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Article

Modelling System Generation: Towards the New Model in Albania and SEE Countries

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Abstract: The electricity utility industry is undergoing rapid and irreversible changes resulting from volatile fuel costs, transmission access, less predictable load growth and a more complex regulatory environment. Due to the rising importance of renewable (and variable) energy sources, power systems are now more vulnerable to uncertainties and intermittent in supply. Hydropower plays an important role in the energy mix and power market, helping in providing base and peak load power as well as being the 'fuel' (water) not subject to fluctuations in the market; these paving the way toward a clean energy by 2030 and net-zero emissions by 2050 as part of de-carbonization agenda. All production and conversion processes in the energy sector require Water for nearly including fuel extraction and processing (fossil and nuclear fuels as well as biofuels) and electricity generation (thermoelectric, hydropower, and renewable technologies). This paper's objective is to analyze cross-border trade in SEE through economic electricity exchange, while also exploring reasons for promoting Hydroelectricity. This is achieved through the following objectives: first, an overview is made of the available energy and economic data in the region; second, a model is developed for regional least cost expansion planning when allowing for cross-border trade. These aim to assess electricity supply and demand in the region with the purpose of making a comparative analysis regarding energy resource endowments.

Keywords: electricity industry; regulatory environment; energy efficiency

1. Introduction

The agreement between Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Greece, Macedonia, Kosovo, Romania, Serbia, and Montenegro to develop a regional electricity market marks a significant development in the Southeast European energy sector. Benefits would arise from competition and coordination in a regional electricity market considering the diverse resources of the countries involved, differences in demand shapes and the possibility of sharing capacity reserves.

In this context, the concept of a Balkan Benelux has been developed regarding regional energy cooperation and views on the Western Balkan six (WB6) countries initiative: Albania, Bosnia and Herzegovina, Kosovo, Macedonia, Montenegro, and Serbia. One key issue is the regional electricity balance and the potential for cross-border trading between the countries in the region. Benefits would be displayed in the form of energy stability and lower end-user prices for a given level of system security. On 27 April 2016, the transmission system operators, national regulatory authorities, energy ministries, and power exchanges of the WB6 countries signed a memorandum of understanding (MoU) [1]. In 2018, the MoU signatories agreed to implement day-ahead market integration between the six countries, aiming to achieve market coupling of national day-ahead markets

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with at least one neighbouring WB6 or EU country and cross-border balancing cooperation between the WB6 countries.

2. Overview of SEE Countries' Economic, Energy and Power Sector Outlooks—A Comparative Analysis

There is a need to understand the geopolitical and geographical aspects within which the SEE countries operate economically, but also to define and evaluate in an objective manner the major policy challenges of the energy sector in the region. The main challenge is to bring together the latest available knowledge on energy developments in the region and provide comprehensive data on energy demand, system characteristics, market integration and cross-border exchange between the Balkan countries. The paper also assesses the status of the energy market and provides insight into future developments. In the framework of regional integration in SEE where the development of economic relations and co-operation is based on mutually beneficial policies, the energy sector would serve as their common denominator. Energy data for the region, which include the primary energy supply for each country, are of interest to understand the region's diverse energy outlook as well as the role and the benefits of Hydropower in the region. This is characterized not only by market disparities in terms of population, economic development, and energy infrastructure (e.g. installed electricity capacity, gas use, oil consumption) but also by the region's great dependence on energy imports. Electricity demand depends on the population and production level of a country; therefore, it follows that these factors would impact cross-border electricity exchange between the regional countries. In this context, being Albania the only country in the region dependent on hydropower for electricity generation, as well as entirely dependent on environmental factors. Under investigation [2] shows that there has been a general decrease in populations in the Balkan countries with few exceptions, such as Montenegro and Macedonia, which have relatively small populations anyway. The reason for the general trend could be falling birth rates directly affecting the population growth rate. Moreover, migration from the region has been continuous.

Regarding the GDP trends, in reference [2] data indicate that despite growth from 2000, the financial crisis in 2008 caused and the pandemic in 2020 and the crisis of energy prices causing a steep fall in economic activity followed by a slow recovery of GDP.

According to reference [3], hydropower is the cheapest renewable energy source and is often economically competitive with current market energy prices. It requires relatively high initial investment but has a long lifespan with very low operation and maintenance costs as will be shown in the following sections. Hydropower has the best conversion efficiencies of all known energy sources (about 90% efficiency, water to wire). Hydropower also shows high reliability, flexibility, and variety in project scales and sizes, which gives it the ability to meet large centralized urban and industrial needs as well as decentralized rural needs, this is the case in Albania. Geographical aspects affect national energy systems. The Balkan region's geopolitical location, positioned amidst energy transportation routes, places it as a transit hub between Europe and other energy-rich regions. Despite the abundance of water and forest resources in the area, the Balkan countries are not considered wealthy in terms of energy resources or power generation technology, particularly when compared to the major oil and gas suppliers to central and western Europe—such as the countries in the Caspian basin, the Middle East, and North Africa [4]. However, these nations are experiencing a growing demand for power and energy, necessitating the need for cost-effective, reliable, and long-term resources to meet their needs. This demand is reflected across the entire Southeast Europe region, which serves as a significant importer of natural gas, oil, and electricity in certain countries [4,5]. These circumstances put countries like Albania, at a disadvantage in terms of natural gas import prices. However, as will be elaborated below, some countries are able to expand their electricity production beyond domestic needs, transforming them into net energy exporters, relying on further development of new hydropower plants having an important role in future mitigation scenarios of climatic change, within the framework of agenda 2050. Moreover, SEE countries possess substantial reserves of coal or lignite. Studies on the construction of thermal power plants in the region have so far given priority to plants using local cheap coal or lignite due to reliability of supply and lower generation costs [6,7].

The SEE region is rich in diverse sources of power generation the two main types being thermal and hydro. Figure 1 shows a more detailed picture of the different technologies and primary energy sources used for producing electricity. This indicates that these countries rely on different fuels for electricity production. In creating a common pool between Albania, Kosovo, Macedonia and Montenegro, the cost differences should be taken into consideration in the analysis of the least cost expansion model. Hence, the cost of each of the regional power generators should be considered when calculating the common regional long-run marginal cost.

Thermal electricity generation is dominant in almost all the countries, making the whole region highly dependent on this source of energy. Hydropower plants dominate in Albania but constitute a very small percentage of power supply in Kosovo. In Macedonia and Montenegro, the shares are about 10% and 40%, respectively. Other renewable sources are used only in a few countries, such as Bulgaria, Greece and Romania. Energy produced from nuclear plants accounts for a large share in Bulgaria (almost 25% of energy produced), Romania and Slovenia [8]. Installed renewable energy capacity in southeast Europe is explained in more detail in the following figure. As can be seen, 80% is hydro and about 20% is shared equally between wind and solar.

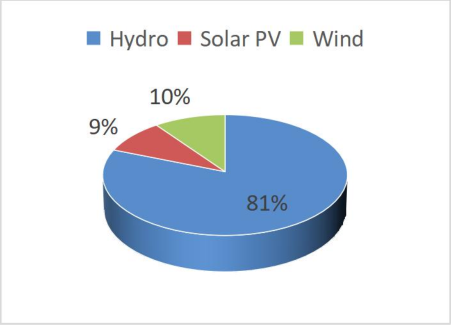

Figure 1. RES capacity mix in SEE (2020). Source: [9].

As the SEE renewable energy sector (RES) outlook (2020) states, the electricity sector and its further expansion constitute the backbone of the region's economic and energy development. Furthermore, the regional electricity mix is diverse as the primary fuel for power generation varies considerably from country to country. In the western Balkans, hydropower and coal (i.e. lignite) serve as the foundation for power generation, while Albania relies almost entirely 100% on hydro while Kosovo depends entirely on 100% on lignite. Considering all the potential sources for power generation in Kosovo, the lignite mines are operated at one of the most favourable lignite deposits in Europe due to their geological conditions. With an average stripping ratio of 1.7 m3 of waste to 1 ton of coal, lignite production at Kosovo mines can supply very competitive fuel to the power plants compared with international fuel sources and energy prices [10]. The other countries operate on a mix of oil, gas and lignite. Lignite is also a strategic and dominant energy source for Serbia and Macedonia (see Figure 2), where the open-cast mines contribute to the countries' stable and secure energy supply. Hence, local and comparatively inexpensive lignite remains one of the primary fuels for power generation in the ongoing long-term development plans for the Southeast European (SEE) region. Local and comparatively cheap lignite, therefore, remains one of the main fuels for power generation in current long-term SEE development plans. In Albania, almost all energy is generated from hydropower. Figure 2 shows the energy resources that are used to generate electricity in Albania [11]. Hydropower has historically been relatively cheap but unreliable as it depends on uncertain hydrology. Hydroelectricity is a renewable resource, that makes it feasible to utilize other resources, promotes energy and price stability, contributes to the storage of drinking water, increases the stability and the reliability of electricity systems, helps fight climate change and improves the air breathe. Diversification of resources should be sought to achieve a more reliable power supply. Almost all energy in Kosovo is sourced from two old, inefficient, and highly polluting lignite-fired power plants with five units in total.

As a study of the western Balkans shows, Kosovo needs a mix of renewable and thermal power to meet the demand for peak and base-load capacity. Regional integration will help increase the development of renewable energy and, in the absence of viable oil and gas-fired projects, new thermal generation would be based on domestic lignite. Macedonia imports all its natural gas and almost all of its oil. Although growth in energy consumption is 4.2% p.a., there is virtually no growth in electricity generation.

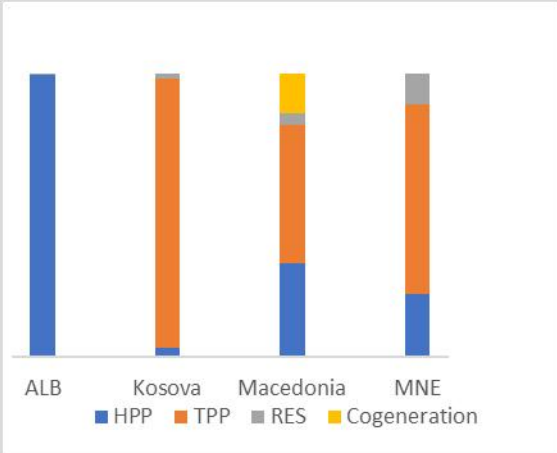

Figure 2. Energy production for the main SEE countries under study. Source: [11] Author's own elaboration.

Figure 3 shows the total primary energy supply (TPES) in SEE and the EU-27. The TPES is defined as energy production plus energy imports minus energy exports minus international bunkers, then plus/minus stock changes. As can be seen, the energy supply structure is different in SEE compared with the EU-27 countries. Coal's share is 2 to 3 times higher than in the EU-27, while the consumption of natural gas is 50% lower than in the EU-27. As is indicated in the ECC, 2012 report, the country cannot meet all its demands from domestic energy resources. The composition of electricity generation in Macedonia is shown in Figure 2 and is mainly based on coal, which leads to extra costs and emissions. Hydro and oil are also used for electricity generation. Electricity generation in Montenegro is composed of 40% thermal (lignite) and 60% hydro, as shown in Figure 2. Montenegro is dependent on imports for about one-third of its supply.

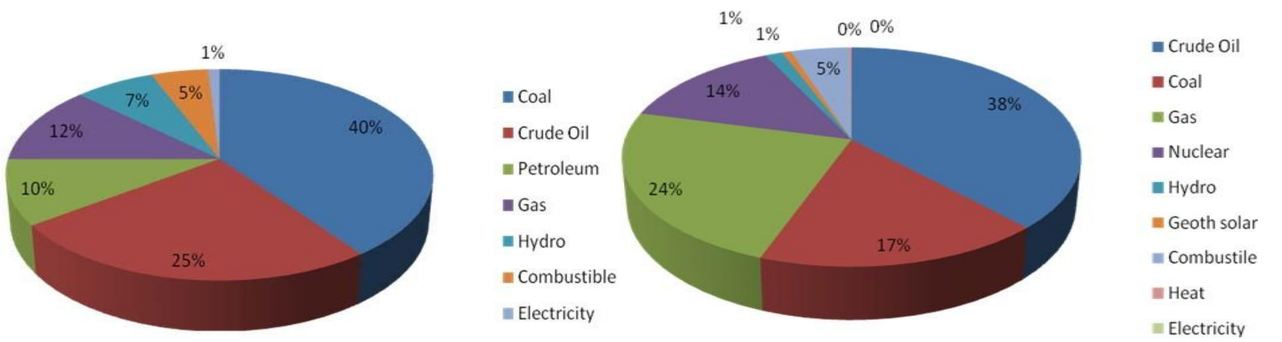

Figure 3. Total primary energy supply in SEE (right panel) and the EU-27 (left panel). Source: [11].

3. Opportunities for Increased Cross-Border Trading in the Balkans

In April 2016, representatives from transmission system operators, national regulatory authorities energy ministries and power exchanges from the western Balkan 6 countries signed a memorandum of understanding (MoU) setting out the general principles for cooperation and concrete actions to develop the regional electricity market [12]. In the memorandum of understanding (MoU), the six countries committed to improving market integration within the WB6 region, involving linking national day-ahead markets with at least one neighbouring WB6 or EU country by July 2018, and establishing cross-border balancing cooperation between the WB6 countries by December 2018. The harmonization of rules can have significant redistributive effects on market participants. Nevertheless, this task is complicated by the highly politicized nature of the energy sector in all countries involved and the political constraints on the private organization of cross-border markets.

This section describes the national energy balances in the Balkans, i.e., demand and supply capacities, exports and imports, and opportunities for increased regional power exchange in the region. The following section further analyzes the benefits that can be derived by a joint pool in terms of regional least-cost capacity expansion. The advantages of market integration can be increased with the amount of renewable energy in the system. Doubling renewable electricity generation from current levels, results in disproportionate increases in efficiencies [13]. Therefore, the ambitious European renewable targets justify greater cross-border transmission capacity. In this context, restricting market integration to regions with similar renewable production patterns means overlooking trading benefits. Depending on the level of integration, different generation technologies are preferable, especially where the world is facing high energy prices because of the dependence on Russian gas, hydropower is becoming the most important source for energy supply and security of supply. While the countries rely on different sources of energy production, they will rely more on sources that provide comparative advantages in a competitive regional market. The potential economic benefits of the interconnection of power systems (considered either individually or together) include fuel cost savings and avoiding generation capacity costs, operating costs and costs for transmission system improvements [14]. Savings in these areas arise largely because the operation of the interconnected system can be optimized for resource utilization in all systems to satisfy load at the lowest possible cost. Grid interconnections offer opportunities to reduce generation fuel costs per unit of electricity delivered by allowing generation plants with low fuel costs to run more intensively when facing a flatter load curve. Grid interconnections, and particularly interconnections between countries with varied resources, offer the option of sitting power plants where generation resources will be cheapest and transport power from those areas to load centers. For Dutch electricity imports from Norway, which occur during peak hours in the Netherlands, Norwegian hydropower plants with lower costs substitute Dutch gas-fired plants with higher costs, thereby leading to a cost saving. The inexpensive imports from Norway replace expensive power plants in the Netherlands, reducing expensive thermal generation and leading to an overall cost saving between the two countries. Additional economic benefits accrue through interconnection resulting from operating costs and transmission system improvements. Related primarily to the use of an interconnection there are variable cost and fixed operating cost savings, that reduce the need for capacity additions. Furthermore, the grid interconnections would reduce the need for national investments in transmission system improvements. Taking into consideration the above-mentioned cost savings, the interconnection allows for the dispatch of the cheapest generation units within the interconnected area, providing an overall cost saving that can be divided among the component systems. Cross-border electricity trade allows countries to have access to a more flexible and broader geographical area, consequently reducing the costs of balancing power resulting from increased Renewable Energy Sources (RES) generation. However, generation from certain RES technologies, such as those based on wind and solar energy, can exhibit significant variations over short periods of time, potentially introducing instability into the power system [15]. Cross-border electricity trade appears to be one of them as it enables countries to gain access to a more diverse portfolio of plants, producing over a wider geographic area. In reference [15], it is confirmed the importance of cross-border electricity trade from an examination of the European electricity market, in the context of a growing share of intermittent renewables in the power sector.

4. Methodology and Data

To evaluate regional benefits derived from the optimal type and location of new candidate generation plants and interconnections in the medium term (2025), the peculiarities of national power systems are taken into consideration in an extended optimization-based planning model. Albania, Kosovo, Macedonia and Montenegro are the participating countries in the simulated power pool developed below. The objective of this section is to determine the optimal generation and interconnection expansion plan over 2025 based on a regional coordinated operation, using the integrated generation/interconnection expansion planning and simulation models with the Solver package.

The generation expansion planning (GEP) problem is defined as a problem to determine the best size and type of generation units to be built over a long-term planning horizon to satisfy expected demand. Since the emergence of electricity systems, significant efforts have been made to optimize generation asset investments. The levelized cost of generating electricity is the conventional methodology for comparing the individual MWh cost of a range of electricity-generating technologies for new entrants. However, for practical purposes, it is necessary to apply this methodology in the context of the existing technology portfolio to achieve the least cost expansion planning. In addition, for intermittent technologies, the value of the power plant will depend on the extent to which it can provide electricity during the high-price "peak" periods. Furthermore, the electricity system may value dispatchable power plants that can respond quickly to unpredictable changes in demand as well as maintain the reliability of the system on a least-cost basis.

The interconnection scenario consists of least cost generation investment planning considering the economic use of the electricity interconnections with emphasis on regional electricity trade and electricity imports/exports between the analyzed power systems to meet national loads in a joint operation with cross-border electricity exchanges and electricity trade in the framework of a regional electricity market.

The model involved here includes an investment decision and operational analysis. The objective function is composed of an investment decision variable (CAPEX) and expected operation costs (OPEX). The expansion planning problem here is formulated as follows in the Equation (1):

$$\text{Min } c(x) + dy, \text{ Subject to } Ax < b \tag{1}$$

The vector x represents the investment decision variables during the study period. The scalar c(x) is the total investment cost associated with the decision vector x. The model's constraints apply to investment decisions, for example, minimum total capacity constraints.

In the above Equation, vector y represents decision variables for the operation problem during the study period. The total expected operation cost is given by dy. The optimal solution to this problem is a candidate plan x*, which has an investment cost of c(x*). This is the "benefit gradient" used by planners to compare unit investment costs, creating benefit/cost indices that guide the selection of the next candidate plant.

In the investment decision process, a candidate plant—all candidate plants act as the input data in the optimization model. Furthermore, in the operation analysis, the input data are the candidate plants for expansion and existing system information on generation, interconnection, and load, which compute the operational cost with the candidate plant. Once the investment and operational costs of the candidate plan are known, the optimality check and feedback to the investment step compare the candidate plan with that of the current best available plan and update the results.

Description of the Input Data of Generation Planning

While literature in the field has been mainly produced for developed economies, this is less the case regarding emerging economies, where power supply faces important challenges. The power industry is rather complex due to the lack of large-scale electricity storage mechanisms and the need to balance supply and demand instantly. Under these circumstances, the price system formation faces many challenges. The optimal plant combination to expand the generation system relates to the portfolio of generation units, which takes into consideration the available technologies. To determine long-run marginal costs, the linear program assumes that the capacity of all the classes of plants is variable. In other words, the mix of generators to supply the load profiles is coal-fired thermal power stations, combined-cycle gas turbines (CCGT), open-cycle gas turbines (OCGT) and hydropower plants. Wind and solar technologies constitute a rapidly increasing share of investment in many countries, they are accounted for as new capacities in which generators could invest.

For a generator to be economically efficient, the average price for energy produced needs to match its average cost of producing this energy (both capital and fuel). In the choice of a generation portfolio, there is a trade-off between capital costs and operating costs. The lower capital cost plant tends to have higher fuel costs and, therefore higher operating costs. The coal generator is a base-load plant that runs all the time with high capital costs and low fuel costs. The CCGT is typically an intermediate generator. Moreover, compared with the base-load generator it has lower capital costs, but higher fuel costs, and the figure illustrates that it is less competitive than a coal-fired plant for a capacity factor (CF) greater than 70%. The OCGT is a peaking generator that is optimal for low-capacity factor usage, competitive for a CF of less than 15%. On the other hand, hydropower plants, run-of-river (RoR), wind farms and solar power are always dispatched (zero variable cost), since the operating costs of hydropower plants are generally very low [16]. Hydroelectric energy is often available only to a limited extent and capacity factors for hydroelectric units are therefore fixed to the degree that water availability can be predicted. The operation of electricity systems depends on rapid and flexible generation sources to meet peak demands, maintain the system voltage levels, and quickly re-establish supply after a blackout. One of the main benefits of the energy generated by hydroelectric installations can be injected into the electricity system faster than that of any other energy source. The capacity of hydroelectric systems to reach maximum production from zero in a rapid and foreseeable manner makes them exceptionally appropriate for addressing alterations in consumption and providing ancillary services to the electricity system, thus maintaining the balance between the electricity supply and demand. With an average lifetime of 50 to 100 years, hydroelectric developments are long-term investments that can benefit various generations. They can be easily upgraded to incorporate more recent technologies and have very low operating and maintenance costs.

As a first step for the dispatching model, the components of the generation cost and the cost characteristic of each generator type are identified. The components considered in this development include:

- Fixed capital costs (CAPEX) that include equipment costs, transformers, interconnection and switchgear, site preparation and buildings, engineering, fixed operations, and maintenance.
- Financial costs: due diligence, legal expenses, financial instruments, etc.
- Variable operating costs: plant operations and maintenance, fuel, fuel transport.
- Financial structure (discount rate).

Other variables taken into consideration are asset life (years); fixed operating cost (expressed as a percentage of the annual fixed cost for capital), and thermal efficiency (GJ/MWh). The second step is to develop an appropriate linear program (LP) approach to perform a long-term planning forecast for the calculation of the long-run marginal cost (LRMC) of electricity generation. The main advantage of the linear programming approach is:

Given the load to be met, a definition of the combination of plants that minimizes the total costs, i.e. the optimal plant program considering capacity plus operating costs can be identified.

The purpose of generation investment planning is to determine the least cost plan of commissioning new generation units of the countries' analyzed power systems to meet national loads. It can be concluded that all the countries under investigation, Albania, Kosovo, Macedonia and Montenegro, face significant differences in generation costs. The differences are more pronounced considering the electricity produced to cover demand in peak periods. Being Albania Hydro dependent makes it possible to cover the demand in peak and base load, and especially in the increasing of fuel prices puts Albania in a very competitive advantage compared with countries sharing common borders.

According to reference [17], "Hydropower is set to play an important role in the energy transition and will be critical to decarbonization". Given the above, the possibility of a common regional electricity market should be explored, meaning that these countries could benefit from exploiting their comparative generation advantages through cross-border power exchange.

As a technology [17] promotes, hydropower is an ideal complement to modern clean energy systems. No country has come close to achieving decarbonization without a significant element of hydropower. IRENA's report (2021) highlights the need to leverage hydropower's flexibility services to balance variable renewables, to help accelerate the decarbonization of electricity grids. To achieve this, there is a need to urgently reshape the market and regulatory frameworks to properly incentivize these flexible services.

Least Cost Generation Expansion Plan in the Region—Estimation and Results

This section proposes an optimal development plan for power generation capacity in the region, based on the least cost optimization method using the linear programming model with the help of Solver in Excel, at the core of which is a calculation of least cost planning. Excel's Solver is a numerical optimization add-in (an additional file that extends the capabilities of Excel). The software emerged from continued research and development in the field of software development for the needs of different businesses and industries. Solver is a powerful way to solve optimization problems fast, easily, and accurately, but has to be implemented in the specific mode for the solution of least cost generation planning. Due to the dimensions of least cost generation planning, in our model, we have not used the standard Solver software supplied with MS Excel, but the Extended Excel Solver software provided by Frontline Systems Inc. This user-friendly software tool was used for building the model that allows for the selection of an appropriate least-cost power generation expansion program in competitive electricity markets. The software considers the capital cost, the fuel consumption and cost, the operation cost, the maintenance cost, the plant load factor, etc. All costs are discounted to a reference date at a given discount rate.

The software encompasses the following procedure: (i) an optimization tool that considers the future development of the electricity production system by replicating the system planning process. The optimum expansion of the generation system is based on the minimization of the present value of the total costs (operating, investment, capital) by explicitly considering the following factors: technical characteristics for the existing and new electricity generation technologies (technical minimum, maximum capacity, heat rates at minimum and maximum capacity, forced outage rates and days of scheduled maintenance). (ii) Economic characteristics for the existing and new electricity generation technologies (fuel expenses, fixed and variable operating and maintenance expenses, initial investment expenditures, and operational life). The optimization tool provides the optimum.

The model and the software are developed to calculate the long-run marginal costs for the supply of electricity in Albania and the region.

The annual average marginal cost is determined using the formula: average marginal cost = total cost / total annual production. The calculation is made possible using formulations and the respective data on existing plants, asset life, working hours, operation and maintenance costs (€/kW) from [18] as explained above. All the estimated indicators from the model simulation are summarized in Table 1 below:

Table 1. Summary of the results of Albania baseline scenario in 2025.

	CAPEX		OPEX			CAPEX & OPEX	Production		Specific Costs	
Generation Extension Plan	**Existing and New Capacity (MW)**	**New Capacity Costs (k€)**	**Operating Cost (Fuel Costs) (k€)**	**Fixed o&m Cost (k€)**	**Total Opex (k€)**	**Total Costs (k€)**	**Annual Production (MWh)**	**Working Hours (h/y)**	**Average Short-Term Production Cost (€/MWh)**	**Average Long-Term Production Cost (€/MWh)**
Existing HPP	1609	-	0	1475	1475	1475	5,752,250	3575	0.26	0.26
Existing TPP steam	0	-	0	0	0	0	0	0	-	-
Existing TPP CCGT	100	-	0	26.4	26	26	0	0	-	-
New HP	313	71,805	0	377	377	72,182	2,744,070	8,760	0.14	26.30
New coal TTP	0	0	0	0	0	0	0	0	-	-
New CC GT	1627	188,269	620,376	4295	624,671	812,941	9,976,142	6132	62.62	81.49
New OC GT	0	0	0	0	0	0	0	0	-	-
New wind farm	35	13,081	0	875	875	13,956	306,600	8760	2.85	45.52
New solar PV	16	7688	0	400	400	8,088	140,160	8760	2.85	57.71
Total	3700	280,843	620,376	7448	627,824	908,668	18,919,222	-	33.18	48.03

Source: Authors' own elaboration.

Table 1 summarizes the results of the annual operational cost of production of each power plant in Albania. For the overall generation system, the short-term cost of electricity generation in 2025 is expected to be €33.18/MWh. This is shown in the last row of the column under average short-term production cost. As already explained, the components of long-term electricity costs are the investment costs and operating costs of the power system. In the baseline scenario, the average long-term cost of electricity generation is expected to be €48.03/MWh and is split into: (i) specific costs to cover the operational costs of €33.18/MWh, and (ii) specific costs to cover the investment costs of €14.84/MWh (equaling: 280,843/18,919,222). As the table shows, the maximum short-term operational cost is €62.62/MWh (624.671/9,976,142), which corresponds to the CCGT power plant. The highest long-term cost is €81.49 /MWh. This is the sum of the construction and operational costs of a CCGT power plant. Moreover, the long-term cost of new solar plants is estimated to be €57.71/MWh, and for wind farms, it is expected to be €45.52/MWh. As can be concluded from the table, the minimum long-term average specific cost is related to the new hydropower plant, which in 2025 is estimated to be €26.30/MWh. This confirms the well-known fact that the cheapest and most economic generation investment in Albania is in hydropower plants. A more detailed illustration of the average long-term production costs of electricity generation for different technologies in the Albanian power system is presented in Figure 4. As already explained, the long-run marginal cost (LRMC) is defined as the cost of supplying an extra kilowatt of power and associated energy at the system's peak period. Since the LRMC of generation includes the capital cost of generators, fuel, operation and maintenance costs, it measures the cost of increasing the production output by one additional unit. If an extra MWh of energy was available from some source, that energy could be used to displace 1 MWh of generation from the most expensive generation unit in the system at the time; therefore, this system marginal energy cost is the economic value of energy to the system at that point in time.

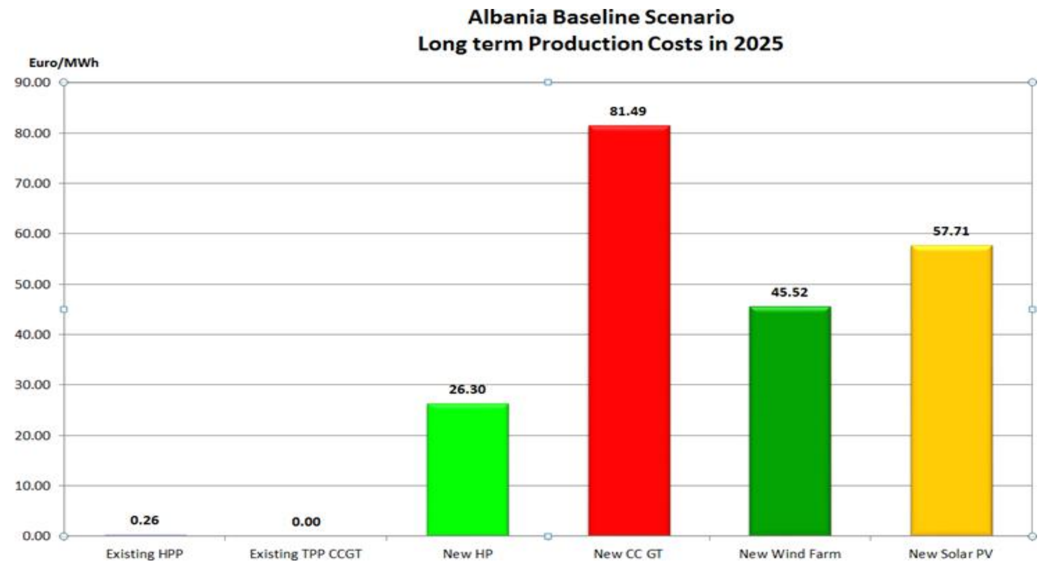

Figure 4. Albania baseline scenario average long-term cost of electricity in 2025. (Source: Authors own elaboration based on model simulation.)

Regional Co-Operation Based on Economic Electricity Exchange

The objective was to address the adequacy of the planned generation system and interconnected network to deliver the economic amount of electricity trade necessary to fulfil the objectives of the Balkan countries' electricity trading market. The data collection focused on establishing an outline of the potential resources and preparing energy balances for each country taking current production, exports, imports and consumption into account. The optimum regional cross-border scenario consists of the constrained least cost generation investment plans to consider economic use of the existing and confirmed interconnections between the respective countries with an emphasis on regional electricity trade, imports, and exports. This study was performed based on a methodology of least-cost integrated development of generation and interconnections (electrical and natural gas) of the countries that share a common border with Albania, namely Kosovo, Macedonia and Montenegro.

There is a vast amount of literature on the calculation of regional least cost expansion models incorporating linear programming and stochastic dynamic programming. As observed earlier in [19], a linearized objective production function (OPF) model with linear constraints can be efficiently solved by a dual simplex algorithm that represents implicitly the power flow balance equations and uses a compact formulation expressing all circuit flow constraints directly in terms of the generation levels. In this framework, the reference [20] describes a methodology for the optimal scheduling of hydrothermal systems considering multiple hydro reservoir characteristics, stochastic inflow and transmission networks represented by a linearized power flow model. The solution algorithm they suggest is based on stochastic dual dynamic programming (SDDP) and applied to the Brazilian Southern-Southeastern system, containing a mix of hydro and thermal plants. As the reference [20] observed, the SDDP algorithm allows for the calculation of the expected marginal costs associated with equipment reinforcement and load variation between neighbouring systems. In the reference [21] it is analyzed a least cost expansion model. They use a probabilistic multi-area hydrothermal production costing model (SDDP) that permits the simultaneous optimization of reservoirs and of hydro and thermal generators, including interconnections, linked with a multi-area generation-interconnection expansion planning model (OPTGEN).

Figure 5 illustrates the average short-term specific cost of electricity generation for different technologies in the interconnected scenario. For the overall generation system, the average short-term cost of electricity generation in 2025 is expected to be €25.34/MWh. As can be observed, the maximum operation cost is €146.68/MWh for the new gas turbine power plant peaking units. This reflects the potentially high cost of power supplied at peak periods if gas plants are at the margin. The next highest average short-term production cost is that of a CCGT thermal plant, followed by a steam thermal plant, while the hydropower plants have the lowest average short-term production costs. Overall, all the costs associated with the construction of new plants in 2025 are expected to be lower than the existing costs. This again highlights one of the advantages obtained from the whole region with the creation of an interconnected pool as well the importance of hydropower plants in the region, where the energy generated by hydroelectric installations can be injected into the electricity system faster than that of any other energy source. The capacity of hydroelectric systems to reach maximum production from zero in a rapid and foreseeable manner makes them exceptionally appropriate for addressing alterations in consumption and providing ancillary services to the electricity system, thus maintaining the balance between the electricity supply and demand. The difference between the two values of the incremental investment and incremental operating costs (energy plus operations and maintenance) has been divided by the increment in demand and yields €81.49/MWh as indicated in Table 2. The value calculated is the overall long-run marginal cost of Albania in 2025 which can be represented by a snapshot of the central view of the software implemented model in the Figure A1. The same procedure is carried out for the remaining countries being analyzed—Kosovo, Macedonia, and Montenegro. The Figure A2 is a snapshot of the central view of the software screen after finding the optimal solution for the incremental case. The final new value of the objective function and different calculated values of the outputs of the program can be observed in cell M17. Calculation and simulation procedures regarding the new entry costs, the new average short-run marginal cost and total annual production are the same as those described above. Because of the incremental change attributed to the demand for energy in the peak periods, values related to the input, constraints and output are different. All of this leads to the estimation of the LRMC value shown in cell P17. The difference between the two values of the incremental investment and incremental operating costs (energy plus operations and maintenance) has been divided by the increment in demand and yields €81.49/MWh as indicated in Table 2. The value calculated is the overall long-run marginal cost of Albania in 2025. The same procedure is carried out for the remaining countries being analyzed—Kosovo, Macedonia, and Montenegro. The calculation of the LRMC has been based on comparing an incremental case optimized in our software with the optimized baseline scenario. The incremental case is created by applying a step in 2025 demand followed by rerunning the software to define the new optimum long-term planting to be established. A step of 10MW has been chosen, or 0.3% of the peak, so that the power and energy increment is close to the size of a new plant. In Appendix 1, the yellow column on the left of the lower panel indicates values that are equal to those in the corresponding column of Appendix 2 plus 10MW. Applying a small step would not lead to the planting of additional generation—i.e. it would be met through generation already in the baseline plan. The Figure A2 shows a snapshot of the central view of the software screen after finding the optimal solution for the incremental case. The final new value of the objective function and different calculated values of the outputs of the program can be observed in cell M17. Calculation and simulation procedures regarding the new entry costs, the new average short-run marginal cost and total annual production are the same as those described above.

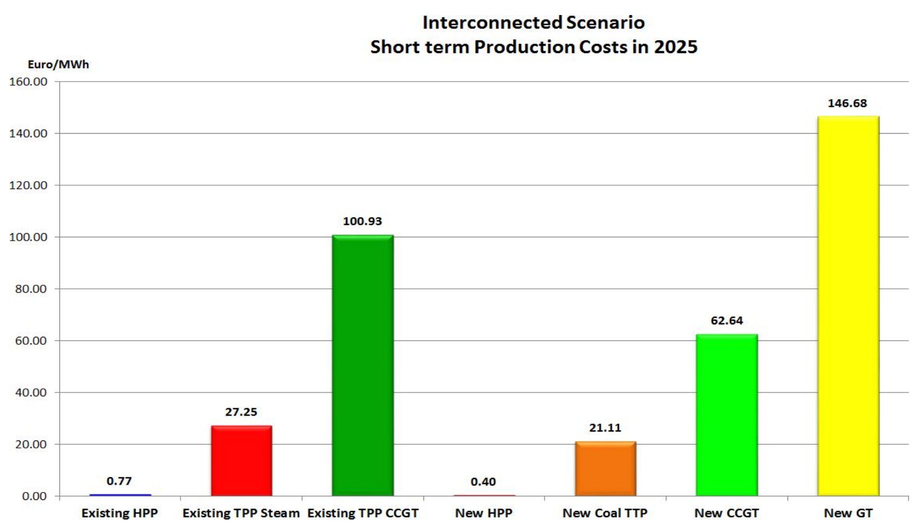

Figure 5. Interconnected scenarios short-term production costs. (Source: Author's calculation based on model simulation.)

Table 2. Generation LRMC of Albania in 2025.

2025	Total Cost (K€)	Total Production (Mwh)	Long Run Marginal Cost (€/mwh)
Baseline scenario	908,668	18,919,222	-
Incremental case	915,806	19,006,822	-
Delta	7138	87,600	81.49

Source: Authors' own elaboration.

A comparison of the LRMC for each of the countries under the scenario of no cross-border trade and the one under the interconnected pool, suggests that optimum use of the interconnections relative to no cross-border power exchange is reflected in a lower LRMC value. With no transmission bottlenecks, the LRMCs would be the same in all countries.

The calculation of the LRMC here is based on a comparison of an incremental case optimized in the software with the interconnected scenario. The incremental case is created by applying a step in 2025 demand followed by rerunning the software to define the new optimum long-term plant to be established. A snapshot of the central view of the software for the procedure to find the optimum solution of the incremental case is presented in Figure 2. Table 3 shows the final new value of the objective function and different calculated values of the outputs of the program and the calculation of the LRMC of energy. The difference of two values of the incremental investment and incremental operating costs (energy plus operations and maintenance) has been divided by the incremented demand and yields a value of €75.70/MWh, equaling the overall LRMC of the pool of interconnected countries in 2025. This is shown in Table 3 where referring to the last row, the value in the first column (6631) divided by the value in the second column (87,600) equals 75.70.

Table 3. Generation LRMC of SEE pool in 2025.

2025	Total Cost (k€)	Total Production (MWh)	Long Run Marginal Cost (€/MWh)
Interconnected Scenario	1,618,060	45,055,314	-
Incremental Case	1,624,691	45,142,914	-
Delta	6631	87,600	75.70

Source: Authors' own elaboration from model simulation.

The LRMC when Albania produces electricity, considering only its limited domestic generation capacity to cover domestic demand, is expected to be €81.49/MWh. This is higher than the LRMC value when it can be exchanged with the other countries in the simulated pool. It can be concluded that there is a benefit for Albania to be part of the simulated pool. The program estimations provide useful results that support the dimensioning of new generation plants and interconnections (e.g., in the form of marginal benefits) under both alternatives with no cross-border power exchange and an interconnected power pool. Results confirm that the most important economic advantage of creating an interconnected market is minimizing the total operating costs by making the best use of regional resources, i.e. by always dispatching the least-expensive generator in the region first (within the constraint of actual interconnection capacity in the region). There is a reduction in capital cost for new generation units derived from simulated power exchanges between neighbouring countries in the interconnected pool. Calculations of both cost components of the objective function (CAPEX and OPEX) indicate that these are lower in the scenario with an interconnected pool for the whole group of countries under analysis. These are illustrated in the second row of Table 4. The advantage of the interconnected pool offers a reduction of about 14% in total production costs. A similar change is reflected in both types of costs—investment and operational costs (CAPEX and OPEX), which are the main decision variables of the objective function.

As anticipated earlier, the interconnected pool changes the technology used, allowing for increased usage of the less expensive sources to be used in an extended market. As can be noted in Table 4, countries will increase production of energy from certain existing sources while decreasing production from other costlier sources. For example, Albania and Macedonia would benefit from reducing the cost of investing in new CCGTs and substituting the missing generated energy with imported production from other countries that produce at lower cost. This is also associated with lower investment in generation capacity in both countries, as indicated in Table 4. Such results are closely related to the countries' balance as they are the largest net importers of energy. The total CAPEX reduction is estimated at €80 million in 2025 and the total OPEX reduction is estimated at €183.7

million. While the highest reduction in investment costs is in Macedonia and Albania, Montenegro shows an increase in capital costs due to investment in new HPPs. Macedonia is the country with the highest reduction of operating costs in the region (€204.8 million). Kosovo and Montenegro are expected to see operating costs increase by €70 million and €35.8 million, respectively, due to an increase in production for export, but these costs will be offset by export revenues.

Table 4. Objective function costs comparison.

No Cross Borders/Interconnected Pool	Objective Function Total Cost (k€)	CAPEX (k€)	OPEX (k€)
Total (no cross border)	1,881,830	556,233	1,325,598
Total (interconnected pool)	1,618,060	476,195	1,141,866
Absolute change	−263,770	−80,037.9	−183,732
Change (in %)	−14.0	−14.4	−13.9

Source: Authors' own elaboration from model simulation.

Table 5 summarizes the comparison between the baseline scenario and the interconnected scenario, indicating the reductions in investment and operational costs for the whole group of countries due to economic power exchanges within the interconnected pool.

Table 5. CAPEX and OPEX in SEE pooling 2025.

Country	Baseline Scenario		Interconnected Scenario		Benefits as Reduction of Costs		
	CAPEX (k€)	OPEX (k€)	CAPEX (k€)	OPEX (k€)	CAPEX (k€)	OPEX (k€)	Total (k€)
Albania	280,843	627,824	245,117	542,715	35,726	85,109	120,835
Kosovo	145,948	168,619	124,942	238,968	21,006	−70,349	−49,343
Montenegro	51,286	152,615	78,517	188,443	−27,231	−35,828	−63,059
Macedonia	78,155	376,540	27,618	171,740	50,537	204,800	255,337
Total	556,233	1,325,598	476,195	1,141,866	80,038	183,732	263770

Source: Authors' own elaboration from model simulation.

Table 6 summarizes the total new installed capacity of the interconnected countries for 2025 based on solving the optimization problem. As indicated in Table 6, the installed capacity in the baseline scenario matches the internal peak power. A reduction in new generation capacity by about 637 MW compared with the baseline scenario is a result of economic power exchange between the countries. All countries, except for Montenegro, will need less new capacity compared with the baseline scenario, although the total regional production level is the same in both scenarios. This is due to better use of available capacity (existing and new). Table 7 summarizes the short and long-term average costs of electricity generation. As explained earlier, the components of short-term cost are the operational and fuel costs of a power system, and the long-run average cost of electricity generation includes costs related to investment. Macedonia, Albania and Kosovo have lower short and long-term electricity production costs in the interconnected scenario than if they were operating separately. The least cost investment plans for the four countries were used to estimate the expected generation cost of electricity in 2025 as a snapshot in Figure A1 as mentioned above. This is shown in the last two columns of average short and long-term production costs in Tables 7. For example, the costs for Albania would be about 4% lower in the power exchange scenario, for Kosovo 4% and 21% for short and long-term costs, respectively, and for Macedonia close to 40% lower for short and long-term costs when the countries are part of the interconnected pool. Lower in the power exchange scenario, for Kosovo 4% and 21% for short and long-term costs, respectively, and for Macedonia close to 40% lower for short and long-term costs when the countries are part of the interconnected pool.

Macedonia imports a large volume of electricity at 3277GWh and would benefit from the highest reduction in costs. Albania follows with imports of 1791GWh, also allowing for a reduction in costs, but it is still the country with the highest generation cost in the region.

Table 6. New installed capacity in SEE countries by scenario.

New Capacity Country	Baseline Scenario (MW)	Interconnected Scenario (MW)	Delta (MW)
Albania	1991	1811	180
Kosovo	748	640	108
Montenegro	263	320	–57
Macedonia	626	220	406
Total	3628	2991	637

Source: Authors' own elaboration from model simulation.

Table 7 also indicates the opportunity costs associated with a scenario with no cross-border exchange. Comparative advantages arise when countries are involved in an interconnected pool. Hence, countries that operate at lower comparative costs will produce more, as in Kosovo and Montenegro, while Albania and Macedonia would produce less. Thus, each country would benefit from gains in economic efficiency associated with the exchange of power, allowing for domestic resources to be used more efficiently in the power and alternative sectors. For instance, the above table shows that both average short and long-term costs would be lower for all countries except for Montenegro. However, given that trade is justified by comparative advantages rather than absolute advantages, even in the case of Montenegro, the interconnected pool would be a better situation than no-cross border exchange.

Table 7. Power production and related average costs in 2025.

Country	No Cross-Border Exchange/Interconnected Pool	Annual Production (MWh)	Average Costs	
			Average Short-Term Production Cost (€/MWh)	Average Long-Term Production Cost (€/MWh)
Albania	No	18,919,222	33.18	48.03
	Yes	17,128,536	31.68	46.00
	Change	–1,790,686 (import)	1.50	2.03
Kosovo	No	8,311,819	20.29	37.85
	Yes	12,259,620	19.49	29.68
	Change	3,947,801 (export)	0.81	8.18
Macedonia	No	11,745,575	32.06	38.71
	Yes	8,468,628	20.28	23.54
	Change	–3,276,947 (import)	11.78	15.17
Montenegro	No	6,078,698	25.11	33.54
	Yes	7,198,530	26.18	37.09
	Change	1,119,832 (export)	–1.07	–3.54
Total	No	45,055,314		
	Yes	45,055,314	25.34	35.91

Source: Authors' own elaboration.

Table 8 summarizes the total generation and total demand for the respective countries in the interconnected pool scenario. As can be observed, total demand equals total supply in the pool, meaning that a portion of the power demand in certain countries will be supplied by other countries where relative cost and prices define the trade direction. The latter would also define the need and degree for each country to invest in new capacity. As a result, countries with lower local marginal costs increase power production and export more energy to those countries with higher local marginal costs, which then reduce their local production by the same amount, implying total demand equals total supply in the pool as shown in the last row of Table 8. The benefits of creating a pool are that the demand in the importing countries will be met at a comparatively lower cost. The demand in exporting countries will however be met at a higher cost, but the increase in local generation costs is offset by export revenues, providing a total net benefit for the exporting countries. To sum up, production in the baseline scenario matches internal demand. The comparison of the baseline scenario with the interconnection scenario is directly related to electricity exchange between the countries. Energy exchange occurs when the cost differential between the countries enables the displacement of more expensive generation in one of the countries.

At a country level, the differences in electricity production depend on the capacities of interconnections to realize the import or export of electricity and the capacity factor of the generating units. The exporting countries (Kosovo and Montenegro) increase their capacity factor and put new units into operation if economically justified. The importing countries (Albania and Macedonia) generally decrease local generation, replacing it with electricity imported from other countries. The following tables show the results obtained for the two scenarios. The comparison of the interconnected scenario with the baseline scenario highlights the reduction in capital cost for investment in new generation units and operational costs due to the replacement of costly local production by economic power exchanges and imports from neighboring countries. We have estimated the benefits that can be achieved by interconnection and efficient power exchange between the respective countries. Table 8, columns 2 and 3, show the total cost of electricity supply under the baseline scenario under the assumption that the price of electricity is not subsidized for each country. Similarly, the costs of electricity supply for each country in the interconnected scenario are presented in columns 5 and 8. Part of the demand is supplied by local production and part from electricity imports when annual domestic demand exceeds internal production in the interconnected scenario, such as in Albania and Macedonia. The differences in local supply between the respective scenarios highlight the exploitation of the comparative advantages achieved by the interconnected scenario, as examined earlier in Table 7. The supply cost in the last column in Table 8 is calculated as the sum of internal production valued at the average long-term cost of local production and the imported quantity valued at the LRMC of the importing countries. Domestic supply cost for the exporting countries equals domestic supply multiplied by domestic long-term cost.

Table 8. Comparisons of electricity supply costs baseline versus interconnection scenario 2025.

Country	Baseline Scenario			Interconnection Scenario				
	Internal Production (MWh)	**Average Long-Term Cost (€/MWh)**	**Supply Cost (k€)**	**Internal Production (MWh)**	**Local Average Long-Term Cost (€/MWh)**	**Import (+) Export (-) (MWh)**	**Price (Pool LRMC) (€/MWh)**	**Supply Cost (k€)**
Albania	18,919,222	48.03	908,668	17,128,536	46	1,790,686	75.7	923,383
Kosovo	8,311,819	37.86	314,710	12,259,620	29.68	−3,947,801	-	246,725
Montenegro	6,078,698	33.54	203,901	7,198,530	37.09	−1,119,832	-	225,430
Macedonia	11,745,575	38.71	454,695	8,468,628	23.54	3,276,947	75.7	447,415
Total	45,055,314	-	1,881,973	45,055,314	-	-	-	1,842,954

Source: Author's own elaboration from model simulation.

Table 9 shows the estimated benefits for each country and the whole pool, based on a comparison of power costs under the baseline and interconnected scenarios.

There are three components of benefits estimated for 2025: (i) reduction in total investment costs quantified as €80 million for the pool; (ii) reduction in total supply costs for electricity demand in the pool estimated at €39 million; and (iii) profits from cross-border trade of exporting countries estimated to be about €383.6 million. The total economic benefits are quantified as €502.67 million for 2025 (last row, column 6). This is the sum of the total benefits for each country involved in the pool, calculated as the sum of values presented in columns 3, 4 and 5. Benefits from supply costs (column 4) are calculated as the difference between supply costs under each scenario [1,2]. Values related to investment reduction are calculated as the difference between investments under the baseline scenario and the interconnected scenario (referring to Table 5 CAPEX). Column 5 indicates the value of the exported power for the interest of exporting countries, calculated by multiplying the exported quantity (Table 7) by the LRMC price (pool price) of €75.70/MWh. Table 9 (column 6) is indicative of the benefits obtained from the creation of a regional electricity market for all the involved countries. Although exporting countries benefit more from the creation of the pool (Kosovo and Montenegro) in terms of domestic economic value, the distribution of profit from imports/exports will depend on the regional electricity market rules or bilateral contracts from which these countries will derive their benefits.

Table 9. Estimation of benefits from cross-border trade in 2025.

Country	Supply Costs Baseline Scenario (k€)	Interconnected Scenario (k€)	Benefits of Interconnected Scenario Investment (k€)	Supply (k€)	Trade of Total Reduction (k€)	Costs Energy (k€)
Albania	908,668	923,383	35,726	−14,716	-	21,010
Kosovo	314,710	246,725	21,006	67,985	298,840	387,830
Montenegro	203,901	225,430	−27,231	−21,529	84,769	36,009
Macedonia	454,695	447,415	50,537	7280	-	57,816
Total	1,881,973	1,842,954	80,038	39,019	383,608	502,665

Source: Author's own elaboration from model simulation.

5. Conclusions

The purpose of this paper is to investigate how power systems can meet their national loads by operating either individually or integrated through cross-border electricity exchange through an interconnected pool. Within the framework of cross-border power exchange and the creation of a common energy market, which is a key objective of the Energy Community, the integration of electricity markets is intimately linked to wholesale competition and liberalization of the power sectors. Market liberalization is expected to provide economic benefits and cost-reflective prices in the long run. This can gradually increase market integration, facilitated by more transparent (explicit or implicit) auctions of transmission capacities, and provide a more commercially oriented approach towards the creation of power exchanges with transparent, hourly price signals, as well as offering other benefits. The added value of this paper is that it provides a cost-benefit analysis from operating under two different scenarios: baseline and interconnected pool. Cost simulations from the model allowed for calculations of expected power exchange and associated benefits. In this framework, one of the economic advantages of the creation of an interconnected pool and the future creation of a regional electricity market is to minimize the total operating costs by making the best use of regional resources, i.e. by always dispatching the least expensive generators first within the constraints of maximum interconnection capacities in the region. For example, it was found that Kosovo and Montenegro have comparative advantages in expanding investment with the purpose of increasing exports in future. Meanwhile, Albania and Macedonia would benefit from reducing expensive investment (as is the case for the new gas plant, being the most expensive technology in terms of costs of CAPEX and OPEX in 2025) and should rely more on imports from countries in the pool in future. We provided insight into the differences that exist among Southeast European (SEE) countries regarding resource endowments and developed a least-cost expansion model to address existing differences in generation costs. Our research has provided an investigation of the role of the creation of an interconnected pool by analyzing generation costs when a group of countries exchange cross-border electricity. Empirically, we provided evidence to explain that there are benefits arising from the creation of an interconnected pool. An investigation into the characteristics related to power sources and production of the whole Southeast European (SEE) region was made in order to understand and highlight the differences in resource endowments in these countries and bring together the latest available knowledge on energy developments in the region. The rationale is that possible variations could be reflected in differences in the generation costs calculated. Based on comprehensive data on energy demand and assuming an efficient framework for regional electricity market integration and cross-border exchange between the Balkan countries, a theoretical model is analyzed to determine the regional least-cost expansion plan for commissioning new generation units. To efficiently ensure the security of supply, a policy package is required that encourages full completion of the liberalization process in Southeast Europe (SEE) in compliance with the Energy Community directives. The issue of designing a package of policy measures was also examined in the context of integrated electricity markets. Among alternative policy prescriptions arising from the same theoretical and empirical results mentioned above, this study could propose a proper legal framework directed to the perspective of a Regional Electricity Market (REM) in SEE integrated into the Integrated Electricity Market (IEM). Proper initiatives must be seen in the view of parallel policies undertaken by the countries in the region since all the involved countries could benefit from more systematic use of comparative advantages in generation costs enabled by a common electricity pool. Cross-border trade by integrating capacity allocation and energy trading paved the way for a market model based on implicit auctions. This is the prerequisite for establishing a regional day-ahead market (DAM) associated with parallel implementation of local markets. Successful examples of Nordic countries indicate that a carefully designed DAM can provide correct hourly price signals from day one of a wholesale market opening. By setting correct hourly prices the market model will provide services to producers, consumers, TSOs and all other market participants in the region. This study contributes to identifying the benefits arising from the creation of an interconnected regional electricity market. To assess this, we suggest that institutions involved in (de)regulating the sector should consider the market participation of domestic and alternative capacity generation in order to ensure market competitiveness. This would then lead to the convergence of prices in the regional electricity market.

Author Contributions

For research articles with several authors, a short paragraph specifying their individual contributions must be provided. The following statements should be used "Conceptualization, V.K. and D.M.; methodology, V.K; software, V.K.; validation, V.K.; formal analysis, V.K.; investigation, V.K.; resources, V.K.; data curation, V.K.; writing—original draft preparation, V.K.; writing—review and editing, D.M.; visualization, V.K; supervision, D.M.; project administration, D.M.; funding acquisition, D.M. All authors have read and agreed to the published version of the manuscript." Authorship must be limited to those who have contributed substantially to the work reported.

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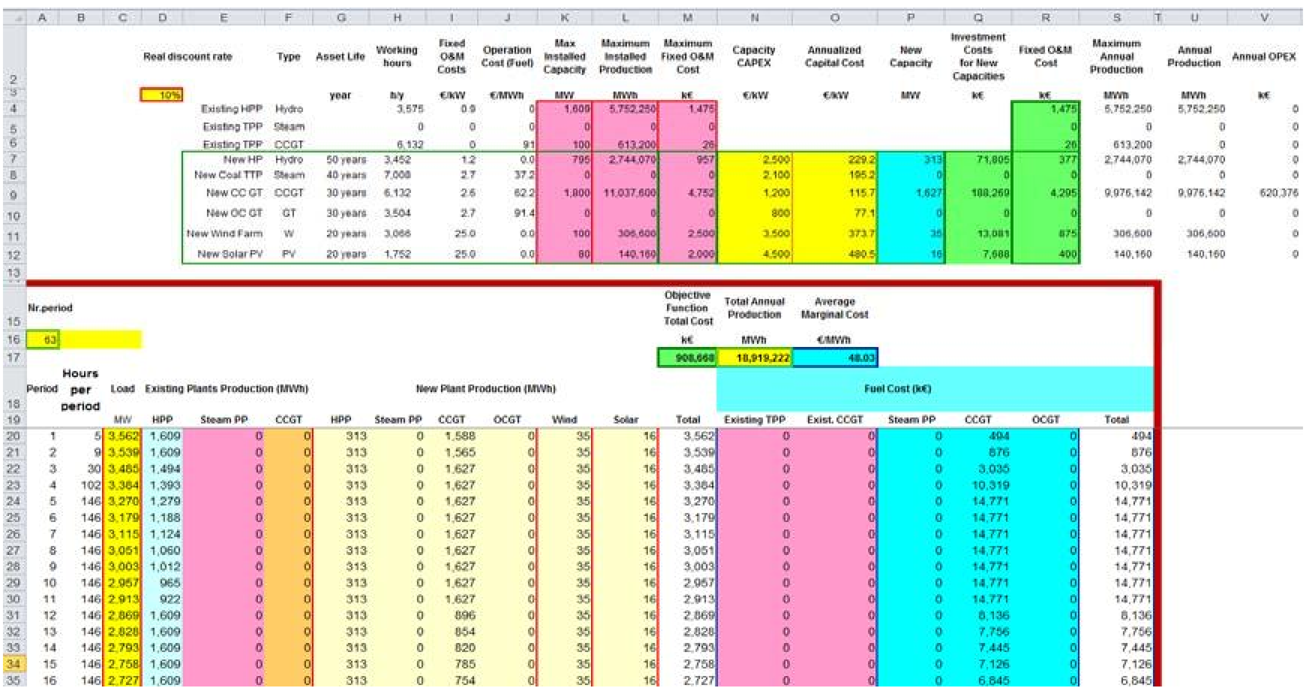
Data Availability Statement

Data is unavailable due to privacy or ethical restrictions.

Conflicts of Interest

The authors declare no conflict of interest.

Appendix A



Real discount rate: 10%

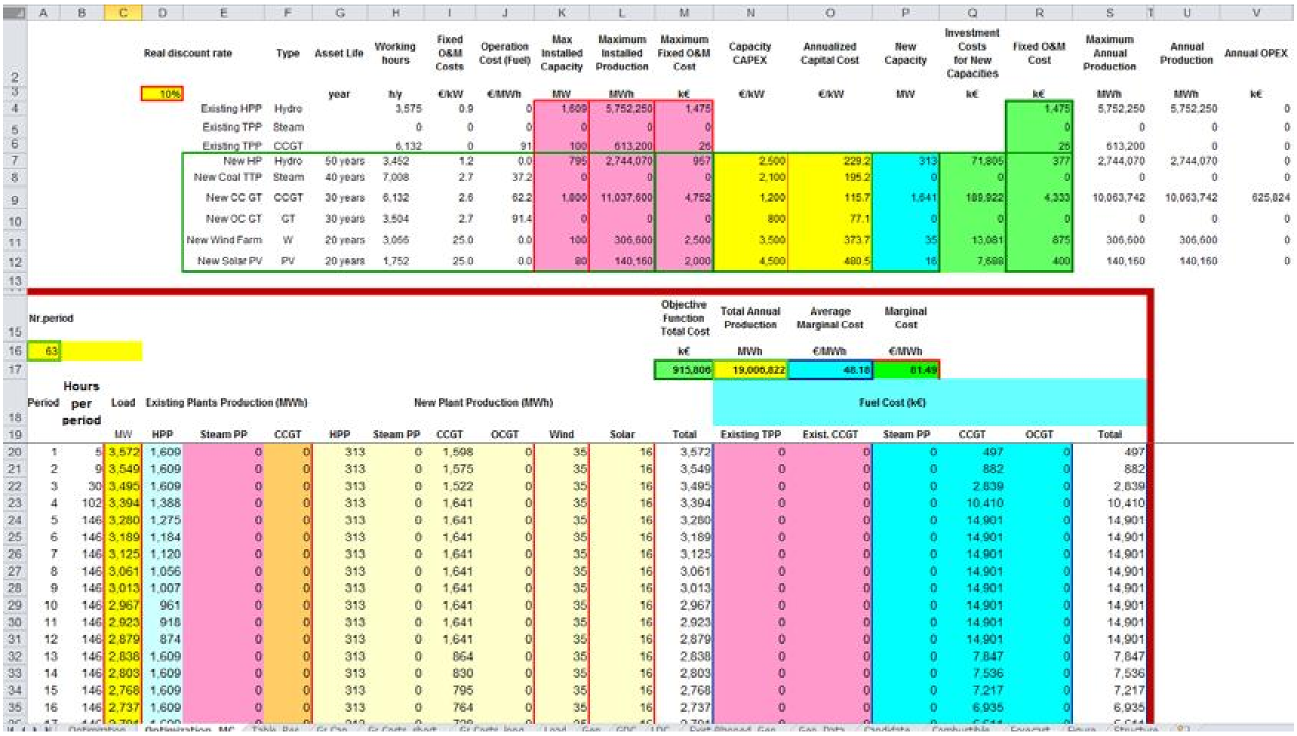
	Type	Asset Life	Working hours	Fixed O&M Costs	Operation Cost (Fuel)	Max Installed Capacity	Maximum Installed Production	Maximum Fixed O&M Cost	Capacity CAPEX	Annualized Capital Cost	New Capacity	Investment Costs for New Capacities	Fixed O&M Cost	Maximum Annual Production	Annual Production	Annual OPEX
		year	h/y	€/kW	€/MWh	MW	MWh	k€	€/kW	€/kW	MW	k€	k€	MWh	MWh	k€
Existing HPP	Hydro		3,575	0.9	0	1,609	5,752,250	1,475					1,475	5,752,250	5,752,250	0
Existing TPP	Steam		0	0	0	0	0	0					0	0	0	0
Existing TPP	CCGT		6,132	0	91	100	613,200	26					26	613,200	0	0
New HP	Hydro	50 years	3,452	1.2	0.0	795	2,744,070	957	2,500	229.2	313	71,805	377	2,744,070	2,744,070	0
New Coal TTP	Steam	40 years	7,008	2.7	37.2	0	0	0	2,100	195.2	0	0	0	0	0	0
New CC GT	CCGT	30 years	6,132	2.6	62.2	1,800	11,037,600	4,752	1,200	115.7	1,627	188,269	4,295	9,976,142	9,976,142	620,376
New OC GT	GT	30 years	3,504	2.7	91.4	0	0	0	800	77.1	0	0	0	0	0	0
New Wind Farm	W	20 years	3,066	25.0	0.0	100	306,600	2,500	3,500	373.7	35	13,081	875	306,600	306,600	0
New Solar PV	PV	20 years	1,752	25.0	0.0	80	140,160	2,000	4,500	480.5	16	7,688	400	140,160	140,160	0

Nr.period: 63

Objective Function Total Cost	Total Annual Production	Average Marginal Cost
k€	MWh	€/MWh
908,668	18,919,222	48.03

Period	Hours per period	Load	Existing Plants Production (MWh)			New Plant Production (MWh)							Fuel Cost (k€)					
		MW	HPP	Steam PP	CCGT	HPP	Steam PP	CCGT	OCGT	Wind	Solar	Total	Existing TPP	Exist. CCGT	Steam PP	CCGT	OCGT	Total
1	5	3,562	1,609	0	0	313	0	1,588	0	35	16	3,562	0	0	0	494	0	494
2	9	3,539	1,609	0	0	313	0	1,565	0	35	16	3,539	0	0	0	876	0	876
3	30	3,485	1,494	0	0	313	0	1,627	0	35	16	3,485	0	0	0	3,035	0	3,035
4	102	3,364	1,393	0	0	313	0	1,627	0	35	16	3,364	0	0	0	10,319	0	10,319
5	146	3,270	1,279	0	0	313	0	1,627	0	35	16	3,270	0	0	0	14,771	0	14,771
6	146	3,179	1,188	0	0	313	0	1,627	0	35	16	3,179	0	0	0	14,771	0	14,771
7	146	3,115	1,124	0	0	313	0	1,627	0	35	16	3,115	0	0	0	14,771	0	14,771
8	146	3,051	1,060	0	0	313	0	1,627	0	35	16	3,051	0	0	0	14,771	0	14,771
9	146	3,003	1,012	0	0	313	0	1,627	0	35	16	3,003	0	0	0	14,771	0	14,771
10	146	2,957	965	0	0	313	0	1,627	0	35	16	2,957	0	0	0	14,771	0	14,771
11	146	2,913	922	0	0	313	0	1,627	0	35	16	2,913	0	0	0	14,771	0	14,771
12	146	2,869	1,609	0	0	313	0	896	0	35	16	2,869	0	0	0	8,136	0	8,136
13	146	2,828	1,609	0	0	313	0	854	0	35	16	2,828	0	0	0	7,756	0	7,756
14	146	2,793	1,609	0	0	313	0	820	0	35	16	2,793	0	0	0	7,445	0	7,445
15	146	2,758	1,609	0	0	313	0	785	0	35	16	2,758	0	0	0	7,126	0	7,126
16	146	2,727	1,609	0	0	313	0	754	0	35	16	2,727	0	0	0	6,845	0	6,845

Figure A1. The optimal solution for the least cost-generation expansion plan for Albania in 2025. (Source: Author's elaboration from model simulation.)



Real discount rate: 10%

	Type	Asset Life	Working hours	Fixed O&M Costs	Operation Cost (Fuel)	Max Installed Capacity	Maximum Installed Production	Maximum Fixed O&M Cost	Capacity CAPEX	Annualized Capital Cost	New Capacity	Investment Costs for New Capacities	Fixed O&M Cost	Maximum Annual Production	Annual Production	Annual OPEX
		year	h/y	€/kW	€/MWh	MW	MWh	k€	€/kW	€/kW	MW	k€	k€	MWh	MWh	k€
Existing HPP	Hydro		3,575	0.9	0	1,609	5,752,250	1,475					1,475	5,752,250	5,752,250	0
Existing TPP	Steam		0	0	0	0	0	0					0	0	0	0
Existing TPP	CCGT		6,132	0	91	100	613,200	26					26	613,200	0	0
New HP	Hydro	50 years	3,452	1.2	0.0	795	2,744,070	957	2,500	229.2	313	71,805	377	2,744,070	2,744,070	0
New Coal TTP	Steam	40 years	7,008	2.7	37.2	0	0	0	2,100	195.2	0	0	0	0	0	0
New CC GT	CCGT	30 years	6,132	2.6	62.2	1,800	11,037,600	4,752	1,200	115.7	1,641	189,922	4,333	10,063,742	10,063,742	625,824
New OC GT	GT	30 years	3,504	2.7	91.4	0	0	0	800	77.1	0	0	0	0	0	0
New Wind Farm	W	20 years	3,066	25.0	0.0	100	306,600	2,500	3,500	373.7	35	13,081	875	306,600	306,600	0
New Solar PV	PV	20 years	1,752	25.0	0.0	80	140,160	2,000	4,500	480.5	16	7,688	400	140,160	140,160	0

Nr.period: 63

Objective Function Total Cost	Total Annual Production	Average Marginal Cost	Marginal Cost
k€	MWh	€/MWh	€/MWh
915,806	19,006,822	48.18	81.49

Period	Hours per period	Load	Existing Plants Production (MWh)			New Plant Production (MWh)							Fuel Cost (k€)					
		MW	HPP	Steam PP	CCGT	HPP	Steam PP	CCGT	OCGT	Wind	Solar	Total	Existing TPP	Exist. CCGT	Steam PP	CCGT	OCGT	Total
1	5	3,572	1,609	0	0	313	0	1,598	0	35	16	3,572	0	0	0	497	0	497
2	9	3,549	1,609	0	0	313	0	1,575	0	35	16	3,549	0	0	0	882	0	882
3	30	3,495	1,609	0	0	313	0	1,522	0	35	16	3,495	0	0	0	2,839	0	2,839
4	102	3,394	1,388	0	0	313	0	1,641	0	35	16	3,394	0	0	0	10,410	0	10,410
5	146	3,280	1,275	0	0	313	0	1,641	0	35	16	3,280	0	0	0	14,901	0	14,901
6	146	3,189	1,184	0	0	313	0	1,641	0	35	16	3,189	0	0	0	14,901	0	14,901
7	146	3,125	1,120	0	0	313	0	1,641	0	35	16	3,125	0	0	0	14,901	0	14,901
8	146	3,061	1,056	0	0	313	0	1,641	0	35	16	3,061	0	0	0	14,901	0	14,901
9	146	3,013	1,007	0	0	313	0	1,641	0	35	16	3,013	0	0	0	14,901	0	14,901
10	146	2,967	961	0	0	313	0	1,641	0	35	16	2,967	0	0	0	14,901	0	14,901
11	146	2,923	918	0	0	313	0	1,641	0	35	16	2,923	0	0	0	14,901	0	14,901
12	146	2,879	874	0	0	313	0	1,641	0	35	16	2,879	0	0	0	14,901	0	14,901
13	146	2,838	1,609	0	0	313	0	864	0	35	16	2,838	0	0	0	7,847	0	7,847
14	146	2,803	1,609	0	0	313	0	830	0	35	16	2,803	0	0	0	7,536	0	7,536
15	146	2,768	1,609	0	0	313	0	795	0	35	16	2,768	0	0	0	7,217	0	7,217
16	146	2,737	1,609	0	0	313	0	764	0	35	16	2,737	0	0	0	6,935	0	6,935

Figure A2. Optimal solution of the incremental case for Albania in 2025. (Source: Author's elaboration based on model simulation.)

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