Consequences of different strategic decisions of market coupled zones on the development of energy systems based on coal and hydropower

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Abstract

Long term planning of energy system's development becomes closely connected to analysis of day-ahead power markets, market coupling and dynamics of integration of both, renewable energy sources and demand response technologies. In this study a scenario approach with minimization of marginal cost of generated electricity is used to investigate and quantify the influence of investments in generation units for the observed zone and the commitment of units in the surrounding zones. Dispa-SET software was used for modelling of a case study which included eight zones connected in the electricity market. Year 2016 was selected as referent, while future scenarios in 2030 are created with different strategic decision made in each of the zones. Results demonstrate the influence of different strategic pathways in different zones, through electricity generation and levels of storage capacities in the investigated zone and neighbouring zones and cross-border electrical energy flows. If most of the zones are pursuing unambitious strategies (2030a), marginal cost of electricity is double in comparison to the most ambitious case, while moderate approach in the most zones brings the cost reduction of 20%. Ambitious scenario 2030c for all zones results in the least cost of electricity, 30% of the cost in scenario 2030.

Keywords: Common power market, Demand response, Dispa-SET, Variable sources integration.

1. Introduction

By introducing Variable Renewable Energy Sources (VRES), it is theoretically possible to gradually replace conventional generation systems (based on oil, coal and natural gas). Many studies have been conducted to investigate whether there are possible 100% renewable systems for individual countries [1], regions like Southeast Europe [2] and the whole EU [3]. New tools, such as MultiNode tool of the EnergyPLAN, are developed to simulate the coupling of systems [4] but lacking the optimization of unit commitment and influence of electricity import/export to surrounding zones. Also, flexibility of certain types of generation units is not explicit for each unit, rather presented for the aggregation of all units with the similar technology (e.g. condensing plants) as a single point value. Market analysis in terms of meeting the upcoming EU regulations and the potential for using a larger share of renewable sources have also been made for Serbia [5] and Bosnia and Herzegovina [6]. In practice, however, there are problems related to the regulation and management of energy systems (ES) based on VRES due to the

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variability and short-term predictability of VRES generation (related to the weather forecast) [7]. Even when the conditions for installing new VRES capacities are good, it is still necessary within ES to have spare capacities in the form of flexible thermal power plants that can respond to a drop-in generation from the RES, according to [8]. Using the RES's surplus electrical energy in storage systems which would have enough capacity to provide enough electrical energy supplies within the ES, was previously deemed costly and inefficient ('circular' efficiency). Although the flexible system is crucial for integration of VRES, these ideas are contested in the present study, by showing the amounts of electrical energy generated from such flexible peak thermal power plants in comparison to the use of demand response (DR), storage inflows and storage levels in the electricity market-coupled environment. Previous research did not consider the possibilities provided by such environment and the present research aims to fill this gap.

In following paragraphs, a review on the relevant literature is provided on the influence of various possible strategic decisions in zones coupled in the same electricity market, such as integration of various technologies that provide flexibility, on the development of energy systems. New trends in integrated energy systems are being studied, such as the 4th generation of district heating (DH) systems associated with cogeneration plants with heat storage tanks for power to heat applications as a source. Also, heat from renewable sources, waste heat integration, heat pumps at household and DH level [9], and ongoing electrification of transport are investigated in various studies. It brings new demands and business opportunities in the area of energy planning, greater utilization of RES, increased energy efficiency and increased quality of life due to lower emissions [10]. A recent study [11] analysed the heat DR in connection to the day-ahead electricity market prices, which is an important step in connecting two sectors on the market basis. In the study, it was concluded that slight variations in the temperature in the distribution grid compared to the baseline operation (±3.5 K) could result in relative socio-economic savings of up to 5.4%, pick pointing the importance of such demand response. In the research on the increase of RES integration, Buonomano et al. [12] developed a simulation model in TRNSYS for bottom-up analysis of economic performance of systems based on solar PV, wind and energy storage for end users, showing how these technologies would be adopted in an economic way, on the case of Italy. The research demonstrated that, for different types of end-users, most economic use of such hybrid (PV, wind and battery) systems is to be connected to the grid and participate in the electricity market. [A scenario analysis for the limited region (Istrian peninsula) was performed in [13], to investigate a battery storage as an option for the security of operation of the power system, in comparison to a lengthy project of a new electricity transmission line. For majority of scenarios the research confirmed that batteries would be beneficial, while for the worst-case scenario ultimate solution would be a new transmission line. In that event, battery storage would continue to benefit the power network on the broader scale. The primary access to the market of ancillary services and reserves, which can provide DR technology on the multilevel market, was explored in [14]. In the observed cases, participation of DR in reserve market was shown to result in 25-27% reduction of the reserve's costs. In [15], two different approaches in a smart grid environment were presented to enable the participation in DR programmes in groups of users such as office buildings and industry. Approaches were elaborated through simulation-based demand control strategies based on simulation and optimization and include control of heating and cooling as well as process control in the industry. The aim was to connect these approaches to the day-ahead electricity market. It was shown that differed loads from households' and industries smart grids will have significant impact on the operation of the future systems. Differed loads' modelling capability was therefore one of the parameters for the choice of the energy planning tool. Research is also conducted in the field of market coupling between the two electricity markets [16] and price-optimally planned development of such markets in [17] and [18]. The impact on price difference, its convergence, and the timing of overlapping / closeness of the price level for significant electricity markets, under the influence of increasing the acceptance of renewable sources, was explored in [19]. Also, emphasis has so far been placed on a significant constraint: the electricity cross-border transmission capacity. Research deals with the problem in trade between large areas [20] and with different methods of market coupling [21]. Zakeri et al. [22] used the Enerallt model (market-based multi-area power and district heating model) to investigate the influence that possible interconnection between UK and Norway would exert on both electricity markets. It was found that the link of 1400 MW would reduce average electricity prices for consumers in the UK, while UK producers would lose some of the economic benefits. Nevertheless, the interconnection would increase the social welfare (defined as socio-economic gain in three possible lines of revenue: consumer's surplus, producer's surplus, and congestion rent) on both electricity markets in optimal scenario for 110 M€/a. The use of multi-agent modelling has been exploited as a machine learning method, using available information in combination with genetic algorithms [23]. Further research has been conducted by multi-agent simulation [24] and by linking two neighbouring electricity markets [25], market-based modelling based on volume of trading [26] and exploring how market consolidation through their merger affects the possibilities of their planning [27]. Detailed terms are related to the correlation of social welfare and the merger of the market - in this case a large market with neighbouring systems' electricity markets, some of which are of interest to this research, namely Southeast Europe, explored in [28]. Results have shown the benefit of electricity markets' coupling for the large market (in this case Italy), which reduced its net imports and provided the opportunity to sell generated electricity at higher prices. Reviewed research, aimed at the electricity markets' coupling, underlined the need to model long-term energy planning problems in the context of the energy system and its neighbouring systems, instead of closed system or a system development which considers prices on neighbouring electricity markets as exogenous variable.

Important flexibility options for an energy system with high share of VRES will be offered through synergies with heating/cooling and electrification of transport sector. Analysis of the possible development of Colombian energy system with integration of VRES [29] shows that the transport sector would remain the main producer of emissions if it is not electrified and coupled to the energy mix with lower emissions, such as VRES based system. As each electric vehicle has an energy storage system, in those periods when the vehicles were parked and connected to the network, they could actively participate in the balancing of electricity supply and demand on the vehicle-to-grid principle (V2G). Dump and smart charge of electric vehicle's batteries was investigated in [30], showing on cases of Germany and Italy the influence of electrification of road transport through scenario analysis in EnergyPLAN. Electricity generation mix based on RES was shown to be crucial for sustainability of electric transport, while smart charge also helped to reduce greenhouse gas emissions (for example, 22% for Italy). In addition to the electrification of transport, the technology of converting excess of electricity produced from VRES to heat (power-to-heat), the production and consumption of synthetic fuels (hydrogen, synthetic gas) are also considered. Use of power to heat and V2G to increase the share of renewable energy was demonstrated in [31], with results showing that starting to implement these technologies can double the projected integration of VRES by 2030 on a case study of Croatia. Electrification of transport and use of V2G mode to integrate excess VRES is analysed as the major storage technology and source of flexibility in the present research as well, in the "LC" scenario described in the Methods. In [32], the study shows that PV, storage and EV battery storage will be economically feasible in this period and gives additional forecasts of cost reduction for lithium-ion batteries and PV panels. In a very recent study [33], electrification of heating and transport sectors has been analysed. The effects of increased shares of EVs and heat pumps, which follow the increase of the VRES share were studied. Techno-economic analysis of the optimal scenario showed the CO_2

emissions reduction of 47% compared to 2017 level and total costs increase of 34% annually. Variables were VRES, EV and HP installations and energy savings.

Different scenarios of the energy system configuration development can be observed as strategic decisions made by the decision makers in each national energy system. In order to evaluate the impacts which different strategic decisions have on electricity market-coupled zones, a more precise tool is needed, compared to the solutions presented in the body of research. Such tool needs to produce outputs such as marginal cost of electricity generation, cross-border power flows and unit commitment in several zones of trading in the same time frame, for example one hour. These outputs would allow comparison of performance for various energy system configurations of the interconnected zones: the cost of generation of electricity, ability to follow the flows of energy between the zones and the ability to answer the question which unit supplied the electricity in each hour of the year. A tool with relevant features was presented in [34] and used to investigate the influence of centralized cogeneration plants with thermal storage, an important technology for energy transition, on efficiency and the marginal cost of electricity generation in case of optimal operation. The overall use of Dispa-SET tool for modelling of interconnected electricity systems with high share of renewable energy is elaborated in [35], for optimized case in a whole year hourly calculation. In [36], four model formulations in Dispa-SET were compared on a case of Western Balkans: “No clustering”, which means considering each power plant separately and using a lot of computer time, “Per unit” - aggregates small and flexible units into larger ones with averaged characteristics, ”Per typical unit” considers one typical power plant per technology and “Per technology” clustering all units using the same technology together without modelling different flexibility capabilities. Results have shown that alternative formulations in Dispa-SET are reliable for estimating the electricity generation mixes in future energy systems, particularly for systems with high shares of RES. The deviation from the baseline formulations decreases significantly with the number of conventional and inflexible units.

In this paper, a model including electricity and heat generation systems of Croatia (HR), Slovenia (SI), Serbia (RS), Bosnia and Herzegovina (BA), Albania (AL), Kosovo (XK), Montenegro (ME) and North Macedonia (MK) as observed zones is created in Dispa-SET. Different dynamics of the energy transition in the year 2030 are proposed. Scenario approach is employed to investigate the influence of different decision for the development of each zone, on unit commitment in the observed zone, electricity generation in all zones and electricity flows between the zones in a coupled day-ahead electricity market. In the method proposed in this paper, operating costs of electricity generation are minimized.

2. Method

The Dispa-SET model is an open source energy planning model which aims to represent the short-term operation of large-scale power systems with a high level of detail. Through minimization of the marginal cost of electricity generation, the model offers solutions for energy planning of the particular zone or region of interconnected zones, taking into account power plant operation (unit commitment) and power flows between the zones. This approach minimises the short-term operation costs for the generation of electricity and heat and enables Dispa-SET to solve the problem of unit commitment and dispatch in large interconnected networks, such as European power system. Pre-processing and post-processing tools are written in Python, and GAMS is used as the main solver engine. The model is written in the form of Mixed Integer Linear Programming (MILP). Dispa-SET is being developed in by the European Commission's Joint Research Centre (JRC), in cooperation with the University of Liège and KU Leuven (Belgium). It is presumed that the system is managed by a central operator with full information on the technical and economic data of the generation units, the demands in each node, and the transmission network. To solve the unit commitment problem, two steps need to be addressed:

- scheduling the start-up, operation, and shut down of the available generation units
- allocation of the total power demand among the available generation units minimizing the electricity systems' operating costs

The second part of the problem is the economic dispatch problem, which determines the continuous output of every generation unit in the system and is formulated through the MILP. Major inputs in order to run these steps are [37]:

- Availability factors for RES power plants (hourly, solar, wind, hydro)
- Cross Border Flows (hourly, historical, between zones)
- Net transfer capacities (NTC) between zones, hourly
- Heat demand (hourly for power plants supplying heat – CHP)
- Scaled Inflow for hydropower storage, hourly
- Reservoir Level of hydro storage, hourly
- Electricity Load, hourly
- Outage factors, hourly
- Power plants database describing parameters for all power plants

The optimization function in Dispa-SET minimizes the short-term operation costs of the electricity and heat generation for the region, which includes different countries, representing electricity trading zones in further discussion. Detailed description of the optimization procedure can be found in [37]. The electricity system costs can be divided into fixed costs, variable costs, start-up and shutdown costs, load-change costs, relieving costs, transmission costs between the two zones, and costs of lost load. The fundamental limitation of power systems is the balance between consumption and generation of electricity. It is met by simulating day-ahead supply-demand balance, for each period (1 hour) and each zone. The sum of all the power produced or discharged by all the units present in the zone that is observed, energy injected from neighbouring zones and the power curtailed from VRES must be equal to the load in that zone, with the addition the energy storage inflow. Other constraints are related to the technological characteristics of generation plants. Further constraints are set at cross-border capacity and consequentially, the flow of electrical energy between two zones cannot be larger than the predefined net transfer capacity (NTC). Before starting the Dispa-SET model calculation, it is necessary to enter data such as hourly load distribution, technical characteristics of generation plants, fuel prices and hourly distribution of cross-border capacity. The optimization problem is split into smaller optimization problems that are run recursively throughout the year.

Figure 1 shows an example of such approach, in which the optimization horizon is one day, with a look-ahead period of one day. The initial values of the optimization for day "j" are the final values of the optimization of the previous day. The look-ahead period is modelled to avoid issues related to the end of the optimization period such as emptying the hydro reservoirs or starting low-cost but non-flexible power plants. In the approach used in this research, the optimization is performed over 48 hours, but only the first 24 hours are conserved.

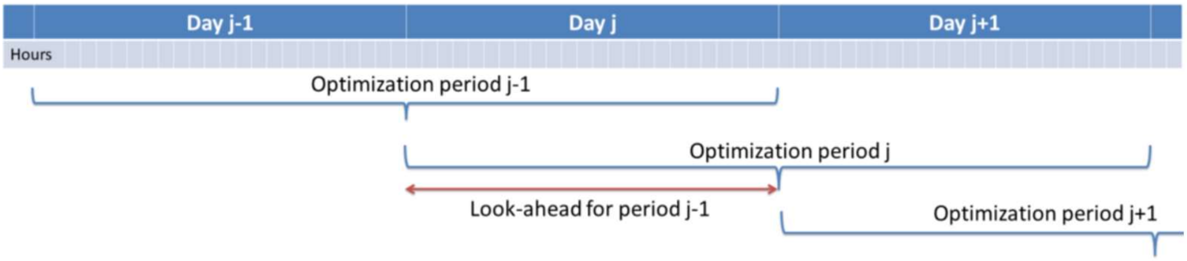

Figure 1 Moving horizon optimization [35]

In this research, scenario approach is implemented in order to compare results in particular zones and in the market as whole, when a zone implements a strategic decision, such as following a low-carbon (LC) or decarbonization pathway or sticking to the business as usual scenario (BAU). General idea of different possibilities for various zones in the scenario approach is illustrated by Figure 2, depicting zones with energy mix based on different technologies and connected to a common system (region). Such zones can make different strategic decisions regarding their long-term configuration and energy mix. Zone in this research represents a national energy system with autonomy to make strategic decisions.

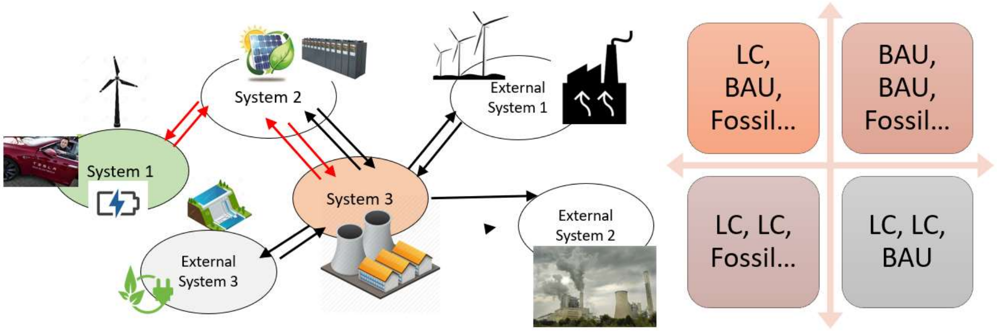

Figure 2 Scenario approach for different zones

For all zones in the market coupled system, a different strategic decision (in further elaboration called "strategy") is proposed, reaching from one end of the scale to the other:

- "Fossil" (typically for zones with own reserves of fossil fuels),
- "BAU" (with orientation towards RES, but with moderate dynamics)
- "RES" (integration of RES in higher dynamics, but without demand response)
- "Extreme RES" (high share of RES, but low local integration)
- "LC" (low-carbon, RES with strong integration).

For each of the zones, concrete numbers for installation of RES technologies, demand response and storage are derived from local potential and data for the zone in question.

Significant limitation of the approach lies in the fact that Dispa-SET unit commitment and dispatch does not consider lifetime costs associated with changing the portfolio of electricity generation capacities. However, the results of such analysis offer the guideline about the possible stranded costs (e.g. coal power capacities which do not enter the merit order on the electricity market) resulting from a strategic decision. Results can indicate if the strategic decision made in the observed zone leads to more stranded costs for that zone or leads to the outcome in which the zone in question exploits other zones for the balancing of electricity supply and demand. Such conclusions can be made based on unit commitment observations.

3. Case study and results

Case study area includes electricity generation and district heating systems of Croatia (HR), Slovenia (SI), Serbia (RS), Bosnia and Herzegovina (BA), Albania (AL), Kosovo (XK), Montenegro (ME) and North Macedonia (MK) connected in a coupled day-ahead electricity market. The data is more detailed for the zone of Croatia (HR), while the input data for all other zones was already elaborated in several papers, such as [36] with the emphasis on the model formulation and data for 2030, [38] dealing with the Western Balkans region, and [39], which collected the relevant data on generation units. Inputs related to VRES for the observed zone (HR) are available in the Annex. In addition to VRES such as solar photovoltaic or wind power plants, the HR zone also has hydroelectric power plants in portfolio, whose availability coincides with river flows. Large hydroelectric power installations are characteristic for all the zones in the region, with usual power generation mix including hydro and coal power plants. Data and river flows can be obtained using the publicly accessible SMHI HypeWeb [40] database. If the zone is located at the border of the studied region, then historical cross-border electricity flows represent a limitation of the model, the flow to zones outside the studied region is not optimized. Data related to historical cross-border flows can be found in the public database ENTSO-E [41]. In this case, HR is surrounded by zones that are part of the modelled region, cross-border flows are in this case the result of the optimization model of the Dispa-SET. However, for each zone, it is necessary to have information about the net transfer capacity to know the limits related to the transmission of electricity from one zone to another. Data related to the NTC from an to Croatia can be found in the annual reports of the transmission system operator for each zone or country. For Croatia (HR) NTC is given in Figure 3.

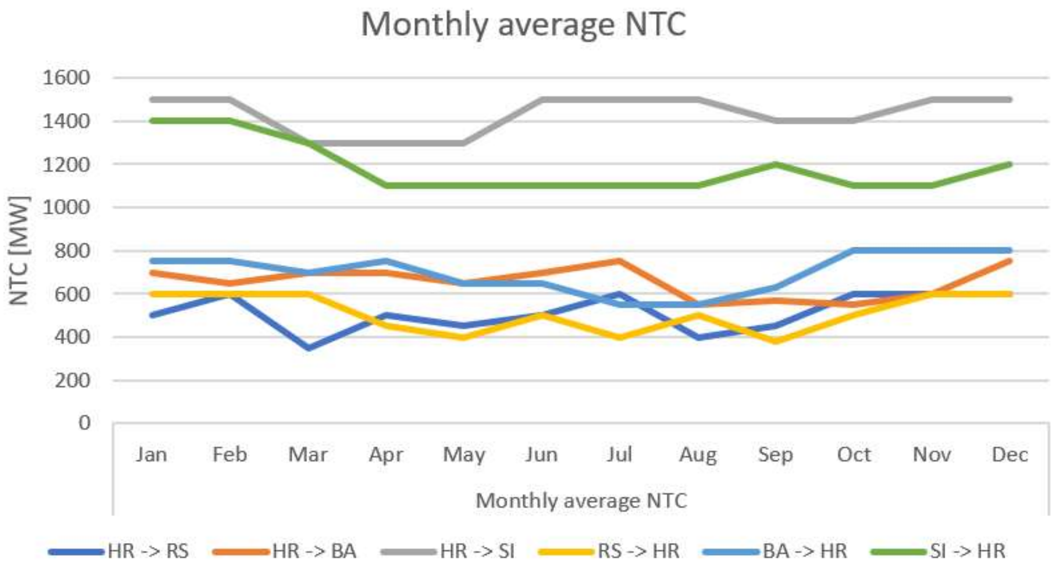

Figure 3 Monthly average NTC for zone HR

The electrical load of a specific zone, the power consumption at the hourly level for the whole year is a required input. This data is available from the public database, such as ENTSO-E [41]. Figure 4 shows the electrical load for the HR model reference year (2016).

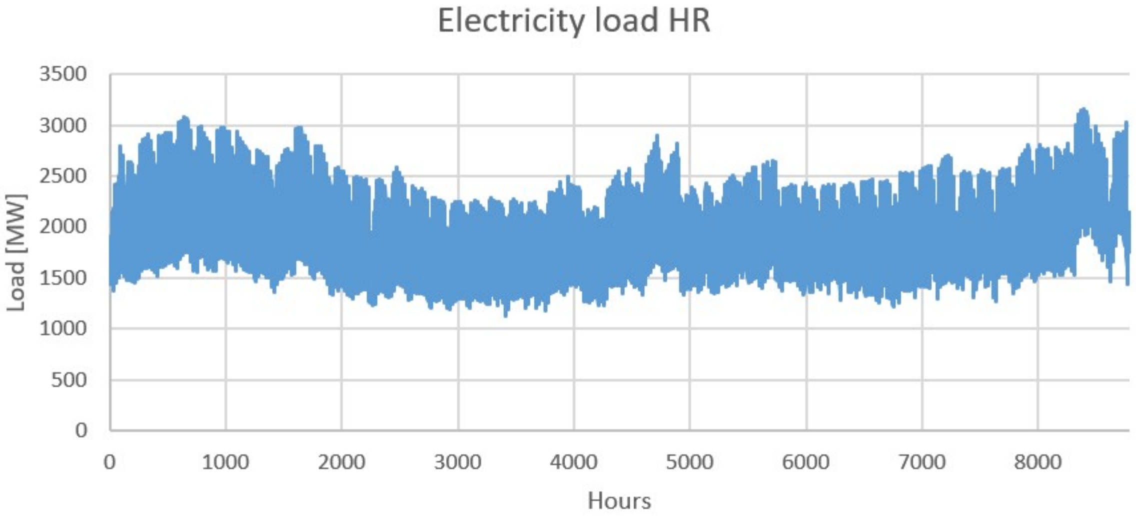

Figure 4 Electricity load for the zone HR

Installed capacities of different technologies are given in Figure 5. This includes Hydro (WAT), Wind power plants (WIN), Solar PV (SUN), Peat Moss (PEA), Oil power plants (OIL), Gas power plant (GAS), Biomass power plants (BIO), Hard coal power plants (HRD), Lignite power plants (LIG) and Nuclear power plants (NUC) and Other, such as connection of EV's chargers to the grid (OTH).

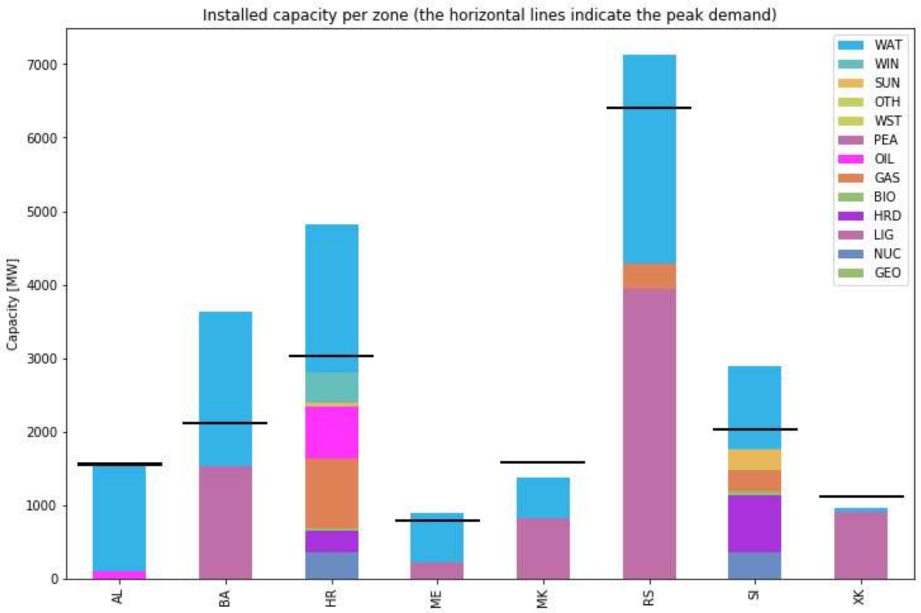

Figure 5 Installed generation capacities for all zones in 2016

For the given inputs, Figure 6 shows generated electricity and imports for each of the zones (Flow In). For the case of nuclear power plant (NPP) Krško, located in SI, the installed capacity, as well as energy produced from the plant is split in half between HR and SI instead of modelling it in SI and arranging a constant export to HR. Compared to the historical data of the zone HR from IEA statistics [42], results are within 15% difference in case of coal (2.6 TWh) and hydro (7 TWh). Imports (5.5 TWh) are expressed as generation from NPP Krško (2.8 TWh) and import of 2.8 TWh. The difference between historical data and calculated data are satisfactory because the Dispa-SET is an optimization tool, while historical data was not a result of the optimal dispatch.

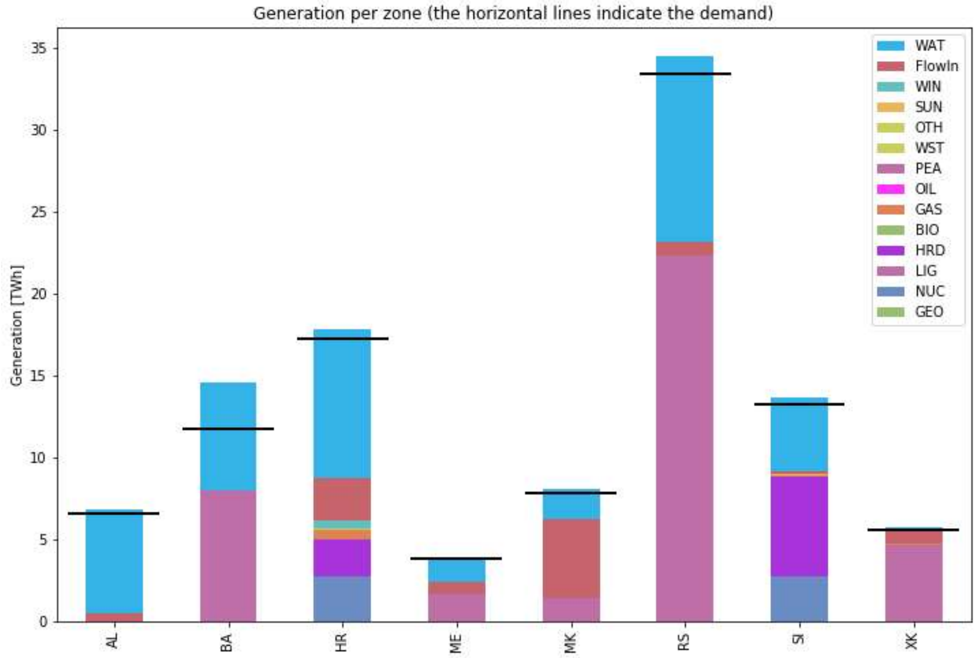

Figure 6 Electricity generation from each technology and imports in 2016

Figure 7 shows solution to dispatch problem in 2016 for HR, considering the electricity demand, dam hydro (HDAM) and pump hydro (HPHS) reservoir levels and export/import balances, as well as other storage. It is characteristic to see the conditions in period of NPP Krško maintenance.

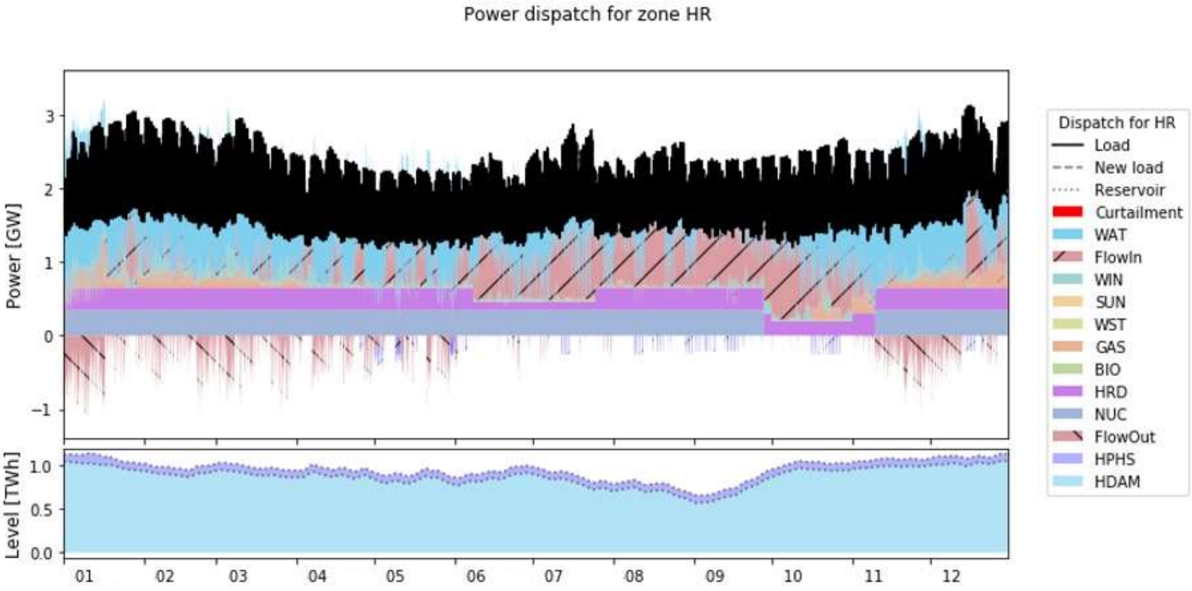

Figure 7 Solution to dispatch problem in HR in 2016

For the same year, Figure 8 shows the unit commitment for all available electricity generation units in HR. It is noticeable that CHP units run only when they are needed for heat production, while the rest of the time the needs are covered by NPP Krško, hydro power plants and import, while two blocks of Coal power plant Plomin work according to their nominal capacity, with modern block 2 working significantly more hours with a lot of ramp up and ramp down.

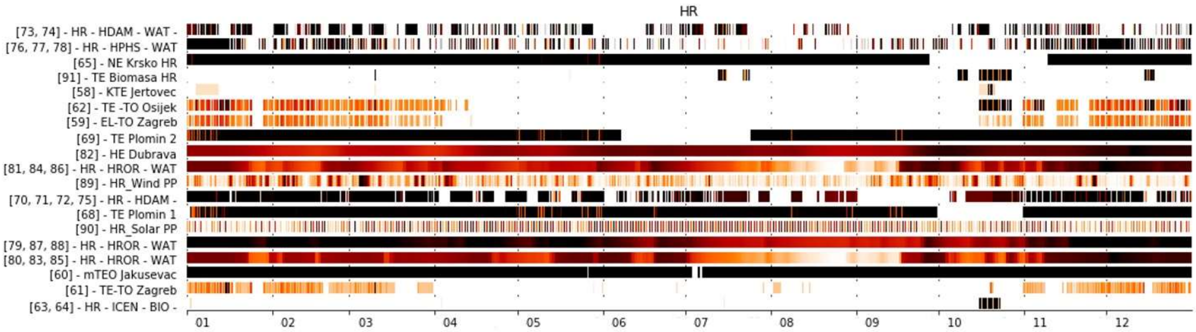

Figure 8 Unit commitment in HR in 2016

Costs used for the optimization of dispatch in future scenarios are given in Table 1. Costs are assessed in the context of the case study area, to represent a best-case scenario [43] for a region rich with locally produced lignite [38].

Table 1 Marginal costs as inputs to the model for future scenarios

Marginal costs [EUR/MWh]	
CO_2 emissions [EUR/t CO_2]	9
Unserved Heat	50
Load Shedding	400
Nuclear	3
Black coal	10
Natural Gas	20
Fuel Oil	35
Biomass	18
Lignite	8
Peat	8
Value of Lost Load (VOLL)	100000
Spillage	1
Water Value	400

Future scenarios in 2030

Four scenarios for the year 2030 were analysed, taking into account the business-as-usual decision making for all zones as a benchmark. Table 2 shows the strategic decision supposed per zone and per scenario.

Table 2 Strategic decisions of zones in different scenarios

	2030	2030a	2030b	2030c
AL	Fossil	BAU	BAU	BAU
BA	Fossil	BAU	RES	extreme RES

ME	Fossil	BAU	BAU	BAU
MK	Fossil	BAU	RES	RES
RS	Fossil	BAU	RES	extreme RES
XK	Fossil	BAU	BAU	BAU
HR	LC	RES	LC	LC
SI	RES	RES	LC	LC

Table 3 gives an overview of the specific changes made in a couple of zones, to investigate scenarios in which one zone (HR) aims to integrate RES and demand response technologies, while other zones integrate RES to higher or lower extent, but do not follow up with demand response (remaining data is given in the Annex). The numbers in all scenarios reflect the decisions, taking into account different starting energy mix, in the following way:

- Low Carbon (LC) decision proposes achievement of minimum of 80% of electrical energy produced from RES and includes demand response and storage technologies (V2G in HR and SL). Such decision proposes for over 300 MW of Solar PV and Wind installations per year until 2030
- Extreme RES decision proposes high share of RES, with over 50% of electrical energy produced from RES. Such decision proposes for over 300 MW of Solar PV and Wind installations per year until 2030
- RES decision proposes moderate increase in RES installations, with 150-200 MW of new Solar PV and Wind capacities per year until 2030, but without special attention given to demand response technologies
- BAU decision proposes reaching shares of RES noted in current public plans
- Fossil decision proposes slow integration of RES and new fossil capacities to be installed until 2030

Table 3 Specific changes compared to BAU for all scenarios

Scenario	2030	2030a	2030b	2030c	Unit
HR EV Connection	6600	4400	6600	6600	MW
HR EV Storage	80	60	80	80	GWh
HR Solar	4460	2460	4460	4460	MW
HR Wind	4500	2500	4500	4500	MW
RS Wind	1000	1500	4500	6500	MW
RS Solar	500	2000	3500	5500	MW
BA Wind	564	2000	2500	4564	MW
BA Solar	0	0	200	500	MW
MK Wind	350	500	1500	2000	MW
MK Solar	100	1000	1000	2000	MW

Scenario 2030

In the “2030” scenario, all zones except HR (LC) and SI (RES) made a decision of relying on local coal capacities combined with hydropower (“Fossil”). Installed capacities are given in Figure 9. The type “OTH” in the figure represents the connection capacity of EV’s batteries to the grid.

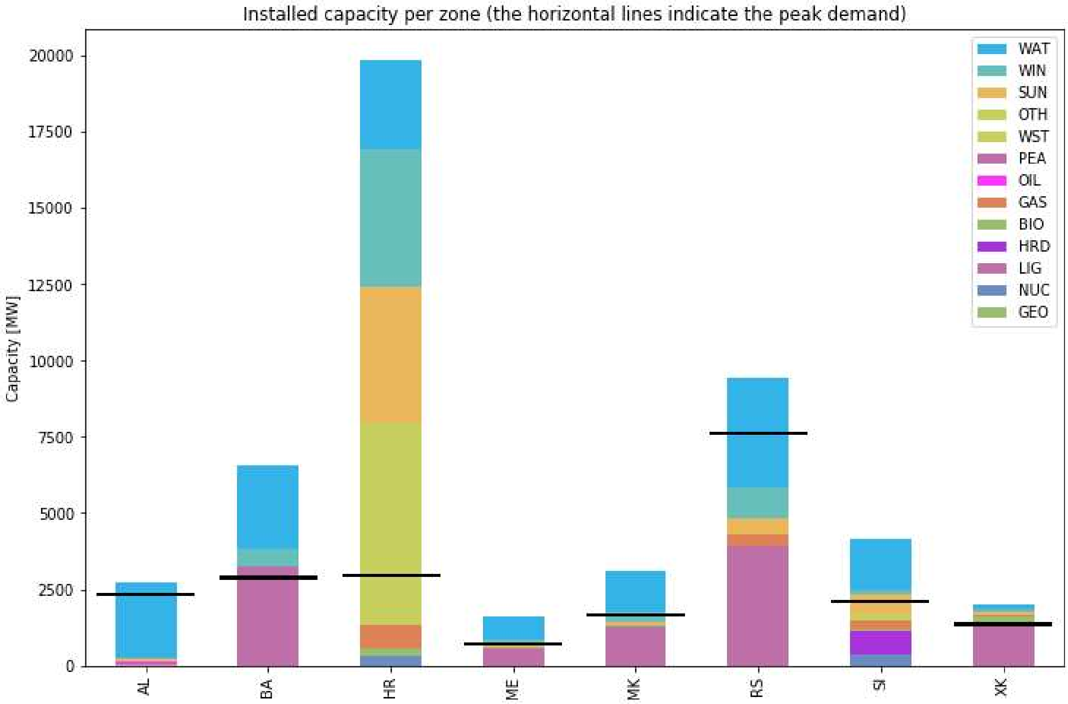

Figure 9 Installed capacities in initial 2030 scenario

After optimization, electricity generation from all technologies in all zones is given in Figure 10. In zones RS, BA and ME, 30-40% of energy is produced from coal while XK exports part of electricity generated from coal. Import has higher share in BA (33%) and lower in ME and MK (less than 10%), at the expense of local electricity generated from coal. Net export occurs from HR, AL and XK (from the former due to large wind and hydro capacities and from the latter due to inflexible coal).

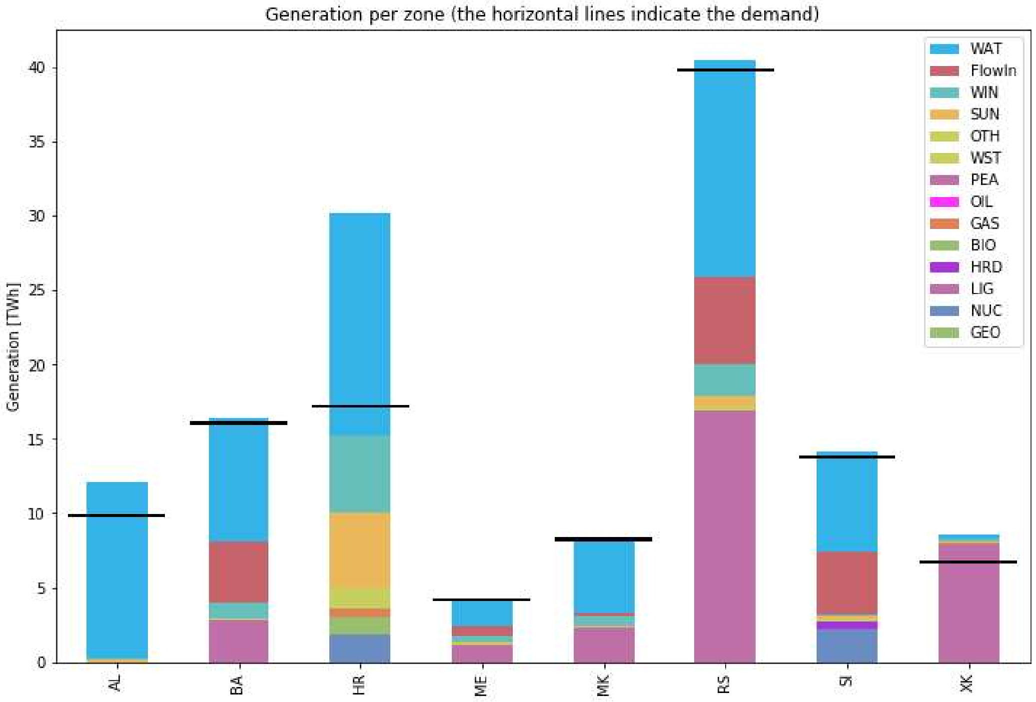

Figure 10 Electricity generation for the energy mix in scenario 2030

Focusing at the leading zone with LC strategic decision, HR, Figure 11 shows the dispatch of energy from all technologies, storage inflows, import/export and energy stored in EV batteries, as well as storage levels in hydro power plants. EV batteries participate in the balancing and RES integration, while their discharge is visible in Figure 10 as "OTH" generation.

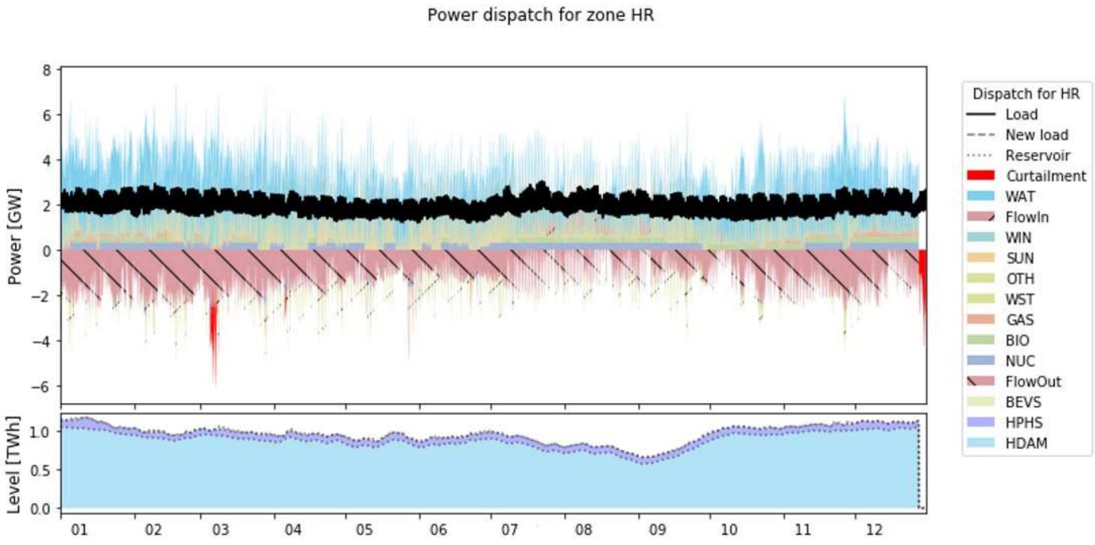

Figure 11 Power dispatch for HR in 2030 scenario

In Figure 12 unit commitment for the HR zone is given, showing in more detail how certain groups of electricity generation unit are operating during the year.

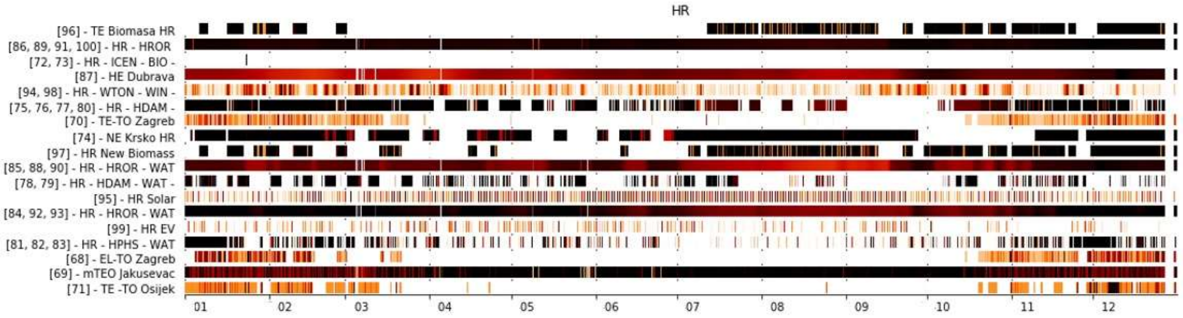

Figure 12 Unit commitment in HR in 2030 scenario

Apart from the hydro power plants, which are operational throughout the year, commitment of solar PV (5.05 TWh), wind (5.24 TWh) and EV vehicle battery discharge (1.2 TWh) is dominating the energy mix. CHP plants are operating during the winter heating season, which leaves up to 4000 hours a year for operation, while NPP Krško works with cycling periods and 1000 hours less compared to the base case in 2016. Curtailment in HR is 0.32 TWh, which is acceptable, as elaborated in [31]. In this scenario, results show that every zone which opted for "fossil" strategy imports electricity from the zone with "LC" strategy. Due to good interconnections and geographical location, even SI zone, with "RES" strategy, imports electricity from HR zone, which is comparatively leading the energy transition of the whole interconnected region, exporting most of the electricity generated from RES. In case of absence of interconnected electricity market, the observed zone would not be able to integrate such amounts of renewable electricity.

Scenario 2030a

In scenario “2030a”, all zones except HR and SI are following BAU strategic decision, while HR and SI are focusing on RES installations. Installed capacities for all zone in scenario 2030a are given in Figure 13.

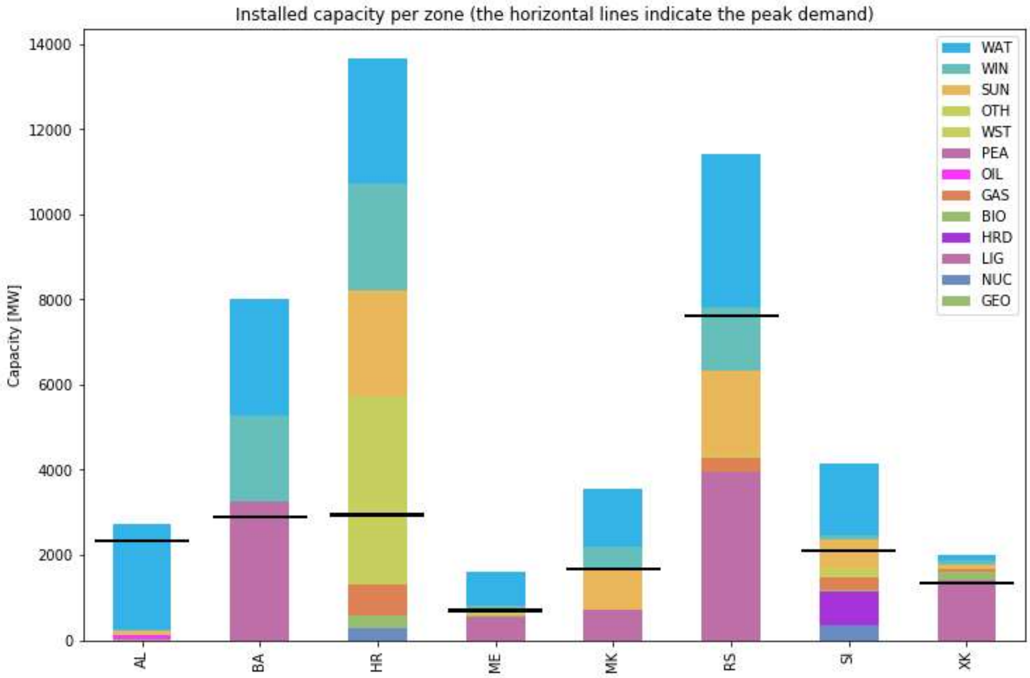

Figure 13 Installed capacities for all zones in 2030a

With the given inputs from Table 3 and Figure 13, electricity generated in all zones is given in Figure 14.

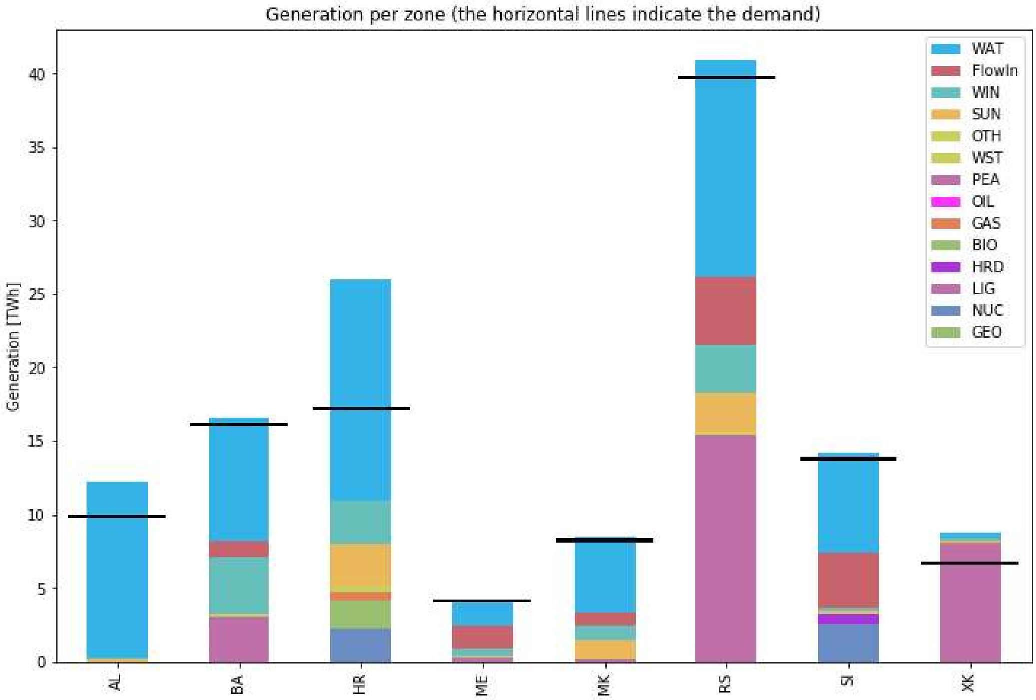

Figure 14 Electricity generated from all technologies in 2030a

Reduction in needed import is visible and amounts to 43% compared to 2030 scenario in zones that have decided to invest in renewable energy (BA, RS), while Croatia (HR) has remained export oriented in the process (in reference case, HR is import oriented). Kosovo remains noticeably non-flexible and exports the energy from the lignite power plants. BA imports around 1.1 TWh of energy from RES in the surrounding zones and, together with local output from wind power (3.9 TWh), this amounts to more energy than it produces from lignite power plants.

The solution to dispatch problem in 2030a scenario for HR zone is shown in Figure 15. There is no significant occurrence of curtailment (amounts to 6 GWh across the market coupled region), not even in September, with reservoir levels being at 60% of initial level. Reduced investments in V2G, with 60 GWh of storage and 4400 MW of interconnection instead of 80 GWh/6600 MW in other scenarios, still provide enough balancing. In all zones, combination of newly installed RES and import from the zone with the high RES share (HR) supress the electricity generation from lignite power plants, although some inflexible lignite blocks remain the main producers for zones such as XK.

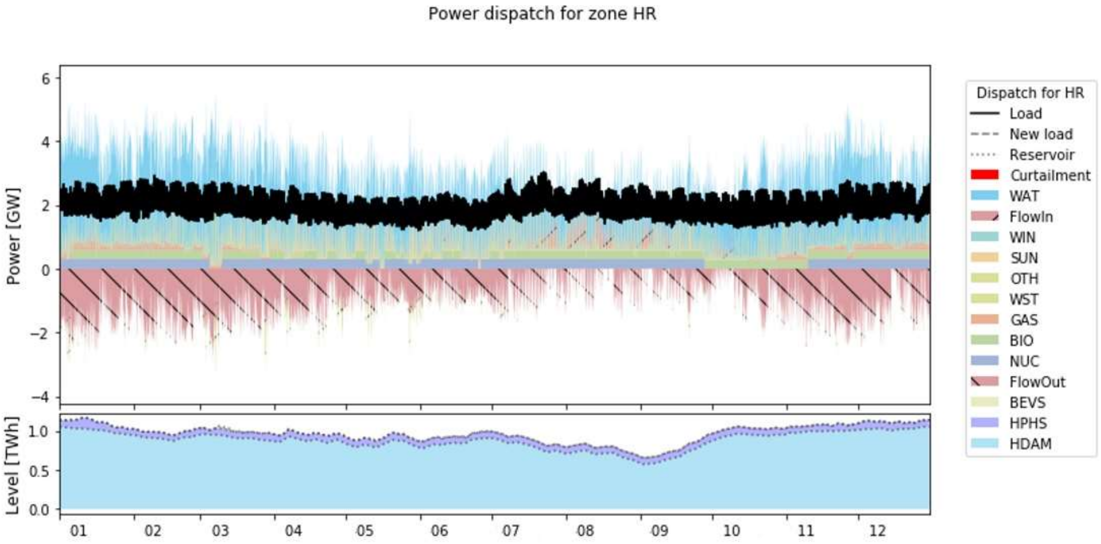

Figure 15 Solution to dispatch problem in HR in 2030a

For the unit commitment it is important to note that in HR, coal power plants are no longer in operation in 2030 and new RES capacities are operating in most of the hours. EV batteries are participating in supply by discharging electricity back to the grid in some hours. These dynamics are visible in Figure 16.

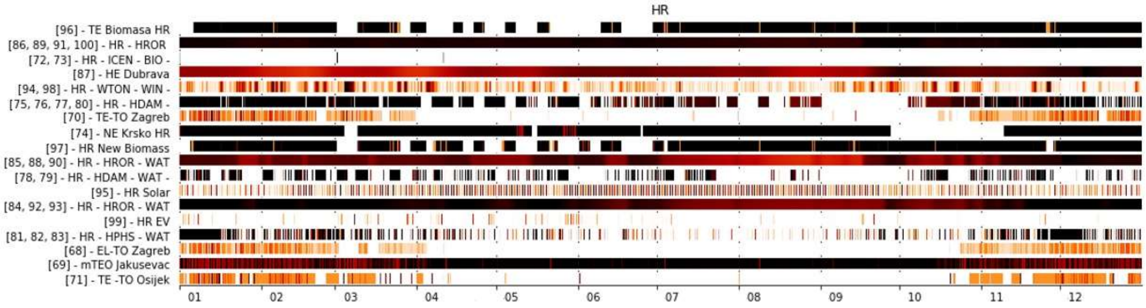

Figure 16 Unit commitment in HR in 2030a

In scenario “2030a”, the leading zone (opting for “RES” strategy) does not generate excessive amounts of electricity from RES. At the same time, all other zones (except for SI) opt for “BAU” strategy, which includes larger installations of RES compared to “fossil” strategy. Resulting situation is still favourable for the zones opting for “RES” strategy, in terms of balancing their generation, but the rest of the zones have increased export. This configuration results in only 10% reduction of short-term operation costs compared to “2030” scenario. However, it is more favourable for the zones opting for “BAU” in terms of stranded costs, due to larger generation from coal.

Scenario 2030b

For the “2030b” scenario, installed capacities of all technologies are given in Figure 17. Capacities of wind and solar power are now 2-3 times larger compared to 2030a (Table 3) and more exports from the zones without demand response or additional storage technologies are expected. “OTH” represents the V2G connection to the grid.

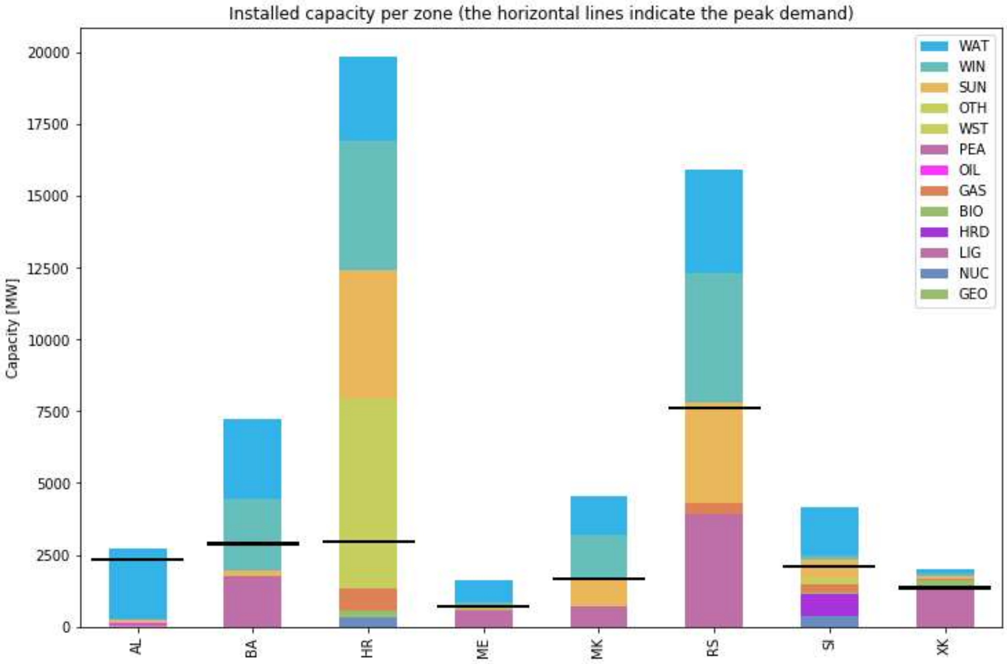

Figure 17 Installed capacities in all zones in 2030b

For this set of inputs, Figure 18 gives the electricity generation from all technologies in 2030b. Due to high installation capacities and availability of renewable energy sources, HR remains export oriented. There is still net import in BA and RS amounting to 1.35 TWh, which is connected to the fact that there are other countries in the region with over 80% of VRES penetration (HR, MK), but without storage and demand response technologies which would enable them to integrate all produced energy. In gross consideration of import and export it is visible that major exporters are HR, MK and AL. Also, XK starts to be import oriented zone, producing only about 80% of their energy from lignite in comparison to 110% in scenario 2030a.

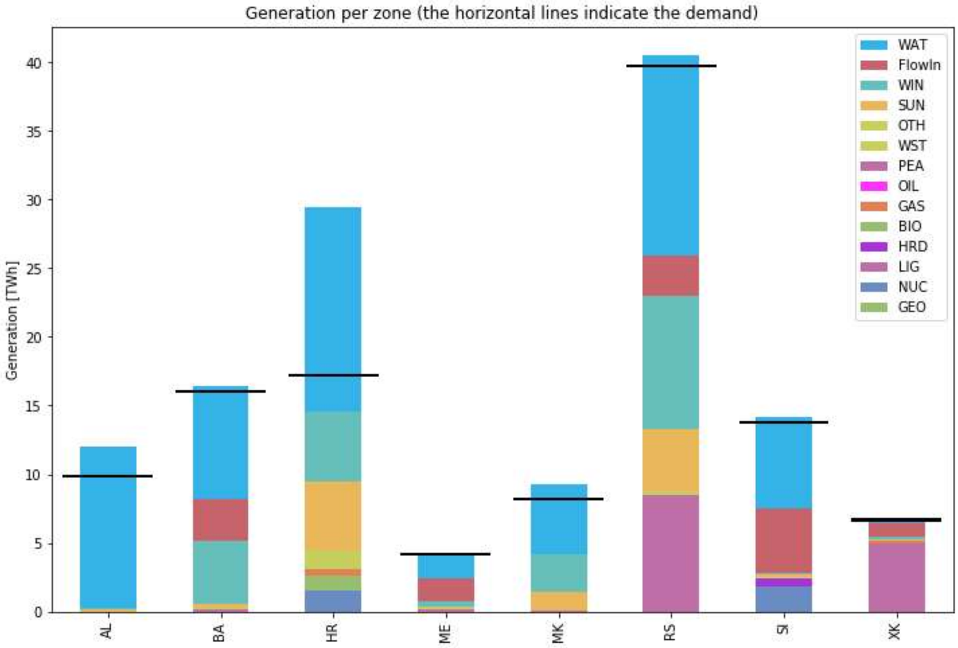

Figure 18 Electricity generated from all technologies in all zones in 2030b

In the other zones, output from VRES supresses the operation of local coal power plants (visible in particular for XK) and the common market enables for energy produced from VRES to be distributed between the zones, in case of inability of a certain zone to integrate all the produced energy. The solution to dispatch problem for HR is shown in Figure 19. In 541 hours, a curtailment occurs in HR (in total 0.67 TWh), mostly in spring, due to high hydropower availability combined with high VRES installations and lower load.

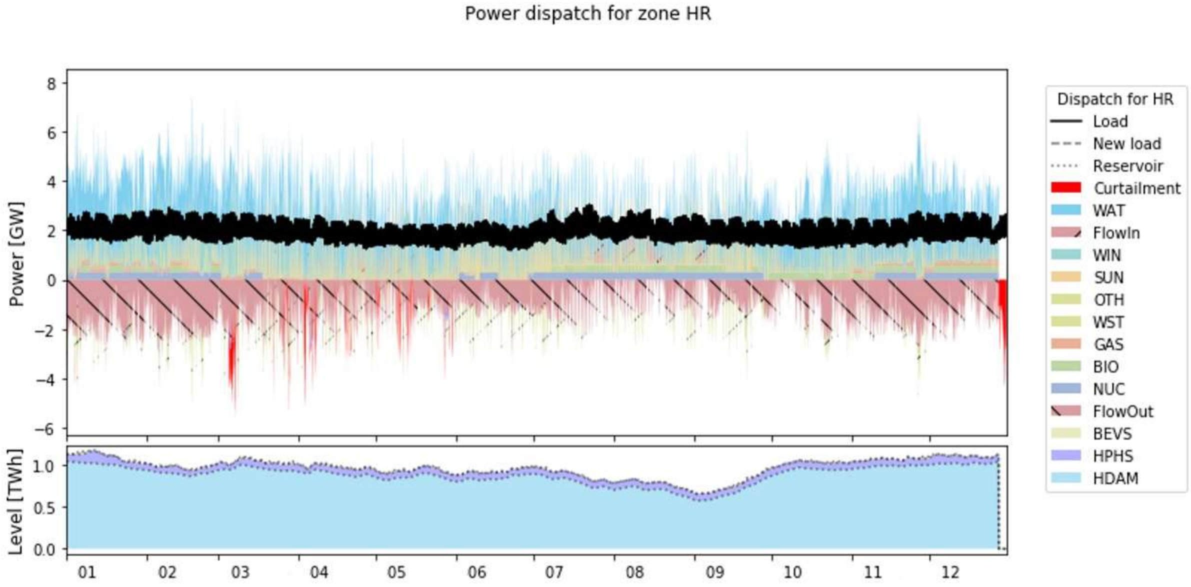

Figure 19 Solution to dispatch problem for HR in 2030b

Figure 20 illustrates the commitment of all available electricity generation units in HR in 2030b. High availability of VRES technologies is visible (HR-WTON-WIN and HR Solar producing), as well as larger number of hours with EV discharge (HR EV in Figure 20 and "OTH" in Figure 19) back to the grid. Biomass power plants take over some of the flexibility and balancing roles that were previously held by large electrical blocks in Plomin and they have more ramp up and ramp down hours, to provide additional balancing of the system.

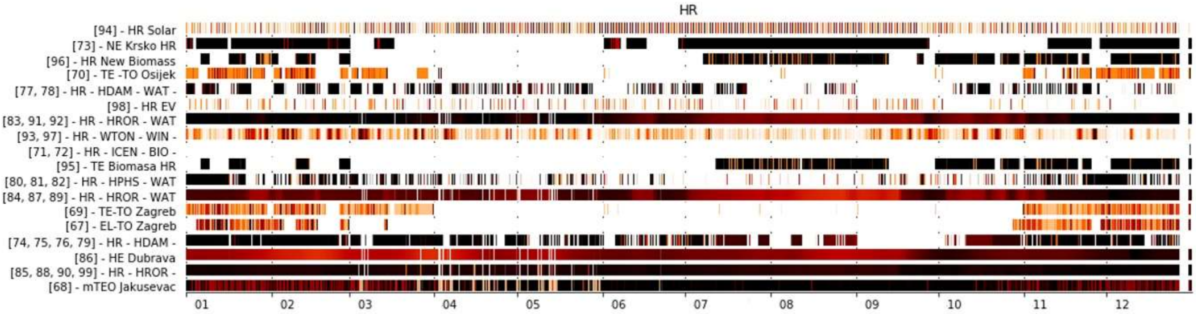

Figure 20 Unit commitment in HR in 2030b

In scenario "2030b", half of the zones that were developing according to "BAU" strategy, now opt for "RES", which further hindered the generation of electricity from coal in all the zones and reduced the short-term operation costs for 50% compared to "2030". Such decision portfolio benefits the zones with "LC" decision the most, but also benefits the zones with "RES" decision.

Scenario 2030c

In scenario 2030c, HR and SI remain at LC strategic decision, while some zones: RS, BA and MK are relying on extreme RES strategy, installing large capacities of RES (Table 3), but without a lot of flexibility options. Installed capacities are shown in Figure 21.

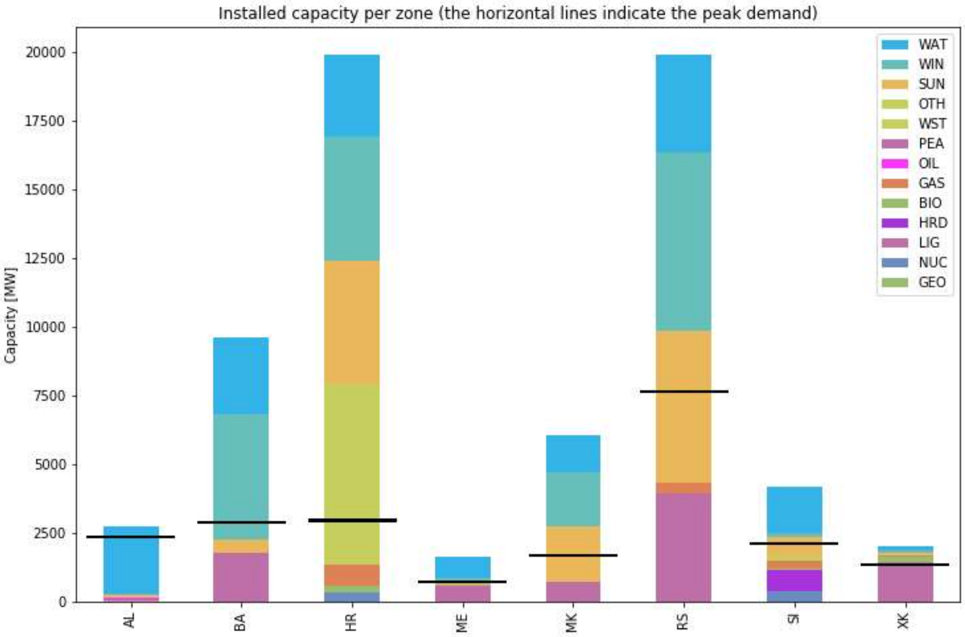

Figure 21 Installed capacities in scenario 2030c

Generation of electricity, shown in Figure 22, is based on RES in majority of zones, while zones previously relying on lignite power now import majority of energy instead of producing it from lignite.

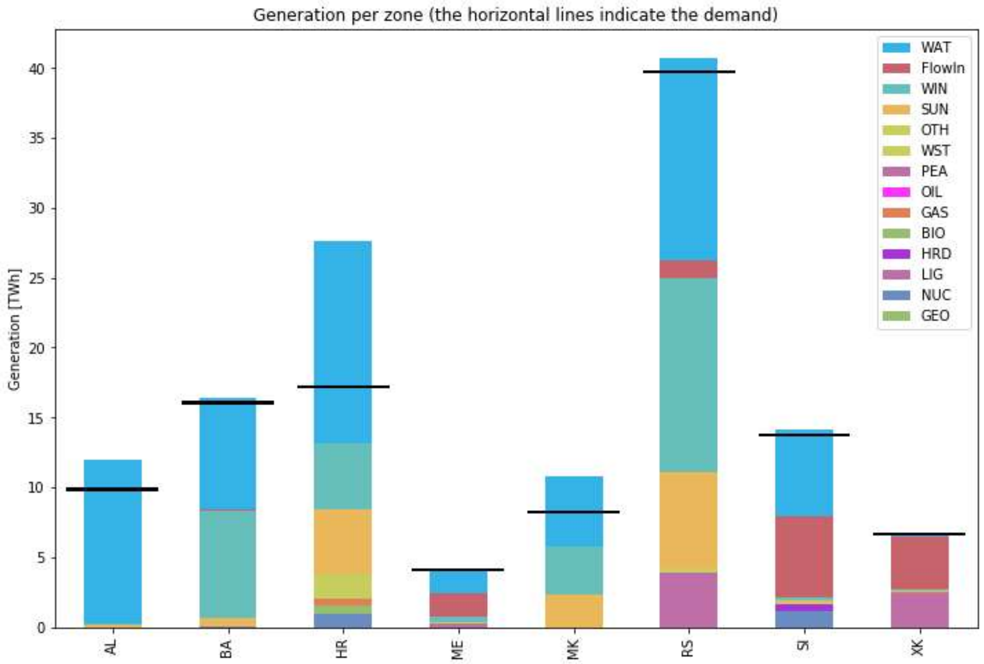

Figure 22 Electricity generated for all zones in 2030c scenario

XK imports 60% of energy, ME imports 40%, while RS produces less than 50% of energy from lignite in comparison to 2030b scenario. In BA and MK there is no electricity generated from coal. The solution to dispatch problem in 2030c scenario for HR zone is shown in Figure 23. The occurrence of curtailment became more significant, amounting to 1.7 TWh. This suggests that additional demand response would be needed across the region, to accommodate the RES penetration levels in scenario 2030c, since curtailment appears in RS (1 TWh) and BA (1.7 TWh) as well.

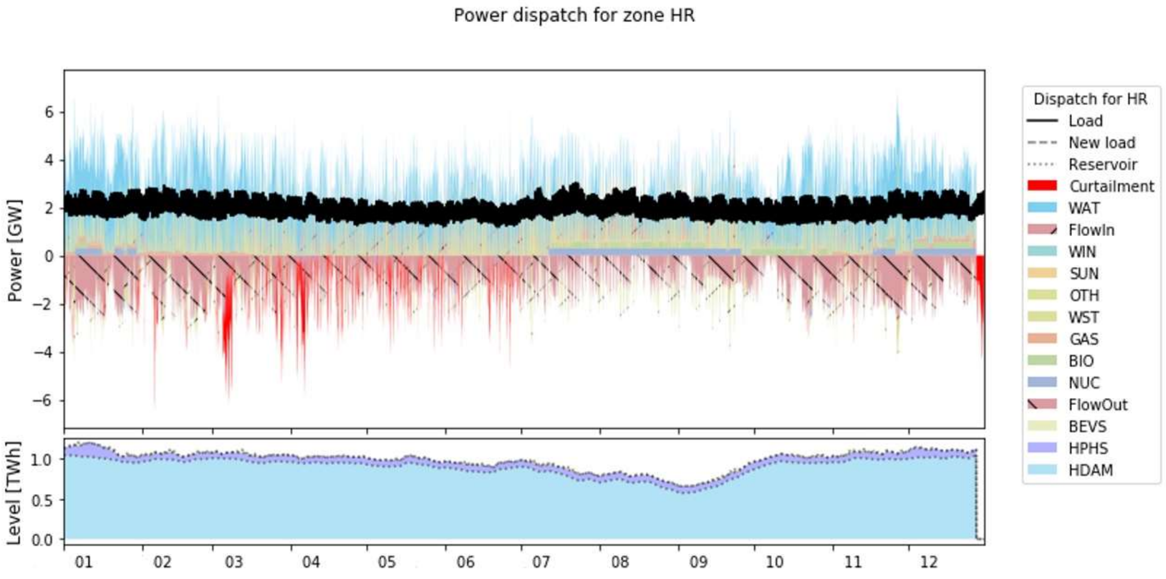

Figure 23 Power dispatch for scenario 2030c, zone HR

The Figure 24 shows unit commitment for scenario 2030c for the duration of the year in zone HR. The HDAM and HPHS units operate during spring and summer seasons, adding on the electricity generated from wind and solar power. In such an energy mix, NPP Krško does not enter the merit order during the spring, due to high availabilities of VRES and HROR.

Figure 24 Unit commitment for zone HR in scenario 2030c

In scenario “2030c”, all the zones that were previously developing in accordance to “RES” strategy, now opt for “Extreme RES”, which results in complete abandonment of coal in all zones except for RS and XK. Consequently, this scenario results in the lowest short-term operation costs (only 30% compared to “2030” scenario). Although the overall capacity of the newly built portfolio of RES power plants is high, the investments would still be lower than in the case of investment in “fossil” strategy, which proves to result in a lot of stranded cost, due to very low operating hours of coal power plants in all scenarios. Also, economic and social costs of such stranded assets in the electricity generation system are increasing in EU towards 2030 [44].

Results of cross-border lines congestion and average marginal cost

The results of cross-border lines’ congestion are relevant for consideration of upgrades of the infrastructure, either of the lines themselves or the local demand response and storage. In Table 4, congestion hours on the electricity transmission lines connecting zones in common electricity market are presented for all scenarios. It can be noted that, as the integration of VRES get to a higher level (scenarios with more zones opting for “RES decision”), number of congestion hours rises in general, although some of the interconnections become less congested. Congestion rises in direction of export from the zones that are integrating VRES, but not demand response technologies, as can be seen on connections between Serbia (RS) and all other countries and Bosnia and Herzegovina (BA) and other countries.

Table 4 Number of congestion hours on each line connecting the zones for both scenarios

Number of hours of congestion on each line:	2030	2030a	2030b	2030c
BA -> HR':	342	824	474	1711
BA -> ME':	2371	3195	2617	3131
BA -> RS':	2214	3002	2780	3304
HR -> BA':	6214	3795	5145	3620
HR -> RS':	6116	4573	5410	3994
HR -> SI':	56	45	146	593
ME -> AL':	1145	1293	1210	1094
ME -> BA':	1636	1345	1575	1262
ME -> RS':	2333	2142	2308	2221
ME -> XK':	4293	3814	3172	3820

MK -> AL':	1840	1889	1908	2450
MK -> RS':	4285	3657	4245	4848
MK -> XK':	1297	1002	2317	3098
RS -> BA':	1615	1541	1785	1894
RS -> HR':	522	892	1031	2129
RS -> ME':	2610	2808	2790	2867
RS -> MK':	1266	1762	1426	994
RS -> XK':	486	592	2118	2741

At the same time, congestion in direction from Croatia (HR) to Serbia (RS) is significantly lower in "2030c" than in "2030". In scenario "2030c", electricity generated from coal in BA and RS is replaced with import from the zones with increased RES share. At the same time, BA is not integrating all renewable energy that is generated but is exporting it to surrounding zones. Similar can be observed for MK and RS. The zone that was in other scenarios exporting its energy generated from coal – XK, in 2030c becomes a net importer. The scenario with HR and SI going for energy transition ("LC"), while other zones stick to "BAU" or "Fossil" decisions (2030) incur more congestion on the transmission lines from the leading zone (HR), but also reduce the energy generated from fossil fuels in the region. When other zones follow with "RES" or "extreme RES" decisions, the congestion hours reduce between them, but remain high towards zones that stick lower energy transition intensity.

In Figure 25 the average marginal electricity cost for all scenarios is given. Marginal cost is the highest in scenarios with more energy generated from various fossil fuels and notably from coal, like it is the case in scenario 2030 (most zones had the strategic decision to remain in "fossil" or "BAU" strategy).

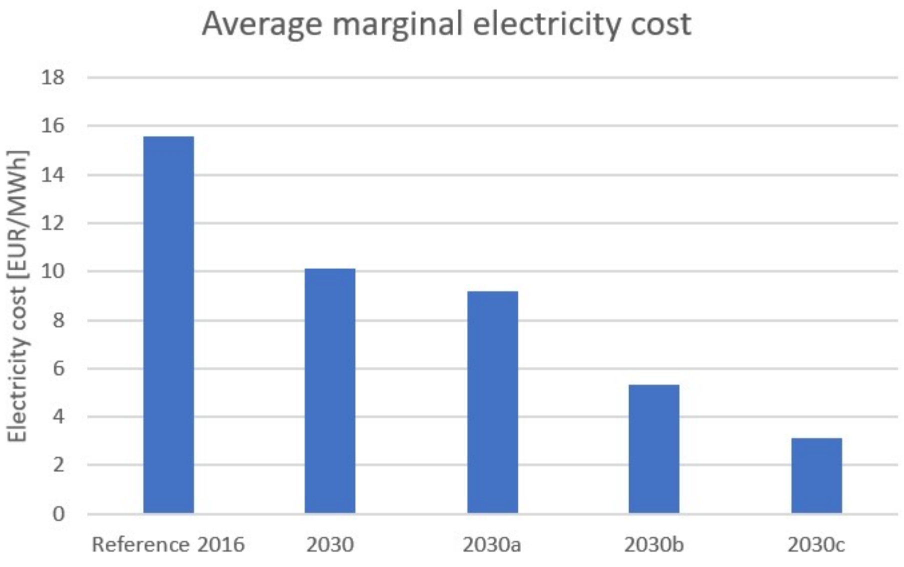

Figure 25 Average marginal electricity costs in all scenarios

From the results presented in the previous chapter, it can be noted that the marginal cost of electricity generated will be lowest in the scenario maximising RES capacities, "2030c", reaching only 30% of the cost of "2030" scenario. The direction of energy transmission provides additional information about the benefits that certain zone had due to strategic decisions it decided to implement. The zones with LC decision will also be the ones to benefit most from all the capacities in the connected electricity market. These zones will use electricity available at lowest price in the hours of abundant generation to store it and use it for decarbonisation of other sectors, such as heating and transport. Observations about the zones that “lead“ the energy transition and those that “follow” are important for future development of energy systems in the observed region and regions with similar characteristics. Results point towards the conclusion that the most favourable way for all zones to move forward would be to follow the “leading zones” (e.g. the ones LC decision) first as soon as possible. In that way, further refinement on the scenario 2030c could be done, since all the zones would include DR technologies and decarbonize the system while achieving the lowest average marginal generation cost of electricity. A boundary condition of the original energy mix of all zones, which is a combination of hydropower and coal power, must be kept in mind. This analysis could be used as a guideline for the regions with similar energy mix. It can be noted that the first zone with the 100% RES based energy system is AL, relying on hydropower.

Some sensitivity parameters need to be observed. In strategic decision making for the chosen case study area, the price of greenhouse gas emissions, namely CO_2, can play an important role in economic feasibility of the future energy system’s configuration. Scenario “2030” is discussed in terms of CO_2 cost. Cost of CO_2 is 50 €/t CO_2, compared to 9 €/t CO_2 considered in previous chapter in “2030” and all other scenarios. This value vas used due to applying the emissions trading rules on all zones, while previously only HR and SI were included in emissions trading system of the EU and the cost of CO_2 was calculated to represent the average across all zones. Resulting average marginal electricity cost for new price of CO_2 is 21.18 €/MWh. Resulting generation from technologies in all zones is given in Figure 26.

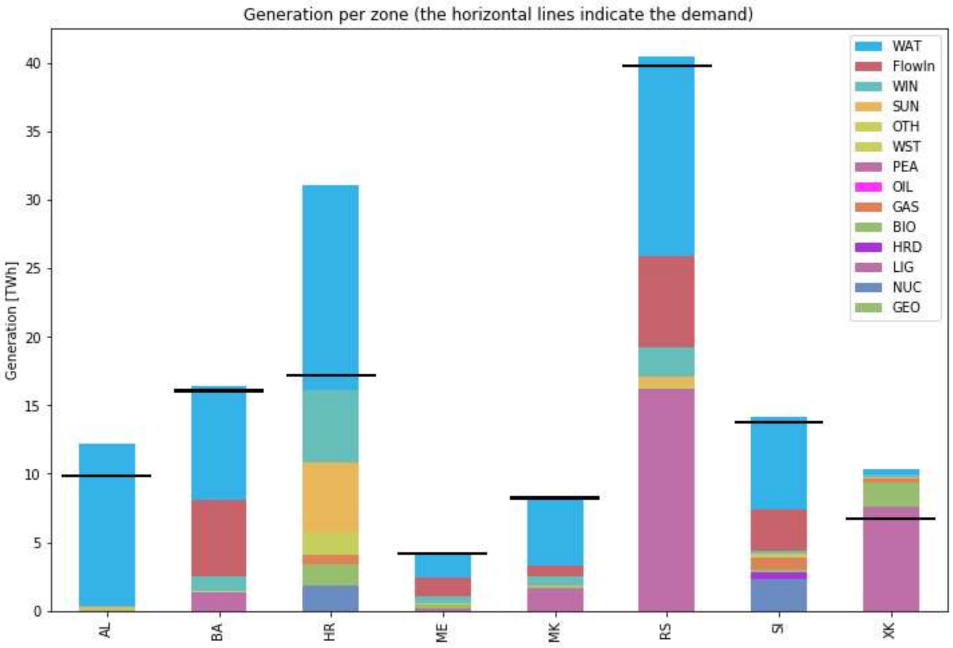

Figure 26 Generation of electricity per zone in case of high cost of CO2

It is noticeable that in zones previously dominated by coal, a combination of import (from the zones rich with RES and hydropower) and gas have larger share of the energy mix. This applies to MK (energy from gas) and SI, while XK export from coal remains 50% of the amount exported in the case with 9 €/t CO_2. BA and ME also import energy and energy produced from coal remains at less than 50% of the case with lower CO_2 cost. In Figure 27, the power dispatch in the case with higher CO_2 price is presented. It can be compared with Figure 11 to notice the change in storage profiles. The comparison suggests that the zone with most ambitious strategic decision (HR) participates more in balancing of the region than it was the case with lower CO_2 price.

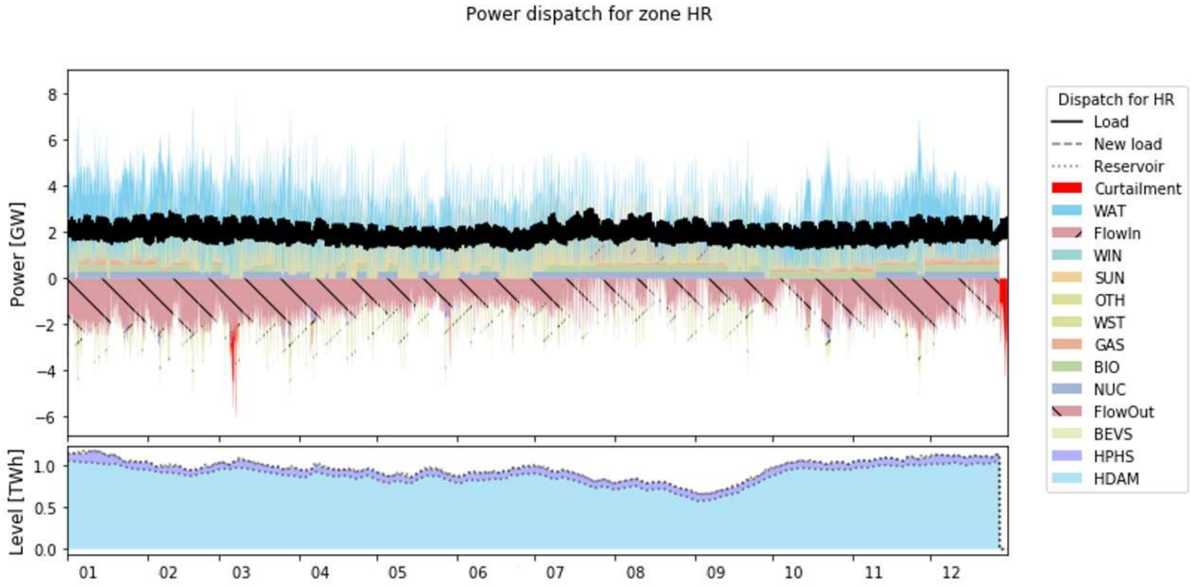

Figure 27 Dispatch for zone HR in the analysis with high CO2 prices

In case that scenario 2030 would be run without V2G implemented in Croatia, the Figure 28 shows the solution to the dispatch problem for zone HR. It is visible that curtailment becomes more regular issue (in red), with more than 100 hours of occurrence.

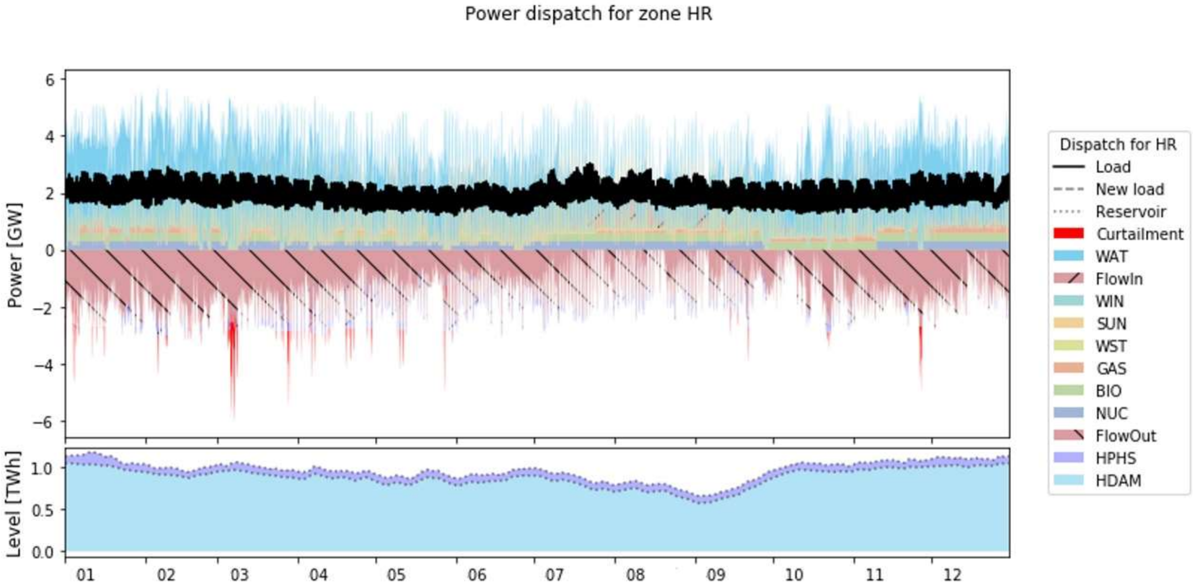

Figure 28 Dispatch for the zone HR in scenario 2030 without V2G

In terms of supply, the discharge of V2G is now compensated by gas, while surrounding zones absorb the increased exports (BA, ME, SI), as shown in Figure 29.

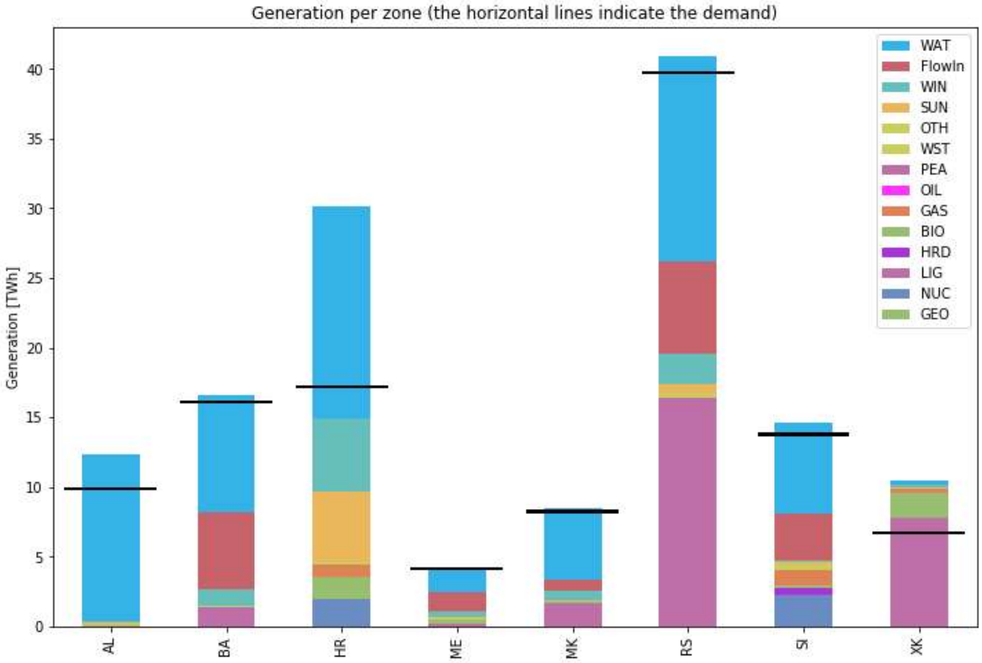

Figure 29 Generation for scenario 2030 without V2G in zone HR

In this case, the resulting average marginal electricity cost is 21.70 €/MWh and the number of congestion hours between zones HR and two large neighbours: BA and RS are at record high, compared to figures from Table 4, amounting to 7065 and 7143 hours respectively. Such results suggest that demand response installations influence the interaction between the zones and the average electricity costs for the market-coupled region more significantly than the proposed change in the CO_2 emissions cost.

4. Conclusion

A method based on the use of Dispa-SET model was demonstrated in this research, on the case of following the consequences of different strategic decisions between the zones in an interconnected electricity market. In scenario analysis, the outputs such as electrical energy flows between the zones and generation from technologies in all zones have been analysed to discuss the influence of different strategic decisions across the region. Main findings can be summarized as follows:

- Decisions for ambitious energy transition (LC and Extreme RES) had the effect of reducing the electricity generation from lignite blocks throughout the case study area (including the zones sticking with fossil or BAU strategy) due to exports of renewable energy from the zones that generated more renewable electricity than they were able to integrate in their energy system.
- The scenario with most zones going for the increased RES integration (2030c) offers the 70% lower average marginal cost of electrical energy compared to “2030” scenario, without causing increase in congestion hours on the cross-border electricity transmission lines.
- Results show that the zones with ambitious decisions benefit at the expanse of less ambitious zones in terms of avoiding stranded cost, while the marginal electricity cost drops for the whole considered region with increase of RES installations.

Perspective for this method can be found in creating the appropriate algorithms for creation of larger number of possible scenarios for each of the zones (including LC scenario for all zones) and creating long-term scenarios (until 2050) for the zones, to investigate the dynamics of energy transition for connected power markets. In the course of such future work, closer attention should be given to various DR and storage technologies, like vehicle to grid, power to heat and other solutions that would provide local flexibility and storage in each of the observed zones and their appropriate mix for different dynamics of energy transition.

5. Acknowledgements

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6. Annex

All the data used for the calculation of scenarios:

- Availability factors for RES power plants (hourly, solar, wind, hydro)
- Cross Border Flows (hourly, historical, between zones)
- Net transfer capacities (NTC) between zones, hourly
- Heat demand (hourly for power plants supplying heat – CHP)
- Scaled Inflow for hydropower storage, hourly
- Reservoir Level of hydro storage, hourly
- Electricity Load, hourly
- Outage factors, hourly
- Power plants database describing parameters for all power plants

can be found on the link: https://github.com/APfeFSB/Strategic-Decisions-Research-2020.git

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