Different Investment Dynamics in Energy Transition Towards a 100% Renewable Energy System

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Abstract

In order to mitigate the climate change process, the European Union has adopted a European Green Deal, which foresees zero net emissions of greenhouse gases for all member states by 2050. This paper investigates the possibility of achieving a 100% renewable energy system that would meet the requirements set out in this agreement. Montenegro was used as a case study to analyse different energy transition pathways. Two scenarios with different dynamics of integrating renewable energy sources in the energy system were determined for 2030, 2040, and 2050. Scenarios were simulated and analysed in the EnergyPLAN model. Due to the large potential in Montenegro, hydropower plants will have a significant share in the production of electricity, but special attention was given to the integration of variable renewable energy sources like solar and wind energy. The analysis shows that it will be possible to achieve a 100% renewable energy system in both scenarios with the implementation of energy efficiency measures, energy storage systems, synergies with the transportation sector, and balancing through demand response.

Keywords

100% Renewable energy systems, EnergyPLAN, Montenegro, Sustainable energy planning, Zero emissions of GHG.

1. Introduction

Fossil fuels are the dominant energy source in the world today, with a total primary energy production of about 80% [1]. As a result, the greenhouse gas (GHG) emissions are so large that they lead to an accelerated process of climate change which is one of the biggest challenges the world is facing today. Due to the problems caused by the excessive use of fossil fuels the European Union (EU) has adopted a European Green Deal, which foresees zero net emissions of greenhouse gases for all EU member states by 2050, to reverse this climate change process [2]. That is why it is necessary to transition current energy systems to fully renewable systems to achieve such a considerable reduction in carbon dioxide (CO_2) emissions. The problem with achieving fully renewable energy systems is the intermittent nature of energy sources like wind and solar.

Depending on the day of year and weather, there may be an excess or shortage of electricity in the grid, so energy storage and demand response technologies need to be introduced to stabilize the system. In European energy systems, flexibility requirements and load variability increase significantly when coupled wind and solar feature share of 30% in generated electricity [3]. Levelized cost of energy measure of high wind and solar penetration in electricity production indicated that the penetration level range from 20 to 80% in Europe and that there is a potential for variation management, especially concerning transmission [4]. An analysis of the proper choice of energy storage size in systems with a high ratio of renewable energy sources (RES) or with fully renewable sources has been conducted in [5]. It has been shown that even the use of low capacity energy storage can drastically ease the job of balancing electricity generation and demand. In [6], the authors demonstrated the integration of transport and energy sectors in island communities with 100% intermittent renewable energy sources. Other examples of balancing the grid, where the integration of RES, electricity, and transport sectors are employing vehicle to grid (V2G) technologies [7] and fuel cell vehicle to grid systems [8]. The results showed that adding electric vehicles and demand response technologies to the national energy systems augmented the integration of wind-generated electricity without the excess of electricity production. Dorotić et al. [9] showed how V2G systems facilitate the achievement of 100% renewable energy systems because they allow for a better balance between demand and power generation and reduce critical excess electricity production (CEEP). In [10], the possibility of integrating photovoltaic solar collectors into the energy system was investigated in order to reduce the emission of harmful gases produced by the system. It was concluded that the V2G integration on a large scale requires balancing technologies such as the power to heat and V2G. Flexibility with V2G systems showed excellent potential for additional power system flexibility by using heat from heat pumps, heat storages, and combined heat and power plants [11]. Authors of [12] demonstrated that the utilization of the heat pumps and storage combined with the wind-generated electricity could significantly reduce the total fuel consumption and the pollutant emissions only if heat pumps are installed. In [13], the renewable heating strategies were indicated as a crucial factor for reaching a 100% renewable energy solution and grid balancing. Kirkerud et al. [14] went even further in their work, so they defined the power-to-heat concept as an index of system flexibility to integrate renewable energy. A detailed review of coupling demand response technologies and RES in sustainable energy systems, where the interconnection between energy excess and the electric vehicles was considered, was given by [15].

Analysis of decarbonization and achieving 100% renewable energy system was performed for different countries and regions. Authors in [16] analysed the possibility of achieving a 50% renewable energy system by 2030 and a 100% renewable system by 2050 in Denmark. It was concluded that the planned system for 2030 is feasible. 100% renewable energy system by 2050 would be physically achievable through effective use of biomass, which would require reorganization of agricultural land use. Another way to achieve such a system would be through obtaining a large amount of energy from the wind, which would request to use of expensive technologies for energy vectors such as hydrogen [17] and fuel cells or any other fuel cell technology [18].

The possibility of producing electricity from renewable sources only in New Zealand was analysed in [19]. Production of electricity based on fossil fuels has been replaced by wind and geothermal sources. It was concluded that due to the isolation of the system, during periods when energy production is higher than demand, part of the wind farms would have to be switched off. An analysis of the possibility of achieving 100% renewable electricity in Portugal was carried out in [20]. It has been shown that such a system can be achieved by using hydropower and wind energy, but that some of the hydropower plants would have to be reversible. In Brazil, as in many large countries, the future of high penetration of RES in electricity production highly depends on hydropower, which also has the potential to increase export and reduce external energy dependency [21]. The paper also demonstrates the necessity of using energy storage technologies to achieve such a system. Finding the optimal scenario for achieving a 100% renewable energy system has been done in the example of Ireland [22]. First, a scenario was created in which the system was based mostly on biomass, then on hydrogen, and finally on electricity. An optimal scenario was created considering the advantages of all three scenarios individually. An analysis of the possibility of achieving 100% renewable electricity in Australia has shown that it is possible to build such a system, and no need for traditional base plants [23]. In [24], the authors performed hourly energy balance calculations for a 100% renewable energy scenario of Australia, in which wind and solar power plants supply around 90% of the yearly electricity demand, while the existing hydropower plants and biomass provide its balance. It turned out to be a much more realistic option to achieve a 50% renewable system, but that 100% renewable system by 2050 can be achieved while improving energy efficiency and reducing energy consumption. In the case of Kosovo, the procedure for increasing the integration of variable RES in coal-based energy system is introduced, where an emphasis was on using power to heat technologies [25]. Results indicate that the wind capacity of 450 MW and solar power plant capacities of 300 MW could be installed in the current energy system of Kosovo. Entirely renewable energy system based on a high share of photovoltaic (PV) in Finland was analysed in [26]. Results show that it is possible to achieve such a system feasibly even in northern latitudes. Possibility of decarbonization of Italy by 2050 was analysed in [27]. The results of the analysis showed that in addition to using renewable energy sources, their integration requires integration with other technologies such as cogeneration, trigeneration, V2G, power to heat, thermal energy storage.

In contrast to research regarding the achievement of 100% renewable national scenarios, the authors of [28] were focused on achieving net-zero emissions by determining the penetration of solar power plants in the case of Israel. The possibility of achieving a zero net carbon dioxide energy system by 2050 for the Southeast Europe region was analysed in [29]. The analysis was carried out so that biomass consumption is at a sustainable level and that no energy source participates in the production of total energy with a share greater than 30%. It was concluded that such a system at the regional level could be achieved by utilizing energy storage technologies and with good potential in the energy transfer between power and transport sectors. In [21], the authors analysed perspectives on 100% renewable energy systems, where the conclusion was that application of a cross-sectoral holistic approach and coordination of individual country studies is needed to be on global general level.

The optimal level of interconnection of the countries of north western Europe's energy systems to achieve the highest possible penetration of renewable energy sources was analysed in [30]. It was concluded that connecting the region would reduce the cost of generating electricity if renewable sources were used. Outlines of the European vision for achieving a hundred percent renewable energy system across Europe by 2050, emphasizing the economic, environmental, and social benefits of such a system, were presented in [31].

For the bottom-up simulations of the energy system, there are two different modelling approaches, optimization of the energy mix for specific scenarios and optimization of the energy transition paths [32]. For the application of such approaches, the software OSeMOSYS [33] and Markal/TIMES [33] are developed and validated. In this work, EnergyPLAN software was used for simulating different scenarios. Prina et al. [34] showed how can EnergyPLAN easily be upgraded with multi-objective optimisation. The developed model based on the multi-objective optimisation from python library DEAP was named EPLANopt, which showed great potential for determining energy efficiency costs for different buildings. An additional method is based on the dispatch model focused on the balancing and flexibility challenges employing GAMS optimisation libraries [35]. The developed method is called the Dispa-SET, which features coupled power and heating balances [36].

This paper investigates the possibility of achieving a stable, self-sustainable, and 100% renewable energy system in Montenegro by the end of 2050 to fulfil the decarbonization level foreseen in the European Green Deal. To do so, the research presents new method of scenario analysis that compares different dynamics of integrating renewable energy sources in the energy system.

2. Method

If the share of RES in the energy system is large, it is necessary to ensure that the system is flexible enough to avoid a mismatch between the time of energy production and energy consumption. The right share of different energy sources and the proper implementation of demand response technologies need to be ensured to avoid system inflexibility. That is especially important when the energy system is 100% renewable, so the transition towards such a system requires to be carefully planned. A method proposed in this research investigates different paths of the energy transition towards a 100% renewable energy system. The first pathway of the energy transition is based on the slower integration of variable renewable energy sources and demand response technologies in the initial phase of energy transition and their faster integration in the later transition period when their cost is lower. The second pathway of the energy transition is based on faster decommissioning of coal and faster integration of variable RES and demand response technologies from the initial phases of transition.

The initial step in analysing energy transition was creating a referent model for the chosen year for which actual data could be obtained. A referent model was created to verify energy consumption and generation distributions. The second step in analysing energy transition was creating a business as usual (BAU) scenario based on energy development strategy, information on ongoing projects, and collected data on energy consumption and generation distributions. The third step to analyse the different energy transition paths was creating two 100% renewable scenarios in the years 2030, 2040, and 2050. Both scenarios have different energy mixes and different levels of use of demand response technologies. Attention was given to the influence of different energy transition pathways on system costs and CO_2 emission reduction rate. Most Southeast European countries have old thermal power plants that would soon have to shut down without revitalization. Revitalization could extend the working life of the thermal power plants by about twenty years. In the first scenario of energy transition, the thermal power plant is expected to continue operating, while integrating a more considerable amount of renewable energy sources would not be easily achieved since the system profitability is significantly decreasing by its inflexibility. Higher penetration of RES in the first scenario is foreseen in the period after decommissioning thermal power plants.

In the second scenario, the revitalization of the thermal power plants is not foreseen, so electricity generation from coal was phased out before 2030. In order to compensate for the necessary electricity production, in this case, it is necessary to increase the integration of renewable energy sources. Since the second scenario has a higher share of variable RES in energy mixture, more demand response technologies must also be implemented to stabilize the system. The chosen ratio of integration of variable RES and demand response technologies is obtained by varying several different levels of installed panel power and V2G chargers' percentage from the total number of chargers for electric vehicles.

Energy system analysis for all scenarios was conducted with the EnergyPLAN model [37]. The model was developed in Denmark at the University of Aalborg and has been used in many publications for analysing energy systems [38]. EnergyPLAN can analyse and simulate national and regional energy systems for one year with a time step of one hour. The model can simulate energy systems with technical and market regulation strategies, but the technical strategy of balancing both heat and electricity has been used in both scenarios. It is considered to be more appropriate than market regulation strategies in studying the problems of balancing. A schematic diagram of the EnergyPLAN model is presented in Figure 1.

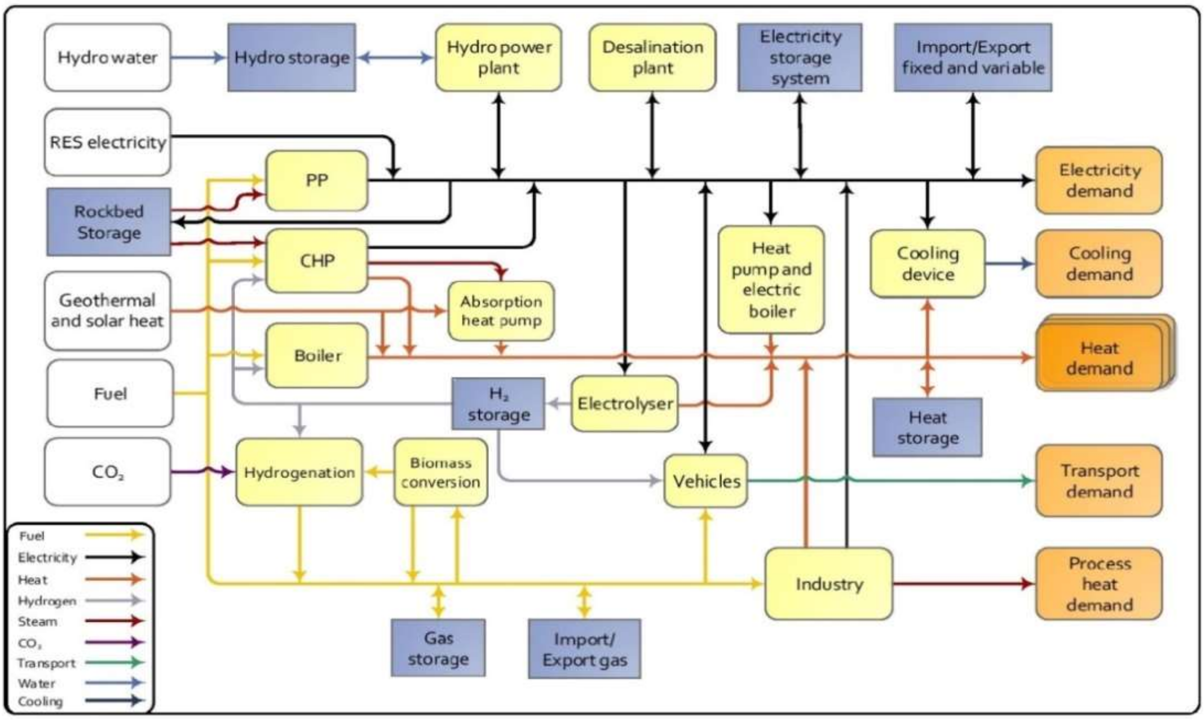

Figure 1 Schematic diagram of the EnergyPLAN model [37]

The dynamics of investments in the energy transition is estimated on the basis of the annual cost of the energy system, which can be expressed as:

$$A_{total} = A_{invest} + A_{FOM} + A_{VOM} + A_{fuel} + A_{CO2} \quad (1)$$

where
A_{total} = total annual cost of the energy system.
A_{invest} = annual investment cost of the energy system.
A_{FOM} = fixed annual operation and maintenance costs of the energy system.
A_{VOM} = variable annual operation and maintenance costs of the energy system.
A_{fuel} = annual fuel costs of the energy system.
A_{CO2} = annual energy system costs for CO_2 taxes.
Annual investment costs of the energy system are calculated as:

$$A_{invest} = \frac{I \cdot i}{1-(1+i)^n} \tag{2}$$

where
I = the investment costs found by multiplying the number of units by the cost unit for each technology (million €/MW).
i = interest.
n = the investment lifetime given in years.

Fixed annual operation and maintenance costs of the energy system are calculated as:

$$A_{FOM} = P_{FOM} \cdot I \tag{3}$$

where P_{FOM} is the annual fixed operation and maintenance costs given in percentage of the investment cost. Variable annual operation and maintenance costs of the energy system are calculated as:

$$A_{VOM} = VOM \cdot E \tag{4}$$

Where VOM stands for the variable operating and maintenance costs expressed in euros per annual energy production for all technologies, and E represents the annual energy production for all technologies. The annual cost for all types of fuel is calculated by multiplying the total annual consumption by the price of fuel, and the annual cost for CO_2 taxes is calculated by multiplying the total annual amount of CO_2 produced by the price of the tax.

3. Case study area

Montenegro is a small country placed in Southeast Europe. Like most of the countries in this region, Montenegro has many problems regarding its energy system. The main problems with the Montenegrin energy system are strong dependence on energy import, low efficiency in energy production and use, and a high percentage of fossil fuel use as primary energy. Electricity production is done in a condensing thermal power plant, supplied by domestic lignite, two large hydropower plants, two wind farms, and some small hydropower plants. Installed power capacities of existing power plants in 2020 and average annual electricity generation are presented in Table 1 [39].

Table 1 Installed power capacities of existing power plants in 2020 and average annual electricity generation [39]

Type of plant	Thermal	Large hydro	Small hydro	Wind
Installed power capacity	200 MW (one block)	649 MW (307 MW + 342 MW)	53 MW	118 MW (72 MW + 46 MW)
Average annual electricity production	1408 GWh	1816 GWh (929 GWh + 887 GWh)	87 GWh	306 GWh (195 GWh + 111 GWh)

Except for years with heavy rainfall, electricity must also be imported. Electricity peak load in Montenegro is 653 MW, while the average load is 381 MW. The highest electricity demand is in the winter, but peak loads can occur in the summer months [40]. This is due to high cooling demands and an increase in the number of tourists in summer. According to the Montenegrin Bureau of Statistic [41], 70% of road vehicles run on diesel, and there is less than 0,001% of vehicles that do not use fossil fuels. Most industrial facilities use heavy fuel oil, and there is no infrastructure for district heating. Due to this state of the energy system, air pollution is at a high level. On most days in the winter, the daily concentration of particulate matter is higher than the maximum allowed, and sometimes it gets even 7-8 times higher. Annual CO_2 emission is around 2,5 Mt [42]. If you take into account the number of citizens and almost no manufacturing industry, emissions are high. The southern part of Montenegro is placed on the Adriatic Sea coast, and the north part is placed in mountain ranges, so the climate consists of a mixture of Mediterranean and continental climates.

Renewable energy sources' potential is large relative to the country's size. According to [42], unused, technically feasible hydropower potential for building large hydropower plants is 3.7-4.6 TWh annually. The unused annual potential for mini-hydropower plants is around 400 GWh. From an economic point of view, it would be feasible for wind farms to install 400 MW wind farms [42–44]. Since 118 MW are already installed, there is a potential for installing another 282 MW. Biomass annual potential is around 3.4 TWh [42,44,45]. At the national level, the average annual number of sunshine hours is over 2000 [44]. The amount of solar radiation is 1450 kWh/m^2 per year [42], which means that there is a large potential to use solar power for heating and electricity production.

4. Modelling scenarios of the energy system

In this section, the definition of referent scenarios and alternative scenarios for the years 2030, 2040, and 2050 is demonstrated, with a detailed explanation of input parameters for the EnergyPLAN model.

4.1 Reference scenario for the year 2015

Reference scenario for 2015 was created for validation of model and distributions of energy consumption and generation. The installed capacity of hydropower plants in 2015 was 649 MW, and the installed capacity of the thermal power plant was 200 MW [39]. Fuel consumptions were obtained from [41], and power load distribution was obtained from [40]. Hourly power load distribution is presented in Figure 2.

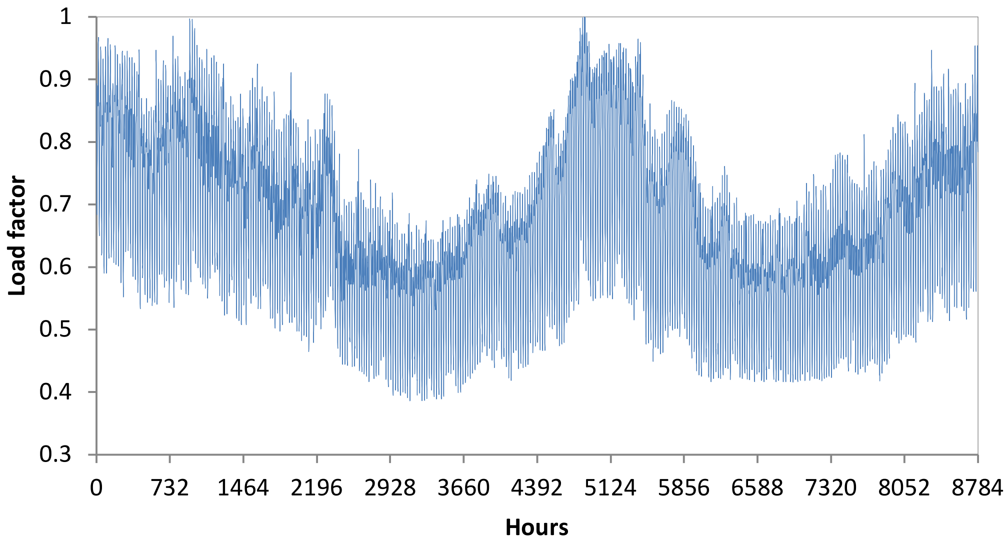

Figure 2 Hourly power load distribution for Montenegro in 2015 [39]

From Figure 2, the electricity demand is highest in the heating season, which is expected. Still, a significant jump in load, even the maximum load, occurs in one part of the summer season. That can be addressed to the energy needed to cool the facilities, especially in the central and southern part of the country, and the massive increase in the number of tourists and thus the increased work of hotels and restaurants.

4.2 Business as usual scenario for the year 2030

BAU scenario for the year 2030 was created by expanding the reference scenario and based on Montenegrin Energy Strategy for the year 2030 [42] and information on ongoing projects. The expected rise in electricity demand from the year when the strategy was made (2015) to 2030 is from 10.32 PJ to 15.72 PJ. The total increase in energy demand was expected to be from 32.18 to 46.38 PJ, with the highest growth in the transport sector (diesel and jet fuel). Strategy predicted building another thermal plant block, but the government has abandoned that idea, so total installed thermal power plant capacity was modelled to be 200 MW. In addition to two existing large hydropower plants, it was planned to build two more, which would give a total installed capacity of 1059 MW in large hydropower plants. The total installed capacity of small hydropower plants was predicted to be 107 MW. The installed capacity of wind farms was planned to be 190 MW. Although the strategy did not foresee this, the construction of a photovoltaic power plant with an installed capacity of 250 MW was started, so it was included in the model.

Hourly wind velocities and solar radiation used to create distribution curves for wind and solar plants were provided by the METEONORM program [46]. The distribution curve for district heating was created by the degree-day method, and the hourly temperature distribution provided by the METEONORM program.

Investment, fixed, and variable operating and maintenance costs for new energy units have been obtained from [47–50]. Annual costs of V2G chargers in 2030 have been obtained from [51]. Prediction in this report is that the decline in V2G charger cost will be proportional to the decline in PV inverter cost, so the annual costs for V2G chargers in 2040 and 2050 are assumed in the same way. It was assumed that the annual cost for standard chargers would be twice as low as the cost for V2G chargers. Assumed annual costs of electric vehicle (EV) charges are presented in **Table 2**.

Table 2 Annual costs of EV chargers

	2030	2040	2050
V2G charger [€/unit]	400	315	245
Standard charger [€/unit]	200	157	123

Taxes for CO_2 emissions were set up to be 30 €/t. Predicted fuel costs for the years 2030 and 2050 were obtained from [52]. For the year 2040, fuel prices were calculated as the median price between 2030 and 2050. Operational and maintenance costs were accounted for existing and new plants, but investment costs were accounted for only for the new plants. Emission factors of CO_2

for different types of fuels were obtained from [53]. Fuel prices and CO_2 emission factors are presented in **Table 3**.

Table 3 Fuel prices and CO_2 emission factors

	Crude oil	Coal	Fuel oil	Diesel	Petrol	N. Gas	LPG	Biomass
CO_2 content in fuels [kg/GJ]	-	101.2	74	74	74	56.7	66.7	-
2030 fuel prices [€/GJ]	20.93	4.53	17.78	22.02	25.04	12.25	17.6	3.8
2040 fuel prices [€/GJ]	27.9	6.41	24.25	28.45	31.74	17.34	22.23	5.53
2050 fuel prices [€/GJ]	34.88	8.29	30.71	34.88	38.02	22.43	26.86	7.06

4.3 First alternative scenario for the years 2030, 2040 and 2050

In the first alternative scenario for the year 2030, no changes were made regarding power plants as electricity production in the BAU scenario matches the first energy transition pathway requirements. Most of the changes made are related to energy efficiency in buildings and transport sector. In [47], it is assumed that the increase in population in the future will be insignificant, which means that economic development would have the most significant impact on the future increase in primary energy consumption. It is assumed that the implemented energy efficiency measures in 2040 and 2050 will be sufficient to increase electricity that would come with economic development. Still, total electricity consumption would increase due to the electrification of transport and heating sectors. It was also assumed that energy efficiency measures would be enough to level the possible increase in heating demand in the southern and central regions of the country. Although it is expected that the development of the northern region, where winters are much colder and more prolonged, will further increase heat demand. New energy production units in 2040 and 2050 were gradually introduced to the system based on energy consumption in that year, their predicted cost in that year and the state of the energy system from the previous analysed year. Actions taken in the modelling system for all three years are presented below.

Actions taken in modelling the first alternative scenario for 2030:

- Reduction of heat demands in the building sector by 10%
- Replacing coal and oil boilers in buildings with heat pumps
- Replacing 10% of gas and biomass boilers with heat pumps
- Reduction of diesel and petrol consumption by 10% with a renewal of the fleet
- Replacing 10% of light road vehicles with electric vehicles
- Reduction of industrial fuel oil consumption by 20%
- Reduction of electricity consumption by 10%

Actions taken in modelling the first alternative scenario for 2040:

- Installation of another 110 MW wind turbines
- Installation of 156 MW large hydropower plant
- Installation of CHP plants with annual heat production of 400 GWh and power capacity of 20 MW
- Replacing 60% of individual gas and 30% of individual biomass boilers with a combination of heat pumps and solar collectors
- Replacing 30% of industrial fuel oil consumption with electricity
- Replacing 60% of regular diesel consumption from heavy-duty vehicles with biodiesel
- Replacing all petrol and 50% light vehicles with electric cars
- Increase of heat demand by 480 GWh and electricity demand by 15%

Actions taken in modelling the first alternative scenario for 2050:

- Installation of another 100 MW wind turbines
- Installation of another 350 MW PV panels
- Doubling of CHP plants capacity and coupling them with 60 MW biomass boilers and 40 MW electric boilers
- Replacing the rest of the gas and 60% of biomass boilers with heat pumps and solar collectors
- Replacing the rest of the regular diesel consumption from heavy-duty vehicles with biodiesel
- Replacing half of the diesel for the light vehicles with hydrogen and half with electricity
- Replacing jet fuel with bio-jet fuel
- Increasement of heat demand by 400 GWh and electricity demand by 12%

4.4 Second alternative scenario for the years 2030, 2040 and 2050

As already described in the method, in this scenario, the thermal power plant was decommissioned from the beginning, and the required electricity was compensated by greater integration of PV panels and demand response technologies. The reason why only PV panels were considered and not wind turbines is the small wind potential, only 400 MW, half of which has already been used in the BAU scenario, so dynamics of wind integration remained the same as in the first scenario. Energy consumption is projected to remain at the same level as in the first scenario for all modelled years. Given that the winters are very mild in the part of the territory where most of the population of Montenegro lives and that there is no infrastructure for district heating, it would not be profitable to build a large number of district heating plants, and therefore the power to heat technologies could not play a significant role in balancing the system. Due to this fact and price projections of different demand response technologies, it was decided that V2G technologies would have the most significant role in balancing the system. The optimal ratio of PV panels and V2G technology is obtained by varying different levels of installed PV power and the percentage of V2G chargers from the total number of chargers for electric vehicles. Compared to the first scenario, no changes are foreseen in the heating sector, and in the transport sector, the only change was the replacement of part of standard chargers with V2G chargers. Installed power capacities for 2030, 2040, and 2050 of all sources except PV are presented in **Table 4**.

Table 4 Installed power plants capacities in the second alternative scenario

	2030	2040	2050
Large hydro [MW]	1,059	1,059	1,059
Small hydro [MW]	107	107	107
Wind [MW]	190	300	400
CHP [MW]	0	20	40

5. Results and discussion

In this section, after the performed model validation is shown, the results of two different energy transition pathways for the years 2030, 2040, and 2050 and referent scenarios are demonstrated. A particular focus is given on their technical, environmental, and economic aspects.

5.1 Model validation for the reference scenario

Data on several parameters obtained from the simulation results were compared with the actual data to validate the model of the reference scenario in 2015. Actual data is taken from [1], [39] and [41]. Data comparison is presented in **Table 5**.

Table 5 Data for model validation

	Model	Actual	Difference [%]
Thermal power plant [GWh]	1,590	1,512	4
Total electricity [GWh]	3,080	3,003	2
CO_2 emissions [Mt]	2.67	2.53	5

Based on a small difference between actual data and data from the model, it can be concluded that the model is valid.

5.2 Installed PV capacity and V2G share in the second alternative scenario

Since the share of variable RES in the energy mix would not be very high in 2030, no demand response technologies would be necessary to balance the system. The criteria for selecting the installed capacity are the annual CEEP of less than 5% and the least necessity of importing electricity. Annual electricity import and CEEP in the scenario for 2030, for different levels of installed PV power, are presented in Figure 3.

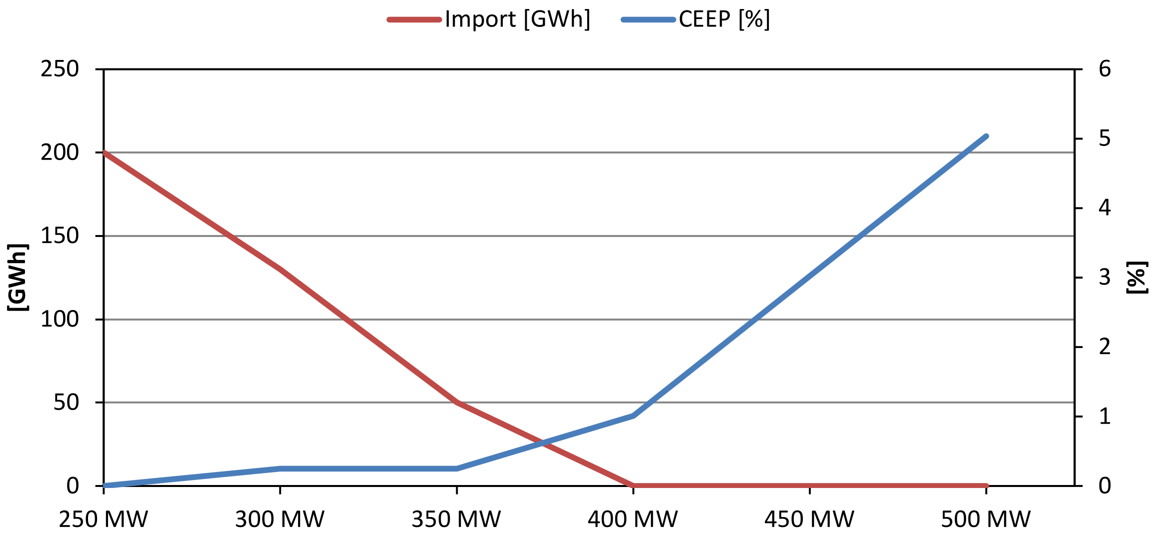

Figure 3 Annual electricity import and CEEP in 2030 for different levels of installed PV power

It can be seen from Figure 3 that the import of electricity would not be necessary only if the installed power of the PV was 400 MW or more. With installed PV power higher than 400 MW, there would be an increase in total investment, operational and maintenance cost for energy system. The annual CEEP would also be higher in these cases. Due to all the above, it was chosen that the installed PV power in 2030, in the second scenario with faster integration of RES into the energy system will be 400 MW. Similar CEEP reduction with high RES penetration was also observed for countries that highly depend on the coal power plants, such as in the case of Kosovo [25].

In order to balance the grid in the scenario for 2040, it was necessary to implement V2G technologies. Given that the projected prices of V2G chargers are higher than the projected prices of standard chargers, it is necessary to find the best ratio between the installed power of PV panels and the percentage of V2G chargers in relation to the total number of electric vehicle chargers. Criteria for selecting the optimal ratio between the installed capacity of PV panels and the percentage of V2G chargers are the annual CEEP of less than 5% and the least necessity of importing electricity. CEEP and annual electricity import in 2040 for different installed PV power and shares of V2G chargers are presented in Figure 4 and Figure 5, respectively.

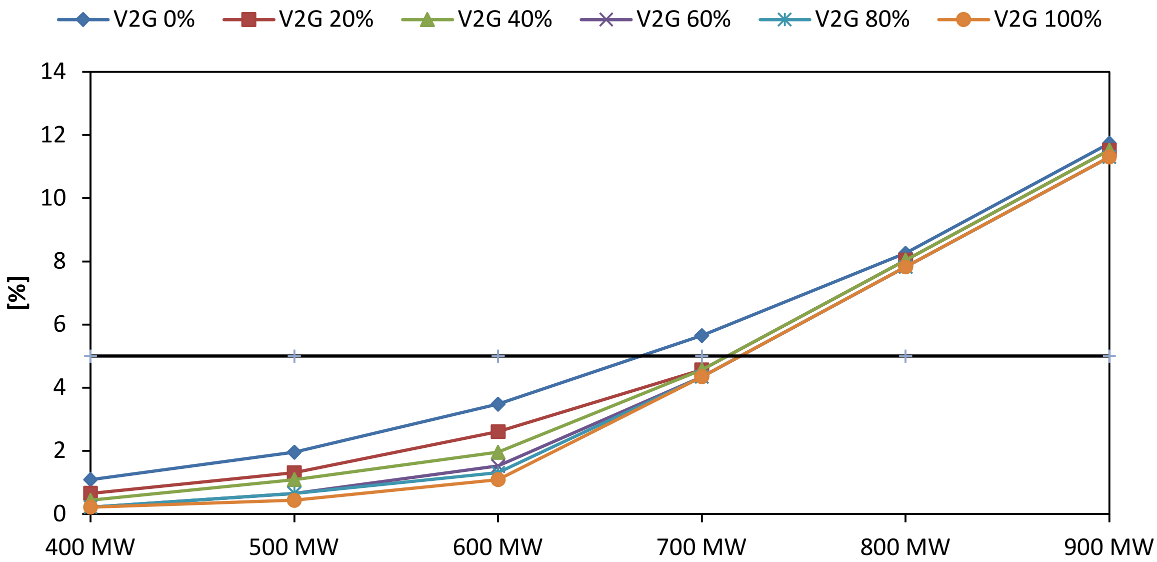

Figure 4 CEEP in 2040 for different levels of installed PV power and shares of V2G

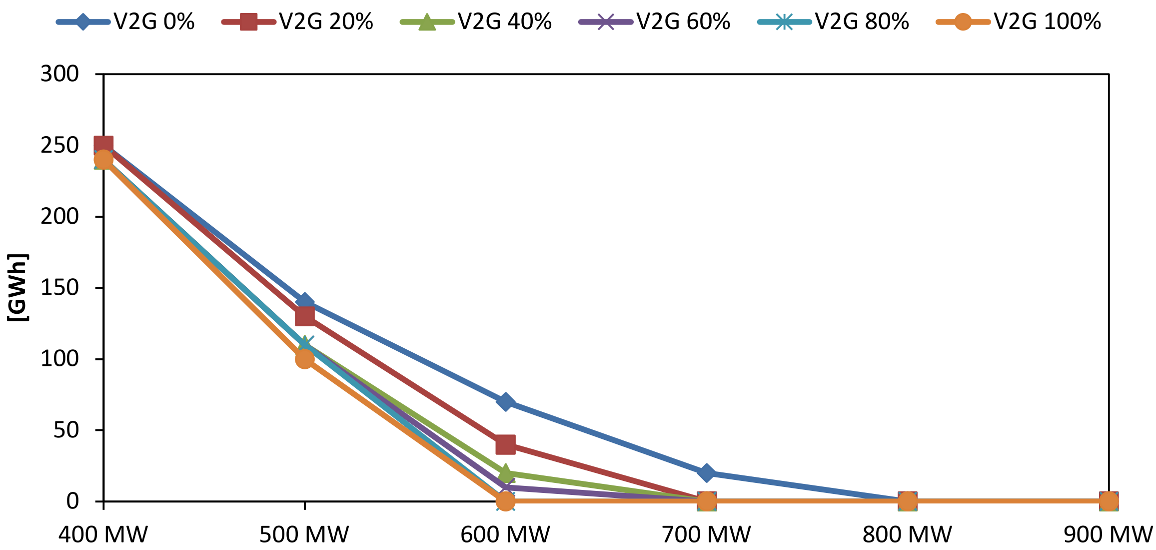

Figure 5 Annual electricity import in 2040 for different levels of installed PV power and shares of V2G

Based on the data presented in Figure 4 and Figure 5, it can be concluded that seven different ratios meet both criteria, CEEP less than 5% and no electricity imports required, all the ratios with 700 MW PV coupled with 20% or more V2G share and 600 MW PV coupled with 80% and 100% V2G share. Considering price projections for both PV and V2G the optimal ratio would be the one with 700 MW PV panels and 20% share of V2G chargers due to the lowest cost.

The best ratio between the installed power of PV panels and the percentage of V2G chargers in relation to the total number of electric vehicle chargers in the scenario for 2050 was analysed and selected in the same way as in the scenario for 2040. CEEP and annual electricity import in 2050 for different installed PV power and shares of V2G chargers are presented in Figure 6 and Figure 7, respectively.

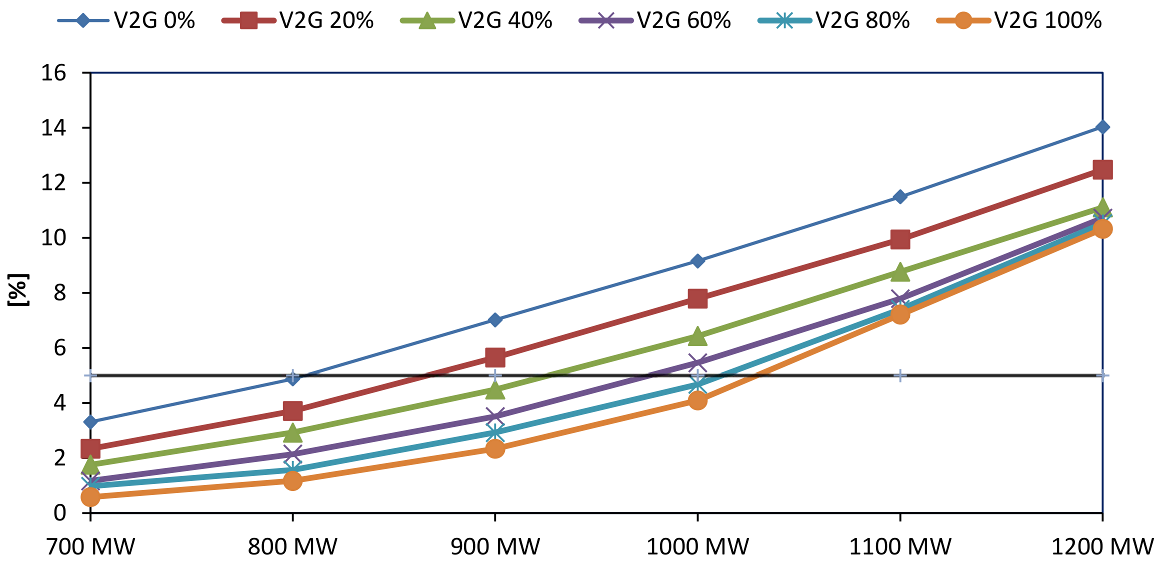

Figure 6 CEEP in 2050 for different levels of installed PV power and shares of V2G

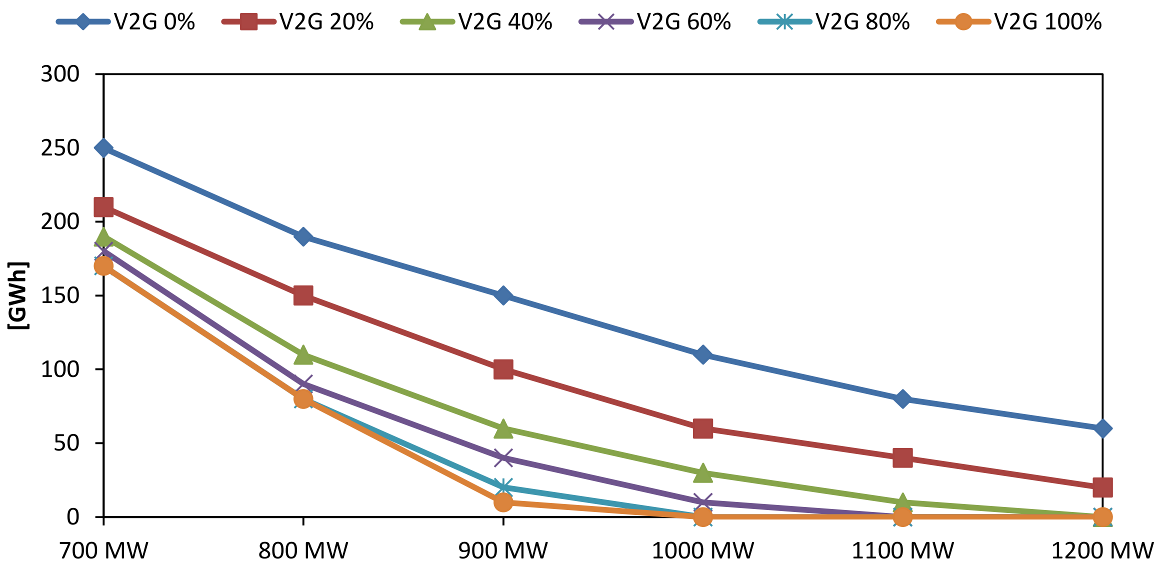

Figure 7 Annual electricity import in 2050 for different levels of installed PV power and share of V2G

Based on the data presented in Figure 6 and Figure 7, it can be concluded that the best ratio would be the one with 1000 MW PV panels and 80% share of V2G chargers. That is one of two ratios that meet both criteria, CEEP less than 5% and no electricity imports required. Since less

V2G is used in this ratio, system cost would be lower; therefore, it is more favourable for implementation.

5.3 Comparison of technical aspects in different scenarios

This section outlines the technical aspects of the energy system in different scenarios. Technical aspects being considered are primary energy supply (PES) and electricity generation. The primary energy supply and expected energy consumption for different scenarios is presented in Figure 8.

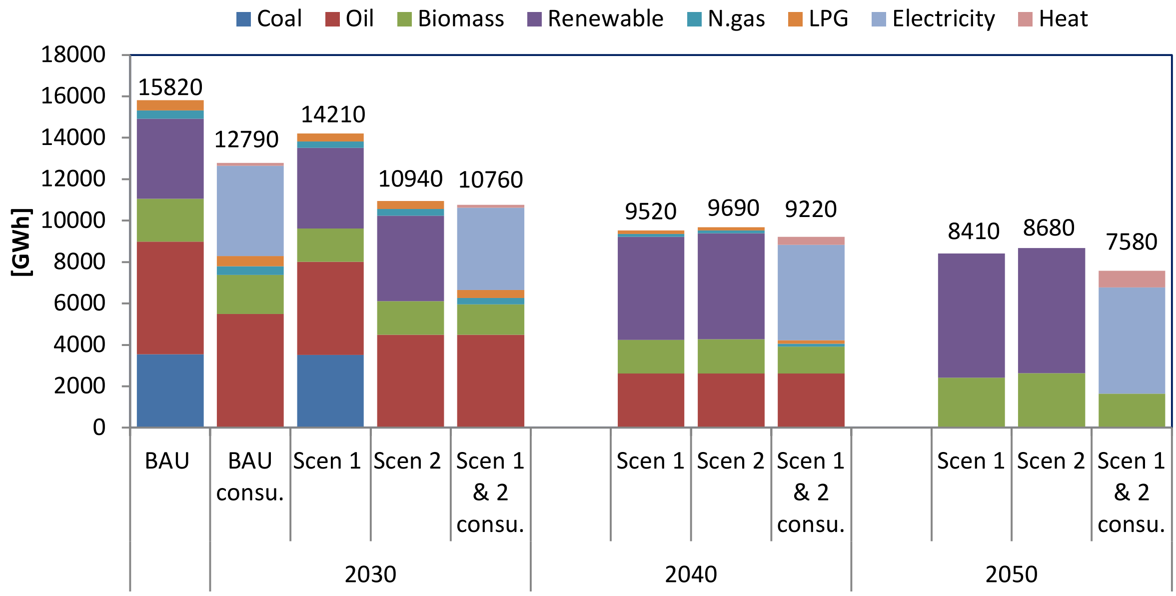

Figure 8 Primary energy supply and expected energy consumption in different scenarios

PES in the first alternative scenario, compared to the BAU scenario for 2030, is lowered by 10% due to implemented energy efficiency measures. In the second alternative scenario, PES is reduced by 24% compared to the first alternative scenario due to the decommissioning of the thermal power plant. In the first scenario for 2040, PES is lowered by 33% compared to the first alternative scenario for 2030. This is mainly due to the decommissioning of the thermal power plant and the increase in traffic electrification. In the second scenario, for 2040, PES is 100 GWh higher than in the first scenario because of higher electricity production from RES. In the first scenario for 2050, the total PES is 8,410 GWh, 47% lower than 15,820 GWh in the BAU scenario. The amount of biomass in PES for the first fully renewable scenario is 2,420 GWh, and the rest is made up of hydro, wind, and solar energy. In the second scenario for 2050, PES is 270 GWh higher than in the first one due to slightly higher electricity production from RES and 210 GWh higher biomass consumption. In both 100% renewable scenarios, biomass consumption is sustainable since the annual potential of the country is 3,400 GWh.

In both the BAU and the first alternative scenario for 2030, the annual electricity production is 4,820 GWh since no changes have been made in power plants between the two scenarios. After decommissioning the thermal power plant in the first scenario and installing new production capacities based on renewable sources in the 2040 scenario, total electricity production is reduced to 4,670 GWh. Even though electricity production had been reduced, it could still meet system demands. In the second scenario for 2040, the total electricity production is higher than the first scenario by 150 GWh. Electricity production from hydropower is lower in this scenario, but electricity production from PV panels is higher. In the first scenario for 2050, after installing new wind, PV, and CHP capacities, the total annual electricity production was 5,560 GWh. Total annual electricity generation in the second scenario for 2050 is higher than the first scenario by 100 GWh. Electricity generation by source for different scenarios is presented in Figure 9.

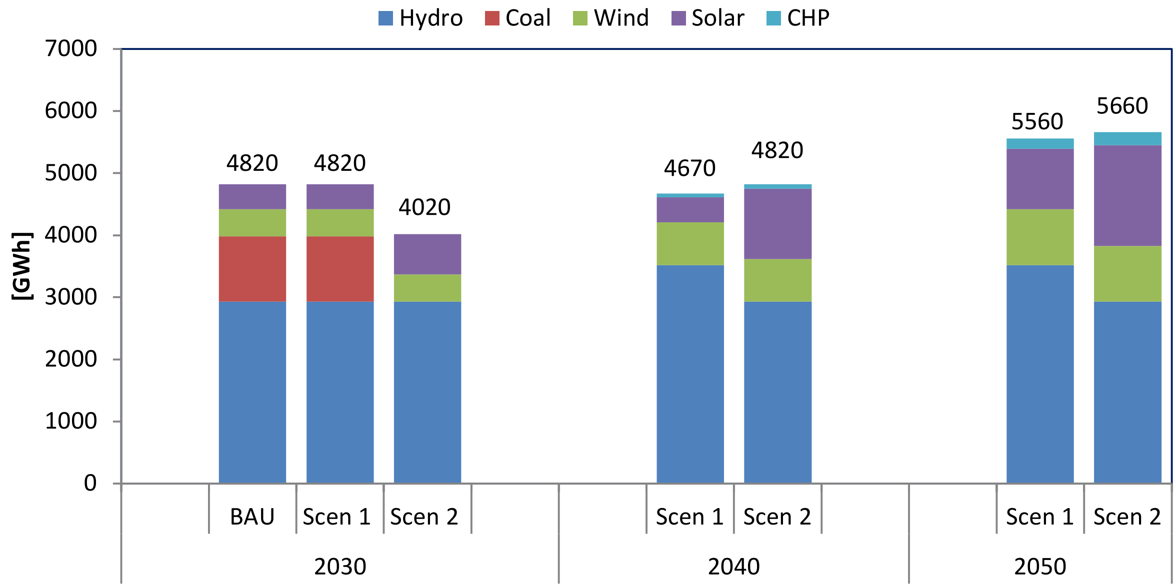

Figure 9 Electricity generation by source in different scenarios

5.4 Comparison of environmental aspect in different scenarios

This section presents annual CO_2 emissions for different scenarios. Implementation of energy efficiency measures in the first alternative scenario for 2030 reduced annual CO2 emissions for 11% regarding BAU scenario. In the second alternative scenario for 2030, CO_2 emission is almost 50% lower than in the first alternative scenario due to thermal power plant decommissioning, which is useful if the goal is to reduce the emissions as soon as possible. Annual CO_2 emissions in both 2040 scenarios are the same (0.76 Mt) since electricity generation in both systems is entirely renewable. The amount of fossil fuels used in other sectors is the same. After total decommissioning of fossil fuels, the energy system reached zero CO2 emissions in both fully renewable scenarios. Annual CO_2 emissions in different scenarios are presented in Figure 10.

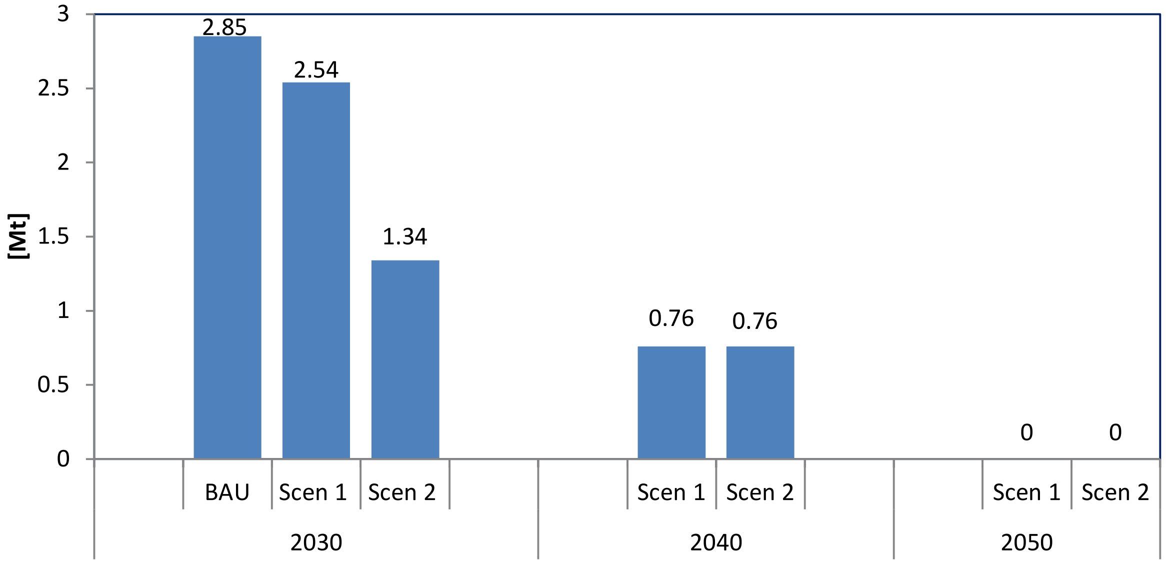

Figure 10 Annual CO_2 emissions in different scenarios

5.5 Comparison of economic aspect in different scenarios

This section presents the annual energy system costs for different scenarios. The costs are divided into four groups: fuel costs, investment costs, operational and maintenance costs, and CO_2 emission taxes. Costs of the energy system for different scenarios are presented in **Figure 11**.

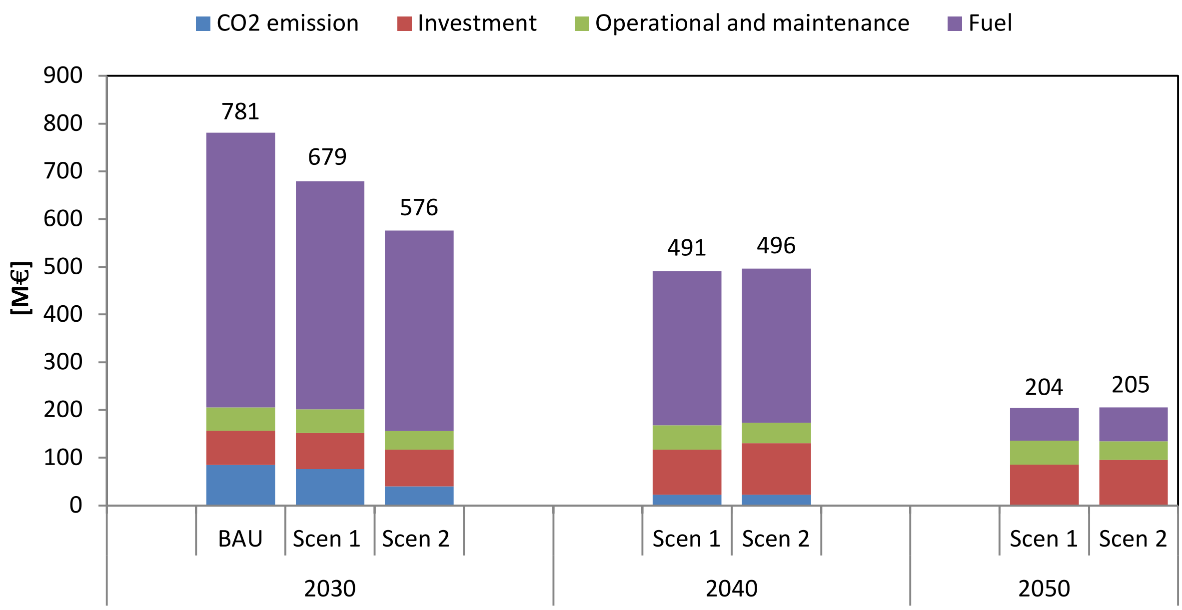

Figure 11 Annual costs of energy system in different scenarios

As a result of the energy efficiency measures applied in the first 2030 alternative scenario, fuel consumption has been reduced, reducing fuel costs and CO_2 emission taxes compared to the BAU scenario. Although the investment costs in the second alternative scenario for 2030 are slightly higher than in the first one, due to phasing out of the thermal power plant, all other costs have decreased, especially the costs for fuel and CO_2 emissions. Compared to the first alternative scenario for 2030, in the first 2040 scenario, investment and operational and maintenance costs are increased, but the fuel costs and CO_2 emission taxes have been reduced, so a total system cost has been reduced to 491 million euros annually. In the second scenario for 2040, the total system cost is 5 million euros higher than in the first scenario due to the higher investment cost necessary for the implementation of V2G. In both 2040 scenarios, investment costs were higher than in 2030 and 2050. Since fossil fuels were completely decommissioned in both 2050 scenario, there were no costs for CO_2 emission taxes. In both scenarios for 2050, total annual system costs were much lower than in alternative scenarios for 2030 and 2040 and more than 70% lower compared to the reference scenario.

Although the costs of the scenario with faster integration of renewable energy sources and demand response technologies are slightly higher in 2040 and 2050 than in the first scenario, the total costs for the entire energy transition period would be lower in this scenario due to significantly lower system costs in 2030. A similar effect was also observed for the energy system of North Macedonia, where the operation cost was increased with the high penetration of RES [53]. Total scenario costs for both 100% renewable scenarios are presented in Figure 12.

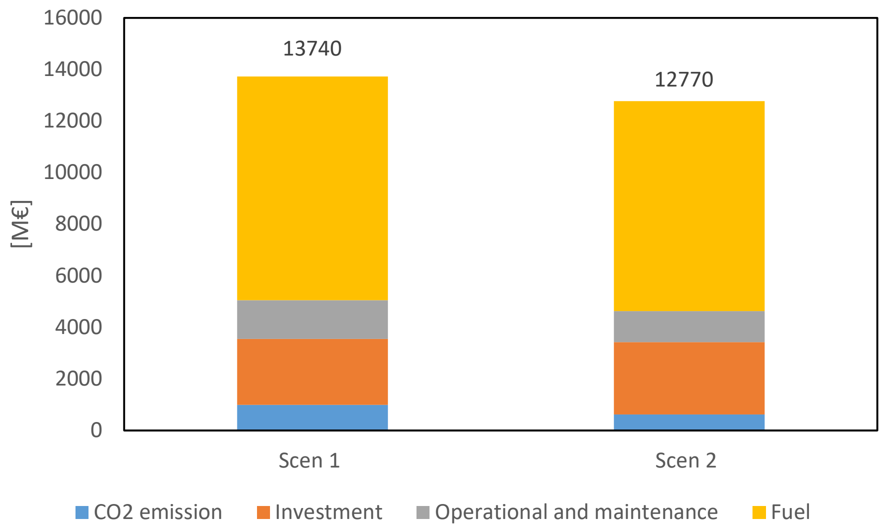

Figure 12 Total scenario costs

6. Sensitivity analysis

In the case where hydropower plants have a dominant share in electricity production compared to any other source individually, sensitivity analysis has to be done. In the first 100% RES scenario, hydropower has a share of 60% in electricity production, and in the second scenario, 52%, so the analysis was done for both of those scenarios. According to data from [1], the lowest generation of electricity from hydropower plants in the last 15 years was 40% lower than the average. The analysis was done for this situation. The most important parameters for sensitivity analysis are presented in **Table 6**.

Table 6 Important parameters for sensitivity analysis

	First scenario 2050	First scenario 2050 40% less hydro	Second scenario 2050	Second scenario 2050 40% less hydro
CO_2 emission [Mt]	0	0	0	0
Biomass consumption [TWh]	2.56	2.87	2.63	2.93
Excess electricity [GWh]	160	60	230	190
Electricity import [GWh]	0	470	0	180

In all situations, it is clear that the system would be carbon-free. In the extremely dry year, biomass consumption would increase from 2.56 to 2.87 TWh in the first scenario, from 2.63 to 2.93 in the second scenario, which is still sustainable in both cases since the country's annual potential is 3.4 TWh. In the first scenario, the system would go from having an excess production of 160 GWh in the average year to having an excess of 60 GWh and a shortage of 470 GWh in an extremely dry year. This should not be a problem, since the shortage is only 8% of total electricity demand and it can happen very rarely so it can easily be imported. Furthermore, if the year is dry, there will be more sunny hours and more solar radiation, which will cause an increase in PV and thermal solar production. In the second scenario, in an average year, the system would have an excess electricity production of 230 GWh. In an extremely dry year, it would have 190 GWh of excess electricity and a 180 GWh shortage due to a mismatch of production and demand, which would leave space for the implementation of additional demand response technologies. If the data obtained from sensitivity analysis is considered, the second scenario would be preferred. It is less sensitive to a dry year, and that the need for energy imports would be lower, so the system costs would be lower.

7. Conclusion

In this paper, the possibility and dynamics of the energy transition towards a 100% renewable and decarbonized energy system in Montenegro were analysed. The analysis was performed by comparing two scenarios with different dynamics of integration of RES. In the first scenario, integration of variable renewable energy sources and demand response technologies is slower in the initial phase of energy transition, but it becomes faster in the later transition period with falling technology prices and after the decommissioning of the thermal power plant. The second scenario is based on faster decommissioning of coal and faster integration of variable RES and demand response technologies from the initial phases of transition. In both scenarios, results showed that it would be possible to achieve a 100% renewable system with energy efficiency measures, energy storage systems, synergies with the transportation sector, and balancing through demand response. Annual biomass consumption of such a system in the first scenario would be 2.56 TWh, and in the second scenario would be 2.63 TWh. Given that the country's annual biomass potential is 3.4 TWh, biomass consumption would be sustainable in both scenarios. CEEP of the decarbonized system in the first scenario would be 2.9% of the total annual electricity generation, which is less than an economic limit of 5%. In the second scenario, the annual CEEP would be 4%, which is still within the acceptable limit. Economic analysis showed that the first scenario would have slightly lower annual costs in 2040 and 2050 but would have higher total costs than the second scenario.

In both scenarios for 2050, the installed power capacity of wind turbines is 400 MW, which is Montenegro's maximum estimated potential according to current studies. Hydropower plants are the primary energy source in both scenarios, with 60% in electricity production in the first scenario and 52% in the second scenario. This can create the risk of energy shortages in dry years. Sensitivity analysis showed that even in an extremely dry year, biomass consumption would still be sustainable in both scenarios. The necessary electricity import would be 8% of total electricity demand in the first scenario and only 3% in the second scenario, which could easily be imported.

Based on a comparison of the obtained data for both scenarios, it turns out that in the case of Montenegro, the energy transition path with faster integration of RES would be favourable over the one with slower integration of RES. For the faster integration of RES, CO_2 emissions would be reduced sooner, and the total costs of energy transition would be lower, and the system would be less sensitive to drought. Given the comparative data, it is clear that the second scenario with faster integration of RES into the energy system would be more favourable for Montenegro, provided that the loans necessary for the construction of the plants could be obtained, because investment costs in the second scenario are higher than investment costs in the first scenario.

Since Montenegro doesn't have an official strategy for the inevitable energy transition, a fast and responsible legislative decision-making and a proactive approach will be crucial for achieving carbon neutrality. This study showed that the shutdown of the thermal power plant should be considered as early as 2030, which is earlier than the official plans of the country. Since the accelerated energy transition would require higher investment costs, raising loans for the construction of RES power plants and supporting infrastructure should already be planned. In order to facilitate the energy transition for Montenegrin citizens, the government should introduce financial incentives for the purchase of electric vehicles and the installation of PV panels on the roofs of households.

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