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Implementing Hydropower Scheduling in a European Expansion Planning Model

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Problem Description

Due to concerns about a changing climate ambitious targets for greenhouse gas emission reductions have been set for the energy sector in Europe. In the electric power sector this naturally means that renewable energy sources (RES) will see an increased share in the total generation mix. As much of the new RES capacity will be wind and solar power, which are variable and non-dispatchable, we face a number of interesting challenges in terms of integrating this capacity. At NTNU and SINTEF there is an ongoing effort to develop models that can address issues such as optimal distribution of more intermittent generation capacity and required expansion of the transmission system in Europe. An investment model has been developed in Mosel Xpress for this purpose.

There is a need to improve the hydropower formulation in this investment model. The Master's thesis will be a continuation of a specialization project which proposed a basic, deterministic modeling structure for hydropower scheduling. This framework is the starting-point of the Master, where the representation is to be developed further by adding robustness and new features to the implementation. Such enhancements should include:

- Stochastic modeling of hydropower parameters
- Implementation of annual water values
- Investigation of run-of-the-river hydropower
- Coupling of normalized inflow and capacity investments
- Utilization of GCAM energy share data
- Examining and updating SINTEF hydropower data sets

Optimization runs shall be done to evaluate the impact of the expanded model, especially towards intermittent renewables.

Supervisor: Olav Bjarte Fosso
Co-supervisor: Christian Skar

Preface

This is the Master's thesis in a 5-year Master of Science program in Energy and Environmental Engineering at the Norwegian University of Science and Technology and the Department of Electric Power Engineering, spring 2014. The thesis is divided into two parts. The first part is a report with detailed descriptions of methodologies and results. The second part is an article that is currently under review for publication in Energy Procedia. The article is placed at the very end of the report.

Several persons have contributed to this thesis, and I wish to thank Olav Bjarte Fosso for the supervision and guidance of the work. Co-supervisor and PhD student Christian Skar deserves my gratitude for invaluable help throughout the semester. I would like to thank Leif Warland at SINTEF for providing necessary data sets. Programming guidance from Thomas Veflingstad and Emil Grunt is also much appreciated.

A special thanks goes to Anders Jerkø, Jørn Hole and the rest of my fellow students at the office. You have all kept the spirit high and we have shared both technical discussions and many laughs. Thank you.

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Abstract

This Master's thesis proposes a method for implementing an enhanced hydropower planning formulation in a long-term expansion planning model. The motivation for this work is the important role that hydropower plays in a generation investment environment. In a time where penetration of intermittent renewable energy sources like wind and solar power is heavily increasing, new challenges in the continuous balancing of supply and demand are also introduced. Hydropower and its use of reservoirs as power batteries can respond more or less immediately to such fluctuations. As such, a detailed framework for hydropower scheduling is highly relevant.

The presented implementation is carried out in an already-existing expansion planning model for Europe called EMPIRE, which is written in Mosel Xpress. This is a two-stage stochastic optimization model whose objective function is to minimize the total net present value of expected operational costs and investment costs for generation and transmission capacities.

The main feature of the proposed framework involves penalization of hydropower through water values. This necessitates a complete hydropower scheduling representation where each reservoir is divided into segments which are assigned a fictitious marginal cost. The inclusion of water values enables comparability with the short-run marginal cost for competitive technologies and introduces the important aspect of conserving water for other periods of the year. Data from SINTEF Energy Research has been used for this purpose.

Results from optimization runs in the time span from 2010 to 2060 for an EU 20-20-20 like policy scenario show that the original hydropower availability is too relaxed, thereby causing an overvaluation of this technology. The revamped cost representation by means of water values leads to a lower utilization of hydropower relative to the original model. An earlier deployment of solar power is carried out to replace the lower generation, with a capacity difference between the final and original models peaking at 45% in 2040. Total costs in the system are therefore increased. For both models extensive investments in intermittent renewables are taking place, amounting to 47% of the total capacity in 2060.

Sammendrag

Denne masteroppgaven fremlegger en metode for å implementere en forbedret formulering for vannkraftplanlegging i en langtidsmodell for kraftutbygging. Motivasjonen for arbeidet er den betydningsfulle rollen som vannkraft spiller i et investeringsmiljø for produksjonskapasitet. I en tid hvor utbredelsen av variable fornybare energikilder som vind- og solkraft er kraftig økende, introduseres samtidig nye utfordringer til kraftbalansen. Benyttelsen av magasiner som kraftbatterier gjør at vannkraft kan respondere mer eller mindre umiddelbart til slike svingninger. Et detaljert rammeverk for vannkraftplanlegging er derfor svært relevant.

Implementeringen gjøres i en eksisterende utbyggingsmodell kalt EMPIRE, som er skrevet i Mosel Xpress. Dette er en to-stegs stokastisk optimeringsmodell hvor objektivet er å minimere nettonåverdi av forventede driftskostnader samt investeringskostnader for produksjons- og overførings-kapasitet.

Hovedelementet i det introduserte rammeverket involverer å straffe bruk av vannkraft gjennom vannverdier. Dette krever en komplett beskrivelse av magasindisponering hvor hvert magasin blir inndelt i segmenter som tildeles en vannverdi. Slik er det mulig å sammenligne denne fiktive marginalkostnaden med korttidsgrensekostnaden til konkurrerende teknologier. I tillegg introduseres lagringseffekter av vann, noe som er svært viktig i slike planleggingsmodeller. Data fra SINTEF Energi AS har blitt brukt til dette formålet.

Resultater fra optimeringskjøringer for perioden 2010 til 2060 og et EU 20-20-20-lignende scenario viser at den originale tilgjengeligheten til vannkraft er for stor, noe som forårsaker en overvurdering av denne teknologien. Den reviderte kostnadssettingen ved hjelp av vannverdier fører til lavere bruk av vannkraft i forhold til den originale modellen. En tidligere utbygging av solkraft gjennomføres for å erstatte den reduserte produksjonen, med en maksimal kapasitetsforskjell i 2040 pålydende 45%. Dermed øker de totale systemkostnadene. Begge modeller gjør omfattende investeringer i variable fornybare energikilder, som i 2060 ligger på 47% av total kapasitet i Europa.

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Nomenclature

The EMPIRE Model

Table 1: Nomenclature for the original EMPIRE model, courtesy of Christian Skar.

Symbol	Description
Sets	
$\mathtt{N}$	Nodes (one per country).
$\mathtt{G}$	Generators. The set $\mathtt{G}_n$ is the set of all generators at node *n*.
$\mathtt{L}$	Transmission lines (exchange corridors) between neighboring nodes in the transmission system.
$\mathtt{A}_n^{\text{in/out}}$	Arcs to/from neighboring nodes in the transmission system. Note that for every line connecting two nodes in the transmission system there exists two arcs. These are used to represent directional flow.
$\mathtt{H}$	Operational hours. The set $\mathtt{H}_s$ is the set of all operational hours in season *s*. $\mathtt{H}_s^-$ is the set of all operational hours except the first hour in season *s*.
$\mathtt{S}$	Seasons (4 regular seasons with 24 hours and 5 peak load seasons with 5 hours).
Ω	Stochastic scenarios.
$\mathtt{T}$	Aggregate generation technologies (E.g. coal, gas, wind, solar, etc.).
Decision variables	
x_{gi}^{gen}	Investment in capacity for generator *g*, time period *i*.
x_{lj}^{tran}	Investment in capacity for transmission line *l*, time period *i*.
$y_{ghi\omega}^{\text{gen}}$	Generation on generator *g*, operational hour *h*, year *i*, stochastic scenario ω.
$y_{ahi\omega}^{\text{flow}}$	Flow on arc *a*, operational hour *h*, year *i*, stochastic scenario ω.
$y_{nhi\omega}^{\text{pump}}$	Energy used for pumping on pump *p*, operational hour *h*, year *i*, stochastic scenario ω.
$y_{nhi\omega}^{\text{LL}}$	Load shedding at node *n*, operational hour *h*, year *i*, stochastic scenario ω.

$w_{nhi\omega}^{\text{upper}}$ Water level upper reservoir for pump storage in node n, operational hour h, year i, scenario ω.

Parameters

δ_i Discount factor year i (at interest rate r this is $\delta_i = (1+r)^{-5i}$).

α_h Operational hour scale factor. This factor represents the total number of hours in a year represented by the operational hour h. Summing a variable/parameter scaled by α_h for all $h \in \mathrm{H}$ yields a yearly total. E.g., $\sum_{h \in \mathrm{H}} \alpha_h \xi_{nhi\omega}^{\text{load}}$ is the total electric energy consumption for node n in year i, scenario ω.

p_ω Probability of scenario ω for the stochastic parameters.

c_{gi}^{gen} Total cost (fixed and capital costs) incurred by investing in 1 MW new capacity for generator g.

c_{li}^{tran} Total cost (fixed and capital costs) incurred by investing in 1 MW new exchange capacity for line l.

q_{gi}^{gen} Variable costs (fuel + emission + O&M) incurred by producing 1 MWh of electric energy on generator g in year i.

q_{ni}^{VoLL} Cost of using load-shedding variable $y_{nhi\omega}^{\text{LL}}$.

$\xi_{nhi\omega}^{\text{load}}$ Load at node n in operational hour h, year i, stochastic scenario ω.

$\xi_{ghi\omega}^{\text{gen}}$ Available share of generation capacity for generator g in operational hour h, year i, stochastic scenario ω. Note that for thermal generation technologies and regulated hydropower the availability parameters are constant across all $\omega \in \Omega$. For intermittent resources such as solar and wind, this parameter represents normalized production values.

$\xi_{gsi\omega}^{\text{RegHydroLim}}$ Total energy available for generation in season s.

ρ_{gi} Retired share of generator g's initial capacity by year i.

γ_g^{gen} Limit on total upward ramping as a fraction of total installed capacity for generator g.

$\bar{x}_{g0}^{\text{gen}}$ Initial installed capacity generator g.

$\bar{x}_{l0}^{\text{tran}}$ Initial exchange capacity line l.

$\bar{x}_{tn*}^{\text{gen}}$ Upper bound on (period-wise/cumulative) investments in new capacity for generator g.

$\bar{x}_{l*}^{\text{tran}}$ Upper bound on (period-wise) investments in new exchange

	capacity line *l*.
η_a^{line}	Exchange losses on arc *a* (given as a share of the total flow).
η_n^{pump}	Pump efficiency for pump storage in node *n*.
hr_{gi}	Heat rate generator *g*, year *i*.
e_f	Carbon content fuel *f*.
EPS_{ni}	Emission performance standard node *n*, year *i*.

Hydropower Scheduling

Table 2 gives nomenclature for the hydropower scheduling. Nomenclature used by the hydropower formulations that is already defined in Table 1 is not included here.

Table 2: Nomenclature specific for the hydropower scheduling implementation.

Symbol	Description
Sets	
M_n	Set of reservoir segments.
G_n^{HydReg}	Set of regulated hydropower generators.
G_n^{HydRoR}	Set of run-of-the-river hydropower generators.
Decision variables	
$xd_{mnsi\omega}$	Discharge from segment *m* of node *n*'s reservoir in season *s*, year *i*, stochastic scenario ω [MWh].
$r_{nsi\omega}$	End-of-season reservoir level for node *n*'s reservoir in season *s*, year *i*, stochastic scenario ω [MWh].
$s_{nsi\omega}$	Spillage from node *n*'s reservoir in season *s*, year *i*, stochastic scenario ω [MWh].
p_{gi}^{gen}	Installed capacity for generator *g*, year *i*. Used for scaling of normalized inflow [MW].
Parameters	
N^{seg}	Number of segments in reservoir. Equal for all reservoirs.
$R_{ns\omega}^{init}$	Initial reservoir level for node *n*'s reservoir in season *s*, stochastic scenario ω [MWh].

$F_{ns\omega}^{init}$ Initial reservoir fraction for node n's reservoir in season s, stochastic scenario ω.

R_{n}^{max} Maximum reservoir level for node n's reservoir [MWh].

R_{n}^{min} Minimum reservoir level for node n's reservoir [MWh].

$R_{ns\omega}^{temp}$ Temporary reservoir level for node n's reservoir in season s, stochastic scenario ω. Used in procedure for setting actual segment size [MWh].

$U_{ns\omega}^{Reg,norm}$ Seasonal normalized inflow to node n's reservoir in season s, stochastic scenario ω [MWh].

$U_{ns\omega}^{Reg,init}$ Seasonal normalized inflow in 2010 (initial inflow) to node n's reservoir in season s, stochastic scenario ω. Used in procedure for setting actual segment size [MWh].

$U_{ns\omega}^{RoR,norm}$ Seasonal run-of-the-river normalized inflow for node n in season s, stochastic scenario ω [MWh].

S_{mn}^{max} Maximum segment size for segment m, node n [MWh].

$xd_{mns\omega}^{max}$ Actual segment size for segment m of node n's reservoir in season s, stochastic scenario ω [MWh].

$WV_{mnsi\omega}$ Water value for segment m of node n's reservoir in season s, year i, stochastic scenario ω [\$/MWh].

ϑ_{s} Seasonal scale factor for season s.

ϕ_{nti} Allow-build parameter. 1 if node n can invest in technology type t in year i, 0 otherwise.

χ_{g} Boolean. 1 if generator g is regulated hydropower, 0 otherwise.

T_{g} Integer. Technology type for generator g. Relevant values: 24 for regulated hydropower, 25 for run-of-the-river hydropower.

$\varsigma_{ns\omega}^{HydReg}$ Regulated hydropower generation in 2010 for node n in season s, stochastic scenario ω.

1 Introduction

The environmental impact of human activities has grown dramatically because of the sheer increase in world population, consumption and industrial activity [1]. During the past two decades, the risk and reality of environmental degradation have become more apparent. For this reason global policy scenarios have been developed, which introduce climate mitigation targets necessary to reduce man-made environmental impacts, herein global warming. The question is, however, *how* these policy scenarios can be met. EMPIRE[1] is a long-term expansion planning model aiming to help provide answers. It is an investment model that can take various policy scenarios as input and determine when, where and what types of generating units and transmission lines should be installed in Europe. This model is the point of departure in the Master's thesis.

The objective in this work is to improve the representation of hydropower in EMPIRE by implementing hydropower scheduling. Originally, EMPIRE models this technology as a stochastic, free (aside from low operation and maintenance costs) availability parameter, largely the same way as wind and solar power are represented. This is a simplification of real-world conditions, where the use of water values as fictitious marginal cost of hydropower generation is a widespread means of assigning monetary values to the available water resources. This is the main feature of the proposed implementation. Inflow, reservoir data and variables for reservoir levels will be used to couple discharge from each reservoir with actual generation from hydropower plants. One of the key purposes of implementing the more detailed hydropower representation is to analyze synergetic effects between installments of hydropower and investment possibilities for intermittent renewable energy sources.

Structurally, the thesis is composed of three main parts: Methodologies and background, model development and optimization results. Chapter 2 provides theoretical background on topics relevant for the problem and Chapter 3

[1] European Model for Power system Investment with (high shares of) Renewable Energy

describes the EMPIRE model, in order for the reader to gain a full comprehension of its properties. Chapter 4 introduces hydropower scheduling methodologies. The modeling to be described has spanned both the project work of autumn 2013 and the Master semester of spring 2014. Therefore, detailed descriptions of the alterations done in the latter are included in Chapter 5. Chapter 6 gives an overview of the final model with all changes implemented. Lastly, in Chapter 7 and 8 results with and without the enhanced hydropower formulation are presented, compared and discussed.

In the project thesis the basic modeling framework was developed and preliminary results were obtained. In the Master work the enhanced hydropower formulation is to be greatly improved: Uncertainty is addressed through stochastic modeling of hydropower parameters and decision variables; run-of-the-river hydropower gains a new representation; GCAM matching of generation mix is added; independent water values for each year are implemented; inflow parameters are made dynamic, changing with presently installed capacity; input data is thoroughly examined and corrected, and missteps in the previous code leading to suboptimal results are rectified.

Chapters 2 and 3 are mainly based on the project thesis. Since model descriptions, results, discussions and detailed explanations of the work carried out in the Master semester are included in this report, its length is fairly extensive.

All modeling in this thesis is performed with FICO® Xpress Optimization Suite.

2 Methodologies and Background

An overview of methodological frameworks and characteristics of main technologies is presented. It is important to understand the background and relevance of the problem and also the impacts in which intermittent renewable energy sources have on power systems and power markets.

2.1 Generation Expansion Planning

In its simplest description, generation expansion planning (GEP) is the process of determining what generating units should be constructed, at what size, and when they should be installed over a long-term planning horizon (usually over a scope of several decades) [2]. The two main objectives of the planning process are to minimize the total costs over the entire planning horizon and at the same time to ensure a reliable security of supply for all nodes in the system.

Thus, a generic form of a GEP problem can be formulated as follows [3]:

$$
\begin{aligned}
&\text{minimize } \sum_{p}\sum_{t} \mathit{investment\ cost}_{t,p} + \mathit{operational\ cost}_{t,p} \\
&\text{subject to} \\
&\sum_{t} \mathit{generation}_{t,p} = \mathit{demand}_{p}, \quad p \in \{\text{periods}\} \\
&\mathit{operation}_{p} \leq \mathit{maximum\ operation\ limits}_{l,p}, \quad l \in \{\text{technical, financial}\},\ p \in \{\text{periods}\} \\
&\mathit{investments}_{t} \leq \mathit{investment\ capacities}_{l,t}, \quad l \in \{\text{technical, financial}\},\ t \in \{\text{technologies}\}
\end{aligned}
$$

where t is generation technologies, p is operational periods and l is technical and financial limits. The objective is to minimize total costs summed over all operational periods and generation technologies. This shall be done whilst securing proper coverage of load in every operational period, and keeping the operation and investments of generating units within technical and financial limits. [4] describes a procedure for undertaking this process. This is presented in Figure 1.

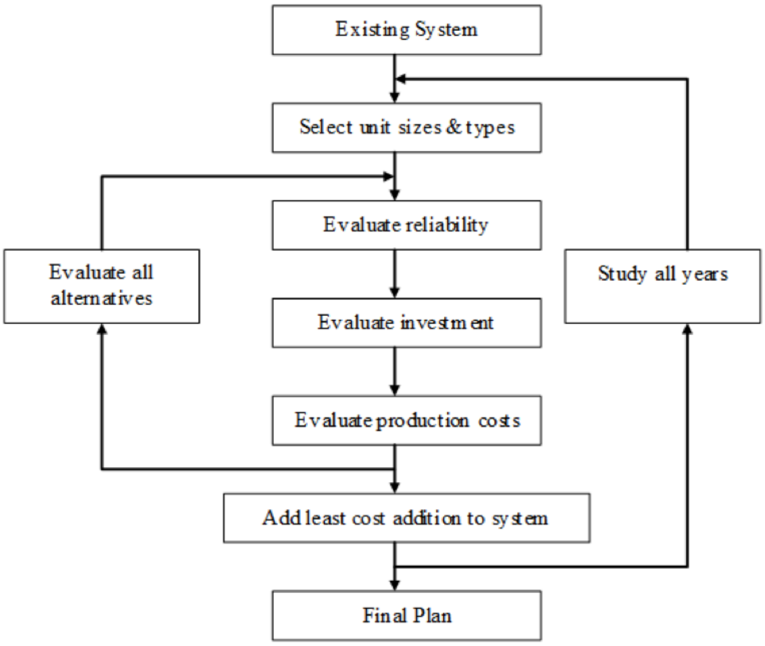


Figure 1: Generation expansion planning procedure [4].

Since deregulation of electricity markets the complexity of GEP has become higher [5]. [2] outlines some of the reasons why this has happened. First, the planning problem is exposed to more uncertainties via the input data (load forecasting, price, availability of fuels, transmission, governmental regulations etc.). Second, several conflicting objectives must be fulfilled in the planning process. Maximization of profit, maximization of system reliability, minimization of greenhouse gas emissions and minimization of investment risks could all be relevant objectives from a system's perspective. However, these objectives are difficult to coordinate or even conflicting with each other. Third, the large-scale integration of renewable energy has a profound impact on system reliability. This effect will be further discussed in Section 2.5.

The competitive nature of the power system after deregulation also introduces changes. Whereas traditional utility practice involves solving centralized planning problems that identify cost-minimizing plans for the utility, under competition multiple firms individually make investment plans intended to maximize profit [6].

All of these issues are increasing the complexity of GEP, and should be carefully handled when planning.

2.2 Transmission Expansion Planning

In addition to the provisioning of generating units the topic of transmission expansion planning (TEP) is also crucial to ensure supply reliability. [7] describes a procedure for how this can be done in a deregulated power system, given in Figure 2.

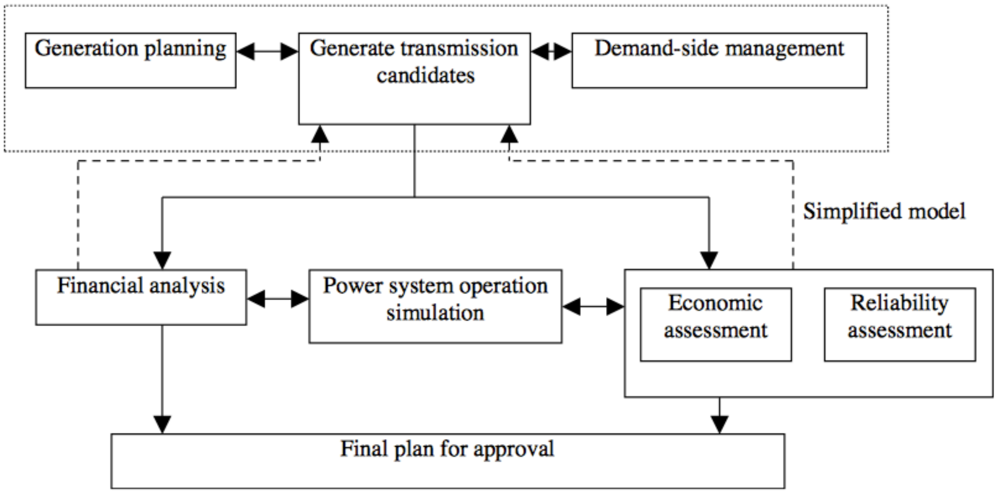


Figure 2: Transmission expansion planning procedure in the deregulated environment [7].

Generation expansion is useless without transmission lines capable of transferring generated power to demand locations. Therefore, from a system administrator's point of view, GEP should be coupled with TEP.

Transmission expansions can be justified if there is a need to build new lines to connect cheaper generators to meet the current and forecasted demand or if new additions are required to enhance the system reliability. Management of grid congestion is a very important issue in market design because [8]: (1) Inadequate handling of transmission constraints may lead to overload and system collapse. (2) Grid bottlenecks have market impact in the form of dissimilar power prices between areas. (3) Too low transfer capacity leads to an inefficient system. TEP should be carried out to minimize such problems.

It is important to stimulate enough transmission investments in order to relieve the transmission system's bottlenecks. Generation firms want to be able to deliver their resources; customers want low prices while society seeks to maximize the socio-economic surplus, which is the sum of producer surplus and consumer surplus. In the regulated world, one single decision maker is planning both generation and transmission, and can therefore acquire close to perfect information about load and generation. In deregulated systems, however, there are substantial uncertainties between generation information and load information. The merging of the generation and transmission investment objectives is therefore a highly complex task, especially in deregulated systems [2].

2.3 Combining GEP and TEP with a System's Perspective

For the analysis to be carried out in this thesis a system administrator's perspective is assumed, which is in possession of perfect information about load, costs and other necessary parameters. Impacts of market dynamics in deregulated systems are therefore not included, other than their influence on price predictions. As such, the model appreciates all nodes equally and whilst costs are to be minimized, load fulfillment is demanded for all nodes.

According to the International Energy Agency (IEA) the global energy demand is expected to increase by more than one-third from 2012 over the period to 2035 in their central scenario [9], led by rising incomes and populations in emerging economies. This foresight clearly justifies the efforts put into generation and transmission expansion planning.

2.3.1 Related Models

There exist a vast number of optimization models used for investment planning and policy studies in Europe. Recent notable examples of linear programming models, where new generation and transmission investments are co-optimized with a system dispatch, are presented in [10] and [11]. The former model has since been adapted to detailed studies of long-term grid extensions in Europe, see [12], and a study of decarbonization of the European power sector, see [13]. In [14] a dedicated hydropower scheduling model is used to compute water values for seasonal hydropower reservoirs, which are consequently used in a detailed DC load flow model of Northern Europe. This is similar to what is done in this thesis, although here the focus is on long-term system expansion.

2.4 A Changing European Power Sector

The portfolio of the European power sector is changing [15]. Figure 3 displays the development of new installations in EU for the last years. The share of annual installations of renewable energy sources has been steadily increasing, and since 2008 they have accounted for more than half of new installations. In 2013 the total installation of new generation was 35 GW. Wind power accounted for 32% (11.2 GW) while solar occupied 31% (11.GW) of new installations [15]. Altogether, wind and solar therefore accounted for almost two thirds of the new capacity installations in this year.

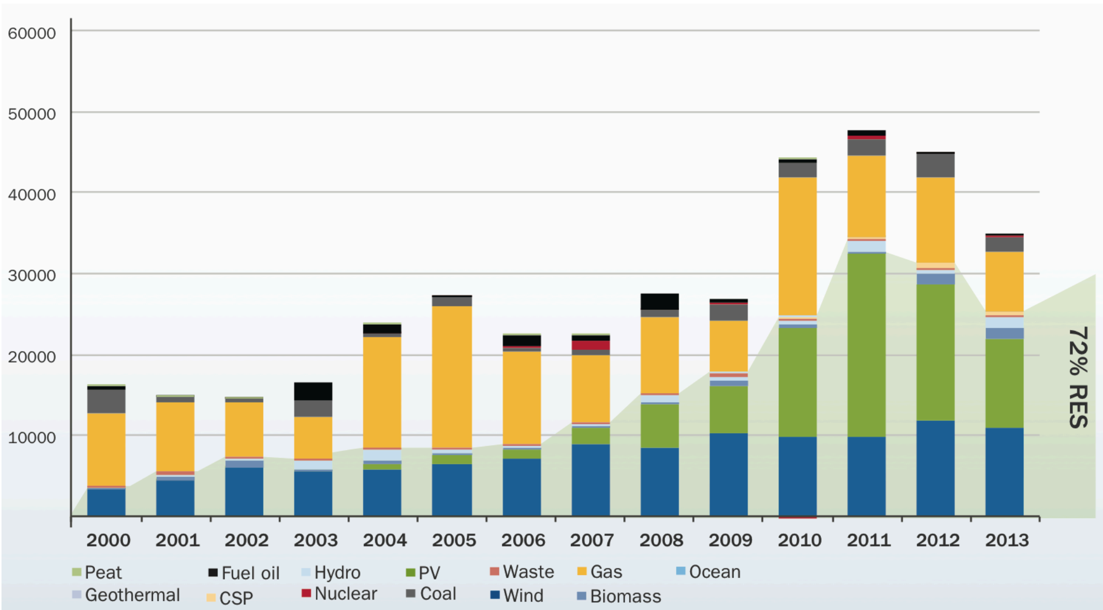


Figure 3: Annually installed generation capacity in MW for the EU region [15].

2.4.1 Incentives for Renewable Energy Sources

Several incentives for renewable power generation have been introduced in recent years to support the development of these energy sources. In general, the incentives can be divided into two main categories [16]:

- Investment-based incentives: Incentives that are proportional to the capital expenditure of the power plant.

- Production-based incentives: Incentives that are proportional to the actual generated amount of energy.

One possibility for production-based incentives is feed-in tariffs, where the producer is guaranteed a tariff per kWh produced for a specific period. This is different for each RES and is depending on the country [17]. Another possibility is the use of trading schemes. The EU Emissions Trading System is the largest in the world to date [18]. It is based on the "cap and trade" methodology, where an upper limit is set on the total emissions that can be emitted by all participating installations. Within this limit, companies can buy and sell emission allowances as needed. This indirectly gives producers incentives to invest in environmentally sustainable technologies. However, the system has been met with criticism, claiming that it fails to reduce emissions [19]. The critics claim that companies have consistently received generous allocations of permits to pollute, meaning they have no obligation to cut their CO_2 emissions.

Investment-based incentives (subsidies) provide awards for the initial investment. These will be implemented differently for each country.

2.5 The Need for Generation Flexibility

Intermittent renewable energy sources, comprising solar and wind (onshore and offshore) are henceforth termed iRES. Wave is also an intermittent renewable energy source, but because of its relatively small potential, wave energy is not further discussed. The continuous "fuel" availability of iRES (i.e. winds and solar radiation) is by nature not predictable and can change from full capacity generation to zero generation in a matter of seconds [20]. As described in the previous section the amount of generated energy from iRES has been growing significantly in the world for the last years, and is expected to continue to do so in decades to come [9]. This large-scale implementation of variable generation introduces additional variations in the power system, and thereby new challenges in the continuous balancing of supply and demand. Figure 4 exemplifies such variations by showing load and wind generation for a given period in Denmark.

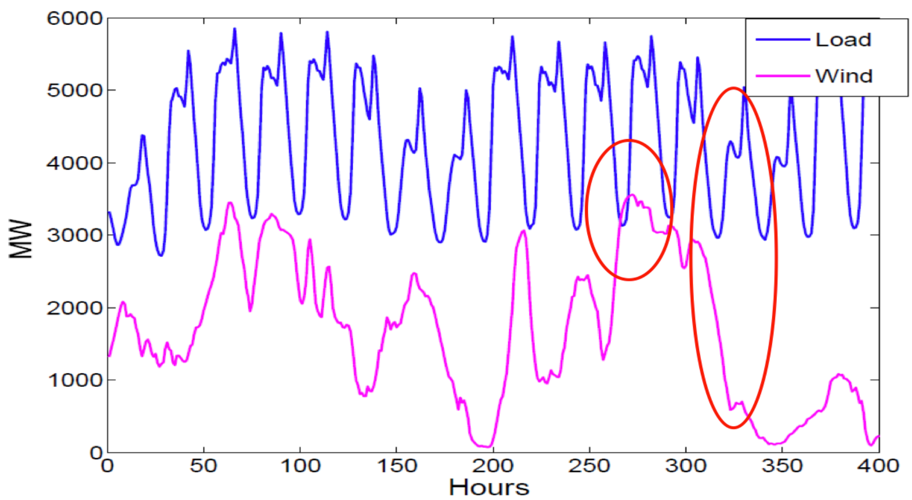


Figure 4: Comparison of power generation from wind and actual load in Denmark [17].

The figure highlights challenges regarding intermittency. In some few hours, wind generation covers the entire demand of Denmark and allows for export of the remaining power. More notably, in some hours the wind generation is very low compared to the load. In these hours the rest of the load is covered by other energy sources. The graph illustrates the underlying problem of intermittency: It is not possible to predict the power generation from iRES. A set of generating units that is predictable and has enough flexibility to cover the load when iRES do not produce as predicted is therefore needed.

2.6 Hydropower Characteristics

2.6.1 General Attributes

There are generally three types of hydropower plants: (1) Regulated hydroelectricity, based on reservoirs that function as "batteries", storing water inflow from rain and melting snow in large dams, giving the decision maker some extent of freedom regarding the timing of generation. (2) Run-of-the-river hydroelectricity, which offers little or no storage possibilities [21]. Such power plants are often used in coherence with reservoirs upstream. (3) Pumped storage, which can be used for load balancing [22]. Water is pumped from lower elevation reservoirs to higher elevation reservoirs during off-peak hours, and can thus be used for generation and sold during hours of peak demand. The focus in this report is regulated and run-of-the-river hydropower.

Hydroelectricity contributed to 16.1% of global electricity consumption by the end of 2010 [23], and is the largest renewable energy source as of 2013 [15]. The most important characteristic of regulated hydropower is the use of reservoirs. Figure 5 gives a typical curve of inflow and load demand throughout a representative year.

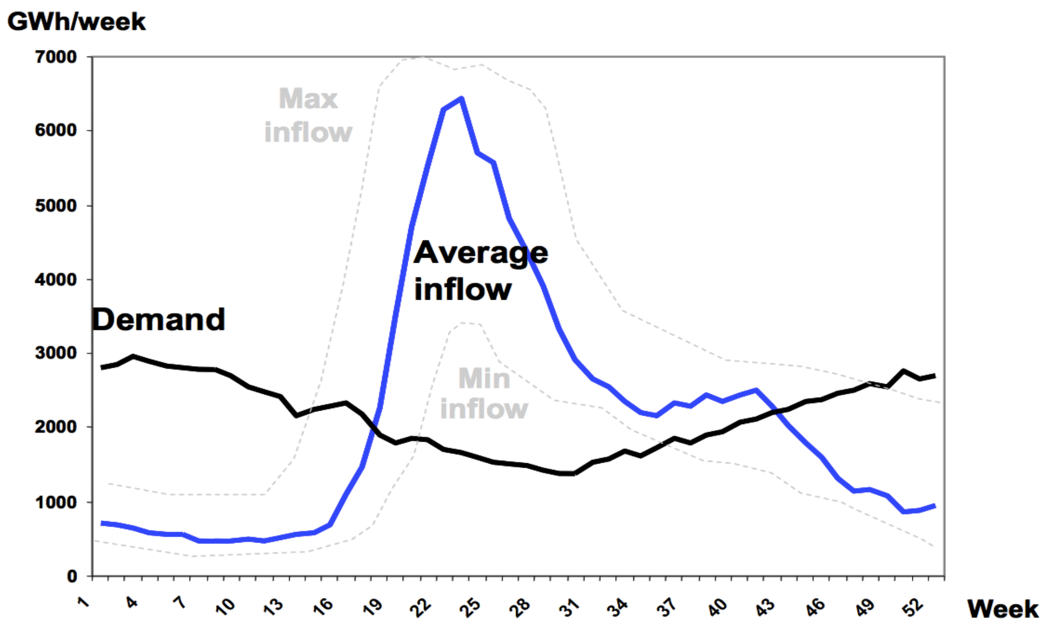


Figure 5: Typical hydropower inflow and power demand in a year [24].

As indicated, there are significant imbalances between the timing of peak demand and peak inflow to the reservoir in the course of a year. Most of the inflow takes place in late spring, while the demand peaks in the winter season. This illustrates the importance of being able to save water in reservoirs.

2.6.2 The Water Value

The water value is an extremely important component in the production planning of hydropower. It can be defined as the expected value of the stored marginal kWh of water [25]. In production planning, the objective is to plan the operation of the plant so as to maximize the expected value of production. Since the water has an alternative cost, it must be assigned a value to ensure that the available resources are spent wisely. The decision maker has two alternatives:

- Use the water for generation and sell the power to a known price today
- Keep it in the reservoir and store it for generation and sale at a later stage

In this manner, the water value can be seen as the fictitious marginal generation cost for hydropower, and is linked to the producer's evaluation of the future revenue opportunity. The general rule is therefore to generate when the water value is lower than the expected price, or save the water if the water value is higher than the expected price. Consequently, it is not sufficient to maximize the income only *during* the season, but it is also necessary to consider the future income that can be obtained from the stored water at the end of the season. As explained in [26], the size of a given reservoir is an important property. A large reservoir obviously gives the owner more choice or freedom with respect to deciding when to use the water than the owner of a small reservoir.

If a reservoir is completely full, the value of the next incoming unit of water is equal to zero, since this unit will be spilled if not used for generation. Using Figure 6 as an illustrative example, this logic implies that $WV_4 = 0$.

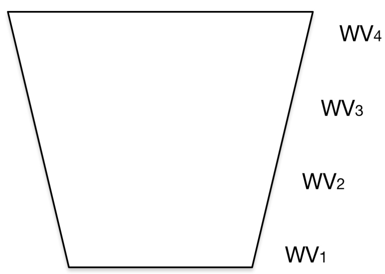


Figure 6: Reservoir and corresponding water values illustration.

The water value is increasing as the reservoir level is reduced, since the water becomes more valuable as the available amount decreases. Therefore, the following inequality must be true:

$$WV_1 > WV_2 > WV_3 > WV_4 \tag{2.1}$$

Figure 7 depicts a schematic of the development of the water value at different filling levels in the reservoir throughout the year [27].

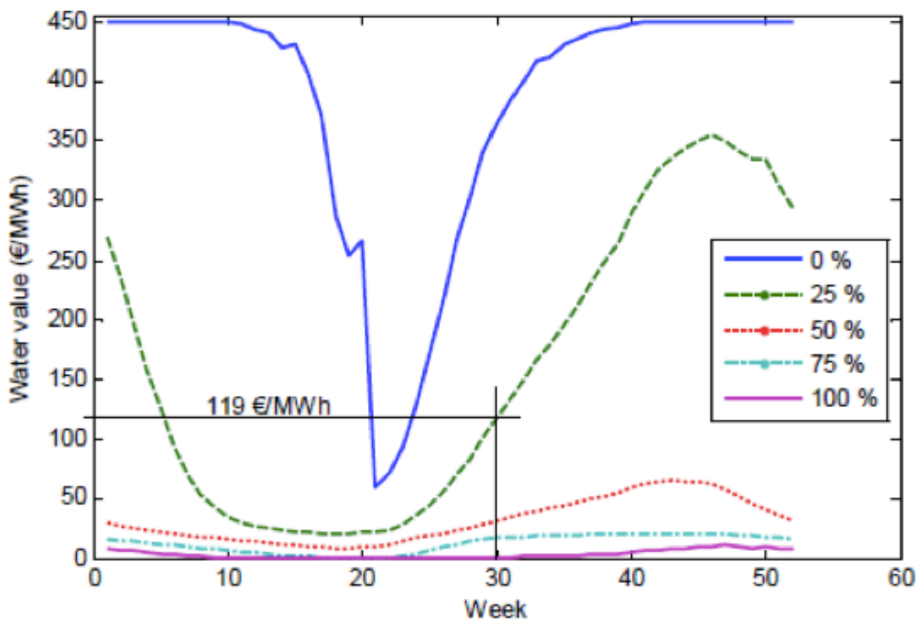


Figure 7: Typical water values throughout the year for different filling levels [27].

When the reservoir is empty (blue line), the water value is extremely high. As time goes by from week 1 towards week 20, spring inflow is entering the reservoir and the water value drops significantly because of the now-available generation resources. Moving towards winter the inflow is reduced and comes to a halt, and once again the water value surges. For a reservoir level of 25%

the same impact can be seen, however in a less dramatic manner. For other reservoir levels the impact is not very large.

2.6.2.1 Calculating the Water Value

According to [28], the water value can be calculated using the following methodology. The value of the water depends partly on how much electricity can be generated from the water and partly on which electricity prices can be expected when the power is sold:

$$WV_r(G_r^{Hyd}) = \theta_e G_{r,T}^{Hyd} \sum_{j \in G_r^{Hyd}} \gamma_j \tag{2.2}$$

where

$WV_r(G_r^{Hyd})$ = Value of the water stored in reservoir r

θ_e = Expected electricity price

$G_{r,T}^{Hyd}$ = Contents of reservoir r after the end of the planning period

γ_j = Expected future production equivalent in power plant j

G_r^{Hyd} = The set of indices for all power plants downstream of reservoir r (including power plant r itself)

The water value is dependent on the expected electricity price, which again is dependent on market conditions, expected generation mix and marginal costs of the generation units at that particular time. In other words, the water value is highly dependent on the costs of alternative generation. Calculating the water value is an iterative procedure and its methodology will not be further examined here. It is assumed that the water value for each reservoir has already been calculated, making it a parameter in the model [24]. The EMPS[2] model at SINTEF Energy Research is utilized for these computations [25]. This will be described further in later sections.

2.6.3 Flexibility

Regulated hydropower plants can respond more or less immediately to fluctuations in electricity demand [29], being able to place generated electricity on the grid faster than any other energy source [1]. This gives

[2] Multi-area Power market Simulator

hydropower an extreme level of flexibility. Together with the inherent storage capabilities of hydro reservoirs, this flexibility makes hydropower "*the most efficient and cost-effective way to support the deployment of intermittent renewables such as wind and solar power*" [1]. When intermittent energy sources generate less than forecasted, available hydropower can quickly deliver the missing supply and thereby function as an ancillary service that regains balance in the power system.

2.6.3.1 The Norwegian Role

Approximately 50% of all European hydro reservoirs are situated in Norway [17], making it the sixth largest hydropower producer in the world [30]. It is therefore relevant to examine how Norway can contribute to ancillary services with its hydropower flexibility. The expansion in use of pumped storage in Norway is suggested as part of the solution [31]. A German study on how Germany could procure all of its electricity from renewable resources by 2050 identifies Norwegian dams as the only realistic way to store large volumes of energy. [31] describes a study performed by Statkraft, aiming at quantifing the technical potential for pumped storage capacity in southern Norway. Excluding any future establishments of new reservoirs, the study estimated a capacity of 30 GW for a typical scenario that assumes reservoir levels can be changed by up to 50 cm per hour in the dams and that discharge can be distributed over five days. Stricter regulations can, however, reduce the potential ten-fold.

If Norway is going to be part of the solution by expanding pumped storage capacity, interconnections to the continent is a prerequisite. The Norwegian Transmission System Operator (TSO), Statnett, is already underway of planning and building such transmission expansions [32], but more has to be done in order to fully utilize the Norwegian battery.

2.7 Impacts of RES on Power Markets

The increased deployment of RES has impacts on power markets. Since the short-run marginal cost (SRMC) of RES, aside from biomass, is assumed to be close to zero because of no fuel requirements, these generators will be the first to produce if input is available. The remaining load that has to be purchased on the electricity markets is reduced correspondingly. Therefore, the guaranteed feed-in of RES-generated electricity has the effect of a reduced electricity demand. The reduced demand leads to lower prices. This is called the “merit order effect” since high-level integration of RES shifts the merit curve (the ranking of available energy sources in ascending order of their SRMC) [33]. This is equivalent of stating that the load demand is reduced, which is illustrated in Figure 8.

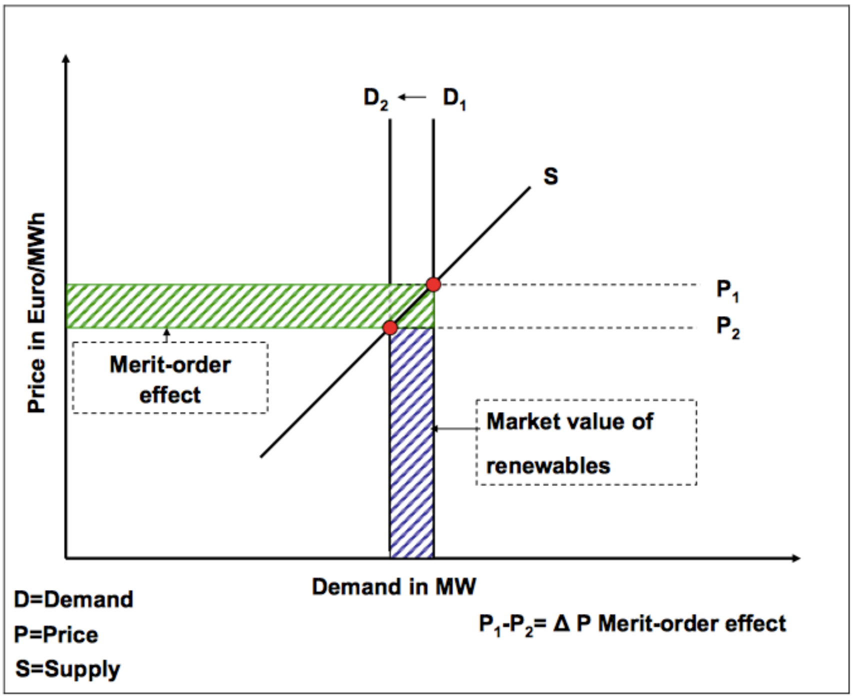
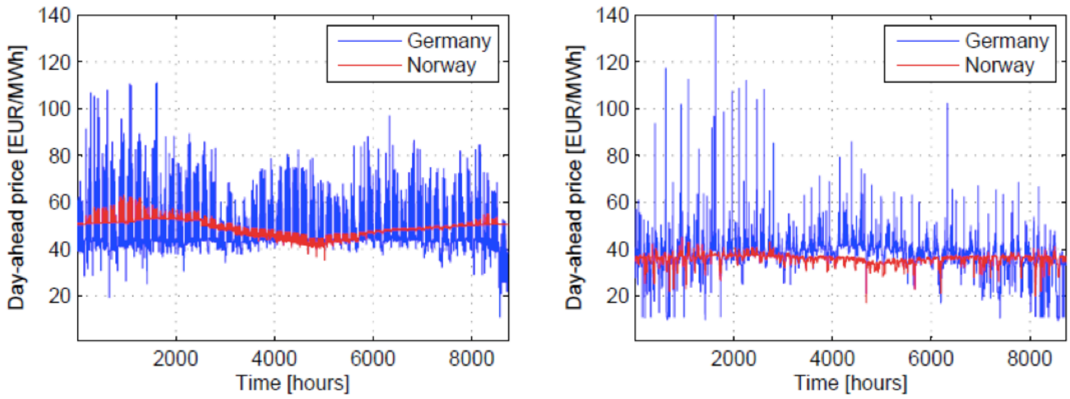


Figure 8: Merit order effect of introducing generation from RES in the power system [33].

RES generation of D_1-D_2 at zero marginal cost shifts the demand curve with an equal amount. This reduces the electricity price by ΔP from P_1 to P_2. The actual reduction of spot price is depending on bottlenecks in the transmission system and the prevailing generator portfolio.

Increasing the share of intermittent RES also leads to higher price volatility [27]. Because of the potential high forecast error when setting the day-ahead spot price, intraday balancing markets and reserve procurement by the TSO have to be utilized to a larger extent in order to adjust generation after the day-ahead market closure. Balancing power is usually measures associated with higher costs, since the next generator being put into the system has a higher marginal cost than the one setting the price. This leads to price fluctuations as depicted in Figure 9.



(a) 2010 (b) 2020

Figure 9: Price variations in the day-ahead market for Germany and Norway in 2010 and 2020 [27].

Germany has a high share of iRES, and its price fluctuations are consequently much larger than the ones seen for Norway (lower share of iRES). The figure illustrates that the volatility in both Germany and Norway is expected to increase in 2020 related to 2010, because of higher expected iRES penetration.

2.8 Linear Programming

The combined GEP and TEP problem introduced in later chapters is to be solved with commercial optimization software. The foundation for the algorithms used is linear programming, which implies that all equations describing the problem are linear. The classic general method for solving linear programs is the Simplex method, developed by George Dantzig [34]. The Simplex algorithm has been listed as one of the top 10 algorithms of the 20^{th} century [35].

2.8.1 Standard Formulation and Simplex Algorithm

The descriptions below are based on [36]. The aim of linear programming (LP) is to maximize or minimize an objective function, considering constraints consisting of inequalities and equalities. All variables are continuous in this general formulation.

An LP problem can be written in the following general form:

$$\min z = \sum_{j=1}^{n} c_j x_j \tag{2.3}$$

$$\text{s. t.} \quad \sum_{j=1}^{n} a_{ij} x_j \leq b_i, \quad i = 1,...,m \tag{2.4}$$

$$x_j \geq 0, \quad j = 1,...,n \tag{2.5}$$

where z is the objective function that depends on decision variables x_j. A solution that minimizes z is called an optimal solution and is generally denoted x^*. The above problem can easily be formulated as a maximization problem. To maximize $z_1 = f_1(x)$ is equivalent to minimize $z_2 = f_2(x) = -f_1(x)$ and it follows that $z_2^* = -z_1^*$. x is here given as a vector.

Depending on the functions and the problem structure, a large number of classes can be defined. For example, if there are no constraints we have an *unconstrained optimization problem* and if the objective function is quadratic and the constraints are linear we have a *quadratic optimization problem.*

The above problem is an *integer programming problem* when a subset of the variables (at least one) is defined as integer variables. These can be defined as only taking integer (discrete) values, $x_j \in \{0,1,2,...\}$, or as binary variables, $x_j \in \{0,1\}$. In both cases, the problem is called a *linear integer programming problem* if the objective function and constraints are still linear.

The intersection of a finite number of constraints builds a polytope, as in Figure 10, which is a convex set with a finite number of vertexes and edges [24]. Moving from line to line in the direction indicated by the arrow, a better result will be obtained.

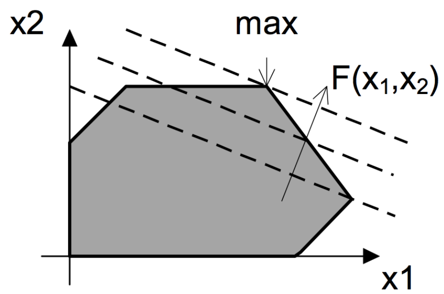


Figure 10: Feasible region and optimal solution of a linear program with two variables [24].

The Simplex algorithm is initiated by finding a feasible solution in a chosen starting point, and it then moves in the direction that increases (maximization problem) or decreases (minimization problem) the objective function the most. The optimal solution will always lie at the intersection between two constraints.

2.8.2 Newton-Barrier Method

Another method for solving optimization problems is the Newton-Barrier method, which is based on the Simplex theories. This is the method used for solving the EMPIRE model. A barrier function is a continuous function whose value on a point increases to infinity as the point approaches the boundary of the feasible region [37]. It is used as a penalizing term for violations of constraints. In the Barrier method, it is presumed that we are given a point x^0 that lies in the interior of the feasible region $\mathcal{F}$, and a very large cost on feasible points that lie ever closer to the boundary of $\mathcal{F}$ is imposed, thereby creating a "barrier" to exiting the feasible region.

The formal definition of a Barrier function is as follows [38]. A barrier function for problem P is any function $b(x): \mathfrak{R}^n \rightarrow \mathfrak{R}$ that satisfies

- $b(x) \geq 0$ for all x that satisfy $g(x) < 0$, and
- $b(x) \rightarrow \infty$ as $lim_x max_i \{g_i(x)\} \rightarrow 0$.

The idea is to dissuade points x from ever approaching the boundary of the feasible region. The Barrier Convergence Theorem defines the way Barrier method finds the optimal solution of a problem P:

Suppose $f(x)$, $g(x)$ and $b(x)$ are continuous functions. Let $\{x^k\}$, $k = 1,\ldots,\infty$, be a sequence of solutions of $B(c^k)$. Suppose that there exists an optimal solution x^* of P for which $N(\varepsilon, x^*) \cap \{x \mid g(x) < 0\} \neq \varnothing$ for every $\varepsilon > 0$. Then any limit point $\bar{x}$ of $\{x^k\}$ solves P.

2.8.3 Deterministic vs. Stochastic Programming

When formulating a basic linear programming model, one acts as if all data elements are known quantities [39]. This is called deterministic programming, where the modeler assumes that there is only *one* definite value that each parameter or decision variable can take. However, in many real-world situations, one parameter can take several values. One example that is relevant for this model is future demand. Today, it is naturally impossible to point out exactly what the demand in a given hour in five years will be. How can this be taken into account by an optimization program?

Stochastic linear programs are linear programs in which some problem data may be considered uncertain [40]. Data uncertainty means that some of the problem data can be represented as random variables. As outlined by [40], an accurate probabilistic description of the random variables is assumed available, under the form of probability measures. Thus, the set of decisions is divided into two groups:

- First-stage decisions: Decisions that have to be taken before the stochastic experiment. The period when these decisions are taken is called the first stage.
- Second-stage decisions: Decisions that can be taken after the experiment. The corresponding period is called the second stage.

A stochastic model will find one solution for each stochastic scenario. The final solution after the second stage will then be weighted with respect to the probabilities that each scenario is assigned.

The EMPIRE model makes use of stochastic programming in order to address uncertainty.

2.9 Software Tools

The high-level commercial software FICO® Xpress Optimization Suite is being utilized for the implementation of the system and its corresponding mathematical model, using the programming language Mosel [41]. The model is implemented using Xpress-IVE v1.24.02, a visual development environment for Xpress-Mosel. The Xpress-MP Optimizer v7.6.0 is used to embed and solve the model. The Mosel language is a procedural programming language that allows formulation of equations close to the original algebraic notations [42]. In Mosel, there is no separation between a modeling statement (e.g. declaring a decision variable or expressing a constraint) and a procedure that actually solves the problem (e.g. call to an optimizing command). Thanks to this synergy, one can program a complex solution algorithm by interlacing modeling and solving statements. Mosel offers a dynamic interface to external solvers provided as “modules”. Each solver module comes with its own set of procedures and functions that directly extends the vocabulary and capabilities of the language. Two modules are used in this thesis. “mmxprs” gives access to the Xpress solver while “mmodbc” allows access to databases and spreadsheets that define an ODBC[3] interface using standard SQL[4] commands [42].

An optimal solution is found by Xpress-MP, which is software solving linear, continuous, quadratic, integer and mixed-integer programs. Simplex and Branch & Bound algorithms are applied to solve problems to optimality [43]. It follows from the definition of linear programs that both the objective function and all constraints must be linearly formulated.

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[3] Open DataBase Connectivity

[4] Structured Query Language

2.10 Climate Mitigation Scenarios

The EMPIRE model has the ability to use different input data to analyze individual policy scenarios. The scenarios will depend on what the modeler wants to find out. By altering the input parameters, virtually any aspect of the generation expansion can be controlled. One scenario might for instance look at the impacts of increased CO_2 prices. Another can set investment limits for a specific technology. Scenarios might also include more severe changes to the data sets. The 650 ppm and 450 ppm scenarios describe policies required to stabilize the atmospheric concentration of CO_2-equivalents at 650 and 450 parts per million (ppm) by volume, respectively. Only the 450 ppm scenario limits the temperature rise to 2°C at the end of the 21st century [44]. Demand, fuel prices, CO_2 prices and availability of certain technologies like Carbon Capture and Storage (CCS) have to be changed in order to implement such scenarios. The actual scenarios are not the main focus of this report, but the importance of modeling them should not be underestimated. As [45] puts it:

"Given current estimates of the relationship between GHG concentrations and global temperature change, stabilizing atmospheric concentrations of carbon dioxide (CO_2) at 450-650 parts per million (ppm) by volume significantly reduces the expected change in global average surface temperature and associated impacts relative to baseline projections for increased GHG concentrations."

Another comprehensive scenario is Global 20-20-20 [46]. This is an extension of the EU 20-20-20 scenario, which is outlined in EU Directive 2009/28/EC, defining a four-split goal [17], [47]: (1) Reduction of GHG emissions by 20%; (2) 20% of the gross final energy consumption shall originate from renewable energy sources; (3) Increase energy efficiency by 20% and (4) 10% of transportation energy shall come from renewables. All of these goals are to be reached within 2020. Global 20-20-20 features extensions of these targets to a global spatial scope, and a prolonged temporal scope. Emissions in this scenario lie between the 650 ppm and 450 ppm scenarios [44].

In this thesis, the Global 20-20-20 scenario will be used.

3 The EMPIRE Model

3.1 General Description

EMPIRE is an advanced capacity investment model for the European power sector, developed by PhD student Christian Skar at NTNU. Its purpose is to provide a long-term plan for timing, size and location of investments in generation capacity and trans-boundary transmission capacity. This objective can be undertaken for policy scenarios defined by climate mitigation targets or other criteria, as described in Section 2.10 [48], [49]. Technology costs, demand projections, CO_2 prices, technology availability and a wide range of other parameters are used as input in EMPIRE. Together with constraints and objective function definitions, these parameters are used in simulations in order to provide an expansion plan that meets the given policy scenario at the lowest possible costs. EMPIRE is formulated as a two-stage stochastic optimization model. The decisions taken in the first stage are investments in generation and transmission capacity, and are not subject to stochastic behavior. The second stage includes decisions for hourly generation for each stochastic scenario.

EMPIRE has previously been used in notable projects at SINTEF and in EU. The former utilized the model in its LinkS project, which is an effort to link global and regional energy strategies [50]. The EU-supported project called Zero Emissions Platform (ZEP) focuses on transitional measures to help deployment of CCS in the European power sector [51]. EMPIRE was utilized in the market economics working group of ZEP.

Most of the principal assumptions of EMPIRE also apply to the hydropower scheduling and understanding the model's strengths and simplifications is therefore useful. For this reason, the general model is granted a fair amount of space in the following sections.

3.1.1 Spatial and Temporal Scopes

The spatial system boundaries of the model comprise the following countries in alphabetical order: Austria, Belgium, Bosnia & Herzegovina, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Great Britain, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Macedonia, the Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden and Switzerland. In this analysis a temporal scope from 2010 to 2060 is used. This is also referred to as the planning period.

3.1.2 Model Characteristics

Various assumptions are incorporated in order to simplify conditions to a system that is practically possible to model within an acceptable amount of time.

3.1.2.1 Simplifications

Because of the extensive spatial and temporal scopes of the model, simplifications are necessary. The spatial resolution of the model is therefore based on country-wise aggregations, where each country is given one aggregated load value and one generator for each generation technology (supposed that the country supports installments of the specific technology). Each country has only one transmission line connecting it to each of its surrounding countries.

As mentioned, the temporal resolution of the model spans from 2010 to 2060. Only the years 2010, 2015, ..., 2060 is actually being modeled in order to reduce the problem size. Investments in generation and transmission capacity are limited to taking place in these years. Each year consists of ten time periods or seasons, which are split into two categories: Regular and peak-load seasons. Four seasons are considered regular, while the remaining six are considered peak-load. The duration of each regular season is 24 hours, and the duration of each peak-load season is 5 hours. These categories are also weighted differently towards the yearly total. The regular seasons are scaled to comprise almost the entire duration of each year, 8750 of 8760 hours, and the peak-load seasons comprise the remaining 10 hours.

Seasons are not consecutive in time, i.e. each season is modeled individually of the others. The time span of each season means that only 4·24 + 6·5 = 126 hours of 8760 hours during a year is actually modeled. Modeling each hour will give unacceptable computation times. Instead, optimal dispatch in these ten seasons are found and scaled to represent the entire year. In order to account for different operational conditions, seasons are dispersed throughout the year. An additional scaling factor takes the five-year leap between the modeled years into account. Figure 11 summarizes how each year is represented in the model.

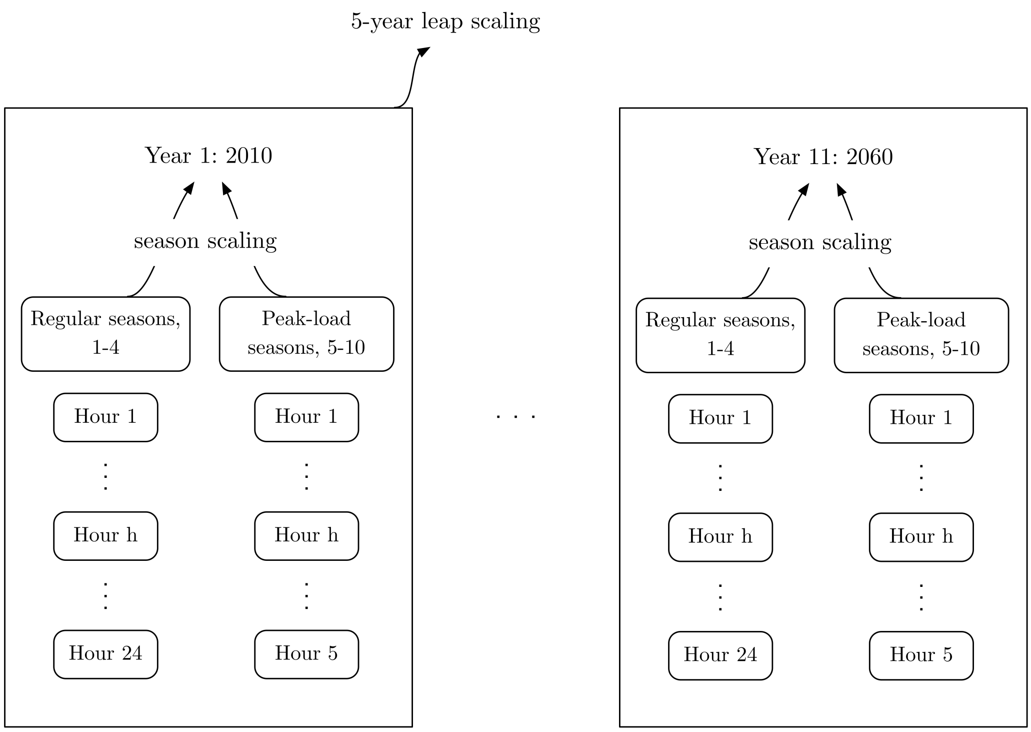

Figure 11: Representation of each year in the EMPIRE model.

3.1.2.2 Stochastic Scenarios

In order to account for uncertainty some parameters are modeled stochastically. This includes the parameters that are variable by nature and that cannot be said to take *one* exact value with 100% probability. The stochastic parameters include hourly load, hourly generator availability and hourly generation from wind, solar and hydropower.

The model can be run with two independent data sets: Three scenarios or ten scenarios. For each scenario, the stochastic parameters take a different value. An optimal generation mix is determined for each of these scenarios, and the final solution is found from a probability distribution between them. Running the model with ten scenarios accounts for uncertainty more than three scenarios do, but this also increases computation durations and requirements for computer hardware on which the model is run.

Figure 12 depicts the two stages in the stochastic optimization model.

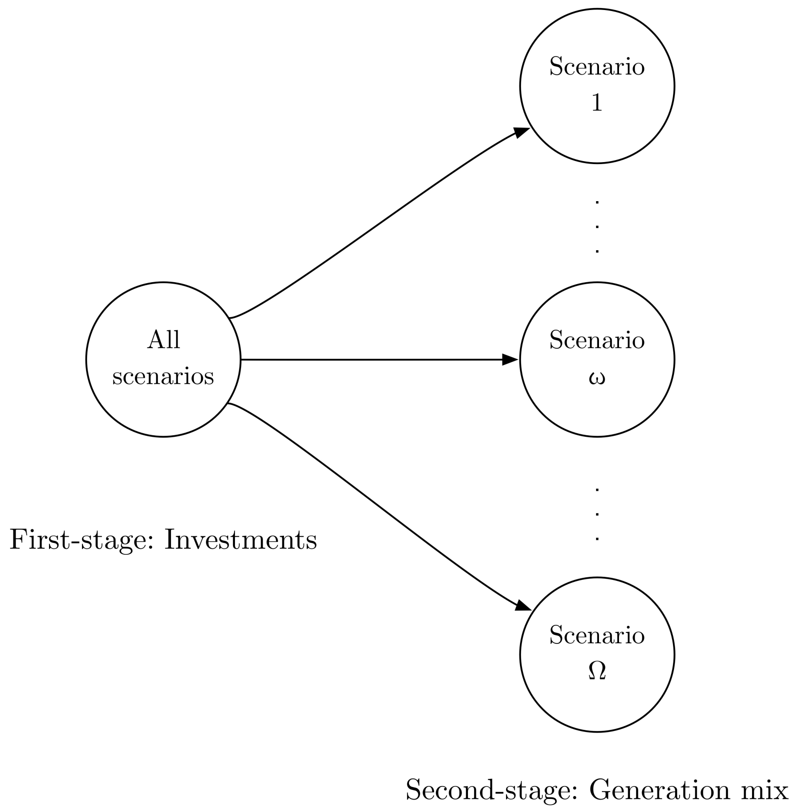

Figure 12: Stages and decisions in the stochastic model.

Second-stage decisions are taken for all scenarios $\omega \in \Omega$. The number of scenarios varies according to what input data set is utilized for the particular optimization run.

The actual weeks throughout the year utilized for seasons are different for each of the data sets and scenarios therein. For an overview of the weeks used for each set, see Section 5.2.3.1 and 5.2.4.1.

3.2 Mathematical Formulation

The below formulation is courtesy of Christian Skar, and is included here to give the reader a full overview of the model before any changes are made. Nomenclature for the EMPIRE model is given on page xix.

3.2.1 Objective Function

The objective function of the model is to minimize the net present value of the combined investment costs and operational costs for the planning period.

$$\min_{\mathbf{x},\mathbf{y}} z = \sum_{i \in I} \delta_i \times \left\{ \sum_{g \in G} c_{gi}^{\text{gen}} x_{gi}^{\text{gen}} + \sum_{l \in L} c_{li}^{\text{tran}} x_{li}^{\text{tran}} + \sum_{\omega \in \Omega} p_\omega \times \sum_{h \in H} \alpha_h \times \sum_{n \in N} \left(\sum_{g \in G_n} \left[q_{gi}^{\text{gen}} y_{ghi\omega}^{\text{gen}} \right] + q_{ni}^{\text{VoLL}} y_{nhi\omega}^{\text{LL}} \right) \right\} \tag{3.1}$$

3.2.2 Constraints

Investment constraints for generation capacity (period-wise and cumulative):

$$\begin{aligned} &\sum_{g \in G_{nt}} x_{gj}^{\text{gen}} \le \overline{x}_{nti}^{\text{gen,Period}}, \quad n \in N, t \in T, i \in I \\ &\sum_{j=1}^{i} \sum_{g \in G_{nt}} x_{gj}^{\text{gen}} \le \overline{x}_{nt}^{\text{gen,Cumulative}} - (1-\rho_{gi}) \overline{x}_{g0}^{\text{gen}}, \quad n \in N, t \in T, i \in I \end{aligned} \tag{3.2}$$

Investment constraints for transmission (exchange) capacity:

$$x_{li}^{\text{tran}} \le \overline{x}_{li}^{\text{tran,Period}}, \quad l \in L, i \in I \tag{3.3}$$

Load constraints (production + net import + load shedding = load + pumping):

$$\sum_{g \in G_n} y_{ghi\omega}^{\text{gen}} + \sum_{a \in A_n^{\text{in}}} (1-\eta_a^{\text{line}}) y_{ahi\omega}^{\text{flow}} - \sum_{a \in A_n^{\text{out}}} y_{ahi\omega}^{\text{flow}} - y_{nhi\omega}^{\text{pump}} + y_{nhi\omega}^{\text{LL}} = \xi_{nhi\omega}^{\text{load}}, \; n \in N, h \in H, \omega \in \Omega, i \in I \tag{3.4}$$

Generation capacity constraints:

$$y_{ghi\omega}^{\text{gen}} \le \xi_{ghi\omega}^{\text{gen}} \times \left((1-\rho_{gi})\overline{x}_{g0}^{\text{gen}} + \sum_{j=1}^{i} x_{gj}^{\text{gen}}\right), \quad g \in G, h \in H, i \in I, \omega \in \Omega \tag{3.5}$$

Upward ramping constraints:

$$y_{ghi\omega}^{\text{gen}} - y_{g(h-1)i\omega}^{\text{gen}} \le \gamma_{g}^{\text{gen}} \times \left((1-\rho_{gi})\overline{x}_{g0}^{\text{gen}} + \sum_{j=1}^{i} x_{gj}^{\text{gen}}\right), \quad g \in G^{\text{Thermal}}, s \in S, h \in H_s^-, i \in I, \omega \in \Omega \tag{3.6}$$

Flow constraints – limit flow on arcs (arcs are directional, lines are symmetric):

$$y_{ahi\omega}^{\text{flow}} \le \overline{x}_{l0}^{\text{tran}} + \sum_{j=1}^{i} x_{lj}^{\text{tran}}, \quad l \in L_n, a \in A_l, h \in H, i \in I, \omega \in \Omega \tag{3.7}$$

Hydro energy constraint – limit total hydropower production within a season (due to water availability):

$$\sum_{h \in H_s} y_{ghi\omega}^{\text{gen}} \le \xi_{gsi\omega}^{\text{RegHydroLim}}, \quad g \in G^{\text{RegHydro}}, s \in S, i \in I, \omega \in \Omega \tag{3.8}$$

Pump-storage upper reservoir balance and limit:

$$\begin{array}{c} w_{n(h-1)i\omega}^{\text{upper}} + \eta_n^{pump} y_{nhi\omega}^{\text{pump}} - y_{nhi\omega}^{\text{gen,pump}} = w_{nhi\omega}^{\text{upper}} \\ w_{nhi\omega}^{\text{upper}} \le \overline{w}_n^{\text{upper}} \end{array} \quad , n \in N, h \in H_s, i \in I, \omega \in \Omega \tag{3.9}$$

Emission performance standard (per generator, assume g burns fuel f):

$$y_{ghi\omega}^{\text{gen}} \times hr_{gi} \times e_f \le EPS_{ni}, \quad n \in \{\text{selected nodes}\}, g \in G_n, h \in H, i \in I, \omega \in \Omega \tag{3.10}$$

All decision variables are assumed to be non-negative.

The mathematical formulation is implemented with the Mosel language (see Section 2.9).

3.3 Data Foundations

Some of the most relevant input data used in EMPIRE are included in the sections to follow. All data sets are acquired from Christian Skar. A number of different sources have been used to obtain them. Some of these include Global Change Assessment Model (GCAM) [52], National Renewable Energy Action Plans (NREAP) [53], The Union of the Electricity Industry (Eurelectric) [54] and The European Network of Transmission System Operators for Electricity (ENTSO-E) [55].

3.3.1 Technologies

The model includes 14 main technologies: Lignite[1,2], coal[1,2], gas[2,3], oil[1,2], biomass[1,2], nuclear, wave, geothermal, regulated hydro, run-of-the-river hydro, pumped hydro storage, wind onshore, wind offshore and solar. Some technologies can be developed further, given by superscripts:

- [1] : Integrated Gasification Combined Cycle
- [2] : CCS
- [3] : Combined Cycle

None of these technology extensions are utilized in 2010.

3.3.2 Initial Capacity

The distribution of the capacity on countries and technologies in the first modeling year, 2010, is depicted in Figure 13.

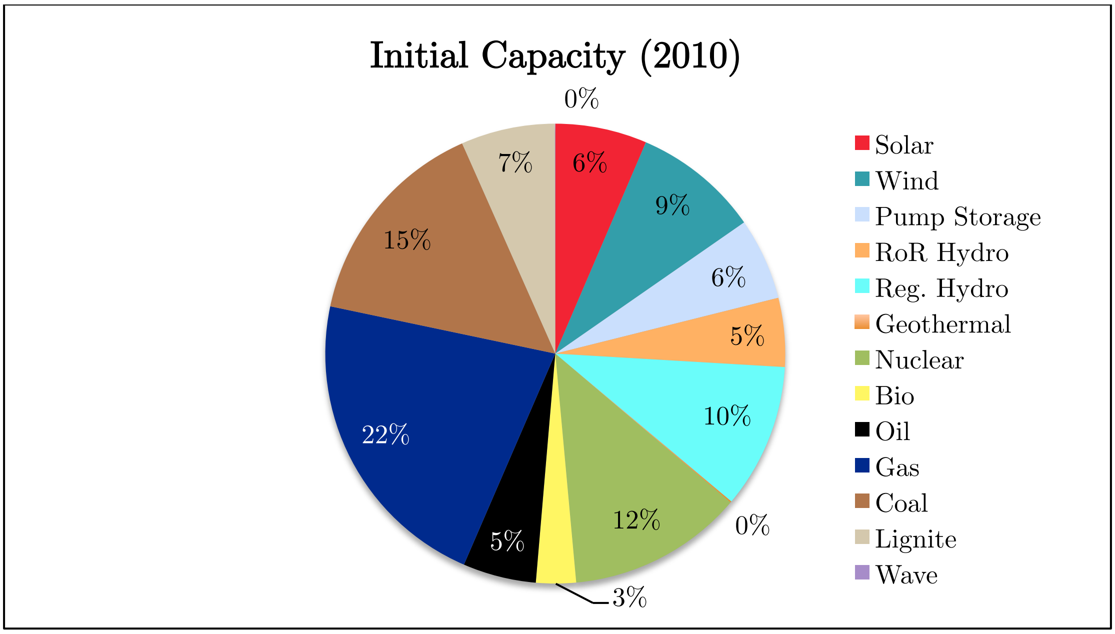

Figure 13: Generation capacity in 2010 [GW].

The total generation capacity aggregated for all countries is 953 GW in 2010. Country-wise, Germany has the highest share of total generation capacity, followed by France, Italy, Spain and Great Britain. These countries aggregated make up 63% of the total capacity in the region. Norway has about 4% of total capacity.

3.3.3 Energy Demand Projections

Future energy demand for the system is one of the input data sets that are dependent on the policy scenario. GCAM has made demand projections for each scenario based on the prevailing policies needed to reach each target [52]. These are depicted in Figure 14.

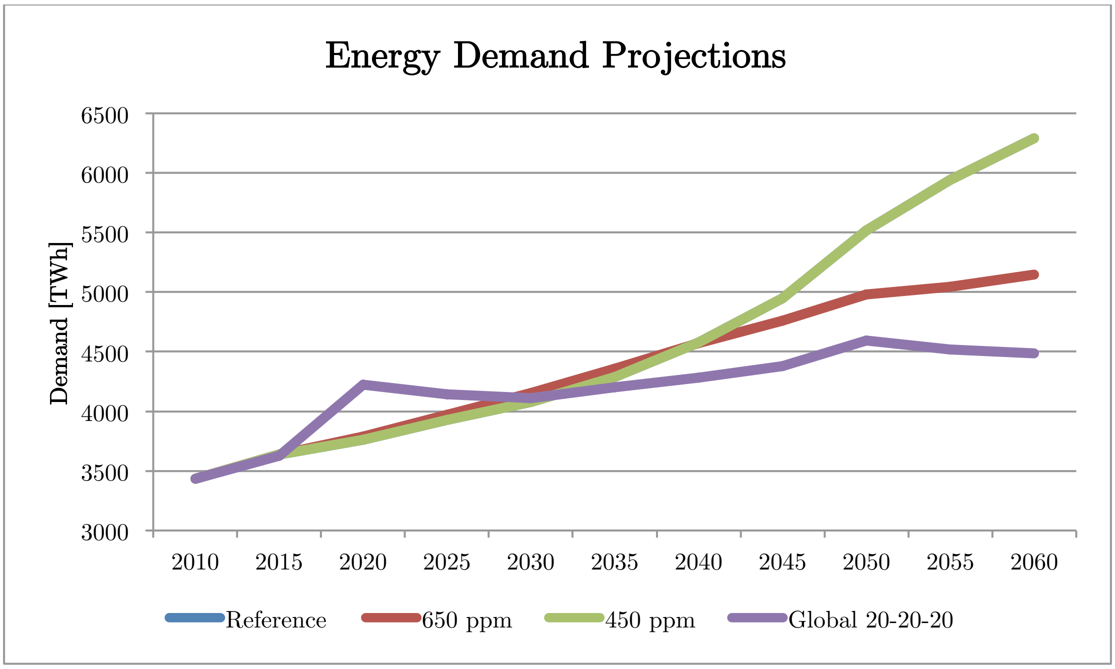

Figure 14: Required demand throughout the planning period in order to satisfy each policy scenario [TWh].

The reference scenario and the 450 ppm scenario have equal demand projections, both foreseeing almost a doubling in energy demand from 2010 to 2060. Global 20-20-20 has lowest projections, peaking in 2050 and with a notable increase from 2015 to 2020. These developments also have to be reflected in the final generation mix.

3.3.4 Fuel and CO_2 Price Projections

Price projections are given separately for Western and Eastern Europe in the data set. The differences between these prices are small, and an average value between the two has been used in the graphing. It is pointed out that the prices for fuel and CO_2 are referred to different years and have different units. However, the important feature of the graphs is the price trends throughout the planning period, more than the actual values.

Fuel price projections for lignite, coal, gas, oil, biomass and uranium are given in Figure 15.

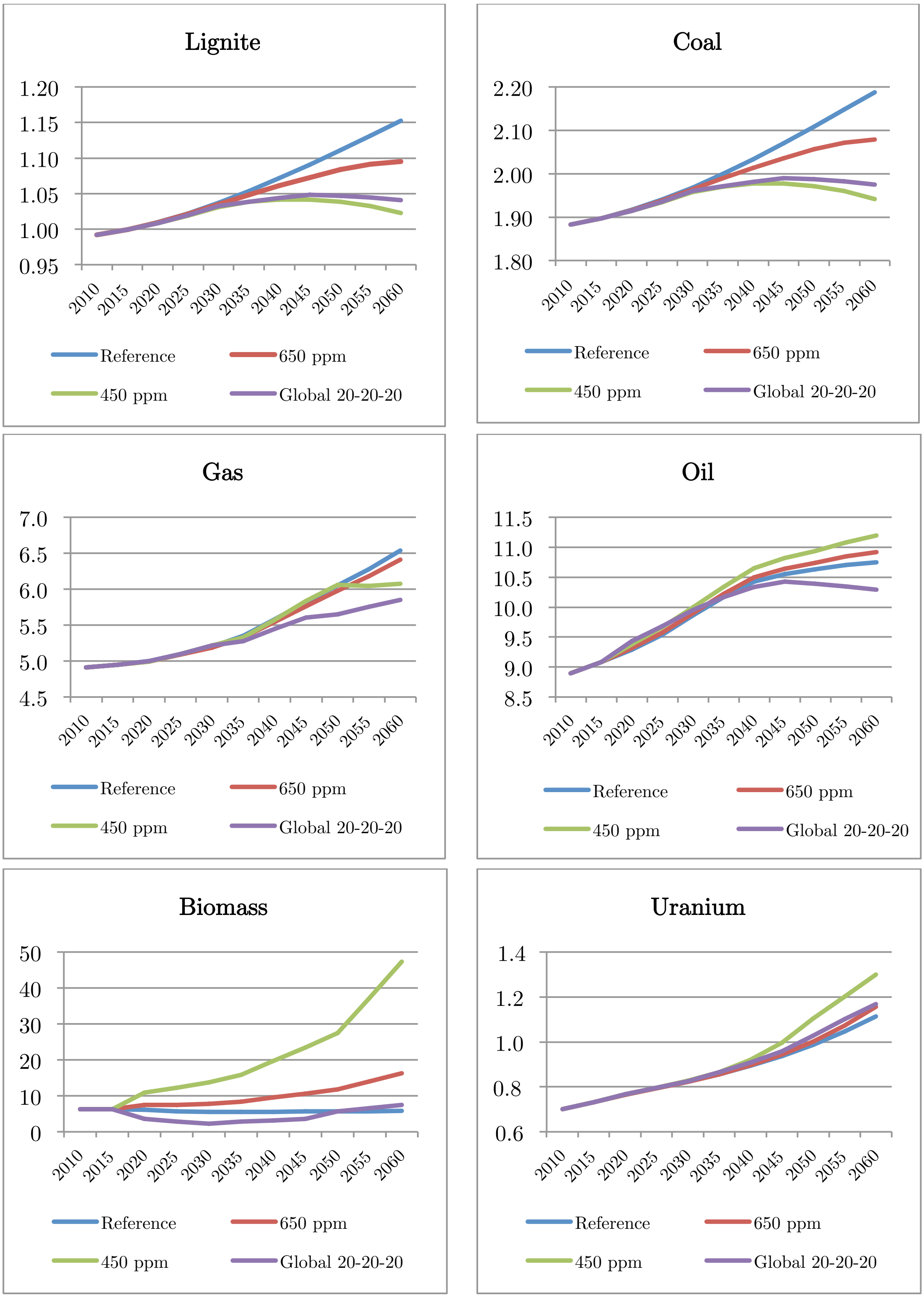

Figure 15: Fuel price projections for lignite, coal, gas, oil, biomass and uranium, in the period 2010-2060 [2007$/GJ].

In order to understand their development, these graphs must be seen in relation to the CO_2 price projections depicted in Figure 16.

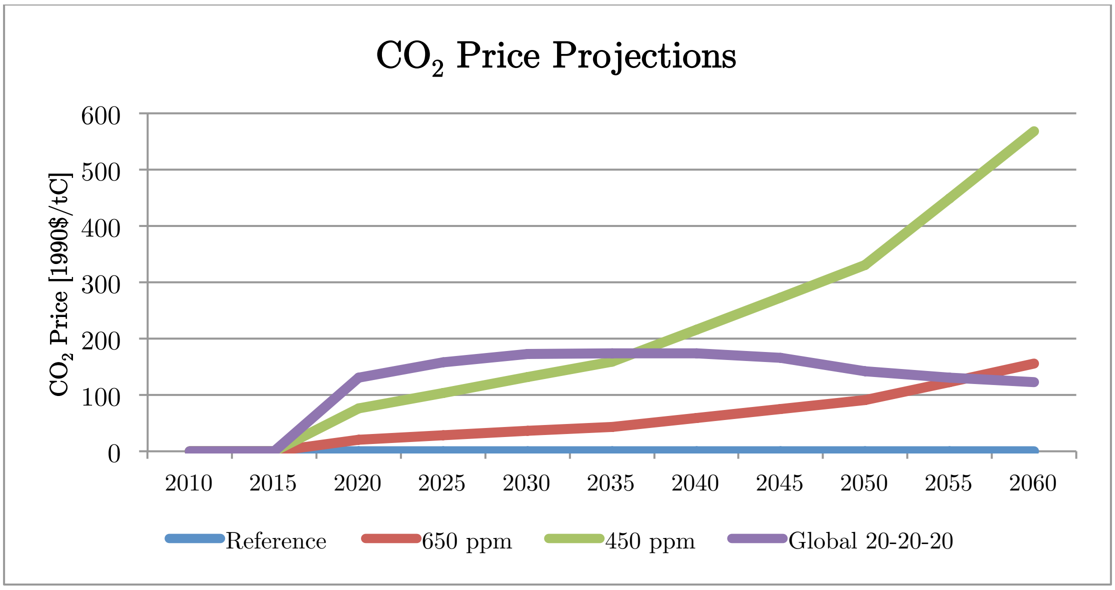

Figure 16: Projections for the CO_2 price in the different scenarios, [1990$/tC], tC = ton of carbon.

Since the CO_2 price in the reference scenario is zero, the demand for fossil-based fuels will stay high. This will stimulate high prices for fuels with high carbon content. In other scenarios, especially the 450 ppm scenario, the CO_2 price is rising sharply going towards 2060. The demand for fossil-based fuels will go down because of the high CO_2 price, and the price for these fuels will be reduced correspondingly. The reference scenario has a CO_2 price of zero in all years. It can be seen that the different scenarios have different strategies for the timing of CO_2 price implementation. The Global 20-20-20 scenario seeks a steep incline in CO_2 price early in the analysis period, whilst the 650 ppm and 450 ppm scenarios show more relaxed gradients.

3.4 Original Hydropower Formulation

Before the implementation of an enhanced hydropower formulation can take place a description of the current formulation is necessary. Originally, each hydropower generator is assigned one reservoir, which contains a given amount of energy at the beginning of each season. Other than low operation and maintenance costs there is no cost associated with using the water for energy generation. Thus, the static amount of energy in the reservoir is practically offered for free and can be used at any time during the included hours in a particular season. No inflow is included. The reservoir can be emptied, and there is no value in saving water for consecutive seasons. This essentially implies that the model can use every drop of the available water in the reservoir for each season without taking into account that it may be more economically beneficial in the long run to save some of it for later periods. Neglecting such impacts altogether is a major simplification of actual hydropower dispatch optimization.

The objective function of the model is to minimize total costs. This will in practice mean that (virtually) free hydropower will be used in hours when load is high and iRES generation is low. In these hours the system has to move furthest up the merit curve of generation technologies in order to cover load. Making use of free hydropower will in these hours give the greatest savings in terms of economic value.

3.4.1 Improvement Strategy

There are several major simplifications done in the original hydropower formulation. The most apparent is the way EMPIRE values regulated hydropower. The only costs associated with hydropower are operation and maintenance costs. Aside from these, using hydropower is not associated with any expenditure. In reality, this is also mostly correct. Natural processes drive water inflow to reservoirs and this comes at no cost for hydropower producers. However, in real-world generation planning, following the description in Section 2.6.2, water in different segments of the reservoir is assigned a monetary value through water values, reflecting its alternative cost. By using these fictitious economical terms, hydropower producers have a method for determining at what time the available water in their reservoirs should be utilized in order to maximize profits. This idea is the main feature of the proposed enhancement of the hydropower scheduling formulation. Omitting this technique completely disregards the value of storing water for later periods in the original model. Since the water comes for free, there is currently no incentive to save it. Additionally, not including reservoir modeling is imprecise. As such, an improvement strategy consisting of four main elements is proposed:

- **Water values:** Assign an economic value to the available water, giving hydropower a marginal cost (or, more correctly, alternative cost) of generation. This enables comparability with the SRMC of competitive technologies.
- **Inflow:** Account for dynamic impacts in each season by including natural inflow to each reservoir.
- **Reservoir level variables:** Keep continually track of reservoir levels in order to know how much water is available, and what water value it is assigned.
- **Hydrological reservoir balance:** Make sure that balance in each reservoir is preserved throughout a season.

Stochastic hydropower parameters will be utilized to account for uncertainty. In addition to the improved formulation for regulated hydropower, an enhanced representation for run-of-the-river hydropower is also included. Chapter 4 will introduce all of these aspects.

4 Introducing Hydropower Scheduling

A model for managing a hydropower system will be specified in the following. It is assumed that each node, i.e. country, has one hydropower generator with one reservoir connected to it, in line with the original EMPIRE model philosophy. The capacity on this generator is the aggregated capacity for each country, and the reservoir is the aggregated size of the combined reservoirs in the country ("one reservoir model"). Discharge from this reservoir releases water onto the turbines of the generator, thereby generating electricity. For consistency, it is important to keep notations for the hydropower scheduling similar to notations in the original EMPIRE model. This is endeavored as far as possible in all modeling formulations.

Before the actual hydropower dispatch framework is introduced, the change in the objective function of the optimization will be described. Nomenclature is given in Table 2 on page xxi.

4.1 Impact on the Objective Function

The change in the objective function is a term representing the fictitious cost of utilizing available water for hydropower generation:

$$\Delta z = \sum_{i \in I} \delta_i \sum_{\omega \in \Omega} p_\omega \sum_{s \in S} \vartheta_s \sum_{n \in N} \sum_{m \in M_n} xd_{mnsi\omega} WV_{mnsi\omega} \tag{4.1}$$

δ_i is the discount factor for year *i*. p_ω is the probability for stochastic scenario ω. ϑ_s is a scaling factor for season *s*, as described in Section 3.1.2.1. $xd_{mnsi\omega}$ is the discharge from reservoir segment *m* of node *n* in season *s* of year *i* and stochastic scenario ω. $WV_{mnsi\omega}$ is the corresponding water value of reservoir segment *m* of node *n* in season *s* of year *i* and stochastic scenario ω.

4.2 Regulated Hydropower

4.2.1 Hydropower Parameters Overview

The parameters that are specifically utilized in the enhanced hydropower formulation include the following sets:

- Water values
- Normalized inflow for regulated and run-of-the-river hydropower
- Maximum reservoir size
- Minimum reservoir size
- Number of segments in each reservoir (equal for all nodes)
- Initial reservoir fraction

The sets will be described further in Section 4.4, but it is worthwhile to have an idea of the parameters that are utilized before the dispatch is defined. Run-of-the-river hydropower will be introduced in Section 4.3, whilst regulated hydropower dispatch will be introduced below. It is divided into two distinct steps.

4.2.2 Step 1: Setting the Segment Sizes

In the first step, the data sets mentioned above is read and utilized in order to determine the available amount of energy in each segment of the reservoir for all nodes, seasons and scenarios. The reservoir in each node is divided into N^{seg} segments. The water contents in each segment are assigned an individual water value.

Definition of the initial reservoir level:

$$R^{init}_{ns\omega} = F_{ns\omega} \cdot R^{max}_{n}, \quad n \in N, s \in S, i \in I, \omega \in \Omega \tag{4.2}$$

The initial reservoir level is defined in terms of a fractional value (initial reservoir fraction $F_{ns\omega}$) of a full reservoir R^{max}_{n}. The initial reservoir fraction is constant for all years, i.e. equilibrium state is assumed from one year to the next.

The maximum size of a reservoir segment is needed when setting the actual size of the segment:

$$S_{mn}^{max} = \frac{R_n^{max}}{N^{seg}}, \quad n \in N, m \in M_n \tag{4.3}$$

The maximum size is equal for all segments, and is equal to a full reservoir divided by the number of segments N^{seg}.

Based on the initial reservoir level, it is clear that not all segments in the reservoir shall be filled. This has to be taken into account in order to limit the available amount of water. With the parameters defined above, the *actual* size of each segment can now be calculated. A procedure for doing so is given below.

for all scenarios, years, seasons, nodes *do*

$$m = N^{seg} \tag{4.4}$$

$$R_{ns\omega}^{temp} = R_{ns\omega}^{init} + U_{ns\omega}^{Reg} \tag{4.5}$$

while $(a \geq 0)$

if $(R_{ns\omega}^{temp} \geq S_{mn}^{max})$ *then*

$$xd_{mns\omega}^{max} = S_{mn}^{max} \tag{4.6}$$

else

$$xd_{mns\omega}^{max} = R_{ns\omega}^{temp} \tag{4.7}$$

end-if

$$R_{ns\omega}^{temp} = R_{ns\omega}^{temp} - xd_{mns\omega}^{max} \tag{4.8}$$

$$m = m - 1 \tag{4.9}$$

end-while

end-do

The procedure sets the actual size of each segment according to the initial reservoir level for each node, season, year and scenario. $xd_{mns\omega}^{max}$ is the actual size of each segment, and is thus the maximum amount of discharge $xd_{mnsi\omega}$ from segment m, hence the chosen notation. The reservoir is being filled from the bottom segment in an upward fashion until all of the available water in the season has been assigned.

The behavior of a reservoir in the beginning of a season can thus be illustrated as in Figure 17.

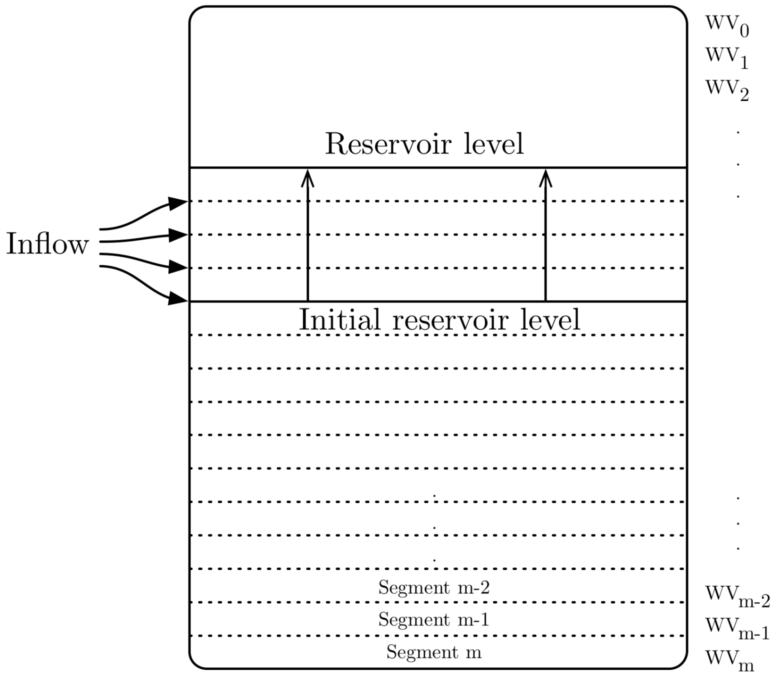

Figure 17: Reservoir behavior in the beginning of a season.

Inflow is assumed to happen in the start of a given season. This can be justified by the short season durations in the model. Inflow will raise the level from “initial reservoir level” to “reservoir level”. The segments above the reservoir level are empty.

4.2.3 Step 2: Reservoir and Discharge Constraints

With the parameters outlined above, constraints and formulations for hydropower scheduling can be presented.

The connection between hydropower generation and segmental reservoir discharge is as follows:

$$\sum_{h \in H_s} y_{ghi\omega}^{gen} = \sum_{m \in M_n} xd_{mnsi\omega}, \quad n \in N, g \in G_n^{HydReg}, s \in S, i \in I, \omega \in \Omega \tag{4.10}$$

The sum of hydropower generation for all hours in season s equals the total discharge from all segments M_n in the corresponding season.

The reservoir dynamics in season s is modeled through a water accumulation equation, taking into account the activities happening throughout the season. End-of-season reservoir balance is then given as:

$$r_{nsi\omega} = R_{ns\omega}^{init} - \sum_{m \in M_n} xd_{mnsi\omega} + U_{ns\omega}^{Reg,norm} \cdot p_{gi}^{gen} - s_{nsi\omega}, \quad n \in N, g \in G_n^{HydReg}, s \in S, i \in I, \omega \in \Omega \tag{4.11}$$

The end-of-season reservoir level is equal to initial reservoir level plus inflow minus total discharge and spillage. Note that the inflow is normalized according to installed capacity, and thus has to be multiplied by the installed capacity for each year. This implies that if the installed capacity is increased from one year to the next the inflow also increases. The feature will be further discussed in Section 5.1.

Limits for the end-of-season reservoir level is included, with one for maximum level and one for minimum level:

$$r_{nsi\omega} \le R_n^{max}, \quad n \in N, s \in S, i \in I, \omega \in \Omega \tag{4.12}$$

$$r_{nsi\omega} \ge R_n^{min} \mid \left(R_{ns\omega}^{init} \ge R_n^{min} \right), \quad n \in N, s \in S, i \in I, \omega \in \Omega \tag{4.13}$$

The end-of-season reservoir level has to lie between these limits. "|" in the minimum reservoir constraint here means "given". It is emphasized that the dispatch in each season is modeled individually. Therefore, an energy balance connecting consecutive time periods is not possible. However, the use of water values incorporates saving mechanisms for the reservoir. If it is more economically beneficial to save the water and make it available for future time periods, the model will choose to do so. The expected future revenue possibility is embraced through the water values.

The segmental discharge cannot exceed the actual available size of each segment, as calculated in the procedure in step 1 earlier:

$$xd_{mnsi\omega} \leq xd_{mns\omega}^{max}, \quad m \in M_n, n \in N, s \in S, i \in I, \omega \in \Omega \tag{4.14}$$

For some nodes having small reservoirs and thereby low degree of regulation, the water value may be equal for some segments. When several segments have the same assigned cost, the model has no incentive to start at the top of the reservoir, but can choose freely what segment it wants to utilize. Since the costs are equal there will be no change in the objective function whatever segment is chosen for discharge. The final solution will therefore not change because of this behavior. Nevertheless, in order to keep the model as close to reality as possible and thereby prevent this practice, the following restriction is added:

$$xd_{m+1,nsi\omega} \leq xd_{mnsi\omega} \mid \left(xd_{mns\omega}^{max} \geq S_{mn}^{max}\right), \quad m \in \left\{1, \ldots, N^{seg}-1\right\}, n \in N, s \in S, i \in I, \omega \in \Omega \tag{4.15}$$

This restriction ensures that discharge from segment *m+1* does not start unless discharge from segment *m* has been initiated.

As mentioned, the dispatch is calculated individually for each season. This implies that the model could theoretically choose to empty the reservoir for each season if this was economically beneficial in the optimization. With the confined season lengths used here, this behavior is highly unrealistic. Also, discharging more water annually than the annual inflow would lead to unsustainable reservoirs over time. To keep equilibrium state for each year, the aggregated annual regulated hydropower generation therefore cannot exceed the aggregated annual regulated inflow:

$$\sum_{h \in H} \alpha_h \cdot y_{ghi\omega}^{gen} \leq \sum_{s \in S} \vartheta_s \cdot U_{ns\omega}^{Reg,norm} \cdot p_{gi}^{gen}, \quad n \in N, g \in G_n^{HydReg}, i \in I, \omega \in \Omega \tag{4.16}$$

Again, inflow is given as normalized values to the installed capacity, and thus has to be multiplied by the installed capacity to retrieve actual values. α_h is an hourly scaling factor in order to account for the two types of seasons: regular and peak-load.

4.3 Run-of-the-River Hydropower

Run-of-the-river (RoR) hydropower is not subject to the use of reservoirs and thus cannot store water like regulated hydropower can. Therefore, the modeling of this hydropower type can be done much easier than what is the case with regulated hydropower. Run-of-the-river is a continuous energy source whose available energy is given as seasonal RoR inflow. Thus, seasonal generation from RoR hydropower cannot exceed seasonal RoR inflow:

$$\sum_{h \in H_s} y_{ghi\omega}^{gen} \leq U_{ns\omega}^{RoR,norm} \cdot p_{gi}^{gen}, \quad n \in N, g \in G_n^{HydRoR}, s \in S, i \in I, \omega \in \Omega \tag{4.17}$$

This restriction is formulated the same way as for regulated hydropower. Additionally, in order to limit the degree of freedom in which RoR hydropower can choose to use the seasonal inflow for generation (due to its lack of reservoir), the following constraint is included:

$$y_{ghi\omega}^{gen} \leq \frac{U_{ns\omega}^{RoR,norm} \cdot p_{gi}^{gen}}{v_s}, \quad n \in N, g \in G_n^{HydRoR}, h \in H, s \in S, i \in I, \omega \in \Omega \tag{4.18}$$

The hourly RoR generation cannot exceed the average RoR inflow for all hours constituting season *s*. v_s is the total number of hours in each season. This number is different for regular and peak-load seasons, hence the season dependency.

With the new hydropower scheduling formulation in place, the stochastic hydropower generation limits, as given in Eq. (3.8), are removed. These limits are no longer necessary since water values are now used as decision-maker for hydropower generation.

4.4 Hydropower Data

4.4.1 Water Values

As explained in Section 2.6.2, water values are highly dependent on the prevailing marginal cost of generation for competitive technologies. Therefore, the water values are calculated based on earlier runs of the original EMPIRE model where expected capacity and prices for each year are found. This exercise has been done through the EMPS model at SINTEF and their "one reservoir model" [25]. Each reservoir is divided into 51 segments, which are assigned unique water values.

4.4.2 Inflow

Inflow data for both regulated and run-of-the-river hydropower was originally calculated in SUSPLAN[5], and obtained from SINTEF for this model. The format of the inflow data requires some conversion in order to make it usable in the model. Raw data for both regulated and run-of-the-river normalized inflow are given as weekly values. These have to be scaled in order to match the duration of each season used in the model. For seasons 1-4, each having duration of 24 hours, the following scaling is done:

$$U_{ns\omega}^{Reg,norm} = \frac{U_{ns\omega}^{Reg,norm}}{7}, \quad n \in N, s \in \{1,...,4\}, \omega \in \Omega \tag{4.19}$$

$$U_{ns\omega}^{RoR,norm} = \frac{U_{ns\omega}^{RoR,norm}}{7}, \quad n \in N, s \in \{1,...,4\}, \omega \in \Omega \tag{4.20}$$

For seasons 5-10, each having duration of 5 hours:

$$U_{ns\omega}^{Reg,norm} = \frac{U_{ns\omega}^{Reg,norm} \cdot 5}{7 \cdot 24}, \quad n \in N, s \in \{5,...,10\}, \omega \in \Omega \tag{4.21}$$

$$U_{ns\omega}^{RoR,norm} = \frac{U_{ns\omega}^{RoR,norm} \cdot 5}{7 \cdot 24}, \quad n \in N, s \in \{5,...,10\}, \omega \in \Omega \tag{4.22}$$

[5] PLANning for SUStainability

As indicated by the indices of the inflow parameters, their values do not change with years. Multiplying normalized inflow with annual capacity does, however, yield different final inflow values if investments take place.

4.4.3 Maximum and Minimum Reservoir Sizes

SINTEF provides data for the maximum reservoir size in each country.

No proper data has been found when it comes to the minimum allowed content in the reservoirs. There are several reasons for including such a consideration. Sediments at the bottom of the reservoir can be sucked into turbines and destroy components. Going below the minimum reservoir level can also cause damage to the reservoir ecosystem [56]. When consulting with SINTEF it is unclear if attention has already been paid to this aspect. I.e., it is possible that the maximum reservoir level given in the data sets have already subtracted the minimum reservoir level and that the entire reservoir size thereby can safely be utilized. However, with the short season lengths applied in EMPIRE, it can be considered highly unlikely that the lower level will be reached. As an approximation the minimum reservoir level is therefore set to be 5% of the full reservoir size.

4.4.4 Initial Reservoir Fractions

The initial reservoir fractions are used to set the initial reservoir levels at the beginning of each season. Because of varying precipitation the fractions are considered to be different for winter and summer seasons. For the base scenario the initial reservoir fractions are assumed to be 60% and 80% for winter and summer, respectively. Other scenarios utilize different fractions, and some countries are treated with special care with regards to these parameters. For actual values and descriptions, the reader is therefore directed to Section 5.2.3.3 for the 3-scenario data set and Section 5.2.4.3 for the 10-scenario data set.

4.5 Remarks on Modeling Precision

From the mathematical framework introduced in the preceding sections it is clear that the proposed implementation offers a simplified view of the hydropower system. The presented model offers a coupling of long-term (yearly resolution) and short-term (hourly resolution) hydropower planning. The long-term model supplies boundary conditions for the short-term model, for instance represented in Eq. (4.16), stating that annual generation is limited by annual inflow.

Generally, different algorithms at each of these two stages call for different time resolution and hydropower system modeling [57]. In this representation, simplifications are necessary because of the described coupling of time resolutions. As such, a number of additional features could be included, such as efficiency curves for hydropower generators and a more detailed view of each country's disaggregated reservoirs. However, the appropriate detail level has to be seen in context with the system that the implementation is to be placed. EMPIRE itself is a simplified representation of the European power system. Because of the vast spatial and temporal scopes of the model, the simplifications carried out in regards to hydropower scheduling can be considered reasonable for the task at hand.

5 Model Alterations in Master Semester

The purpose of this chapter is to describe what is specifically done during the Master semester of spring 2014. The work included in this thesis spans both the project and Master semesters, and a detailed description of the topics carried out in the latter is therefore necessary.

In the project thesis, the code framework and architecture was developed. In the Master work, the model is further improved and some misinterpretations from the project have been rectified. This chapter is divided into sections based on the changes made to the previous model from the project. Some of these changes are already included in Chapter 4 and are more thoroughly described here. The resolved misconceptions in the previous model version are detailed in Appendix A. Less pronounced changes have also been carried out, and these are specified in Appendix B.

Because of the detailed nature of this chapter the general reader may proceed to Chapter 6 if desired.

5.1 Dynamic Inflow

In the previous hydropower formulation inflow was treated as a definite parameter that did not change over time. However, the data from SINTEF is given as normalized values relative to the currently installed hydropower capacity, for both regulated and run-of-the-river hydropower. Therefore, it is possible to treat inflow as a "dynamic" parameter that changes when hydropower investments take place. This is implemented in the final version of the model. It involves that the inflow is imported as normalized values and the currently installed capacity is multiplied with these normalized values when the model is being run. The installed capacity variable is updated for each year if new investments take place or if power plants are dismantled. This way, the actual inflow is more accurate than before. Investment incentives will increase since the total amount of energy will increase with investments in hydropower. The described behavior is implemented for both regulated and run-of-the-river hydropower.

Comparing with real-world conditions, this methodology is reasonable. If it is decided to invest in a new hydropower generator, it can be assumed that this will be built in places where the energy stored in the water could not be previously accessed. For example, if a hydropower plant is built in an entirely new location where hydropower is not already present, this new generator will now have access to the inflow in this location. Therefore, making the inflow increase as new capacity is being installed is considered most correct.

To enable this behavior and at the same time being able to set the available segment size correctly prior to optimization, the procedures used to set the segment size is moved to the hydropower data handler file. This implies that the segment sizes are based on the installed capacity in the first year of the optimization, i.e. 2010. Therefore, in addition to having a data set with the normalized inflow values, a data set with the total, scaled inflow for 2010 is necessary. This parameter is termed 'initial inflow', $U_{ns\omega}^{Reg,init}$.

5.1.1 Adjusting Installed Regulated Hydropower Capacity in 2010

During analyses it is discovered that the initial hydropower capacities used in the original EMPIRE model are slightly different than the installed capacities given in the SINTEF data sets. Since inflow is now given as normalized values to the presently installed capacity, it is important that consistency across the model is preserved. It is therefore decided to use the EMPIRE capacities for inflow scaling to determine the initial inflow. This can be justified because the data material in EMPIRE has been thoroughly crosschecked and can be assumed to be more accurate than the SINTEF data. Since the normalized inflow values for all other years are multiplied with the installed capacity in the model, the described adjustment will only yield changes in the initial inflow, which again sets the available segment sizes. Table 3 presents the relevant values.

Table 3: Comparison of installed capacities for regulated hydropower in EMPIRE and SINTEF data sets.

Country	Regulated Hydropower Capacity, EMPIRE [MW]	Regulated Hydropower Capacity, SINTEF [MW]	Difference [MW]
Germany	1374.2	1572.5	-198.3
Hungary	0	9.7	-9.7
Poland	141.2	336.6	-195.4
Sweden	9677.2	9686.6	-9.4

For all other countries, there is no difference between the sets. Initial inflow for run-of-the-river hydropower is not necessary since this hydropower generation type does not utilize segments. Therefore, any differences between the data sets with regards to installed RoR hydropower will not yield any changes. The installed capacities in EMPIRE are used for all RoR inflow scaling purposes.

5.2 Addressing Uncertainty: Stochastic Modeling

5.2.1 Background

Generation expansion models are highly prone for uncertainty since the very purpose of such models is to describe the future. The EMPIRE model gives expansion plans from 2010 to 2060 and a number of parameter values are based on empirical estimates. As an example, the inherent uncertainty regarding solar generation in a given hour in 2060 is obvious. To account for such uncertainties, EMPIRE makes use of stochastic modeling. This involves the introduction of a number of stochastic scenarios in which the uncertain parameters take different values. Continuing the example with solar generation in 2060, one can imagine having three different values: high, medium and low generation. For each scenario, each of the three values is used as the actual generation and the model is solved for each scenario. The final solution for the decision variables dependent on these stochastic parameters is based on a probability distribution of the scenarios, as described in Section 3.1.2.2.

The EMPIRE model is designed to allow for a chosen number of scenarios. In this thesis, two data sets are described:

- 3 scenarios, henceforth called the 3-scenario version
- 10 scenarios, henceforth called the 10-scenario version

A probability $P(\omega)$ is assigned to each scenario ω. The probability of each scenario is assumed to be the same in the EMPIRE model. For the 3-scenario version this implies probabilities of $P(1) = P(2) = P(3) = 1/3$, and for the 10-scenario version it implies probabilities of $P(1) = P(2) = ... = P(10) = 1/10$ for each scenario. The final value must be weighted towards the corresponding probability of each scenario in the objective function of the optimization.

5.2.2 Stochastic Hydropower Scheduling

Hydropower parameters are no exceptions to the uncertain nature of future predictions. Two parameters are especially prone for uncertainty: inflow and initial reservoir level for each season. Stochastic modeling for these parameters will be introduced in the following. This will also yield stochastic specifications for the segment sizes because of the link between these values as explained in Section 4.2.2.

Introducing stochastic modeling involves a substantial expansion of the data sets in order to gain individual parameter values for all scenarios. Such an expansion requires a rebuilding of the structure of the Excel data sets for hydropower. In order to enable a full stochastic representation of reservoir behavior and hydropower scheduling, the decision variables, parameters and constraints in Table 4 are made dependent on stochastic scenarios.

Table 4: Decision variables, parameters and constraints made dependent on stochastic scenarios.

<u>*Decision variables*</u>	
$xd_{mnsi\omega}$	Discharge from segment m of node n's reservoir in season s, year i, scenario ω.
$r_{nsi\omega}$	End-of-season reservoir level for node n's reservoir in season s, year i, scenario ω.
$s_{nsi\omega}$	Spillage from node n's reservoir, season s, year i, scenario ω.
<u>*Parameters*</u>	
$R_{ns\omega}^{init}$	Initial reservoir level for node n's reservoir in season s, scenario ω.
$R_{ns\omega}^{temp}$	Temporary reservoir level for node n, season s, scenario ω.
$F_{ns\omega}^{init}$	Initial reservoir fraction for node n's reservoir in season s, scenario ω.
$U_{ns\omega}^{Reg,norm}$	Seasonal normalized inflow to node n's reservoir in season s, scenario ω.
$U_{ns\omega}^{Reg,init}$	Seasonal normalized inflow in 2010 (initial inflow) to node n's reservoir in season s, scenario ω.
$U_{ns\omega}^{RoR,norm}$	Seasonal run-of-the-river normalized inflow for node n in season s, scenario ω.

$xd_{mns\omega}^{max}$ Actual segment size for segment m of node n's reservoir in season s, scenario ω.

Constraints and procedures

Because of the new stochastic representation, all constraints in the formulation and procedures for data handling and results analysis are made dependent on scenario ω.

The succeeding sections describe the preparation of input data used in the 3-scenario and 10-scenario versions.

5.2.3 Input Data for the 3-Scenario Version

5.2.3.1 Weeks and Seasons Matching

A number of instances in the original model are already dependent on scenarios. The week numbers that are used for seasons are different for each of the scenarios. This makes the model more realistic, since the timing of year will have an impact on parameters. In order to make the hydropower values correlate with data used in the rest of the EMPIRE model the same weeks are used for seasons for hydropower data. The seasons used in the 3-scenario version are given in Table 5.

Table 5: Week numbers used for different seasons in the three stochastic scenarios.

Season	Week nr, scenario 1	Week nr, scenario 2	Week nr, scenario 3
1	6	10	7
2	23	21	26
3	27	29	38
4	52	46	52
5	4	50	5
6	4	1	50
7	50	48	3
8	5	1	1
9	26	29	26
10	5	2	50

It can be seen that all scenarios make use of summer and winter timing. As explained in Section 3.1.2, the weighting of regular (number 1-4) and peak-load seasons (number 5-10) is different. The same weighting is used for the 3-scenario and the 10-scenario versions.

5.2.3.2 Inflow

Inflow to hydropower reservoirs is uncertain by nature and should be modeled as a stochastic parameter. Inflow data have been obtained from SINTEF Energy Research for three separate years (2003, 2004 and 2005), for both regulated and run-of-the-river hydropower. It is emphasized that even though these data sets are quite old, inflow is a type of parameter that does not vary extensively over time. And since inflow is given as normalized values to the installed capacity, any new installments will correctly lead to higher inflow values (more available energy). In the 3-scenario version, inflow data for each of these years are used for one scenario:

- Scenario 1: 2005 data
- Scenario 2: 2004 data
- Scenario 3: 2003 data

For each of the scenarios, inflow data from the weeks corresponding with the matching in Table 5 is utilized.

5.2.3.3 Initial Reservoir Level

The values for initial reservoir level for the different scenarios in the 3-scenario version are based on an interval related to the values chosen in the previous model formulation. For most nodes, the previous values are 60% for winter seasons and 80 % for summer seasons, with corrections done for nodes located in southern parts of Europe and having large reservoirs. This is relevant for Spain and Italy, where the levels are set to 80% for all seasons. This is done because these nodes are less prone to variations in reservoir levels throughout the year caused by fluctuating precipitation.

The original values mentioned above are used for scenario 1. For scenario 2 and 3, the initial reservoir levels are calculated by assuming a variation of 10% related to the values in scenario 1:

$$R^{init}_{ns,\omega=1} = R^{init,orig}_{ns}, \quad n \in N, s \in S \tag{5.1}$$

$$R^{init}_{ns,\omega=2} = 0.9R^{init}_{ns,\omega=1}, \quad n \in N, s \in S \tag{5.2}$$

$$R^{init}_{ns,\omega=3} = 1.1R^{init}_{ns,\omega=1}, \quad n \in N, s \in S \tag{5.3}$$

$R^{init,orig}_{ns}$ is the initial reservoir level from the previous model formulation. Since the levels for scenario 2 are consistently lower than the base scenario for all nodes, and levels for scenario 3 are consistently higher, the impacts of dry- (scenario 2) and wet-year (scenario 3) situations are introduced. Such features are appreciated in a stochastic model, where one would like to include variations in the input data. Table 6 gives levels for all scenarios.

Table 6: Initial reservoir levels for different scenarios in the 3-scenario version.

Scenario	Winter seasons	Winter seasons
1	60%	80%
2	54%	66%
3	72%	88%

By changing the initial reservoir level, the amount of water available to generate electricity is modified. The only reservoir segments that will change value are the ones that are in direct proximity to the uppermost segment that originally was partially filled. I.e., the impact of the alteration can be seen as a larger or smaller available amount of energy in a segment relatively high in the reservoir, where the water value is relatively low. Therefore, implementing this change is very likely to have an impact on the generated amount of regulated hydropower since the lowest available marginal cost will change.

Initial Reservoir Levels for Norway and Sweden

For nodes with high amounts of regulated hydropower the initial reservoir level plays a particularly important role. In order to make the model as accurate as possible, the initial reservoir level for Norway and Sweden has been thoroughly examined, using data from the Norwegian TSO (Statnett). The median filling degree in the 20-year time period from 1993-2013 is used as a guideline for setting a more accurate initial reservoir level for each of the seasons in each of the stochastic scenarios. Limiting this added level of detail to only Norway and Sweden can be justified by their vast reservoir capacities compared to other countries (see Appendix C.1). Norway has approximately 50% of Europe's reservoir capacity [58], and Sweden has the second largest reservoir. Thus, their seasonal initial reservoir level will have a large impact on the available hydropower energy in Europe. For other countries similarly accurate data has not been found and their values have therefore not been altered.

Figure 18 illustrates how the reservoir level for the aggregated hydropower reservoirs in Norway fluctuates throughout the year. Raw data is given in Appendix C.3.

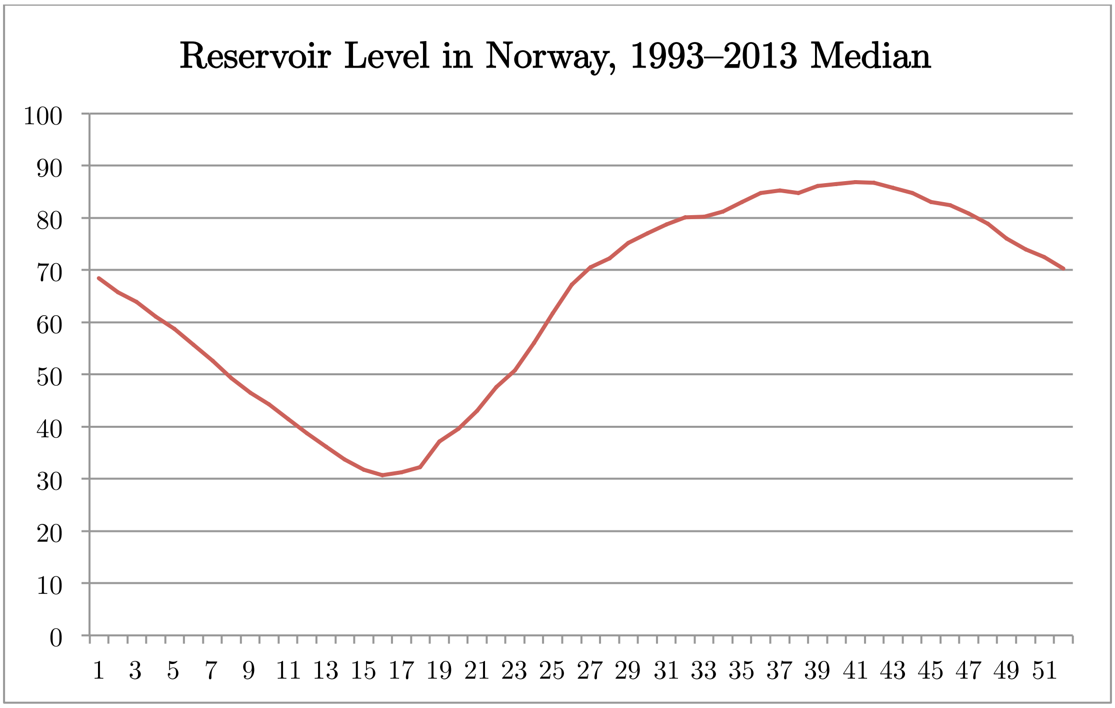

Figure 18: Reservoir level aggregated for all hydropower reservoirs in Norway, throughout the year. Values are based on the median filling degree from 1993-2013 [59].

Based on the values in Figure 18 and the same 10% scenario variations described previously, Table 23 in Appendix C.3 gives the initial reservoir levels for Norway and Sweden. Similar reservoir data for Sweden has not been found, but due to Norway and Sweden's closely matching geographical properties, data from Norway are also used for Sweden.

5.2.4 Input Data for the 10-Scenario Version

5.2.4.1 Weeks and Seasons Matching

As with the 3-scenario version, seasons and weeks are matched in accordance with the matching done in the general EMPIRE model to preserve correlation. Table 7 presents the week numbers for each season and each scenario.

Table 7: Week numbers used for different seasons in the 10-scenario version.

Season	Week nr, scenario 1	Week nr, scenario 2	Week nr, scenario 3	Week nr, scenario 4	Week nr, scenario 5
1	3	12	1	11	6
2	18	22	20	20	25
3	29	28	32	38	38
4	46	45	52	41	49
5	5	50	4	51	5
6	50	50	4	51	50
7	3	48	50	49	3
8	1	49	5	51	1
9	26	29	26	51	26
10	50	2	5	51	50
Season	Week nr, scenario 6	Week nr, scenario 7	Week nr, scenario 8	Week nr, scenario 9	Week nr, scenario 10
1	8	10	10	13	5
2	18	22	24	21	23
3	39	37	31	31	32
4	41	45	47	48	46
5	51	5	50	50	50
6	51	50	50	50	50
7	49	3	48	48	48
8	51	1	49	49	49
9	51	26	29	29	29
10	51	50	2	2	2

Comparing with Table 5, it can be seen that the weeks utilized in the 10-scenario version are spread wider throughout the year than in the 3-scenario version. This accounts for uncertainty in the data material to a larger extent.

5.2.4.2 Inflow

The same data sets from SINTEF used for the 3-scenario version are also used for the 10-scenario version in the following way:

- Seasons 1-3: 2005 data
- Seasons 4-6: 2004 data
- Seasons 7-9: 2003 data
- Season 10: Average values of 2003, 2004 and 2005 data

Referring to Table 7, it can be seen that the weeks used for seasons are different for the 3-scenario and 10-scenario versions. Therefore, utilizing the same data set for both versions will still yield variations in inflow. Also, even though the same data set is used for several seasons in the 10-scenario version (for instance seasons 1-3), differing week numbers for the scenarios internally in this version leads to variations in the resulting inflow as well.

5.2.4.3 Initial Reservoir Level

When using 10 scenarios the initial reservoir level can be allowed to vary to a greater extent compared to the 3-scenario version.

Depending on the week numbers from Table 7, seasons are divided into two categories: winter and summer seasons. As explained for the 3-scenario version in Section 5.2.3.2, in the deterministic formulation initial reservoir levels for winter and summer were set to be 60% and 80%, respectively. These values are still considered most correct also for the 10-scenario version [60]. Consequently, there is a wish to have these values as starting point for the ten scenarios and both season categories (winter and summer). The initial reservoir levels therefore revolve around 60% and 80% for winter and summer seasons. However, the distribution of initial reservoir levels on scenarios is done in a different way for the 10-scenario version.

Initial reservoir levels are chosen to lie in the range from 50% to 70.25% for winter seasons, giving an average of 60.125% for all scenarios. For summer seasons the levels lie in the range from 70% to 90.25%, with an average of 80.125%. Winter seasons are defined as seasons that reside in the period from mid-October to mid-April (week 43 to 17), and summer seasons as residing in the remaining period (week 18 to 42).

As for the 3-scenario version there is a desire to include dry- and wet-year behavior in the model. To do this, the regulated inflow for each scenario is used to determine which scenarios can be defined as 'dry' and 'wet'. The scenario with highest total inflow is assigned the highest value for initial reservoir level (wet year), and the scenario with lowest total inflow is assigned the lowest value for initial reservoir level (dry year). Ordering the rest of the seasons in a similar manner, the initial reservoir level is set for each scenario as seen in Table 8.

Table 8: Initial reservoir levels for the 10-scenario version.

Scenario	Initial reservoir level, winter seasons [%]	Initial reservoir level, summer seasons [%]
1	63.5	83.5
2	70.25	90.25
3	54.5	74.5
4	52.25	72.25
5	56.75	76.75
6	50	70
7	59	79
8	68	88
9	65.75	85.75
10	61.25	81.25

These values are used for all nodes, with some exceptions. As with the 3-scenario version, the reservoirs of Spain and Italy are considered more stable and are given summer-specific initial reservoir levels for all seasons. Norway and Sweden are given detailed initial reservoir levels for all seasons in each scenario based on the values given in Figure 18 and Appendix C.3. Because of the vast data material in the 10-scenario version the actual numbers are not included here.

5.3 Restricting Run-of-the-River Hydropower

5.3.1 Background

In order to further expand the hydropower representation in EMPIRE, a new formulation for run-of-the-river (RoR) hydropower is proposed. Inflow values for this technology type are available from SINTEF in the same format as for regulated hydropower.

In the original EMPIRE model run-of-the-river hydropower was constrained by a parameter called 'Availability', which is defined for each operating hour and consists of a fractional value between zero and one. This value specified the available share of the installed capacity in a given hour and thereby restricted the possible generation from RoR hydropower. However, since the continuous inflow to the run-of-the-river turbine is the restricting factor for this technology, new constraints can be formulated by utilizing the SINTEF data. Inflow is given for each week of the year in the data sets.

5.3.2 Implementation

First, the original constraint for RoR hydropower is disabled by setting the 'Availability' parameter equal to 1 for all RoR generators, thereby relaxing this restriction:

$$\xi^{\text{gen}}_{ghi\omega} = 1 \mid \left(p^{gen}_{gi} > 0 \right), \quad g \in G^{HydRoR}_{n}, h \in H, i \in I, \omega \in \Omega \tag{5.4}$$

Second, the total generation from RoR hydropower summed over all operational hours in a season is restricted by the RoR inflow in that season:

$$\sum_{h \in H_s} y^{gen}_{ghi\omega} \leq U^{RoR}_{ns\omega} \cdot p^{gen}_{gi}, \quad n \in N, g \in G^{HydRoR}_{n}, s \in S, i \in I, \omega \in \Omega \tag{5.5}$$

This restriction states that the total generation from run-of-the-river hydropower during one season cannot exceed the total seasonal inflow.

The above restriction sets an upper limit for the *seasonal* generation. However, keeping in mind that RoR hydropower does not have a reservoir available for water storage, an additional restriction is needed in order to limit the *hourly* generation. With only the above constraint the model will be able to move water around during each season and generate at the hours where it is most economically beneficial to do so, for example when load is high and wind and solar generation is low. Since the availability of RoR hydropower is continuous, this should not be allowed. Therefore, the following restriction is introduced:

$$y_{ghi\omega}^{gen} \leq \frac{U_{ns\omega}^{RoR,norm} \cdot p_{gi}^{gen}}{v_s}, \quad n \in N, g \in G_n^{HydRoR}, h \in H, s \in S, i \in I, \omega \in \Omega \tag{5.6}$$

where v_s is defined as

$$v_s = \sum_{h \in H_s} 1, \quad s \in S \tag{5.7}$$

Consequently, v_s is the total number of hours in season *s*. Equation (5.6) therefore affirms that the hourly generation from RoR hydropower cannot exceed the average inflow for all hours constituting season *s*. This will limit the degree of freedom in which the model can determine at what hours inflow can be utilized throughout each season.

5.4 Evaluation and Corrections of SINTEF Data Sets

The data material from SINTEF contains water values, inflow and capacities for regulated and RoR hydropower as well as reservoir sizes for regulated hydropower. However, water values and inflow data are not given for ten of the 31 countries. Table 9 below includes these countries and their associated capacities and reservoir sizes from the SINTEF data sets.

Table 9: Countries that have missing water values and inflow data in SINTEF data sets.

Node	Country	Regulated Capacity [MW]	RoR Capacity [MW]	Reservoir Size [GWh]
3	Belgium	0	137	0.1
4	**Bulgaria**	**2027**	**203**	**0.1**
5	**Switzerland**	**8350**	**3992**	**0.1**
8	Denmark	0	9	0.1
9	Estonia	0	5	0.1
16	Hungary	10	50	0.1
17	**Ireland**	**215**	**32**	**18**
21	**Latvia**	**0**	**1550**	**0.1**
23	Netherlands	0	56	0.1
30	**Slovenia**	**0**	**1027**	**0.1**

For most of these countries, the missing inflow and water values can be justified since the capacities and reservoirs are very small. This justification is valid for all of the countries above except for Bulgaria, Switzerland, Ireland, Latvia and Slovenia (shown in bold), all of which have large or relatively large installed capacities in either regulated or run-of-the-river hydropower. Such capacities cannot be ignored and have to be corrected for. This is done in the paragraphs to follow. The described corrections are carried out for both the 3-scenario and the 10-scenario versions.

5.4.1 Switzerland

Switzerland has 8 350 MW of regulated hydropower capacity, but the reservoir size in the SINTEF data is set to be only 0.1 GWh. Cross-checking this number with other sources leads to the conclusion that the SINTEF number must be wrong. The total annual hydropower generation in Switzerland is 37.59 TWh [61]. 49% of this generation comes from regulated hydropower, yielding an annual generation from regulated hydropower of 18.42 TWh [62]. In lack of better data, it is assumed that the reservoir size is equal to the total annual generation. Therefore, the reservoir size of Switzerland is set to 18.42 TWh.

When it comes to inflow, data from a neighboring country is used as an estimate. This can be justified since inflow is given as normalized data relative to the installed capacity. Therefore, the normalized values are more dependent on other criteria like geographical characteristics of the area than the installed capacity. This implies that the normalized values should not be extensively different for two neighboring countries. Choosing two neighboring countries and comparing their normalized values for regulated and run-of-the-river inflow can be done as an illustration. Norway and Sweden are used in such an example. For Norway, the aggregated inflow for all ten seasons and for the three scenarios used in the 3-scenario version is 221.28 MWh/MW_{inst} and 193.50 MWh/MW_{inst} for regulated and RoR hydropower, respectively. For Sweden, the corresponding values are 186.46 MWh/MW_{inst} and 193.79 MWh/MW_{inst}, respectively. The inflow difference between the countries is 18.6% for regulated inflow and 0.1% for RoR hydropower. The difference is noticeable for regulated inflow. Nevertheless, using inflow data from neighboring countries is still a decent approximation and better than having no data at all.

Based on this logic, inflow data for Switzerland is chosen to be the same as for the neighboring country of Austria. The same is done for water values. The size of Austria's reservoir is in vicinity to the updated reservoir size of Switzerland, so this approximation should be applicable [61].

5.4.2 Bulgaria

Bulgaria has 2 027 MW of regulated hydropower capacity and 203 MW of RoR hydropower capacity. The reservoir size from SINTEF is only 0.1 GWh. Other sources claim that the total developed hydropower potential is 4.61 TWh in Bulgaria [61]. The given distribution between installed capacity of regulated and RoR hydropower in these sources implies that most of the hydropower generation originates from regulated hydropower. An estimation of 4 TWh for Bulgaria's reservoir size is therefore used.

Water values and regulated and run-of-the-river inflow for Bulgaria are set to be the same as data for the neighboring country of Romania.

5.4.3 Latvia

Latvia has 1 550 MW of RoR hydropower capacity. The closest neighboring country with any significant installed capacity of this technology is Poland. Normalized inflow data from Poland is therefore used for Latvia as well.

5.4.4 Slovenia

Slovenia has 1 027 MW of RoR hydropower capacity. To correct for missing RoR inflow data, values for the neighboring country of Croatia is used.

5.4.5 Ireland

The reservoir size for regulated hydropower in Ireland is given as 18 GWh by SINTEF. World Hydro Atlas 2010 claims that Ireland has developed an annual potential of 725 GWh [61]. The distribution of installed capacity for hydropower in Ireland is 215 MW for regulated and 32 MW for RoR. Based on this allocation, as an estimate, the reservoir size in Ireland is therefore upgraded to 600 GWh.

Regulated and RoR inflow for Ireland is set to be the same as Great Britain's inflow data. The same is done for water values.

5.4.6 Germany

In the SINTEF data set, water values for Germany were set to zero for all segments in all seasons and years. This is clearly not correct. In order to gain applicable water values for Germany, the values for Czech Republic are used. These countries have reservoir sizes and regulated hydropower capacities that are not differing extensively. Their geographical locations are also not very contrasting, making Czech Republic a valid approximation.

5.5 Corrections of Season-Year Inflow Scaling

This section describes corrections of inaccuracies related to scaling of inflow from season to year. In order to understand how such imprecisions might occur, it is useful to explain how the model handles scaling of seasons. From the description of the modeling framework in Section 3.1.2, it is known that for each year ten seasons are modeled, consisting of four regular and six peak-load seasons. These seasons are then scaled to comprise an entire year. This is done by converting the ten seasons into four main seasons, and scaling regular and peak-load seasons according to a predetermined weighting between the two types. Consequently, a parameter P_s that is defined for each season s is scaled to one year the following way:

$$P^{year} = \frac{8760}{24 \cdot 4} \cdot \left[\begin{array}{l} \frac{8750}{8760}\left(P_1 + P_2 + P_3 + P_4\right) + \\ \frac{10}{8760}\left(P_5 + P_6 + P_7 + P_8 + P_9 + P_{10}\right) \end{array} \right] \tag{5.8}$$

For the inflow parameters, where seasonal values are chosen based on the corresponding week the seasons reside in, the actual inflow value for this particular week will have a large impact on the total annual inflow. For example, if the inflow for the week that season 1 resides in is (incidentally) significantly larger than in the surrounding weeks, the inflow scaled to a year will be larger than the actual annual inflow. Also keeping in mind the relatively short season lengths it is understandable that scaling inaccuracies will occur. These imprecisions have to be taken into account and corrected for. Analyses for both the 3-scenario version and the 10-scenario version will therefore be performed.

5.5.1 The 3-Scenario Version

5.5.1.1 Regulated Inflow

Table 24 in Appendix D.1 gives country-wise aggregated regulated inflow for all three scenarios (aggregation is done in order to save space). The difference is largest for Finland, with a percentage-wise deviation of 30%. However, Finland's reservoir is relatively small compared to the country with the second largest difference: Norway. Summed over the three scenarios, the scaled inflow is 81 TWh larger than the actual inflow for Norway. Evaluating scenario-wise differences, it is found that most of the deviation originates from scenario 2. For each of the scenarios, the scaled annual inflow used in the model is 115 TWh, 157 TWh and 103 TWh, respectively. Thus, inflow for scenario 2 is extremely high and should be corrected for. This is done in the next section. The variations for the other nodes and scenarios are generally not very large and does not have to be corrected for.

Correction of Norwegian Regulated Inflow

It is determined that the inflow is to be capped at 140 TWh (still a high value, but variations in scenarios are aspired). To do this, 17 TWh shall be removed from the total annual value. This removal is done in all ten seasons, based on their contribution towards the total annual inflow. The original inflow values, seasonal contributions and adjusted inflow are given in Table 25 in Appendix D.1. Utilizing the corrections outlined in the table and scaling the adjusted seasonal inflow values with Equation (5.8) indicates that the updated annual inflow is now correctly 140 TWh.

5.5.1.2 Run-of-the-River Inflow

The same analysis is carried out for run-of-the-river inflow. For all values, see Table 26 in Appendix D.1. Inflow is also here aggregated for all three scenarios. Most of the countries have small differences between the actual and scaled inflow. Norway has a difference of 25 TWh, or 18%, for the three scenarios combined. Further analysis demonstrates that most of the deviation again originates from scenario 2, with a variation of 16.2 TWh. This is a large difference and will be accounted for in the following.

Correction of Norwegian Run-of-the-River Inflow

Correction of the scaled inflow value in scenario 2 is done the same way as for regulated inflow. 16 TWh has to be removed from the scaled inflow to make up for the difference. The correction is done in all seasons, weighted towards each season's inflow share. Table 27 in Appendix D.1 gives the original inflow, seasonal share of total inflow, the amount to be removed from each season and finally the adjusted inflow. Taking this removal into account and scaling the adjusted seasonal inflow values now gives an annual total inflow of 52.3 TWh for scenario 2. This is just above the scenario's actual annual value of 49.5 TWh.

5.5.2 The 10-Scenario Version

The scaling of inflow from season to year is investigated the same way as for the 3-scenario version.

5.5.2.1 Regulated Inflow

The differences between actual and scaled regulated inflow are given as the sum for all ten scenarios in Table 28 in Appendix D.2. Poland has a very large difference. This is caused by the relatively low inflow values for this country, making the percentage-wise difference sensitive to changes. For most nodes, however, the summed difference for all ten scenarios can be considered negligible. Examining scenario-specific differences illustrates that the scenario-wise differences also are negligible for most nodes. Exceptions are Norway and Sweden. Here, the differences for each scenario are large enough that manual corrections have to be carried out.

Correction of Norwegian and Swedish Regulated Inflow

Table 29 in Appendix D.2 gives the actual inflow, scaled inflow and difference for each of the ten scenarios for Norway and Sweden. Regulated inflow for Norway and Sweden are corrected for by removing the percentage in the right-most column of the table. As with the 3-scenario version, the correction for each season is done depending on their share towards total annual inflow. The distribution of seasonal corrections is not presented in the table due to large amounts of data, but the procedure is the same as the one given for the 3-scenario version.

5.5.2.2 Run-of-the-River Inflow

Table 30 in Appendix D.2 gives a comparison of the actual and scaled inflow used in the model for the 10-scenario version. It can be seen that the country-wise differences for all scenarios is insignificant. Examining scenario-specific data, the largest difference for a single country (and all seasons) is found to be 35%, while the largest difference for each scenario summed over all countries and seasons is found to be 28%. However, the average difference is close to negligible. It is therefore decided to not perform any corrections of run-of-the-river inflow in this case.

5.6 Restricting Regulated Hydropower Investments

In order to increase model stability with regards to investments in regulated hydropower, a parameter termed 'Allow-build', ϕ_{nti}, has been implemented. This is a data set informing the model which countries are actually able to invest in regulated hydropower. The following countries cannot invest in this generator type for any of the years: Bosnia & Herzegovina, Belgium, Denmark, Estonia, Croatia, Hungary, Latvia, Macedonia, the Netherlands and Slovenia. The data set is made by Christian Skar, but was not utilized originally.

The creation of investment variables is disabled if the 'Allow-build' parameter is 0, for which a simplified pseudo code is given below.

for all years in $\{2015, \ldots ,2060\}$, nodes, aggregate technologies *do*
    if $\left(\phi_{nti} = 0 \text{ and } \mathrm{T}_g = 24\right)$ *then*
        Investment variables are not created
    end-if
end-do

Mosel code for reading the 'Allow-build' parameter is given in Appendix E.4.

The 'Allow-build' parameter comes with another benefit. The procedure that creates generation variables works in a way that ensures that if investment variables are not created and the given node has no initial capacity for the given technology type, generation variables are not created. This way, adding the 'Allow-build' parameter limits creation of unnecessary investment and generation variables. This lowers computation times.

5.7 Implementing Annual Water Values

Previously, water values for 2010 were utilized for the entire analysis period. This means that water values for the years 2015 to 2060 were based on the state of the energy system in 2010. The accuracy of such a strategy will generally not be sufficient. As explained in Section 2.6.2, water values are directly dependent on the expected generation mix of other technologies through the expected electricity price [63]. The generation mix, in turn, is closely linked to the currently installed capacity of a given technology. When capacities and generation mix change throughout the planning period, water values should consequently reflect these changes as well. Implementing annual water values is therefore of considerable importance. As they are used as decision-making tool for hydropower generation, the influence of their quality cannot be emphasized enough. They are therefore discussed thoroughly in this section.

The power price is given by the marginal cost of the last generator needed to cover demand (price-setting generator). With increasing CO_2 prices in the future, the marginal costs of sources with high CO_2 content are also bound to increase. At the same time, higher penetration of renewables with very low short-run marginal costs will generally lead to lower power prices, as explained in Section 2.7. Because of these conflicting trends, the resulting power price and thereby the correct water value for a certain year is not easy to predict. In order to account for these annual variations, the EMPS model at SINTEF Energy Research is used to generate water values for each year. These simulations are based on capacity results from the original EMPIRE model.

5.7.1 Stochastic Considerations

Water values are given as weekly values. Stochastic scenarios are incorporated by matching the seasons in EMPIRE with the corresponding actual week for each scenario. This will have an impact since the water values are changing throughout the year, and the actual weeks used for seasons in EMPIRE are different for the stochastic scenarios. Scenario-based matching follows the same weeks and seasons as for other parameters, given in Table 5 and Table 7 for the 3-scenario version and the 10-scenario version, respectively.

For the latter version, the total size of the data set amounts to 1.8 million values (10 scenarios, 11 years, 10 seasons, 31 nodes, 51 segments).

5.7.2 Analyzing Data Quality

While performing preliminary optimization runs with the new annual water values acquired from SINTEF, it was quickly discovered that the quality of the data set is insufficient. When the EMPS model is about to generate water values, several settings can be determined in the initialization phase. This includes calibration factors and definitions of spatial grouping of areas [64]. The spatial grouping is determining the amount of load each country is witnessing. For the initial simulation each country was defined as one “group”. This means that each country only witnessed its own load. For most countries, total load heavily exceeds the available hydropower capacity. The so-called feedback factor (ratio between load and available hydropower) therefore turns out to be very large. When the EMPS model comprehended that there was no possibility of total load coverage since each country was modeled as its own system, it chose to save water altogether instead of covering as much as it possibly could. This leads in practice to water values equal to the cost of energy rationing. The rationing cost is the price a consumer has to pay if more energy is used than what is allocated to the consumer in a rationing situation, and is preventively high [65]. The cost is therefore equivalent of artificially forcing reductions in load. Because of the described behavior of the EMPS simulations, the water values ended up being unreasonably high. For example, in 2060, 40% of all water values were placed on the rationing cost of 37.5 ¢/kWh or 520 $/MWh.

With these exceedingly high water values, optimization runs yielded virtually non-existent levels of regulated hydropower generation, especially towards the end of the planning period. The results are reasonable with the high costs associated with hydropower generation, but are clearly erroneous.

Remedying the issue with faulty water values are partly solved by introducing a different set of spatial area groups in EMPS. This is done by arranging neighboring countries together:

- *Group 1 - The Nordic countries:* Norway, Sweden, Denmark, Finland
- *Group 2 - The British Isles:* Great Britain, Ireland
- *Group 3 - Central Europe:* Germany, the Netherlands, Czech Republic, Austria, Portugal, Spain, Switzerland, Italy, Poland, Belgium, Luxembourg, France
- *Group 4 - The Baltic states:* Estonia, Latvia, Lithuania
- *Group 5 - South-Eastern Europe:* Hungary, Slovakia, Slovenia, Bulgaria, Serbia, Romania, Greece, Macedonia, Croatia, Bosnia & Herzegovina

Generating water values based on the groupings declared above gives a better data set, where there is no use of rationing costs. For 2010, the values are actually very good. However, the quality is still not satisfying for the rest of the years. Performing optimization runs with the updated values leads to very differing country-wise generation results. Examining the actual water values further shows that their magnitude for each country is very different, with water values for some countries being several times higher than for others. Variations will indeed naturally be occurring due to different conditions for each country. The extent of differences observed here are nevertheless too large to be termed correct. The model will in this situation favor generation in some countries and chooses to invest heavily in generation capacity. Other countries see unreasonably low generation.

Attempts have been made in order to rectify the issue and this will be described in the following.

As we now know, water values are partly dependent on the marginal costs of alternative generation technologies at a given time. A closer look at the short-run marginal costs (SRMCs) is therefore worthwhile. An exploratory measure can involve scaling the water values from 2010, where generation levels are reasonable, in the same manner as the SRMC of a competitive technology is changing throughout the planning period. Short-run marginal costs of other energy sources are readily available for all years in the planning period since the original EMPIRE model uses them as parameters. The SRMCs for some relevant technologies are shown in Table 10.

Table 10: SRMC of relevant technologies for possible use as water value scaling factors for the Global-20-20-20 scenario. All values are in 2010$/MWh.

	Technology		
Year	Lignite IGCC CCS	Gas conventional	Bio IGCC CCS
2010	15.4	48.7	67.4
2015	15.4	49.1	67.5
2020	17.5	60.8	51.6
2025	17.9	65.4	41.3
2030	18.2	70.2	32.2
2035	18.4	74.5	30.5
2040	19.4	84.5	21.6
2045	20.3	94.6	13.2
2050	21.1	104.0	7.3
2055	23.6	118.2	8.4
2060	26.0	132.7	9.8

It is evident that the change throughout the planning period is very different for the technologies. Because of the high CO_2 contents of conventional gas, its SRMC is increasing at high rates throughout the planning period under the Global 20-20-20 scenario. Lignite IGCC CCS increases somewhat, but much less than conventional gas because of the use of CCS. Bio is heavily decreasing. Regardless of the actual values, however, the table shows that the vast relative differences between technologies make it hard to use either one of them for scaling. The main problem with this approach is that one individual technology cannot be used as basis for scaling for the entire planning period. The true increase in system marginal cost should be measured by the *marginal* generator, i.e. the last generator needed to fulfill the load requirement. This is the price-setting generator and is changing for different configurations. The marginal cost can therefore be accessed by the dual value, or shadow price, of the load balance constraint. The shadow price is defined as the change in the value of the objective function when the right hand side of a constraint is increased by one unit [66]. For the load constraint, this translates to the added cost of covering 1 MW of additional load, and is essentially the resulting power price. Since load is defined for each hour in every country, there will also be a shadow price for every such configuration. For illustrative purposes, annual median values for all scenarios, hours and nodes are shown in Table 11.

Table 11: Shadow price median for the load balance constraint throughout the planning period. Values are in $/MWh.

Year	Load constraint shadow price	Change from 2010
2010	43.45	0%
2015	18.61	-57%
2020	46.78	8%
2025	48.69	12%
2030	49.20	13%
2035	48.56	12%
2040	49.03	13%
2045	47.16	9%
2050	58.61	35%
2055	63.96	47%
2060	82.87	91%

These values are found by running the original model without enhanced hydropower formulation, in order to gain independent results unaffected by erroneous water values. Evidently, the change in marginal cost for the entire system is differing from the change in specific technologies as depicted in Table 10. The combination of increased penetration of renewables and rising CO_2 prices are the main reasons for the development. As an exploratory attempt, an optimization run for the final model is performed with water values scaled towards the changes in shadow prices as shown in the table. The scaling is done individually for each year, scenario, season and node in order to use as detailed data as possible. However, regulated hydropower generation results from this optimization are yet again unsatisfactory, yielding unrealistic levels. This shows that the exercise of scaling water values from one year (2010) is not an approach that gives tolerable results.

SINTEF has been confronted with the issue, but they have not been able to offer a remedy that gives acceptable water values from 2015 to 2060. As a consequence, the final model results that are presented in Chapter 7 will be shown for two main cases: One where the original water values are utilized and one where limitations related to the generation from regulated hydropower are included. These will be described further in Chapter 7.

5.7.3 Water Values Statistics

Figure 19 shows water values for the top 30 reservoir segments (out of 51) for ten selected countries in season 1, 2015, for the Global 20-20-20 policy scenario. The graph is included here in order to visualize the differences in water values provided by SINTEF.

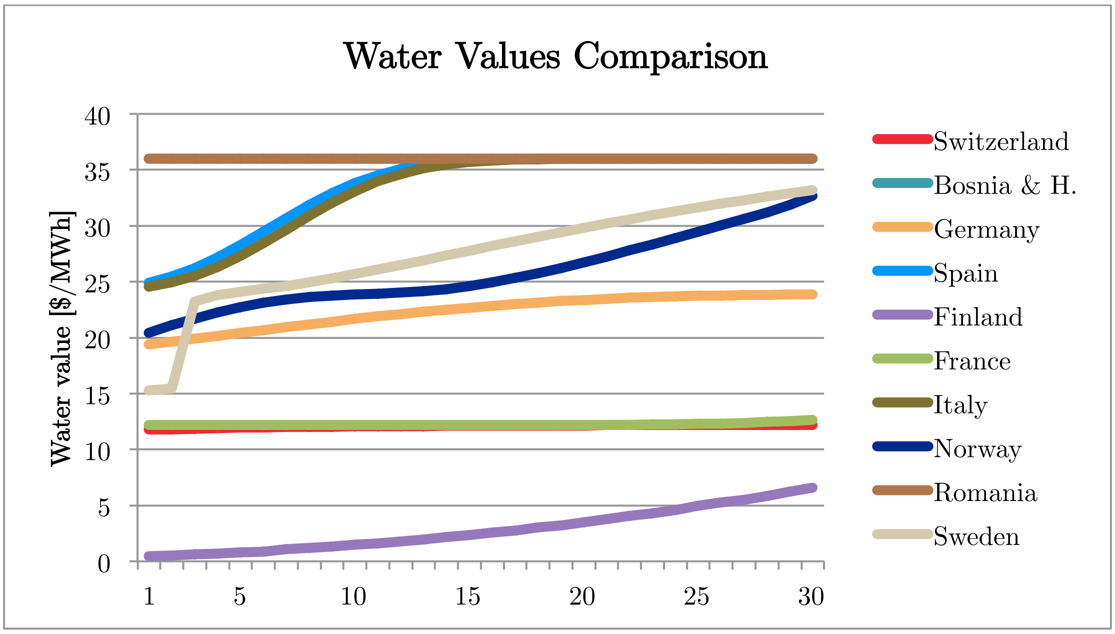

Figure 19: Water values for the top 30 segments in select countries, in 2015. This is for season 1 in scenario 1, Global 20-20-20 scenario.

The countries for which water values are depicted above are chosen based on the regulated hydropower generation in the original model in 2015; the countries with highest generation are depicted. The graph clearly shows great variations in water values between the included countries, with values in the top segment ranging from 0.5 $/MWh (Finland) to 36 $/MWh (Romania). When descending in the reservoir the development of the water values is also significantly dissimilar. Some experience almost no increase, like France, Switzerland and Romania. Others fluctuate to some extent, like Norway, Sweden and Spain. Only the top 30 segments are shown because the variations in water values for lower segments than these are very large, disabling comparison between countries with low values.

The standard deviation is a measure for the variation in a data set, stating how far the observations are scattered away from the mean. For the water values in the top segment the standard deviation between the countries for the given configuration is 11.0 \$/MWh. For segment 30 it is 11.8 \$/MWh, while the bottom segment (number 51) has 186.4 \$/MWh as standard deviation. This adds to the conclusion that water values are fluctuating to a large extent.

The water values discussed here are for the Global 20-20-20 policy scenario. Data sets for other scenarios actually have even lower quality than Global 20-20-20. Therefore, all optimization runs for which final results are presented will be carried out for this scenario.

5.8 GCAM Matching of Generation Mix

The EMPIRE model is by definition based on cost minimization. At the current model state, this formulation tends to favor low-cost technologies in a way that may not be fully realistic. When the model finds the technology that can deliver energy at the lowest cost it will invest as much as possible in this technology, constrained by limits for annual build capacity and maximum installed capacity in each country. However, such a modeling pathway does not fully account for aspects like political policies and implications for other sectors that are dependent on a certain technology. An example is biomass. The substantial CO_2 savings accompanied with this technology causes a large-scale expansion, which may be beyond reality.

The Global Change Assessment Model (GCAM) is developed by the Joint Global Change Research Institute and is an integrated assessment tool focusing on exploring consequences and responses to global changes [52]. Being a global model, the level of geographical detail in its results is limited. Europe is modeled as two regions, implying high level of aggregation. However, GCAM takes many aspects into account in its modeling, such as political policies and consequences accompanied with climate change for a wide range of sectors. As such, GCAM results are satisfactory for large regions. A part of its results is expected generation shares for each technology and region in the world required to meet policy scenarios.

Matching generation shares through the GCAM framework will add model stability and bring it closer to reality by integrating the considerations mentioned above. This is carried out by including restrictions that limit generation mix in EMPIRE to a matching of the generation shares provided by GCAM. Since GCAM shares are given for aggregated regions, one for Western Europe and one for Eastern Europe, the model still has a large degree of freedom when it comes to where it chooses to geographically place the generation. The shares are visualized in Figure 20, where average values of Western and Eastern European shares are shown for the Global 20-20-20 scenario.

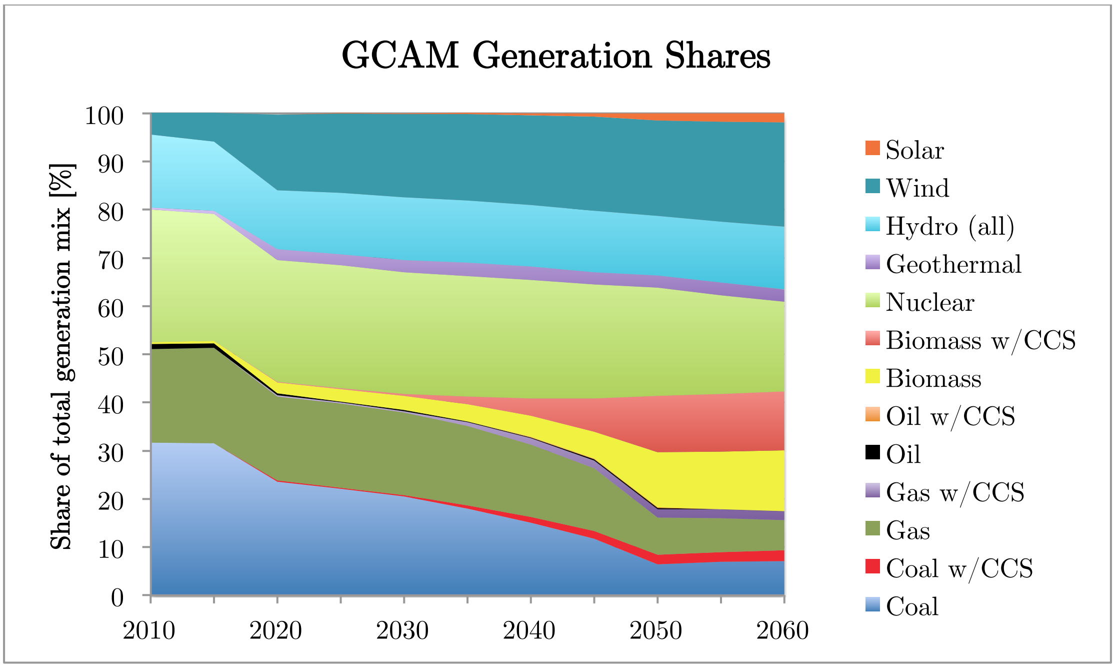

Figure 20: GCAM generation shares for the Global 20-20-20 scenario. Values are given as percentages of total generation.

EMPIRE is allowed to deviate from these values to a certain extent by defining share error tolerances for each aggregated technology. When the enhanced hydropower formulation is introduced there is also a desire to be able to clearly see the impacts accompanied by its implementation. The GCAM share matching will constrain the model and as such, effects may be more difficult to identify. Therefore, the GCAM share error tolerances are altered. The allowed deviations are given in Table 12, along with the previous values.

Table 12: Share error tolerances for matching of GCAM values for generation mix. Previous values are given in parenthesis.

Technology	Lower allowance	Upper allowance
Coal, gas, oil	40% (5%)	40% (5%)
Coal, gas, oil w/CCS	40% (5%)	0% (5%)
Bio	40% (5%)	0% (5%)
Bio w/CCS	40% (5%)	0% (5%)
Nuclear	no limit (no limit)	0% (5%)
Geo	no limit (3%)	0% (3%)
Hydro	no limit (3%)	no limit (20%)
Wind, solar	no limit (3%)	no limit (no limit)

These changes are carried out for both the original model and the enhanced version with hydropower scheduling. As indicated, the model incorporates lower limits of 40% for fossil and bio technologies. Most technologies are not allowed to exceed the GCAM values upwards. Hydro, wind and solar are notable exceptions, with no limits in either direction. Adding these relaxations allows us to identify impacts of the new hydropower formulation more clearly, while at the same time preserving some of the added stability by incorporating GCAM matching.

By including the changes described in this chapter, the final model is ready to be presented.

6 Final Model Formulation

The complete, final model with enhanced hydropower formulation is given in the following sections.

6.1 Objective Function

The objective function is to minimize the net present value of the combined investment costs and operational costs for the planning period:

$$\min_{\mathbf{x},\mathbf{y}} z = \sum_{i \in I} \delta_i \times \left\{ \begin{array}{l} \sum_{g \in G} c_{gi}^{\text{gen}} x_{gi}^{\text{gen}} + \sum_{l \in L} c_{li}^{\text{tran}} x_{li}^{\text{tran}} + \\ \sum_{\omega \in \Omega} p_\omega \left(\begin{array}{l} \sum_{h \in H} \alpha_h \times \sum_{n \in N} \left(\sum_{g \in G_n} \left[q_{gi}^{\text{gen}} y_{ghi\omega}^{\text{gen}} \right] + q_{ni}^{\text{VoLL}} y_{nhi\omega}^{\text{LL}} \right) + \\ \sum_{s \in S} \vartheta_s \times \sum_{n \in N} \sum_{m \in M_n} xd_{mnsi\omega} WV_{mnsi\omega} \end{array} \right) \end{array} \right\} \tag{6.1}$$

The cost of regulated hydropower is represented by the last term: discharge from segment m multiplied by the corresponding water value for all segments, nodes, seasons, stochastic scenarios and years. The other terms include investment costs of generation and line transmission capacity and costs of power generation and lost load.

6.2 Constraints

6.2.1 Original Model

Investment constraints for generation capacity (period-wise and cumulative):

$$\sum_{g\in G_{nt}} x_{gj}^{\text{gen}} \le \overline{x}_{nti}^{\text{gen,Period}}, \quad n\in N, t\in T, i\in I.$$
$$\sum_{j=1}^{i}\sum_{g\in G_{nt}} x_{gj}^{\text{gen}} \le \overline{x}_{nt}^{\text{gen,Cumulative}} - (1-\rho_{gi})\overline{x}_{g0}^{\text{gen}}, \quad n\in N, t\in T, i\in I. \tag{6.2}$$

Investment constraints for transmission (exchange) capacity:

$$x_{li}^{\text{tran}} \le \overline{x}_{li}^{\text{tran,Period}}, \quad l\in L, i\in I. \tag{6.3}$$

Load constraints (production + net import + load shedding = load + pumping):

$$\sum_{g\in G_n} y_{ghi\omega}^{\text{gen}} + \sum_{a\in A_n^{\text{in}}} (1-\eta_a^{\text{line}}) y_{ahi\omega}^{\text{flow}} - \sum_{a\in A_n^{\text{out}}} y_{ahi\omega}^{\text{flow}} - y_{nhi\omega}^{\text{pump}} + y_{nhi\omega}^{\text{LL}} = \xi_{nhi\omega}^{\text{load}}, \; n\in N, h\in H, \omega\in\Omega, i\in I. \tag{6.4}$$

Generation capacity constraints:

$$y_{ghi\omega}^{\text{gen}} \le \xi_{ghi\omega}^{\text{gen}} \times \left((1-\rho_{gi})\overline{x}_{g0}^{\text{gen}} + \sum_{j=1}^{i} x_{gj}^{\text{gen}}\right), \quad g\in G, h\in H, i\in I, \omega\in\Omega. \tag{6.5}$$

Upward ramping constraints:

$$y_{ghi\omega}^{\text{gen}} - y_{g(h-1)i\omega}^{\text{gen}} \le \gamma_g^{\text{gen}} \times \left((1-\rho_{gi})\overline{x}_{g0}^{\text{gen}} + \sum_{j=1}^{i} x_{gj}^{\text{gen}}\right), \quad g\in G^{\text{Thermal}}, s\in S, h\in H_s^-, i\in I, \omega\in\Omega. \tag{6.6}$$

Flow constraints – limit flow on arcs (arcs are directional, lines are symmetric):

$$y_{ahi\omega}^{\text{flow}} \le \overline{x}_{l0}^{\text{tran}} + \sum_{j=1}^{i} x_{lj}^{\text{tran}}, \quad l\in L_n, a\in A_l, h\in H, i\in I, \omega\in\Omega. \tag{6.7}$$

Pump-storage upper reservoir balance and limit:

$$\begin{array}{c} w^{\text{upper}}_{n(h-1)i\omega} + \eta^{pump}_{n} y^{\text{pump}}_{nhi\omega} - y^{\text{gen,pump}}_{nhi\omega} = w^{\text{upper}}_{nhi\omega} \\ w^{\text{upper}}_{nhi\omega} \le \overline{w}^{\text{upper}}_{n} \end{array} \quad , n \in N, h \in H_s, i \in I, \omega \in \Omega. \tag{6.8}$$

Emission performance standard (per generator, assume g burns fuel f):

$$y^{\text{gen}}_{ghi\omega} \times hr_{gi} \times e_f \le EPS_{ni}, \quad n \in \{\text{selected nodes}\}, g \in G_n, h \in H, i \in I, \omega \in \Omega. \tag{6.9}$$

6.2.2 Hydropower Scheduling

Only the constraints are included here, and not the definitions and procedures for setting parameter values. Return to Section 4.2 for a more thorough description.

Coupling of hydropower generation and discharge:

$$\sum_{h \in H_s} y^{gen}_{ghi\omega} = \sum_{m \in M_n} xd_{mnsi\omega}, \quad n \in N, g \in G^{HydReg}_n, s \in S, i \in I, \omega \in \Omega \tag{6.10}$$

End-of-season reservoir balances:

$$r_{nsi\omega} = R^{init}_{ns\omega} - \sum_{m \in M_n} xd_{mnsi\omega} + U^{Reg,norm}_{ns\omega} \cdot p^{gen}_{gi} - s_{nsi\omega}, \quad n \in N, g \in G^{HydReg}_n, s \in S, i \in I, \omega \in \Omega \tag{6.11}$$

End-of-season reservoir limits:

$$r_{nsi\omega} \le R^{max}_n, \quad n \in N, s \in S, i \in I, \omega \in \Omega \tag{6.12}$$

$$r_{nsi\omega} \ge R^{min}_n \mid \left(R^{init}_{ns\omega} \ge R^{min}_n\right), \quad n \in N, s \in S, i \in I, \omega \in \Omega \tag{6.13}$$

Discharge constraints:

$$xd_{mnsi\omega} \le xd^{max}_{mns\omega}, \quad m \in M_n, n \in N, s \in S, i \in I, \omega \in \Omega \tag{6.14}$$

Discharge sequence constraints:

$$xd_{m+1,nsi\omega} \leq xd_{mnsi\omega} \mid \left(xd_{mns\omega}^{max} \geq S_{mn}^{max}\right), \quad m \in \left\{1, \ldots, N^{seg}-1\right\}, n \in N, s \in S, i \in I, \omega \in \Omega \tag{6.15}$$

Annual regulated hydropower generation limits:

$$\sum_{h \in H} \alpha_h \cdot y_{ghi\omega}^{gen} \leq \sum_{s \in S} \vartheta_s \cdot U_{ns\omega}^{Reg,norm} \cdot p_{gi}^{gen}, \quad n \in N, g \in G_n^{HydReg}, i \in I, \omega \in \Omega \tag{6.16}$$

Seasonal run-of-the-river hydropower constraints:

$$\sum_{h \in H_s} y_{ghi\omega}^{gen} \leq U_{ns\omega}^{RoR,norm} \cdot p_{gi}^{gen}, \quad n \in N, g \in G_n^{HydRoR}, s \in S, i \in I, \omega \in \Omega \tag{6.17}$$

Hourly run-of-the-river hydropower generation constraints:

$$y_{ghi\omega}^{gen} \leq \frac{U_{ns\omega}^{RoR,norm} \cdot p_{gi}^{gen}}{\nu_s}, \quad n \in N, g \in G_n^{HydRoR}, h \in H, s \in S, i \in I, \omega \in \Omega \tag{6.18}$$

All decision variables are assumed to be non-negative.

6.3 Data Handling

All data sets used in the model are formatted using Microsoft Excel spreadsheets. This is a convenient format for reading by the human eye, but might, however, cause trouble for other software that uses these Excel files as input. In the Mosel Xpress environment different versions of the software (often related to operating system) might not be able to read Excel files because of missing drivers and modules. To ensure that the final model is compatible with different systems containing different software versions, drivers and modules, the following is done.

A separate Mosel file is written that reads the mentioned Excel spreadsheets as input. This file has to be run on a machine that has the right version and drivers installed. The Mosel file then uses procedures to write all of the data to a single, regular text file (.txt extension). This format is much more versatile in terms of compatibility across systems. The Mosel code for converting hydropower data to a text file is given in Appendix E.1. The final model writes all output data to a single text file, which can be converted back to Excel for readability. Mosel code for the conversion of specific hydropower results from text file to Excel files is given in Appendix E.5.

The data sets for all parameters specific to the EMPIRE model are also used in the final model with the enhanced hydropower formulation. The scope of this work is not to improve the entire model, only the hydropower formulation. The rest of the original model is held intact in order to verify any changes when the hydropower formulation is added.

6.3.1 Data Flow in the Final Model

The model makes use of several files for the treatment of data. Figure 21 presents the structure of files and actual data flow. As can be seen from the figure, there is a parallel data flow, one for hydropower data and one for the other EMPIRE data. When all relevant data is collected in hydro_data.txt and other_data.txt, two Mosel files import the sets as parameters into the actual model. This is done by enhanced_hydro.mos and utility.mos, for hydropower data and other data, respectively. The parameters can subsequently be processed and utilized in optimization by the actual model, named Merged_expansion_model.mos. When the model run is complete and an optimal solution has been found, one text file with all results is created. This text file is processed with Results_analysis.mos, which writes csv files that are easily readable by Microsoft Excel.

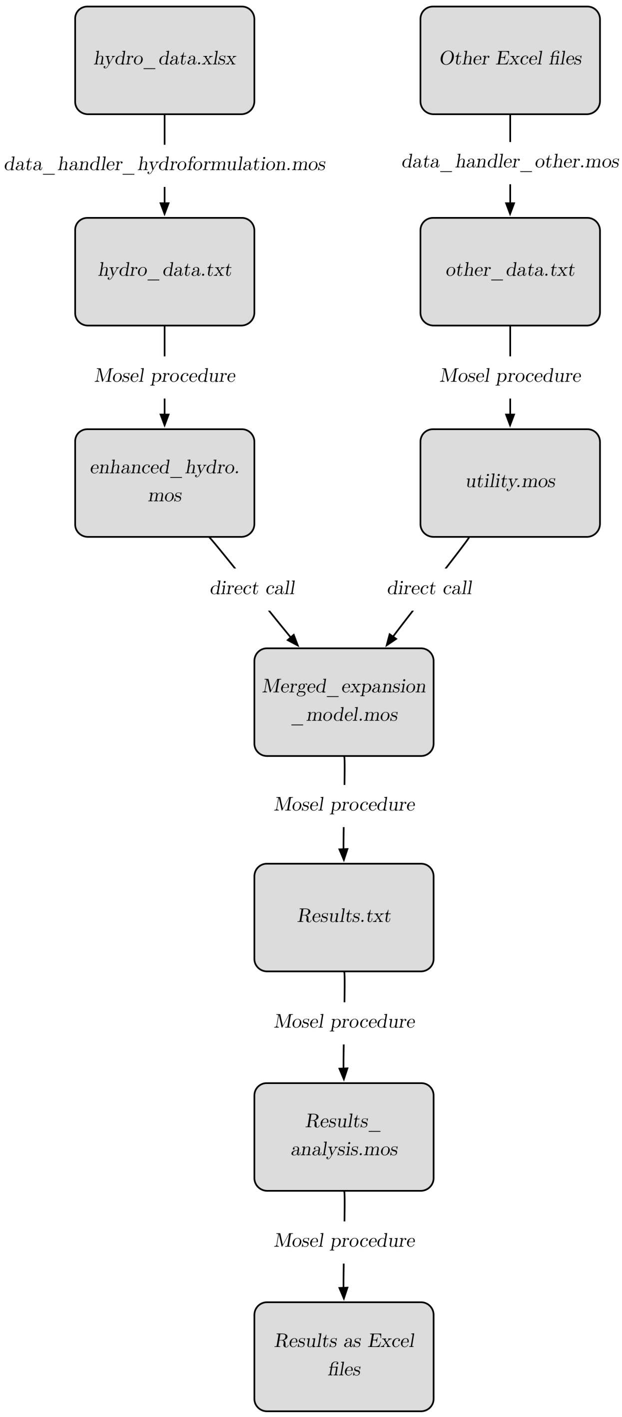

Figure 21: Data flow in the final model.

6.4 Input and Output in the Final Model

Figure 22 gives an overview of the most important input and output that are included in the final version of the model.

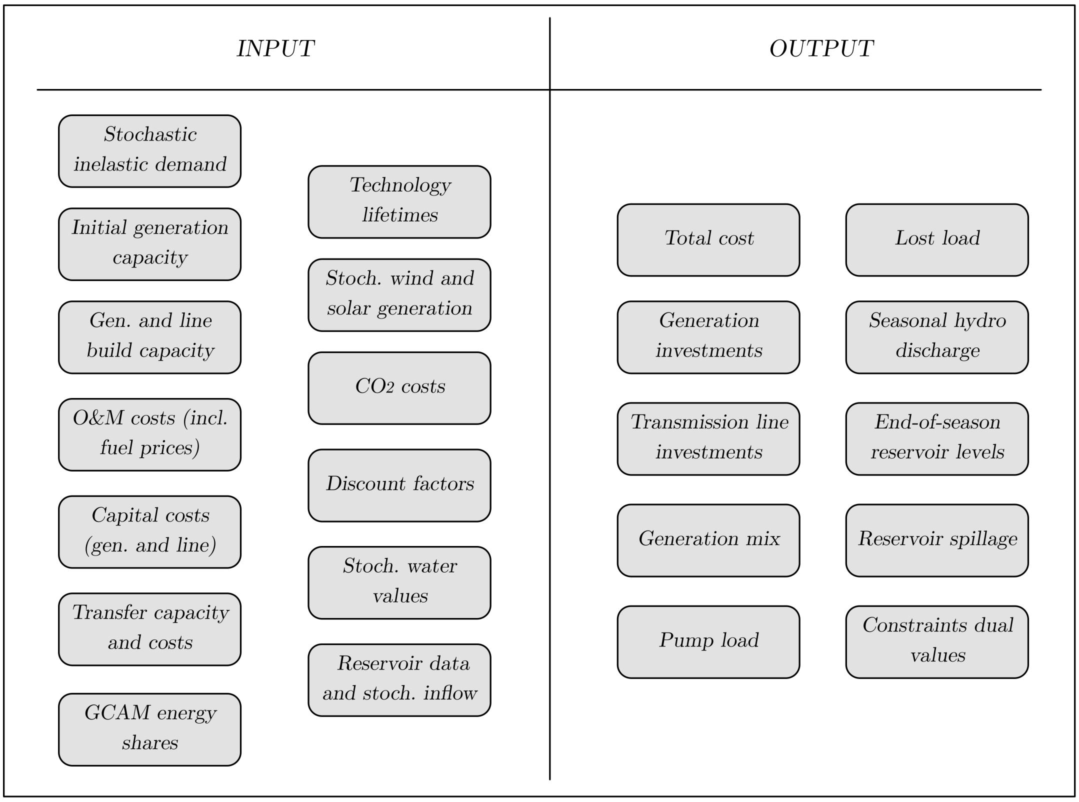

Figure 22: Overview of input and output in the final model.

With the final model now in place, optimization results can be presented. This is done in the next chapter.

7 Optimization Results and Analysis

7.1 Introduction

Optimization runs have been carried out for both the final model with enhanced hydropower formulation and the original EMPIRE model, in order to identify changes accompanied with the updated version. Newton-Barrier method is used for optimization in both models. Option for full matrix eliminations in the Barrier pre-solve algorithm is chosen.

The constraint for maximum build limits of generators in each 5-year leap is disabled for all optimization runs, in agreement with Christian Skar. This is done out of two considerations. First, the original EMPIRE model has seen some problems with load coverage. Removing the maximum build constraint has solved such issues. Additionally, a relaxed model is beneficial for the current analysis in order to see impacts of the revamped hydropower formulation. The constraint disablement is carried out for both the final model and the original model.

As previously mentioned, hydropower input data sets have been generated for both the 3-scenario and the 10-scenario version. When utilizing 10 scenarios together with the final model the problem size read by Mosel Xpress exceeds 121 million elements. The vast matrices that have to be dealt with by the program hinder Mosel to initiate the iteration procedure in the Newton-Barrier method. Attempts have been made to rectify this issue by accessing computational servers with greater capacity, but the 10-scenario version still refuses to start. As a solution, the results presented are based on the 3-scenario version. Data sets for 10 scenarios are available, but are not utilized because of the lack of computational power to carry out the actual optimizations. For reference, the 3-scenario version incorporates simulation durations of approximately three hours. Its total number of elements is approximately 22 million.

The rest of this chapter is divided into four sections. In Section 7.2, the behavior of regulated hydropower will be reviewed. The three following sections present results from optimization runs with the final model and comparisons to the original model, for three different cases. Case 0 incorporates the model as it is described in Chapter 6. Case 1 introduces generation limits for regulated hydropower, while Case 2 features relaxed maximum installed capacities for each country.

All results presented are based on the Global 20-20-20 policy scenario.

7.2 Reviewing Regulated Hydropower Behavior

The purpose of this section is to confirm the implemented framework for regulated hydropower. This will be done by performing a spot check of generation results for a random country and year. The selected country is Finland (node 11), in 2030. By utilizing the equations from Section 4.2 together with input data and model results the framework can be reviewed. Data for scenario 1 (from the 3-scenario data set) and season 2 is used in the first part of the analysis.

7.2.1 Analyzing Input Data

Table 13 gives the input data for Finland's reservoir in the selected configuration.

Table 13: Input data for Finland in scenario 1 and season 2, 2030.

Maximum reservoir size	Initial reservoir level, s = 2, ω = 1	Initial inflow, s = 2, ω = 1
2 508 GWh	80%	65 816.76 MWh

Following the procedures from step 1 of the hydropower scheduling methodology, as described in Section 4.2.2, the initial reservoir level is:

$$R^{init}_{n=11,s=2,\omega=1} = 0.8 \cdot 2\ 508 \cdot 10^3 MWh = 2\ 006\ 400\ MWh$$

Including initial inflow gives the temporary reservoir level:

$$R^{temp}_{n=11,s=2,\omega=1} = 2\ 006\ 400\ MWh + 65\ 816.76\ MWh = 2\ 072\ 216.76\ MWh$$

This implies that

$$\frac{2\ 072\ 216.76\ MWh}{2\ 508\ 000\ MWh} \approx 0.8262 = 82.62\ \%$$

of the reservoir is filled, or that

$$(1 - 0.8262) \cdot 51 \approx 8.8616$$

reservoir segments are empty (from the top), since the total number of segments in each reservoir is 51. Thus, segments $m \in \{1,...,8\}$ are empty. The maximum segment size is equal for all segments, as defined by Eq. (4.3):

$$S_{m,n=11}^{max} = \frac{2508 \cdot 10^3\, MWh}{51} \approx 49176.47\ MWh$$

The 9th segment is therefore filled with

$$(9 - 8.8616) \cdot 49\ 176.47\ MWh \approx 6\ 806.06\ MWh$$

Reservoir segments $m \in \{10,...,51\}$ are full, and are all filled with an amount equal to $S_{m,n=11}^{max}$. Returning to Figure 17 from Section 4.2.2, the theories for reservoir filling can be applied to Finland. It follows that the reservoir for the given configuration is as depicted in Figure 23.

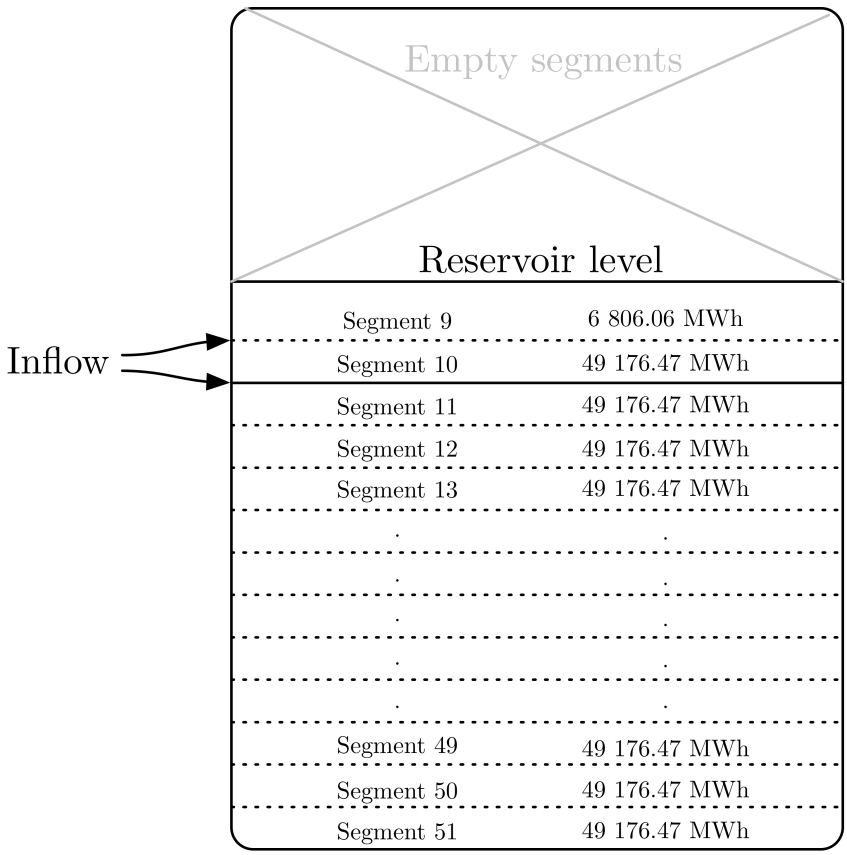

Figure 23: Reservoir situation for Finland in scenario 1, season 2 of 2030.

7.2.2 Analyzing Output Data

Seasonal Results

Discharge from Finland in the given scenario and season can be read from the model output. The input data analysis in the previous section is done without utilizing the same procedures for calculating segment sizes as the model itself does. Showing that the behavior of the model correlates to the calculations performed in the previous section will therefore verify its correctness. Table 14 gives an overview of seasonal discharge and the corresponding water value for the top 15 segments from the optimization output.

Table 14: Seasonal discharge results for the top 15 segments in Finland's reservoir, scenario 1, season 2, 2030.

Segment	Seasonal discharge [MWh]	Water value [$/MWh]
1	0	3.2092
2	0	3.30262
3	0	3.31579
4	0	3.32057
5	0	4.20037
6	0	4.4298
7	0	4.64607
8	0	4.87962
9	6 805	5.07661
10	49 176.5	5.19209
11	49 176.5	5.33789
12	49 175.5	6.94739
13	2 687.7	7.23438
14	0	7.29974
15	0	7.43105

Results for segments 16 through 51 are not included here in order to save space – the discharge is zero in all of them. It is observed that the water value assigned to each segment is increasing when descending downwards in the reservoir (increasing segment number). All of the water that is available at the lowest water value, i.e. the 9th segment, is utilized. Segment 10 and 11 are emptied, while a portion of segment 12 is also utilized. The rest of the segments are untouched, since their cost is higher. Comparing with the calculations performed in Section 7.2.1, the model behavior is verified to work as intended.

Procedures for setting the segment sizes and decisions about seasonal discharge have now been reviewed and found to function as expected, based on cost minimization. Additionally, the coupling between discharge and actual generation from regulated hydropower needs to be examined. This practically means to assure the authenticity of Eq. (6.10). For the given configuration the aggregated generation in the model output for all hours in the season is found to be 157 022.2 MWh. This corresponds to the sum of seasonal discharge for all segments from Table 14: 6 805 + 49 176.5 + 49 176.5 + 2 687.7 = 157 022.2 MWh. Thus, the coupling between seasonal discharge and seasonal generation has been confirmed.

Annual Results

A similar review can be done for the *annual* regulated hydropower generation. Procedures for constructing numbers for aggregated generation in each operational year, while also considering stochastic scenarios, will now be explained.

First, optimal dispatch is found for each stochastic scenario. Continuing the example for Finland, we already know that seasonal discharge is found by summing the results for segmental discharge in the corresponding season. When optimal discharge has been determined for each scenario the final value can be found, based on a probability distribution between the scenarios. As mentioned earlier, probabilities are assumed to be the same for all scenarios in this model. Since data sets for three scenarios have been used in these optimization runs, the probability for each scenario is 1/3. Table 15 gives results for all scenarios and seasons in 2030 for Finland.

Table 15: Discharge results for regulated hydropower in Finland in 2030, for all seasons and scenarios.

Season	Discharge, scn 1 [MWh]	Discharge, scn 2 [MWh]	Discharge, scn 3 [MWh]	Final discharge [MWh]
1	128 475.00	99 703.76	56 392.01	94 856.92
2	157 022.16	157 022.16	156 973.32	157 005.88
3	126 123.5	41 320.89	0	55 814.80
4	0	0	0	0
5	0.038	0.017	0.048	0.034
6	14 831.28	499.78	0.03	5 110.36
7	0.023	0.019	0.069	0.037
8	6 562.26	0.025	0.047	2 187.45
9	30 590.50	0.055	17 803.75	16 131.43
10	0.040	0.020	0.020	0.027

Differences between stochastic scenarios within each season can be witnessed. Such differences reflect the varying parameter values for each scenario, such as initial reservoir level and inflow. The final discharge value in the right-most column is calculated using weights according to the probability distribution:

$$xd_{season}^{final} = \sum_{\omega\in\Omega} p_{\omega} \sum_{m\in M} xd_{mnsi\omega}, \quad n \in N, s \in S, i \in I \tag{7.1}$$

For the 3-scenario version, this yields:

$$xd_{season}^{final} = \frac{1}{3}\cdot\left(xd_{season}^{\omega=1} + xd_{season}^{\omega=2} + xd_{season}^{\omega=3}\right), \quad n \in N, s \in S, i \in I \tag{7.2}$$

The final values for each season can now be aggregated to annual results. This involves the use of a seasonal scaling factor, ϑ_s, accounting for the weighting between regular and peak-load seasons. In line with the original EMPIRE model, one year is also assumed to consist of four main seasons. The annual discharge is thus found through the following calculation:

$$\frac{8760}{24\cdot 4}\cdot\left\{\begin{matrix}\frac{8750}{8760}(94\ 856.92+157\ 005.88+55\ 814.80+0.00)+ \\ \frac{10}{8760}(0.034+5\ 110.36+0.037+2\ 187.45+16\ 131.43+0.027)\end{matrix}\right\} MWh/year = 28\ 045.98\ GWh$$

Examining the results for annual generation from the model output, the exact same number is found. The equivalent calculation can be repeated for all countries. Summing country-wise hydropower generation yields total values for the European power system.

From the review outlined in the previous sections the model framework for hydropower scheduling has been shown to function as intended. Thus, we may proceed to analyze system results for capacity and generation. This will be done in the following.

7.3 Case 0: Initial Results

Results are presented for the final model with enhanced hydropower formulation in place, and changes relative to the original model. As described in Section 5.7.2, the quality of the water values is unsatisfactory. However, results are presented for this case in order to show how the model is behaving with the given water values and to explain through analysis why the results turn out the way they do.

7.3.1 Generation Capacity and Generation Mix

Figure 24 and Figure 25 depict the generation capacity and generation mix in the final model, with enhanced hydropower implemented.

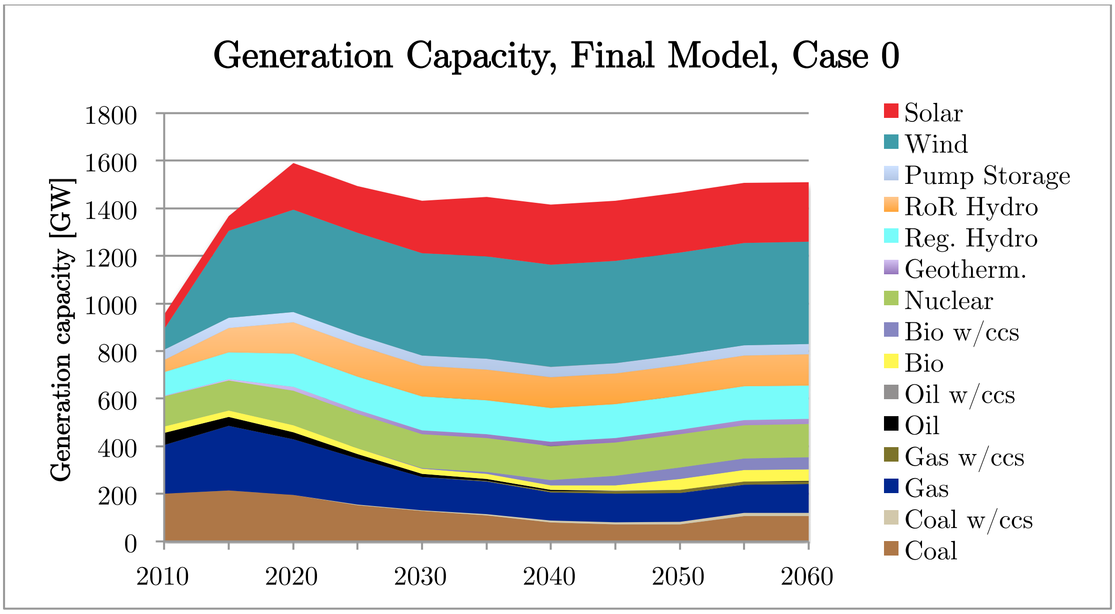

Figure 24: Generation capacity in the final model, aggregated for Europe [GW], Case 0.

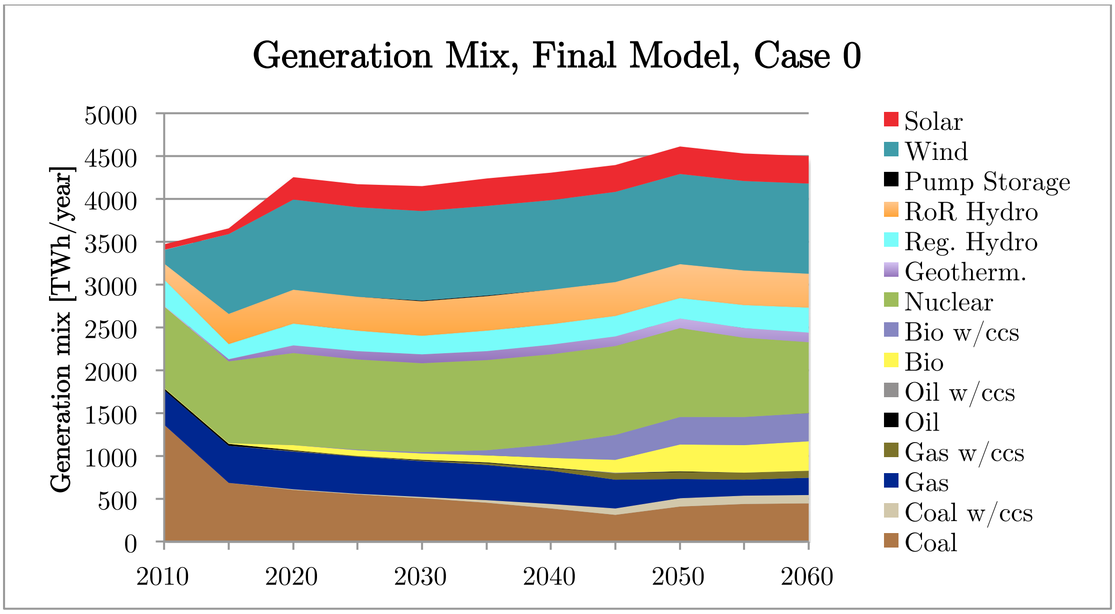

Figure 25: Generation mix in the final model, aggregated for Europe [TWh/year], Case 0.

It is evident that within the Global 20-20-20 policy regime the EMPIRE framework favors wind to an extensive degree. The policy scenario requires immediate departure from the situation in 2010, with large-scale expansions of renewables taking place early in the planning period. Fossil technologies are present in the entirety of the temporal scope, although with significantly lower amounts towards the end of the period, as a result of the increased penetration of renewables. The GCAM matching values also plays a role in this regard. Wind investments are prominent, with a vast expansion from 85 GW in 2010 to 367 GW in 2015. The added capacity is also reflected in the generation mix, with significant increases due to the large wind deployment.

It can be seen that the total system capacity is largest in 2020. The large-scale investments in wind and solar are the main drivers of the high capacity, and can partly be traced to the rapid increase in the CO_2 price early in the planning period for this scenario (see Figure 16 on page 35). Throughout the period, parts of the fossil technologies are dismantled and this causes the total capacity to decrease somewhat, even though demand is peaking in 2050.

7.3.2 Differences Between Models

Figure 26 and Figure 27 show the changes in capacity and generation mix for the final model relative to the original model without the enhanced hydropower formulation.

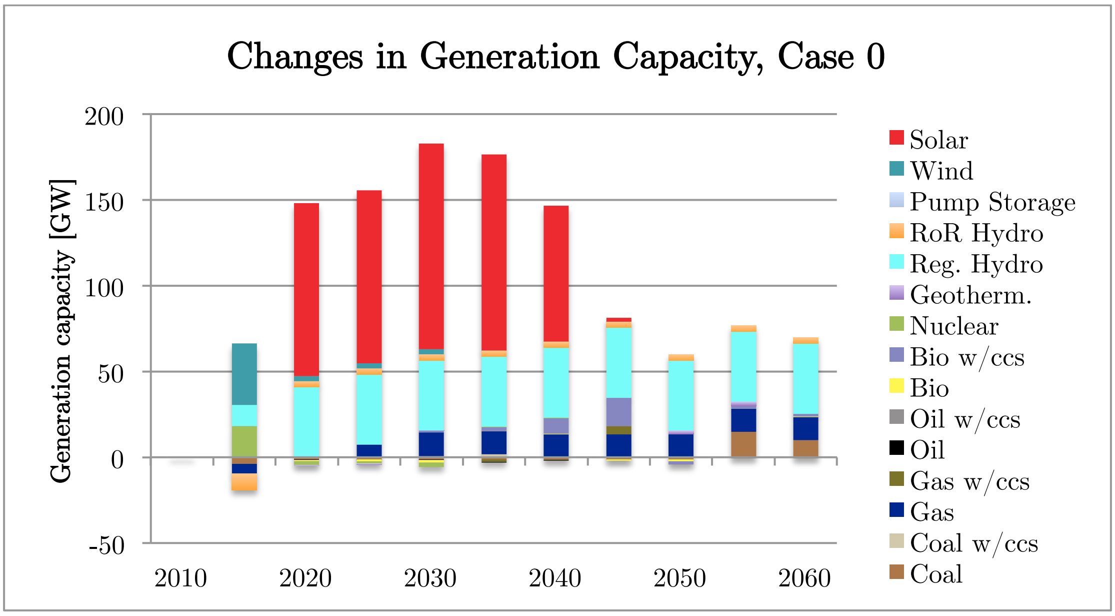

Figure 26: Changes in generation capacity between the final model and the original model for Europe [GW], Case 0.

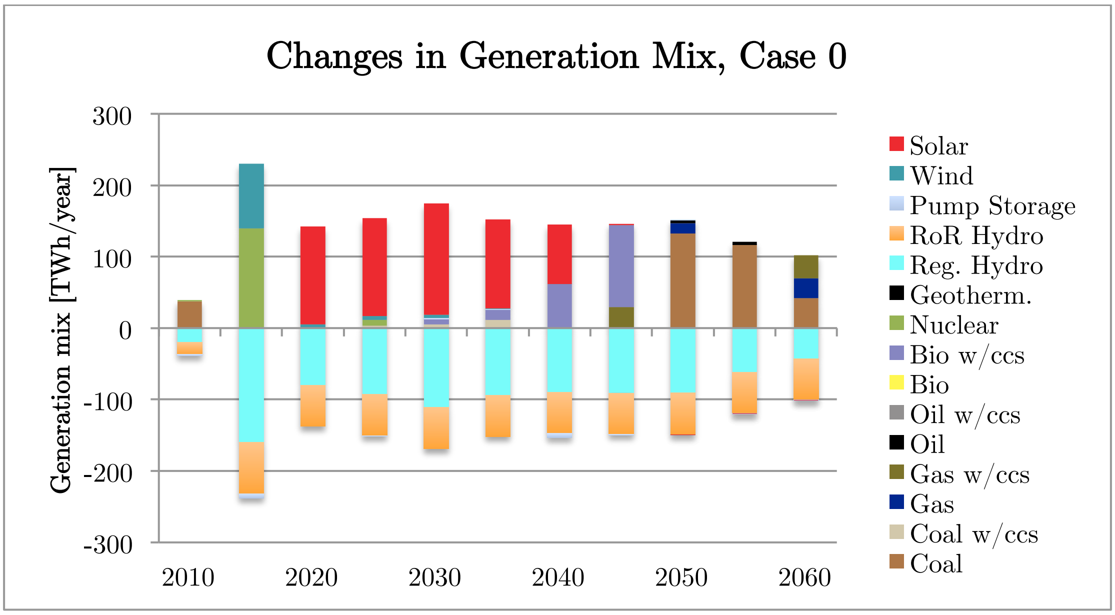

Figure 27: Changes in generation mix between the final model and the original model for Europe [TWh/year], Case 0.

Positive value means that the capacity is larger in the final model than in the original model, and vice versa. Before any further analyses of these results are carried out, the results for regulated hydropower must be investigated. Considering the above figures together, intriguing findings can be made for the combination of generation capacity and generation mix developments for regulated hydropower. For the generation capacity there is a notable increase in the final model relative to the original model, with a consistent percentage-wise difference of 40% for the years 2020 to 2060. These additional investments in the final model mostly take place in Austria (15 GW), Switzerland (14 GW), Germany (5 GW) and Finland (4 GW). In the original model similar investments in regulated hydropower are not to be found. Here, regulated hydropower increases only by 1 GW (corresponding to 1%), from 100 GW to 101 GW. When it comes to the generation mix, as evident from the graph, this is actually *decreasing* in the final model relative to the original model. In 2010, generation from regulated hydropower is 6% lower in the final model; a difference that is within acceptable limits. In 2015, however, the generation is reduced by 48%. In the same year, the final model has invested 12 GW, compared to 1 GW in the original model. It does not seem logical to invest significantly in more capacity without utilizing it. In order to understand this behavior and amend it, an examination of country-wise results must be conducted. This will be done in the following section.

7.3.3 Study: Regulated Hydropower in Case 0

At first look, the results for regulated hydropower presented above seem incorrect, indicating errors in the model framework. However, the utilized water values are key to understanding the origin of the results. Aggregated capacities and generation mix for Europe can be explained by breaking down system-wide results, as shown in the previous section, into country-wise results. Two countries with very different outcomes are used as examples for this analysis: Austria and Norway. Table 16 gives annual results for Austria. The shadow price in the table is given as an average for the scenarios, and belongs to Eq. (6.16), i.e. the constraint stating that annual generation cannot exceed annual inflow. The water value is the median for all years, scenarios, seasons and segments for Austria. As such, it is not an accurate measure but will suffice for trend analysis.

Table 16: Annual generation and capacity results for regulated hydropower in Austria, Case 0.

Year	Capacity [MW]	Generation [GWh]	Annual Gen. Shadow Price [$/MWh]	Water Value Median [$/MWh]
2010	2 453	10 086	-2843.58	11.33
2015	5 317	21 863	-262.43	11.33
2020	17 130	70 433	-2264.18	21.11
2025	17 130	70 433	-1275.50	26.13
2030	17 130	70 433	-89.73	39.77
2035	17 130	70 433	-144.98	38.22
2040	17 130	70 433	-86.11	38.61
2045	17 130	70 433	-22.04	38.10
2050	17 130	70 433	-12.85	40.41
2055	17 130	70 433	-23.27	39.12
2060	17 130	70 433	-49.35	37.20

Austria's initial capacity (2010) for regulated hydropower is 2 453 MW. By 2020, large investments increase its capacity to the maximum allowed installment of 17 130 MW. Generally, if the shadow price of a constraint is less than zero in a minimization problem the value of the objective function will be reduced, i.e. improved, if the right hand side is increased. In other words, the restriction is binding if the shadow price is less than zero. In this case, increasing the right hand side means to increase the annual inflow. From the table it is clear that the annual generation constraint is binding in all years for Austria, and the model sees benefit in having more inflow available. As introduced in Section 5.1, inflow has been made dynamic in the current model version. This implies that if the capacity is changed, the inflow is also changed. Investing in new capacity makes more inflow available and the right hand side of the applicable constraint increases, thus giving the model investment incentives. As evidenced by the shadow price magnitudes, generation in each year is restricted by the annual generation constraint and not by the water values. This is an indication of too low water values for Austria. For Norway, the situation is quite different. Annual results are given in Table 17.

Table 17: Annual generation and capacity results for regulated hydropower in Norway, Case 0.

Year	Capacity [MW]	Generation [GWh]	Annual Gen. Shadow Price [$/MWh]	Water Value Median [$/MWh]
2010	21 867	107 952.52	- 302.66	33.70
2015	21 867	0	0	33.70
2020	21 867	20.76	0	52.01
2025	21 867	0	0	55.20
2030	21 867	0	0	53.40
2035	21 867	0	0	52.15
2040	21 867	332.42	0	52.43
2045	21 867	0.36	0	52.01
2050	21 867	0	0	58.81
2055	21 867	0	0	47.85
2060	21 867	9 856.01	0	46.88

The first feature of the table that should be recognized is the water value median. Compared to Austria, the Norwegian water values are consistently higher: In 2015, the median of Norway's water values is 230% higher than Austria's median. Though less prominent, this positive difference is held throughout the planning period. Keeping in mind that the water values are very high for Norway, the rest of the table can be investigated. The generation in 2010 is very close to reality at 108 TWh [60]. However, for 2015, the generation is reduced to 0 TWh, which is unquestionably incorrect. The shadow price is zero for all years from 2015 to 2060, indicating that the annual generation constraint is non-binding (objective function will not change if the right hand side is increased). This means that the inflow is not limiting generation; the limitation is rather done by the overly high water values. The initial capacity of 21 867 MW is held throughout the planning period. In order to cover load in Norway the missing hydropower generation has to be compensated for. This is done through larger transmission expansions to Germany and consequent import.

Water Values and Load Constraint Shadow Prices

In order to further explain the behavior seen above, the water values can be compared with the shadow price of the load balance constraint. This dual value is described in some detail in Section 5.7.2 as the change in the objective function if the load is increased by 1 MW in a given country and hour. If the water value is lower than this shadow price, hydropower should in theory be utilized in this particular hour, since hydropower then can cover load at a lower cost than the price-setting generator.

Continuing the example above comparisons are carried out for Austria and Norway in the following configuration: Scenario 1, season 1 in 2015. The shadow price of the load constraint is given as one value for each hour. For Austria, out of the 24 hours constituting season 1, the shadow prices lie in the range between 13.29 $/MWh and 15.20 $/MWh. The water values for all segments in this season are lower than these shadow prices. Therefore, a maximum utilization of regulated hydropower is viable. When it comes to Norway, the situation is different. Here, the shadow prices of the load constraint lie in the range between 13.71 $/MWh and 21.40 $/MWh. With an initial reservoir level at 55.7% for this particular season the upper-most segment filled with water (and thereby available for discharge) is segment 22. Its corresponding water value is 27.81 $/MWh. Since the water value is decreasing as we descend in the reservoir, no segments will have a lower water value than this. Thus, the cheapest available water has a higher alternative cost than the short-run marginal cost of the price-setting generator (i.e. the shadow price of the load balance constraint). Utilization of regulated hydropower will in this case not be optimal, since doing so will increase the system costs. From dispatch results the argumentation in this section is followed, with maximum generation in Austria and zero generation in Norway.

Water Value Development in the Reservoir

In the base scenario for 2015, Norway's water value for the top segment is on average 74% higher than Austria's water value for the same segment for all ten seasons. Descending to the middle of the reservoir (segment 26), Austria's water value has increased 11% from the top segment on average for all seasons, while the same value for Norway has increased 142% from the top segment. This means that not only is the water value for Austria considerably lower than for Norway, but the percentage-wise increase when moving down in the reservoir is much lower for Austria than for Norway. For scenario 1 and season 1 in 2015, Austria's water value for the bottom segment is still lower than Norway's water value for the top segment. Thus, costs are minimized by utilizing Austria's reservoir as much as allowed, constrained by the annual inflow, before Norway's reservoir is even touched.

The water value and load constraint shadow price can be compared for other countries than Austria and Norway as well. Section 5.7.3 describes water value variations for ten countries, giving a standard deviation of 11.0 \$/MWh for the top segment in scenario 1, season 1 in 2030 (random spot-check). From the results in Case 0 it is found that the standard deviation for the load constraint shadow price between the same ten countries in the same period is only 1.4 \$/MWh, with an average value of 13.9 \$/MWh. Each country's value is given as the median amongst the individual shadow prices for the 24 hours residing in season 1. These results show that while the water values are varying to a large extent between countries, the shadow prices are more or less the same.

Reservoir Size Impact

Water values are dependent on the size of the reservoir. For smaller reservoirs the degree of regulation is smaller and thus the freedom to store water is more limited. This could in theory be an explanation for the low water values for some countries. The reservoir size of Austria is significantly smaller than Norway's: 2.7 TWh versus 85 TWh, respectively. However, since large investments are also happening for countries with large reservoirs, like Switzerland, the impact of small reservoirs cannot be fully responsible for the described behavior.

Case Study Conclusive Comments

Some concluding remarks can now be made. It has been seen that the water values, and consequently the generation levels, are fluctuating to a great extent between both countries and years. In 2010 generation for regulated hydropower is close to reality. In 2015 the model learns that some countries have very low water values, for instance Austria. It therefore finds it optimal to invest heavily in regulated hydropower for these countries and utilize it as much as possible, only limited by inflow. Because of higher water values for other countries, like Norway, their generation levels are very low. This explains the trends seen in Figure 26 and Figure 27 earlier. Total regulated hydropower capacity is increased in 2015 and 2020 because of investments in countries that have low water values (e.g. Austria). Changes in generation mix depict lower system-wide generation in the final model relative to the original model. Lower, or non-existent as in the case for Norway, generation from several countries causes this. Because of the high water values, not even the existing capacity is utilized. The argumentation above illustrates that the model framework itself is working as intended, based on the provided input data. However, results are far from realistic. An absence of regulated hydropower generation in Norway is unheard of and obviously incorrect. Through the analysis of water values it becomes clear that they are the origin of the problem. The consequences of low quality of the water values data set have therefore been demonstrated.

In order to account for some of the major inaccuracies found in Case 0, some approximations are carried out. This is detailed next, in Case 1.

7.4 Case 1: Introducing Hydropower Generation Limits

From the results and discussion in Case 0 it is found that the highly unrealistic investments and generation mix for regulated hydropower is caused by erroneous water values. However, the results for 2010 seem correct, with relatively small deviations from the original model results (6% for regulated hydropower generation). This suggests that the water values for 2010 are accurate, but flawed for later years. In order to gain more realistic results than those presented in Case 0, regulated hydropower generation values from 2010 are used as guidelines for the rest of the years in Case 1. The water values themselves cannot be used for later years since the system is changing when investments in technologies are done, and the water values will change accordingly. However, the actual generation levels can be utilized. Large-scale investments in regulated hydropower can be assumed not to happen for the duration of the planning period, as pointed out by the European Commission in their projections [67]. Also, in the original model, investments in regulated hydropower are very limited; total capacity increases from 100 GW to 101 GW, adding to the feasibility of this approximation. Thus, utilizing generation values from 2010, assuming that this dispatch is correct, will likely yield admissible generation values for the remainder of the years. Country-wise regulated hydropower generation in 2010 used for the limits is given in Appendix C.2. It is assumed that the generation is allowed to vary to some extent. Generation restrictions limit generation in the years from 2015 to 2060 to stay inside a 20% deviation band from the generation in 2010 on a seasonal country-wise level. These restrictions are therefore formulated in the optimization model as follows:

$$0.8\varsigma_{ns\omega}^{HydReg} \leq \sum_{h\in H_s} y_{ghi\omega}^{gen} \leq 1.2\varsigma_{ns\omega}^{HydReg}, \quad n\in N, g\in G_n^{HydReg}, s\in S, i\in\{2015,...,2060\}, \omega\in\Omega \tag{7.3}$$

Evidently, the model still has quite a bit of tolerance when it comes to the generation level, as it can fluctuate between these limits.

The inclusion of such generation limits is obviously a simplification, and as such, results do not reflect final investment recommendations but can rather be seen as projection guidelines.

7.4.1 Generation Capacity and Generation Mix

With the introduced constraints, the generation capacity and generation mix for Europe are as presented in Figure 28 and Figure 29.

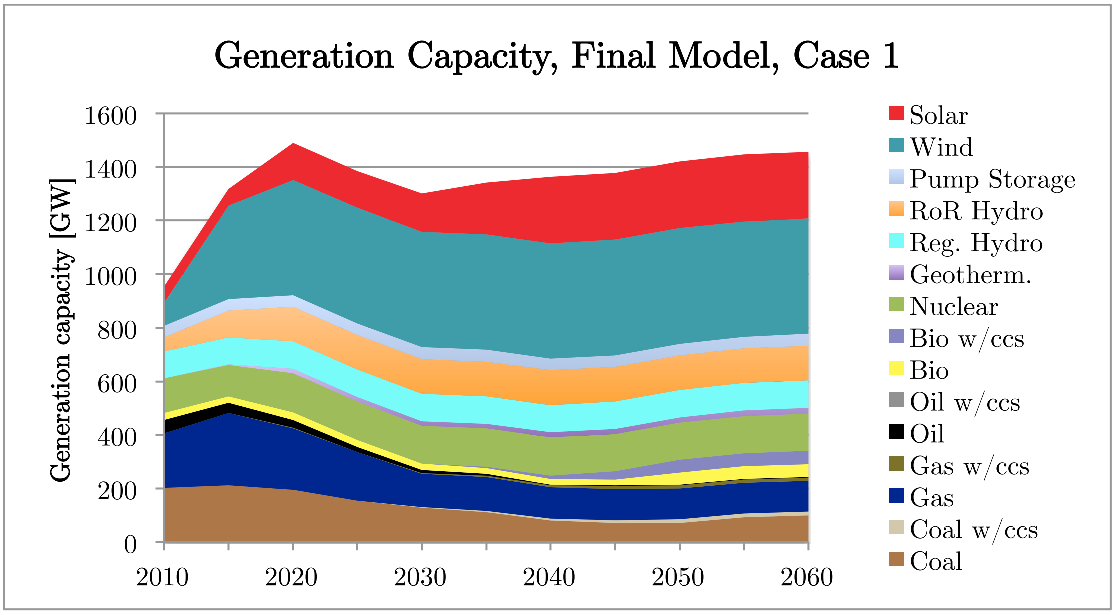

Figure 28: Generation capacity for Europe in the final model, Case 1 [GW]. Generation limits for regulated hydropower are introduced.

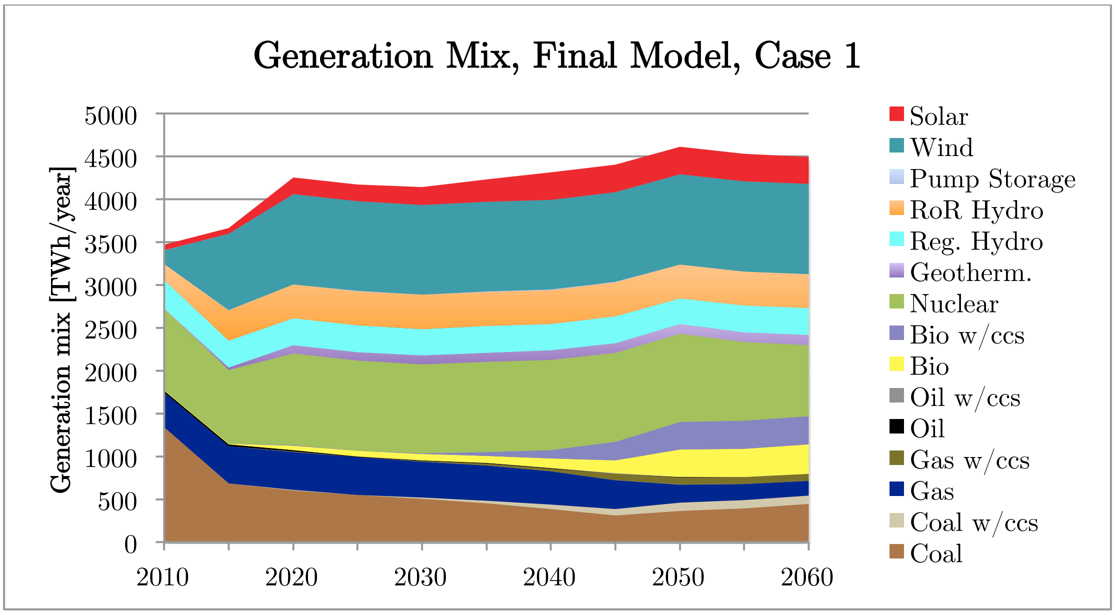

Figure 29: Generation mix for Europe in the final model, Case 1 [TWh/year]. Generation limits for regulated hydropower are introduced.

The largest difference from Case 0 is that regulated hydropower capacity does not increase as much as it did previously. Aggregated capacity is now increasing from 100 GW in 2010 to 103 GW in 2060 – a much more reasonable result. Breaking down the system-wide results to countries shows that for Austria, which invested almost 15 GW in regulated hydropower in Case 0 now invests only 0.5 GW. The model sees no benefit in investing more capacity than this because of the newly introduced generation limits. Regulated hydropower generation for Norway in 2015, which was zero in Case 0 (and obviously wrong) now amounts to 96 TWh. As such, the implementation of the generation limits has rendered reasonable results for regulated hydropower. Therefore, Case 1 can be analyzed further.

The total system capacity has been increased from 953 GW in 2010 to 1 458 GW in 2060 in order to accommodate the rise in demand. In order to seek compliance with the policy scenario large expansions of wind and solar power are carried out. Also, the nature of intermittency for these iRES sources can be observed when comparing results for capacity and generation mix. In 2060, iRES sources occupy 45% of the total capacity, while in the same year they cover only 30% of the total generation mix. As such, the inherent variability accompanied by iRES sources leads to a relatively low utilization factor. It can be seen that the large iRES deployment in 2015 leads to noticeable declines in the generation mix for other sources, mainly coal and gas.

Run-of-the-river (RoR) hydropower sees considerable investments in the first years of the planning period, from 52 GW in 2010 to 130 GW in 2020. This capacity is held constant for the remainder of the planning period. RoR investments happen in a wide range of countries, with Portugal (27 GW), Norway (9 GW), France (8 GW) and Spain (6 GW) as the most prominent.

When comparing generation mix results with the demand projections in Figure 14 (page 33) for the Global 20-20-20 scenario it can be observed that the demand and supply exactly match each other. Load requirements are fulfilled and there is consequently no need for load shedding.

7.4.2 Differences Between Models

Figure 30 and Figure 31 depict the differences between the final model with enhanced hydropower formulation (and generation limits), and the original model.

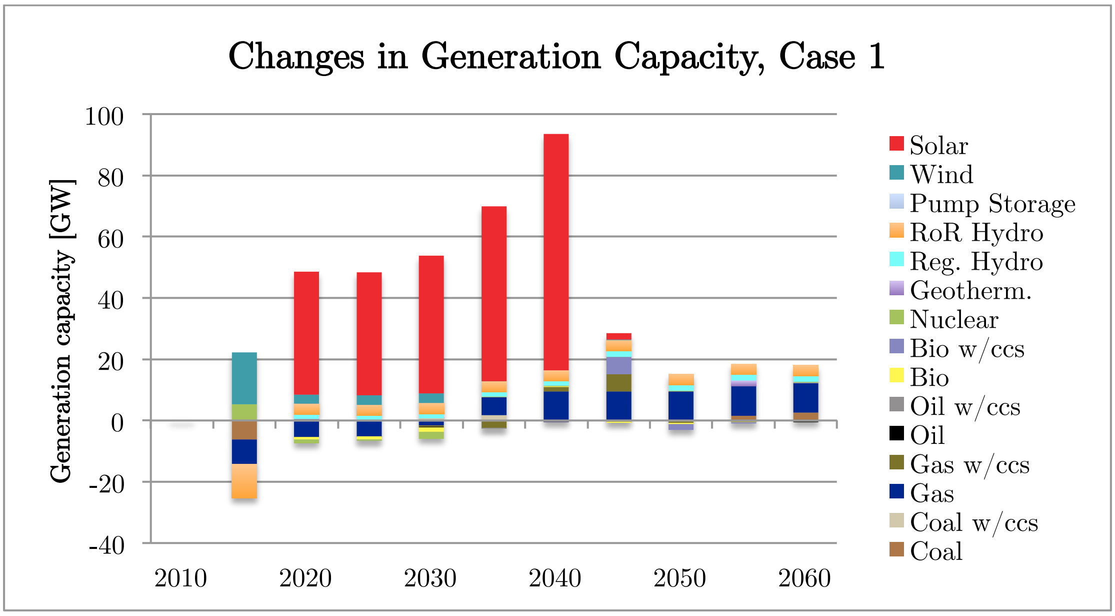

Figure 30: Changes in generation capacity for Europe between the final and the original model, Case 1 [GW].

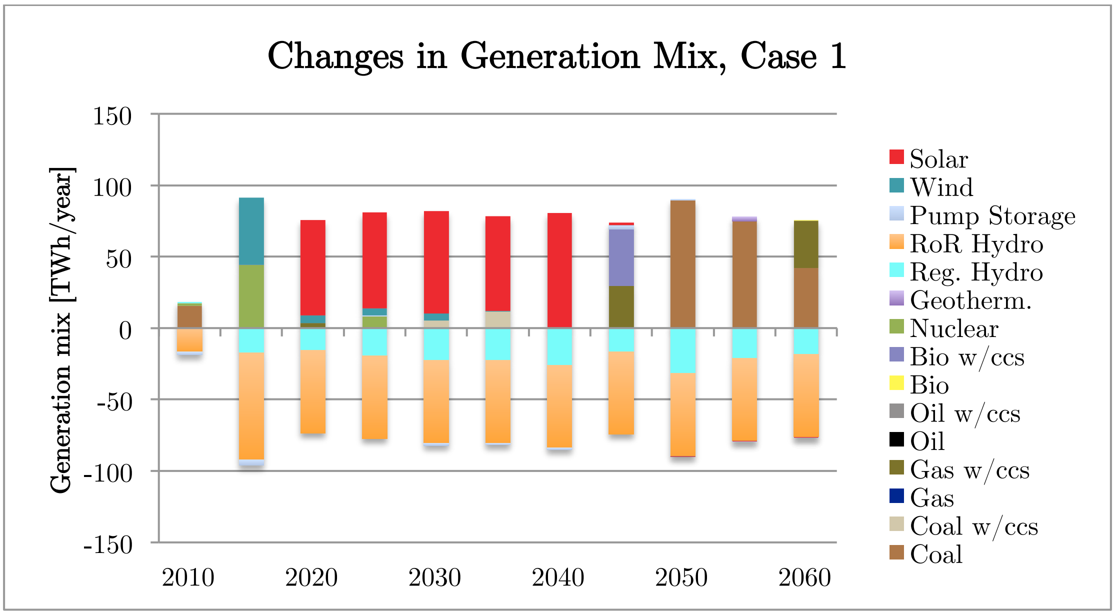

Figure 31: Changes in generation mix between the final and the original model for Europe, Case 1 [TWh/year].

For regulated hydropower it is already stated that the capacities in the final model are marginally higher than in the original model. Looking at the generation mix it can be seen that its system-wide generation is somewhat decreased. As in Case 0 these results must be broken down to country-specific results. The model finds it optimal for the countries with low water values to increase capacity in order to generate as much as possible within the upper generation limit. The additional investments are found in countries with low water values: Switzerland (1 GW), Finland (0.5 GW), Austria (0.5 GW) and Germany (0.3 GW). Countries with high water values seek to keep generation at, or close to, the lower generation limit. As such, this behavior is similar to Case 0, but in a much less prominent degree because of the generation limits. Thus, the abnormalities that were evidenced in Case 0 have largely been rectified. In Section 7.4.5 the impacts of generation limits on individual countries are investigated.

The same behavior can be seen for run-of-the-river hydropower: Its capacity is slightly increased while the actual generation is decreased. This can be explained by the fact that the normalized inflow values are lower in the final model compared to the RoR availability in the original model. Investments are carried out in order to utilize a larger amount of inflow (which comes at no cost). In the original model investments are also taking place, but the normalized RoR availability is higher. This means that the final model has to make *larger* investments, but is given *lower* total inflow in return. Therefore, the actual generation is lower even though the investments are slightly larger.

This reduced combined hydropower generation forces EMPIRE to invest in more substitution capacity at an earlier stage, thereby increasing total costs. Notably, in the first and middle parts of the planning period this is carried out by larger investments in solar power, with a percentage-wise difference peaking in 2040 at 45%. This is mainly caused by larger installments in Germany, Italy and Greece. The larger solar capacity is also reflected in the generation mix, with significant differences in the same years, peaking in 2030 at 54%. However, from 2050 both models find it optimal to reach maximum capacity of wind and solar power. The differences for wind are small for all years aside from 2015, where the final model has 17 GW more installed capacity. System-wide maximum limit for wind is reached in 2020 for the final model, while the original model has installed 99% of maximum capacity in this year. It chooses to install the last percent in 2035. Since the lifetime of wind and solar generators is 30 years the investments carried out early in the planning period will be dismantled before the end of the planning period. It can be seen that re-investments take place in the last years in order to keep the capacities at the maximum installed limits. This analysis proves that the cost representation for these technologies is beneficial for EMPIRE, opting to keep maximum capacities by re-investing.

In the last part of the planning period (2050 to 2060), after solar and wind have reached their system-wide maximum installed capacities, the reduced hydropower generation is compensated for by a higher utilization of coal and gas with CCS. The application of fossil technologies can in these late years be justified because the installments of solar and wind are so large that the emission targets in the policy scenario have already been met.

7.4.3 Cumulative Investments

Figure 32 and Figure 33 depict cumulative investments for the final model in 2030 and 2060, respectively.

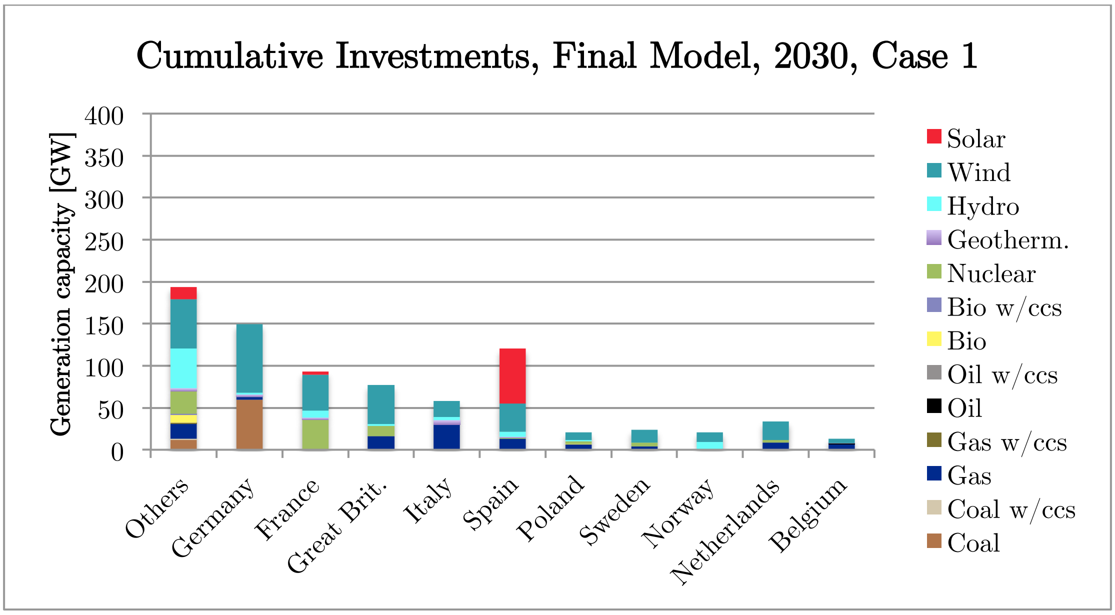

Figure 32: Cumulative investments in select countries in 2030 for the final model, Case 1 [GW].

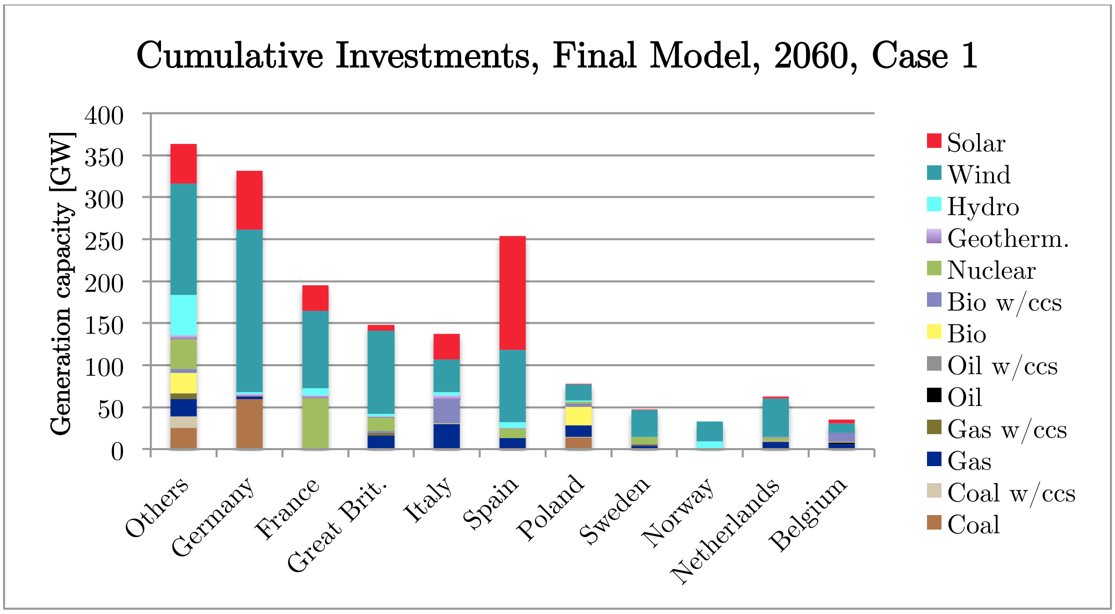

Figure 33: Cumulative investments in select countries in 2060 for the final model, Case 1 [GW].

The total capacity investments amount to 804 GW in 2030 and 1 683 GW in 2060, showing equal investment dispersion between the first and last parts of the planning period. Cumulative wind investments from 2010 to 2060 are largest in Germany (194 GW), Great Britain (99 GW), France (93 GW) and Spain (87 GW). Main countries for solar investments are Spain (135 GW), Germany (70 GW) Italy (30 GW) and France (30 GW). The important roles of Germany and Spain as renewable energy providers should be noted in this context.

7.4.4 Transmission Line Investments

The final model and the original model also give differences when it comes to transmission capacity investments. Most notably, transmission expansions take place earlier in the final model due to its earlier investments in solar capacity that requires transmission corridors to load locations. Total line capacity investments in the final model amount to 234 GW, while the same number for the original model is 224 GW. Table 18 shows system-wide aggregated investments for each year in the final model and relative differences to the original model.

Table 18: Overview of annual transmission line investments in the final model and changes relative to the original model.

Year	Cumulative line investments [GW]	Difference from original model [GW]
2010	0.0	0.0
2015	140.2	-0.5
2020	65.6	33.6
2025	1.3	1.2
2030	6.9	-3.4
2035	2.1	-24.0
2040	9.6	-0.3
2045	2.2	0.6
2050	1.3	0.7
2055	1.5	1.0
2060	3.8	3.5

The large expansions in 2015 and 2020 are caused by investments in a variety of locations. Transmission corridors from Spain towards Central Europe are an important part of the proposed solution. Reinforcements between Central European countries like France, Italy, Germany and Poland are also vital.

7.4.5 Binding Conditions for Hydropower Generation Constraints

The dual values (shadow prices) of the newly introduced regulated hydropower generation constraints in Case 1 contain valuable information about how binding these restrictions are. By examining the shadow prices on a country-wise level it is possible to find out which countries are affected by the upper and lower limit. Also, it is possible to examine if any of the countries are governed by water values alone. This will imply that the generation limit constraints are non-binding, i.e. the dual values are equal to zero.

The data material is vast. Therefore, this simplified analysis is carried out for the year 2015 and seasons 1 through 4 (seasons with regular load). The shadow prices of the minimum and maximum generation constraint are computed and analyzed for each country. Based on these values, Table 19 provides a summary of the findings on a country-wise level. For each country the table states whether or not the regulated hydropower generation is limited by the upper or lower generation constraint, or none of them, in which case the water values are the governing entity of generation.

Table 19: Investigation of binding conditions for regulated hydropower generation limits in Case 1, year 2015 and seasons 1 through 4.

Country	Upper restriction binding?	Lower restriction binding?	Water values governing?
Austria	Yes	No	No
Bosnia & H.	No	Yes	No
Bulgaria	No	Yes	No
Switzerland	Yes	No	No
Czech R.	Yes	No	No
Germany	Yes	No	No
Spain	No	No	Yes
Finland	Yes	No	No
France	Yes	No	No
Great Brit.	No	Yes	No
Greece	Yes	No	No
Croatia	No	Yes	No
Ireland	No	Yes	No
Italy	No	No	Yes
Lithuania	Yes	No	No
Luxemb.	No	No	Yes
Macedonia	No	No	Yes
Norway	No	Yes	No
Poland	Yes	No	No
Portugal	No	Yes	No
Romania	No	No	Yes
Serbia	Yes	Yes	No
Sweden	No	Yes	No
Slovakia	No	Yes	No

Some key trends can be identified:

- Few countries are governed by water values alone.
- Variations between countries are very large.
- There is a clear link between the water value magnitudes and whether or not the individual constraints are binding for a given country.

For most countries either the upper or lower constraint is binding in all seasons. Serbia sees great variations between seasons, with some being limited by the upper constraint and some by the lower constraint.

When observing the water values in conjunction with the shadow prices of the constraints, a clear trend is found: High water values correlate with binding lower generation limit, while low water values correlate with binding upper generation limit. Paying special attention to Austria and Norway, continuing the example from Section 7.3.3, the results are logical based on the water values utilized. Austria has binding *upper* generation constraints (and low water values), while the *lower* generation constraints are binding for Norway (having high water values). Intuitively, this is expected with the given data and has now been confirmed through the above analysis.

There seems to be no correlation between each country's binding conditions for regulated hydropower generation and the countries in which larger solar investments in the final model are taking place. These investments are happening in the countries where it is most economically beneficial to carry them out from a system's perspective.

In Case 0 and Case 1 wind and solar power reach their system-wide maximum capacity limits. It is interesting to see what investment schemes the models employ when these limits are relaxed. This case analysis will be done next, in Case 2.

7.5 Case 2: Relaxed Installed Capacity Constraints

In the previous cases the maximum installed limits for wind and solar power are reached for both models. In this case study the country-wise maximum installed capacities are doubled for these sources. Additionally, the cost of expanding the transmission grid has been somewhat increased. Since the model is already favoring wind and solar power to the maximum amount, more expensive grid connections is one aim at limiting the expansion slightly, while at the same time maintaining the possibility of larger investments. The costs for line investments are increased by augmenting the length in kilometers necessary to connect two nodes. On average, the increase amounts to 191% of the original costs. The utilized cost data is part of the original EMPIRE model. Relaxing limits only for wind and solar can be justified since none of the other technologies reach their maximum installed capacities. The regulated hydropower generation limits from Case 1 are preserved.

7.5.1 Generation Capacity and Generation Mix

Generation capacity and generation mix for the final model in this case are depicted in Figure 34 and Figure 35.

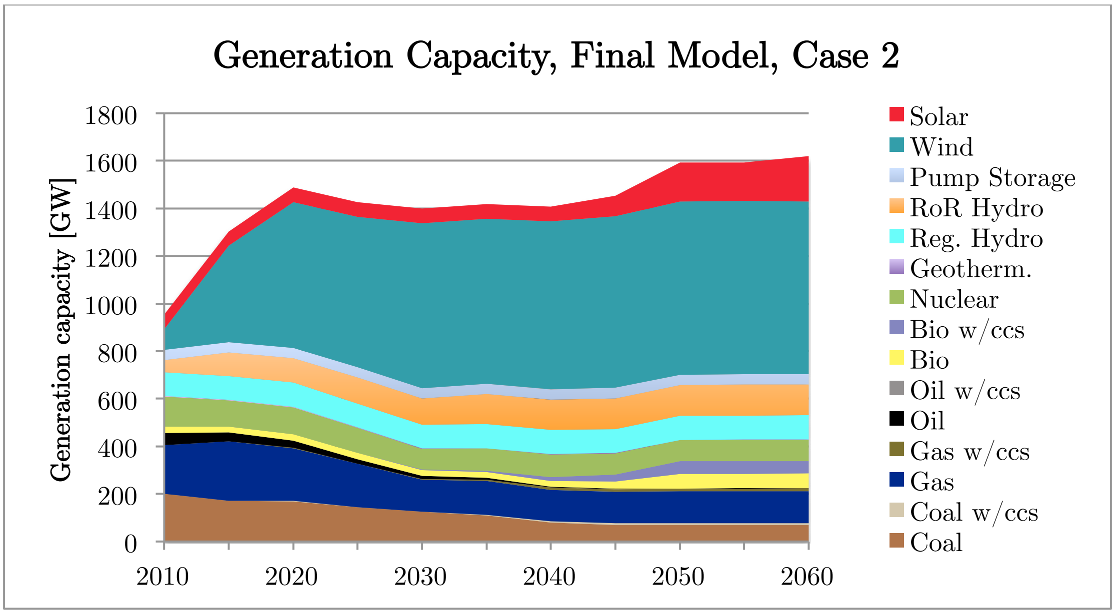

Figure 34: Generation capacity in the final model for Europe, with doubled maximum installed limits for wind and solar [GW].

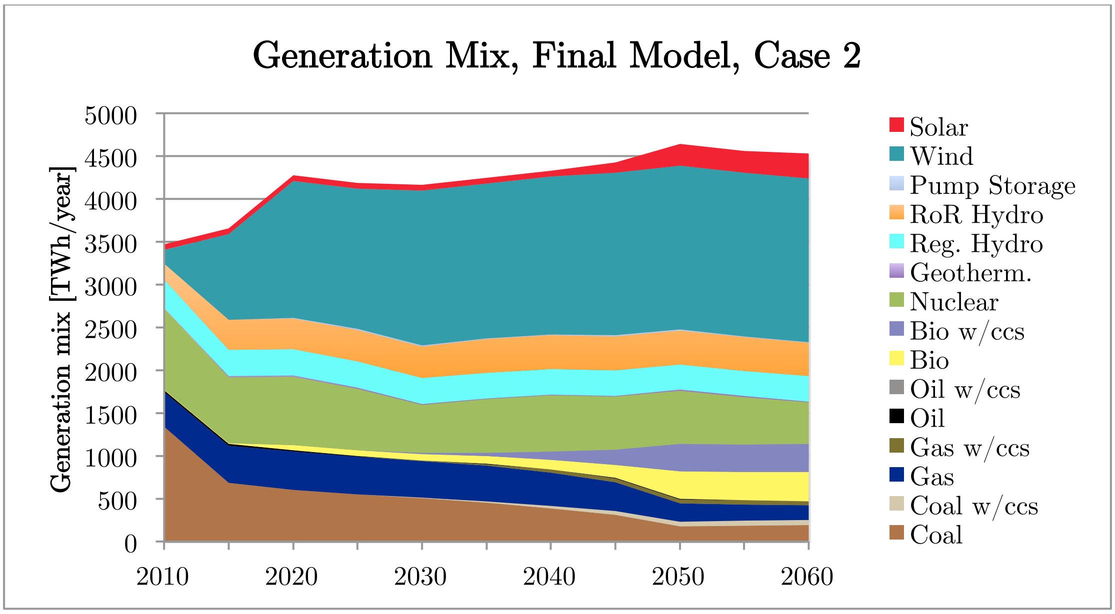

Figure 35: Generation mix in the final model for Europe, with doubled maximum installed limits [TWh/year].

In order to enable effortless comparisons between Case 2 and Case 1, the differences in generation capacity in the final models for these cases are shown in Figure 36. For this illustrative example generation mix will not be shown.

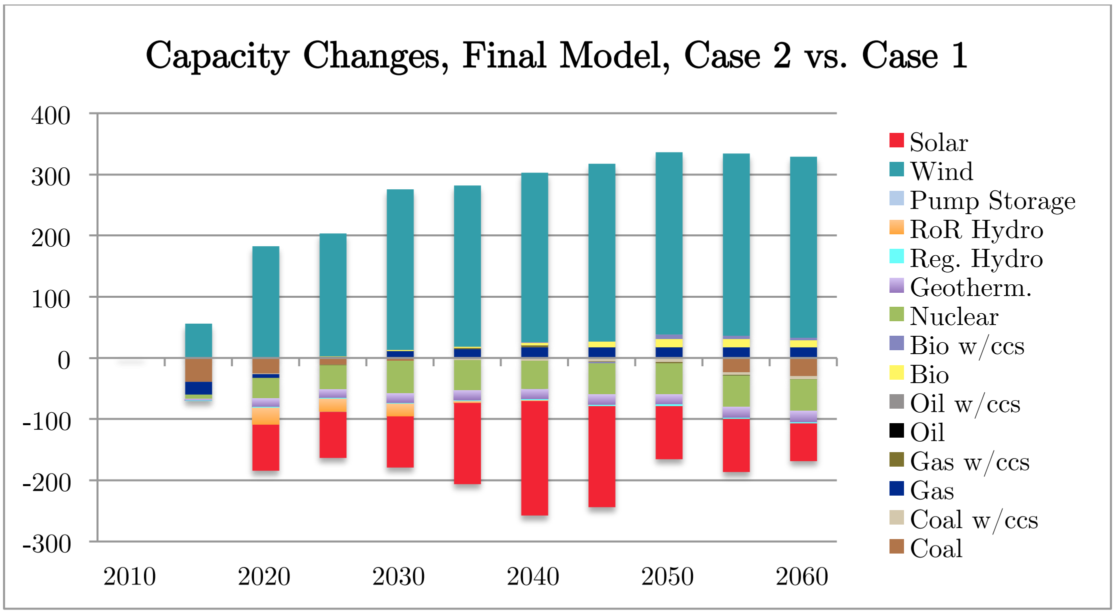

Figure 36: Changes in generation capacity between Case 2 and Case 1, for the final model [GW].

The deployment of wind is much larger in Case 2 relative to Case 1, with an increase in 2060 at 69% compared to Case 1. The implementation of solar is noticeably decreased, and nuclear and coal also see lowered installments. As witnessed from Figure 36, wind capacity increases more than the decrease for the other technologies for most years. Thus, the total capacity in the system is higher in Case 2 relative to Case 1. It is therefore clear that the model favors wind power to a more extensive degree than solar, partly because of its lower investment costs and fixed O&M[6] costs.

The total generation capacity now amounts to 1 619 GW in 2060, compared to 1 458 GW in the same year for Case 1, yielding a percentage-wise increase of 11%.

For reference, Figure 37 depicts the changes in capacity between Case 2 and Case 1 for the *original* model.

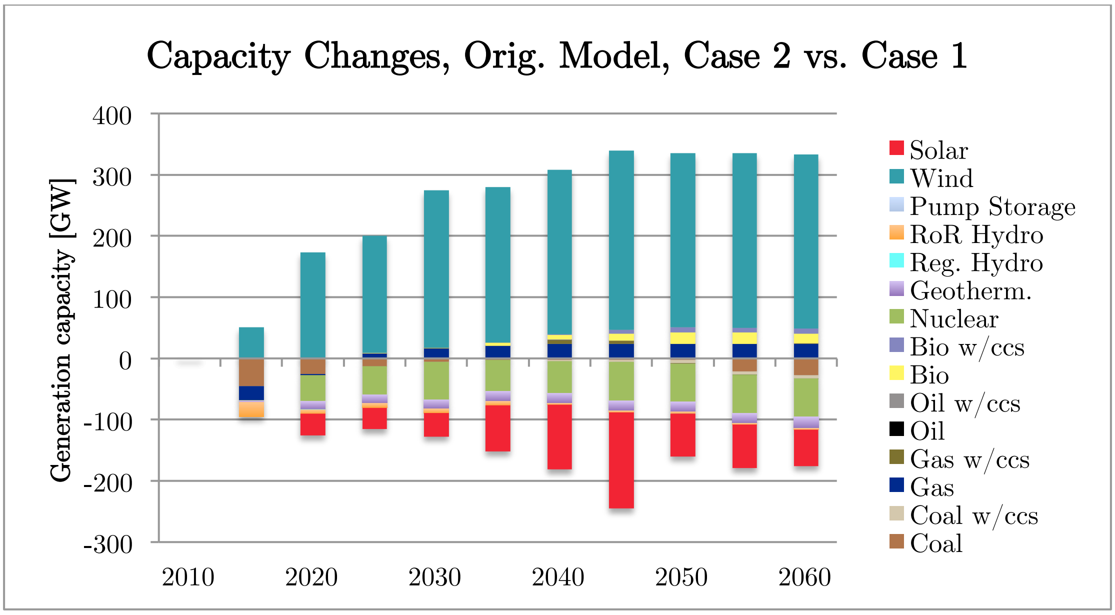

Figure 37: Changes in generation capacity between Case 2 and Case 1, for the original model [GW].

The same trends can be seen for the original model, with higher installments of wind and lower installments of solar. The total capacity is also here increased by 11% relative to Case 1. However, there are still differences between the final and the original model internally in Case 2. These will be examined in the next section.

[6] Operation and maintenance

7.5.2 Differences Between Models

In Figure 38 and Figure 39 differences in generation capacity and generation mix between the final and the original models for Case 2 are illustrated.

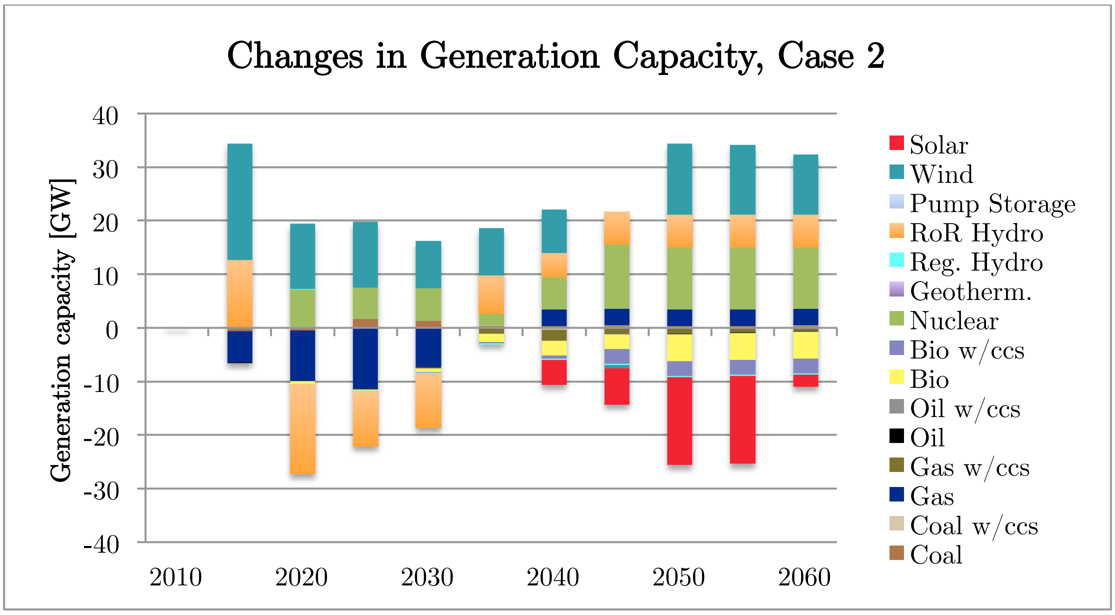

Figure 38: Changes in generation capacity between the final and the original model, Case 2 [GW]. Wind and solar have doubled maximum installed limits.

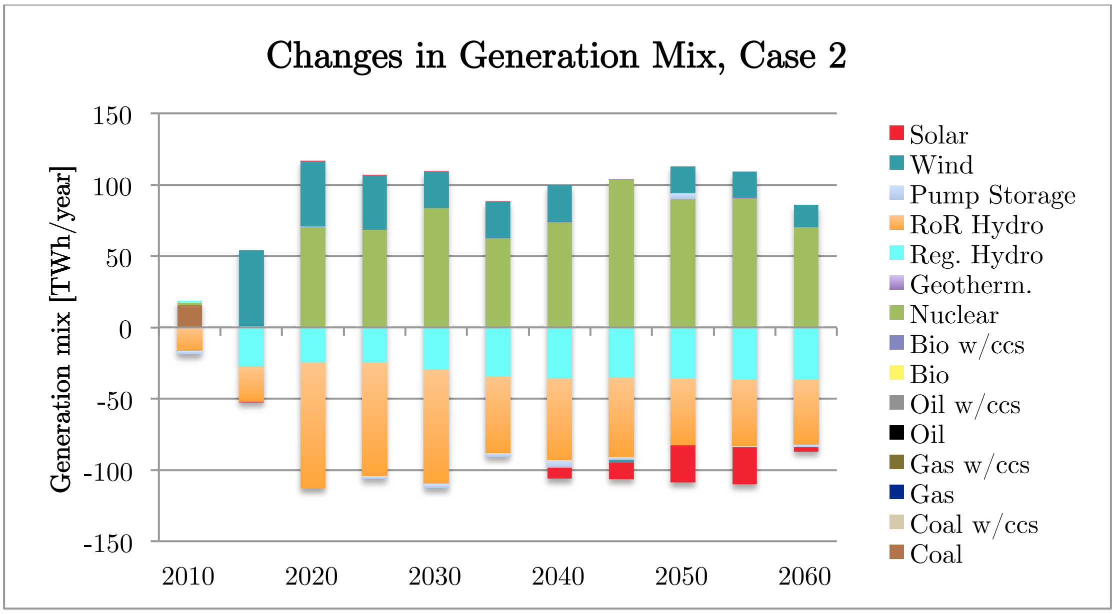

Figure 39: Changes in generation mix between the final model and the original model, Case 2 [TWh/year]. Wind and solar have doubled maximum installed limits.

The changes between the model versions are now rather different than the ones seen for Case 1. Run-of-the-river hydropower sees larger investments in 2015 and from 2035 to the end of the planning period. Nevertheless, as in Case 1, its actual generation is consistently lower because of the reduced inflow availability. Regulated hydropower generation has also been decreased, in line with Case 1. To compensate for the reduced hydropower generation, wind and nuclear see larger investments and consequent generation in the final model compared to the original model. Investments in gas are somewhat decreased in the first years, mainly due to larger investments in wind power.

8 Discussion

Results Characteristics

In Section 7.2 the framework for hydropower scheduling is scrutinized by examining input and output in an example case. This is done by extracting data given by the model behavior and comparing them to calculations carried out manually by hand. All aspects are found to work as intended. Input-wise, this includes procedures for filling reservoir segments while taking initial reservoir levels and inflow into consideration. Output-wise, the hydropower scheduling restrictions, cost setting through water values and integration in the EMPIRE model are functioning as planned.

Sections 7.3 to 7.5 present optimization results for three different case studies. Case 0 (see Section 7.3) shows initial results for the model as it is described in Chapter 6. The country-wise results presented make it clear that the quality of the water values is unsatisfactory. In 2010 the dispatch is suitable, but the rest of the years incorporate a utilization of water that is far from realistic. For instance, exceedingly high water values for Norway leads to extreme hydropower parsimony. The water values will be discussed shortly. In order to acquire reasonable results for the later years, an approximation is introduced in Case 1 (see Section 7.4). Here, the hydropower dispatch from 2010 is used as basis for the dispatch in all of the following years, restricting regulated hydropower generation in 2015 to 2060 to a deviation band of 20% from the generation in 2010. With the introduction of these constraints it is assumed that the reservoir management utilized in 2010 is held constant throughout the planning period, within the given deviation allowance. Incorporating such limits is unquestionably a simplification. However, the European Commission has predicted that regulated hydropower deployment is not going to change significantly in the coming decades [67]. While keeping these assumptions in mind, the results from Case 1 are treated as central and can be discussed further.

Main findings show that the final model with enhanced hydropower leads to a decrease in the utilization of both regulated and run-of-the-river hydropower relative to the original model. These impacts can be explained individually. For regulated hydropower, the more precise cost information through water values (and the use of generation limits) leads to a decrease in generation levels. For run-of-the-river hydropower, which does not incorporate water values, inflow is the limiting factor. The final model chooses to make larger investments than the original model, but since the normalized inflow is smaller, investments yield similarly lower total inflow. Thus, the final model has to make *larger* capacity investments to obtain a *smaller* amount of inflow. This explains the results presented in Figure 30 and Figure 31. While the combined hydropower generation is reduced, cheaper sources are selected as generation providers to take its place. In the first and main parts of the planning period this is carried out by larger investments in solar power, mainly happening in Germany, Italy and Greece. The increased capacity is also reflected in the generation mix, with solar generation at a consistently higher level in the final model for the years 2020 to 2040. Indeed, in 2030 solar generation is 54% higher than in the original model. For the last years, after solar has reached its system-wide maximum installed capacity, a higher utilization of coal and gas with CCS serve as substitution suppliers.

From 2050 both models choose to maximize the installment of wind and solar, leading to small differences between the models in the finishing years of the planning period. Therefore, another case study is conducted where the maximum installed limits for wind and solar are relaxed, allowing for a country-wise doubling in installed capacity for these technologies (see Section 7.5). The observed differences are interesting. By 2060 both the final and original models increase the total capacity relative to Case 1 by 11%. The differences are mostly traced to larger installments of wind power, while deployment rates of solar power are reduced. These results therefore show that wind is treated very economically beneficial in both models. When maximum capacity restrictions are relaxed the model turns to wind to cover additional load, pushing out solar, which was more extensively utilized in Case 1.

Comparing Results with EU Projections

The results obtained through the modeling in this thesis can be compared with the projections EU has set for the coming decades in their Reference 2013 scenario, see [67]. The forecasts are quite similar, but differences are still present. Results for Case 1 are used for this comparison. From Figure 29 it can be seen that investments in intermittent renewables in EMPIRE are carried out extensively in 2015 and 2020, resulting in a share of wind and solar generation at 28% in 2020. For the same year EU envisions a percentage-wise generation from the same sources at 20%. However, in 2050 EU shows an expected generation share from wind and solar at 35%. Results from EMPIRE calls for a somewhat lower share of 30% in the same year. This implies that EMPIRE shows a more progressive investment scheme in the first part of the planning period, while EU expects the generation from wind and solar to be higher towards the end of the planning period. Both models envision wind as the largest supplier of intermittent energy.

Simplifying Model Assumptions

The EMPIRE model itself is a simplified representation of the European power system. Country-wise aggregation of load, generation and line connections are obviously major simplifications of the actual system appearance. Such assumptions are underlying for the modeling done in the thesis. However, expansion planning on this level is associated with vast temporal and spatial scopes. This necessitates simplifying assumptions like the ones made in EMPIRE. Thus, the gained results will be of an indicative character. The results are optimal in terms of cost minimization while preserving load coverage and compliance with climate mitigation targets in the policy scenario. However, even though the proposed solution is optimal from a system's perspective, results for individual countries may not be optimal from their point of view. As an example, Spain is supposed to invest heavily in solar power with consequent export to Central Europe. This requires large investments in grid transmissions, as pointed out in Section 7.4. Which actor faces the costs associated with this grid expansion? Would a cost-benefit analysis from Spain's perspective yield the same results as the system-wide perspective does? Probably not, and such effects are not taken into account in EMPIRE. All results are subject to the perspective of a system administrator. Therefore, the results presented can only be seen as projection guidelines: What amount of each technology is needed at what locations in order to satisfy the given policy scenario regime subject to cost minimization.

As much as the original EMPIRE model incorporates simplifications, the proposed hydropower scheduling formulation is also of a simplified kind, adjusted to accommodate the EMPIRE structure. For example, country-wise aggregations are utilized for hydropower as well. As such, the implementation and model improvements carried out in the thesis will also lead to indicative results. However, compared to other technologies, hydropower is given considerably more attention with the proposed implementation. For this setup, simplified reservoir behavior and country-wise aggregations can be deemed as satisfactory assumptions since EMPIRE itself is a simplification of the European power system.

Modeling Challenges

Water Values Quality

Some challenges have been met in the modeling phase. The most notable is the issue related to water values, as described several places in the thesis. The source for hydropower data, SINTEF Energy Research, is a recognized institution in the field. Making use of their 'one reservoir model' to obtain data for each country can therefore be considered precise. However, inconsistencies are found in the water values, concerning both years and countries. Raising the question of why the water values lack consistency is inevitable. Dispatch results were tangible for 2010, a year where investments are not allowed. It therefore seems likely that the origin of the problem is related to the investments that are taking place from 2015 and onwards. Investments change the system significantly, and as described in Section 2.6.2, the water values are also affected by such changes. While the EMPS model intrinsically takes investments into account when calculating water values since it uses annual capacities as input, the connection between the EMPS and EMPIRE models is most likely the cause of the inconsistency issue.

Several efforts have been executed in order to remedy the inconsistencies, with a total of four different water values data sets being tested in the model. When these efforts were not successful, generation limits incorporating deviations based on generation in 2010 were finally utilized. This is obviously a simplification. The utilized water values are indeed independent for each year, as described in Section 5.7, but when generation limits are introduced the reservoir management is assumed to be constant throughout the planning period (within the given deviation allowances). This management will change when the system changes, and should ideally be controlled through annual water values that take such power portfolio transformations into account.

There are many active variables affecting the calculation of water values: Generation and transmission capacity investments, calibration factors in the EMPS model, GCAM energy shares and more. The results presented in this thesis show that a direct link between the EMPS and EMPIRE (and, to some extent, GCAM) models is hard to establish. A different technique that may be necessary to carry out is presented in Chapter 10: Further Work.

Computational Power

Another modeling challenge that is faced is computational power. There has been a desire to improve the model's awareness towards parameter uncertainty by incorporating a large number of stochastic scenarios, ten in total, as described in Section 5.2. Considerable amounts of time were spent formatting the data sets and choosing appropriate conditions for the individual scenarios. However, when model runs were attempted the Newton-Barrier method used in the optimization was not able to initiate. The size of the input data set was simply too large for the hardware on which the model was run, thereby refusing to start iterations in the Barrier procedure. When additional computational power is made available, the model can be run with the 10-scenario data set and thereby further account for uncertainty.

Sources of Error

- The SINTEF data set lacked entries for some countries. As detailed in Section 5.4 assumptions have been made for these countries, most notably by the use of values from neighboring countries.

- Detailed initial reservoir levels have only been found for Norway. These are used for Norway and Sweden, while initial reservoir levels for other countries are qualified guesses based on the levels found for Norway. As such, inaccuracies in these parameters will be present.

Regardless of the precision in which a model is formulated, it will always be limited by the quality of the input data. This is also the case for the model in this thesis. Because of the described issues with water values, the results do not reflect final investment recommendations as such but can rather be seen as projection guidelines. Nevertheless, the usefulness of the enhancements in hydropower modeling proposed in this thesis is valuable, since its representational level of detail has been greatly improved compared to the original framework.

9 Conclusion

In this Master's thesis hydropower scheduling has been implemented in EMPIRE, which is an expansion planning model for the European power system. A framework for reservoir management representation is written in the Mosel programming language.

By implementing an enhanced hydropower formulation the level of detail for this energy source in the EMPIRE framework has been increased. The presented results are affected by inconsistent quality of the water values data set, necessitating the use of generation limits for regulated hydropower. Still, results show that the original hydropower availability is too relaxed, thereby causing an overvaluation of this technology. The revamped cost representation by means of water values leads to a lower utilization of hydropower relative to the original model. This goes for both regulated and run-of-the-river hydropower. In order to replace the lower generation an earlier deployment of solar power is carried out, with capacity differences between the final and the original model peaking in 2040 at 45%. The earlier deployment causes an increase in total system costs. From 2050 both models find it optimal to reach the maximum installed capacities for wind and solar. The extensive investments place the intermittent renewable capacity at 681 GW, or 47% of the total capacity, in 2060. Relaxing the maximum installed limits leads to even greater deployment of these sources.

The modeling carried out in this work has been a part of improving the EMPIRE expansion planning framework, which will hopefully be used in further projects in order to assist decision-makers in the European power sector.

10 Further Work

The most notable aspect of the model that has improvement potential is the water values. Obtaining consistent data sets for the entire planning period has proven difficult. Ideally, the water values should be calculated through an iterative procedure between EMPS and EMPIRE. Such a technique would involve running the model with a preliminary set of water values and feed the results for generation and transmission capacities back to EMPS for a new iteration of water value calculations. The new water values can then be used in an additional EMPIRE model run, and the capacity results should be fed back to EMPS yet again, since the changes in the system will affect the water values. This procedure should be continued until convergence in results is found. However, this is a time-consuming task because of considerable computation times in the EMPS model.

Another solution that may be sufficient is to perform a valuation of regulated hydropower in EMPIRE itself, detached from the EMPS model. Such a valuation can be based on the SRMCs of alternative technologies. This will not be as precise as performing the calculations through EMPS, but the problems faced and described in this thesis show that establishing a robust link between the two models is more difficult than anticipated.

When correct water values have been obtained, the model can be run within several other policy scenarios (450 ppm and 650 ppm) in order to analyze potential differences between the scenarios brought into effect by the enhanced hydropower formulation.

As described in Chapter 7.1, hardware limitations made the 10-scenario version of the model unable to run. This data set can be used in future simulations as additional computing power is available.

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Appendices

A Resolving Model Framework Issues

The basic implementation of hydropower scheduling and its framework was the main focus in the project thesis. In the process of analyzing preliminary results, some issues in the model framework have been found. Because of the time-consuming modeling tasks done in the project semester, an insufficient amount of time was left to analyze the results from the project. Therefore, the missteps were not found until the beginning of the Master semester. A great deal of time has been spent in order to investigate the origin of these errors to be able to resolve them. This had to be done before any other improvements to the model could be performed and was consequently first priority. The model framework errors and solving of these are presented below.

A.1 Model Structure Issue

When analyzing the results from the project thesis it was discovered that the model chose to discharge water from reservoir segments that did not have the lowest water values, i.e., it chose to discharge from segments lower in the reservoir even though the segments above were not empty. This led to a suboptimal solution, where a dispatch yielding higher total cost than possible was used. Of course, this is not optimal and since Xpress-IVE shall always choose the optimal solution, an error had to be present in the code. A time-consuming investigation followed, where different sections of the implementation were changed or removed. Every time an alteration took place, a new optimization run was performed to see if the suboptimal behavior was resolved. All restrictions and formulations related to hydropower scheduling were researched and found to be working as they should, but the model still gave suboptimal solutions. Finally, after dozens of attempts and corresponding model runs the problem was found. It was associated with the code structure of the model. In the Mosel language, all variables have to be created in order for them to be used. The creation of reservoir discharge variables, $xd_{mnsi\omega}$, was initially located *below* the definition of the objective function in the code. Even though the Xpress-MP Optimizer reported no syntax errors, the location of the creation statements for the discharge variables led these variables to not be taken into account by the objective function. This means that the discharge was still correctly limited by scheduling constraints, but no cost was associated with the discharge since it was not being acknowledged by the objective function. Solving the problem therefore implied to simply move the creation statements of the reservoir discharge variables *above* the definition of the objective function. Examining results showed that the objective function was correctly being penalized when generating hydropower. The optimal solution was now chosen and the model structure issue had been resolved.

A.2 Constraints Disablement

Inconsistencies related to the generation from regulated hydropower were discovered. Some nodes, having no inflow and very small reservoirs, still gave high generation levels. It seemed like there was an error in the coupling between reservoir discharge and their generation.

In the original formulation two parameters help the model to determine whether or not we are dealing with a regulated hydropower generator:

- χ_g - A Boolean parameter yielding 1 if the generator has a hydropower reservoir and 0 otherwise.
- T_g - An integer parameter yielding a number from 1 to 29 to identify the technology of a given generator. Technology number 24 is regulated hydropower.

The constraints used in the implementation of hydropower scheduling are meant to be invoked only for regulated hydropower generators and not generators of all technology types. The χ_g parameter was therefore used to identify the relevant generators. For example, the coupling of reservoir discharge and regulated hydropower generation was formulated in the following way:

$$\sum_{h \in H_s} \sum_{g \in G_n, \chi_g = 1} y_{ghi\omega}^{gen} = \sum_{m \in M} xd_{snmi\omega}, \quad n \in N, s \in S, i \in I, \omega \in \Omega \tag{A.1}$$

Here, the generation variable $y_{ghi\omega}^{gen}$ is summed over all hours in season s and all generators in node n's set of generators, given $\chi_g = 1$, thus ending up with the regulated hydropower generator for node n. However, from the original EMPIRE formulation the χ_g parameter is only created if the hydropower generator actually has any available energy in its corresponding reservoir. This happens to not be the case for eight of the nodes (even though they have, by definition, a hydropower reservoir). Therefore, $\chi_g = 0$ for these nodes. This led the constraints dependent on this parameter to ignore the generation variables, effectively disabling the constraints for these eight nodes. Since the original constraints for regulated hydropower in the EMPIRE model have been removed, there were no active constraints that restricted the regulated hydropower generation from these nodes. Thus, the only constraint that would limit hydropower generation was the installed capacity in the node. The model could generate at no cost. This led to high investments in hydropower capacity and maximum generation levels for these nodes, which is clearly wrong.

Doing an extensive debugging of the model discovered this error. Running the model in debugging mode means that instead of actually solving the model the entire problem is written out to a text file, showing the objective function and constraints for all indices they are defined for. This way, it is possible to find out if some constraints are not including the correct variables or parameters. Neither the original model nor the implementation of hydropower scheduling was done incorrectly. The error arose simply because of incompatibilities between the two formulations.

After this error was discovered the constraints were changed to be enabled for all generators of technology number 24, $T_g = 24$, i.e. regulated hydropower. This parameter is defined for all generators with a hydropower reservoir, even though there is no energy available in the reservoir ($\chi_g = 0$). This will yield correct results since the Excel file with hydropower data contains reservoir sizes for all hydropower generators: For nodes with no energy available the generation must also be zero. Thus, using the same example as above with the coupling of regulated hydropower generation and reservoir discharge, the constraint is changed to the following:

$$\sum_{h \in H_s} \sum_{g \in G_n, T_g = 24} y^{gen}_{ghi\omega} = \sum_{m \in M} xd_{snmi\omega}, \quad n \in N, s \in S, i \in I, \omega \in \Omega \tag{A.2}$$

After this change, the generation from regulated hydropower in nodes with negligible reservoir sizes is correctly zeroed for all years and seasons. In the model formulation of Section 4.2.3, Equation (A.2) is simplified to the following:

$$\sum_{h \in H_s} y^{gen}_{ghi\omega} = \sum_{m \in M_n} xd_{mnsi\omega}, \quad n \in N, g \in G^{HydReg}_n, s \in S, i \in I, \omega \in \Omega \tag{A.3}$$

Instead of summing all generators in a node, given $T_g = 24$, the latter restriction is valid only for regulated hydropower generators, $g \in G^{HydReg}_n$. This formulation is easier to comprehend, and means the same as Equation (A.2).

A.3 Regulated Inflow Overvaluation

The results from the project thesis showed significant increases in generation from regulated hydropower: in some cases an increase of 50%. Because of this massive increase, the input parameters were thoroughly examined. In this process it was found that the inflow to the reservoirs, which is one of the most important parameters for hydropower generation, was valued too high.

Inflow data is given as normalized values to the installed capacity, meaning a multiplication of these data sets is necessary. In the project thesis the sum of both regulated and run-of-the-river hydropower capacity was incorrectly used to scale only regulated inflow. The regulated inflow was therefore too high. This error arose because of a misunderstanding of the terminology in the SINTEF data files, and has been resolved in the current version. The correct values are given in Appendix C.1.

A.4 Water Value Currency Conversion

In the project thesis the water values were mistakenly used as Euros. All of the other cost parameters in the EMPIRE model use U.S. Dollars as currency. In the final version of the model, the water values are converted into U.S. Dollars. The currency conversion factor used is as follows (as of 8$^{\text{th}}$ March 2014):

1 EUR = 1.38700 USD [68].

A.5 Adjusting the SRMC for Regulated Hydropower

In the original EMPIRE model, discharge from hydropower reservoirs had no assigned cost and it was therefore necessary to include operation and maintenance costs for the hydropower plant in some way. This was carried out with the short-run-marginal cost (SRMC).

With the inclusion of water values as decision-making tool in the current version of the model, the use of a different penalizing term in the objective function is not necessary. Water values already contain all of the relevant cost information that determines the marginal cost of hydropower generation. From the objective function definition, see Section 6.1, it can be seen that the cost of utilizing water for power generation is already being penalized through the water values term. Because of this, the SRMC for regulated hydropower generators are set to zero for all years in the final version of the model.

B Additional Model Alterations

Some changes to the general model formulation have been made. Certain changes are done specifically in support of the enhanced hydropower formulation, while others are included in order to maintain correlation with updates of the original EMPIRE model carried out by Christian Skar.

B.1 Nested Dissection Method

One of the parameters for the Newton-Barrier method used to solve the optimization problem in Xpress is changed. The following line of code is included:

```
setparam("XPRS_BARORDER",3); ! Use nested dissection method
```

This command toggles the control of the Cholesky factorization in the Newton-Barrier method used to solve the model in Xpress-IVE. Option '3' sets the control to nested dissection method, which was originally proposed by Alan George [69]. The nested dissection method considers the adjacency graph and recursively seeks to separate it into non-adjacent pieces [70]. This may lead to more effective solving of the model.

B.2 Pumped Hydropower Investment Restrictions

The original model formulation was too relaxed when it comes to investments in pumped hydropower. To solve this, a restriction for setting investment variables for this type of generator is included:

```
! Don't create pumped hydro investment variables if the initial capacity
is less than 50
forall(gg in GENERATORS | GEN_IS_PUMP(gg)) do
    if CAP_GEN_INIT(gg) < 50 then
        forall(yy in YEARS) GEN_INVEST_ON(yy,gg) := false;
    end-if
end-do
```

This constraint ensures that if the initially installed pumped hydropower capacity for a given generator is less than 50 MW, no additional investments in pumped hydropower can be done for that particular generator in the remaining years.

B.3 Barrier Method Control Parameter

During test runs, convergence problems with the Newton-Barrier Method occurred. The problem was related to insufficient improvements between iterations in the Barrier solving algorithm, leading the optimization run to stop and no solution to be given. The Barrier Method control parameter 'Barregularize' was changed to solve this problem:

```
setparam("XPRS_BARREGULARIZE",8); ! Default: -1.
```

This control determines how the Barrier algorithm applies regularization on the KKT[7] system. Using a parameter value of '8' forces to preserve degenerate rows in the KKT system [70].

B.4 Isolation of Enhanced Hydropower Formulation Code

In order to make it easy to run the EMPIRE model with and without the enhanced hydropower formulation, the Mosel code for the new framework has been isolated into a separate file. A toggle in the main model file enables the user to choose whether or not the new hydropower formulation shall be used. The new file organization also makes it easier to see the contributions made in this Master's thesis, since it is now isolated from the original, main EMPIRE model file. Christian Skar carried out this isolation work.

[7] Karush-Kuhn-Tucker

B.5 Discharge Variable Existence Requirement

Previously, the hydropower discharge variables were created for all segments and nodes. However, if there is no available water to be used for power generation, creating these variables will only increase model size and computation time. An existence criterion for the discharge variables is therefore implemented. As long as the available segment size is equal to zero, the variable will not be created. A simplified pseudo code is given below.

```
for all (scenarios,years,seasons,nodes,segments) do
    if (actual segment size > 0)
        create discharge variables
    end-if
end-do
```

Discharge variables are created for all scenarios, years, seasons, nodes and segments. For the 3-scenario version, with 3 scenarios, 11 years, 10 seasons per year, 31 nodes and 51 segments for each reservoir, the total number of variables amounts to $3 \cdot 11 \cdot 10 \cdot 31 \cdot 51 = 521\ 730$. Assuming an average initial reservoir level of 70%, the existence requirement reduces the optimization problem with nearly 157 000 variables. For the 10-scenario version the total number of variables becomes $10 \cdot 11 \cdot 10 \cdot 31 \cdot 51 = 1\ 739\ 100$. In this case the existence requirement reduces the problem size with nearly 522 000 variables.

C Essential Data Sets

C.1 Country-Specific Hydropower Data

Table 20: Reservoir size and initial capacities for hydropower.

Country	Res. Size [GWh]	Regulated Capacity [MW]	RoR Capacity [MW]
Austria	2 696	2 453	5 645.3
Bosnia & H.	2 132	1 587	29
Belgium	0.1	0	113
Bulgaria	4 000	2 027	143
Switzerland	18 420	8 350	3 770
Czech Republic	300	780	276
Germany	123	1 573	2 631.8
Denmark	0.1	0	9
Estonia	0.1	0	4
Spain	23 965	13 231	3 153
Finland	2 508	2 750	310
France	8 449	13 515	7 612
Great Britain	395	622	989
Greece	89	2 544	0
Croatia	1 543	1 407	430
Hungary	0.1	0	50
Ireland	600	215	32
Italy	21 601	9 212	4 765
Lithuania	21	115	0
Luxembourg	3	17	15
Latvia	0.1	0	1 550
Macedonia	5	503	0
Netherlands	0.1	0	38
Norway	84 995	21 867.4	5 938.6
Poland	470	141.2	411.7
Portugal	8 700	1 421	2 595
Romania	4 917	3 810	2 277
Serbia	436	397	1 852
Sweden	44 184	9 677.2	6 522.8
Slovenia	0.1	0	1 027
Slovakia	370	1 694	0

C.2 Regulated Hydropower Generation Results for 2010

Table 21: Regulated hydropower generation results for 2010, from Case 0. These are the basis for the limits used in Case 1 and Case 2.

Country	Generation in 2010 [GWh]
Austria	10 086
Bosnia & H.	4 466
Belgium	0
Bulgaria	5 185
Switzerland	34 332
Czech Republic	1 171
Germany	9 347
Denmark	0
Estonia	0
Spain	31 389
Finland	11 788
France	39 036
Great Britain	1 612
Greece	3 296
Croatia	3 532
Hungary	0
Ireland	557
Italy	27 652
Lithuania	216
Luxembourg	57
Latvia	0
Macedonia	944
Netherlands	0
Norway	107 953
Poland	153
Portugal	3 141
Romania	9 746
Serbia	745
Sweden	40 040
Slovenia	0
Slovakia	4 086

C.3 Initial Reservoir Levels for Norway

Table 22: Median filling degree in the period 1993-2013 for Norway. Obtained from the Norwegian TSO, Statnett [59].

Week nr	Reservoir level [%]	Week nr	Reservoir level [%]
1	68.5	27	70.5
2	65.8	28	72.2
3	63.9	29	75.2
4	61.1	30	77
5	58.8	31	78.8
6	55.7	32	80.1
7	52.6	33	80.2
8	49.3	34	81.2
9	46.5	35	83.1
10	44.3	36	84.8
11	41.5	37	85.3
12	38.8	38	84.8
13	36.2	39	86.1
14	33.7	40	86.5
15	31.7	41	86.9
16	30.7	42	86.7
17	31.3	43	85.7
18	32.2	44	84.8
19	37.2	45	83
20	39.6	46	82.4
21	43.1	47	80.8
22	47.6	48	78.9
23	50.8	49	76.1
24	56.1	50	74
25	61.7	51	72.5
26	67.2	52	70.3

The values in the table above are used as initial reservoir levels for Norway and Sweden. The resulting seasonal levels are shown in Table 23 on the next page.

Table 23: Stochastic initial reservoir levels for Norway and Sweden. Values are taken from Statnett's median values in the 20-year period from 1993 to 2013 [59].

	Scenario 1		Scenario 2		Scenario 3	
Season	Week number	Reservoir level [%]	Week number	Reservoir level [%]	Week number	Reservoir level [%]
1	6	55.7	10	44.3	7	52.6
2	23	50.8	21	43.1	26	67.2
3	27	70.5	29	75.2	38	84.8
4	52	70.3	46	82.4	52	70.3
5	4	61.1	50	74	5	58.8
6	4	61.1	1	68.5	50	74
7	50	74	48	78.9	3	63.9
8	5	58.8	1	68.5	1	68.5
9	26	67.2	29	75.2	26	67.2
10	5	58.8	2	65.8	50	74

D Tables for Inflow Scaling Corrections

The tables in this appendix belong to Section 5.5.

D.1 The 3-Scenario Version

Regulated Inflow

Table 24: Investigation of regulated inflow scaling inaccuracies in the 3-scenario version.

Country	Actual Inflow [TWh]	Scaled Inflow [TWh]	Difference [TWh]	Difference [%]
Austria	32.64	30.26	-2.38	-7.3%
Bosnia & H.	14.45	13.40	-1.05	-7.3%
Czech Republic	3.79	3.51	-0.28	-7.3%
Germany	34.61	32.10	-2.51	-7.3%
Spain	101.57	94.17	-7.40	-7.3%
Finland	27.23	35.37	8.14	29.9%
France	126.31	117.11	-9.21	-7.3%
Great Britain	5.21	4.83	-0.38	-7.3%
Greece	10.66	9.89	-0.78	-7.3%
Croatia	11.43	10.60	-0.83	-7.3%
Italy	89.48	82.96	-6.52	-7.3%
Lithuania	0.70	0.65	-0.05	-7.3%
Luxembourg	0.18	0.17	-0.01	-7.3%
Macedonia	3.05	2.83	-0.22	-7.3%
Norway	294.38	375.34	80.95	27.5%
Poland	1.18	1.09	-0.08	-7.2%
Portugal	10.96	10.16	-0.80	-7.3%
Romania	31.54	29.24	-2.30	-7.3%
Serbia	2.41	2.23	-0.18	-7.3%
Sweden	131.37	120.24	-11.12	-8.5%
Slovakia	13.22	12.26	-0.96	-7.3%

The scenario-wise aggregation is done in order to save space. Nodes that are missing data in the SINTEF data sets, as described in Section 5.4, are not included. Data are summed for all three scenarios. The difference in TWh is scaled minus actual inflow.

Table 25: Correcting Norwegian inflow in scenario 2, due to high scaled inflow values.

Season	Orig. Inflow [MWh]	Share	Removal [MWh]	Adjusted Inflow [MWh]
1	12 101.60	0.6%	1 299.54	10 802.06
2	764 987.66	37.5%	82 149.07	682 838.59
3	444 206.27	21.8%	47 701.60	396 504.68
4	504 071.49	24.7%	54 130.29	449 941.20
6	48 701.54	2.4%	5 229.87	43 471.67
7	42 388.96	2.1%	4 551.99	37 836.98
8	25 082.26	1.2%	2 693.49	22 388.78
8	42 388.96	2.1%	4 551.99	37 836.98
9	92 542.97	4.5%	9 937.83	82 605.14
10	64 555.98	3.2%	6 932.42	57 623.56
Sum	2 041 027.70	-	219 178.08	1 821 849.62

Run-of-the-River Inflow

Table 26: Investigation of run-of-the-river inflow scaling inaccuracies.

Country	Actual Inflow [TWh]	Scaled Inflow [TWh]	Difference [TWh]	Difference [%]
Austria	85.09	86.97	1.88	2.2%
Bosnia & H.	0.26	0.26	0.01	2.2%
Czech Republic	1.30	1.33	0.03	2.2%
Germany	69.51	71.05	1.54	2.2%
Spain	28.88	29.51	0.63	2.2%
Finland	4.98	4.86	-0.12	-2.4%
France	74.87	76.52	1.65	2.2%
Great Britain	8.03	8.21	0.18	2.2%
Greece	0.00	0.00	0.00	0.0%
Croatia	3.38	3.46	0.07	2.2%
Table continues on the next page.				

Italy	44.84	45.83	0.99	2.2%
Lithuania	0.00	0.00	0.00	0.0%
Luxembourg	0.16	0.16	0.00	2.2%
Macedonia	0.00	0.00	0.00	0.0%
Norway	134.21	158.95	24.74	18.4%
Poland	2.97	3.03	0.06	2.1%
Portugal	21.06	21.53	0.46	2.2%
Romania	18.26	18.66	0.40	2.2%
Serbia	15.33	15.67	0.34	2.2%
Sweden	84.49	85.74	1.25	1.5%
Slovakia	0.00	0.00	0.00	0.0%

Data are summed for all three scenarios. The difference in TWh is scaled minus actual inflow.

Table 27: Correction of run-of-the-river inflow for Norway in scenario 2, due to high values for scaled inflow compared to actual values.

Season	Orig. Inflow [MWh]	Share	Removal [MWh]	Adjusted Inflow [MWh]
1	59 921.81	7.0%	12 213.60	47 708.21
2	175 243.49	20.4%	35 719.11	139 524.38
3	251 331.52	29.2%	51 227.80	200 103.72
4	233 739.53	27.2%	47 642.10	186 097.43
5	19 755.14	2.3%	4 026.60	15 728.54
6	15 251.56	1.8%	3 108.66	12 142.90
7	16 635.90	1.9%	3 390.82	13 245.08
8	15 251.56	1.8%	3 108.66	12 142.90
9	52 360.73	6.1%	10 672.46	41 688.27
10	20 766.03	2.4%	4 232.65	16 533.38
Sum	860 257.27	-	175 342.47	684 914.81

D.2 The 10-Scenario Version

Regulated Inflow

Table 28: Comparison of actual and scaled regulated inflow used in the model for the 10-scenario version.

Node	Actual Inflow [TWh]	Scaled Inflow [TWh]	Difference [TWh]	Difference [%]
Austria	108.79	107.46	-1.33	-1.2%
Bosnia & H.	48.17	47.58	-0.59	-1.2%
Czech Republic	12.63	12.47	-0.15	-1.2%
Germany	115.37	114.00	-1.38	-1.2%
Spain	338.57	334.43	-4.14	-1.2%
Finland	90.76	104.17	13.41	12.9%
France	421.05	415.90	-5.15	-1.2%
Great Britain	17.38	17.17	-0.21	-1.2%
Greece	35.55	35.11	-0.43	-1.2%
Croatia	38.10	37.63	-0.47	-1.2%
Italy	298.26	294.62	-3.64	-1.2%
Lithuania	2.33	2.30	-0.03	-1.2%
Luxembourg	0.61	0.61	-0.01	-1.2%
Macedonia	10.18	10.05	-0.12	-1.2%
Norway	981.28	1047.83	66.56	6.4%
Poland	3.93	1.63	-2.30	-141.4%
Portugal	36.52	36.07	-0.45	-1.2%
Romania	105.13	103.84	-1.29	-1.2%
Serbia	8.03	7.94	-0.10	-1.2%
Sweden	437.89	428.88	-9.01	-2.1%
Slovakia	44.07	43.53	-0.54	-1.2%

Difference in TWh is scaled minus actual inflow. Data is summed for all 10 scenarios.

Table 29: Comparison of actual regulated inflow and scaled regulated inflow used in the model for Norway and Sweden.

Scenario	Actual inflow [TWh]	Scaled inflow [TWh]	Difference [TWh]	Removal [%]
Norway				
1	88.77	101.76	12.99	12.8%
2	88.77	182.32	93.55	51.3%
3	88.77	124.05	35.28	28.4%
4	112.65	76.91	-35.74	-46.5%
5	112.65	153.61	40.96	26.7%
6	112.65	75.78	-36.87	-48.6%
7	92.96	77.71	-15.25	-19.6%
8	92.96	82.16	-10.79	-13.1%
9	92.96	57.10	-35.85	-62.8%
10	98.13	116.41	18.29	15.7%
Sweden				
1	45.38	77.05	31.68	41.1%
2	45.38	37.18	-8.19	-22.0%
3	45.38	65.54	20.16	30.8%
4	38.78	25.59	-13.19	-51.5%
5	38.78	26.03	-12.75	-49.0%
6	38.78	30.89	-7.89	-25.6%
7	47.21	37.36	-9.85	-26.4%
8	47.21	38.80	-8.41	-21.7%
9	47.21	50.42	3.21	6.4%
10	43.79	40.02	-3.77	-9.4%

Differences are given as scaled minus actual inflow.

Run-of-the-River Inflow

Table 30: Comparison of actual and scaled run-of-the-river inflow used in the model for the 10-scenario version.

Node	Actual inflow [TWh]	Scaled inflow [TWh]	Difference [TWh]	Difference [%]
Austria	42 961.78	42 362.02	-599.76	-1.4%
Bosnia & H.	29 405.74	28 995.22	-410.51	-1.4%
Czech Republic	15 683.06	15 464.12	-218.94	-1.4%
Germany	61 399.26	60 542.11	-857.15	-1.4%
Spain	24 789.04	24 442.97	-346.06	-1.4%
Finland	46 673.82	46 404.41	-269.41	-1.4%
France	30 180.09	29 758.76	-421.32	-1.4%
Great Britain	27 072.88	26 694.93	-377.95	-1.4%
Greece	0.00	0.00	0.00	0.0%
Croatia	26 229.92	25 863.74	-366.18	-1.4%
Italy	31 366.12	30 928.24	-437.88	-1.4%
Lithuania	0.00	0.00	0.00	0.0%
Luxembourg	35 002.63	34 513.98	-488.65	-1.4%
Macedonia	0.00	0.00	0.00	0.0%
Norway	42 089.06	42 242.39	153.33	0.0%
Poland	13 330.50	13 144.40	-186.10	-1.4%
Portugal	14 333.97	14 133.86	-200.11	-1.4%
Romania	26 729.81	26 356.66	-373.16	-1.4%
Serbia	16 252.75	16 025.86	-226.89	-1.4%
Sweden	42 936.35	40 539.18	-2 397.17	-5.9%
Slovakia	0.00	0.00	0.00	0.0%

Data is summed for all ten scenarios. Difference in TWh is scaled minus actual inflow.

E Mosel Code

E.1 Data Handler for Hydropower Formulation

The Mosel code below converts and collects the Excel input files into one text file, easily readable by the Xpress solver.

```
(!***************************************************************
   Data handler for enhanced hydropower formulation for use with the EMPIRE
model
   ==============================================================

   file data_handler_hydroformulation.mos
   ``````````````````

   Converts data from Excel files to text file readable by Xpress.

   (c) 2013,2014 Sondre Heen Brovold
       author: S. H. Brovold, rev. June 2014
***!)

model "Expansion model - Data handler for new hydro formulation"
uses "mmodbc"; !gain access to the SQL drivers
uses "mmxprs";
options noimplicit
options explterm

parameters
    ROOTFOLDER = "..\\data\\";
    MODELNAME = "europe_v30_Project2013";
    HYDRO_DATA = "hydro_data";
    POLICYSCENARIO =
"Global202020";!"Global202020";!"Reference";!"650";!"650_noCCSnuc";!
    TEMPEXT = "test";
    DATAFOLDER = ROOTFOLDER + "excel\\" + MODELNAME + "\\";

    OUTPUTDATAFILE = ROOTFOLDER + "input\\" + MODELNAME + "_" +
POLICYSCENARIO + "_" + HYDRO_DATA + "_" + TEMPEXT + ".txt";

    SCENARIOS_10 = false;

end-parameters

forward procedure read_hydro_data
forward procedure write_hydro_data
forward procedure set_segment_size

declarations
    SCENARIOS   :   set of integer;
    SEGMENTS   :   set of integer;
    NUMOFSEGMENTS   :   set of integer;
    YEARS   :   set of integer;
    SEASONS   :   set of integer;
    NODES   :   set of integer;
    INFLOW   :   dynamic array(SCENARIOS, SEASONS, NODES)
of real; ! Normalized regulated inflow
    NON_REG_INFLOW   :   dynamic array(SCENARIOS, SEASONS, NODES)
of real; ! Normalized RoR inflow
    INFLOW_INIT   :   dynamic array(SCENARIOS, SEASONS, NODES)
of real; ! 2010 total regulated inflow
    WATERVALUES   :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES,
SEGMENTS)   of real; ! Water values for all years
    WV_SET1   :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES,
```
```

```
SEGMENTS)   of real; ! Part 1 of water values set for 10 scenarios
    WV_SET2             :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES,
SEGMENTS)   of real; ! Part 2 of water values set for 10 scenarios
    MAXRESLEVEL         :   dynamic array(NODES)
of real; ! Maximum reservoir size
    MINRESLEVEL         :   dynamic array(NODES)
of real; ! Minimum reservoir size
    INITRESFRACTION     :   dynamic array(SCENARIOS, SEASONS, NODES)
of real; ! Initial reservoir, given as fraction of maximum reservoir size
    INITRESLEVEL        :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES)
of real; ! Initial reservoir level
    SEG_FULL_SIZE       :   dynamic array(NODES, SEGMENTS)
of real; ! Max possible size of a segment
    SEG_SIZE            :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES,
SEGMENTS)   of real; ! Real segment size given initial level
    TEMP_RES_LEVEL      :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES)
of real; ! Temporary reservoir level used in calculations
    MIN_REG_HYDRO_GEN   :   dynamic array(SCENARIOS, SEASONS, NODES)
of real; ! Minimum generation limit for regulated hydro

    end-declarations

! Executing the procedure that reads the hydropower data
read_hydro_data;

! Procedure for reading hydropower data from Excel
procedure read_hydro_data
    write("Reading hydro data...\n");
    write("Connecting...\n");

    SQLconnect('Driver={Microsoft Excel Driver (*.xls, *.xlsx, *.xlsm,
*xlsb)};DBQ=' + DATAFOLDER + HYDRO_DATA + '.xlsx');

    write("reading...\n");


    ! Number of segments
    SQLexecute("SELECT NUMOFSEGMENTS FROM NumOfSegments", NUMOFSEGMENTS);
    finalize(NUMOFSEGMENTS);

    ! Scenarios
    SQLexecute("SELECT SCENARIOS FROM Scenarios", SCENARIOS);
    finalize(SCENARIOS);

    ! Years
    SQLexecute("SELECT YEARS FROM Years", YEARS);
    finalize(YEARS);

    ! Inflow
    SQLexecute("SELECT SCENARIO,SEASON,NODE,INFLOW FROM Inflow", INFLOW);

    ! RoR inflow
    SQLexecute("SELECT SCENARIO,SEASON,NODE,NON_REG_INFLOW FROM Inflow",
NON_REG_INFLOW);

    ! Initial inflow
    SQLexecute("SELECT SCENARIO,SEASON,NODE,INFLOW_INIT FROM Inflow",
INFLOW_INIT);


    ! Initial reservoir fraction
    SQLexecute("SELECT SCENARIO,SEASON,NODE, INITRESFRACTION FROM
InitResfraction", INITRESFRACTION);

    ! Maximum reservoir level
    SQLexecute("SELECT NODE,MAXRESLEVEL FROM ResLevels", MAXRESLEVEL);

    ! Minimum reservoir level
    SQLexecute("SELECT NODE,MINRESLEVEL FROM ResLevels", MINRESLEVEL);
```

```
    ! Water values
    if(SCENARIOS_10) then ! Water values for 10 scenarios are divided in two
sets because of large
                          ! amount of data (exceeds row limits in Excel)
        SQLexecute("SELECT SCENARIO,YEAR,SEASON,NODE,SEGMENT,WV_1 FROM
WV_Set1", WV_SET1);
        SQLexecute("SELECT SCENARIO,YEAR,SEASON,NODE,SEGMENT,WV_2 FROM
WV_Set2", WV_SET2);

        forall(scn in 1..5, yy in YEARS, seas in SEASONS, nn in NODES, mm in
SEGMENTS) do
            WATERVALUES(scn,yy,seas,nn,mm) := WV_SET1(scn,yy,seas,nn,mm);
        end-do

        forall(scn in 6..10, yy in YEARS, seas in SEASONS, nn in NODES, mm
in SEGMENTS) do
            WATERVALUES(scn,yy,seas,nn,mm) := WV_SET2(scn,yy,seas,nn,mm);
        end-do

        else ! Water values for 3 scenarios are imported directly
            SQLexecute("SELECT SCENARIO,YEAR,SEASON,NODE,SEGMENT,WV FROM
Watervalues", WATERVALUES);
    end-if


    ! Minimum regulated hydro generation
    SQLexecute("SELECT SCENARIO,SEASON,NODE,MIN_REG_HYDRO_GEN FROM
MinRegHydroGen", MIN_REG_HYDRO_GEN);


    write("Disconnecting...\n");
    SQLdisconnect;
    write("Reading Excel file is done.\n");

end-procedure

! Executing the procedure for setting the segment size
! based on initial reservoir levels
set_segment_size;

! Procedure for setting the segment size
procedure set_segment_size

    ! Setting res level at start of week
    forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES) do
        INITRESLEVEL(scn,yy,seas,nn) :=
INITRESFRACTION(scn,seas,nn)*MAXRESLEVEL(nn);
    end-do

    ! SEG_FULL_SIZE is the fixed size of a full segment.
    forall(nn in NODES, mm in SEGMENTS) do
        SEG_FULL_SIZE(nn,mm) := MAXRESLEVEL(nn)/(NUMOFSEGMENTS(1));
    end-do

    declarations
        aa: integer;
    end-declarations

    ! Set the real segment size. Was located in utility.mos earlier.
    forall(scn in SCENARIOS, yy in YEARS, ss in SEASONS, nn in NODES) do
        aa := NUMOFSEGMENTS(1);
        TEMP_RES_LEVEL(scn,yy,ss,nn) := INITRESLEVEL(scn,yy,ss,nn) +
INFLOW_INIT(scn,ss,nn);

            while(aa>=1) do

                if(TEMP_RES_LEVEL(scn,yy,ss,nn)>= SEG_FULL_SIZE(nn,aa)) then
                SEG_SIZE(scn,yy,ss,nn,aa) := SEG_FULL_SIZE(nn,aa);
                else
                    SEG_SIZE(scn,yy,ss,nn,aa) :=
```

```
TEMP_RES_LEVEL(scn,yy,ss,nn);
                end-if

            TEMP_RES_LEVEL(scn,yy,ss,nn) := TEMP_RES_LEVEL(scn,yy,ss,nn)-
SEG_SIZE(scn,yy,ss,nn,aa);

            aa := aa-1;
            end-do
    end-do

end-procedure

! Executing the procedure for writing the hydropower data to text file
write_hydro_data;

! Procedure for writing the hydropower data to text file
procedure write_hydro_data
    write("Writing hydro data to txt file...\n");
    initializations to OUTPUTDATAFILE
        NUMOFSEGMENTS;
        INFLOW;
        NON_REG_INFLOW;
        INITRESFRACTION;
        MAXRESLEVEL;
        MINRESLEVEL;
        WATERVALUES;
        SEG_SIZE;
        INITRESLEVEL;
        SEG_FULL_SIZE;
        MIN_REG_HYDRO_GEN;
        INFLOW_INIT;
    end-initializations

    write("Writing hydro data to txt file is done.\n");

end-procedure

end-model
```

E.2 Enhanced Hydropower Implementation

The Mosel code below contains the formulations for the enhanced hydropower formulation. The code is imported by the Mosel file that executes the model.

```
(!*************************************************************
   Enhanced hydropower formulation for use with the EMPIRE model
   =============================================================

   file enhanced_hydro.mos
   ```````````````

   Declares additional variables/parameters for advanced hydro-
   power scheduling in EMPIRE. Creates necessary variables.
   Updates objective function and constraints. Reads additional
   data required.

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       author: S. H. Brovold, rev. June 2014
***!)

declarations

    SEGMENTS   :   set of integer;   ! Set of segments
    NUMOFSEGMENTS   :   set of integer;   ! Number of segments in each
reservoir
    INFLOW   :   dynamic array(SCENARIOS, SEASONS, NODES)
of real; ! Normalized regulated inflow
    NON_REG_INFLOW   :   dynamic array(SCENARIOS, SEASONS, NODES)
of real; ! Normalized RoR inflow
    WATERVALUES   :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES,
SEGMENTS)   of real; ! Water values for all years
    MAXRESLEVEL   :   dynamic array(NODES)
of real; ! Maximum reservoir size
    MINRESLEVEL   :   dynamic array(NODES)
of real; ! Minimum reservoir size
    INITRESFRACTION :   dynamic array(SCENARIOS, SEASONS, NODES)
of real; ! Initial reservoir, given as fraction of maximum reservoir size
    INITRESLEVEL   :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES)
of real; ! Initial reservoir level
    SEG_SIZE   :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES,
SEGMENTS)   of real; ! Real segment size given initial level
    SEG_FULL_SIZE   :   dynamic array(NODES, SEGMENTS)
of real; ! Max possible size of a segment
    MIN_REG_HYDRO_GEN: dynamic array(SCENARIOS, SEASONS, NODES)
of real; ! Minimum generation limit for regulated hydro
    INFLOW_INIT   :   dynamic array(SCENARIOS, SEASONS, NODES)
of real; ! 2010 total regulated inflow

    ! Used in utility.mos
    ALLOW_BUILD   :   dynamic array(YEARS, NODES, TECHNOLOGIES)
of real; ! Parameter telling the model if a certain node can invest in a
certain teechnology

    ! Total number of hours in a season, for use with hourly RoR generation
constraint.
    TOTAL_HOURS_IN_SEASON: array(SEASONS) of real;

    seg_tap_season   :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES,
SEGMENTS)of mpvar; ! Discharge from segments in hydro reservoir per season
    end_season_res_lev   :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES)
of mpvar; ! Reservoir level at end-of-season
    spillage   :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES)
of mpvar; ! Spillage from each reservoir each season
```
```

```
    ! Hydropower scheduling constraints
    MaxSeasonSegTapCtr:             dynamic array(SCENARIOS, YEARS, SEASONS,
NODES, SEGMENTS)   of linctr; ! Seasonal segmental discharge constraint
    EndSeasonResLevelCtr:           dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of linctr; ! End-of-season reservoir balance
    EndSeasonMaxResLevelCtr:        dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of linctr; ! Max end-of-season reservoir level constraint
    EndSeasonMinResLevelCtr:        dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of linctr; ! Min end-of-season reservoir level constraint
    HydroGenDischargeBalanceCtr:    dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of linctr; ! Coupling of seasonal discharge and
generation variables
    RoRHydroGenDischargeBalanceCtr: dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of linctr; ! Coupling of seasonal discharge and
generation variables, for RoR
    RegHydroDischargeSeqCtr:        dynamic array(SCENARIOS, YEARS, SEASONS,
NODES, SEGMENTS)   of linctr; ! Discharge sequence constraint
    MaxYearlyHydroGenCtr:           dynamic array(SCENARIOS, YEARS, NODES)
of linctr; ! Maximum yearly regulated hydropower generation
    RoRHydroSeasonalGenCtr:         dynamic array(SCENARIOS, YEARS, HOURS,
NODES)               of linctr; ! Hourly RoR generation constraint in season
    MinRegHydroGenCtr:              dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of linctr; ! Minimum generation constraint for regulated
hydro
    MaxRegHydroGenCtr:              dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of linctr; ! Maximum generation constraint for regulated
hydro


    ! Seasonal hydropower scale parameter
    SEASON_SCALE_HYDRO   :    array(SEASONS) of real;
    ! Solution containers
    SEG_TAP_SEASON       :    dynamic array(SCENARIOS, YEARS, SEASONS, NODES,
SEGMENTS)   of real;
    SPILLAGE             :    dynamic array(SCENARIOS, YEARS, SEASONS, NODES)
of real;
    END_SEASON_RES_LEV   :    dynamic array(SCENARIOS, YEARS, SEASONS, NODES)
of real;

    MAX_YEARLY_HYDRO_DUAL:          dynamic array(SCENARIOS, YEARS, NODES)
of real; ! Shadow price for maximum yearly hydropower gen. constraint
    HYDRO_DISCHARGE_BALANCE_DUAL:   dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of real; ! Shadow price for hydro disch/generation
constraint
    ROR_SEASONAL_GEN_DUAL:          dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of real; ! Shadow price for RoR seasonal generation
constraint
    ROR_AVERAGE_DUAL:               dynamic array(SCENARIOS, YEARS, HOURS,
NODES)               of real; ! Shadow price for RoR hourly generation
constraint
    MIN_REG_HYDRO_GEN_DUAL:         dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of real; ! Shadow price for minimum reg. hydro generation
contraint
    MAX_REG_HYDRO_GEN_DUAL:         dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of real; ! Shadow price for maximum reg. hydro generation
constraint

end-declarations

! Create variables associated with hydropower
procedure create_enhanced_hydro_variables

    forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES, mm
in SEGMENTS) do
        if (SEG_SIZE(scn,yy,seas,nn,mm)>0) then ! Create varibles only if
energy is available in segment
            create(seg_tap_season(scn,yy,seas,nn,mm));
            end-if
    end-do
```

```
    forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES) do
        create(end_season_res_lev(scn,yy,seas,nn));
        create(spillage(scn,yy,seas,nn));
    end-do

end-procedure


procedure add_enhanced_hydro_obj_and_cons


    !! ** Penalizing objective function through water values when regulated
hydropower is utilized ** !!

    MinTotalExpectedCost +=  ALPHA/LEAP_CFR * sum(scn in SCENARIOS, yy in
YEARS, ss in SEASONS, nn in NODES, mm in SEGMENTS |
exists(seg_tap_season(scn,yy,ss,nn,mm)))
                  (1 + DISCOUNT_RATE)^(-LEAP*(yy-1))
                        * PROB(scn) * SEASON_SCALE_HYDRO(ss) *
seg_tap_season(scn,yy,ss,nn,mm)*WATERVALUES(scn,yy,ss,nn,mm);


    !! ** Constraints associated with hydropower scheduling ** !!

    ! Seasonal segmental discharge cannot exceed segment size
    forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES, mm
in SEGMENTS | exists(seg_tap_season(scn,yy,seas,nn,mm))) do
        MaxSeasonSegTapCtr(scn,yy,seas,nn,mm) :=
            seg_tap_season(scn,yy,seas,nn,mm) <=
SEG_SIZE(scn,yy,seas,nn,mm);
    end-do

    ! End-of-season reservoir level balance
    forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES) do
        EndSeasonResLevelCtr(scn,yy,seas,nn) :=
            end_season_res_lev(scn,yy,seas,nn) =
                INITRESLEVEL(scn,yy,seas,nn) - sum(mm in SEGMENTS)
seg_tap_season(scn,yy,seas,nn,mm)
                + (INFLOW(scn,seas,nn)*sum(gg in GENS_IN_NODE(nn) |
GEN_TECH(gg) = 24) cap_gen(yy,gg))
                - spillage(scn,yy,seas,nn);
    end-do

    ! End-of-season maximum reservoir level
    forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES) do
        EndSeasonMaxResLevelCtr(scn,yy,seas,nn) :=
            end_season_res_lev(scn,yy,seas,nn) <= MAXRESLEVEL(nn);
    end-do

    ! End-of season minimum reservoir level
    forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES |
INITRESLEVEL(scn,yy,seas,nn)> MINRESLEVEL(nn)) do
        EndSeasonMinResLevelCtr(scn,yy,seas,nn) :=
            end_season_res_lev(scn,yy,seas,nn) >= MINRESLEVEL(nn);
    end-do


    ! Discharge sequence control. Discharge is forced to start at the upper-
most reservoir segment with energy available.
    ! Lower segment index number is higher in the reservoir.
        forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES,
mm in SEGMENTS
                 | mm < 51 and SEG_SIZE(scn,yy,seas,nn,mm) >=
SEG_FULL_SIZE(nn,mm) and exists(seg_tap_season(scn,yy,seas,nn,mm)) and
exists(seg_tap_season(scn,yy,seas,nn,mm+1))) do
            RegHydroDischargeSeqCtr(scn,yy,seas,nn,mm) :=
            seg_tap_season(scn,yy,seas,nn,mm+1) <=
seg_tap_season(scn,yy,seas,nn,mm);
        end-do
```

```
    ! Seasonal generation from run-of-the-river hydropower cannot exceed
seasonal RoR inflow
    forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES) do
        RoRHydroGenDischargeBalanceCtr(scn,yy,seas,nn) :=
            sum(hh in HOURS, gg in GENS_IN_NODE(nn) | HOUR_SEASON(hh) = seas
and GEN_TECH(gg) = 25)
                gen_prod(scn,yy,hh,gg)
                <=
                (NON_REG_INFLOW(scn,seas,nn)*sum(gg in GENS_IN_NODE(nn) |
GEN_TECH(gg) = 25) cap_gen(yy,gg));
    end-do


    ! Limiting the degree of freedom in which run-of-the-river hydropower
can be utilized throughout a season
    forall(scn in SCENARIOS, yy in YEARS, hh in HOURS, nn in NODES) do
        RoRHydroSeasonalGenCtr(scn,yy,hh,nn) :=
            sum(gg in GENS_IN_NODE(nn) | GEN_TECH(gg) = 25)
gen_prod(scn,yy,hh,gg)
            <=

NON_REG_INFLOW(scn,HOUR_SEASON(hh),nn)/TOTAL_HOURS_IN_SEASON(HOUR_SEASON(hh)
)
            *sum(gg in GENS_IN_NODE(nn) | GEN_TECH(gg) = 25) cap_gen(yy,gg);

    end-do


    ! Yearly regulated hydropower generation cannot exceed yearly inflow to
each node
    forall(scn in SCENARIOS, yy in YEARS, nn in NODES) do
        MaxYearlyHydroGenCtr(scn,yy,nn) :=
                sum(hh in HOURS, gg in GENS_IN_NODE(nn) | GEN_TECH(gg) = 24)
                    gen_prod(scn,yy,hh,gg)*SEASON_SCALE(hh)
                <=
                sum(ss in SEASONS)
                    (INFLOW(scn,ss,nn)*SEASON_SCALE_HYDRO(ss)*sum(gg in
GENS_IN_NODE(nn) | GEN_TECH(gg) = 24) cap_gen(yy,gg));
    end-do

    if(REG_HYDRO_GEN_LIMITS) then
        ! Lower limit on regulated hydropower generation based on generation
values for 2010 from previous simulation without limits.
        forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES)
do
            MinRegHydroGenCtr(scn,yy,seas,nn) :=
                sum(hh in HOURS, gg in GENS_IN_NODE(nn) | HOUR_SEASON(hh) =
seas and GEN_TECH(gg) = 24) gen_prod(scn,yy,hh,gg)
                    >= 0.8 * MIN_REG_HYDRO_GEN(scn,seas,nn);
        end-do


        ! Upper limit on regulated hydropower generation. WARNING: Hard-
coded limit.
        forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES)
do
            MaxRegHydroGenCtr(scn,yy,seas,nn) :=
                sum(hh in HOURS, gg in GENS_IN_NODE(nn) | HOUR_SEASON(hh) =
seas and GEN_TECH(gg) = 24) gen_prod(scn,yy,hh,gg)
                    <= 1.1 * MIN_REG_HYDRO_GEN(scn,seas,nn);
        end-do
    end-if


    ! Coupling of seasonal discharge and generation variables.
    ! Seasonal generation from regulated hydropower is the sum of discharge
from each reservoir segment
    forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES) do
        HydroGenDischargeBalanceCtr(scn,yy,seas,nn) :=
```

```
            sum(hh in HOURS, gg in GENS_IN_NODE(nn) | HOUR_SEASON(hh) = seas
and GEN_TECH(gg) = 24) gen_prod(scn,yy,hh,gg)
             = sum(mm in SEGMENTS) seg_tap_season(scn,yy,seas,nn,mm);
    end-do

end-procedure


! Change some of the hydropower parameters from the original model
procedure change_original_hydro_parameters

    ! Relax the availability constraint for RoR hydropower
    forall(scn in SCENARIOS, hh in HOURS, nn in NODES, gg in
GENS_IN_NODE(nn) | GEN_TECH(gg) = 25) do
        if(CAP_GEN_INIT(gg) > 0) then
            AVAILABILITY(scn,hh,gg) := 1;
        end-if
    end-do

    ! Set SRMC for regulated hydropower generators to zero, due to the use
of water values instead
    forall(yy in YEARS, gg in GENERATORS | GEN_TECH(gg) = 24) do
        SRMC(yy,gg) := 0;
    end-do

end-procedure

procedure setup_enhanced_hydro_data

    ! Setting the seasonal hydropower scale parameter
    forall(seas in SEASONS) do
        case seas of
            1,2,3,4:
                SEASON_SCALE_HYDRO(seas) := 8750/8760;
                else
                    SEASON_SCALE_HYDRO(seas) := 10/8760;
        end-case
    end-do

    ! Setting the total number of hours in each season
    forall(seas in SEASONS) do
        TOTAL_HOURS_IN_SEASON(seas) := sum(hh in HOURS | HOUR_SEASON(hh) =
seas) 1;
    end-do


    initializations from DATAFILE
        ALLOW_BUILD;
    end-initializations


    forall(nn in NODES, at in AGG_TECH) do
        forall(yy in YEARS-{1}) do
            forall(gg in AGG_TECH_GEN(nn,at)) do
                if(ALLOW_BUILD(yy,nn,GEN_TECH(gg)) = 0 and GEN_TECH(gg) =
24) then
                    GEN_INVEST_ON(yy,gg) := false;
                end-if
            end-do
        end-do
    end-do


    initializations from DATAFILE_HYDRO
        NUMOFSEGMENTS;
        INFLOW;
        NON_REG_INFLOW;
        WATERVALUES;
        MAXRESLEVEL;
        MINRESLEVEL;
```

```
        INITRESFRACTION;
        SEG_SIZE;
        INITRESLEVEL;
        SEG_FULL_SIZE;
        MIN_REG_HYDRO_GEN;
        INFLOW_INIT;
    end-initializations
end-procedure


! Print solution variables to solution containers.
! Includes all necessary variables.
procedure writeresultsDEQ_enhanced_hydro
    forall(yy in YEARS, gg in GENERATORS)
        INVEST_GEN(yy, gg) := getsol(inv_gen(yy, gg));
    forall(yy in YEARS, ll in LINES)
        INVEST_LINE(yy, ll) := getsol(inv_line(yy, ll));

    declarations
        ARC : array(1..2) of integer;
        FLOW:  array(1..2) of real;
    end-declarations

    forall (ss in SCENARIOS, yy in YEARS, hh in HOURS)
        DUMP_ENERGY(ss,yy,hh) := false;

    forall (ss in SCENARIOS, yy in YEARS, hh in HOURS, ll in LINES) do
        ARC := ARCS(ll);
        FLOW(1) := flow_line(ss,yy,hh,ARC(1),ARC(2)).sol;
        FLOW(2) := flow_line(ss,yy,hh,ARC(2),ARC(1)).sol;

        if FLOW(1) > 0 and FLOW(2) < 1e-8 then
            FLOW_LINE(ss,yy,hh,ll) := FLOW(1);
        elif FLOW(2) > 0 and FLOW(1) < 1e-8 then
            FLOW_LINE(ss,yy,hh,ll) := -1*FLOW(2);
        elif FLOW(2) < 1e-8 and FLOW(1) < 1e-8 then
            FLOW_LINE(ss,yy,hh,ll) := 0;
        else
            FLOW_LINE(ss,yy,hh,ll) := FLOW(1) - FLOW(2);
            DUMP_ENERGY(ss,yy,hh) := true;
        end-if
    end-do

    forall(ss in SCENARIOS, yy in YEARS, hh in HOURS, nn in NODES, n in
NODES | exists(flow_line(ss, yy, hh, nn, n))) do
          FLOW_ARC(ss,yy,hh,nn,n) := getsol(flow_line(ss,yy,hh,nn,n));
    end-do

    forall(ss in SCENARIOS, yy in YEARS, hh in HOURS, gg in GENERATORS |
exists(gen_prod(ss,yy,hh,gg))) do
        GEN_PROD(ss, yy, hh, gg) := getsol(gen_prod(ss, yy, hh, gg));
        if(exists(pump_load(ss,yy,hh,gg))) then
            PUMP_LOAD(ss, yy, hh, gg) := getsol(pump_load(ss, yy, hh, gg));
            if(GEN_PROD(ss, yy, hh, gg) > 0 and PUMP_LOAD(ss, yy, hh, gg) >
0) then
                DUMP_ENERGY(ss,yy,hh) := true;
            end-if
        end-if
    end-do

    forall(ss in SCENARIOS, yy in YEARS, hh in HOURS, nn in NODES) do
        LOST_LOAD(ss, yy, hh, nn) := getsol(lost_load(ss, yy, hh, nn));
    end-do

    forall(yy in YEARS, gg in GENERATORS) do
        CAP_GEN(yy, gg) := getsol(cap_gen(yy,gg));
    end-do


    forall(ss in SCENARIOS, yy in YEARS, hh in HOURS, nn in NODES) do
```

```
        LOAD_CTR_DUAL(ss, yy, hh, nn) := getdual(LoadBalanceCtr(ss, yy, hh,
nn));
    end-do

    forall(scn in SCENARIOS, yy in YEARS, ss in SEASONS, nn in NODES, mm in
SEGMENTS) do
        SEG_TAP_SEASON(scn,yy,ss,nn,mm) :=
getsol(seg_tap_season(scn,yy,ss,nn,mm));
    end-do

    forall(scn in SCENARIOS, yy in YEARS, ss in SEASONS, nn in NODES) do
        SPILLAGE(scn,yy,ss,nn) := getsol(spillage(scn,yy,ss,nn));
        END_SEASON_RES_LEV(scn,yy,ss,nn) :=
getsol(end_season_res_lev(scn,yy,ss,nn));
    end-do

    forall(scn in SCENARIOS, yy in YEARS, nn in NODES) do
        MAX_YEARLY_HYDRO_DUAL(scn,yy,nn) :=
getdual(MaxYearlyHydroGenCtr(scn,yy,nn));
    end-do

    forall(scn in SCENARIOS, yy in YEARS, ss in SEASONS, nn in NODES) do
        HYDRO_DISCHARGE_BALANCE_DUAL(scn,yy,ss,nn) :=
getdual(HydroGenDischargeBalanceCtr(scn,yy,ss,nn));
    end-do
    forall(scn in SCENARIOS, yy in YEARS, hh in HOURS, nn in NODES) do
        ROR_AVERAGE_DUAL(scn,yy,hh,nn) :=
getdual(RoRHydroSeasonalGenCtr(scn,yy,hh,nn));
    end-do

    forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES) do
        MIN_REG_HYDRO_GEN_DUAL(scn,yy,seas,nn) :=
getdual(MinRegHydroGenCtr(scn,yy,seas,nn));
    end-do

    forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES) do
        MAX_REG_HYDRO_GEN_DUAL(scn,yy,seas,nn) :=
getdual(MaxRegHydroGenCtr(scn,yy,seas,nn));
    end-do

    forall(scn in SCENARIOS, yy in YEARS, ss in SEASONS, nn in NODES) do
        HYDRO_DISCHARGE_BALANCE_DUAL(scn,yy,ss,nn) :=
getdual(HydroGenDischargeBalanceCtr(scn,yy,ss,nn));
    end-do!)

    initializations to RESULTFILE
        COMMENT;
        TOTAL_COST;
        INVEST_GEN;
        INVEST_LINE;
        CAP_GEN;
        GEN_PROD;
        PUMP_LOAD;
        FLOW_LINE;
        LOST_LOAD;
        LOAD_CTR_DUAL;
        DUMP_ENERGY;

        SEG_TAP_SEASON;
        SPILLAGE;
        END_SEASON_RES_LEV;
        MAX_YEARLY_HYDRO_DUAL;
        HYDRO_DISCHARGE_BALANCE_DUAL;
        ROR_SEASONAL_GEN_DUAL;
        ROR_AVERAGE_DUAL;
        MIN_REG_HYDRO_GEN_DUAL;
        MAX_REG_HYDRO_GEN_DUAL;
        SEASON_SCALE_HYDRO;
    end-initializations
end-procedure
```

E.3 Implementation in EMPIRE Model File

When the implementation of the enhanced hydropower formulation is isolated in its own file, the required alterations in the main model file, merged_expansion_model.mos, are limited. The code added is given below.

```
parameters
    ! Including the hydropower data file
    HYDRO_DATA = "hydro_data";
    DATAFILE_HYDRO  = DATAFOLDER + "input\\" + MODELNAME + "_" + HYDRO_DATA
+ "_" + TEMPEXT + ".txt";

    ! Hydro specific parameters:
    ! Turn on or off enhanced hydropower formulation
    ENHANCED_HYDRO = true;
    ! Turn on or off generation limits for regulated hydropower
    REG_HYDRO_GEN_LIMITS = true;
end-parameters

! Barrier specific parameters
setparam("XPRS_BARORDER",3); ! Use nested dissection method
setparam("XPRS_BARREGULARIZE",8); ! Default: 1.


! Function definitions found in enhanced_hydro.mos
forward procedure change_original_hydro_parameters
forward procedure create_enhanced_hydro_variables
forward procedure add_enhanced_hydro_obj_and_cons
forward procedure setup_enhanced_hydro_data
forward procedure writeresultsDEQ_enhanced_hydro


!***************************
! Include enhanced hydro file here (dependent on above declarations)
include "enhanced_hydro.mos"
!***************************


! Execute Sondre's code for enhanced hydropower formulation
if (ENHANCED_HYDRO) then
    setup_enhanced_hydro_data;
    create_enhanced_hydro_variables;
    change_original_hydro_parameters;
    add_enhanced_hydro_obj_and_cons;
end-if


!**** Write solution results to file
if getprobstat = XPRS_OPT then
    if ENHANCED_HYDRO then
        writeresultsDEQ_enhanced_hydro;
    else
        writeresultsDEQ;
    end-if
end-if
```

E.4 Formulations Added to Other Data Handler

The Mosel code below contains the changes made to the data handler for the other data sets in the EMPIRE model. The changes include reading and interpreting the 'Allow-build' parameter.

```
declarations
    ALLOW_BUILD:     array(YEARS, NODES, TECHNOLOGIES)        of real; ! 1 if
agg. technology type can be build in node, 0 otherwise
end-declarations

forward procedure rexcel_agg_tech_allow_build(EXCEL_FILE_NAME:string,
                                        FIELD_NAME:string)

rexcel_agg_tech_allow_build("build_capacity.xlsx", "allow_build");


! Read Excel file with allow-build parameters
procedure rexcel_agg_tech_allow_build(EXCEL_FILE_NAME:string,
                                        FIELD_NAME:string)

    declarations
        TECH_PARAM              :   set of integer;
        TECH_ALLOW_BUILD_PARAM  :   array(NODES, TECH_PARAM) of real;
    end-declarations

    initializations from "mmodbc.excel:" + DATAFOLDER + EXCEL_FILE_NAME
        TECH_PARAM as "[AllowBuild$B2:O2]";
        TECH_ALLOW_BUILD_PARAM as "noindex;" + FIELD_NAME;
    end-initializations

    forall(yy in YEARS, nn in NODES, tr in TECH_PARAM) do
        ALLOW_BUILD(yy,nn,tr) := TECH_ALLOW_BUILD_PARAM(nn,tr);
    end-do

end-procedure


! Outputting the allow_build parameter
initializations to OUTPUTDATAFILE
    ALLOW_BUILD
end-initializations
```

E.5 Results Handler for Hydropower Formulation

The following Mosel code reads the results text file from the optimization and writes the solution containers to csv files.

```
parameters;
    HYDRO_DATA = "hydro_data";
    HYDRO_DATAFILE = ROOTFOLDER + "input\\" + MODELNAME + "_" +
POLICYSCENARIO + "_" + + HYDRO_DATA + "_" + TEMPEXT + ".txt";
end-parameters


forward procedure make_hydro_reservoir_csv_files
forward procedure make_load_ctr_dual_csv_files
forward procedure make_seasonal_reg_hydro_prod_csv_files
forward procedure make_yearly_inflow_csv_files
forward procedure make_max_yearly_hydro_dual_csv_files

declarations

    SEGMENTS          :   set of integer;
    NUMOFSEGMENTS     :   set of integer;
    INFLOW            :   dynamic array(SCENARIOS, SEASONS, NODES)
of real;
    WATERVALUES       :   dynamic array(SCENARIOS, YEARS, SEASONS, NODES,
SEGMENTS)   of real;
    MAXRESLEVEL       :   dynamic array(NODES)
of real;
    MINRESLEVEL       :   dynamic array(NODES)
of real;
    INITRESFRACTION :     dynamic array(SCENARIOS, SEASONS, NODES)
of real;


    SEG_TAP_SEASON            :   dynamic array(SCENARIOS, YEARS, SEASONS,
NODES, SEGMENTS)   of real;
    SPILLAGE                  :   dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of real;
    END_SEASON_RES_LEV        :   dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of real;
    MAX_YEARLY_HYDRO_DUAL     :   dynamic array(SCENARIOS, YEARS, NODES)
of real;
    ROR_SEASONAL_GEN_DUAL:            dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of real; ! Shadow price for RoR seasonal generation
constraint
    ROR_AVERAGE_DUAL:                 dynamic array(SCENARIOS, YEARS, HOURS,
NODES)               of real; ! Shadow price for RoR hourly generation
constraint
    MIN_REG_HYDRO_GEN_DUAL:           dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of real; ! Shadow price for minimum reg. hydro generation
contraint
    MAX_REG_HYDRO_GEN_DUAL:           dynamic array(SCENARIOS, YEARS, SEASONS,
NODES)             of real; ! Shadow price for maximum reg. hydro generation
constraint


end-declarations


initializations from HYDRO_DATAFILE
    NUMOFSEGMENTS;
    INFLOW;
    WATERVALUES;
    MAXRESLEVEL;
```

```
    MINRESLEVEL;
    INITRESFRACTION;
end-initializations

initializations from RESULTFILE
    SEG_TAP_SEASON;
    SPILLAGE;
    END_SEASON_RES_LEV;
    MAX_YEARLY_HYDRO_DUAL;
    ROR_SEASONAL_GEN_DUAL;
    ROR_AVERAGE_DUAL;
    MIN_REG_HYDRO_GEN_DUAL;
    MAX_REG_HYDRO_GEN_DUAL;
end-initializations


! Executing procedure for creating hydropower csv files
make_hydro_reservoir_csv_files;

! Executing procedure for creating csv files with load constraint dual
values
make_load_ctr_dual_csv_files;

! Executing procedure for creating csv files with regulated hydro generation
values
make_seasonal_reg_hydro_prod_csv_files;

! Executing procedure for creating csv files with misc constraint dual
values
make_max_yearly_hydro_dual_csv_files;

! Executing procedure for creating csv files with yearly regulated inflow
make_yearly_inflow_csv_files;



! Procedure for creating hydropower reservoir csv files
procedure make_hydro_reservoir_csv_files
    fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO +
"\\seg_tap_season.csv", F_OUTPUT);

    write(",Scenario,Year,Season,Node,Segment,Seg_tap_season,Watervalue");
    write("\n");
        forall(scn in SCENARIOS, yy in YEARS, ss in SEASONS, nn in NODES, mm
in SEGMENTS) do
            write("," + scn + "," + yy + "," + ss + "," + nn + "," + mm);
            write("," + SEG_TAP_SEASON(scn,yy,ss,nn,mm));
            write("," + WATERVALUES(scn,yy,ss,nn,mm));
        write("\n");
        end-do
    fclose(F_OUTPUT);


    fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO +
"\\spillage.csv", F_OUTPUT);

    write(",Scenario,Year,Season,Node,Spillage");
    write("\n");
        forall(scn in SCENARIOS, yy in YEARS, ss in SEASONS, nn in NODES) do
            write("," + scn + "," + yy + "," + ss + "," + nn);
            write("," + SPILLAGE(scn,yy,ss,nn));
        write("\n");
        end-do
    fclose(F_OUTPUT);

    fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO +
"\\end_season_res_lev.csv", F_OUTPUT);

    write(",Scenario,Year,Season,Node,End_season_res_lev");
    write("\n");
```

```
        forall(scn in SCENARIOS, yy in YEARS, ss in SEASONS, nn in NODES) do
            write("," + scn + "," + yy + "," + ss + "," + nn);
            write("," + END_SEASON_RES_LEV(scn,yy,ss,nn));
        write("\n");
        end-do
    fclose(F_OUTPUT);

end-procedure


! Procedure for creating csv files with load constraint dual values
procedure make_load_ctr_dual_csv_files
    declarations
        PRICES : array(SCENARIOS, YEARS, HOURS, NODES) of real;
    end-declarations

    forall(scn in SCENARIOS, yy in YEARS, hh in HOURS, nn in NODES) do
        PRICES(scn,yy,hh,nn) := LOAD_CTR_DUAL(scn,yy,hh,nn) /(ALPHA/LEAP_CFR
* (1 + DISCOUNT_RATE)^(-LEAP*(yy-1)) * PROB(scn)*SEASON_SCALE(hh));
        end-do

    forall(yy in YEARS) do
        fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO
+ "\\load_ctr_dual" + yy + ".csv", F_OUTPUT);

        write(",Scenario,Hour,Node,LOAD_CTR_DUAL");
        write("\n");
            forall(scn in SCENARIOS, hh in HOURS, nn in NODES) do
                write("," + scn + "," + hh + "," + nn);
                write("," + PRICES(scn,yy,hh,nn));
            write("\n");
            end-do
            fclose(F_OUTPUT);
    end-do

    forall(yy in YEARS) do
        fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO
+ "\\load_ctr_dual_yearly" + yy + ".csv", F_OUTPUT);

        write(",Scenario,Node,LOAD_CTR_DUAL_YEARLY");
        write("\n");
            forall(scn in SCENARIOS, nn in NODES) do
                write("," + scn + "," + nn);
                write("," + sum(hh in HOURS) PRICES(scn,yy,hh,nn)/126); !
WARNING: Hard-coded hours division. Use 126 for 3 scn, 222 for 10 scn.
            write("\n");
            end-do
            fclose(F_OUTPUT);
    end-do

end-procedure

! Procedure for creating csv files with regulated hydro generation values
procedure make_seasonal_reg_hydro_prod_csv_files

    declarations
        SEASONAL_SCN_AGG_HYDRO_PROD:    array(SCENARIOS, YEARS, SEASONS,
NODES) of real;
    end-declarations

    ! Seasonal generation aggregated for all scenarios
    forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES) do
        SEASONAL_SCN_AGG_HYDRO_PROD(scn,yy,seas,nn) := sum(hh in HOURS, gg
in GENS_IN_NODE(nn) | HOUR_SEASON(hh) = seas and GEN_TECH(gg) = 24)
GEN_PROD(scn,yy,hh,gg);
    end-do

    fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO +
"\\seasonal_reg_hydro_prod.csv", F_OUTPUT);
```

```
    write(",Scenario,Year,Season,Node,Reg_hydro_prod,Seasonal_inflow");
    write("\n");
        forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES)
do
            write("," + scn + "," + yy + "," + seas + "," + nn);
            write("," + SEASONAL_SCN_AGG_HYDRO_PROD(scn,yy,seas,nn));
            write("," + INFLOW(scn,seas,nn)*(sum(gg in GENS_IN_NODE(nn))
CAP_GEN_INIT(gg)));
        write("\n");
        end-do
    fclose(F_OUTPUT);

end-procedure

! Procedure for creating csv files with yearly regulated inflow
procedure make_yearly_inflow_csv_files

    declarations
            YEARLY_SCALED_INFLOW:   array(YEARS, NODES) of real;
            SEASON_SCALE_HYDRO: array(SEASONS) of real;
    end-declarations

    forall(seas in SEASONS) do
        case seas of
            1,2,3,4:
                SEASON_SCALE_HYDRO(seas) := 8750/8760;
                else
                    SEASON_SCALE_HYDRO(seas) := 10/8760;
        end-case
    end-do

    forall(yy in YEARS, nn in NODES) do
        YEARLY_SCALED_INFLOW(yy,nn) := sum(scn in SCENARIOS, seas in
SEASONS, gg in GENS_IN_NODE(nn)) ALPHA * PROB(scn) *
SEASON_SCALE_HYDRO(seas) * INFLOW(scn,seas,nn)*CAP_GEN(yy,gg);
    end-do

    fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO +
"\\yearly_scaled_inflow.csv", F_OUTPUT);

    write(",Year,Node,Yearly_scaled_inflow");
    write("\n");
        forall(yy in YEARS, nn in NODES) do
            write("," + yy + "," + nn);
            write("," + YEARLY_SCALED_INFLOW(yy,nn));
        write("\n");
        end-do
    fclose(F_OUTPUT);

end-procedure

   !  Procedure for creating csv files with misc constraint dual values
procedure make_max_yearly_hydro_dual_csv_files

    fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO +
"\\max_yearly_hydro_dual.csv", F_OUTPUT);

    write(",Scenario,Year,Node,max_yearly_hydro_dual");
    write("\n");
        forall(scn in SCENARIOS, yy in YEARS, nn in NODES) do
            write("," + scn + "," + yy + "," + nn);
            write("," + MAX_YEARLY_HYDRO_DUAL(scn,yy,nn));
        write("\n");
        end-do
    fclose(F_OUTPUT);


    fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO +
"\\ror_seasonal_dual.csv", F_OUTPUT);
```

```
    write(",Scenario,Year,Season,Node,RoR_seasonal_dual");
    write("\n");
        forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES)
do
            write("," + scn + "," + yy + "," + "," + seas + nn);
            write("," + ROR_SEASONAL_GEN_DUAL(scn,yy,seas,nn));
        write("\n");
        end-do
    fclose(F_OUTPUT);

    fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO +
"\\ror_average_dual.csv", F_OUTPUT);

    write(",Scenario,Year,Season,Node,RoR_average_dual");
    write("\n");
        forall(scn in SCENARIOS, yy in YEARS, hh in HOURS, nn in NODES) do
            write("," + scn + "," + yy + "," + hh + "," + nn);
            write("," + ROR_AVERAGE_DUAL(scn,yy,hh,nn));
        write("\n");
        end-do
    fclose(F_OUTPUT);

    fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO +
"\\min_hydro_dual.csv", F_OUTPUT);

    write(",Scenario,Year,Season,Node,Min_hydro_dual");
    write("\n");
        forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES)
do
            write("," + scn + "," + yy + "," + seas + "," + nn);
            write("," + MIN_REG_HYDRO_GEN_DUAL(scn,yy,seas,nn));
        write("\n");
        end-do
    fclose(F_OUTPUT);

    fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO +
"\\max_hydro_dual.csv", F_OUTPUT);

    write(",Scenario,Year,Season,Node,Max_hydro_dual");
    write("\n");
        forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, nn in NODES)
do
            write("," + scn + "," + yy + "," + seas + "," + nn);
            write("," + MAX_REG_HYDRO_GEN_DUAL(scn,yy,seas,nn));
        write("\n");
        end-do
    fclose(F_OUTPUT);

    fopen(ROOTFOLDER + "output\\csv\\" + TEMPEXT + "\\" + POLICYSCENARIO +
"\\nodal_WV.csv", F_OUTPUT);

    write(",Scenario,Year,Season,Node,Segment,WV");
    write("\n");
        forall(scn in SCENARIOS, yy in YEARS, seas in SEASONS, mm in
SEGMENTS) do
            write("," + scn + "," + yy + "," + seas + "," + mm);
                forall(nn in NODES) do

                write("," + WATERVALUES(scn,yy,seas,nn,mm));
                end-do
        write("\n");
        end-do
    fclose(F_OUTPUT);


end-procedure
```

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Implementing hydropower scheduling in a European expansion planning model

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Abstract

A method for implementing an enhanced hydropower planning formulation in a long-term expansion planning model is proposed. The methodological framework involves assigning hydropower generation a marginal cost through water values, enabling comparability with the marginal costs of competitive technologies. Added robustness and detail in the representation of hydropower and its inherent storage capabilities allows for a more precise evaluation of the technology's impact on optimal investments for other power resources. The impact for intermittent renewable energy sources such as wind and solar power is especially interesting to analyze. Examination of effects from the enhanced formulation is carried out for an EU 20-20-20 like policy scenario. Optimization results for Europe in the period 2010 to 2060 show that the new framework leads to decreased utilization of hydropower due to its more precise valuation through water values, as well as lower inflow for run-of-the-river hydropower than previously. Therefore, additional investments are carried out for other energy sources that are deemed more economically beneficial. Notably, an earlier deployment of solar power is part of the revamped investment scheme.

Keywords: Hydropower; emission reduction policy; GEP; generation planning; optimization

1. Introduction

The goal of generating enough energy to sustain the rapidly increasing global population, while simultaneously minimizing environmental impacts associated with energy extraction and consumption is a global pursuit of supreme importance. Models have been developed to analyze how this goal can be met at lowest possible cost. One

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of these is the EMPIRE[†] model, which is a European power investment model capable of incorporating various climate policy scenarios. Its framework is the starting point for the work presented in this paper, which consists of improving how hydropower is formulated in EMPIRE. One of the main objectives for doing so is to enable a more precise analysis of synergetic effects between installments of hydropower and intermittent renewables. The ongoing and future large-scale implementation of such variable generation introduces additional fluctuations in the power system and thereby new challenges in the continuous balancing of supply and demand [1]. Regulated hydropower can respond more or less immediately to fluctuations and can act as an ancillary service that regains balance in the power system [2]. This way, hydropower may support further investments in intermittent renewables.

Nomenclature

SYMBOL		DESCRIPTION	SYMBOL	DESCRIPTION
Sets and indices			**Parameters cont.**	
G	g	Generators	$F^{init}_{ns\omega}$	Initial reservoir fraction of full reservoir
H	h	Hours	$R^{init}_{ns\omega}$	Initial reservoir level
I	i	Years	R^{max}_{n}, R^{min}_{n}	Maximum and minimum reservoir level
L	l	Transmission lines	$R^{temp}_{ns\omega}$	Temporary reservoir level
M_n	m	Reservoir segments	$U^{Reg,norm}_{ns\omega}$	Seasonal normalized inflow
N	n	Nodes (one per country)	$U^{Reg,init}_{ns\omega}$	Seasonal inflow in 2010 (initial inflow)
S	s	Seasons	$U^{RoR,norm}_{ns\omega}$	Seasonal run-of-the-river inflow
Ω	ω	Stochastic scenarios	S^{max}_{mn}	Maximum reservoir segment size
Decision variables			$xd^{max}_{mns\omega}$	Actual reservoir segment size
$xd_{mnsi\omega}$		Segmental discharge	$WV_{mnsi\omega}$	Water value
$r_{nsi\omega}$		End-of-season reservoir level	α_h	Operational hour scale factor
$s_{nsi\omega}$		Spillage	ϑ_s	Seasonal scale factor
p^{gen}_{gi}		Generation capacity	δ_i	Discount factor
x^{gen}_{gi}		Generation capacity investment	ν_s	Number of hours in season
x^{tran}_{li}		Line capacity investment	p_ω	Scenario probability
$y^{gen}_{ghi\omega}$		Generation	c^{gen}_{gi}	Generator investment cost
$y^{LL}_{nhi\omega}$		Load shedding	c^{tran}_{li}	Transmission investment cost
Parameters			q^{gen}_{gi}	Generator short-run marginal cost
N^{seg}		Number of segments in reservoir	q^{VoLL}_{ni}	Cost of using load shedding variable

1.1. Related literature

There exist a vast number of optimization models used for investment planning and policy studies in Europe. Recent notable examples of linear programming models, where new generation and transmission investments are co-optimized with a system dispatch, are presented in [3] and [4]. The former model has since been adapted to detailed studies of long-term grid extensions in Europe, see [5], and a study of decarbonization of the European power sector, see [6]. In [7] a dedicated hydropower scheduling model is used to compute water values for seasonal

[†] **E**uropean **M**odel for **P**ower system **I**nvestment with (high shares of) **R**enewable **E**nergy

hydropower reservoirs, which are consequently used in a detailed DC load flow model of Northern Europe. This is similar to what has been done in this paper, although in this setting we focus on long-term system expansion.

1.2. Brief overview of the EMPIRE model

The purpose of the EMPIRE model is to provide a long-term plan for timing, size and location of investments in generation capacity and inter-country transmission capacity in Europe. This is done through cost minimization in the period 2010 to 2060, subject to various policy scenarios. EMPIRE is formulated as a linear, two-stage stochastic optimization model and has been implemented in Mosel Xpress [8]. The spatial resolution of EMPIRE is based on country-wise aggregation where each country represents a node n in the system. Investments can take place in 5-year leaps. Each year i is modeled as 10 non-consecutive seasons s, constituted by a number of operational hours h in which load balances are requested. Stochastic scenarios ω integrate uncertainty related to some parameters such as load and generation from intermittent energy sources. Generation capacities, annual build limits and a number of other restrictions are included. For more information about the EMPIRE model, see [9]. In the next chapter, the strategy for improving the hydropower framework will be described.

2. Hydropower scheduling methodology

Regulated and run-of-the-river hydropower are modeled independently. In the original EMPIRE model, regulated hydropower availability is represented as a no-cost parameter for each season, aside from low operation and maintenance costs. Thus, the model will tend to empty the reservoirs towards the end of each season. This is a major simplification of real-world conditions, where the use of water values as marginal cost for hydropower generation is a widespread means of assigning monetary values to the available water resources. The water value can be defined as the future expected value of the stored marginal kWh of water, i.e. its alternative cost [10]. Therefore, it will generally be optimal to generate power from a unit of water whenever the water value is lower than the expected power price, or save the unit in the opposite case. This introduces the significance of saving water to other periods of the year, which is not present in the original EMPIRE model. Since seasons are modeled individually, the original formulation has no incentive to conserve water for later periods. The use of water values is one method of enabling this water-saving feature, and is the key concept of the improvement strategy we propose.

The methodology starts by dividing each reservoir into M segments of equal size, and each of these segments are given an associated water value. In the start of each season we set an initial reservoir level based on a fractional value of a full reservoir. Inflow to the reservoir is assumed to take place immediately in the beginning of a season, which can be justified by the short season durations in the model. As the reservoir level is reduced the water values increase, since the water becomes more valuable as the available amount decreases. When assuming that the lowest index number indicates the top-most reservoir segment, the inequality $WV_0 < WV_1 < \ldots < WV_{m-1} < WV_m$ must therefore hold for all segments $m \in M$.

2.1. Mathematical formulation

In this section we describe the mathematical framework for enhanced hydropower. The implementation of hydropower scheduling is done in two separate steps. The first step utilizes reservoir data to determine the available amount of energy in each reservoir segment, setting the bounds for segmental discharge. The second step includes restrictions for generation and reservoirs, and is given in the following. Reservoir discharge is connected with hydropower generation as

$$\sum_{h \in H_s} y^{gen}_{ghi\omega} = \sum_{m \in M_n} xd_{mnsi\omega}, \quad n \in N, g \in G^{HydReg}_n, s \in S, i \in I, \omega \in \Omega \tag{1}$$

It is necessary to keep track of the reservoir level at the end of each season. The end-of-season reservoir level is equal to initial reservoir level plus inflow minus total segmental discharge and spillage. This is shown in Eq. (2), while minimum and maximum reservoir levels are shown in Eq. (3):

$$r_{nsi\omega} = R^{init}_{ns\omega} - \sum_{m \in M_n} xd_{mnsi\omega} + U^{Reg,norm}_{ns\omega} \cdot p^{gen}_{gi} - s_{nsi\omega}, \quad n \in N, g \in G^{HydReg}_n, s \in S, i \in I, \omega \in \Omega \tag{2}$$

$$R^{min}_n \leq r_{nsi\omega} \leq R^{max}_n, \quad n \in N, s \in S, i \in I, \omega \in \Omega \tag{3}$$

Segmental discharge bounds are represented as follows:

$$xd_{mnsi\omega} \leq xd^{max}_{mns\omega}, \quad m \in M_n, n \in N, s \in S, i \in I, \omega \in \Omega \tag{4}$$

For some nodes with small reservoirs and thereby a low degree of regulation, the water values of some segments may be identical. In these cases the discharge sequence has to be controlled through

$$xd_{m+1,nsi\omega} \leq xd_{mnsi\omega}, \quad m \in \{1, \ldots, N^{seg} - 1\}, n \in N, s \in S, i \in I, \omega \in \Omega \tag{5}$$

This constraint states that discharge from segment $m+1$ cannot start unless discharge from segment m has been initiated. To keep reservoirs sustainable, it is assumed that yearly generation cannot exceed yearly inflow:

$$\sum_{h \in H_i} \alpha_h \cdot y^{gen}_{ghi\omega} \leq \sum_{s \in S} \vartheta_s \cdot U^{Reg,norm}_{ns\omega} \cdot p^{gen}_{gi}, \quad n \in N, g \in G^{HydReg}_n, i \in I, \omega \in \Omega \tag{6}$$

Run-of-the-river (RoR) hydropower can be modeled in a simpler manner. Inflow is used to bound the hourly generation as a continuous, no-cost power availability. Eq. (7) describes seasonal limits for RoR generation, whilst Eq. (8) describes an hourly generation limit based on the average hourly inflow value for all hours in season s:

$$\sum_{h \in H_s} y^{gen}_{ghi\omega} \leq U^{RoR,norm}_{ns\omega} \cdot p^{gen}_{gi}, \quad n \in N, g \in G^{HydRoR}_n, s \in S, \omega \in \Omega \tag{7}$$

$$y^{gen}_{ghi\omega} \leq \frac{U^{RoR,norm}_{ns\omega} \cdot p^{gen}_{gi}}{\nu_s}, \quad n \in N, g \in G^{HydRoR}_n, h \in H, s \in S, i \in I, \omega \in \Omega \tag{8}$$

The objective function seeks to minimize the net present value of investment costs and expected operational costs over all years $i \in I$. With the hydropower scheduling modeled as above, it can now be formulated as

$$\min_{\mathbf{x},\mathbf{y}} z = \sum_{i \in I} \delta_i \times \left\{ \sum_{g \in G} c^{\text{gen}}_{gi} x^{\text{gen}}_{gi} + \sum_{l \in L} c^{\text{tran}}_{li} x^{\text{tran}}_{li} + \sum_{\omega \in \Omega} p_\omega \left(\begin{array}{l} \sum_{h \in H} \alpha_h \times \sum_{n \in N} \left(\sum_{g \in G_n} \left[q^{\text{gen}}_{gi} y^{\text{gen}}_{ghi\omega} \right] + q^{\text{VoLL}}_{ni} y^{\text{LL}}_{nhi\omega} \right) \\ + \sum_{s \in S} \vartheta_s \times \sum_{n \in N} \sum_{m \in M_n} xd_{mnsi\omega} WV_{mnsi\omega} \end{array} \right) \right\} \tag{9}$$

where the cost of utilizing regulated hydropower is represented by the last term: discharge from segment m multiplied by its water value for node n, season s, year i and stochastic scenario ω. The other terms include costs for generation and line transmission investments, power generation and lost load.

2.2. Data sets

Water values, maximum reservoir levels and regulated and run-of-the-river inflow has been collected from SINTEF Energy Research in Trondheim, Norway. In order to account for variations throughout the year, seasons have been divided into two categories, summer and winter. Values for initial reservoir levels are assumed higher in summer than winter. For the base scenario, 80 and 60 per cent are assumed to be initial levels for summer and winter seasons, respectively. The other scenarios use ranges from 70 to 90 per cent for summer and 50 to 70 per cent for winter. Initial reservoir levels for Norway and Sweden, the two countries with the largest reservoirs in the system, have been given more accurate data [11]. Minimum reservoir level is assumed to be 5 per cent of a full reservoir.

Due to difficulties related to computation of water values, it is noted that presented results are affected by inconsistent quality of these parameters. The EMPS model, see [10], was used to produce water values; however, the quality of the data set is modest for the years after 2010. As an approximation, we have therefore introduced generation restrictions for regulated hydropower, limiting generation from 2015 to 2060 to a 20 per cent deviation band from the generation in 2010 on a seasonal country-wise level. While large expansions of regulated hydropower in Europe is not expected in the coming decades [12], incorporating such limits is unquestionably a simplification. As such, results do not reflect our final investment recommendations, but can rather be seen as projection guidelines.

Global Change Assessment Model, see [13], provides expected generation shares for various technologies throughout the planning period, given policy scenarios. We utilize these shares in the model, though with two relaxations: Hydro-, wind and solar power are entirely excepted from the GCAM matching constraints, and a deviation allowance of 40 per cent from the GCAM values are embraced for the remaining technologies. Adding these relaxations allows us to identify effects of the new hydropower formulation more clearly, while at the same time preserving some of the added stability by incorporating GCAM matching.

3. Optimization results and analysis

Optimization results are presented for the Global 20-20-20 policy scenario, which is an extension of the EU 20-20-20 scenario to a global scope [14]. All original parameters in EMPIRE unrelated to hydropower are kept intact. It is evident that within the Global 20-20-20 policy regime, the framework favors wind to an extensive degree. As seen in Figure 1 the policy scenario involves large-scale expansions of renewables which take place early in the planning period. Fossil technologies are present in the entirety of the temporal scope, although with significantly lower amounts towards the end of the period, as a result of the increased penetration of renewables.

Differences between the original and the enhanced hydro version of EMPIRE, see Figure 2, show a significant increase in solar capacity for the final model, with a percentage-wise difference peaking in 2040 at 45 per cent. However, from 2050 both models find it optimal to reach maximum capacity of wind and solar power.

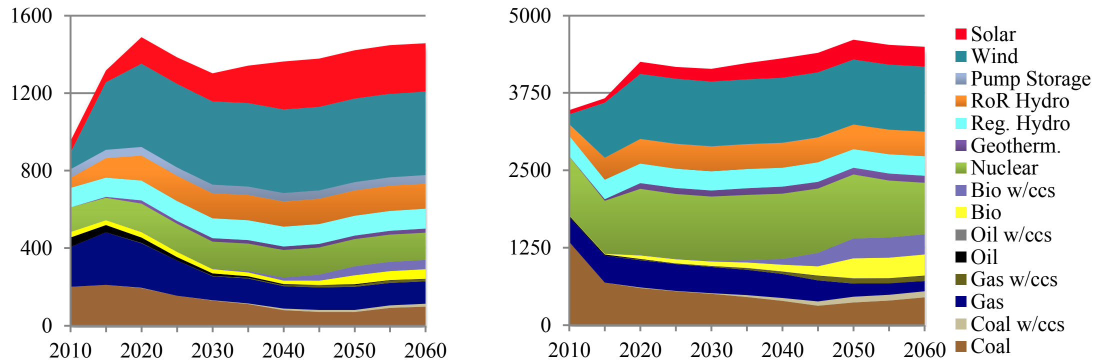

Figure 1: Generation capacity in GW (left) and generation mix in TWh/year (right) aggregated for the European power system.

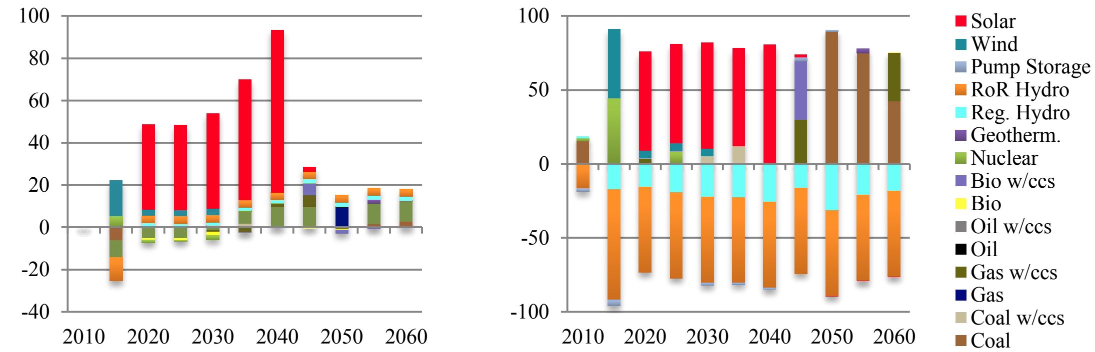

Figure 2: Generation capacity differences in GW (left) and generation mix differences in TWh/year (right) between the final and original models.

The combination of these findings suggests that the use of water values forces EMPIRE to invest in more capacity at an earlier stage, thereby increasing total costs. This can be explained through two effects: Regulated hydropower generation decreases due to more precise cost information through water values, and run-of-the-river hydropower generation is reduced because of a lower amount of available inflow. Consequently, hydropower is found to be overvalued in the original model.

While the combined hydropower generation is reduced, cheaper sources are selected as generation providers to take its place. In the first part of the planning period this is carried out by larger investments in solar power, mainly happening in Germany, Italy and Greece. The increased capacity availability is also reflected in the generation mix, with solar generation at a consistently higher level in the final model for the years 2020 to 2040. Indeed, in 2030 solar generation is 54 per cent higher than in the original model. For the last years, after solar has reached its system-wide maximum installed capacity, a higher utilization of coal serves as substitution supplier.

4. Conclusion

By implementing an enhanced hydropower formulation we have increased the level of detail for this energy source in the EMPIRE expansion planning framework. Results show that the original hydropower availability is too relaxed, thereby causing an overvaluation of this technology. The revamped cost representation by means of water values leads to a lower utilization of hydropower relative to the original model. An earlier deployment of solar power is carried out to replace the lower generation. Total costs in the system are therefore increased. For both models, extensive investments in intermittent renewables are taking place, amounting to 47 per cent of the total capacity in 2060.

It is noted that the results presented are affected by inconsistent quality of the water values data set. The usefulness of the implementation is nonetheless valuable because of a more comprehensive and accurate representation of hydropower in this investment environment than previously. In further work, an in-depth study of water values parameters would be interesting to conduct.

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