FlexPlan: testing an innovative grid planning tool using European wide regional cases

Nuno Amaro
R&D NESTER
Lisbon, Portugal
nuno.amaro@rdnester.com

Aleksandr Egorov
R&D NESTER
Lisbon, Portugal
aleksandr.egorov@rdnester.com

Gianluigi Migliavacca
RSE
Milan, Italy
gianluigi.migliavacca@rse-web.it

Marco Rossi
RSE
Milan, Italy
marco.rossi@rse-web.it

Izabella Faifer
RSE
Milan, Italy
izabella.faifer@rse-web.it

Iver Bakken Sperstad
SINTEF Energy Research
Trondheim, Norway
iver.bakken.sperstad@sintef.no

Vegard Viken Kallset
SINTEF Energy Research
Trondheim, Norway
vegard.kallset@sintef.no

Michele Garau
SINTEF Energy Research
Trondheim, Norway
michele.garau@sintef.no

Oscar Aristo Damanik
KU Leuven/EnergyVille
Leuven/Genk, Belgium
oscar.damanik@kuleuven.be

Giacomo Bastianel
KU Leuven/EnergyVille
Leuven/Genk, Belgium
giacomo.bastianel@kuleuven.be

Raúl Rodríguez-Sánchez,
TECNALIA
Derio, Spain
raul.rodriguez@tecnalia.com

Santiago García-Lázaro
TECNALIA
Derio, Spain
santiago.garcialazaro@tecnalia.com

***Abstract*— The H2020 project FlexPlan considers the development and validation of an innovative grid planning tool. In this paper, we present the methodology used in the simulation toolchain and preliminary results for optimal power flow simulation performed in four different regional cases covering most parts of Europe. An energy scenario, created in the scope of the project, for 2030 is used and results obtained illustrate both the tool capability to run complex simulations and the need for grid reinforcements. Obtained OPF results will be further used in the project to identify grid expansion candidates and solve the grid expansion problem.**

Keywords*— *Grid Planning, flexibility, storage, RES integration, FlexPlan

I. Introduction

Ambitious decarbonization goals for 2050 push for an increasing penetration of Renewable Energy Sources (RES). RES are characterized by high variability, and this brings challenges to grid planning and operation procedures. One example is the existence of strong congestions for a short duration due to RES variability. This kind of congestion, yet hardly justifying new grid investments, negatively affects the economic efficiency of the system dispatch, by forcing the curtailment of RES generation and the selection of more expensive resources. In this case, resorting to flexibility sources as storage and/or demand side management would avoid or strongly reduce RES curtailment and improve dispatch efficiency. System flexibility could also be of support to grid planning in the many situations where building new grid infrastructures would face strong public opposition, resulting in excessive approval time. Additionally, as grid planning is based on the analysis of scenarios of generation and load in the mid-long term, and as these scenarios have become more and more uncertain, resorting to system flexibility can help avoiding investments that could led to potential stranded assets.

All this motivates the FlexPlan Horizon 2020 project [1], which aims at creating an innovative new methodology and a tool supporting the European Transmission and Distribution System Operators (TSOs and DSOs) in performing mid-long term planning studies. Three grid years are considered: 2030, 2040 and 2050, and system flexibility is taken into account as an alternative to new grid investments.

The FlexPlan methodology, instead of analyzing a new investment at a time and considering its economic impact with respect to the status quo situation, elaborates a set of potentially interesting investments (candidates) and analyses all of them in one shot by determining the combination that minimizes the sum of CAPital EXpeditures (CAPEX) and OPeration EXpenditure (OPEX). The formulation of this problem results in a large Mixed Integer Linear Problem (MILP), which becomes numerically treatable due to the usage of decomposition techniques (Benders decomposition and decomposition between transmission and distribution planning).

FlexPlan includes many other advanced features including: i) integrated transmission-distribution planning; ii) embedded environmental analysis on air quality, carbon footprint and landscape constraints; iii) simultaneous mid- and long-term planning calculation over 2030, 2040 and 2050; iv) analysis of the variability of RES and load time series through yearly climatic variants resulting in a probabilistic optimisation model; v) full incorporation of cost-benefit analysis into the target function; and vi) probabilistic security criteria replacing the traditional N-1 criterion. These unique features represent an important step forward with respect to state-of-the-art grid planning tools. The comprehensive scope of the methodology also sets it apart from previous publications on grid planning considering flexibility alternatives [2],[3]. Details on the FlexPlan methodology can be found in [4].

The project also aims at testing this innovative methodology with six Regional Cases (RC) encompassing altogether nearly the whole European continent. Each of these cases has at least the size of a usual TSO planning study. In this way, successfully deploying these cases will prove the usability of the FlexPlan tool by the European TSOs and DSOs. This is the main contribution of this paper: to demonstrate the workflow necessary for setting up large-scale simulations for real-world mid-long term grid planning cases. Later in the project, the results of the RC will allow FlexPlan to analyze the real potential for system flexibility to provide a support to grid planning, and to formulate regulatory guidelines to analyze potential barriers to the deployment of such potential as well as possible regulatory provisions to overcome them.

While a more detailed overview can be found in [5], the present paper will concentrate upon providing details on four out of the six RC and on preliminary results. At the time that this paper was prepared, this includes optimal power flow results for European transmission systems in 2030, while the distribution systems were yet to be included. Section 2 will provide the overall methodology utilized for setting up these RC and retrieving the relevant data. Section 3 will describe the four cases considered in this paper. Section 4 will present the preliminary results before the paper is concluded in section 5.

II. METHODOLOGY

A general workflow for the implemented methodology to simulate the RC is depicted in Fig. 1.

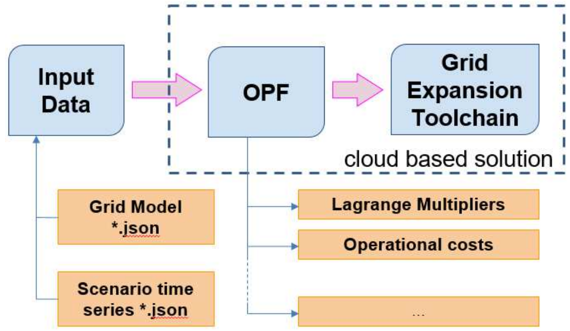

Fig. 1. The workflow of the execution of FlexPlan RC simulations.

The necessary input data consists of the scenarios to be simulated (time series) and the corresponding grid model. Using this input data, a cost minimisation Optimal Power Flow (OPF) is run, in order to identify existing congestions and other relevant results (e.g., costs related to system operation including load and generation curtailment costs). This OPF considers a multi-period simulation considering time coupling constraints for demand flexibility and storage. Congestions are identified through the existence of non-zero Lagrange Multipliers (LM) associated with branch flow constraints. These OPF results are then used as input to the next steps of the toolchain to 1) propose a list of grid expansion candidates and 2) solve the grid expansion problem. The detailed methodology for these steps is presented in [4].

The chosen format for the input files is JSON. Among other properties, JSON allows to represent objects that can be easily exchanged through APIs and databases, being an effective format for, e.g., parsing and generation of files. Furthermore, it is supported by Python natively, which is the language of choice for the implementation of the planning tool. This means that the expected performance when reading the files is high. Two input files are required for each case to be simulated: 1) JSON file with regional network data for OPF calculation. 2) JSON file with time series (hourly time-step) for load, and non-dispatchable RES.

The first JSON file consists of the topology of the power system, providing information related to buses, lines, converters, transformers, loads, generators, and storage devices. This information includes equipment technical characteristics, i.e., static values which do not vary through the considered period (e.g., generators' nominal capacity or branches' thermal rating), similar to equipment profile (EQ) data files used in the Common Grid Model Exchange Standard (CGMES) by ENTSO-E [6]. The second file consists of time-dependent data through a year (e.g., load and generation profiles), similar to the steady-state hypothesis (SSH) data files, used in CGMES.

In order to decrease computational effort, a set of simplifications was put into place. These simplifications answer to a two-fold objective: on one side to reduce the required simulation time (measure of computational effort), on the other side to preserve a high level of accuracy and fidelity of the results. The latter objective is of upmost importance as the RC are not only aimed at testing the FlexPlan tool, but also at providing realistic results that can shed light on the role of storage and other flexibility solutions in grid planning, feeding the subsequent elaboration of regulatory guidelines.

The simplification measures, designed and validated by RC, do not include significant reductions in the level of detail of the power systems to be simulated. Instead, they are focused on the following two aspects:

- Simplification of the mathematical description of some models (especially wherever they imply integral constraints) and limitations to individual OPF periods;
- Reduction of the time-series to be simulated.

The first set of simplifications includes those performed at modelling level. As one example, these include a fixed 24-hour time limitation for the recovery of a previous demand shift. In order to maintain the tractability of the problem, an OPF of the large systems considered is not run for a full year. Instead, smaller periods are considered.

The minimum required length of the time series is 168 hours (one week), but longer periods can be inputted, as this is a user-defined feature. To maintain the fidelity of the obtained results, this split of the year into smaller periods required the decomposed modelling of large hydro storage so as to keep the seasonality of these units. For this purpose, an initial and final energy content for each period (here: each week) is required. Additionally, users have the possibility to perform an explicit modelling of the inflow, by means of the time-series JSON input file. For other types of storage (e.g., batteries), it is assumed that the charging and discharging periods are performed within the considered period and the energy content available at the beginning and end of each period is half of the maximum capacity of each device.

The second simplification performed is related to the reduction of time-series to be simulated (scenario reduction). Time-series considered in FlexPlan consist of three different scenarios for the three target years to be simulated (2030, 2040 and 2050). These scenarios were constructed using as main source the TYNDP 2020 visions and a full methodological explanation on the creation of the FlexPlan scenarios is given in [7]. In order to account for the variability of RES generation and load conditions, a probabilistic OPF (based on Monte Carlo (MC) variants) was used to take into consideration different climatic conditions for each one of the considered scenarios. This approach is explained in detail in [8]. For the purpose of this paper, it is nonetheless important to mention that this methodology results in the creation of 35 different yearly variants for each scenario (in each target year), resulting in the existence of 35x3x3 = 315 yearly time-series sets of data for each RC.

The implemented scenario reduction methodology aims at reducing drastically the amount of time-series data to be simulated, while maintaining its representativeness. A clustering-based approach is followed, reducing the number of variants to be simulated for each scenario, while its representativeness is maintained through the usage of a probability associated to each variant (each cluster).

To use clustering, the data objects must have common features by which they are compared. The network state, or in other words the need for extending transmission capacity or flexibility, is defined by the load and/or renewable generation at each network node. Similar network states are thus defined by a similar combination of nodal load and generation. Both load and generation vary over time, and as such, load/generation time series can be considered similar when a similar variation in the load/generation time series is observed. Within the network planning problem, one data object consists of all the time series of load and generation at all network nodes. The data objects thus have features in two dimensions:

- Node dimension: the value of load/generation at each separate node, or the power of each demand/generation element can be considered as separate features;
- Time dimension: the node values at each separate time step of the time series can be considered as separate features.

Given the size of the considered networks, as well as the minimal required time series length, this number of features become very large, and feature reduction techniques should be used to make sure sensible clusters are produced from the initial dataset. As clustering algorithm, K-means clustering was chosen [9] due to its simple but effective characteristics. The size of each cluster gives an indication of the probability of occurrence of the combination of load and generation present in that cluster and this probability is used as an input for the planning problem as well.

The implemented scenario reduction methodology is presented in Fig. 2 and consists of two steps:

- Clustering of the number of yearly variants;
- Clustering of the number of weeks to be simulated within one year.

The first step consists in performing a reduction on the number of yearly variants. For this purpose, the 35 variants are clustering into two different clusters (K = 2) and one random variant is selected for each cluster, using as well the respective cluster probability.

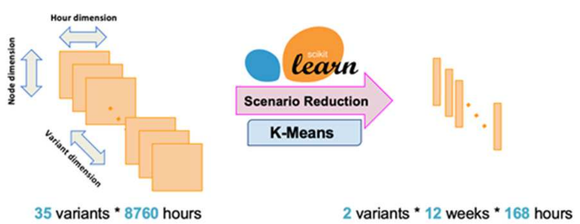

Fig. 2. Scenario reduction.

The second step consists in splitting independently every remaining yearly variant in 52 weekly variants (pre-processing) and then performing a second clustering, in order to reduce the number of weeks to be simulated for each variant, resulting in the simulation of representative weeks. The number of representative weeks is user-defined and in this paper, 12 weeks are considered, resulting in K = 12. The representativeness of each one of the selected weeks is found by using the probability of each cluster.

The selected set of 12 weeks needs to be representative of the whole year in order to retain the seasonal variability of different energy resources. So, for this purpose, the K-means clustering algorithm returns the full 12 clusters. A selection is then performed to have a week for each cluster while maintaining the seasonality. This approach is implemented so as to allow the selection of one week per month. If this is not possible (because the K-means clustering results do not allow it), a relaxation consists in the selection of 3 variants per season (winter, spring, summer and autumn).

These simplifications aim at contributing not only to a faster execution of the project simulations, but also to reducing the computational efforts of future users of the tool.

III. Regional Cases Description

In order to demonstrate the robustness and applicability of the proposed solution, four out of the six RC are herein shortly described. These four cases will be used to highlight some preliminary results in the next section as well. The six cases considered in FlexPlan are fully described in [10].

A. Iberian Regional Case

The Iberian RC includes the peninsular power systems of Portugal and Spain. Different data sources were used as reference to model the networks. For transmission network the ENTSO-E grid model [14] was used. In the case of Spain, this data does not include the sub-transmission lines (110-132kV) and, therefore, a simplified model was built for these networks based on Open Street Map (OSM) and REE [16] data. The complete transmission grid model considered has around 1840 buses and 2600 branches.

B. Italy Regional Case

The main data for the transmission network modelling was downloaded from the Ministero della Transizione Ecologica (Ministry of Ecological Transition) website [15]. The obtained geographical network model of transmission, 110–380 kV, dating back to 2008, was updated to the 2020 reference year by using available information from OSM and the ENTSO-E Map [15]. The obtained data sets include the list of the grid nodes names with coordinates, voltage, type of substations, length of the lines. More details on the transmission network model construction are reported in [10]. Finally, after the introduction of few network simplifications (aimed at containing OPF computational time), the final model counts 3166 nodes, 4071 AC lines, 302 transformers and 2 HVDC lines. The main flexibility sources are represented by 171 dispatchable generators (mostly based on fossil fuels) and 33 units with energy storage capabilities (15 large pumped-hydro power plants and 18 hydroelectric generators with water reservoir).

In addition, approximatively 2400 loads and 4200 generators are part of the current OPF model and many of them represent the aggregated demand and generation connected to distribution system. As soon as a representative portion of the medium-voltage (MV) network will be integrated within the RC model, these aggregated load/generation elements will be split and spread over about 4000 additional AC buses.

C. Nordic Regional Case

The Nordic regional case consists of the countries Norway, Sweden, Finland, and Denmark. The Nordic synchronous system is not included in the ENTSO-E grid data set used for the other regional cases. Therefore, the grid models for Norway and Denmark were acquired from Norwegian energy regulator and the Danish TSO [11], respectively, while the grid models used for Sweden and Finland were based on the PyPSA-EUR [12] model and OpenStreetMap data.

The simplification strategy for the Nordic RC consists of 1) focusing on the Norwegian sub-regional case, and 2) representing in more detail the grid and planning candidates for one specific area of interest in the western part of the country. The Norwegian grid model includes 2148 buses. Among these, 945 buses are at transmission and sub-transmission voltage levels (107 kV to 420 kV). The remaining buses (at voltage level 0.4 kV to 95 kV) mostly represent connections to distribution grids. When focusing on Norway, an existing equivalent model for the rest of the Nordic system is used in the OPF to reduce the number of buses and branches. The selected area is the area around Bergen and is currently a net importer of electric energy. Electrification initiatives and establishment of new power-intensive industry is expected to further exacerbate the situation.

Norway is a hydropower-dominated power system, and to ensure a realistic modelling of hydropower, the approach is adjusted for this regional case. Reference hydropower generation schedules are generated by the EMPS model, which is a fundamental multi-area hydro-thermal power market model [13]. This reference production is modelled as non-dispatchable (VRES-based) generation. The reservoir-hydropower plants' flexibility to deviate from this reference production is modelled as energy storage elements with a time-dependent power capacity to capture seasonal variation in the flexibility of the hydropower plants. In the resulting model there are 436 reservoir-hydropower generators, 31 of which are in the area of interest.

For wind power the scenario data from [7] is adjusted with datasets of existing wind turbines/farms. Similarly load data is augmented with realistic data from industrial loads. For PV the existing capacity is very small for the Nordic region, so for this type, the data from [5] is used directly.

D. France and BeNeLux Regional Case

The transmission grid data for France and BeNeLux are obtained from ENTSO-E [14], and extended with the sub-transmission network as described in [10]. The whole regional case consists of 6252 grid nodes, where France has the lion's share of 2734. Regarding BeNeLux, Belgium is represented with 1850 nodes, the Netherlands with 1617 and Luxembourg with 51. Two modifications are applied to the transmission networks to model storage and RES generators since they are not fully incorporated in the ENTSO-E transmission data. First, large pump storage hydropower stations are modeled as storage in the model. This leads to adding 6 and 2 storage devices to France and BeNeLux regions, respectively. Second, all the RES generators are modeled as non-dispatchable generators. As a result, 4177 and 2262 non-dispatchable generators are added to France and BeNeLux regions, respectively.

In addition to the internal transmission grid, the cross-border interconnections are modeled as described in the ENTSO-E Transmission System Map [15]. There are 27 and 21 interconnections with neighboring countries identified in France and BeNeLux regions, respectively. Their flows are generated from the market simulation module of MILES [7].

IV. Results

Results presented in this paper include a preliminary analysis of OPF simulations for the four aforementioned RC. The considered scenario is the DE2030 scenario, fully detailed in [7]. At this stage, only transmission systems are considered. Two cases (Iberian and Italy) include a simulation of 12 weeks, while the other two cases consider one-week long simulations. These provide already important information on the existence of network congestions, which will be further used in the project toolchain to solve the grid expansion problem, as described in section 2.

A. Iberian Regional Case

Time-series of 12 representative weeks (2016 hours) for a 2030 scenario were considered as input to run the OPF. The scenario is characterized by a high renewable generation. However, in some hours, demand is higher than generation. Storage units (hydro plants with reservoir) balance generation and demand in most of the cases, but generation and load curtailment are also required.

This 2030 scenario causes the congestion of around 3% of the transmission lines and both, level and number of hours of congestions are variable. Lines are congested between 1 hour and a maximum of 1130 (around a 56% of the time), with an average of 4% of the time. The congestion level is quantified through the LMs, resulting from the OPF. Fig. 3 shows their value for all congested lines, which are spread out in the whole Iberian Peninsula.

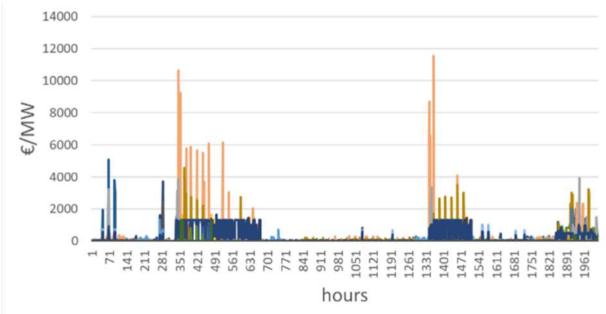

Fig. 3. Congestion level of congested lines in the Iberian RC (2030).

Two main system patterns have been observed at the hours when congestions happen:

- Demand is higher than generation, hydro plants inject power and few generators or loads are curtailed.
- Generation is higher than demand, pumped-hydro plants absorb power and some generation is curtailed.

B. Italy Regional Case

Similarly to the rest of RC, the simulations of the Italian system with the hypothesized 2030 scenario returned several figures, from which the level of congestion of transmission system can be deduced. In addition to the amount of overloading hours, the LMs associated with the lines/transformers loading limits can be processed in order to deduce their impact in terms of network operation costs.

Fig. 4 reports, for each HV line and transformer subject to congestion, the achievable yearly savings in case their transport capacity would be increased by 1 MW. This information can be particularly useful in order to optimally allocate investments (new lines/transformers and/or storage units), resulting a maximum reduction in terms of operation costs.

Another interesting aspect to be investigated is represented by the occurrence of curtailment for loads and non-dispatchable generators. As it can be noticed from the results reported in Fig. 5, generation is expected to be curtailed uniformly over the territory and the associated energy identifies the most critical areas (center-south of Italy, border with France, Milan, the most northern buses). On the other side, the less attractive load curtailment is experienced only in the north of Italy. Since load reduction is the most expensive source of flexibility (value of lost load is order of magnitudes higher than penalties for generation curtailment), this phenomenon highlights the importance of investments in proximity of the interested areas.

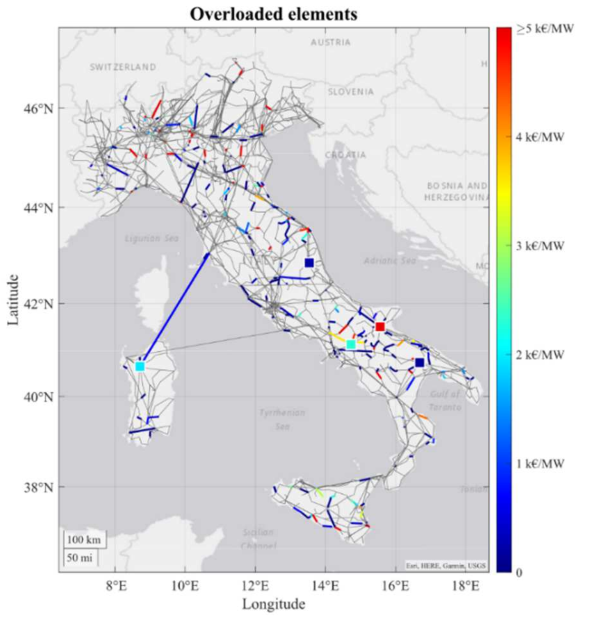

Fig. 4. Overloaded lines (plotted as lines) and transformers (plotted as squares) for the Italian RC and related Lagrange Multipliers (2030).

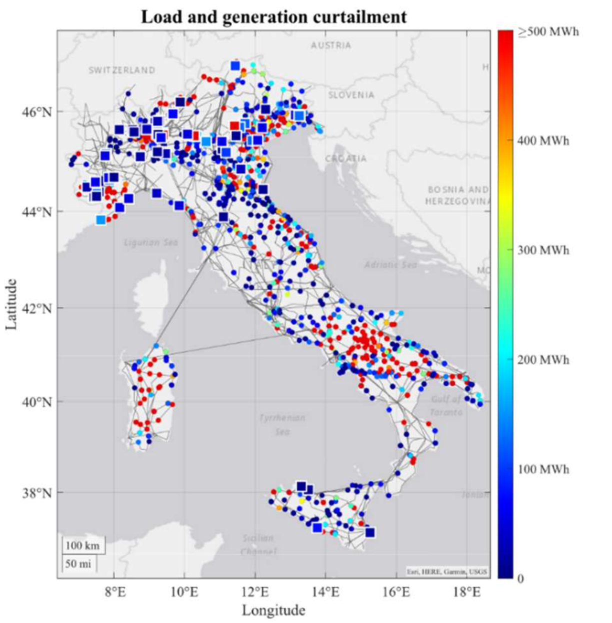

Fig. 5. Curtailed generators (plotted as circles) and loads (plotted as squares) for the Italian RC and yearly curtailed energy (2030).

Focusing on Italian islands only, their behavior is considerably different. Sardinia is subject to a significant amount of generation curtailment (which can be due to the overloaded HVDC interconnections with the continental Italy). Sicily, instead, experiences difficulties in supplying the load foreseen by the adopted 2030 scenario. Contrarily to Sardinia and according to results reported in Fig. 4, this behavior seems to be not related to the connection with the continental Italy, but rather to congestions internal to the island.

C. *Nordic Regional Case*

Fig. 6 shows the hydropower modelling approach used for Norway in practice. In the top plot the orange curve gives the reference production, while the blue curve gives the actual production after the impact of the storage unit is taken into account. The actual production still mostly follows the reference curve, which is known to be realistic, but the generation is still flexible enough to balance the variable wind production. In the selected representative week there is a significant dip in the wind power production around hour 140. The second plot shows that stored energy from the first part of the week is used to counteract this.

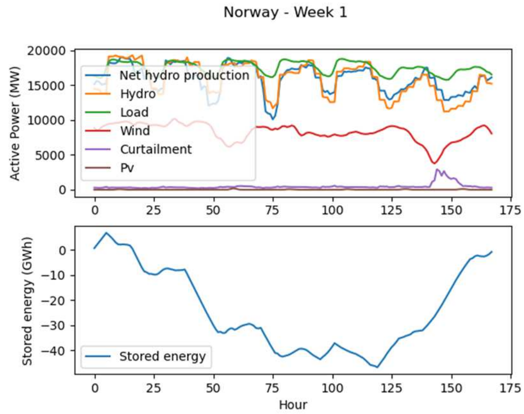

Fig. 6. Results for hydropower modelling for Norway for representative week (2030).

OPF results show congestions on 79 out of 1109 transmission lines. This includes two of the three transmission corridors into the area of interest. However, these overload events do not coincide in time, so at any given time there is remaining capacity on two out of three of the lines. This level of transmission line overloading is depicted in Fig. 7. Here, the colour scale indicates the number of hours of the representative week that a given transmission line is congested.

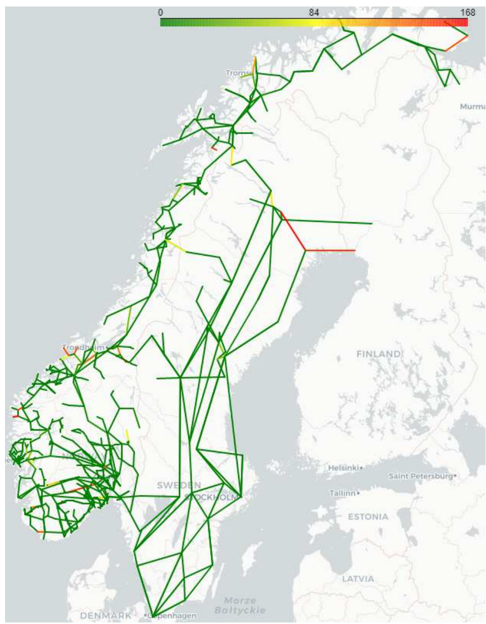

Fig. 7. Congested transmission lines in Norway (2030).

In the Nordic regional case, there is currently a rather large amount of load curtailment. A portion of this can be attributed to the fact that the grid model is for the year 2020, while the load and generation data are for a 2030 scenario.

For instance, as of 2022 the total installed wind capacity in Norway is 4.65 GW. However, in the scenario used for the presented simulations installed wind power capacity in Norway is 11.5 GW. Due to this, and similar increases for load and PV, it should be expected that the grid from 2020 will be insufficient to distribute the necessary power.

D. France and BeNeLux Regional Case

The one-week OPF problem that combines France and BeNeLux as one transmission network is solved in 60 hours. To reduce the computational time, the two regions are split into two transmission networks. As a result, the simulation times are reduced to 8.7 hours and 24.7 minutes for France and BeNeLux, respectively.

An analysis is conducted to locate congested lines throughout the simulation period. The lines being congested for the highest number of hours are depicted in Fig. 8. The figure shows that the majority of the congested lines are located in the south of France, mostly with a mild number of congestion hours. The line which is congested for the highest amount of time is found in the Netherlands. Furthermore, congestions appear more likely to occur in lines close to the borders of the regional case. This becomes clear for France, where several lines on the borders with Spain, Italy, and Switzerland are congested.

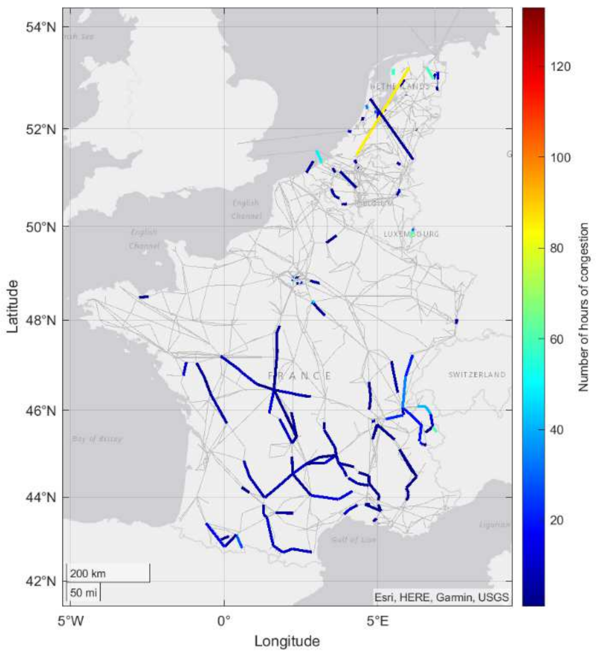

Fig. 8. Number of hours and location of congestions in the France and BeNeLux RC (2030).

V. Conclusion

This paper depicts the implemented simulation toolchain for an innovative grid planning tool developed in the FlexPlan project. A description of the workflow of the methodology is included, as well as simplifications that have been implemented to reduce the simulation time but retain the high level of accuracy of the results. A description of four of the six regional cases considered in the project is included, as well as results for the first step of the simulation toolchain. The obtained results, considering the simulation of an OPF for a 2030 scenario, demonstrate the capacity of the tool to solve complex OPF, due to the considered timeframes and size of the networks.

At the time that this paper was prepared, only transmission systems are considered, with timeframes up to 12-weeks. Ongoing work considers the inclusion of distribution systems in these OPF simulations. These simulation results will be further processed to identify grid expansion candidates and solve the grid expansion problem for the multiple scenarios considered in FlexPlan.

Acknowledgement

This work has been funded by the European project FlexPlan (H2020 Grant Agreement No. 863819).

References

[1] Project FlexPlan, “FlexPlan H2020 Project,” 2019. https://flexplan-project.eu/ (accessed Apr. 12, 2022).

[2] I. Konstantelos and G. Strbac, ‘Valuation of Flexible Transmission Investment Options Under Uncertainty’, IEEE Transactions on Power Systems, vol. 30, no. 2, pp. 1047–1055, 2015, doi: 10.1109/TPWRS.2014.2363364.

[3] P. U. Müller, B. Schachler, M. Scharf, W.-D. Bunke, S. Günther, J. Bartels, et al., "Integrated Techno-Economic Power System Planning of Transmission and Distribution Grids," Energies, vol. 12, 2019, doi: 10.3390/en12112091.

[4] G. Migliavacca *et al.*, “The Innovative FlexPlan Grid-Planning Methodology: How Storage and Flexible Resources Could Help in De-Bottlenecking the European System,” *Energies*, vol. 14, no. 4, p. 1194, Feb. 2021, doi: 10.3390/en14041194.

[5] G. Migliavacca *et al.*, “The innovative FlexPlan methodology to reap the benefits of including storage and load flexibility in grid planning: methodology and regional study cases,” in *CIGRE Session 2022*, 2022, p. 10786.

[6] ENTSO-E, “Common Grid Model Exchange Standard (CGMES) Library,” 2021. https://www.entsoe.eu/digital/cim/cim-for-grid-models-exchange/ (accessed Apr. 12, 2022).

[7] Project FlexPlan, “D4.1 Pan-European scenario data,” 2020. [Online]. Available: https://flexplan-project.eu/wp-content/uploads/2020/08/D4.1_20200803_V1.pdf.

[8] Project FlexPlan, “D1.1 Monte Carlo scenario generation and reduction,” 2020. [Online]. Available: https://flexplan-project.eu/wp-content/uploads/2020/12/D1.1_20201210_V1.0.pdf.

[9] A. K. Jain, M. N. Murty, and P. J. Flynn, “Data clustering,” *ACM Comput. Surv.*, vol. 31, no. 3, pp. 264–323, Sep. 1999, doi: 10.1145/331499.331504.

[10] Project FlexPlan, “D5.1 Data sets and planning criteria for the regional studies,” 2021. [Online]. Available: https://flexplan-project.eu/wp-content/uploads/2021/09/D5.1_20210915_V1.0.pdf.

[11] Energinet, “Transmission System Data,” 2021. https://en.energinet.dk/Electricity/Energy-data/System-data (accessed Jan. 21, 2021).

[12] J. Hörsch, F. Hofmann, D. Schlachtberger, and T. Brown, “PyPSA-Eur: An open optimisation model of the European transmission system,” *Energy Strateg. Rev.*, vol. 22, pp. 207–215, Nov. 2018, doi: 10.1016/j.esr.2018.08.012.

[13] O. Wolfgang, A. Haugstad, B. Mo, A. Gjelsvik, I. Wangensteen, and G. Doorman, “Hydro reservoir handling in Norway before and after deregulation,” *Energy*, vol. 34, no. 10, pp. 1642–1651, Oct. 2009, doi: 10.1016/j.energy.2009.07.025.

[14] ENTSO-E, “ENTSO-E Grid Model for TYNDP 2018,” 2018. https://www.entsoe.eu/publications/statistics-and-data/#entso-e-on-line-application-portal-for-network-datasets.

[15] ENTSO-E, “ENTSO-E Transmission System Map,” 2022. https://www.entsoe.eu/data/map/ (accessed Apr. 12, 2022).

[16] REE - Red Eléctrica de España, “Sistema Eléctrico Ibérico,” 2018. www.ree.es (accessed Jun. 17, 2021).

[17] Ministero della Transizione Ecologica, “Italy Transmission Network,” 2022. http://sinva.minambiente.it/mapviewer/index.html?collection=http://sinva.minambiente.it/WMC /Collection/VA/D5DB339E-DB14-9144-B043-B141DCABC108&v=full (accessed Apr. 12, 2022).