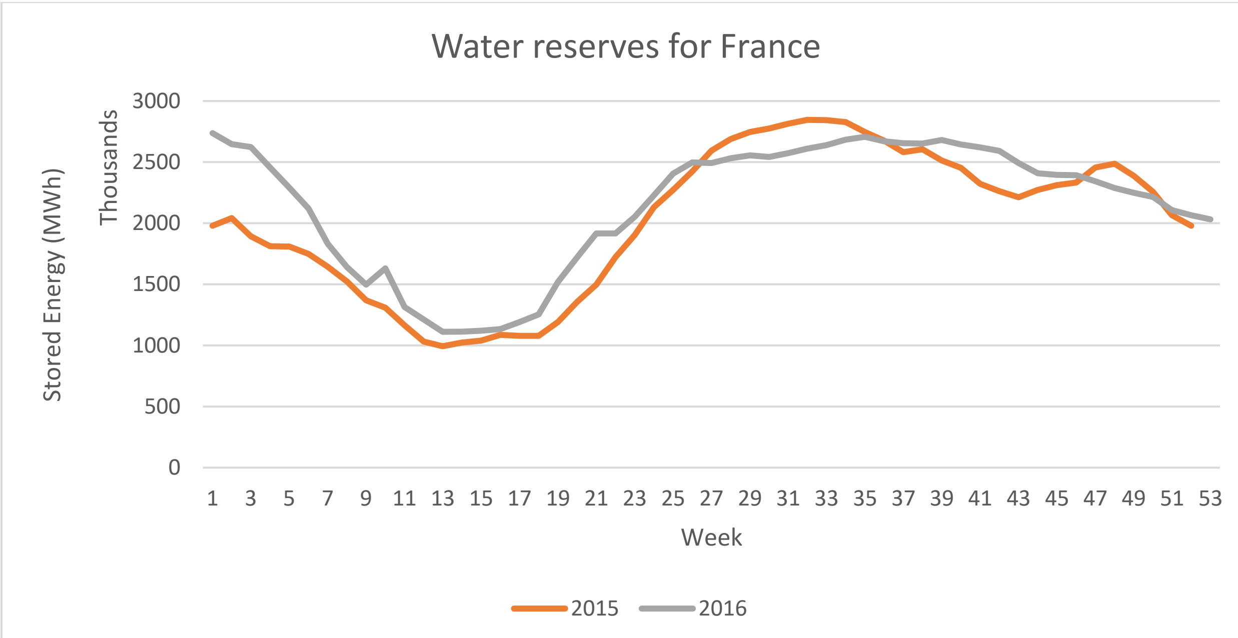

Fig E1. Aggregate average weekly filling rate of all water reservoirs for hydro storage plants for France in 2015 and 2016. Source (RTE, 2017).

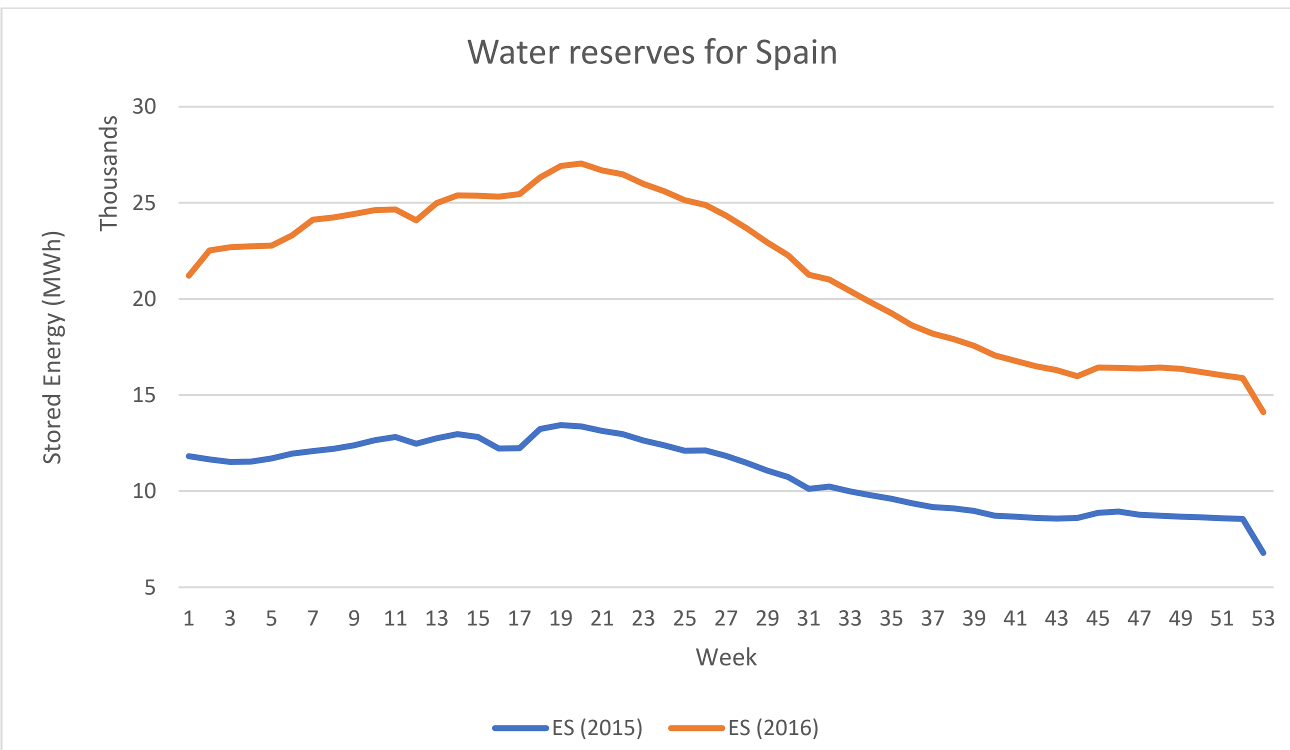

Fig E2. Aggregate average weekly filling rate of all water reservoirs for hydro storage plants in 2015 and 2016. Source (Entsoe, 2017)

Appendix F. Efficiency curves

Efficiency curves in this study are constant for any load in all power plant. Efficiency curves can be approximated with a quadratic equation ($ax^2 + bx + c$) where 'x' is the load in the plant and 'a', 'b', 'c' are parameters defined for each technology (Brouwer, Van Den Broek, Seebregts, & Faaij, 2015).

Figure 6.1 shows efficiency curves (as a percentage of maximum efficiency) for Nuclear, NGCC and GT. Additionally a black dashed line represents a constant maximum efficiency regardless of the load level as it is the case in this study. The vertical distance between the quadratic efficiency curve of a generator to the constant maximum efficiency of that generator (black dashed line) represents the overestimation of the efficiency at a given load. For loads > 80% of the maximum load, the effect is small; however, as the load decreases the effect is increasingly amplified.

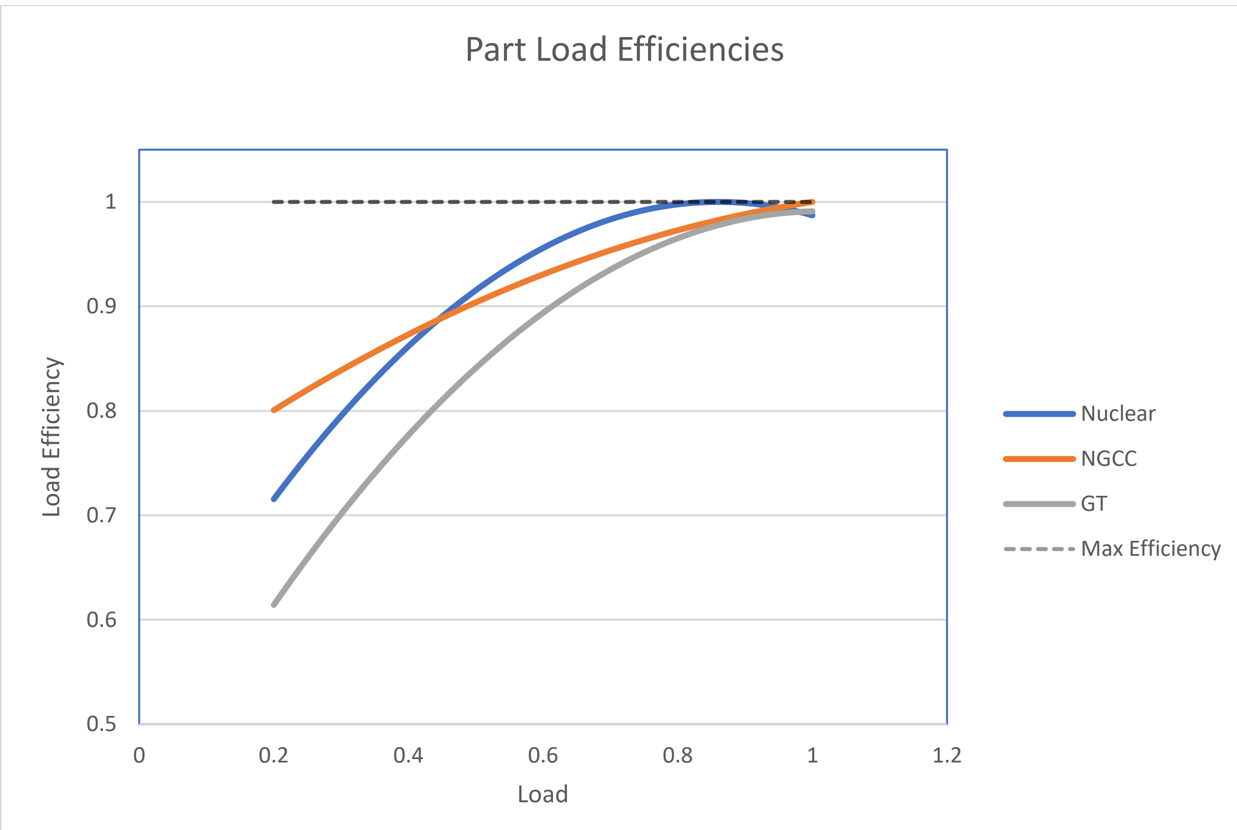

Figure F. Load efficiencies (as percentage of maximum generator efficiency) vs load (as percentage of maximum load). Technologies considered: Nuclear, NGCC, GT. Source: (Brouwer et al., 2015).