The role of run-of-river hydropower dispatchability in power system flexibility

MSc Thesis Energy Science

May 30, 2018

Diede Streng[1]

Under supervision of:
Dr. ir. Machteld van den Broek[2]
Ir. William Zappa[2]

Second reader:
Dr. Wilfried van Sark[2]

Universiteit Utrecht

[1] d.m.streng@students.uu.nl, Vlietstraat 7 Bis, 3581 SZ Utrecht, The Netherland
[2] Copernicus Institute of Sustainable Development, Utrecht University

Abstract

To meet emission targets set by the European Commission for 2050, the European power sector needs to reduce its emissions by 95-100% compared to 1990 levels. These targets started a transition towards a low-carbon power system, in which intermittent renewable energy sources (iRES) play an increasingly important role. iRES are non-dispatchable and not fully predictable and as the penetration of these sources increases, so will the need for flexible generation by conventional thermal generators and dispatchable RES. An important source of flexibility is hydropower, because of its fast ramping abilities and its storage availabilities when reservoirs are present. The level of flexibility hydropower can provide depends on the type of plant. One of these types is run-of-river (RoR) hydropower, which is known to have limited storage capacity and is thus mainly dependent on the inflow from the river. However, it is unclear how much storage capacity European RoR plants have and how dispatchable they really are. Therefore this research investigates the dispatchability of European RoR hydropower capacity and evaluates its role in providing power system flexibility.

The dispatchability of RoR plants is assessed based on the natural inflows they receive and the storage capacity the plants have. A database is constructed containing technical and hydrological details of 126 plants. Subsequently, the impact of RoR dispatchability on the European power system is analysed by modelling these plants with the detailed data in a low-carbon power system model. This detailed approach is compared to an aggregated modelling approach, where RoR plants are aggregated per geographical region. Additionally we study the impact of annual variation of water availability for RoR generation on the power system by modelling an average, a dry and a wet inflow scenario. Lastly, by means of interviews with RoR operators and experts we investigate if there are important aspects, other than water inflow and storage size, affecting the dispatchability of RoR plants.

For 84 of the 126 plants in the database, data on storage size is found. Of the 84 plants, 28 plants can be classified as pure RoR plants (less than two hours of storage) and the remaining 56 plants can be classified as pondage RoR plants (more than two but less than 400 hours of storage). On average, natural inflow for RoR plants is highest during spring and early summer but there is a considerable variation in inflow patterns between regions due to the geographical diversity of river regimes. Modelling these aspects in a low-carbon power system shows that the flexibility of RoR plants is overestimated when using an aggregated approach. As a result of the limited flexibility of RoR plants, flexible generation has to be provided by more expensive flexible generators such as biothermal and GT capacity. In an aggregated approach, total generation costs tend to be underestimated by 4%. An analysis of the inter-annual variation of the water availability for RoR generation shows that the power system is mainly sensitive to a dry inflow scenario. In such a scenario RoR generation decreases with 28 TWh (-20%) compared to an average inflow scenario, resulting in increased generation costs as the system is more dependent on more expensive generators. A wet inflow scenario mainly results in water spill by the plants due to the limited storage size of the plants and limited turbine capacity. Finally, interview results show that besides storage capacity and inflows, there are a lot of other operational constraints for RoR hydro plants which are specific for each water course. Most of these factors concern controlled river flows and can therefore be included in the power system model by imposing a minimum generation level on the plants.

This research shows that the role of RoR plants in providing power system flexibility is limited due to their limited storage size. Policy makers could use this knowledge when preparing the power system for higher iRES penetration towards 2050. Future research on hydropower flexibility can build upon this work by making use of the constructed database of European RoR plants.

Acknowledgements

Several persons contributed to the realization of this research, which I would like to thank.

I would like to thank my supervisors William Zappa and Machteld van den Broek. Will, thank you for the extensive feedback you provided, for guiding me through the process of writing a thesis and for always being available to discuss my questions. Machteld, thank you for providing me with detailed feedback and useful suggestions, your attention to detail provided valuable insights. Also I would like to thank Wilfried van Sark for being the second reader of this thesis.

Edwin Sutanudjaja, thank you for providing the hydrological data input for this study, for explaining your work to me and for your suggestions on methodological aspects of this research. Also I would like to thank the interviewees for their valuable time, your insights truly contributed to a better understanding of the operation of run-of-river hydropower plants.

Finally, I would like to thank my family, friends and boyfriend for their unconditional support. A special thanks to Jos Streng and Oskar Meijerink for their extensive review sessions.

Table of Contents

Abstract ... 2

Acknowledgements ... 3

List of abbreviations ... 6

List of Figures ... 7

List of Tables ... 8

1. Introduction ... 9

2. Method ... 13

2.1. Hydro plant data collection ... 13

2.2. Hydrological modelling and inflow data collection ... 14

2.3. Data processing: river flow processing, inflow validation and inflow scenarios ... 14

2.4. Power system modelling ... 17

2.4.1. Model description ... 17

2.4.2. Model inputs ... 19

2.4.3. Indicators for analysis ... 22

2.4.4. Sensitivity runs ... 23

2.5. Interviews with RoR experts and operators ... 23

3. Results ... 24

3.1. Hydro plant data collection: detailed database of Europe's RoR hydro plants ... 24

3.2. Natural inflow scenarios ... 26

3.3. Impact of accounting for the dispatchability of RoR plants on the power system ... 29

3.3.1. Generation capacity built ... 29

3.3.2. Generation and capacity factors per generator ... 29

3.3.3. Total generation costs ... 31

3.3.4. Total CO_2 emissions ... 31

3.3.5. Seasonal dispatch ... 32

3.3.6. Hourly dispatch ... 35

3.3.7. Curtailment ... 37

3.3.8. Electricity price ... 37

3.4. The impact of inter-annual variation of hydropower generation on the power system ... 38

3.5. Sensitivity analyses ... 40

3.6. Evaluation of other factors affecting the dispatchability of RoR plants ... 42

4. Discussion ... 45

4.1. Limitations and uncertainties ... 45

4.2. Comparison with other studies 46
4.3. Contribution to established knowledge 47
4.4. Recommendations for future research 47
5. Conclusion 49
6. References 51
Appendix I 56
Appendix II 57
Appendix III 58
Appendix IV 59
Appendix V 60
Appendix VI 62
Appendix VII 67
Appendix VIII 68

List of abbreviations

ENTSO-E – European Network of Transmission System Operators for Electricity

ESHA – European Small Hydropower Association

GT – Gas Turbine

iRES – intermittent Renewable Energy Sources

IHA – International Hydropower Association

MIP – Mixed Integer Programming

NGCCe – Natural Gas Combined Cycle

NGCC-CCS – Natural Gas Combined cycle with Carbon Capture Storage

PC – Pulverized Coal

PCR-GLOBWB - PCRaster GLOBal Water Balance model

PSH – Pumped Storage Hydropower

RES – Renewable Energy Sources

RSH – Reservoir Hydropower

Solar PV- Solar Photovoltaics

UC – Unit Commitment

List of Figures

Figure 1 - Schematic diagrams of hydropower facilities 10
Figure 2 - Schematic overview of the research method 13
Figure 3 - Validation process for inflow values calculated by the PCR-GLOBWB model 15
Figure 4 - Regions within the geographical scope. 19
Figure 5 – Overview of model inputs 20
Figure 6 - Overview of how RSH, PSH and RoR plants are modelled in each scenario. 21
Figure 7 - Run-of-river capacity in geographical scope according to different sources 24
Figure 8 - Storage size distribution of European RoR plants expressed in storage hours 26
Figure 9 - Nominal plant capacity distribution of European RoR plants 26
Figure 10 – Average, dry and wet inflow scenarios for RoR plants 27
Figure 11 – Average inflow patterns for RoR plant per region.. 28
Figure 12 – Newly installed capacity and total installed capacity in 2050 for the aggregated and detailed scenario 29
Figure 13 - Generation and capacity factors by generator type in the year 2050 in a low-carbon power system. 30
Figure 14 – Water spill by detailed RoR plants in the detailed scenario 30
Figure 15 - Total annual generation costs and total annual CO_2 emissions in the aggregated and detailed scenario 31
Figure 16 - Annual CO_2 emissions in the aggregated and the detailed scenario 32
Figure 17 - Aggregated scenario: daily profiles for the residual load and RoR generation 32
Figure 18 – Detailed scenario: daily profiles for residual load and RoR generation 33
Figure 19 - Correlation between residual load and RoR generation for the aggregated and the detailed scenario 33
Figure 20 – Daily profiles for RoR generation and residual load per region in the aggregated scenario and detailed scenario. 34
Figure 21 – Aggregated scenario: generation during week with minimum residual load 35
Figure 22 – Detailed scenario: generation during week with minimum residual load 35
Figure 23 - Aggregated scenario: generation during week with maximum residual load 36
Figure 24 - Detailed scenario: generation during week with maximum residual load 36
Figure 25 - Monthly curtailment figures for the aggregated and the detailed scenario 37
Figure 26 - Average daily electricity price (averaged across all regions) for the aggregated and the detailed scenario 38
Figure 27 - Difference in daily average electricity price between the detailed and aggregated scenario 38
Figure 28 - Generation per generator for the detailed-wet, detailed-dry, detailed-average and the aggregated scenario 39
Figure 29 - Water spill by detailed RoR plants in the detailed-average, detailed-wet and detailed-dry scenario 39
Figure 30 - Generation per generator for both the sensitivity runs. 41
Figure 31 - Environmental, operational and regulatory factors influencing flexible operation of RoR hydro plants 42
Figure 32 - Schematic overview of a PCR-GLOBWB 2 cell and its modelled states and fluxes. Adapted from (Sutanudjaja, van Beek, et al., 2017). 58

List of Tables

Table 1 - Different inflow scenarios used in this study to assess inter-annual variation of water availability for RoR generation........16
Table 2 - Overview of the 4 main scenarios used to analyze the impact of RoR dispatchability on power system flexibility........17
Table 3 - Indicators to compare power system flexibility for the aggregated and detailed scenarios ..22
Table 4 - Overview of parameters for which a sensitivity run is performed 23
Table 5 - Overview of RoR plants in the detailed database produced in this study........25
Table 6 - Curtailment in the aggregated and detailed scenario........37
Table 7 – Total generation costs, CO_2 emissions and curtailment in the aggregated, detailed-average, detailed-dry and detailed-wet scenario 40
Table 8 – Total generation costs, CO_2 emissions and curtailment in the aggregated, detailed-average, detailed-5hours and detailed-MinLoad scenario........41
Table 9 - Overview of RoR hydropower definitions by different organizations 56
Table 10 - Data gathered for each RoR plant........57
Table 11 - Interconnection capacity between regions, adapted from Brouwer et al. (2016). 60
Table 12 - Techno-economic parameters of hydropower plants. Adapted from Gerritsma (2016)......60
Table 13 – Specifications of hydro plants in the aggregated scenario........62
Table 14 - Specifications of RoR hydro plants in the detailed scenarios........62
Table 15 - Specifications of detailed RoR hydro plants. 62
Table 16 - Generation profiles for RoR rest plants for the detailed-average. 65
Table 17 - Generation profiles for RoR rest plants for the detailed-dry. 65
Table 18 - Generation profiles for RoR rest plants for the detailed-dry. 66
Table 19 - List of interviewees 68

1. Introduction

The European Commission has set targets to cut CO_2 emissions by 80% in 2050 compared to 1990 levels (European Commission, 2012b). To achieve this target, the European power sector needs to reduce emissions by 95-100% by 2050 (ECF, 2010). This started a transition towards a low-carbon power system, in which renewable energy sources (RES) play an increasingly important role. In 2014, 27.5% of European electricity supply was provided by RES (EEA, 2017) and this is projected to rise to 40% to 86.4%, depending on the mitigation scenario (European Commission, 2012a). Some RES are intermittent (e.g. solar and wind) and unlike conventional thermal generators (e.g. coal, nuclear), intermittent renewable energy sources (iRES) are not dispatchable[3] and their generation is not fully predictable. To cope with this limited predictability, flexibility in the power system is needed (Brouwer, Van Den Broek, Seebregts, & Faaij, 2014). Flexibility is the ability of the power system to deploy its resources to respond to changes in the residual load[4] (Lannoye, Flynn, & O'Malley, 2012). This can for example be provided by plants with fast ramping capabilities or plants which are able to quickly start up and shut down (Hentschel, Babić, & Spliethoff, 2016). When the system cannot offer the required flexibility, several problems may arise such as grid frequency not staying within defined limits (Hell, 2017), or negative market prices which are costly to society (Brandstätt, Brunekreeft, & Jahnke, 2011). Hence, in a future with increasing penetration of iRES, flexibility of conventional thermal generators and dispatchable RES will play a crucial role.

The most common flexible RES technologies available today are concentrated solar power, geothermal, biomass and hydropower. In Europe, hydropower is the largest RES and provided 17% of European electricity generation in 2015 (ENTSO-E, 2015a). Hydropower is perceived as one of the most flexible sources of power generation (Huertas-Hernando et al., 2017; IRENA, 2012), because of its fast ramping abilities and its storage availabilities when reservoirs are present (Stoll, Andrade, Cohen, Brinkman, & Brancucci Martinez-Anido, 2017). Hydropower thus plays an important role in providing flexibility to the power system. However, the level of flexibility hydropower can provide depends on the type of plant. Hydro plants can be categorized in various ways: by head, by storage capacity, by purpose or by size. Those categorizations are not mutually exclusive (Egré & Milewski, 2002), which is why there is no consistent use of definitions for hydropower plants in literature. However, the categorization by storage capacity, consisting of pumped storage hydropower, reservoir storage hydropower and run-of-river hydropower is the most common (IPCC, 2009; IRENA, 2012). A description is provided below and a visualization of the different types is given in Figure 1.

- *Pumped storage hydropower (PSH)* – PSH plants pump water from a lower to a higher reservoir when electricity prices are low. At high electricity prices, the plant can generate electricity by running water through the turbine from the higher to the lower reservoir. Pumped storage hydropower is therefore not an energy source but an energy storage mechanism (IRENA, 2012). This type of plant can offer short-term flexibility and storage capabilities to the energy system (Huertas-Hernando et al., 2017). PSH plants can be divided into pure and mixed PSH. The difference is that mixed PSH receive natural inflow into the storage reservoir and pure PSH plants do not (Kougias & Szabó, 2017). PSH plants typically have a roundtrip efficiency[5] of 75% (Geth, Brijs, Kathan, Driesen, & Belmans, 2015).

[3] In this study dispatchability is defined as the ability to set the target generation level of a power plant at will.
[4] The remaining system load not served by iRES.
[5] The roundtrip efficiency reflects the part of the electricity generated by the turbines that is causally related to the earlier electricity consumption by the pumps (Geth et al., 2015).

- *Reservoir storage hydropower (RSH)* - Reservoir plants allow for storage of water due to the presence of a reservoir. This increases the flexibility of this type of plant as generation can be decoupled from the timing of rainfall and glacier melt (IRENA 2012). Reservoir systems can regulate flow throughout the year, on a daily or monthly basis, or sometimes even on a multi-annual basis in case of very large reservoirs (Egré & Milewski, 2002). The conversion efficiency of a well-operated RSH plant can be around 85% (Kaunda, Kimambo, & Nielsen, 2012).
- *Run-of-river (RoR) hydropower* - RoR plants have no or only limited storage capacity. When not connected to reservoirs upstream, the generation potential is dependent on the river inflow. The definition of RoR varies around the world; in many countries a facility is also called RoR when it can store inflow for hours or even days (IRENA, 2012). RoR plants with small storage capacity are known as pondage, while plants with no storage are known as pure RoR plants (Lee, 2014). An overview of different RoR definitions is provided in Appendix I. RoR facilities can use all of the river flow (often using a dam) or only take a fraction of the flow, which is done by conveying a portion of the water towards the turbines by means of channels or pipelines (IRENA, 2012). The system efficiency of a RoR facility can be, similar to RSH plants, around 85% (Kaunda et al., 2012)

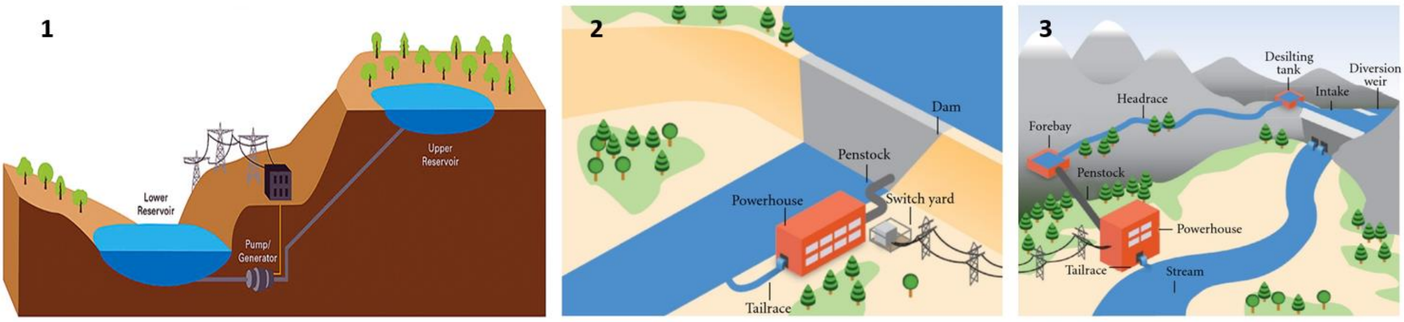


Figure 1 - Schematic diagrams of hydropower facilities - 1) Pumped storage hydropower. 2) Reservoir storage hydropower. 3) Run-of-river hydropower. 1 adapted from (Wade, 2017), 2&3 adapted from (Kaunda et al., 2012)

The level of flexibility which can be provided by hydro plants depends on the type of hydro plant due to their different configurations and operational constraints. PSH and RSH plants allow for storage and thus electricity generation can be regulated. On the contrary, RoR plants do not (or to a limited extent) allow for storage and the generation potential for these plants is thus mainly dependent on the natural inflow of the river. In addition, hydro plants connected to a river often face environmental operational constraints because they affect river ecology and river flow regimes. The presence of a dam can influence habitats of aquatic species and cause erosion. These issues place constraints on the flexible generation by hydro plants, including minimum generation levels and reservoir level restrictions (Stoll et al., 2017).

The flexibility of hydropower and its impact on the power system has been the subject of several earlier studies. Many of those focused on the role of hydropower systems in the integration of large amounts of iRES (Acker, 2011; Hirth, 2016; Ibanez et al., 2014; Kapsali & Kaldellis, 2010). However, the accuracy of the representation of hydropower systems in previous research is limited in several ways:

- Several studies focus on the integration of iRES in combination with pumped storage or reservoir facilities in the power system (Caralis, Papantonis, & Zervos, 2012; Ibanez et al., 2014; Kapsali & Kaldellis, 2010), less attention is paid to the role of RoR in integrating iRES in the power system (François, Hingray, Raynaud, Borga, & Creutin, 2016; Rasmussen, Andresen, & Greiner, 2012).

- Some studies did investigate the integration of iRES with RoR hydropower by including a detailed representation of RoR hydro plants in the power system (Holttinen & Koreneff, 2012; Krajačić, Duić, & Carvalho, 2011). However, those studies mainly concern case studies on a national scale or on a specific water course. On the European level, a detailed representation of RoR hydropower is lacking (Brouwer, van den Broek, Zappa, Turkenburg, & Faaij, 2016; Zentrum für nachhaltige Energiesysteme, 2012). Brouwer et al. (2016) aggregate RoR and RSH plants and Zentrum für nachhaltige Energiesysteme (2012) include RoR as a separate category but only 8 countries are included and RoR plants are modelled as aggregated plants. By modelling aggregated plants instead of individual plants, the flexibility of the plants can be over- or underestimated (Deml, Ulbig, Borsche, & Andersson, 2014).
- The seasonal variation of water availability is not accounted for in determining the hydropower generation potential (Brouwer et al., 2016). As river inflows are known to fluctuate significantly depending on the season (Abrahamsson & Håkanson, 1998), it is important to include this fluctuation to make sure the power system can only use hydropower when it is really available. This is especially important for RoR plants as these plants often have limited storage capacity.
- Besides seasonal variation, annual variation in availability of water is also neglected in several studies (François, Hingray, et al., 2016; Holttinen & Koreneff, 2012; Krajačić et al., 2011). One previous study highlighted the importance of including inter-annual variation of water availability by showing that different inflow scenarios resulted in 79% more RoR generation in a high inflow scenario compared to a low inflow scenario (Gerritsma, 2016).
- River flow restrictions are not accounted for (Kiviluoma & Holttinen, 2006). River flows are sometimes regulated to ensure there is enough water flowing in the river, or to prevent sudden floods by limiting the maximum allowed discharge by hydro plants. By neglecting this, the flexibility of hydropower plants can be overestimated.
- RoR plants are assumed to have no storage size (Hirth, 2016), and are modelled as variable generation, of which dispatch cannot be altered (Borges & Pinto, 2008). Although this may be true for some RoR plants, plants with some storage capacity could add to system flexibility by shifting generation to better match demand peaks (Stoll et al., 2017). Due to a lack of consistent definitions (Appendix I), it is unclear how much storage RoR plants have and thus how flexible they really are.

These limitations affect the possibility to adequately assess the ability of RoR plants to provide the required system flexibility to the European power system. Since RoR plants make up about 21% (33 GW out of 160 GW) of the installed hydropower capacity in Europe (ENTSO-E, n.d.-a), it is important to understand the role RoR plants play in providing flexibility to the power system. Therefore, this research answers the following question:

How dispatchable is Europe's Run-of-river (RoR) hydro capacity, and what is its role in providing power system flexibility?

To answer this research question, the research is structured into five sub-questions:

- *SQ 1: How much storage capacity do Europe's RoR plants actually have?*
- *SQ2: How does the availability of water for RoR plants vary throughout the year?*
- *SQ3: What is the impact on the power system when accounting for the dispatchability of RoR plants?*
- *SQ4: What are the implications of the inter-annual availability of water for RoR plants on the power system?*

- *SQ5: What other factors, besides storage capacity and natural inflow, affect the dispatchability of RoR hydro plants?*

To answer SQ1 and SQ2, we compile a database of Europe’s largest RoR plants containing details on storage capacity and the natural inflows that RoR plants receive. SQ3 is answered by feeding the data from the database into a power system model to analyse the impact of accounting for the dispatchability of RoR plants on a low-carbon power system. SQ4 is answered by developing different inflow scenarios and assessing the impact of these different inflow scenarios on RoR dispatchability in the power system. To answer SQ5, interviews are conducted with RoR operators and expects.

The relevance of this study is threefold. First, the rapid deployment of iRES cause the power system to quickly change to a power system with increased need for flexibility. Better understanding of the flexibility potential of hydropower is important for current grid development. Second, future scientific work can build upon the plant data gathered in this study. Detailed data on hydropower plants can improve the accuracy of modelling power systems in the future. Thirdly, the dependency of simulation results on natural inflow scenarios is important, as natural inflow may undergo significant changes as a consequence of climate change.

This study continues with a description of the research method (Section 2), followed by the results (Section 3), a discussion,(Section 4) and concluding remarks (Section 5).

2. Method

The research method consists of two main parts, a quantitative and a qualitative part. The quantitative part consists of determining the dispatchability of RoR plants and evaluating its role in a power system. The qualitative part consists of interviews with RoR operators and experts to gain additional insights into the factors, other than water inflow and storage, limiting the operational flexibility of RoR plants. A schematic overview of the research method is presented in Figure 2. The different steps of the research method are elaborated upon below.

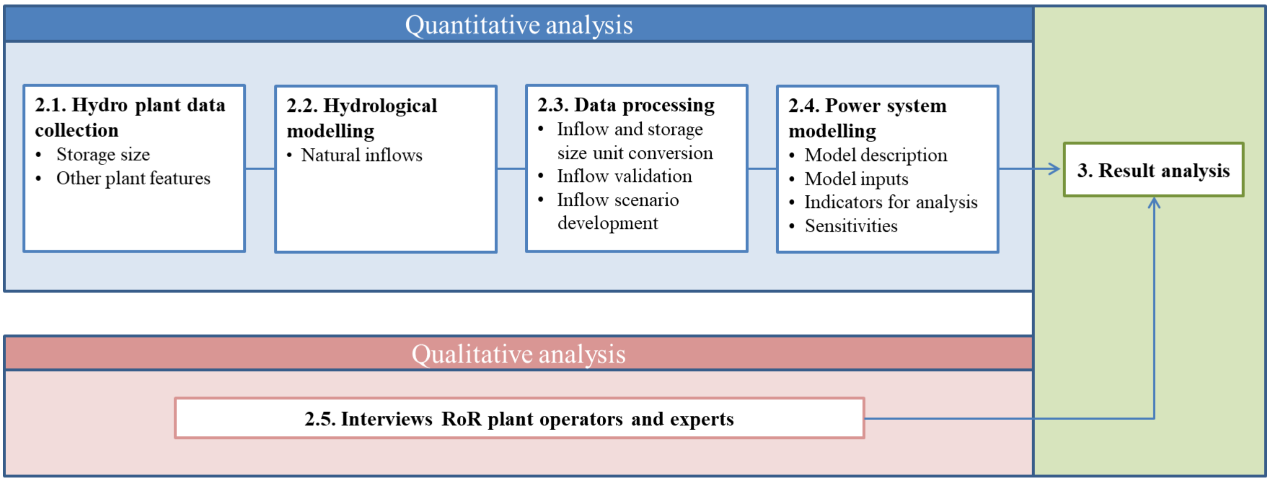


Figure 2 - Schematic overview of the research method

2.1. Hydro plant data collection

The first step of the quantitative analysis is to collect data on the storage size of RoR plants in Europe. The geographical scope of this analysis covers all EU-28 member states, Norway and Switzerland. This study focuses on the largest RoR plants (plants with capacity > 100 MW), as with thousands of small hydro plants in Europe (ESHA, 2012), collecting data on all of them is not possible. Besides data on storage size, other data such as hydraulic head or nominal plant capacity[6] are gathered as well, as these data are needed as input for the modelling part of this study. In Appendix II, a table is provided with the types of data that are gathered for each plant.

The starting point for data collection is a list of hydropower plants provided by the website of the European Network of Transmission System Operators for Electricity (ENTSO-E, n.d.-b). This list provides an extensive overview of hydropower plants in Europe and distinguishes by the type of plant (i.e. PSH, RSH and RoR). ENTSO-E's defines pure RoR plants as plants with less than two hours of storage, pondage plants as plants with more than two hours but less than 400 hours of storage, and plants with more than 400 hours of storage are defined as RSH plants. (ENTSO-E, 2015b).

In this study we collect data on 126 RoR plants, equal to 66% of Europe's RoR capacity of 33 GW (based on (ENTSO-E, n.d.-a)).The ENTSO-E list only provides data on the nominal plant capacity and the country the plant is located in. Additional data are gathered from other sources. To keep data gathering consistent, this study follows the order of sources specified below, based on our assessment of the most reliable sources (most reliable to least reliable):

1. Website of operator

[6] Defined as the maximum rated output of a generator (EIA, n.d.). Also known as the rated capacity, nameplate capacity or installed capacity.

2. Global Energy Observatory (2018)
3. Enipedia TU Delft (n.d.) or Wikipedia

2.2. Hydrological modelling and inflow data collection

In the second step, a hydrological model is used to determine the natural inflow for the RoR plants for which data are collected. The model used in this study is the grid-based PCRaster GLOBal Water Balance 2.0 model (PCR-GLOBWB), developed at the department of physical geography at Utrecht University[7]. PCR-GLOBWB uses (amongst others) historical meteorological data to simulate river discharge for each grid cell[8] for each time step (on a monthly basis). River discharge is simulated by accumulating and routing all runoff flows along the river network to the ocean or lakes and wetlands (van Beek & Bierkens, 2008). A description of these flows, meteorological data input and other details of the PCR-GLOBWB model can be found in Appendix III.

The latitude and longitude coordinates of the RoR plants obtained in 2.1, are first matched with the river network in the PCR-GLOBWB model to make sure that the plants are located on a river. Based on these coordinates, the PCR-GLOBWB calculates monthly average inflow values in m^3/s for each RoR plant. The model is run for the years 1979-2015, so that afterwards a probabilistic natural inflow scenario can be created for each plant for each month of the year. This inflow scenario is needed as input for the power system model in step 2.4.

2.3. Data processing: river flow processing, inflow validation and inflow scenario development

In the third step, the gathered data are processed so that they can be implemented in the power system model in step 2.4. The following three processing steps are taken:

1. Inflow and storage size conversion

The power system model software used in this study, Plexos[9] (see 2.4.1), can model hydropower systems on the basis of either energy (e.g. MW), or water level and volume (e.g. m, m3/s). In this study we use the hydro energy model. To be able to use this model, storage size needs to be converted from m^3 to GWh and inflow values need to be converted from $m^{3/}s$ to MW. See Appendix IV for calculation methods.

2. Inflow validation

Due to model biases and possible errors matching plant locations to rivers, the river flow results from PCR-GLOBWB may not match reality. To make sure that the inflow values generated by PCR-GLOBWB are appropriate, the inflow values are first validated before they are used in the power system model. Figure 3 shows an overview of the validation process. For clarification an example calculation is provided as well.

[7] The model is run by Edwin Sutanudjaja, from the department of physical geography at Utrecht University.
[8] The resolution of the grid cells is 5 arcminutes, which is about 10 by 10 km at the equator (Sutanudjaja, Beek, Wada, Wisser, & De, 2017)
[9] An Integrated Energy Model, developed by Energy Exemplar (www.energyexemplar.com)

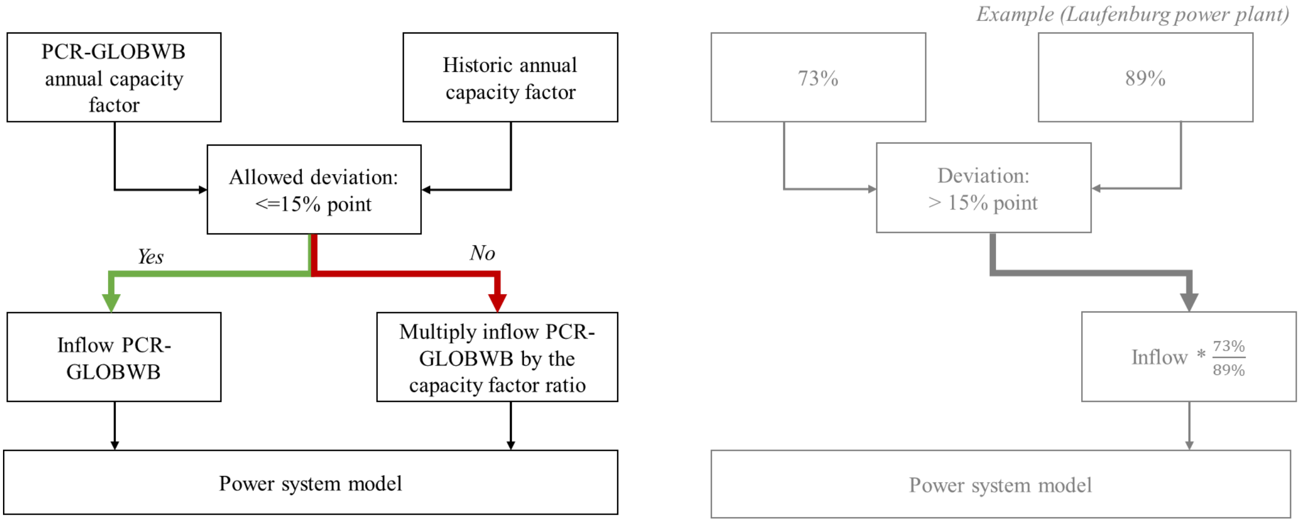


Figure 3 - Validation process for inflow values calculated by the PCR-GLOBWB model

For each plant three parameters are calculated:

1) **Historic annual capacity factor (ACF_{his})** – determined from the literature either directly, or as the quotient of the annual generation (long-term average or individual years, depending on data availability) and maximum plant capacity
2) **PCR-GLOBWB annual capacity factor ($ACF_{PCR\text{-}GLOBWB}$) –** determined as the quotient of the weighted average yearly inflow value (in MW) and the maximum plant capacity
3) **The capacity factor ratio –** determined as the quotient of ACF_{his} and $ACF_{PCR\text{-}GLOBWB}$

Hydro generation varies from year to year, which is approximately 15% (based on calculations for 15 RoR plants from the compiled database). To account for this inter-annual variation in generation, a deviation of 15% point is allowed between ACF_{his} and $ACF_{PCR\text{-}GLOBWB}$. Thus, when the absolute value of the difference between the historical and model-calculated capacity factors is 15% or less, the inflow values as simulated by PCR-GLOBWB are implemented directly in the power system model. When the absolute value of the difference is more than 15%, the simulated inflow values are scaled by multiplying them by the capacity factor ratio. Preference is given to the historic capacity factor because this value is in most cases provided by the plant operator and is thus based on actual measured values.

3. *Construction of inflow scenarios*

To assess the impact of inter-annual variation of water availability for RoR generation, three inflow scenarios are considered in this study. The three inflow scenarios reflect years with average, high and low rainfall.

The average inflow scenario is based on the mean river flow. For every month, the average natural inflow is calculated over the period 1979-2015.

In the context of climate change and associated extreme weather events, it is worthwhile to also assess a wet and dry inflow scenario[10]. The dry and wet inflow scenarios are based on monthly inflows in a typical dry and a typical wet year. A known historic dry year is 2003 and a known historic wet year is 2013. These years are chosen based on expert opinions of the department of Physical Geography of Utrecht University and were cross-checked with Eurostat hydropower generation data (Eurostat, 2018).

[10] An overall decrease of hydropower potential is expected in Europe, with an expected increase in North European countries and a strong decrease in Southern and South-eastern parts (Van Vliet et al., 2013).

The most consistent method would be to take a typical average year for the average inflow scenario as well. However, a typical average inflow year can have unusual high or low inflow values for certain months. This is thus also a drawback of the dry and wet inflow scenario as currently chosen. Nonetheless, a typical dry and wet year are still deemed more realistic than taking a high or low discharge value for all plants for each month for the wet and dry scenario. The latter would represent an extreme, unrealistic case, because it is not likely that extreme dry or wet conditions occur simultaneously on all rivers throughout Europe[11]. By choosing a typical dry and wet year, spatial variation of dry and wet weather events is taken into account. An overview of the inflow scenarios considered in this study is presented in Table 1.

Table 1 - Different inflow scenarios used in this study to assess inter-annual variation of water availability for RoR generation. Inflow values are based on validated PCR-GLOBWB values.

Scenario	Description
Average inflow scenario	The average inflow value (over the period 1979-2015) for each month for each plant for which data are gathered
Dry inflow scenario	Monthly 2003 values for each plant for which data are gathered
Wet inflow scenario	Monthly 2013 values for each plant for which data are gathered

[11] This is confirmed by previous research which shows that there is no significant correlation between energy inflow in Scandinavia and the Alpes region (Killingtveit, 2005), two of the main hydropower production regions. Research by Van Vliet et al. (2013) also highlighted that there are different trends in rainfall patterns expected for different European regions.

2.4. Power system modelling

After the compilation of a database of parameters determining the dispatchability of RoR plants, the next step is to assess the impact of improved modelling of RoR plant dispatchability on a low-carbon power system. This is done by running two types of scenarios in a power system model. In the first case, the *aggregated scenario***,** RoR plants are modelled as aggregated plants per region with a single constraint on the annual capacity factor without taking into account seasonal availability of water. In the second case, the *detailed (average) scenario*, RoR plants are modelled in detail including storage capacity and average monthly natural inflows. Additionally two more detailed scenarios are run to assess the impact of inter-annual variation of water availability on RoR generation: the *dry and wet scenario*. These scenarios are modelled in the same way as the detailed average scenario, however the average inflows to the plants are replaced with a dry and wet inflow scenario. An overview of the different scenarios is provided in Table 2.

Table 2 - Overview of the 4 main scenarios used to analyze the impact of RoR dispatchability on power system flexibility

Scenario	**Description**
Aggregated scenario	Aggregated RoR plants for which annual generation is constrained by applying a maximum annual capacity factor
Detailed average scenario	Detailed RoR plants, modelled with storage size and annual generation is based on an *average* inflow scenario
Detailed dry scenario	Detailed RoR plants, modelled with storage size and annual generation is based on an *dry* inflow scenario
Detailed wet scenario	Detailed RoR plants, modelled with storage size and annual generation is based on a *wet* inflow scenario

2.4.1. Model description

The European power system is simulated using a power system simulation model (PSM). The software tool used to simulate the power system, is the Plexos Integrated Energy Model. This software is developed by Energy Exemplar[12] and used by industry and academics around the world (Ibanez et al., 2014). An in-house power system model of Utrecht University, based on Plexos, is used to model the power system, which is developed by Brouwer et al. (2016). The model simulates a power system with 96% CO_2 reduction in 2050 compared to 1990 levels. The fossil generation-capacity is cost optimized, for an exogenously defined RES penetration scenario (60%). The model is used to optimize power system operations over three different time horizons:

1. *Long-term (LT) plan:* determines the long-term expansion capacity by finding the cost-optimal combination of newly installed generators, retirements and transmission upgrades. The objective function of the LT plan is to minimise the net present value (NPV) of the total costs of the system. Other settings for the LT plan are:
   - 12 periods per month are simulated.
   - The installed capacity for the year 2050 for solar, wind, nuclear and biothermal plants is exogenously defined. Five types of fossil power plants can be built: Natural Gas Combined Cycle plants with CCS (NGCC-CCS), Natural Gas Combined Cycle Plants without CCS (NGCCe), Pulverized Coal Plants with CCS (PC-CCS) and Gas Turbines (GT). Extra biothermal capacity can be built as well, on top of the exogenously defined capacity. No hydro capacity can be built.

[12] www.energyexemplar.com

- The solution has to meet a maximum emission constraint of 45 Mtonne CO_2 per year, equal to 96% CO_2 emission reduction for the power sector compared to 1990 levels (Brouwer et al., 2016).

2. *Medium-term (MT) schedule:* decomposes annual constraints, such as maximum hydropower generation, planned outages, maintenance and storage volumes, into weekly constraints so that they can be fed as an input into the short-term schedule. The MT schedule also optimizes seasonal storage. In the MT schedule 12 periods per week are simulated, equal to 624 periods per year.
3. *Short-term (ST) schedule:* determines unit commitment and economic dispatch (UCED) of generators on an hourly basis. Unit commitment is the selection of generating units to be on or off during a scheduling period and for how long. The committed units must meet system load and reserve requirements, while also meeting generator constraints (Soliman & Mantawy, 2012). Economic dispatch determines the optimal allocation of the load among the committed units, while satisfying power balance equations and unit operating limits (Soliman & Mantawy, 2012). The objective function of the ST schedule is to minimise the total cost of generation. The ST schedule is optimized for steps of 1 week (so 52 weeks in total). The costs of emissions produced above the emission cap of 45 Mtonne are 50€/tonne CO_2.

The LT plan and the MT and ST schedule are run using linear relaxation (unit commitment can occur in non-integer increments), as no solver is available to solve the problem as a mixed-integer program (MIP) in this research. The advantage of the linear relaxation solving method is reduced running time, but the solving method had the following disadvantages:

- In the LT plan the units built can take non-integer values.
- In the ST schedule, some constraints cannot be enforced, amongst others: the generator's minimum stable level and minimum up and down time.

The study area of the power system includes 7 regions (Figure 4). Six regions are based on the prevalent types of iRES potential in these regions (Brouwer et al., 2016): British Isles (BRI), Scandinavia (SCA), France (GAL), Iberian Peninsula (HIS), Germany & Benelux (GER) and Italy & Alpine States (ITA), as in the original study. The 7th region, Eastern Europe (EAS), includes hydro capacity for the Eastern European countries in the EU-28.

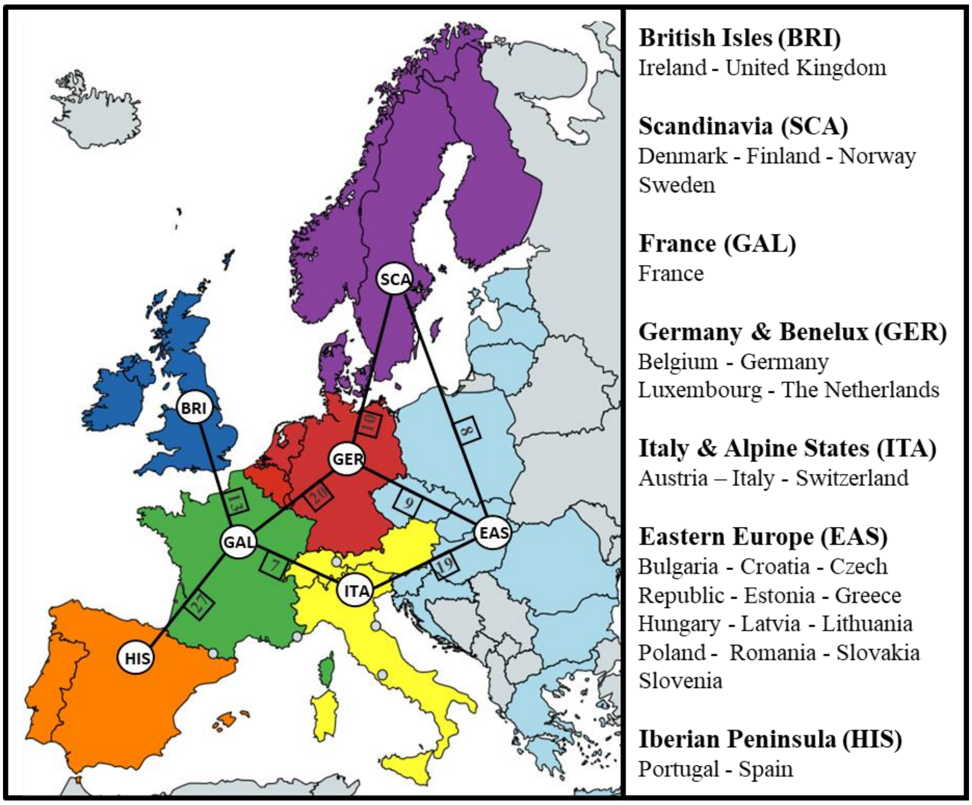


Figure 4 - Regions within the geographical scope. The black lines represent transmission lines and the figures in the black boxes show the assumed transmission capacity (GW) between the regions

2.4.2. Model inputs

Figure 5 shows all model inputs for each scenario. Model inputs as specified in the model by Brouwer et al. (2016) are used as a basis in this study. As the focus of this study is on analysing the role of RoR plant dispatchability in the power system, only inputs related to the hydropower capacity are adjusted. All other elements of the model by Brouwer et al. (2016) remain unchanged.

The unchanged model inputs (shown in green boxes in Figure 5) are: load profiles per country (for simplicity no additional load is added for the EAS region), iRES (solar and wind) production patterns and power plant flexibility parameters. For these inputs we refer to Brouwer et al. (2016). The inputs in the red dotted boxes are (partially) adjusted:

- The assumed interconnection capacity for BRI, GAL, SCA, HIS, GER and ITA is based on Brouwer et al. (2016). However, interconnection capacity between EAS and other regions is added in this study. Details on the assumed transmission capacity can be found in Appendix V.
- The techno-economic data for hydropower plants are based on the parameters specified by Gerritsma (2016), presented in Appendix V.
- The hydropower capacity in the low-carbon scenario is adjusted. The capacity for all other generators remain unchanged. Below an elaboration is given on the assumed hydropower capacity in this study and how this capacity is modelled.

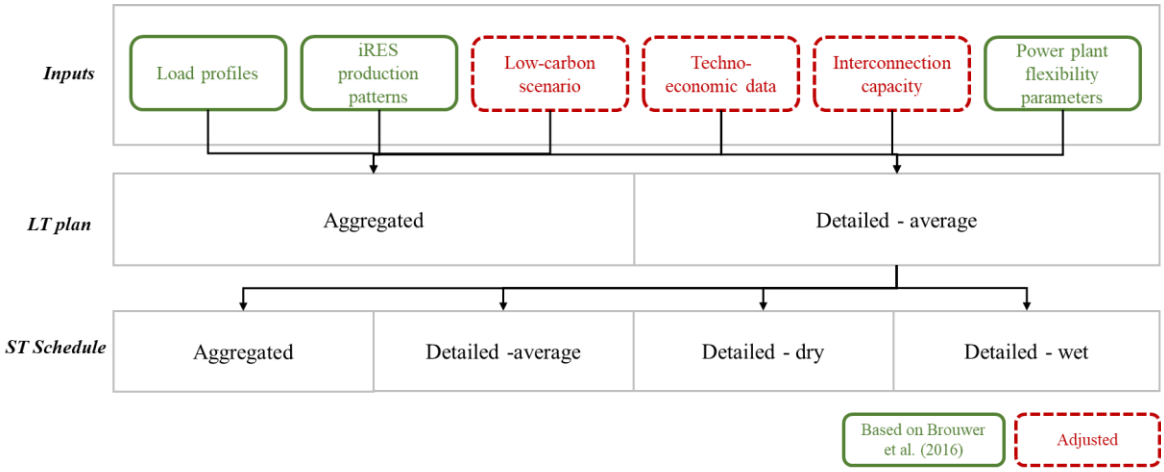


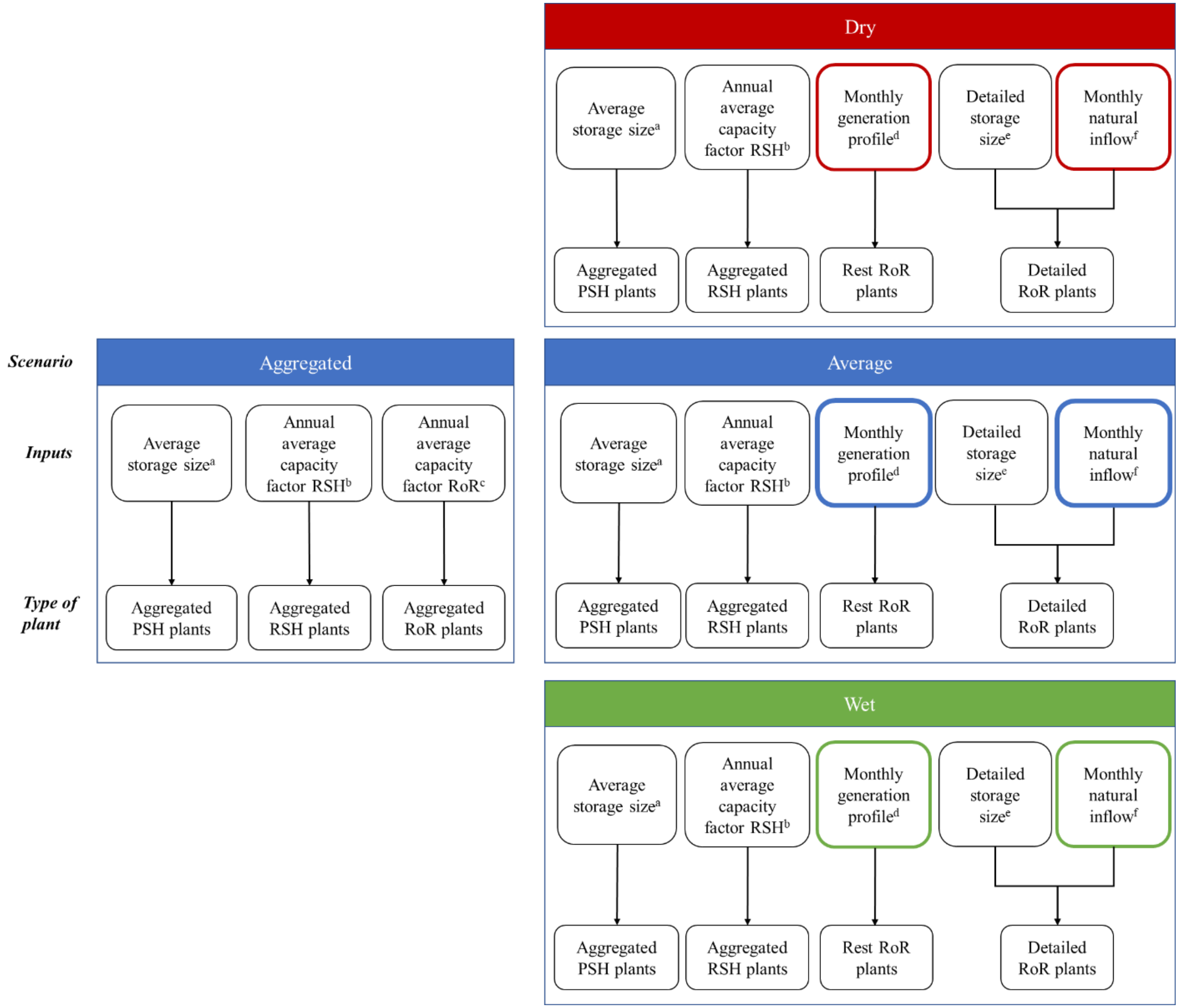
Figure 5 – Overview of model inputs

The hydropower capacity modelled in the power system is divided into three categories: RoR, RSH and PSH (described in section 1). Total assumed capacities for RoR, RSH and PSH are based on the sum of the individual production units provided by ENTSO-E (duplicates are removed from this list). The total hydropower capacity for the geographical scope is 160 GW, divided over 33 GW of RoR capacity, 81 GW of RSH capacity and 46 GW of PSH capacity.

In Figure 6 an overview is provided for the modelled hydropower categories in each scenario. RoR plants are modelled differently in the aggregated scenario and the detailed scenarios. In the aggregated scenario, RoR plants are modelled as an aggregated plant per region, without storage and without natural inflow. Annual generation is constrained by an annual maximum capacity factor. In the detailed scenarios RoR capacity is split into *detailed plants* and *rest plants*. *Detailed plants* are plants for which detailed data are gathered and are modelled with corresponding storage size (if applicable) and monthly natural inflows. For detailed plants for which no storage size can be found storage size is assumed to be zero hours, as the largest fraction of operating RoR plants are found to be in this category (see Figure 8, in results section 3.1). *Rest plants* are also modelled as an aggregated plant per region, without a storage and with a generation profile which reflects the seasonal availability of water. This generation profile is based on the inflows of plants for which data are available. Generation profiles consist of the monthly available capacity for each region, and are constructed by dividing total natural inflow of all plants by total nominal plant capacity in that region (Appendix). In this way, seasonal variation of water availability is also accounted for when modelling rest plants. The difference between the average, dry and wet scenario are the type of inflow scenario (average, dry and wet) and the type of generation profile (as the generation profile is based on the corresponding inflow scenario).

RSH and PSH capacity are modelled in the same way in the aggregated scenario and the detailed scenarios (average, dry and wet) so that any differences in the results are purely due to the RoR modelling approach. RSH plants are modelled as an aggregated plant per region with an annual average capacity factor and without storage. PSH plants are modelled as an aggregated plant per region with an average storage size and no annual maximum capacity factor. No natural inflow is modelled for any of these plants, so seasonal variation of water availability is not accounted for.

An overview of the number of units and the nominal capacity per type of plant for all scenarios is provided in Appendix VI.



[a] *Average storage size*: average storage size of 12.4 GWh based on Geth et al. (2015).

[b] *Annual average capacity factor RSH plants:* 50% based on Gerritsma (2016).

[c] *Annual average capacity factor RoR plants:* 49%, based on the average capacity for RoR plants in the database compiled in this study.

[d] *Monthly generation profile:* a profile of the monthly available capacity. Based on the total (average, dry or wet) inflow per month divided by the total installed capacity for a specific region. See Appendix VI

[e] *Detailed storage size:* storage size from the database, if applicable. If no storage size could be found, the storage size is assumed to be zero hours as most RoR plants have no or little storage capacity (Figure 8).

[f] *Monthly natural inflow:* based on the monthly inflow values as determined in the average, dry or wet natural inflow scenario. See 2.3 for a description of the different inflow scenarios.

Figure 6 - Overview of model inputs for RSH, PSH and RoR plants in each scenario. RSH and PSH plants are modelled in the same way in all scenarios, so that any difference in results can be attributed exclusively to improved modelling of the dispatchability of RoR plants. The difference between the inputs for RoR plants in the detailed-average, detailed-wet and detailed-dry scenario concerns the inflow values (in figure 'monthly natural inflow') and the monthly generation profiles.

2.4.3. Indicators for analysis

To be able to answer sub-questions 3 and 4, a list of indicators is constructed to compare the aggregated modelling approach with the detailed modelling approach. If most RoR plants are non-dispatchable, the plants do not provide flexibility to the power system, which affects the system's ability to respond to changes in demand. The flexibility of the power system is analysed by comparing several indicators, as shown in Table 3.

As can be seen in Figure 5, the generation mix is determined (in the LT plan) for both the aggregated and the detailed-average scenario. This is used to see if improved modelling of RoR dispatchability results in different generation mixes. Furthermore the generation mix (LT plan results) of the detailed-average is used as input for the ST schedule for all four scenarios. This is done to make sure that any difference in simulated generation is caused by changes in the way RoR plants are modelled, and not by differences in the generation mix.

Table 3 - Indicators to compare the power system flexibility for the aggregated and detailed scenarios

	Indicator	**Description**
LT plan	Generators built	When more peak generators are built in the detailed-average scenario, this could indicate an increased need of power system flexibility due to non-dispatchable RoR plants.
ST schedule	Generation by generator	An increase in generation by peak units is expected for a less flexible power system.
	Capacity factor by generator	An increase in capacity factors of peak units is expected for a less flexible power system.
	Total generation costs	Expected to increase in a less flexible power system due to the need for more start-ups amongst others (Arima, 2012).
	Annual CO_2 emissions	Partial loading of power plants increases total system emissions, because during start-up, start-down and steep ramping, emissions are higher than during stable operation (Arima, 2012). Annual CO_2 emissions are thus expected to be higher for a less flexible power system.
	Seasonal dispatch RoR plants	Compare the seasonal dispatch of RoR plants with the residual load (demand minus solar and wind generation) to see if it complements the residual load. Dispatchable RoR capacity is expected to follow the residual load, non-dispatchable RoR capacity may not be able to follow the residual load.
	Hourly dispatch for week with minimum and maximum residual load	Dispatchable RoR capacity is expected to reduce output during peaks of solar and wind generation in the week with minimum residual load and is expected to increase output in the week with the maximum residual load.
	Curtailment	Curtailment of RES is expected to be higher in a less flexible power system.
	Electricity price	Negative or volatile electricity prices are indicators for a non-flexible power system (Cochran et al., 2014).

2.4.4. Sensitivity runs

Table 4 presents the parameters for which a sensitivity analysis is performed.

Table 4 - Overview of parameters for which a sensitivity run is performed

Parameter	Change	Description
Storage size RoR plants	5 hours	For the plants for which no storage size can be found, the storage size is modelled with 5 hours of storage as 50% of the RoR plants (for which data are available) have a maximum storage size of 4-5 hours (Figure 8).
Minimum load	10% of nominal plant capacity	RoR plants are often restricted by river flow regimes and have to discharge at least a certain percentage of the river flow to maintain river ecology. The European Small hydropower Association (ESHA) provides a document which states that in several countries the minimum ecological flow should be 10% of the mean flow (ESHA, 2012).

2.5. Interviews with RoR experts and operators

The qualitative analysis of the research consists of conducting semi-structured interviews with RoR plant operators and experts. The purpose of these interviews is to understand how RoR plants are operated and if there are important flexibility limitations other than limitations of water inflows and storage capacity. A categorization of the constraints hydropower plants face is provided by Stoll et al. (2017):

- Environmental constraints (imposed to limit negative impact on the environment)
- Operational constraints (limitation of generation equipment)
- Regulatory constraints (binding obligations to contracted purchasers or the grid)

This categorization is used as a guideline for the interviews. An outline of the interviews can be found in Appendix VII.

3. Results

3.1. Hydro plant data collection: detailed database of Europe's RoR hydro plants

Data are found for 126 plants, equal to 22 GW of RoR capacity. To compare the RoR capacity covered by the constructed database, Figure 7 shows the RoR capacity in the geographical scope (EU-28 + Norway + Switzerland) according to different sources. ENTSO-E reports two lists with RoR capacities on their data Transparency Platform: one list based on the installed capacity per production unit (i.e. generator) and one list based on the total installed capacity per production type (e.g. RoR). The difference between the two RoR capacities is almost 20 GW (84%). The reason for this difference is that for several countries total capacities are reported per production type but no capacity for individual production units is reported. On the contrary, the sum of the individual units for some countries is larger than the total capacity per production type. This indicates that there are some inconsistencies in ENTSO-E's reporting on RoR capacity. The reported capacity by DNV GL also differs from ENTSO-E capacities, which is partially explained by the fact that DNV GL has a wider geographical scope of all European countries. This includes countries (e.g. Turkey and Bosnia Herzegovina) for which no capacity is reported or no data are available in ENTSO-E's list.

A total RoR capacity has to be assumed so that this capacity can be modelled in the power system model. The total assumed RoR capacity in this study is based on the total capacity in the ENTSO-E production unit list and additional RoR plants found during data collection[13]. The total assumed capacity equals 33.2 GW, as shown in Figure 7.

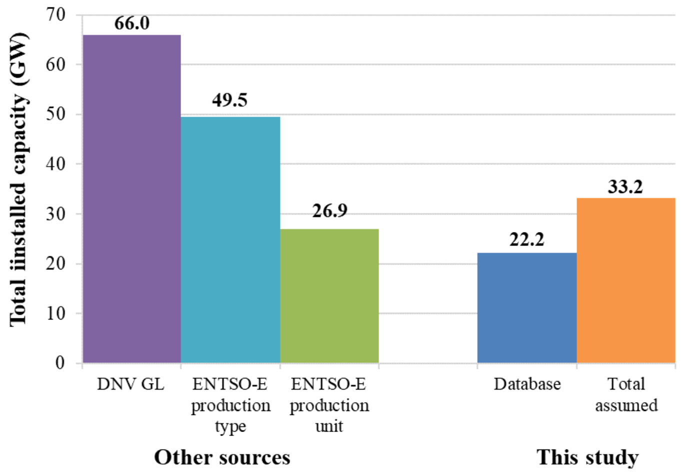


Figure 7 - Run-of-river capacity in geographical (eu-28+Norway+Swizerland) scope according to different sources, and the total capacity assumed in this study. From left to right: DNV GL (DNV GL, 2015) (this source includes other countries in Europe, such as Turkey), ENTSO-E by production type (ENTSO-E, n.d.-b) , ENTSO-E by production unit (ENTSO-E, n.d.-a), Database is the installed RoR capacity collected during data collection and the total capacity assumed in this study. The total assumed RoR capacity in this study is based on the ENTSO-E capacity by production unit and additional plants found which are not covered by the ENTSO-E production unit data.

[13] This assumed total capacity is considered as most transparent. The DNV GL source is regarded as less transparent because it is not clear which countries are exactly included in the total capacity and it is not clear what is defined as a RoR plant. The ENTSO-E production type is also regarded as less transparent as their might be duplicate values in the reported capacities for countries (this was also the case in the production unit list). In the production unit list however, duplicate values can be removed and misclassified units can be reclassified.

For five out of seven regions, more than 60% of the installed capacity is covered in the database (Table 5). For the other two regions, BRI and ITA, a relatively low percentage of capacity is covered. For the BRI region this can be explained by the fact that, according to the Transparency Platform database, there are no plants with an installed capacity larger than 100 MW. As the focus of this research is on collecting data on Europe's largest RoR plants, and data gathering started with the largest plants in the ENTSO-E database, only a small share of British and Irish RoR capacity is included. For the ITA region, a relatively small percentage of the total capacity is covered due to two reasons. First, similar as the BRI region, Italy has a large amount of RoR plants with a small capacity (of the 229 units included in the ENTSOE transparency platform, 214 units have a capacity smaller than 100 MW). Second, for several of the larger (>100 MW) RoR units, no plant information is found.

Table 5 - Overview of RoR plants in the detailed database produced in this study

Region	Total installed capacity by ENTSO-E[1] (MW)	Capacity of detailed plants included in database (MW)	% of capacity covered	Nr of plants reported by ENTSO-E[2]	Nr of plants included in detailed database	% of plants covered
BRI	1279	231	18%	34	8	24%
GAL	4850	4483	92%	28	23	82%
GER	297	297	100%	3	3	100%
HIS	3557	3557	100%	12	9	75%
ITA	12599	4731	38%	257	32	12%
SCA	4718	2860	61%	153	23	15%
EAS	6184	6083	98%	32	28	88%
Total	33153	22240	66%	519	126	26%

[1] Based on the 'Total installed capacity per production unit' reported on the ENTSO-E transparency platform and supplemented with additional plant capacity found during data collection.
[2] Based on the total number of plants in the individual production unit list on the ENTSO-E transparency platform and supplemented with the additional number of plants found during data collection.

Figure 8 shows the distribution of the storage size of RoR plants for which data are gathered. For 84 out of 126 plants, data on storage size is found. Figure 8 also shows how the plants are distributed according to ENTSO-E's definition of RoR plants: less than 2 hours storage is pure RoR, more than 2 and less than 400 storage hours is pondage and 400+ storage hours are Storage (RSH) plants (ENTSO-E, 2015b). This figure shows that 28 out of 84 plants have less than 2 hours of storage. These plants can thus be defined as 'pure' RoR plants. According to Figure 8, 56 plants can be classified as Pondage. The total storage of all RoR plants together amounts to 2300 hours, or 462 GWh. Additionally, the distribution by (nominal) plant capacity for the plants is shown in Figure 9. Up to a share of 80% of the total number of plants, the nominal capacity per plant quickly rises (shown by the red line in Figure 9). At a share of 80% or higher, the red lines flattens out, which shows that generally RoR plants are not bigger than approximately 220 MW.

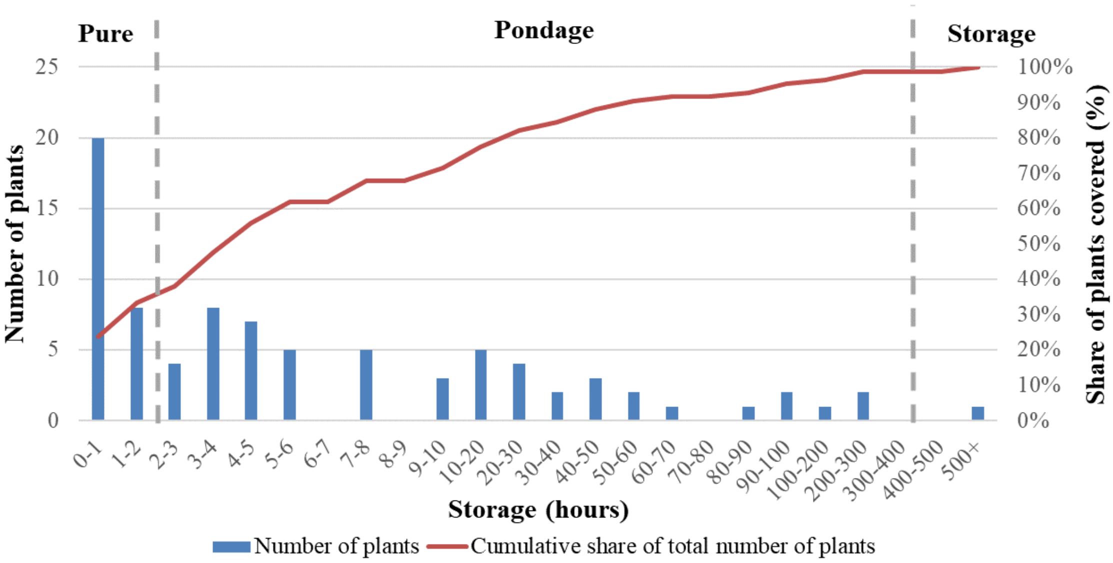


Figure 8 - Storage size distribution of European RoR plants expressed in storage hours, estimated by dividing the active storage volume by the maximum flow rate of the turbines of the plant. Based on the 84 plants in the database for which detailed storage data were available. The blue bars express the number of plants with the corresponding hours of storage and the red line expresses the cumulative share of plants with corresponding (or lower) storage size.

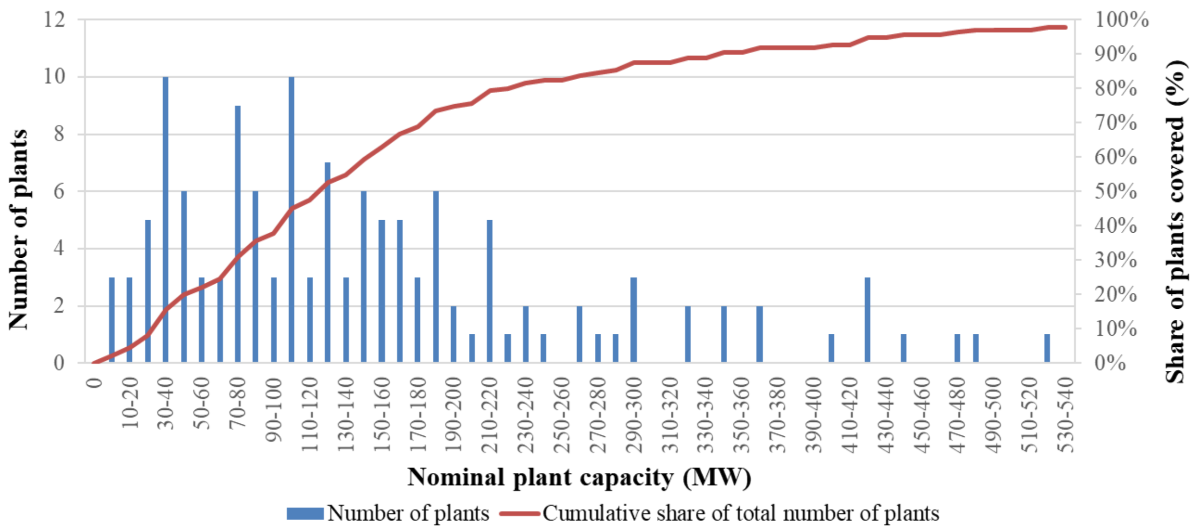


Figure 9 - Nominal plant capacity distribution of European RoR plants, based on the 126 plants in the database for which detailed data were available. The blue bars express the number of plants with the corresponding nominal plant capacity category and the red line expresses the cumulative share of the total number of RoR plants with the corresponding (or lower) nominal plant capacity.

3.2. Natural inflow scenarios

The average, dry and wet inflow scenario for all plants for which data are gathered are presented in Figure 10 (an average for all plants is shown). The total inflow pattern for all regions is dominated by plants located in snowfall dominated areas where discharge is highest in spring due to snow melt. Figure 10 also shows that during certain months (July, August, September and December) the wet inflow scenario has lower discharge values than the average scenario, and in certain months (February and October) the dry inflow scenario has higher discharge values than the average scenario. This is the consequence of choosing one typical year as a reference scenario for the dry and wet year scenario: dry scenario values can exceed or wet scenario values can fall below the average value for the corresponding month. However, the total annual inflow in the dry scenario is still higher (7%) than in the average scenario and total annual inflow in the dry scenario is still lower (28%) than in the average scenario. Therefore these scenarios are still considered as suitable scenarios to assess dry and wet inflow years.

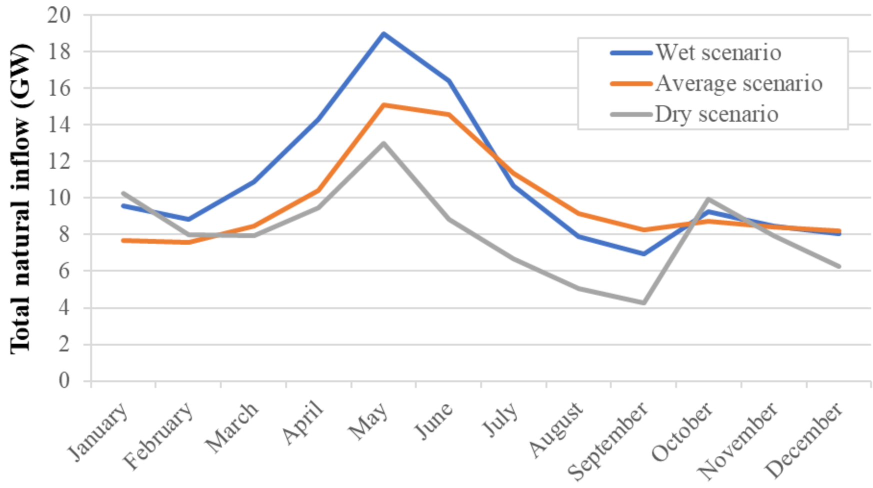


Figure 10 – Average, dry and wet inflow scenarios for RoR plants. The inflow scenarios reflect the sum of the inflow of all 126 plants. The inflow values are based on validated PCR-GLOBWB values.

The seasonal availability of water differs per region, which is shown by the totals at the end of each table in Figure 11. The differences in inflow patterns can mainly be attributed to the dominating river flow regimes: inflows in rainfall dominated areas usually peak during winter months and snowfall dominated areas have inflow peaks in spring. From Figure 11 it can be concluded that for the plants included in the database, water availability is highest in winter months in the BRI and HIS region, and that in the other regions water availability is highest during spring. However, it must be noted that there are also intra-regional differences in inflow patterns, which is reflected by the correlation between the inflow patterns of the plants in each region. For regions with similar flow regimes, (e.g.: HIS, GER and BRI) we find a very strong correlation (>0.99) between inflow patterns. For regions that cover a large area with both rain dominated and snowfall dominated river flow regimes, such as the EAS region, we find a very weak correlation (0.35).

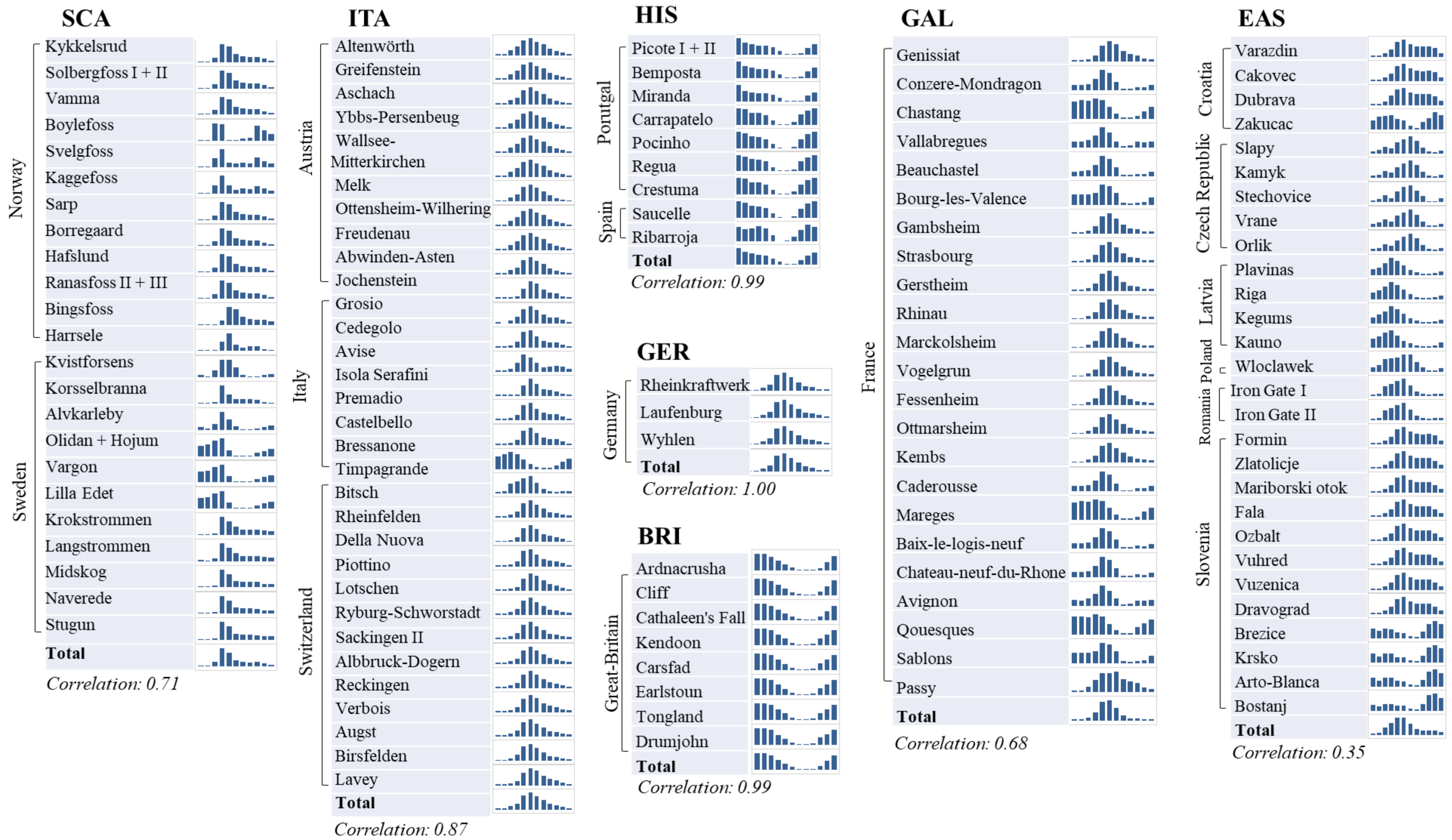


Figure 11 – Average inflow patterns for RoR plant per region. The inflow values are based on validated PCR-GLOBWB values.

3.3. Impact of accounting for the dispatchability of RoR plants on the power system

To be able to analyze the effect of accounting for RoR dispatchability on the power system, the *aggregated scenario* is compared with the *detailed-average scenario*. Whenever we refer to the detailed scenario in this section, we refer to the *detailed-average* scenario.

3.3.1. Generation capacity built

The newly installed capacity is nearly equal for the detailed and the aggregated scenario (Figure 12). In the detailed scenario, the GT capacity built increases by 1.1 GW and the NGCCe capacity built by 1.4 MW compared to capacity built in the aggregated scenario, while the NGCC-CCS capacity decreases by 1.9 GW. The total newly installed capacity corresponds to 327.5 GW and 327.0 GW in the aggregated scenario and detailed scenario respectively. The difference of 0.5 GW cannot be distinguished from the effect of rounding[14]. Those results show that modelling the dispatchability of RoR capacity in detail does not result in a (significant) difference in generator capacity built. Both scenarios require GT and NGCC capacity to be built by 2050 (in addition to the exogenously defined capacity), since these are the generators with lowest costs (Brouwer et al., 2016).

	Aggregated (GW)	Detailed (GW)
NGCC-CCS	34.7	36.6
NGCCe	15.3	13.9
GT	277.6	276.5
Total	327.5	327.0

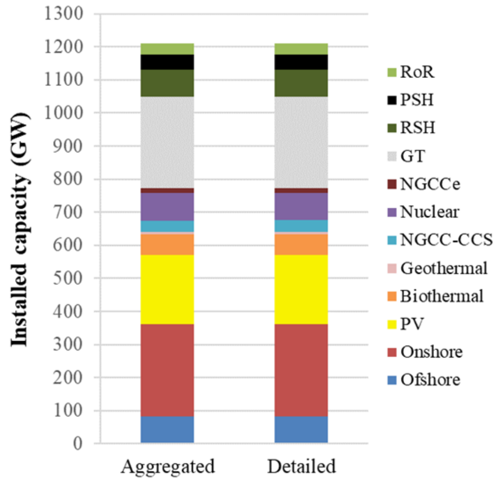


Figure 12 – Newly installed capacity (left) and total installed capacity (right) in 2050 for the aggregated and detailed scenario

3.3.2. Generation and capacity factors per generator

The generation and capacity factors per generator for the aggregated and for the detailed scenario are shown in Figure 13. RoR generation decreases in the detailed scenario, even though inflow values in the detailed scenario allow for similar production as in the aggregated scenario. Also the total modelled RoR capacity remains the same in both scenarios. This indicates that at some moments water availability for RoR generation is so high that it cannot be used by the power system in the detailed scenario. This finding is confirmed by the water spill (Figure 14) which shows that water is mainly spilled during the months May and June.

When RoR capacity is constrained by limited storage capacity and seasonal availability of water, the system requires more flexible generation by other sources. This need for low-carbon flexible generation is provided by biothermal plants, whose generation increases by 28 TWh (+28%) in the detailed scenario. The power system dispatches biothermal plants with high fuel costs rather than flexible plants

[14] Small variations in the results can occur due the numerical round-off or random selection of alternative options (Energy Exemplar, n.d.)

with cheaper fuel costs such as NGCC and GT plants because of the emission constraint of 45 Mtonne. As the RoR generation decreases in the detailed scenario, which is a zero-emission source, and the need for flexible generation increase, biothermal plants are dispatched to provide zero-emission flexible generation to meet the emission target. Additionally, PSH generation increases in the detailed scenario because these plants take advantage of price differences, which are more extreme since RoR generation is at some moments abundantly available and scarce at other moments (see 3.3.8). Furthermore, some RoR plants are forced to generate due to limited storage size. As a result RoR plants provide more baseload generation in the detailed scenario, which is why there is a decrease in the generation of baseload plants such as nuclear (-1%), and mid-merit plants like NGCC-CCS (-3.6%) and NGCCe (-11%).

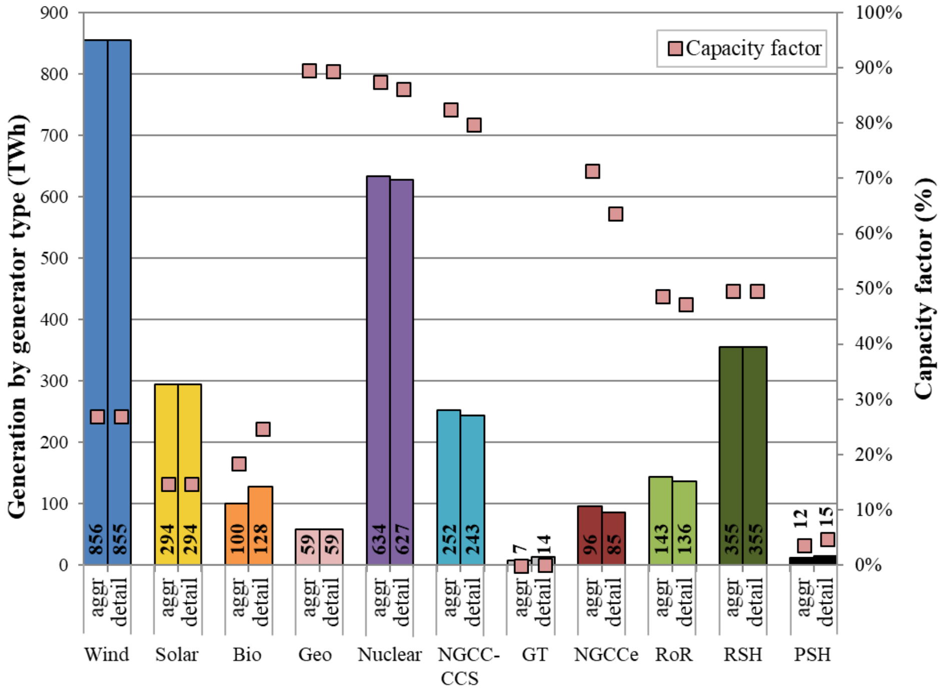


Figure 13 - Generation and capacity factors by generator type in the year 2050 in a low-carbon power system. Figures in the bars express the generation in TWh

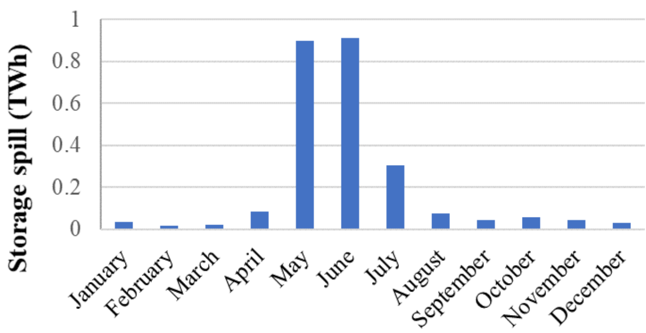


Figure 14 – Water spill by detailed RoR plants in the detailed scenario

3.3.3. Total generation costs

Total annual generation costs[15] are presented in Figure 15. Total generation costs are 1.19 bn€ higher in the detailed scenario, an increase of 4% over the aggregated scenario. This increase can mainly be attributed to increased fuel costs, which are responsible for 87% (1.05 bn€) of the increase in total generation costs. Fuel costs increase due to more biothermal generation, which compensates for the reduction in flexible hydro capacity when RoR constraints are more fully accounted for with detailed modelling. Changes in emission costs[16] and VO&M costs[17] are small, they only represent 8% (0.10 bn€) of the change in the total generation costs. Start and stop costs slightly increase in the detailed scenario (+0.14 bn€), which is caused by almost a doubling in start and stops by GT plants.

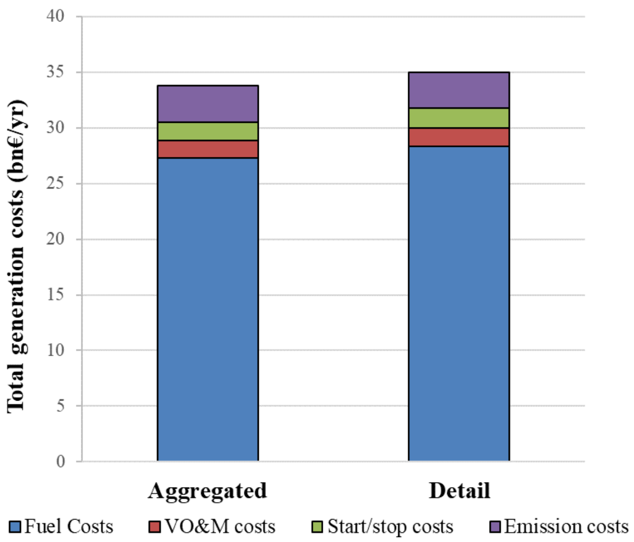


Figure 15 - Total annual generation costs and total annual CO_2 emissions in the aggregated and detailed scenario

3.3.4. Total CO_2 emissions

Annual CO_2 emissions and CO_2 stored in the aggregated and detailed scenario are shown in Figure 16. In both scenarios, CO_2 emissions amount to 43 Mtonne which means that both scenarios meet the emission target of 45 Mtonne. The CO_2 stored is 3 Mtonne more in the aggregated scenario (4% increase compared to the detailed scenario) due to higher fossil generation in the aggregated scenario. From this figure we can conclude that detailed modelling of the dispatchability of RoR plants does not result in higher CO_2 emissions. In both scenarios the emission target is met, the only difference is that in the detailed scenario the emission target is met at higher costs.

[15] Generation costs include fuel costs, VO&M costs, start and stop costs and emission costs. Investment costs are not included.
[16] Emission costs are the costs of emissions allocated to a specific generator
[17] VO&M costs stand far variable operation and maintenance costs and are maintenance costs that are a direct function of generation (e.g. wear and tear)

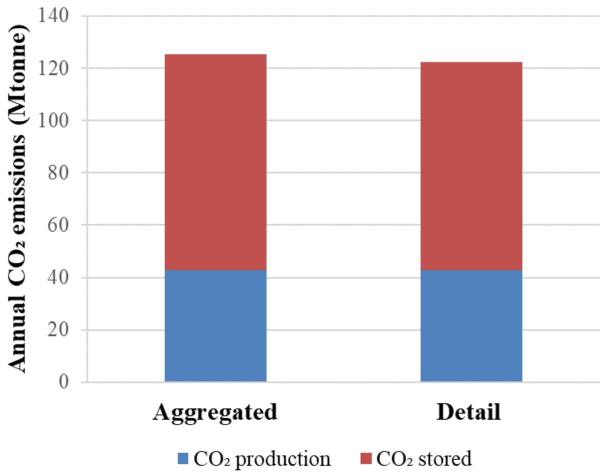


Figure 16 - Annual CO_2 emissions in the aggregated and the detailed scenario

3.3.5. Seasonal dispatch

Figure 17 and Figure 18 show RoR generation and the residual load for the aggregated and the detailed scenario respectively. In the aggregated scenario the RoR generation pattern follows the residual load pattern. In the detailed scenario however, the RoR generation pattern is flattened out; the RoR capacity is to a lesser extent able to follow the residual load peaks. Peaks in residual load have to be covered by other generators (GT and biothermal plants). These graphs show that on a daily time scale, detailed RoR capacity is less able to complement i-RES generators such as wind and solar PV than when RoR capacity is modelled as an aggregated units without inflows. This indicates that the aggregated approach overestimates the dispatchability of RoR plants. This is also confirmed by the correlation between residual load and RoR generation, shown in Figure 19. The graphs shows that in the aggregated scenario residual load and RoR generation are strongly correlated: when the residual load increases, RoR generation increases as well. In the detailed scenario the residual load and RoR generation have a slight negative relation but are not significantly correlated.

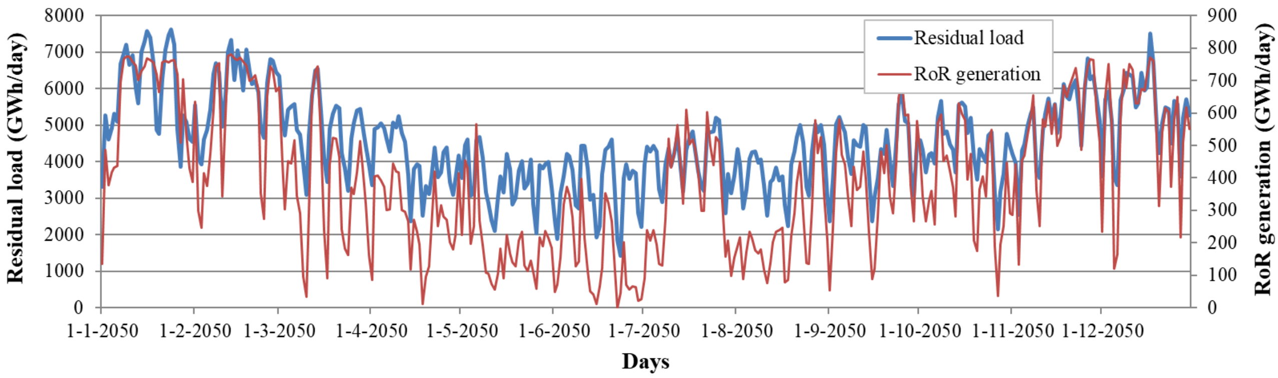


Figure 17 - Aggregated scenario: daily profiles for the residual load and RoR generation

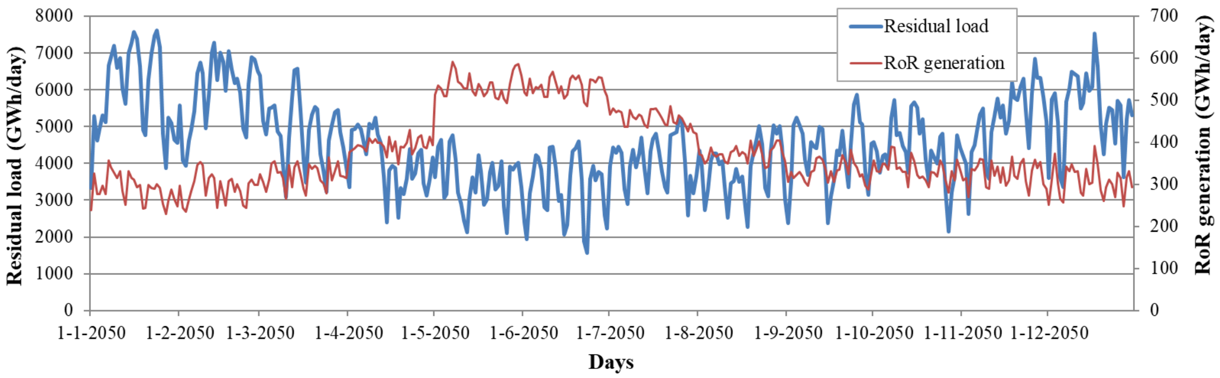


Figure 18 – Detailed scenario: daily profiles for residual load and RoR generation

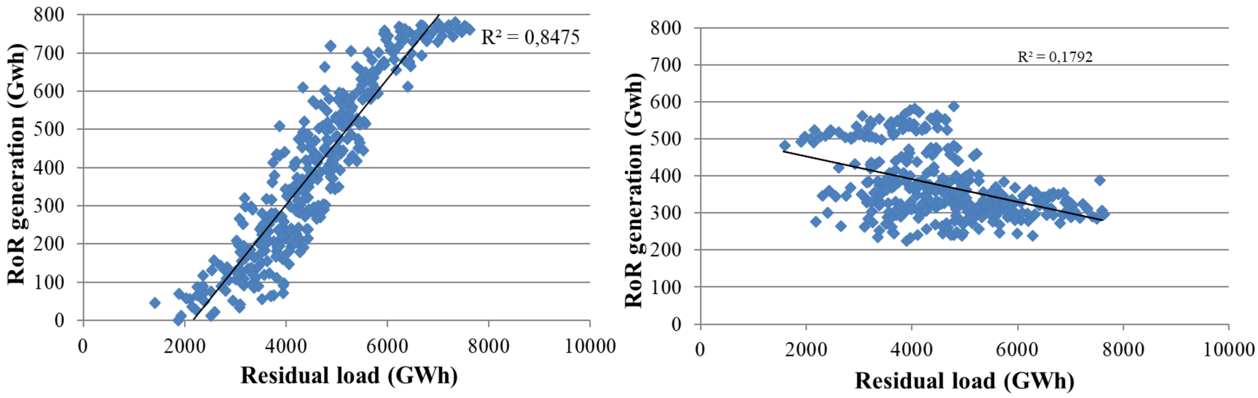


Figure 19 - Left: correlation residual load and RoR generation for the aggregated scenario. Right: correlation residual load RoR generation for the detailed scenario

The complementarity between RoR generation and the residual load differs per region, which is illustrated in Figure 20 for the aggregated and the detailed scenario. In the aggregated scenario, in all regions RoR generation follows the residual load pattern. In the detailed scenario, RoR generation in the regions BRI (A) and HIS (A) follows the residual load pattern, whereas in the other regions the RoR generation pattern is opposite to the residual load pattern. However, it must be noted that the impact of modelling the dispatchability in detail has more impact in some region than others because the share of RoR generation in the total generation mix differs per region. To illustrate this, Figure 20 shows the contribution of RoR generation to the residual load (demand minus solar PV and wind generation), which is calculated by dividing the RoR generation by the residual load for each region. The contribution of RoR generation to the regional residual load is highest in the ITA (15.7%) and SCA (12.5%) region (in the detailed scenario). In these regions the RoR generation pattern does not match the residual load pattern. This means that especially for the ITA and SCA region more generation is needed from other generators to provide the required flexibility to the power system.

Figure 18 and Figure 20 show that RoR capacity is to a lesser extent able to complement the residual load when modelling the dispatchability in detail. This suggests that part of the RoR capacity also provides variable generation which cannot be controlled. Recall that the definition of the residual load is the system load minus the generation by variable (non-dispatchable) generators. Considering this, we can conclude that residual load could possibly be calculated more realistically by load minus solar, wind and variable RoR generation (pure RoR capacity).

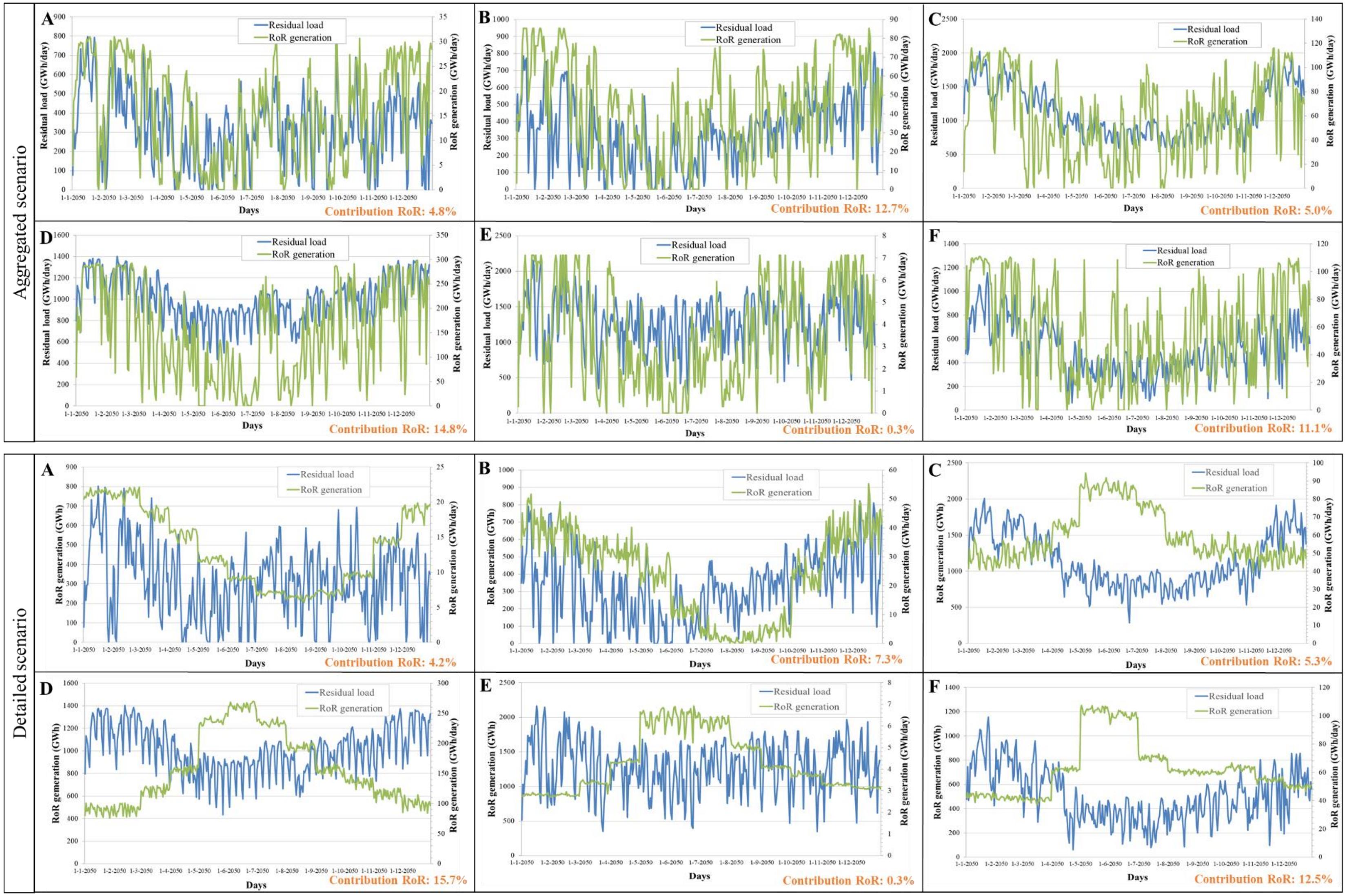


Figure 20 – Daily profiles for RoR generation and residual load per region in the aggregated scenario (top) and detailed scenario (bottom). A=BRI, B=HIS, C=GAL, D=ITA, E=GER, F=SCA. Note that the in the detailed scenario RoR generation in some regions shows a stepwise pattern, which is the result of modelling RoR plants with monthly generation profiles. Also note that the EAS region is not shown as no load is modelled for this region.

3.3.6. Hourly dispatch

The hourly generation profiles for the week with minimum residual load (17-6/23-6) for the aggregated and the detailed scenario are shown in Figure 21 and Figure 22 respectively. In the aggregated scenario, RoR capacity provides flexible generation. It generates only when no (or less) solar or wind is available. In the detailed scenario, RoR capacity appears to be less flexible than assumed in the aggregated scenario: the generation is rather constant and RoR plants also generate during solar and wind generation peaks (highlighted by the red circle in Figure 22). The share of RoR generation increases with 5% (absolute difference) compared to the aggregated scenario. This is because water availability for RoR generation is high during the week with minimum residual load and RoR generation cannot be reduced as some RoR plants have limited storage size and high inflows. As a result, curtailment of wind increases from 93 GWh in the aggregated scenario to 253 GWh in the detailed scenario. This is highlighted by the black circles in Figure 21 and Figure 22: in the aggregated scenario there is a small drop in offshore wind generation and there is no RoR generation, whereas in the detailed scenario the drop in offshore generation is bigger because RoR generates during the peak in solar generation. Since RoR generation provides more baseload power in the detailed scenario, the share of nuclear generation is reduced with 2% compared to the aggregated scenario. Also the share of RSH generation decreases with 2% in the detailed scenario.

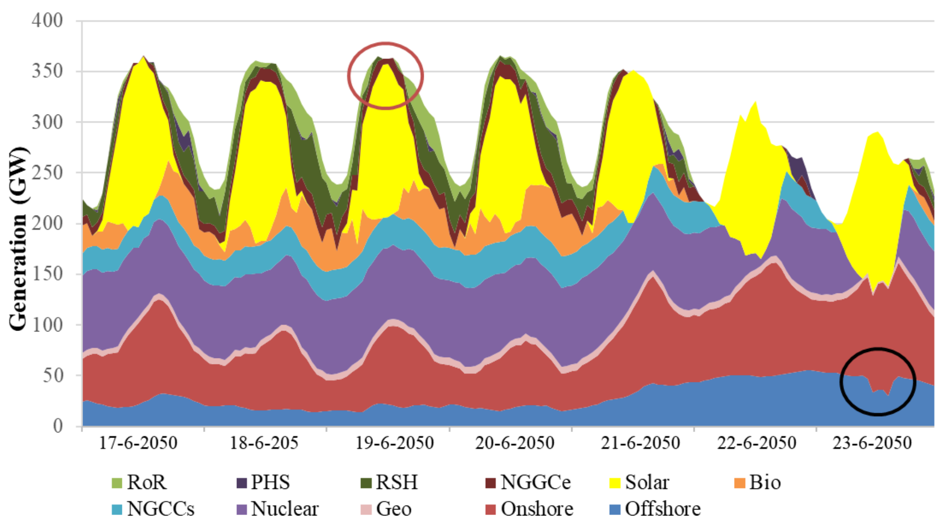


Figure 21 – Aggregated scenario: generation during week with minimum residual load

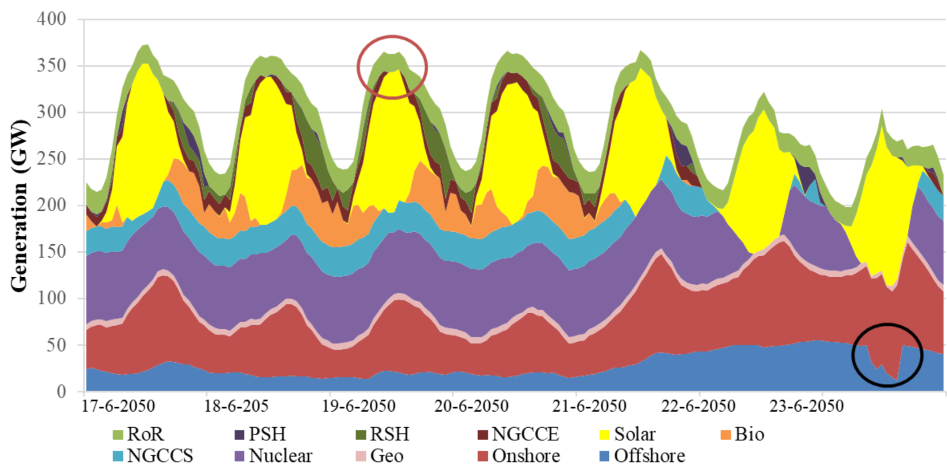


Figure 22 – Detailed scenario: generation during week with minimum residual load

Additionally, Figure 23 and Figure 24 show the hourly dispatch for the week with maximum residual load (18-2/14-2) for the aggregated and the detailed scenario respectively. These graphs show that RoR generation is much lower in the detailed scenario: RoR capacity is less dispatchable than the system needs during periods of low availability of solar and wind. As a result, more biothermal capacity is dispatched in the detailed scenario to cover peaks in demand, which can no longer be provided by RoR capacity. Also, opposite to the weeks with minimum residual load, the share of RSH generation increases by 1% in the detailed run in this week. This shows that RSH capacity compensates for reduced RoR generation in the week with maximum residual load by increasing output, and compensates for increased RoR generation during the week with minimum residual load by reducing output.

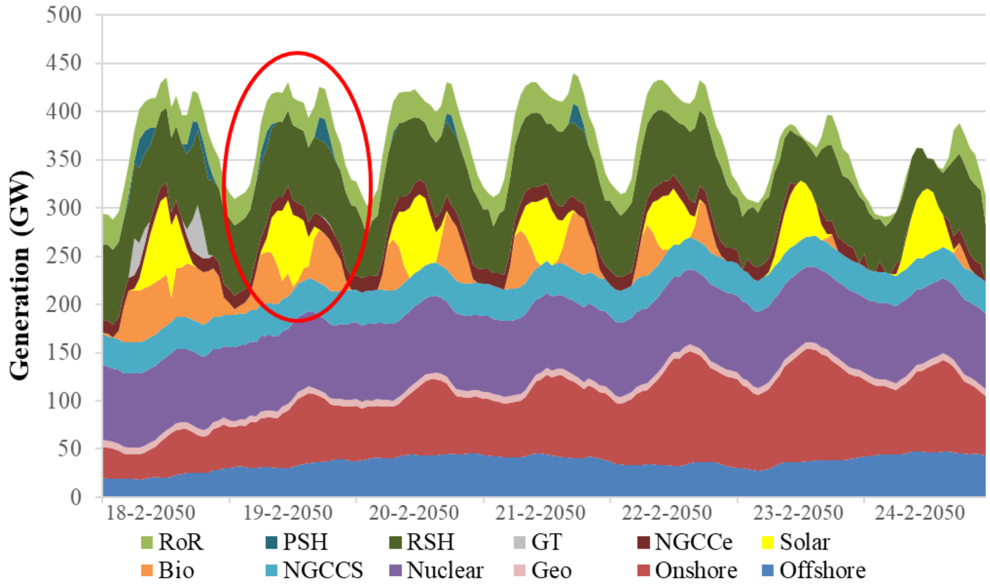


Figure 23 - Aggregated scenario: generation during week with maximum residual load

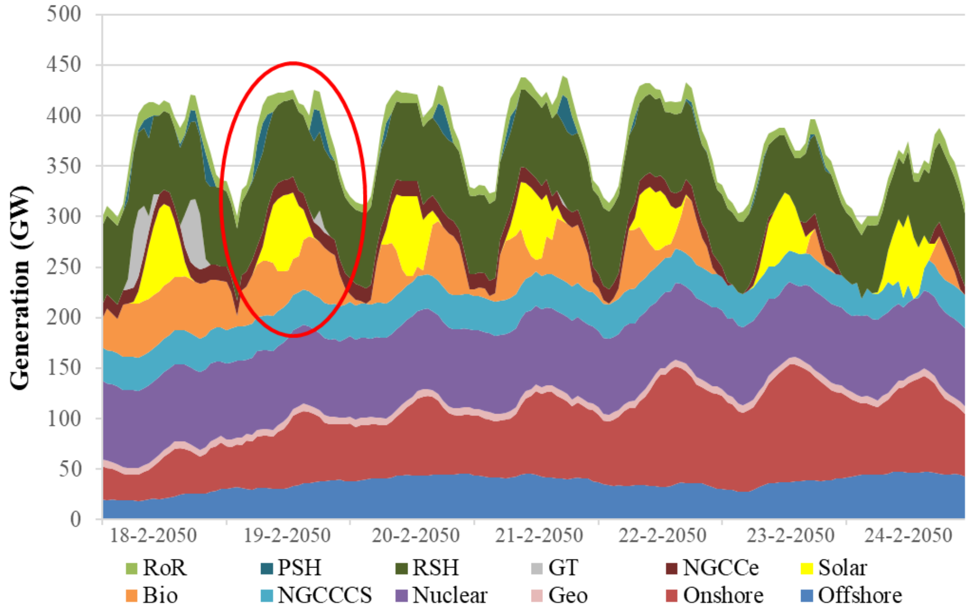


Figure 24 - Detailed scenario: generation during week with maximum residual load

3.3.7. Curtailment

In Table 6 curtailment of wind, solar and geothermal capacity is presented for the aggregated and the detailed scenario. Curtailment is higher in the detailed scenario, especially in the months May and June (Figure 25). In the aggregated scenario, curtailment occurs during these months because the demand is generally lower in summer and there is high availability of solar capacity. In the detailed scenario curtailment is higher during these months because water availability for RoR generation is highest during these months as well, which mainly results in more curtailment of wind.

Table 6 - Curtailment of solar, wind and geothermal capacity in the aggregated and detailed scenario.

	Aggregated scenario (GWh)	Detailed scenario (GWh)
Solar	29	72
Wind	952	1343
Geothermal	1	2
Total	980	1415

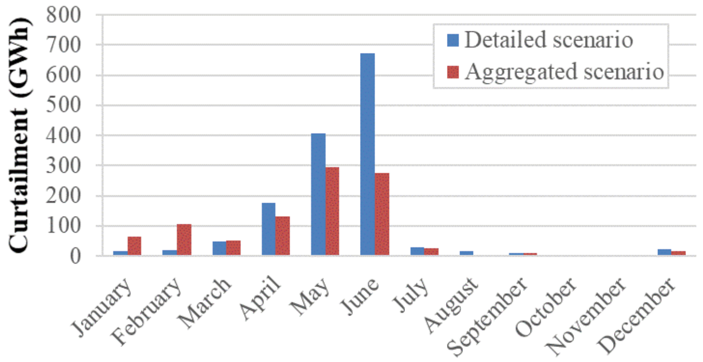


Figure 25 - Monthly curtailment figures for the aggregated and the detailed scenario

3.3.8. Electricity price

Figure 26 shows the daily average electricity price averaged across all regions for both the detailed and the average scenario. The figure shows that price peaks are more extreme in the detailed scenario. To clearly see the price differences between the two scenarios, Figure 27 provides the daily average price in the detailed scenario minus the daily average price in the aggregated scenario. Electricity prices in the detailed scenario are lower in late spring and summer months due to high water availability for RoR generation. With some exceptions, the opposite can be stated as well: prices are higher in winter months in the detailed scenario as less water is available for RoR generation. Decreases in RoR generation have to be covered by more expensive peak units such as biothermal and GT plants, which results in higher prices in winter months.

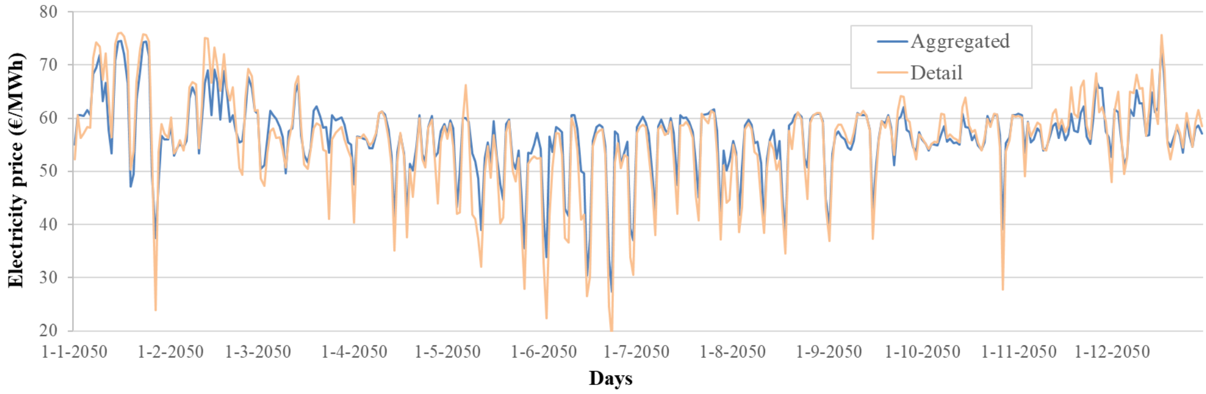


Figure 26 - Average daily electricity price (averaged across all regions) for the aggregated and the detailed scenario

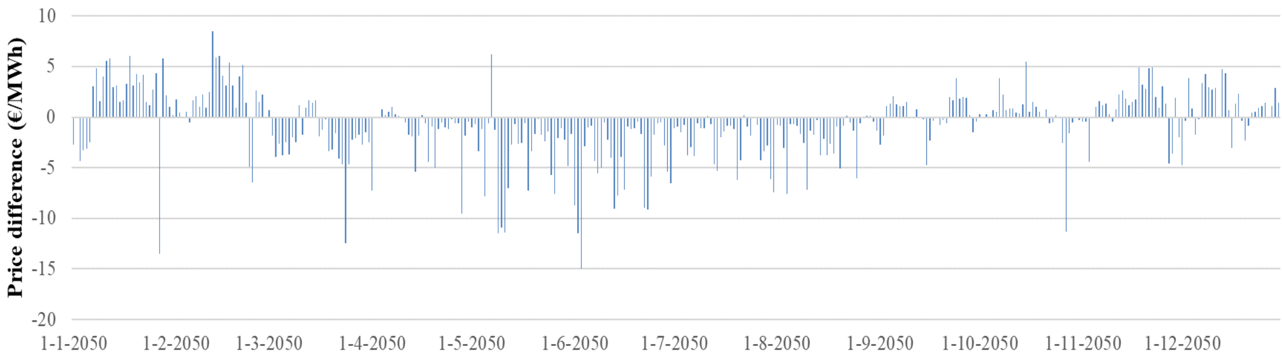


Figure 27 - Difference in daily average electricity price between the detailed and aggregated scenario, calculated as the daily average price in the detailed scenario minus the daily average price in the aggregated scenario

3.4. The impact of inter-annual variation of hydropower generation on the power system

The generation by generator for the detailed-dry and the detailed-wet scenario are presented in Figure 28. For comparison, results for the the detailed-average and the aggregated scenario are shown as well. A wet inflow scenario results in 3% (5 TWh) more RoR generation compared to the detailed-average scenario. The inflow in the wet scenario is mainly higher in spring in comparison to the detailed-average inflow scenario, as shown in 3.2. The detailed plants cannot process all of the higher inflow during these months, which is shown by the water spill results in Figure 29. Spill occurs because the plants cannot store the additional inflow and the inflow cannot be processed by the turbines due to limited turbine capacity. As RoR generation only increases by 3%, the difference in generation by other generators is also small compared to the detailed-average scenario. Biothermal generation decreases by 2%, and GT and PSH generation increases by 5% and 3% respectively. This shows that a wet inflow scenario (as chosen in this study) has limited impact on the generator dispatch in the power system. A scenario with a wet winter, or with high inflows more evenly spread over the year, is expected to have more impact on the power system. In the dry scenario, RoR generation significantly decreases with 28 TWh (-20%) compared to the detailed-average scenario. This results in an increase in generation by nuclear (+0.4%), NGCC-CCS (+2%) and NGCCe (+7%) plants, which are providing baseload generation that can no longer be provided by RoR capacity. Also biothermal generation increases by 11% and GT generation by 3% compared to the detailed-average scenario. The latter indicates that the few RoR plants with relatively large storage size are still able to provide some flexibility to the system. If RoR capacity could only provide baseload generation and no peak generation, a dry inflow scenario would not increase the need for a flexible generator but only the need for base load generation.

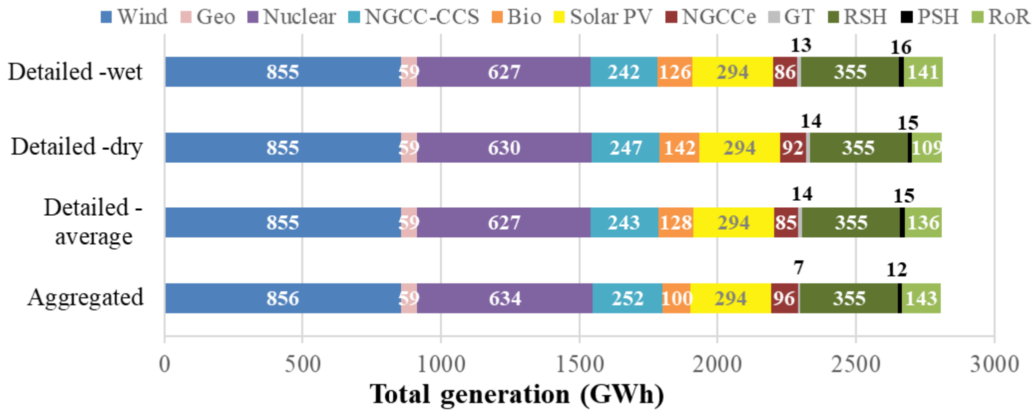


Figure 28 - Generation per generator for the detailed-wet, detailed-dry, detailed-average and the aggregated scenario

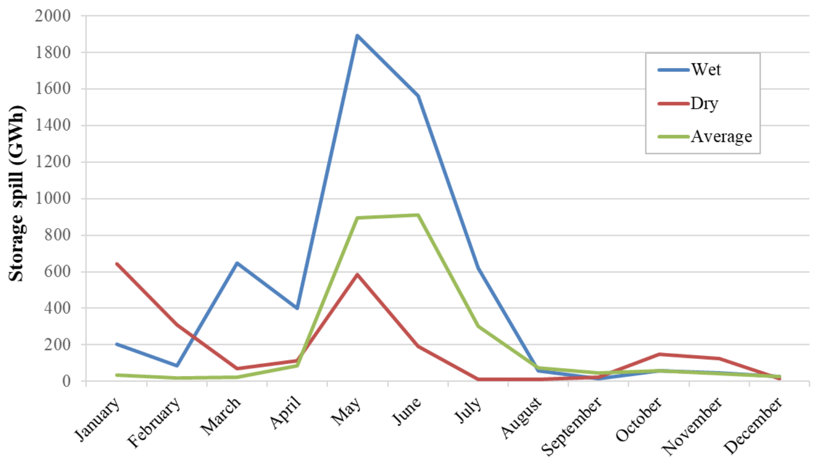


Figure 29 - Water spill by detailed RoR plants in the detailed-average, detailed-wet and detailed-dry scenario

Total generation costs for the dry and wet scenario are shown in Table 7. A detailed-wet scenario does not result in much lower costs compared to a detailed-average scenario. The costs only decrease by 0.3bn€ (0.6%) due to increased RoR generation and decreased biothermal generation. In the detailed-dry scenario however, total generation costs are significantly higher: + 4% compared to the detailed average scenario and an even increase of 8% compared to the aggregated scenario. This is because the decrease in (no-cost) RoR generation is covered by the more expensive generators such as biothermal, GT and NGCCe/NGCC-CCS plants. Additionally, Table 7 shows that due to the small differences in generator dispatch, the annual CO_2 emissions in the detailed-wet scenario are only slightly lower (-0.6%) than in the detailed-average. In the detailed-dry scenario CO_2 emissions increase by 5.7% compared to the detailed-average. Unlike the other scenarios, emissions in the detailed-dry scenario slightly exceed the emission cap of 45 Mtonne. This indicates that extreme dry weather conditions can be a limiting factor in achieving the climate targets set by the European Commission for 2050. Finally, curtailment figures are shown in Table 7. In the detailed-wet scenario curtailment of wind and solar increases by 6.5% compared to detailed-average, and in the detailed-dry curtailment decreases by 20.1%. This shows that an increase RoR generation, partially replaces solar and wind during moments with high RES availability and low demand.

Table 7 – Total generation costs, CO_2 emissions and curtailment in the aggregated, detailed-average, detailed-dry and detailed-wet scenario

	Aggregated	Detailed-average	Detailed-wet	Detailed-dry
Total generation costs (bn€/year)	33.8	35.0	34.7	36.5
Relative change to detailed-average scenario	-3.4%		-0.6%	+4.3%
CO_2 emissions (Mtonne/year)	43.0	42.8	42.6	45.2
Relative change to detailed-average scenario	+0.4%		-0.6%	+5.7 %
Curtailment (GWh/year)	980.5	1414.7	1506.4	1130.7
Relative change to detailed-average scenario	-31%		+6.5%	-20.1%

3.5. Sensitivity analyses

We test the sensitivity of the results to two assumptions. The first assumption concerns the storage size assumed for detailed RoR plants for which no data could be found. In the detailed scenarios (average, dry and wet) the storage size for these plants is assumed to be zero hours. Here we will analyse the effect of modelling these plants with five hours of storage. The second assumption regards the minimum generation level. In the detailed scenarios, no minimum generation level is modelled. However, RoR plants often need to maintain a minimum discharge level to limit the effect on river ecology. Which was also confirmed by the interviewees (3.6). In the detailed-average scenario it was found that for 76 plants (plants with some storage) the generation sometimes drops to zero. Therefore we test the effect of modelling RoR plants with a minimum generation level of 10% of its nominal plant capacity. The main findings for these sensitivity runs are described below:

- *5 hours storage scenario* – Adding extra storage to the system, results in nearly equal RoR generation compared to the detailed-average scenario (0.1 TWh less RoR generation in the 5 hours scenario). Although one would expect the RoR generation to increase when the RoR capacity has more storage (and thus becomes more dispatchable), this is not what happens because the additional dispatchable RoR capacity is used to decrease curtailment of solar PV and wind (Table 8). Furthermore, due to an increase in storage size, a bit less flexible generation has to be provided by biothermal plants (-1 TWh), GT plants (-1TWh) and NGCCe (-0.3 TWh) (Figure 30). CO_2 emissions are slightly lower (-0.4 Mtonne) compared to the detailed-average scenario as a result of lower GT and NGCCe generation (even though NGCC-CCS generation increases, this increase is not more than the combined decrease of GT and NGCCe plants). Total generation costs slightly decrease due to declines in biothermal, NGCCe and GT generatio. Considering these results, the changes induced by adding 5 hours storage to the system for 42 plants are relatively small.
- *MinLoad scenario* – Applying a minimum load to all RoR plants does not have a significant impact on the total annual generation of the generators. The generation by all generators is (nearly) equal in the MinLoad and the detailed-average scenario. Also total generation costs and CO_2 emissions are comparable to the detailed average scenario (Table 8). As rest plants are found to always operate above 10% of its installed capacity in the detailed-average scenario and detailed plants without storage have to generate the inflow they receive (otherwise water is spilled), it is logical that for these plants modelling a minimum generation level does not make much of a difference. However, of the 76 plant for which generation sometimes dropped to zero in the detailed-average scenario, it is unclear why applying a minimum generation level shows

no difference in results. An explanation could be that 10% of the installed capacity as a minimum generation is too low to result in differences of the dispatch of all generators.

Table 8 – Total generation costs, CO_2 emissions and curtailment in the aggregated, detailed-average, detailed-5hours and detailed-MinLoad scenario

	Aggregated	**Detailed-average**	**Detailed-5hours**	**Detailed-MinLoad**
Total generation costs (bn€/year) Relative change to detailed-average scenario	33.8 -3.4%	35.0	34.9 -0.3%	35.0 -0.0%
CO_2 emissions (Mtonne/year) Relative change to detailed-average scenario	43.0 +0.4%	42.8	42.4 -1.1%	42.8 -0.1%
Curtailment (GWh/year) Relative change to detailed-average scenario	980.5 -31%	1414.7	1221.8 -14%	1452.2 +3%

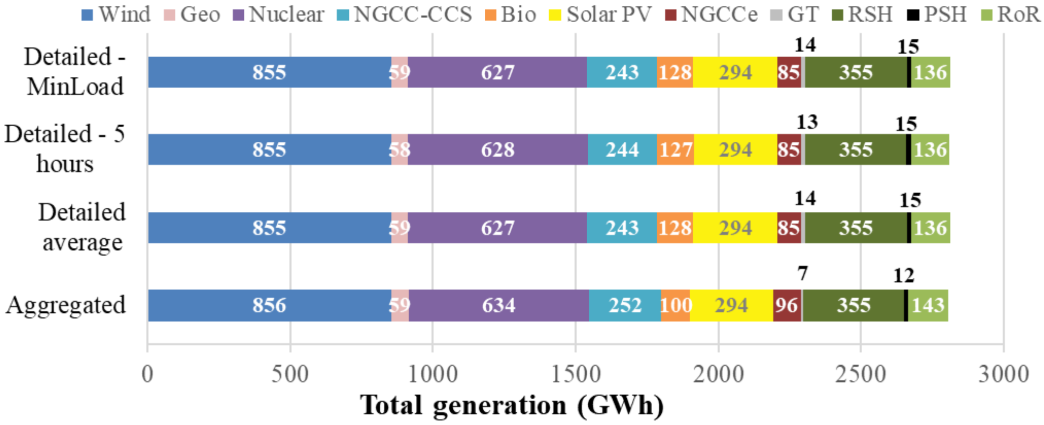


Figure 30 - Generation per generator for both the sensitivity runs. For comparison the aggregated and detailed-average scenario are shown as well.

3.6. Evaluation of other factors affecting the dispatchability of RoR plants

Interviews with four RoR operators and experts are conducted to gain additional insights in what factors, other than water inflow and storage, limit the operational flexibility of RoR plants. For more details about the interviewees, see Appendix V. The results are categorized into three types of factors which influence the flexibility of RoR operation (Figure 31). In the remainder of this section the factors are shortly touched upon.

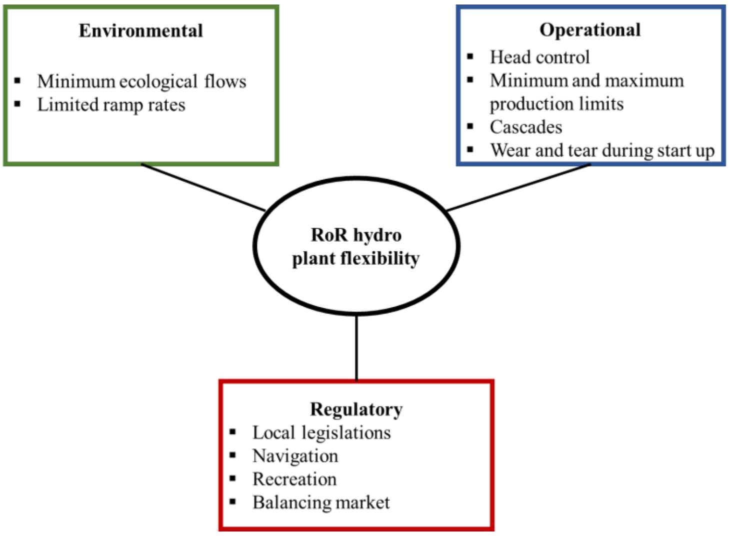


Figure 31 - Environmental, operational and regulatory factors that influence flexible operation of RoR hydro plants

Environmental factors

For most RoR plants, flexible operation of RoR hydro plants is limited by a **minimum discharge level**, which must be maintained to maintain river flow regimes and river ecology. Also, although technically RoR hydro plants are able to ramp up to around a hundred MW in several minutes**, ramping rates** are sometimes constrained by local legislations in order to prevent sudden floods downstream of the plant.

Operational factors

Most of the Austrian RoR hydro plants are operated with a **head control** system. This system constantly measures the head by measuring the water level at the intake of the plant. When the head exceeds or falls below a prespecified head, the output of the turbines is automatically adjusted to a discharge level which will restore the water level that matches the allowed head. The head that needs to be maintained is set when requesting the building permit for a new hydro plant. This head control system is a way to ensure that river flow regimes are maintained. A large part of the Austrian RoR plants can thus only provide baseload generation due to this head control system.

RoR hydro units are also limited in flexible operation by **minimum and maximum production** levels. Hydro turbines have to be operated at a minimum capacity which equals the minimum design flow. When the turbine is operated below this minimum design flow, cavitation can occur. Cavitation is the formation of bubbles at the turbine blades, which causes pitting on metallic surfaces of the turbine (Kumar & Saini, 2010). Therefore, hydro units do not run below a minimum discharge level which depends on the type of turbine. Three types of turbines are the most used in RoR plants, which are

Kaplan, Francis and Pelton turbines[18]. The minimum discharge of a Kaplan, Francis and Pelton turbine should be 15%, 40% and 10% respectively of the nominal turbine flow rate. Furthermore, turbine efficiency significantly drops when the plant is operated at minimum or below the minimum flow design. Additionally, RoR operators do not always prefer to operate at maximum plant capacity because turbine efficiency is not optimal at its maximum capacity either.

The flexibility of the plant to start and stop is limited by **wear and tear**. Each time a plant starts or stops, the physical condition of the plant decreases. This is not a hard constraint applied by operators but it is an aspect which is considered when determining to dispatch the plant or not.

Cascade configurations[19] can provide flexible generation, but can limit flexible generation as well. Flexibility of RoR plants can be increased when RoR plants in a cascade are connected to an upstream reservoir. This reservoir can store water during moments of high inflow and release this water when inflows for pure RoR plants are low so that RoR plants are still able to generate. Also, some peak generation can be provided by the plans in the chain if the reservoir releases water, together the plants can provide some peak generation. If not connected to an upstream reservoir, the flexibility of the plants in a cascade system is limited and the plants can only generate whatever they receive from an upstream plant.

Regulatory factors
Flexibility in generation of RoR plants can be limited due to **navigation**. This is for example the case in the Netherlands where small hydro plants were built after the construction of ship locks. The main purpose of the river is navigation, the second purpose is hydro generation. Therefore, there is limited flexibility in deciding on when to generate.

Release from reservoirs in Sweden in summer months is constrained due to **recreational** use of the reservoirs. Sometimes **local legislations** also restrict plant operators to determine dispatch at will. An example of a very specific local legislation: when reservoirs are filled in the spring, it is not allowed to empty those again until autumn. This rule dates back to a long time ago, when the belief had arisen that the filling and emptying of reservoirs should follow a natural pattern. Another Swedish **legislation** is that for rivers with multiple plants owned by different operators, a regulation company is responsible for determining the discharge in that river. This is to make sure that all hydro plant on the river can compete on the electricity market. The discharge level is set by the regulating company, which limits the plants operators to increase or decrease generation.

Finally, there is another regulatory factor which limits RoR plants to completely shut down generation or to generate at nominal capacity. From an economic viewpoint it can sometimes be more profitable to reduce production levels or to keep the plant running so that capacity can be provided to the **balancing market**.

Summarizing
To summarize, this concise overview of factors affecting RoR hydropower flexibility shows that besides storage capacity and inflows, there are a lot of other constraints which are specific for each water course. It is hard to capture such detailed constraints in a simulation of the European power system as a whole. First, because it would significantly increase computational time and second, because it would require

[18] Generally Kaplan turbines are used for RoR plants with a low head (2-40 m) and a high flow rate, Francis turbines are used for RoR plants with middle head heights (10-700 m) and Pelton turbines are used for RoR plants with high heads (50-1300) and low flow rates (Marence, 2018).
[19] Multiple RoR plants in a succession on a river (Acker, 2011)

a lot of data gathering to include such details. However, most of these factors concern controlled river flows or technical limitations. Both of these aspects can be included in the power system model by imposing a minimum generation level on the plants.

4. Discussion

4.1. Limitations and uncertainties

As this study covers a large study region, the model complexity is limited in several ways to keep computational times within bounds:

- The linear relaxation optimization method has the disadvantage that constraints involving integer decisions such as the generator's minimum stable level and minimum up and down times cannot be enforced. This limitation affects the dispatch of thermal generators such as NGCC(CCS), GT, nuclear, PCC(CCS) and biothermal units, which usually face these constraints. The simulated generation by thermal power plants in this study might be more flexible than technically possible. As a consequence, total generation costs and CO_2 emissions can be underestimated because thermal generators can run below minimum stable levels and can be switched on for shorter periods. Furthermore, price peaks are presumably more extreme when minimum stable levels and minimum up and down times are enforced. The system will in some cases not be able to increase or decrease generation, resulting in dump energy or curtailed demand. When interpreting absolute numbers in this study (specifically the output of the power system simulations), all of the above must be taken into consideration. However, as this study analyses the difference between two model approaches (detailed and aggregated) by using the same optimization method, the main results are not expected to be different. Modelling the dispatchability of RoR plants is likely to result in more flexible and less baseload generation by other generators compared to an aggregated approach, regardless of the solving method used.
- Hydro cascade systems are not modelled in this study. As a consequence, hydro plants in a cascade can generate independently of each other. This simplification only affects cascades with small reservoirs. Cascade plants without reservoirs are forced to generate anyway and thus the timing of generation for these plants is accurate. Of the 126 plants within the geographical scope, 37 plants are part of a cascade and have a few hours storage capacity. For these 37 plants the simulated dispatch can be less accurate on an hourly time scale. The flexibility of the power system might be overestimated as plants can generate independently of each other, while in cascades usually all plants provide constant generation to keep the head constant for all plants to increase overall output, as mentioned by an RoR expert.
- The efficiency of RoR hydro plants is modelled as constant and is assumed to equal the maximum efficiency. In reality the efficiency of a hydro plant varies with changing head and generator discharge. Most of the RoR plants included in this study have Kaplan turbines. For these types of turbines the efficiency varies around 10% compared to the maximum efficiency depending on generator output, provided that the turbine is operated above minimum flow design (Mesa Associates & Oak Ridge National Laboratory, 2011). When the turbine is operated below the minimum flow design, generator efficiency reduces quickly to zero (Kaldellis, Vlachou, & Korbakis, 2005). Since efficiency curves are neglected for RoR plants in this study, the RoR generation potential might be overestimated.
- The operating range of hydro units is unconstrained in the power system model. However, as highlighted by RoR operators and experts, the operation of hydro units does face some technical constraints. The foremost constraint being the minimum generation level, which has to equal or exceed the minimum design flow. When the turbine is operated below the design flow, cavitation can occur. To prevent this from happening, the turbine is not operated below the

minimum flow design. The flexibility of hydro units is presumably overestimated in this respect.

Besides simplifications, there are also some uncertainties in data input:

- The hydrological inflow values used as input are monthly inflow values. This possibly affects the accuracy of the daily and hourly simulated dispatch of pure RoR plants because daily and even sub-daily discharges can fluctuate significantly as shown by daily river discharge data (National River Flow Archive, n.d.; Sistema Nacional de Informação de Recursos Hidricos, n.d.). However, the detailed data is not expected to affect the main results because the ability to regulate the generation by RoR plants does not change. Nonetheless, more detailed data might result in a more fluctuating RoR generation pattern, which has to be covered by more fluctuating generation by flexible generators.
- Uncertainty exists in the amount of RoR capacity modelled. As shown in Figure 7, different sources report different capacities. This study assumes 33 GW RoR capacity based on ENTSO-E (n.d.-a), while DNV GL reports double this capacity (66 GW). However, the geographic scope of the DNV GL report concerns Europe instead of EU-28 and Norway and Switzerland. Because DNV GL does not show a breakdown of RoR capacity per country, it is hard to say how much RoR capacity DNV GL includes for the same geographic scope as used in this study. The International Hydropower Association (IHA) reports a total hydro capacity of 193 GW for the geographic scope used in this study. When multiplying this total capacity by the share of RoR capacity of the total hydro capacity reported by ENTSO-E (22%), the RoR hydro capacity would be 42.6 GW. Compared to the assumed capacity of 33 GW, RoR generation could be underestimated by 27% at most. The impact of the dispatchability of RoR plants on power system flexibility might therefore be underestimated. However, in comparison to the total installed capacity, RoR capacity represents a relatively small share of the total generation mix. Therefore, the impact of the assumed RoR capacity on the power system as a whole is limited.
- Due to the large study regions, spatial smoothing occurs with the use of generation profiles for the rest plants in the detailed scenarios. As an example: the generation profile for the ITA region has most inflow during summer months. Italy, part of the ITA region, has different river regimes: rain fed and snow-fed. The northern parts are often reliant on snow-fed inflow and for these plants the ITA generation profile is a realistic approximation. For the plants located in more southern parts, the generation profile might be less accurate because plants located in Southern regions often have rain-fed catchments (François, Borga, et al., 2016). This simplification might have overestimated RoR availability during summer months and underestimated RoR availability during winter months. Furthermore, for Finland, which has considerable RoR capacity, no (usable) inflow values are found for the plants which are included in the database. Therefore, Finnish RoR capacity is excluded in the construction of the generation profiles, which reduces the accuracy of the generation profile of the SCA region.

4.2. Comparison with other studies

The generation profiles for RoR plants found in this study correspond for most regions to generation profiles found in the study by François et al., (2016b). However, there are some exceptions: the generation profiles for France and Great-Britain used by Francois et al, deviate from the generation profiles found in this study. There can be two reasons for this. First, the plants included in our study are located in other or more diverse areas than the regions chosen by Francois et al. (2016), resulting in varying predominating river flow regimes. Second, Francois et al. exclude contribution of upstream areas to river flow within the considered domain, whereas in this study river flows of upstream areas are included in the inflows of the hydro plants. Also the average inflow scenario across all RoR plants for which data is gathered in this research deviates from the average inflow scenario for RoR plants found by Gerritsma (2016). This can be attributed to two reasons. First, of the 10 RoR plants included in the study of Gerritsma, 6 plants are located in the HIS region. Plants in this region have rain-fed catchments, resulting in higher inflows in winter months. Second, although Gerritsma makes use of the same hydrological model (PCR-GLOBWB) to calculate natural inflow, inflow scenarios in that study are based on the period 1971-2000 whereas in this study we base the inflow scenarios on the period 1979-2015.

In line with previous research (Banfi, Filippini, & Mueller, 2005; Wagner, Hauer, Schoder, & Habersack, 2015; Zentrum für nachhaltige Energiesysteme, 2012) , this research found that RoR hydropower mainly provides baseload generation to the power system. Nonetheless, as the definition of RoR hydropower varies by different organisations, the RoR plants in the detailed database are not strictly pure RoR plants, but also RoR plants with (limited) storage capacity. These plants can provide some flexibility to the system by shifting generation a few hours, as shown by (Holttinen & Koreneff, 2012).

4.3. Contribution to established knowledge

This study contributes to established knowledge on run-of-river hydropower in Europe by the construction of a database containing details of technical and hydrological aspects of 126 European RoR plants. This database provides a comprehensive overview of 66% of Europe's RoR capacity. Future research on European RoR hydropower can benefit from this research by making use of this publicly available database. RoR hydropower can be modelled more accurately by using the generation profiles constructed for the regions within the geographical scope.

In contrast to previous studies, which focused mainly on the combined integration of iRES with storage hydropower, this study investigates the effect of a detailed representation of RoR dispatchability on the dispatch of other generating units in the power system. This more realistic representation of RoR capacity allows for a more reliable assessment of its flexibility potential. It is found that RoR capacity mainly provides baseload power and has limited potential for providing the flexibility which is increasingly needed in the European power system due to increasing penetration of iRES.

This study also contributes to the knowledge base of policy makers and electricity system providers. An analysis of the inter-annual variation of water availability for RoR generation showed that RoR generation is especially sensitive to drought. Modelling a dry inflow scenario showed that RoR generation may decrease as much as 28% (-28 TWh) compared to an average inflow scenario. This may decrease the profitability of operating these plants. Additionally dry weather will make it harder to meet emissions target set by European Commission for 2050. Due to decreased RoR generation, low-carbon (flexible) generation has to be provided by other more expensive generators which will be more costly to society. These outcomes can be considered in future capacity expansion planning.

4.4. Recommendations for future research

Future research could model the dispatchability of RoR units in even more detail by modelling aggregated RoR units and corresponding generation profiles per country, rather than per region. In this way the spatial smoothing is reduced. Additionally, future research can include a detailed representation of both European RoR and RSH capacity by combining the database compiled in this study and the database compiled in the study by Gerritsma (2016). Gerritsma highlighted that the generation potential of RSH units is also dependent on the inflow scenario used. Combining the detailed representation of European RoR capacity in this study with Gerritsma's (2016) detailed representation of RSH units would yield an even more realistic assessment of the flexibility limitations of Europe's hydropower capacity. This would require a further analysis of the inflow patterns for both studies, as they do not seem to match (4.2).

Finally, future modelling of hydropower could include a more accurate climate change induced inflow scenario by combining dry and wet conditions into one scenario, rather than assessing dry and wet conditions separately. Recent research highlighted that annual inflows are projected to decrease for Southern and South-Eastern European regions and projected to increase for Northern European regions (Van Vliet, Vögele, & Rübbelke, 2013). To account for these trends in a single natural inflow scenario, an inflow scenario could be constructed using low inflow values for Southern and South-Eastern Europe and high inflow values for Northern European regions and average inflow values for the remaining regions. Furthermore, seasonality of river flows is projected to change for most of Europe. The peak in daily average inflow is expected to occur earlier in the year than currently the case (Forzieri et al., 2014). A shift in the seasonality of river flows is neglected in this study and could be part of future studies.

5. Conclusion

This research investigates the dispatchability of European RoR hydropower capacity and evaluates its role in providing power system flexibility.

European RoR plants have limited storage capacity. For 84 out of 126 plants in the database information could be found on storage size. Of the 84 plants, 28 plants can be classified as pure RoR plants (less than two hours of storage) and the remaining 56 plants can be classified as pondage RoR plants (more than two but less than 400 hours of storage). Total storage capacity of RoR plants for which data is found amounts to 462 GWh. To give an impression of the magnitude: total European RoR storage capacity can buffer currently installed PV capacity in Germany (43 GW, (Frauenhofer ISE, 2015)) for 10 hours.

The availability of water for RoR generation varies throughout the year and this inflow pattern varies between different regions due to the geographical diversity of river regimes. RoR plants located in the British Isles (BRI) and the Iberian Peninsula (HIS) region have highest water availability in the winter months caused by rain, while plants located in the other regions receive most inflows in spring due to snow melt.

Accounting for the dispatchability of RoR plants in the power system shows that more flexibility is needed in the power system than an aggregated modelling approach implies. In reality, RoR plants are less dispatchable and provide more baseload power. This reduces the need for baseload generation by nuclear and NGCC-CCS plants and increases the need for flexible generation by GT and biothermal plants. As a result, total generation costs increase by 4% due to more expensive fuel costs for biothermal plants and increased start-up costs for GT plants. In addition, price peaks are more extreme due to an abundance of water availability during spring and scarcity of water availability in winter months. Considering these indicators we can conclude that the role of RoR plants in providing flexibility to the system is limited.

An analysis of inter-annual variation of water availability for RoR generation shows that RoR generation is more sensitivity to a dry inflow scenario than a wet inflow scenario. A wet inflow scenario only results in 3% more RoR generation compared to an average inflow scenario. This is because the increase in inflow in the wet scenario occurs in spring, which is the period in which inflows are highest in the average inflow scenario as well. The plants cannot process the additional inflow in the wet scenario and thus is the additional inflow mainly spilled by the plants. A dry inflow scenario decreases RoR generation by 20% (-28 TWh) compared to an average inflow scenario. This decrease in RoR generation is mainly covered by an increase in biothermal generation, to still be able to meet the emission target of 45 Mtonne in 2050. As biothermal capacity is expensive to dispatch due to high fuel costs, total generation costs increase by 4% compared to an average inflow scenario. In a future where climate change will play an increasingly important role and more extreme weather events are expected, these annual water availability fluctuations are important to consider as they require a more flexible power system.

Finally, interviews outcomes show that there are many factors, other than storage size and water inflow, which affect the dispatchability of RoR plants. These constraints are specific for each water course and thus it is hard to capture such details in a large scale power system such as the European power system. However, most of these factors concern controlled river flows or technical limitations of the plant. Both can be included in the power system model by imposing a minimum generation level on the plants.

The main implication of this research is that European RoR capacity has limited potential for providing the flexibility which is increasingly needed in the European power system due to the increasing penetration of iRES. Policymakers should consider the limited flexibility potential of RoR plants and especially its sensitivity to dry weather conditions, in expansion planning and investment decisions towards a carbon neutral power system in 2050. Future research on hydropower flexibility can build upon this work by making use of the constructed database. Combining this database with detailed modelling of other types of hydro plants would yield in an even more realistic assessment of the flexibility limitations of Europe's hydropower capacity.

6. References

Abrahamsson, O., & Håkanson, L. (1998). Modelling seasonal flow variability of European rivers. *Ecological Modelling*, *114*(1), 49–58. https://doi.org/10.1016/S0304-3800(98)00117-3

Acker, T. (2011). *IEA Wind Task 24 Integration of Wind and Hydropower Systems; Volume 1: Issues, Impacts, and Economics of Wind and Hydropower Integration* (Vol. 1). https://doi.org/10.2172/1033033

Arima, K. (2012). *Dispatch modelling : Quantifying long term benefits via high resolution analysis*.

Banfi, S., Filippini, M., & Mueller, A. (2005). An estimation of the Swiss hydropower rent. *Energy Policy*, *33*(7), 927–937. https://doi.org/10.1016/j.enpol.2003.10.015

Borges, C. L. T., & Pinto, R. J. (2008). Small hydro power plants energy availability modeling for generation reliability evaluation. *IEEE Transactions on Power Systems*, *23*(3), 1125–1135. https://doi.org/10.1109/TPWRS.2008.926713

Brandstätt, C., Brunekreeft, G., & Jahnke, K. (2011). How to deal with negative power price spikes?-Flexible voluntary curtailment agreements for large-scale integration of wind. *Energy Policy*, *39*(6), 3732–3740. https://doi.org/10.1016/j.enpol.2011.03.082

Brouwer, A. S., Van Den Broek, M., Seebregts, A., & Faaij, A. (2014). Impacts of large-scale Intermittent Renewable Energy Sources on electricity systems, and how these can be modeled. *Renewable and Sustainable Energy Reviews*, *33*, 443–466. https://doi.org/10.1016/j.rser.2014.01.076

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

Caralis, G., Papantonis, D., & Zervos, A. (2012). The role of pumped storage systems towards the large scale wind integration in the Greek power supply system. *Renewable and Sustainable Energy Reviews*, *16*(5), 2558–2565. https://doi.org/10.1016/j.rser.2012.01.068

Cochran, J., Miller, M., Zinaman, O., Milligan, M., Arent, D., Palmintier, B., … Soonee, S. K. (2014). Flexibility in 21st Century Power Systems. https://doi.org/10.2172/1130630

Deml, S., Ulbig, A., Borsche, T., & Andersson, G. (2014). The Role of Aggregation in Power System Simulation, (October).

DNV GL. (2015). *The Hydropower sector's Contribution to a sustainable and prosperous Europe*. Retrieved from http://www-wds.worldbank.org/external/default/WDSContentServer/WDSP/IB/1998/11/17/000009265_3980313101650/Rendered/PDF/multi0page.pdf

ECF. (2010). *Roadmap 2050; practical guide to a prosperous, low-carbon Europe*. https://doi.org/10.2833/10759

EDF. (2013). *Edf, european leader in hydroelectric power generation*.

EDP. (2004). *The Value of Hydro*. Retrieved from http://web3.cmvm.pt/sdi2004/emitentes/docs/FR16634.pdf

EEA. (2017). *Renewable energy in Europe — recent growth and knock-on effects*. https://doi.org/10.2800/123258

Egré, D., & Milewski, J. C. (2002). The diversity of hydropower projects. *Energy Policy*, *30*(14), 1225–1230. https://doi.org/10.1016/S0301-4215(02)00083-6

EIA. (n.d.). Glossary. Retrieved May 6, 2018, from https://www.eia.gov/tools/glossary/index.php?id=G

Energy Exemplar. (n.d.). *PLEXOS Applications*.

Engie. (n.d.). Hydropower. Retrieved May 20, 2018, from https://www.engie.com/en/businesses/electricity/hydropower/

Enipedia. (n.d.). Portal: Power Plants. Retrieved December 18, 2017, from http://enipedia.tudelft.nl/wiki/Portal:Power_Plants#All_the_world.27s_power_plants_in_a_single_database

ENTSO-E. (n.d.-a). ENTSO-E transparanency platform - Installed capacity per production unit. Retrieved January 22, 2017, from https://transparency.entsoe.eu/generation/r2/installedCapacityPerProductionUnit/show

ENTSO-E. (n.d.-b). ENTSO-E transparency platform - Installed capacity per production type. Retrieved December 10, 2017, from https://transparency.entsoe.eu/dashboard/show

ENTSO-E. (2015a). *Electricity in Europe*.

ENTSO-E. (2015b). Glossary. Retrieved January 10, 2018, from https://docstore.entsoe.eu/data/data-portal/glossary/Pages/home.aspx

ENTSO-E. (2017). Statistical Factsheet 2016. *Entso-E*, (April), 1–8.

ESHA. (2012). *Small Hydropower Roadmap*.

European Commission. (2012a). *Impact Assessment*.

European Commission. (2012b). Roadmap 2050. *Policy*, (April), 1–9. https://doi.org/10.2833/10759

Eurostat. (2018). Supply, transformation and consumption of renewable energies - annual data. Retrieved January 22, 2018, from http://ec.europa.eu/eurostat/web/energy/data/main-tables

Forzieri, G., Feyen, L., Rojas, R., Flörke, M., Wimmer, F., & Bianchi, A. (2014). Ensemble projections of future streamflow droughts in Europe. *Hydrology and Earth System Sciences*, *18*(1), 85–108. https://doi.org/10.5194/hess-18-85-2014

François, B., Borga, M., Creutin, J. D., Hingray, B., Raynaud, D., & Sauterleute, J. F. (2016). Complementarity between solar and hydro power: Sensitivity study to climate characteristics in Northern-Italy. *Renewable Energy*, *86*, 543–553. https://doi.org/10.1016/j.renene.2015.08.044

François, B., Hingray, B., Raynaud, D., Borga, M., & Creutin, J. D. (2016). Increasing climate-related-energy penetration by integrating run-of-the river hydropower to wind/solar mix. *Renewable Energy*, *87*, 686–696. https://doi.org/10.1016/j.renene.2015.10.064

Frauenhofer ISE. (2015). *Recent facts about photovoltaics in Germany*. *Fraunhofer ISE* (Vol. 1). https://doi.org/Fraunhofer ISE

Gerritsma, M. (2016). *Role of detailed hydropower modelling in investigating power system flexibility*.

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

Global Energy Observatory. (2018). Current List of Hydropower Plants. Retrieved from http://globalenergyobservatory.org/list.php?db=PowerPlants&type=Hydro

GWSP. (n.d.). Global Reservoir and Dam (GranD) Database. Retrieved December 12, 2017, from http://www.gwsp.org/products/grand-database.html

Hell, J. (2017). International Conference on Recent Trends in Physics 2016 (ICRTP2016). *Journal of Physics: Conference Series*, *755*, 011001. https://doi.org/10.1088/1742-6596/755/1/011001

Hentschel, J., Babić, U., & Spliethoff, H. (2016). A parametric approach for the valuation of power plant flexibility options. *Energy Reports*, *2*, 40–47. https://doi.org/10.1016/j.egyr.2016.03.002

Hirth, L. (2016). The benefits of flexibility: The value of wind energy with hydropower. *Applied Energy*, *181*, 210–223. https://doi.org/10.1016/j.apenergy.2016.07.039

Holttinen, H., & Koreneff, G. (2012). Imbalance costs of wind power for a hydro power producer in Finland. *Wind Engineering*, *36*(1), 53–68. https://doi.org/10.1260/0309-524X.36.1.53

Huertas-Hernando, D., Farahmand, H., Holttinen, H., Kiviluoma, J., Rinne, E., Söder, L., … Menemenlis, N. (2017). Hydro power flexibility for power systems with variable renewable energy sources: an IEA Task 25 collaboration. *Wiley Interdisciplinary Reviews: Energy and Environment*, *6*(1), 1–20. https://doi.org/10.1002/wene.220

Ibanez, E., Magee, T., Clement, M., Brinkman, G., Milligan, M., & Zagona, E. (2014). Enhancing hydropower modeling in variable generation integration studies. *Energy*, *74*(C), 518–528. https://doi.org/10.1016/j.energy.2014.07.017

IEA. (n.d.). Hydropower. Retrieved May 20, 2018, from https://www.iea.org/topics/renewables/hydropower/

IHA. (n.d.). Types of hydropower. Retrieved May 20, 2018, from https://www.hydropower.org/types-of-hydropower

IPCC. (2009). *Contribution to Special Report Renewable Energy Sources (SRREN), Chapter 5*.

IRENA. (2012). *Hydropower*. *Renewable Energy Technologies: Cost Analysis Series* (Vol. 1). Retrieved from http://www.irena.org/documentdownloads/publications/re_technologies_cost_analysis-hydropower.pdf

Kaldellis, J. K., Vlachou, D. S., & Korbakis, G. (2005). Techno-economic evaluation of small hydro power plants in Greece: A complete sensitivity analysis. *Energy Policy*, *33*(15), 1969–1985. https://doi.org/10.1016/j.enpol.2004.03.018

Kapsali, M., & Kaldellis, J. K. (2010). Combining hydro and variable wind power generation by means of pumped-storage under economically viable terms. *Applied Energy*, *87*(11), 3475–3485. https://doi.org/10.1016/j.apenergy.2010.05.026

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

Killingtveit, Å. (2005). European Hydropower Capacity – A Study of the Correlation Between the Scandinavian and the Alps Hydropower System European Hydropower Capacity – A Study of the.

Kiviluoma, J., & Holttinen, H. (2006). Impacts of wind power on energy balance of a hydro dominated power system. In *European Wind Energy Conference 2006*.

Kougias, I., & Szabó, S. (2017). Pumped hydroelectric storage utilization assessment: Forerunner of renewable energy integration or Trojan horse? *Energy*, *140*, 318–329. https://doi.org/10.1016/j.energy.2017.08.106

Krajačić, G., Duić, N., & Carvalho, M. da G. (2011). How to achieve a 100% RES electricity supply for Portugal? *Applied Energy*, *88*(2), 508–517. https://doi.org/10.1016/j.apenergy.2010.09.006

Kumar, P., & Saini, R. P. (2010). Study of cavitation in hydro turbines-A review. *Renewable and Sustainable Energy Reviews*, *14*(1), 374–383. https://doi.org/10.1016/j.rser.2009.07.024

Lannoye, E., Flynn, D., & O'Malley, M. (2012). Evaluation of power system flexibility. *IEEE Transactions on Power Systems*, *27*(2), 922–931. https://doi.org/10.1109/TPWRS.2011.2177280

Lee, C. H. (2014). Evaluation of the Performance Improvement for Application of Short Term Rainfall Forecast Data at Pondage Hydropower Plant, *1*(1), 73–75.

Marence, M. (2018). Turbines HERBD 08 – Storage and Hydropower.

Mesa Associates, I., & Oak Ridge National Laboratory. (2011). Best Practice Catalog Propeller / Kaplan Turbine, 1–28.

National River Flow Archive. (n.d.). Gauging Stations. Retrieved from https://nrfa.ceh.ac.uk/data/search

NOAA. (n.d.). Glossary of Hydrologic Terms. Retrieved December 7, 2017, from www.nws.noaa.gov/om/hod/SHManual/SHMan014_glossary.htm

Ott, R. F. (1995). Glossary of hydropower terms. In *Guidelines for design of intakes for hydroelectic plants*. New York: American Society of Civil Engineers. Retrieved from https://ascelibrary.org/doi/pdf/10.1061/9780784400739.bm

Rasmussen, M. G., Andresen, G. B., & Greiner, M. (2012). Storage and balancing synergies in a fully or highly renewable pan-European power system. *Energy Policy*, *51*, 642–651. https://doi.org/10.1016/j.enpol.2012.09.009

Sistema Nacional de Informação de Recursos Hidricos. (n.d.). Redes de Monitorização. Retrieved from http://snirh.pt/

Soliman, S. A.-H., & Mantawy, A.-A. H. (2012). Modern Optimization Techniques with Applications in Electric Power Systems. https://doi.org/10.1007/978-1-4614-1752-1

Statkraft. (2009). *Hydropower*. *Hydropower*. Retrieved from http://www.statkraft.com/Images/Hydropower 09 ENG_tcm9-4572.pdf

Stoll, B., Andrade, J., Cohen, S., Brinkman, G., & Brancucci Martinez-Anido, C. (2017). Hydropower Modeling Challenges, (April). Retrieved from http://www.nrel.gov/docs/fy17osti/68231.pdf

Sutanudjaja, E. H., Beek, L. P. H. Van, Wada, Y., Wisser, D., & De, I. E. M. (2017). Development and validation of PCR-GLOBWB 2 . 0 : a 5 arc min resolution global hydrology and water resources model. *Egu*, *16*(2013), 2013–2014.

Sutanudjaja, E. H., van Beek, L. P. H., Wanders, N., Wada, Y., Bosmans, J. H. C., Drost, N., … Bierkens, M. F. P. (2017). PCR-GLOBWB 2.0: a 5 arc-minute global hydrological and water resources model. *Geoscientific Model Development Discussions*.

van Beek, L. P. H., & Bierkens, M. F. P. (2008). *The Global Hydrological Model PCR-GLOBWB: Conceptualization, Parameterization and Verification*. *Department of Physical Geography*. Retrieved from http://vanbeek.geo.uu.nl/suppinfo/vanbeekbierkens2009.pdf

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*(3). https://doi.org/10.1088/1748-9326/8/3/035010

Verbund. (n.d.). Run-of-River Plants – A Reliable Power Supplier. Retrieved May 20, 2018, from https://www.verbund.com/en-at/about-verbund/power-plants/power-plant-types/run-of-river

Wade, A. (2017). How pumped hydro storage can help save the planet. Retrieved from https://www.theengineer.co.uk/pumped-hydro-storage/

Wagner, B., Hauer, C., Schoder, A., & Habersack, H. (2015). A review of hydropower in Austria: Past, present and future development. *Renewable and Sustainable Energy Reviews*, *50*, 304–314. https://doi.org/10.1016/j.rser.2015.04.169

Zentrum für nachhaltige Energiesysteme. (2012). Modeling Sustainable Electricity Systems for the Baltic Sea Region, (November), 37. Retrieved from http://www.znes.fh-flensburg.de/fileadmin/templates/multiflex4/Downloads/Reports/Sustainable_electricity_System_Baltic_Region.pdf

Appendix I

Table 9 - Overview of RoR hydropower definitions by different organizations

Category	Organisation	Definition of RoR
Plant operators	Verbund	"Run-of-river plants supply electricity reliably and generally without major fluctuations. They are therefore utilized in to cover majority of electricity consumption, known as the base load. Run-of-river plants do not have reservoirs to hold the water back" (Verbund, n.d.).
	Statkraft	"Hydropower schemes without reservoirs" (Statkraft, 2009, p1)
	EDF	"Run-of-river plants are used in order to meet normal day-to-day demand. These facilities do not have reservoirs and use some of the river flow to continuously generate electricity" (EDF, 2013).
	EDP	"Run of River: EDP has run of river plants (éclusees) have a storage capacity up to ~6 hours allowing to sell at peak hours over the day" (EDP, 2004, p3).
	Engie	"Run-of-the-river power plants which use the continuous flow of the water and provide a constant supply of basic energy" (Engie, n.d.).
Network of transmission system operators	ENTSO-E	"A hydro unit at which the head installation uses the cumulative flow continuously and normally operates on base load" (ENTSO-E, 2015b). Pure Run-of-river plants have 2 hours storage or less. Pondage plants have more than 2 hours storage, and less than 400 hours storage (ENTSO-E, 2015b)
Hydropower associations	IHA	"A facility that channels flowing water from a river through a canal or penstock to spin a turbine. Typically a run-of-river project will have little or no storage facility. Run-of-river provides a continuous supply of electricity (base load), with some flexibility of operation for daily fluctuations in demand through water flow that is regulated by the facility. These technologies can often overlap. For example, storage projects can often involve an element of pumping to supplement the water that flows into the reservoir naturally, and run-of-river projects may provide some storage capability." (IHA, n.d.).
Intergovernmental organizations	IRENA	"Run-of-river hydropower projects have no, or very little, storage capacity behind the dam and generation is dependent on the timing and size of river flows" (IRENA, 2012, p8).
	IEA	"Harness energy for electricity production mainly from the available flow of the river. These plants may include short-term storage or "pondage", allowing for some hourly or daily flexibility but they usually have substantial seasonal and yearly variations" (IEA, n.d.).

Appendix II

Table 10 - Data gathered for each RoR plant

Type	Unit	Additional information
Plant name	-	
Country	-	Country in which the plant is located
River	-	Name of the river on which the plant is located
Installed plant capacity	MW	The total installed capacity of the plant, also known as the rated or nominal plant capacity
Number of turbines	-	The number of turbines in the plant
Nominal flow rate turbines	m^3/s	The maximum flow through the turbines when the plants is operated at nominal capacity
Max generation time	h	At nominal capacity
Historic capacity factor	%	For a specific year or for several years, depending on data availability
Annual generation	MWh	For a specific year or for several years. Depending on data availability
Coordinates plant	Decimal degrees	The geographical location of the plant is used to match plants with the river network in the hydrological model
Head storage size	MWh or m^3	A head storage is the upper reservoir connected to a plant
Head storage GRanD ID		Identification number of the head storage in the GRanD database. This is an international database containing details on dams and reservoirs (GWSP, n.d.)
Active volume storage	m^3	The volume available for release from a reservoir below the maximum storage level. Also equals the maximum capacity minus the inactive storage capacity (NOAA, n.d.)
Average hydraulic head	m	The elevation difference between the upper and lower reservoirs (Ott, 1995).
Connected to another plant	-	Plants are connected when an upstream plant influences the generation pattern of a downstream plant. It will be indicated to which other plant the plant is connected, and if this other plant is located upstream or downstream.

Appendix III

PCR-GLOBWB 2.0 calculates river discharge for each grid cell for each time step (monthly basis). The spatial resolution of those cells is 5 arcminutes (about 10 km at the equator). River discharge is calculated by means of accumulating and routing all runoff components along the river network to the ocean or lakes and wetlands (van Beek & Bierkens, 2008). Runoff, which is the amount of water that leaves the catchment area for each cell, is generated by three components:

1. Surface runoff (precipitation and glacier melt)
2. Interflow (runoff from second soil reservoir)
3. Baseflow (groundwater runoff from the lowest reservoir)

See Figure 32 , for a visual representation of these flows. The meteorological data input for precipitation, temperature and reference evaporation are the CRU TS. 3.2., ERA-40 and ERA-interim data sets (Sutanudjaja, van Beek, et al., 2017).

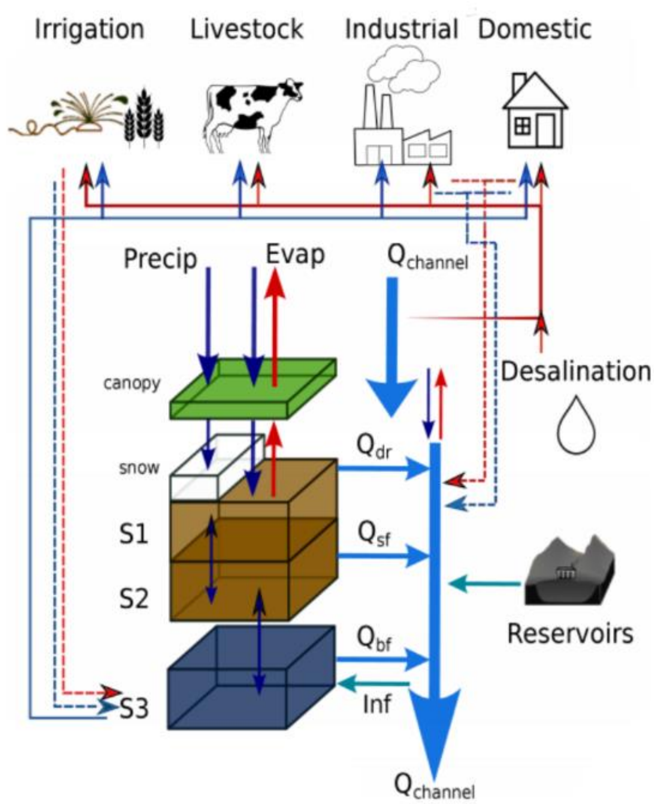


Figure 32 - Schematic overview of a PCR-GLOBWB 2 cell and its modelled states and fluxes. S1, S2 (soil moisture storage), S3 (groundwater storage), Qdr (surface runoff – from rainfall and snowmelt), Qsf (interflow or stormflow), Qbf (baseflow or groundwater discharge), Inf (riverbed infiltration from to groundwater). The thin red lines indicate surface water withdrawal, the thin blue lines groundwater abstraction, the thin red dashed lines return flows from surface water use and the thin dashed blue lines return flows from groundwater use surface. For each sector: withdrawal - return flow = consumption. Water consumption adds to total evaporation. Adapted from (Sutanudjaja, van Beek, et al., 2017).

Appendix IV

Storage size conversion
The following formula is used to determine storage size in GWh (adapted from Gerritsma (2016)):

$$E_{storage} = \rho\ g\ H\ V\ \eta\ C$$

Where:
E = energy content of the storage (GWh)
ρ = density of water (kg/m^3), assumed to be 1000 (kg/m^3)
g = gravitational acceleration (m/s^2), assumed to be 9.81 m/s^2
H = hydraulic head of the storage (m)
η = efficiency of the turbine (%), assumed to be 85% for RoR based on (Kaunda et al., 2012)
V = active volume of the storage (m^3)
C = conversion factor, $3.6*10^{-12}$ (J)

Natural inflow conversion
As the output of the PCR-GLOBWB 2.0 is in m^3/s per month, a conversion step is needed to create an energy value (MW) as input for Plexos. Natural inflow can be converted from m^3/s to MW using the following formula:

$$P = \rho\ Q\ g\ H\ \eta\ C$$

Where:

P = natural inflow into storage or turbine (MW)
ρ = density of water (kg/m^3) assumed to be 1000 (kg/m^3)
Q = water inflow (m^3/s)
g = gravitational acceleration (m/s^2), assumed to be 9.81 m/s^2
H = hydraulic head of the storage (m)
η = efficiency of the turbine (%), assumed to be 85% for RoR based on (Kaunda et al., 2012)
C = conversion factor, $1*10^{-6}$ MW

Appendix V

Table 11 - Interconnection capacity between regions, adapted from Brouwer et al. (2016). Note that significantly more (223.4 GW) is assumed from current levels.

Transmission line	Interconnection capacity (GW)
BRI ↔ GAL	12.8
BRI ↔ GER	4.9
GAL ↔ GER	19.9
GAL ↔ HIS	27.4
GAL ↔ ITA	13.1
GER ↔ ITA	6.6
SCA ↔ GER	9.8
EAS ↔ SCA*	8.4
GER ↔ EAS*	8.8
EAS ↔ ITA*	18.5
Total	260.4

*Interconnection between EAS and other regions was added in this study as East Europe is not included in the study scope of Brouwer et al. (2016). Source: (ENTSO-E, 2017). The transmission capacity is based on the largest transmission capacity to EAS or from EAS to or from a certain region, to make sure that there is enough transmission capacity for the added hydropower capacity.

Table 12 - Techno-economic parameters of hydropower plants. Adapted from Gerritsma (2016).

	Aggregated/rest RoR	Aggregated RSH	Aggregated PSH	Detailed RoR
Units	Table 13	Table 13	Table 13	Table 15
Max capacity	Average per region (table 13)	Average per region (table 13)	Average per region (table 13)	Per plant (table 15)
Max ramp up	4.1% of max cap	4.1% of max cap	4.1% of max cap	Max ramp reported or 4.1% of max cap
Max ramp down	4.1% of max cap	4.1% of max cap	4.1% of max cap	Max ramp reported or 4.1% of max capacity
Firm capacity	80% of max cap	80% of max cap	80% of max cap	80% of max cap
Pump load			Equal to max cap	
Pump units			1	
Pump efficiency			76	
Head storage			12.8 GWh[1]	Database
Tail storage			12.8 GWh[1]	
VO&M charge (€2012/MWh)	5	3 if max cap > 100 MW, otherwise 5	5	5
Annual max capacity factor (%)	49%[2]	50%		
Build cost ($€_{2012}$/kW)	5204	2037 if max cap > 100 MW, otherwise 3120	1389	5204
FO&M charge	1.5% of build cost	1.5% of build cost	1.0% of build cost if max cap > 100 MW, otherwise 1.5% of build cost	1.5% of build cost

Equity charge (€$_{2012}$/kW)	245.4	245.4	0	245.4
Forced outage rate (%)	5	5	-	5
Mean time to repair (hours)	50	50	-	50
WACC (%)	8	8	8	8
Economic life (years)	60	60	60	60

[1]It is assumed that head and tail storage size for lumped PSH is equal to 12.8 GWh as no distinction is made between large and small plants. Value is based on Geth et al. (2015), storage size large plants.
[2] Average historic annual capacity factor for all RoR plants in the database

Appendix VI

Table 13 – Specifications of hydro plants in the aggregated scenario.

	RSH aggregated plants			PSH aggregated plants			RoR aggregated plants		
	Total installed capacity (MW)	Installed capacity per plant (MW)	Units	Total installed capacity (MW)	Installed capacity per plant (MW)	Units	Total installed capacity (MW)[1]	Installed capacity per plant (MW)	Units[2]
BRI	153	153	1	3585	598	6	1292	38	34
GAL	5614	244	23	4955	826	6	4844	173	28
GER	870	435	2	9683	570	17	297	99	3
HIS	19062	578	33	7139	340	21	3208	214	15
ITA	9331	117	80	12798	376	34	12593	49	257
SCA	40411	72	562	1164	388	3	4743	31	153
EAS	5841	209	28	6627	414	16	6176	193	32
Total	81282	-	729	45951	-	103	33153	-	522

[1] Total installed capacity is based on the production unit list on the ENTSO-E transparency platform, and additional RoR plants found during data collection.

Table 14 - Specifications of RoR hydro plants in the detailed scenarios. RSH and PSH plants have the same specifications as in the aggregated scenario (see table 10)

	Detailed RoR plants			Rest RoR plants		
	Total installed capacity (MW)	Installed capacity per plant (MW)	Units	Total installed capacity (MW)	Installed capacity per plant (MW)	Units
BRI	231	Table 15	Table 15	1064	38	28
GAL	4483	Table 15	Table 15	346	173	2
GER	297	Table 15	Table 15			
HIS	2712	Table 15	Table 15	7889	49	161
ITA	4968	Table 15	Table 15	240	80	3
SCA	2621	Table 15	Table 15	2170	31	70
EAS	5360	Table 15	Table 15	772	193	4
Total	20672	-	Table 15	12481	-	268

Table 15 - Specifications of detailed RoR hydro plants. This table presents data of 126 plants. For the other 4 plants in the database (Imatra, Tainonski, Beeston, Gabcikovo, Beeston and Valeira), no usable inflows were simulated and therefore these plants are not modelled as detailed plants. The capacity of those plants is lumped with rest RoR plants.

Plant name	Country	Region	Installed plant capacity (MW)	Turbine units	Annual generation (GWh)	Storage size (GWh)
Iron Gate I	Romania	EAS	1166	6	5400	165,38
Plavinas	Latvia	EAS	884	10	1564	46,33
Saucelle	Spain	HIS	525	6	835	34,89
Zakucac	Croatia	EAS	486	4	1701	0,00
Cedillo	Spain	HIS	473	4	517	25,90
Picote I + II	Portugal	HIS	441	4	1113	2,30
Bemposta	Portugal	HIS	430	4	1058	2,28
Grosio	Italy	ITA	428	4	728	1,63
Genissiat	France	GAL	420	6	1700	8,69
Riga	Latvia	EAS	402	6	674	14,18

Miranda	Portugal	HIS	370	4	898	0.83
Conzere-Mondragon	France	GAL	348	6	740	0.01
Bitsch (Biel)	Switzerland	ITA	340	3	564	15.98
Kegums	Latvia	EAS	264	7	551	5.09
Ribarroja	Spain	HIS	263	4	287	12.94
Altenwörth	Austria	ITA	328	9	2004	3.23
Chastang	France	GAL	290	3	591	32.49
Greifenstein	Austria	ITA	293	9	1717	2.20
Aschach	Austria	ITA	287	4	1686	3.93
Kykkelsrud Fossumfoss	Norway	SCA	230	4	1265	0.00
Solbergfoss I	Norway	SCA	108	13	350	0.00
Solbergfoss II	Norway	SCA	100	1	550	0.00
Vamma	Norway	SCA	215	11	1350	0.00
Ybbs-Persenbeug	Austria	ITA	237	7	1336	1.87
Harrsele	Sweden	SCA	223	3	970	0.00
Vallabregues	France	GAL	210	6	1300	2.19
Wallsee-Mitterkirchen	Austria	ITA	210	6	1342	1.31
Carrapatelo	Portugal	HIS	201	3	806	1.03
Beauchastel	France	GAL	198	6	1211	0.00
Melk	Austria	ITA	187	9	1235	1.00
Pocinho	Portugal	HIS	186	3	408	0.52
Bourg-les-Valence	France	GAL	180	6	1082	0.00
Regua	Portugal	HIS	180	3	581	0.66
Ottensheim-Wilhering	Austria	ITA	179	9	1153	0.83
Gambsheim	France	GAL	100	4	656	0.00
Strasbourg	France	GAL	150	6	835	0.00
Gerstheim	France	GAL	140	6	815	0.00
Rhinau	France	GAL	150	4	940	0.00
Marckolsheim	France	GAL	150	4	920	0.00
Vogelgrun	France	GAL	140	4	820	0.00
Fessenheim	France	GAL	180	4	1020	0.00
Ottmarsheim	France	GAL	160	4	980	0.00
Kembs	France	GAL	160	6		0.30
Fratel	Portugal	HIS	132	3	358	1.13
Formin	Slovenia	EAS	116	2	548	0.30
Zlatolicje	Slovenia	EAS	126	2	577	0.34
Mariborski otok	Slovenia	EAS	60	3	270	0.07
Fala	Slovenia	EAS	58	3	260	0.03
Ozbalt	Slovenia	EAS	73	3	305	0.06
Vuhred	Slovenia	EAS	72	3	297	0.09
Vuzenica	Slovenia	EAS	56	3	247	0.06
Dravograd	Slovenia	EAS	26	3	142	0.12
Caderousse	France	GAL	156	6	843	0.00
Wloclawek	Poland	EAS	160	6	739	1.08
Mareges	France	GAL	272	5	338	8.93

Rheinkraftwerk Iffezheim	Germany	GER	148	5	870	0.00
Baix-le-logis-neuf	France	GAL	215	6	1177	0.00
Kvistforsens	Sweden	SCA	140	2	600	1.39
Freudenau	Austria	ITA	172	6	1052	1.10
Rheinfelden	Switzerland	ITA	100	4	600	0.00
Crestuma	Portugal	HIS	117	3	360	0.51
Timpagrande	Italy	ITA	214	3	224	0.00
Cedegolo	Italy	ITA	72	3	135	0.00
Korsselbranna	Sweden	SCA	130	4	428	0.00
Alvkarleby	Sweden	SCA	125	5	510	0.00
Della Nuova Biaschina	Switzerland	ITA	141	3	380	0.28
Piottino	Switzerland	ITA	72	3	300	0.10
Lotschen	Switzerland	ITA	122	2	330	0.29
Ryburg-Schworstadt	Switzerland	ITA	120	4	760	0.00
Laufenburg	Germany	GER	110	10	700	0.00
Sackingen II	Switzerland	ITA	74	4	485	0.00
Albbruck-Dogern	Switzerland	ITA	84	3	580	0.02
Reckingen	Switzerland	ITA	38	2	250	0.00
Verbois	Switzerland	ITA	100	4	466	0.60
Augst	Switzerland	ITA	32	9	200	0.00
Wyhlen	Germany	GER	39	11	255	0.00
Birsfelden	Switzerland	ITA	100	4	570	0.00
Lavey	Switzerland	ITA	93	3	402	0.00
Abwinden-Asten	Austria	ITA	168	9	1039	1.03
Jochenstein	Austria	ITA	132	5	850	0,00
Olidan	Sweden	SCA	104	10	1260	0.00
Hojum	Sweden	SCA	184	3	1000	0.00
Lilla Edet	Sweden	SCA	46	4	210	0.05
Boylefoss	Norway	SCA	65	8	400	0.00
Svelgfoss	Norway	SCA	96	2	541	0.00
Kaggefoss	Norway	SCA	88	4	590	0.00
Sarp	Norway	SCA	80	1	317	0.00
Borregaard	Norway	SCA	31	6	236	0.00
Hafslund	Norway	SCA	31	4	145	0.00
Ranasfoss III	Norway	SCA	81	6	303	0.00
Ranasfoss II	Norway	SCA	44	1	280	0.00
Bingsfoss	Norway	SCA	33	3	170	0.00
Kaunas	Latvia	EAS	101	4	349	1.91
Ardnacrusha	Ireland	BRI	86	4	332	0.00
Cliff	Ireland	BRI	20	2	0	0.00
Cathaleen's Fall	Ireland	BRI	45	2	206	0.00
Kendoon	Great Britain	BRI	21	2	65	0.11
Carsfad	Great Britain	BRI	12	2	0	0.05
Earlstoun	Great Britain	BRI	12	2	0	0.05
Tongland	Great Britain	BRI	33	3	0	0.07

Avise	Italy	ITA	126	5	285	5.28
Isola Serafini	Italy	ITA	76	4	484	0.00
Castelbello	Italy	ITA	87	4	369	0.01
Bressanone	Italy	ITA	120	5	515	0.00
Chateau-neuf-du-Rhone	France	GAL	295	6	1575	0.00
Avignon	France	GAL	176	6	857	0.00
Qouesques	France	GAL	124	4	280	8.43
Sablons	France	GAL	160	4	885	0.00
Passsy	France	GAL	109	4	379	1.59
Varazdin	Croatia	EAS	94	2	479	0.14
Cakovec	Croatia	EAS	76	4	389	0.43
Dubrava	Croatia	EAS	76	5	403	0.67
Slapy	Czech Republic	EAS	144	3	288	35.02
Krokstrommen	Sweden	SCA	103	3	523	0.43
Langstrommen	Sweden	SCA	57	4	265	0.06
Midskog	Sweden	SCA	155	3	725	1.08
Naverede	Sweden	SCA	70	4	292	0.01
Stugun	Sweden	SCA	47	4	159	0.02
Brezice	Slovenia	EAS	48	3	161	0.09
Krsko	Slovenia	EAS	40	3	146	0.02
Arto-Blanca	Slovenia	EAS	39	3	148	0.03
Bostanj	Slovenia	EAS	33	3	109	0.02
Kamyk	Czech Republic	EAS	40	4	92	0.41
Stechovice	Czech Republic	EAS	23	2	120	0.45
Vrane	Czech Republic	EAS	14	2	80	0.24
Total			20672	565	81412	462.17

Table 16 - Generation profiles for RoR rest plants for the detailed-average. Monthly capacity availability is found by dividing total inflow per month (MW) by the total installed capacity in the corresponding region.

	January	February	March	April	May	June	July	August	September	October	November	December
BRI	71%	71%	63%	52%	40%	31%	24%	22%	24%	32%	48%	64%
EAS	28%	30%	36%	41%	46%	46%	40%	34%	33%	32%	32%	30%
GAL	41%	41%	46%	57%	81%	82%	68%	50%	45%	45%	41%	42%
HIS	59%	53%	46%	44%	36%	17%	3%	1%	8%	35%	52%	59%
ITA	28%	29%	40%	52%	84%	96%	82%	65%	52%	45%	37%	32%
SCA	39%	37%	365	60%	100%	100%	66%	57%	56%	59%	50%	45%

Table 17 - Generation profiles for RoR rest plants for the detailed-dry. Monthly capacity availability is found by dividing total inflow per month (MW) by the total installed capacity in the corresponding region.

	January	February	March	April	May	June	July	August	September	October	November	December
BRI	61%	56%	48%	33%	27%	29%	23%	15%	12%	13%	24%	41%
EAS	32%	24%	28%	26%	34%	23%	27%	15%	17%	33%	32%	20%
GAL	55%	39%	35%	43%	54%	44%	28%	29%	17%	51%	29%	36%
HIS	100%	97%	75%	72%	35%	11%	3%	3%	8%	81%	80%	59%

ITA	41%	29%	39%	42%	76%	53%	50%	30%	24%	52%	33%	19%
SCA	26%	23%	26%	70%	100%	92%	44%	47%	43%	33%	35%	4%

Table 18 - Generation profiles for RoR rest plants for the detailed-dry. Monthly capacity availability is found by dividing total inflow per month (MW) by the total installed capacity in the corresponding region.

	January	February	March	April	May	June	July	August	September	October	November	December
BRI	70%	74%	61%	54%	47%	37%	26%	20%	19%	23%	37%	52%
EAS	30%	34%	46%	60%	64%	60%	28%	31%	29%	27%	38%	25%
GAL	43%	46%	62%	76%	100%	88%	92%	38%	35%	57%	48%	52%
HIS	75%	51%	100%	78%	51%	24%	5%	0%	4%	37%	28%	48%
ITA	31%	27%	33%	69%	100%	100%	66%	54%	52%	54%	43%	33%
SCA	88%	72%	59%	64%	100%	89%	50%	63%	33%	50%	41%	43%

Appendix VII

Introduction

- Thank you for cooperation, is it okay if I record this interview?
- Explain thesis project and purpose of interviews
- What is your position within this company?

Plant operation general

- Is the plant operated according to a predefined operation plan?
    - If yes: can you explain how is this established?
    - If no: how is the plant operated?
        - Are weather forecasts included in deciding when to generate for example?
        - Do you have much choice in how much to generate?
        - How do you deal with requests to generate more or less?

Environmental constraints

- Are there environmental policies in place which require the plant to operate within certain limits?
    - If so: what are those limits? (minimum amount of water that must be released/reservoir level restrictions/flow rate requirements?)
- Is the plant operated in a cascade configuration?
    - If so: how is this coordinated?

Operational constraints

- Is there a minimum or maximum amount of power that must be generated if the turbine is to be operated?
- Does the planned experience force outages often?
- How often does planned maintenance take place?

Regulatory constraints

- Is there a power purchase agreement in place?

Are there other factors which according to you significantly influence the flexibility of the operation of a RoR plant?

Appendix VIII

Table 19 - *List of interviewees*

Name	Position	Company
Jeremy Bricker	Associate Professor	TU Delft
Thomas Kropf	Generation and operation control	Verbund
Miroslav Marence	Associate Professor	IHE Delft Institute for Water Education
Martin Ulfstein Lund	Dispatch and planning of hydropower at Statkraft	Statkraft