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Cost/benefit analysis of transmission grid expansion to enable further integration of renewable electricity generation in Austria

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ABSTRACT

This paper elaborates on the costs and benefits of expanding the Austrian transmission system and the implementation of innovative grid-impacting technologies (e.g. flexible AC transmission systems (FACTS), dynamic line rating (DLR)) to support further integration of renewable energy sources for electricity generation (RES-E). Therefore, a fundamental market model has been developed - respecting DC load flows - and applied for analysing different future scenarios, notably for the time horizon 2020, 2030 and 2050. Up to 2020 and 2030, special focus is put on the finalisation of the so-called "380 kV-level transmission ring" in Austria to enable enhanced RES-E integration. The results confirm that transmission power line expansion in the states of Salzburg and Carinthia is important to connect imports from Germany with pumped hydro storage capacities, on the one hand, and the wind farms in the east with the pumped hydro storages in the western part of Austria, on the other hand. For 2050, the results indicate that the implementation of FACTS and DLR can reduce RES-E curtailment significantly.

1. Introduction

The target of the European Commission is to achieve a harmonized European electricity market with an almost single price for wholesale electricity across all EU Member States. This objective is based on the following main reasons: significant social welfare increase due to optimal utilization of electricity generation and transmission assets in Europe, increasing security of supply and renewable electricity generation as well as limitation of price fluctuations due to variable renewable electricity generation as a result of improved market coupling.

The work presented in this paper is part of a European project in the Intelligent Energy Europe program (called GridTech[1]), where a fully integrated impact assessment of the implementation of new technologies (e.g. RES-E generation, bulk storage, transmission network technologies) into the European electricity system is conducted and the optimal exploitation of the full potential of future RES-E generation across Europe with lowest possible total electricity system costs is studied. In the GridTech project two approaches are applied: (i) top-down modelling covering the EU30+ region and (ii) bottom-up modelling of selected European target countries. The analyses in GridTech are fully in line with actual EU policies and legislation, e.g. the ambitious climate and energy targets for 2020[2] and the related National Renewable Energy Action Plans (NREAPs), the guidelines on developing priority corridors and areas of trans-European energy infrastructure (i.e. the so-called Projects of Common Interest (PCIs)[3]), which will benefit from faster and more efficient permit granting procedures and improved regulatory treatment. In addition, the "Energy Roadmap 2050"[4] with its decarbonisation ambitions for the upcoming three decades is considered for moving towards competitive, sustainable and secure energy for Europe. Also the "Ten-Year Network Development Plans (TYNDPs)" as well as the Cost Benefit Analyses Methodology (having been adopted by the European Commission

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[1] "Impact Assessment of New Technologies to Foster RES-Electricity Integration into the European Transmission System" (IEE/11/017/SI2.616364); Available: www.gridtech.eu.

[2] Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

[3] Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009.

[4] Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions - Energy roadmap 2050 (COM(2011) 885 final of 15.12.2011).

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0960-1481/

Nomenclature

Sets

H (index h)	set of time steps (hours)
I (index i)	set of nodes
$L \subset L_{AC} \dot{\cup} L_{DC}$	(index l, l_{AC}, l_{DC}) set of transmission power lines
TH_i	(index th_i) set of thermal units in node i

Parameters

C^{CO_2}	CO_2 certificate price, EUR/t CO_2
C^{WindPV}	generation costs of wind and PV systems, EUR/MWh
C^{Hydro}	generation costs of Run-of-River (RoR), EUR/MWh
$CapLines_l$	net transfer capacity (NTC) values, MW
DLR_h	dynamic line rating, %
α^{max}	maximum phase shifter angle, °
$Demand_{h,i}$	demand in step h and node i, MWh/h
$VoLL$	Value of Lost Load, EUR/MWh
$SRMC_{h,i,th_i}$	short run marginal costs of thermal power plants, EUR/MWh
$ThEm_{i,th_i}$	CO_2 emissions of thermal power plants, t CO_2/MWh
η^{Th}_{i,th_i}	efficiency of thermal power plants, %
$rampLimit$	ramping limit of thermal power plants, %
$ThCap^{max}_{i,th_i}$	max capacity of thermal power plants, MW
$HyCap^{max}_i$	max capacity of RoR, MW
$Inflow_{h,i}$	natural inflow RoR, MWh/h
$PHSTuCap^{max}_i$	max turbine capacity, MW
$PHSPuCap^{max}_i$	max pump capacity, MW
η^{Tu}, η^{Pu}	efficiency of turbine and pump, %
$PHSStor_h$	relative value of storage level, %
$PHSEn^{min(max)}_i$	min (max) storage level PHS, MWh
$InflowPHS_{h,i}$	natural inflow PHS, MWh/h
$Wind_{h,i}$	generation of wind turbines, MWh/h
$PV_{h,i}$	generation of PV systems, MWh/h
$PTDF_{l_{AC},i}$	power transfer distribution factors, node i
$PSDF_{l_{AC},l_{pst}}$	phase shift distribution factors
$DCDF_{l_{AC},l_{DC}}$	DC lines distribution factors

Decision variables

thP_{h,i,th_i}	generation of thermal power plants, MWh/h
$hyP_{h,i}$	generation of RoR plants, MWh/h
$tuP_{h,i}$	generation of PHS, MWh/h
$puP_{h,i}$	demand for pumping, PHS, MWh/h
$storLev_{h,i}$	storage level of PHS, MWh/h
$Spill^{Hy}_{h,i}$	RoR spillage (RES-E curtailment), MWh/h
$Spill^{WindPV}_{h,i}$	wind/PV spillage (RES-E curtailment), MWh/h
$NSE_{h,i}$	not supplied energy (NSE), MWh/h
$Exch_{i,h}$	power injection in node i, MWh/h
$Flow_{l,h}$	power flow on transmission line l, MWh/h
$\alpha_{l_{pst},h}$	phase shifter angle, °

recently) of the European Network of Transmission System Operators for Electricity (ENTSO-E) are taken into account accordingly.

For the top-down modelling of the EU30+ region the simulation tool MTSIM[5] is used. The focus of the pan-European study is to evaluate the most cost-effective investments in cross-border transmission interconnection on European level. This is done by applying the planning modality functionality of the MTSIM tool. To guarantee consistency of the two GridTech approaches, some of the results of the European-wide top-down analysis, notably those concerning electricity exchanges between countries and the associated wholesale prices, serve as inputs for the regional case study analysis in selected target countries. Moreover, they are setting the boundary conditions of the regional analysis. On target-country level the transmission power line investment planing itself is not the main focus, the objective is to analyse how different measures impact the regional electricity system in detail. Therefore, several target countries, based on their specific characteristics, have been chosen, e.g. Austria because of the high installed capacities of pumped hydro storage (PHS), the Netherlands due to the huge amounts of off-shore wind farms, and Italy due to the high shares of RES-E, which are planned to be implemented in the coming decade.

This paper examines the bottom-up modelling approach for Austria (one of the target countries) of the above mentioned project and comprises several selected scenarios for different time horizons (i.e. 2020, 2030 and 2050). The main focus is put on the following specific measures and technology developments:

- Completion of two major 380 kV High-Voltage AC overhead line projects to close the so-called "380 kV HVAC transmission ring" in Austria.
- Increasing/upgrading PHS capacities to support balancing of electricity systems in neighbouring countries.
- Studying the impact of further increase of wind (eastern part of the country) and notably PV (across the country) penetration.
- Studying the growing load flows from north to south, also including the possibility of a future east-west HVDC link from Austria to Slovakia.
- Implementing Flexible AC Transmission Systems (FACTS) and Dynamic Line Rating (DLR) based overhead lines.
- Furthermore, the impact of high/low Run-of-River (RoR) electricity generation on the transmission grid is studied for the time horizon 2050.

In the next section the methodology of the bottom-up approach is explained, notably the details of the market model used, the underlying objective function and all respected constraints. Section 4 comprises the results of several selected scenarios of the Austrian case study analysis. Special focus in result interpretation is put on the transmission system operators point-of-view. Finally, the paper is closed by the conclusions.

2. Methodology

For the Austrian bottom-up approach a fundamental market model called EDisOn (Electricity Dispatch Optimization) has been developed in MATLAB (for more information see Refs. [1] and [2]), to analyse in detail the further development of the Austrian electricity market and transmission grid to enable the further integration of RES-E generation. EDisOn is designed as a linear programming problem and is deterministic in nature, assumes a perfect competitive market with perfect foresight, and uses an hourly resolution of a full year. Generation capacities are given exogenously. PHS and RoR are following an annual pattern. Electricity generation of wind and PV are considered based on historical data, but it is also possible to implement a time series based on a stochastic process. EDisOn covers the whole transmission system of Austria (220 and 380 kV-level) as well as its interconnections to

[5] MATLAB tool developed from Ricerca sul Sistema Energetico - RSE S.p.A., Milano.

neighbouring countries.

In the model, Austria is divided into 17 load and generation nodes, correlating with the main substations within Austria. Seven nodes in the neighbouring countries define the geographical system boundaries of the Austrian bottom-up case study analyses. Generation is allocated to the closest node and the load allocation is based on population figures and large industrial sites. All parallel transmission power lines between the nodes are merged to one representative power line, resulting in a total of 35 (see Fig. 1 below).

The objective of the Linear Programming (LP) model is to determine the schedule that minimizes the total operational costs of the electricity system by considering various costs such as variable costs (e.g. fuel, O&M and CO_2 costs). The power plant dispatch on power exchanges follows the principle of short-run marginal cost pricing. Therefore, no investment costs are considered in the objective function. Several technical constraints are implemented, e.g. generation capacity constraints, maximum ramp rates, reservoir balance, spillage of hydro, RES-E generation technologies etc. The constraints have to be met in the whole simulation horizon. The power flows between nodes are simulated via a power transfer distribution factor (PTDF) matrix. FACTS is considered as phase shifters by phase shifter distribution factors (PSDF) and also HVDC lines with DC distribution factors (DCDF) (see Refs. [3] and [4]).

To enable Dynamic Line Rating (DLR) for transmission power lines, which means that weather conditions allow transmission power line utilization at more than 100% of rated capacity, time series of historical values of temperature and wind are needed. The DLR profile is based on the combination of the average hourly temperature[6] of the last 10 years and the assumed wind profile. Fig. 2 shows the dependence of temperature on rated current as well as the dependence of wind on the load factors. For example, the maximum temperature is 35 °C and the minimum wind speed is 0.6 m/s for using DLR for transmission power lines. The assumed wind profile and the resulting DLR profile are stated in Fig. 3. The peaks of the DLR vector arise from the dependence of wind on the load factor.

2.1. Objective function

The minimisation of total generation costs is the objective function of the market model. Not only thermal generation is considered with its short run marginal costs (SRMC), but also minor operating costs of RoR, PV and wind generation are taken into account. The last term in (1) is for demand, which cannot be covered. In literature, e.g. Ref. [5], the average value of lost load (VoLL) is assumed to be between 10,000 and 20,000 USD/MWh. In this analysis a VoLL of 10,000 EUR/MWh is assumed.

$$\min TotalCs = \sum_{i,h}\sum_{th_i} \mathrm{thP}_{h,i,th_i}\cdot SRMC_{h,i,th_i} + \mathrm{hyP}_{h,i}\cdot C^{Hydro} + \left(PV_{h,i} + Wind_{h,i} - \mathrm{Spill}_{h,i}^{\mathrm{WindPV}}\right)\cdot C^{WindPV} + \mathrm{NSE}_{h,i}\cdot VoLL \quad (1)$$

with $SRMC_{h,i,th_i} = C^{O\&M} + C_{th_i}^{fuel}/\eta_{i,th_i}^{Th} + C^{CO_2}\cdot ThEm_{i,th_i}/\eta_{i,th_i}^{Th}$ (where the indices h describe time (hour), i the node and th_i the type of thermal unit in node i).

[6] Source: www.zamg.ac.at/cms/de/klima/klimauebersichten/jahrbuch.

2.2. Constraints

Demand in every node has to be covered by supply in every simulated hour.

$$\forall h\in H, \forall i\in I:$$
$$Demand_{h,i} - \mathrm{NSE}_{h,i} = \sum_{th_i}\mathrm{thP}_{h,i,th_i} + \mathrm{hyP}_{h,i} + Wind_{h,i} + PV_{h,i} - \mathrm{Spill}_{h,i}^{\mathrm{WindPV}} + \mathrm{tuP}_{h,i} - \mathrm{puP}_{h,i} - \mathrm{Exch}_{h,i} \quad (2)$$

For thermal power plants there are some technical constraints, which have to be considered in market models. Thermal units are able to produce less than the maximum capacity only, which is defined in equation (3) and are limited by ramp rates (see inequalities (4)).

$$0 \le \mathrm{thP}_{h,i,th_i} \le ThCap_{i,th_i}^{max} \quad \forall(h,i,th_i) \quad (3)$$

$$\forall h \ge 2, \forall(i,th_i):$$
$$\mathrm{thP}_{h,i,th_i} - \mathrm{thP}_{h-1,i,th_i} \le rampLimit\cdot ThCap_{i,th_i}^{max}$$
$$-\mathrm{thP}_{h,i,th_i} + \mathrm{thP}_{h-1,i,th_i} \le rampLimit\cdot ThCap_{i,th_i}^{max} \quad (4)$$

The RoR plants can generate less than the maximum capacity only and should be equal to the natural inflow, which is calculated by using an hourly profile and the annual production. In this context the variable $\mathrm{Spill}_{h,i}^{\mathrm{Hy}}$ means that the lock of a RoR plant is open, i.e. a certain amount of hydro energy is not used for electricity generation.

$$\forall(h,i):$$
$$0 \le \mathrm{hyP}_{h,i} \le HyCap_i^{max}$$
$$\mathrm{hyP}_{h,i} + \mathrm{Spill}^{\mathrm{Hy}}{}_{h,i} = Inflow_{h,i} \quad (5)$$

The pumps and the turbines of the PHS plants are limited to their technical maximum.

$$\forall(h,i):$$
$$0 \le \mathrm{puP}_{h,i} \le PHSPuCap_i^{max}$$
$$0 \le \mathrm{tuP}_{h,i} \le PHSTuCap_i^{max} \quad (6)$$

In Austria, the reservoir content of PHS plants follows a certain annual pattern based on data of E-Control (Austrian Regulator) from 1997 to 2011. In general, it is limited to its maximum and minimum storage level. Therefore, the equations describing the storage level balance are very important (see equations (7)–(9)).

$$\mathrm{storLev}_{1,i} = PHSstor_1\cdot PHSEn_i^{max} - \frac{\mathrm{tuP}_{1,i}}{\eta^{Tu}} + \mathrm{puP}_{1,i}\cdot\eta^{Pu} + InflowPHS_{1,i} \quad \forall i\in I \quad (7)$$

for $h \ge 2$ and $\forall i\in I$:

$$\mathrm{storLev}_{h,i} = \mathrm{storLev}_{h-1,i} - \frac{\mathrm{tuP}_{h,i}}{\eta^{Tu}} + \mathrm{puP}_{h,i}\cdot\eta^{Pu} + InflowPHS_{h,i} \quad (8)$$

$$PHSEn_i^{min} \le \mathrm{storLev}_{h,i} \le PHSEn_i^{max} \quad \forall(h,i) \quad (9)$$

The exchanges - or more precisely the injections - have to be equal to the sum of the flows, which are going out and coming in of each node (see e.g. also [4]). Therefore, negative injection in a node means that demand is higher than supply and vice versa. The power flow on each transmission power line has to be between

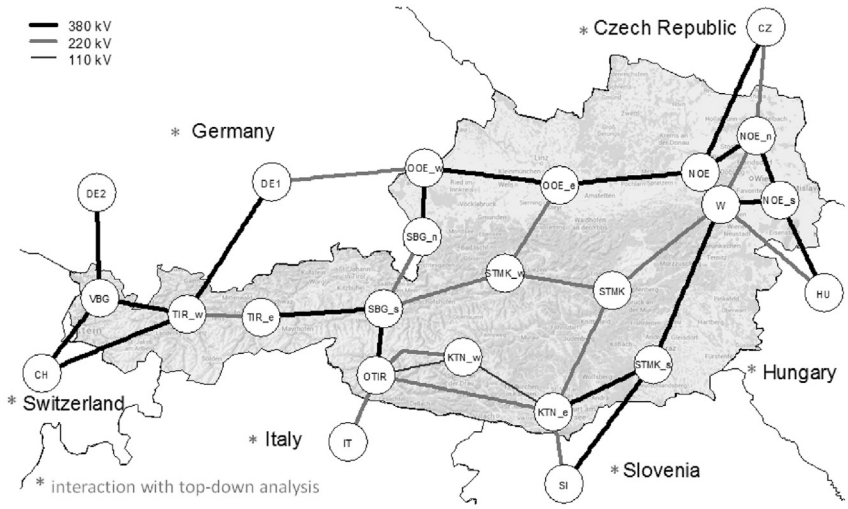
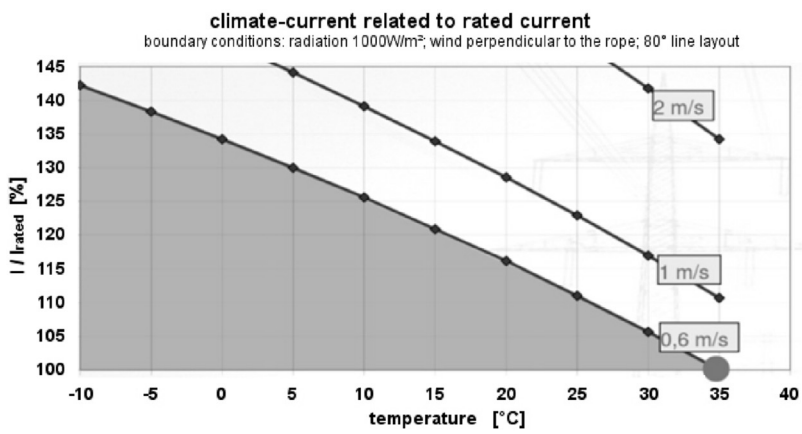


Fig. 1. Austrian transmission grid model for the year 2020.



Wind	Load factor
< 0.5	100 %
< 0.8	105 %
< 1	115 %

Fig. 2. Climate based on rated current, source: presentation of Dr.-Ing. Ralf Puffer at the "Kongress Erneuerbare ins Netz! Akzeptanz - Kosten - Technik", 6 May 2010 in Berlin (left); Wind and possible Load factor, source: dena-Netzstudie II 2010 (right).

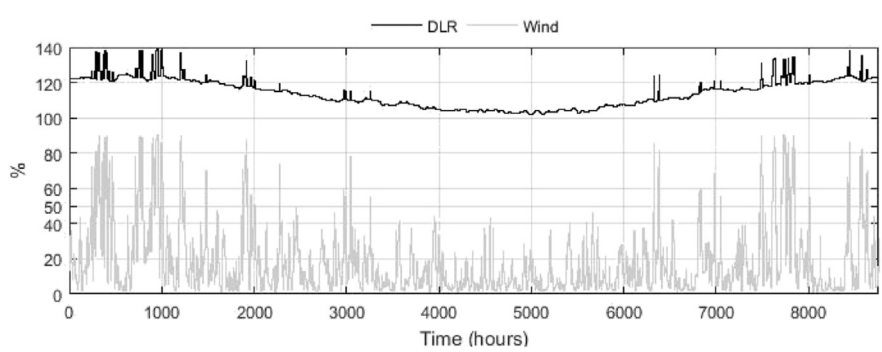


Fig. 3. DLR and Wind profile.

capacity limits of each power line and the same applies for the phase angles of the phase shifters and their maximum value, variables $\alpha_{l_{pst},h}$ and α^{max} (see equation and inequalities (10)–(12)). The power flows also have to satisfy equation (13), where the matrices PTDF, PSDF and DCDF are respected.

$$\mathrm{Exch}_{i,h} = \sum_{l \in L} A_{l,i} \cdot \mathrm{Flow}_{l,h} \quad \forall h \in H, \forall i \in I \tag{10}$$

$$\begin{aligned} &\forall l \in L \subset L_{AC} \dot{\cup} L_{DC}, \forall h \in H: \\ &-CapLines_l \cdot DLR_h \leq \mathrm{Flow}_{l,h} \leq CapLines_l \cdot DLR_h \end{aligned} \tag{11}$$

$$\forall l_{pst} \in L_{pst} \subset L_{AC}, \forall h \in H: \\ -\alpha^{max} \leq \alpha_{l_{pst},h} \leq \alpha^{max} \tag{12}$$

$$\forall l_{AC} \in L_{AC}, \forall h \in H: \mathrm{Flow}_{l_{AC},h} \\ = \sum_{i \in I} PTDF_{l_{AC},i} \cdot \mathrm{Exch}_{i,h} \\ + \sum_{l_{pst} \in L_{pst} \subset L_{AC}} PSDF_{l_{AC},l_{pst}} \cdot \alpha_{l_{pst},h} \\ + \sum_{l_{DC} \in L_{DC}} DCDF_{l_{AC},l_{DC}} \cdot \mathrm{Flow}_{l_{DC},h} \tag{13}$$

The remaining constraints consider RES-E curtailment of wind and PV, and limit the occurrence of NSE.

$$\forall h \in H, \forall i \in I: \\ 0 \leq \mathrm{Spill}_{h,i}^{\mathrm{WindPV}} \leq Wind_{h,i} + PV_{h,i} \\ 0 \leq \mathrm{NSE}_{h,i} \leq Demand_{h,i} \tag{14}$$

2.3. Calculation of the PTDF, PSDF and DCDF matrices

When applying the power transfer distribution factor (PTDF) matrix approach in a model, three assumptions are made [3]:

1 Line resistances are negligible compared to line reactances ($R_L \ll X_L$ lines). This implies that grid losses are neglected and line parameters are simplified.

$$G_L = \frac{R_L}{R_L^2 + X_L^2} \approx 0, \qquad B_L = \frac{-X_L}{R_L^2 + X_L^2} \approx -\frac{1}{X_L}$$

$$\underline{Z_L} \approx j \cdot X_L, \ \underline{Y_L} \approx j \cdot B_L$$

2 The voltage amplitude is equal for all nodes (in per unit values).

$$|V_N| \approx 1 p.u.$$

3 Voltage angle differences between neighbouring nodes are small. This results in a linearisation of the sine and cosine terms in the AC power flow equations.

$$\sin(\delta_N - \delta_Q) \approx \delta_N - \delta_Q, \qquad \cos(\delta_N - \delta_Q) \approx 1$$

The matrix B_d is a symmetric L_{AC}-dimensional matrix with the susceptances of the transmission power lines in the diagonal entries. The remaining entries are zero. The matrix A comprises the incidence matrix; it describes which nodes are connected with each other. The PTDF, PSDF and DCDF matrices are calculated as follows (for details see Ref. [3]):

$$PTDF^{L_{AC} \times I} = (B_d \cdot A) \cdot \left(A^T \cdot B_d \cdot A\right)^{-1} \tag{15}$$

$$PSDF^{L_{AC} \times L_{pst}} = B_d - (B_d \cdot A) \cdot \left(A^T \cdot B_d \cdot A\right)^{-1} \cdot (B_d \cdot A)^T \tag{16}$$

$$DCDF^{L_{AC} \times L_{DC}} = -PTDF \cdot A_{DC}^T \tag{17}$$

3. Results

The hourly simulation results of the different scenarios provide the basis for the calculation of the electricity system benefits (welfare, congestion rent, fossil fuel consumption, CO_2 emissions and others). For the evaluation of the benefits the key indicators as shown in Table 1 are used (see Ref. [6]).

In this section selected results are presented. The corresponding assumptions, information on input data and additional simulation results of 2030 can be found in Ref. [7].

3.1. Selected scenarios for the time horizon 2020

For the time horizon 2020 in Austria it is important to extend the interconnection to Germany, mainly due to high import expectations of RES-E generation from Germany. Therefore, the expansion of the transmission power line in Salzburg (see power line between node "SBG_n" and "SBG_s" in Fig. 1) is necessary to connect the imports with the high PHS capacities in the Alps. Furthermore, the extension in Salzburg is of high interest for closing the 380 kV circle in Austria, which is necessary for guaranteeing sufficient security and reliability of supply. In addition, the interconnection to Italy will also be extended. In Table 2 the selected scenarios for 2020 are defined.

Simulation results show that due to the power line expansion in Salzburg electricity generation of renewables can be slightly increased, especially the activities of PHS plants can be increased. Also thermal generation has increased and in this case a fraction of electricity generation from gas-fired power plants has been replaced by the much more polluting coal technology. This can be explained by two reasons: firstly, the CO_2 certificate price is low; therefore electricity generation of coal-fired power plants is cheaper than gas-fired power plants. Secondly, the transition to a more flexible grid allows transferring excess generation of coal power plants to the load centres, see Fig. 4.

The cumulative number of hours of transmission power lines with load factors higher than 70% is reduced in the (2020B) scenario compared to scenario (2020A), see Fig. 5. In particular, for the expanded power line in Salzburg no load factor exceeds 70% in scenario (2020B). The average number of hours for the 23 power lines within Austria can be reduced by around 15%, from 976 to 832 h per line.

Other important parameters determining security and reliability of supply are Not Supplied Energy (NSE). For the time horizon 2020 for both scenarios there exists no hour where NSE occurs. The electricity generation of RES-E is curtailed in a few hours. Spillages of RoR emerge in scenario A and B in 8 h; wind is curtailed in scenario A in 4 h and in B 6 h. However, RES-E curtailment can be reduced by 41 MWh due to the power line expansion.

The implication of all above mentioned facts is that the total generation costs for electricity in Austria can be reduced by 0.64% compared to the base case, which is in absolute numbers 2.1 M EUR. In addition, the wholesale electricity prices are slightly lower in scenario (2020B) in a few hours.

An additional important variable in terms of transmission power line expansion is the achievable annual congestion rent, which is calculated for two markets A and B as follows:

$$CR = |p_A - p_B| \cdot Flow_{A-B}$$

The variables p_A, p_B are the price vectors of the two markets and $Flow_{A-B}$ is the vector of the power flows on the considered power line between these two markets.

Assuming a nodal pricing system in Austria an annual

Table 1
Key indicators.

Benefit/Aspect	Explanation of the key indicators	Parameters
Social welfare increase	Ability of a power system to reduce congestion as a basis for an efficient market	Welfare, producer and consumer surplus, congestion rents
System reliability	Adequate and secure supply of electricity	NSE, load factors of power lines and generation capacity margins
CO_2 emissions reduction	CO_2 emissions in the power system	CO_2 emissions
RES-E spillage reduction	Reduce RES-E curtailed energy	$Spill^{Hy}$,$Spill^{WindPV}$
Controllability & flexibility	Possibility to control power flows and different possible future development paths or scenarios	Type of grid technology
Socio-environmental impact	Public acceptance and environmental impact	Type of expanded power line

congestion rent of around 235 kEUR is generated on the transmission power line in Salzburg for scenario (2020A). In this case the annual average price levels of the two considered nodes are slightly different only; the mean price in node "SBG_n" is 0.28 EUR/MWh higher than in "SBG_s". After the power line expansion the prices in the nodes converge and reach the same level on average. Due to the converging prices the congestion rent is reduced in scenario (2020B). Only around 11.8 kEUR can be earned, which are just 5% of the (2020A) scenario.

An implication of the above mentioned changes is that a nodal pricing approach within a control zone would not provide enough incentives to invest in extending the transmission power line in Salzburg. Therefore, regulated grid tariffs are still necessary to guarantee sustainable transmission grid investments in the future.

Table 3 gives an overview of the key indicators for the two cases of the time horizon 2020, summarizing the results of the previous paragraphs. It becomes clear, that the expansion of the 220 kV-level transmission power line in Salzburg and the extension of the German interconnection via Bavaria have positive effects on the Austrian transmission grid, except the socio-environmental impact (reflecting public acceptance) is negative. The increase of CO_2 emissions is around 1%. Therefore, the evaluation is zero. In addition, the upgrade to a 380 kV-level power line in Salzburg is necessary to achieve a closed 380 kV circuit in Austria in the near future guaranteeing sufficient security of supply.

Table 2
Defined scenarios for the year 2020.

Scenario	2020
(2020 A)	Reference scenario
(2020 B)	with 380 kV expansion in Salzburg

3.2. Selected scenarios for the time horizon 2050

In 2050 a RES-E share of 64% is assumed for Austria, especially the increase of wind and PV capacity is significant. Therefore, in order to provide more flexibility in the transmission system one focus will be the analysis of the impact of DLR and FACTS. The second emphasis is put on the extension of PHS capacities (turbine as well as pumping capacity). This could provide more flexible generation and additional storage potentials to neighbouring countries, e.g. Germany. Furthermore, the impact of high/low annual production of RoR is analysed. Finally, the focus of analysis is put on the first possible interconnection to Slovakia, a 2 GW HVDC line. An overview of the selected scenarios is provided in Table 4.

For the first scenarios the differences in electricity generation show that the transition to a flexible transmission grid leads to an increase of RES-E generation (see Fig. 6). In contrast, electricity generation of thermal power plants is reduced (see Fig. 7). Additionally, the use of PHS plants is diminished except for scenario (2050r), due to less annual electricity generation of RoR plants. For the other scenarios the need for PHS is slightly reduced, which is a result of the more flexible transmission system or because of

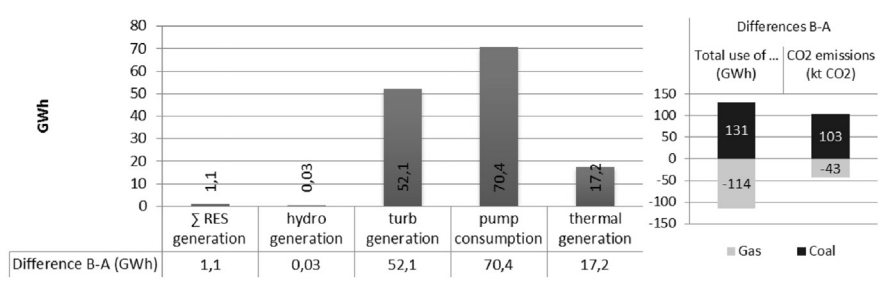


Fig. 4. Differences in the generation structure for the (2020 B) case compared to (2020 A).

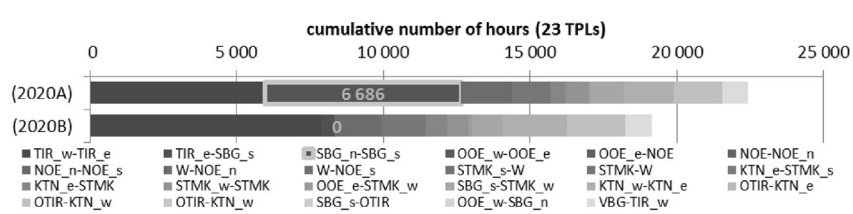


Fig. 5. Cumulative number of hours of transmission power lines with load factors higher than 70% for the 2020 cases.

Table 3
Key indicators for 2020 cases.

Benefit/aspect	Social welfare increase	System reliability	CO_2 emissions reduction	RES-E spillage reduction	Controllability &flexibility	Socio-environmental impact
(2020 A) Base	0	0	0	0	0	0
(2020 B) Expansion	+	+	0	+	+	−

additional imports from Slovakia as for the case (2050 SK). The differences in the generation structure of RES-E, RoR and PHS generation for the year 2050 are shown in Fig. 6.

As mentioned above, electricity generation of thermal power plants is reduced in all 2050 scenarios compared to the base case. The fossil fuel savings are shown in Fig. 7 both in GWh as well as their monetary values. As a result of the additional imports from Slovakia thermal generation is reduced by 12% in scenario (2050 SK).

The generation costs of the analytical objective function (see (1)) can be split into costs of thermal generation (1282 M EUR), RoR, wind and PV generation costs (34 M EUR) and costs for NSE (717 M EUR). These values are shown in Fig. 8 relative to the base case. The costs of NSE for the cases (2050 r) and (2050 SK) are higher than for the reference scenario. From this result it can be concluded that for 2050 it is necessary to achieve a more flexible transmission grid in Austria to guarantee electricity transmission without congestion and to avoid redispatch measures and NSE.

An annual congestion rent of 86 M EUR could be earned on the new 2 GW SK-AT HVDC interconnection with the assumptions made. In Fig. 9 the hourly congestion rent, nodal prices of Austria and Slovakia and the hourly load factors of the transmission power lines are shown for the week, where the maximum of the congestion rent occurs.

The major results for the 2050 analysis are summarized (as for the 2020 analysis in Table 3) in Table 5.

Particularly the application of DLR is very encouraging and cost effective. In the analysed cases there is, on the one hand, a strong positive correlation between large amounts of wind generation and cooling of the overhead lines by wind (therefore, curtailment of wind can be significantly reduced). But, on the other hand, it must be kept in mind that in case large amounts of power (non-wind related RES-E or conventional generation) have to be transported during periods with low wind speeds, DLR is less effective and the upgrade of lines will be the preferable solution to increase the grid transfer capacity.

4. Conclusions

The major conclusions of the Austrian case study analyses for the time horizons 2020 and 2030 (see Ref. [7] for more details) are that transmission power line expansions (from 220 kV to 380 kV-level) in Salzburg and Carinthia are quite important for closing the Austrian 380 kV circle and, therefore, to guarantee transmission adequacy in Austria up to 2030. The future Austrian 380 kV circuit also provides a significant contribution for enhanced national and European RES-E integration; especially for Austria it is important to

Table 4
Defined scenarios for the year 2050.

Scenario	2050
(2050 A)	Reference scenario
(2050 D)	with FACTS & DLR
(2050 F)	high PHS, FACTS & DLR
(2050 r)	−33.3% RoR
(2050 SK)	HVDC SK-AT

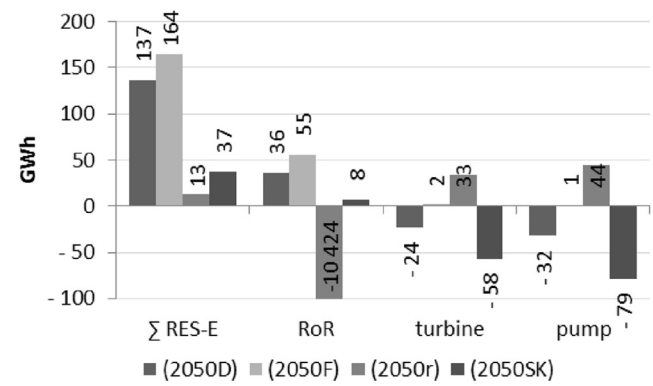


Fig. 6. Differences in the generation structure for the 2050 cases compared to (2050 A).

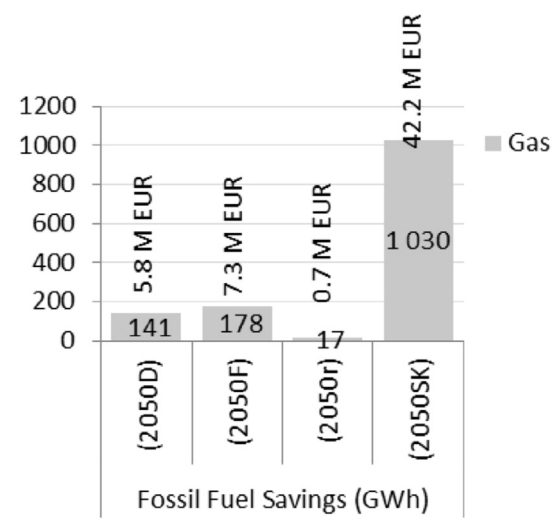


Fig. 7. Fossil fuel savings (in GWh) for the 2050 cases and the resulting monetary values.

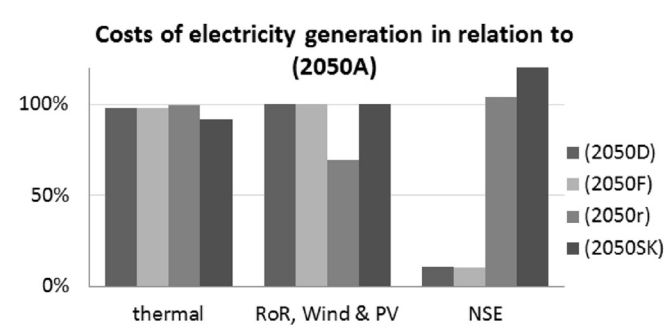


Fig. 8. Generation costs relative to (2050 A).

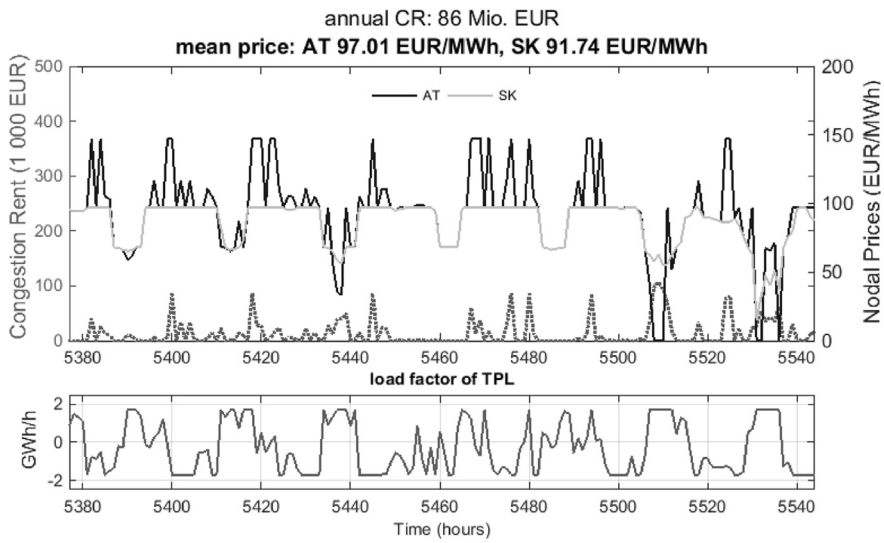


Fig. 9. Selected week indicating the congestion rent of the 2 GW HVDC connection to Slovakia.

Table 5
Key indicators for 2050 cases.

Benefit/aspect	Social welfare increase	System reliability	CO_2 emissions reduction	RES-E spillage reduction	Controllability &flexibility	Socio-environmental impact
(2050 A) Base	0	0	0	0	0	0
(2050 D) FACTS & DLR	++	+	+	++	++	0
(2050 F) High PHS, FACTS & DLR	++	+	+	++	++	−
(2050 r) −33.3% RoR	0	0	0	0	0	0
(2050 SK) HVDC SK-AT	0	0	++	+	+	−

foster the connection of wind farms in the eastern part and PHS in the west.

For the time horizon 2050 the analyses of the different scenarios indicate that the implementation of innovative transmission technologies like FACTS and DLR can reduce RES-E curtailment significantly. Thus, more flexibility in the transmission grid will be necessary to support the optimal integration of all electricity produced by renewable technologies. The major implication from the Cost/Benefit Analysis in terms of congestion rent is that the revenues earned mainly contribute to cover the cost of expansions of cross-border interconnections, due to the prevailing differences in zonal prices in Europe. As a consequence, regulated grid tariffs are still necessary in the future to finance transmission expansion, especially within control zones.

Last but not least, the GridTech regional analyses of Austria confirm the time line of the Austrian Masterplan 2030 [8], having been published by the Austrian transmission system operator Austrian Power Grid. In addition, the implementation of DLR and/or FACTS could achieve further supplementary flexibility in the Austrian transmission grid.

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