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Analysis of electricity investment strategy for Bosnia and Herzegovina

Thomas Nikolakakis[b,c], Debabrata Chattopadhyay[b], Dzenan Malovic[b], Jari Väyrynen[b], Morgan Bazilian[a,*]

[a] Payne Institute, Colorado School of Mines, 1501 Illinios Ave, Golden, CO, 80401, USA
[b] Energy and Extractives Practice, The World Bank, 1818 H St, Washington, DC, 20433, USA
[c] IRENA Innovation and Technology Center, Robert-Schuman-Platz 3, 53175, Bonn, Germany

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ABSTRACT

This Case Study considers generation capacity expansion planning in Bosnia and Herzegovina (BiH) including a range of issues related to renewable, energy efficiency, local emission and carbon reduction commitment policies. In addition, our analysis considers an outlook of wholesale electricity prices in the region. We have also compared our findings with the country's current official plan ("Indicative Plan"), which includes development of as many as four additional lignite-based plants. Our findings suggest that BiH, as a low-cost producer in the region, has significant opportunities to modernize and expand its current generation system with nearly €3 billion in new investments. This investment level is much lower than the €5 billion investment program promulgated in the Indicative Plan. These differences primarily have to do with the treatment of lignite plants. Since the end of the war roughly twenty years ago, the country has progressed quickly. Aspirations to join the EU compose a significant part of the authorizing environment for the power sector.

1. Introduction

1.1. Context

Bosnia and Herzegovina (BiH) is a small country with a population of roughly 3.8 million. BiH is in the process of creating a foundation for sustainable economic growth after a period of successful post-conflict recovery since the war of 1992–1995. The power sector has largely rebounded from its lows during the war. Power generation increased by 50% between 2001 and 2013, per capita generation reached that of other Eastern European countries, distribution losses halved between 2007 and 2010, exports more than quadrupled between 2001 and 2011, and net exports also showed an upward trend [1,2]. Electricity demand growth rates over the past 10 years averaged around 1% pa reflecting sluggish growth largely due to insufficient growth from the manufacturing sector.

BiH has about 4000 MW of installed power generation capacity, with generation varying between 14 and 16 TWh pa over the last five years [3]. Coal-fired power plants account for about 60% of total generation, with hydropower plants providing the balance. In 2013, more than 95% of generation capacity was owned by the three vertically integrated state-owned enterprises namely EPBiH, EPRS (for Republic of Srpska) and EPHZB (Hrvatske Zajednice Herceg Bosne) in Mostar. All three companies perform generation, distribution, trade, and supply in their respective license areas and have maintained a reasonable degree of financial sustainability.

However, this positive recent performance disguises several problems including inadequate strategic planning and slow pace of sector reforms, one of Europe's most energy inefficient and carbon-intensive economies, and deteriorating assets and underutilized resources. There is currently no BiH-wide energy strategy, although there is one being designed. Historically, the strategic planning efforts of FBiH and RS have not been harmonized, reflecting a fragmented governance structure and energy market. An electricity market liberalization planned for January 1, 2015, was not fully implemented, and there is no platform to determine electricity prices by the market. Energy tariffs are below cost recovery. Large electricity exports historically are, in part, a reflection of less than perfectly functioning domestic markets, as electricity firms would have to sell to each other internally at below-market prices. With pre-tax residential tariffs at around 7.6 (Euro) cent per kilo-Watt-hour (kWh) at the end of 2013, energy tariffs are also too low to encourage the private sector to finance the construction of new power plants.

If no significant power generation facilities are brought on-line in the next 10 years, BiH may become an electricity importing country. A little over half of thermal capacity dates from the 1960s and 1970s, and the list of thermal power plants (TPPs) slated for closure includes about

* Corresponding author.
E-mail address: mbazilian@mines.edu (M. Bazilian).

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30% of the country's thermal capacity (470 MW out of about 1900 MW net capacity). The aging existing thermal capacity also does not comply with EU emission standards. There will therefore be a significant need for new investment in the generation sector not only to build new capacity, but also to modernize some of the existing plants and install emissions control equipment. The privately owned TPP Stanari has already incurred a total investment value of €550 million for 300 MW of generation capacity; an additional €3 billion (if not a substantially higher amount) may be required over the next 20 years to keep pace with demand, and to replace existing obsolete capacity. Other TPPs in the pipeline have uncertain completion dates, and long development periods for TPP plants are not uncommon. For example, an Engineering, Procurement and Construction (EPC) contract for TPP Stanari was signed in May 2010, and the plant was commissioned in September 2016.

Primarily thanks to the wide use of woody biomass for heating, the renewable energy sector is progressing towards fulfillment of the obligations under the Energy Community Treaty (40% share in gross consumption by 2020). However, on the power generation side the development of renewables has been slow. Currently there are no wind projects or utility scale solar projects in operation. The available hydro potential estimates date back to the Yugoslav period and are unlikely to be very reliable. They indicate a technical hydropower potential of 23,396 GWh pa, with utilized hydropower potential amounting to 9000 GWh pa (approximately 40% of the technical potential), which includes part of the hydro utilized outside BiH (EPBiH, 2006). Actual utilization of hydro within BiH has been 4500–6000 GWh pa depending on the hydrology. Notwithstanding the significant potential, addition of substantial new hydropower capacity appears unlikely without increased participation by the private sector. Hydropower potential is continually unrealized as large projects are postponed or cancelled, and the pace of development of small projects has been slow.

1.2. Planning conundrum

BiH is currently considering a number of generation development possibilities that include significant lignite/brown coal projects, multiple small to medium scale hydro projects, wind, solar, and a major gas project. The total investment requirement of these projects is around €5 billion according to the current Indicative Plan (IP, [3]) for the next 10 years, i.e., more than 30% of the country's GDP in 2015. The IP (put in place by the Independent System Operator (ISO or NOSBiH) based on inputs from BiH stakeholders), is likely to be ambitious and requires further scrutiny. Is the IP for instance in line with the efficient/least-cost plan for the sector? This is one of the central questions of this Case Study, and the need for creating an efficient benchmark plan is one of the major motivating drivers.

In addition, BiH also has put in place multiple policy goals, and the IP at the very least will need to be tested in terms of its compliance with:

- A 9% Energy Efficiency target as a part of BiH's Energy Community treaty obligations; A National Energy Efficiency Action Plan (NEEAP) was adopted in 2017 [25].
- A 40% Renewable Energy target (as per the National Renewable Energy Action Plan, NREAP) [5];
- Carbon reduction commitment as per the Intended Nationally Determined Contributions (INDC) to the UNFCCC [6]; and
- Local emissions reduction as per the National Emission Reduction Plan (NERP) [7].

1.3. Related literature

Policy analysis around generation capacity expansion including the trade-off among cost, emissions and other objectives including reliability, national security, employment, etc. dates back several decades. Meieir and Mubyai [8] was one of the early applications of an energy sector wide linear programming (LP) model. The LP model in Ref. [8] covers electricity, refinery and industrial end-use together with a macroeconomic model, albeit it was deliberately kept simple for it to be useful for developing countries with significant limitations on data. Manne and Richels [9] published an extensive analysis using their Global 2100 model that is often cited as the first authoritative study on cost of carbon reduction using an energy-economy planning model. Gomes Martin and de Alemeida [10] is one of the early applications of multi-criteria decision making embedded in a generation expansion model to explicitly evaluate the trade-off among cost, emissions and reliability. Application of optimization models for electricity planning expanded significantly during the nineties including comprehensive applications for emissions reduction policy analyses in China [11] and India [12]. There are dozens of modeling tools developed over the last 25 years that are capable of analyzing policies including a number of commercially available production-grade tools such as PLEXOS [13], as well as research-grade tools such as ReEDS [14] and OSeMOSYS [15].

Finding a generation plan that can meet sometimes conflicting policy goals continue to be a prominent issue. Diffney et al. [16] presents an analysis of the replacement strategy of the Moneypoint coal plant in Ireland using a dispatch model for a specific year 2025. They conclude that the technology options for replacing a single plant for a single year in itself quite a complex task with carbon and fuel prices changing the merit order of these options quite considerably. Bjelic and Ciric [17] focused on the distributed generation technologies including wind, solar PV, hydro and CHP plants to form mini-grids as a means to develop decentralized power systems to cut down on carbon emissions. Their conclusions include a relatively modest €4.8–7.8/MWh increase in end-user tariff needed to accommodate such reduction in emissions. Dominkovic et al. [18] and Kittne et al. [19] also broadly support these conclusions on use of renewable energy to reduce emissions in the entire South East Europe (SEE) and Kosovo, respectively. Both analyses use a high level system planning tool called HOMER. Wind and solar are shown to be prominent options that may account for up to 52% of total generation in SEE to achieve a zero emission state in Ref. [18]. Kittne et al. [19] analyzes the case of a 600 MW coal plant in Kosovo and compares it to other alternatives in the country including renewables. Their analysis suggests that Kosovo is better off by €200–400 million by using a non-coal alternative even before other substantial benefits around health and employment are taken into consideration.

The findings over the last 25 years including those in the early nineties [11,12], to more recent analyses [16–19] show a trend away from coal plants. However, a modeling exercise can also illuminate a number of nuances on technology, timing and sizing of alternatives that can vary a great deal. In the context of BiH such a study has not been conducted to date. The objective of the paper is to assess power sector investment requirements in BiH, including those needed to mitigate environmental emissions, through development of a least-cost power generation development plan. The study also aims at quantitatively addressing the major policy issues for the power sector including those pertaining to energy efficiency, renewable power generation, carbon and local pollutant emissions reduction. Section 2 presents the methodology used, and Section 3 outlines the scenarios. Section 4 presents results, and Section 5 concludes.

2. Methodology

There has been two broad set of techniques for capacity optimization namely, variants of optimization techniques, and the mean-variance portfolio theory. Hobbs [20] presents an excellent summary of the mainstream optimization methods. Awerbuch and Berger [21] presents an extensive application of the portfolio optimization for the EU countries. It is also possible to mix the elements of the two methods—an idea we outline briefly at the end of this paper for future work. We have however relied on a conventional optimization model for the purpose of

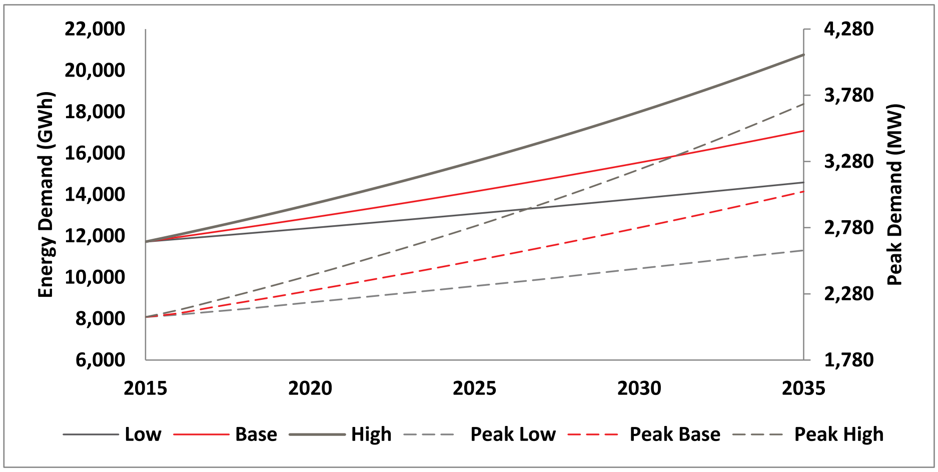


Fig. 1. Peak (MW) and energy (GWh) projections for BiH based on the IP scenarios.

this Case Study.

A mixed-integer linear programming model [20] is used to model the BiH power system over 2016–2035. One the critical issues in the BiH analysis are the emissions (both carbon dioxide and local pollutants including sulphur dioxide, dust/particulate matters and nitrogen dioxide) constraints that may require (a) significant adjustments among the power stations to dispatch to be under the limits; and more importantly (b) investment in cleaner plants/technologies to meet future limits that progressively become more stringent. There are also additional policy targets such as a renewable and energy efficiency target that need to be directly captured in the analysis to understand the implications of these targets for dispatch and generation investment. The model also considers exogenous price driven imports and exports from three neighboring countries. Thus, the objective function of the mixed integer programming (MIP) based least-cost model takes the following form (Eq. (1)):

$$\textit{Net system costs for BiH} = \textit{Total system costs} - \textit{Export revenue} \qquad (1)$$

It should be noted that export revenue is calculated using exogenously defined prices for other regions. These prices are also calculated based on a regional least-cost planning analysis prepared by the International Finance Corporation [22] and reflects system marginal costs.

3. Input assumptions and scenarios

3.1. Input assumptions

3.1.1. Demand

Fig. 1 shows the peak demand energy projections adopted from the Indicative Plan [4]. There are divergent views among BiH stakeholders on likely level of demand growth that mainly hinges on the future development of the manufacturing sector. The Low demand growth path at 1.1% pa largely reflects the average growth in the past decade. The IP uses a higher growth rate of 1.9% pa that is labeled as ‘Realistic’ growth rate in the Plan and assumes a stronger uptake from the manufacturing sector. The Realistic scenario's 1.9% pa demand growth rate is adopted as the Base scenario (‘BASE’) assumption for the purposes of the analysis. However, the Low and High (Optimistic) scenarios were in addition analyzed to understand how the capacity plan would change if the low demand trend observed during 2005–2016 would continue, or if significantly higher growth of 2.9% pa occurs going forward.

3.1.2. Supply

Table 1 lists the assumptions on major existing thermal generation plants and candidate projects. Bulk of the existing coal capacity (1334 MW) is retired by 2035 with the exception of the Ugljevik plant

Table 1
Key assumptions on major thermal generation projects.

Unit	Fuel Price (€/GJ)	Earliest comm. Year	Retire Year	Net Capacity (MW)	Efficiency	Capital Cost (€/kW)
Tuzla 3	2.55	1966	2021	90	30%	Existing
Tuzla 4	2.55	1971	2023	180	29%	Existing
Tuzla 5	2.55	1974	2030	180	29%	Existing
Tuzla 6	2.55	1978	2035	200	34%	Existing
Kakanj 5	2.53	1969	2024	100	31%	Existing
Kakanj 6	2.53	1977	2027	100	31%	Existing
Kakanj 7	2.53	1988	2035	208	32%	Existing
Gacko	2.07	1983	2031	276	31%	Existing
Ugljevik	1.98	1985	> 2035	279	31%	Existing
Stanari	2.07	2015	> 2035	263	39%	Existing
Banovici	2.30	2020	> 2035	350	41%	€ 1500
Zenica	9.4–15.0	2020	> 2035	385	55%	€ 928
Tuzla 7	2.30	2020	> 2035	410	42%	€ 1823
Kakanj 8	2.30	2024	> 2035	400	42%	€ 1490
Ugljevik 3	1.98	2019	> 2035	600	40%	€ 1416

Note: (a) Gas price varies between €9.4–15 (from 2020) per GJ across the scenarios and sensitivities; (b) capital cost of existing projects is treated as sunk; (c) Retirement year > 2035 indicate it is beyond the planning horizon for this exercise.

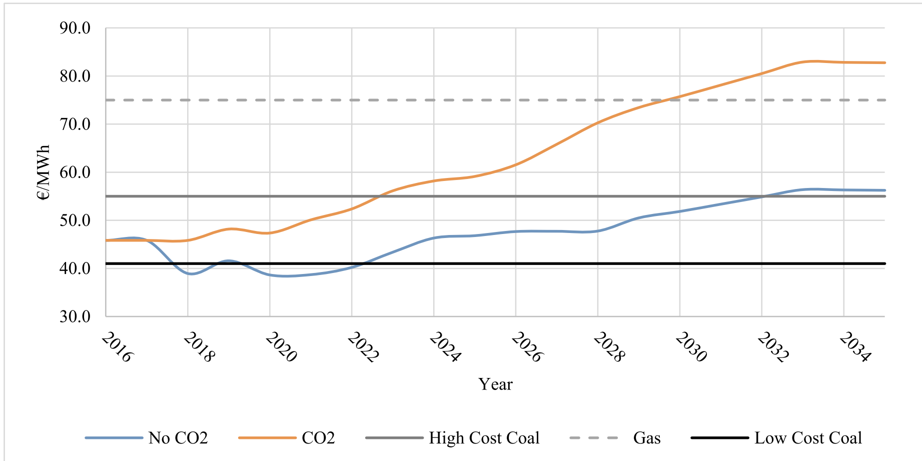


Fig. 2. Average regional electricity price with and without carbon prices (€/MWh).
Source: IFC study [22]
Note: Coal prices are assumed to remain constant over the study period.

(279 MW), which is currently undergoing investments in pollution control and rehabilitation of the generation equipment. There is, however, a portfolio of 2408 MW planned new thermal generation capacity that the planning optimization model considers (i.e., bringing in the most economical projects depending on demand and policy constraints). All candidate TPPs are coal/lignite powered, with the exception of the Zenica gas TPP.

In addition, the model considers as part of its portfolio of candidate projects significant hydro and other renewable energy projects including:

- An array of small and medium size hydro projects totaling 1830 MW;
- 350 MW of wind;[1] and
- 150 MW of solar PV.

3.1.3. Import/export and regional price

The planning analysis considers import/export from BiH using the following interconnection limits:

- BiH-Serbia: 600 MW
- BiH-Croatia: 800 MW
- BiH-Montenegro: 500 MW

Import/export is driven by regional electricity prices shown in Fig. 2. The model considers prices for individual trading partners using a price duration curve. Fig. 2 averages the prices for all trading partners and highlights two key issues: (a) Prices without carbon are very low but they do trend upwards over the years (reaching approximately €56/MWh by the end of the planning period), which may render some of the existing and new to have a reasonable upside opportunity to export power; (b) prices inclusive of carbon prices are significantly higher exceeding €80/MWh post 2032 – given that lignite/brown coal based generation would also have a very significant additional carbon cost impost, cleaner alternatives such as hydro and wind may be more competitive in a carbon constrained regime.

3.1.4. Other assumptions

In addition, the analysis was based on the following assumptions:

- Discount rate: 8%;
- Currency: Real 2016 Euro;
- Variable and fixed O&M costs obtained from multiple international sources including the Energy Information Administration Annual Energy Outlook [24];
- Load represented as monthly load duration curves (LDC) with 10 blocks for each month;
- Energy efficiency (EE) has been modelled as negative demand by scaling the monthly LDC uniformly since bulk of the EE measures will reflect a long-term reduction in energy (as opposed to demand response that targets the peak). Capital investments for energy efficiency measures have not been accounted. Not accounting of EE related investments will unlikely affect the least-cost plant as EE is generally cheaper compared to investing into new generation capacity to balance growing demand. The model considers EE as a scenario parameter reaching 9% energy demand reduction each year below the demand in the Base scenario, from 2020 through 2035. Demand reduction is applied linearly starting 2017 to reach 9% in 2020.
- CO_2 limits are based on the INDC [6]. The term ‘Stringent’ is used for the CO_2 limit which is 3% below the 1990 level of emissions or 7.7 mt in 2030. This is achievable only with international support. We also simulate a ‘Relaxed’ CO_2 limit scenario that is set at 18% above the 1990 level, or 9.4 mt in 2030, and is unconditional [6];
- Local pollutant emissions caps are based on the National Emissions Reduction Plan [7] and are the following for 2030 (in tons): 780 t for dust/particulate matters, 7446 t for NOx and 14,243 t for SOx;
- RE limit is set to 40% based on the National Renewable Energy Action Plan dated March 2016 [5];
- Variable hydro resource modelled based on historical data provided by NOSBiH;
- Renewable energy (solar & wind) modelled using detailed/hourly data from neighboring countries from the repository of renewable resource maps collected from miscellaneous World Bank planning studies in the region; and
- EPBiH's plan to provide District Heating through Kakanj 8 and Tuzla

[1] In accordance with the official limit adopted by a decision of the State Electricity Regulatory Commission in 2012, taken with a view to capacity of the grid to integrate wind without risk of instability. The BiH power system has since 2012 been more integrated in the regional power market with the possibility of procuring balancing reserve services; this ability may potentially allow for a higher volume of wind and variable RE in general be integrated to the grid. In light of this the ISO conducted a study [23] which lead to a conclusion that higher capacities of variable RE could indeed be integrated. However, this study retained the 350 MW limit on wind based on discussions with all BiH stakeholders, including the ISO and the State Electricity Regulatory Commission.

Table 2
Main scenarios.

	Capacity	RE&EE targets	CO_2 cap	Local pollutant cap
Base	Optimal	No	No	No
Indicative Plan (IP)	Enforced as per the IP	No	No	No
RE&EE	Optimal	Yes	No	No
Stringent CO_2 Limit[a] + Local Pollutants	Optimal	No	Yes	Yes
Relaxed CO_2 Limit[b] + Local Pollutants[c]	Optimal	No	Yes	Yes
Stringent CO_2 Limit + Local Pollutants + Energy Efficiency	Optimal	Yes	Yes	Yes

Note: Scenarios with CO_2 limits use regional electricity prices inclusive of carbon costs, i.e., the higher prices in Fig. 2. We have used the terms 'pollutants' and 'emissions' interchangeably to describe the emissions scenarios.
[a] 3% below 1990 level.
[b] 18% above 1990 level.
[c] As per NERP.

Table 3
Comparison of main scenarios (2006–2035).

	Net System Cost	CAPEX[a]	OPEX	System LCOE[b]	Total Generation	Net Exports as % of internal demand
	€m	€m	€m	€/MWh	(GWh)	(%)
BASE	3774	3451	4221	42	397,851	36%
Indicative Plan	4772	3888	4589	53	427,373	47%
RE&EE[c]	3232	3058	3956	41	370,134	39%
Stringent CO_2 limit + local pollutants	4200	2235	3010	40	291,216	0%
Relaxed CO_2 limit + local pollutants	3994	2760	3254	39	315,522	8%
Stringent CO_2 limit + local pollutants + EE	3433	2235	3010	38	291,216	9%

[a] Total overnight capital cost of all plants over 2016–2035. Note that the net system cost includes only the annualized component of capital costs over 2016–2035 which is typically a fraction of total overnight CAPEX. More specifically, adding CAPEX and OPEX does NOT yield the system cost because the former is undiscounted and includes all of the upfront capital costs including plants that will continue to operate beyond 2035.
[b] Resource costs only (excludes carbon costs).
[c] Specific EE investment costs are NOT included; demand is reduced to meet EE policy targets.

7 units are modelled as a minimum loading restriction for the relevant heating periods, ensuring the plants are kept on to meet heating load.

3.2. Scenarios and sensitivities

3.2.1. Main scenarios

The analysis considers six main scenarios which include three 'emissions unconstrained scenarios', followed by three emissions constrained scenarios:

1. **Base:** Medium demand growth of 1.9%/pa, no carbon or local pollutant emission caps, optimized capacity plan;
2. **Indicative Plan (IP):** Fixed capacity plan, based on the current IP of the ISO;
3. **RE&EE:** Renewable energy target of 40% and energy efficiency target of 9% included;
4. **Stringent CO_2 Limit + Local Pollutants Caps:** 3% below 1990 CO_2 level and NERP limits;
5. **Relaxed CO_2 Limit + Local Pollutants Caps:** 18% above 1990 CO_2 level and NERP limits; and
6. **Stringent CO_2 Limit + Local Pollutants Caps + EE:** Energy efficiency targets added to Scenario 4.

Table 2 summarizes the specification of the main scenarios.

3.2.2. Other scenarios and sensitivities

The following variations and sensitivities on the Base Case were also analyzed:

- Low (1.1% pa) and High (2.9% pa) demand scenarios;
- Variation in hydro availability;
- Coal plants with higher costs and power purchase agreements (PPAs) in a range of €55–60 per MWh;
- Coal plants with higher costs and PPAs in a range of € 55–60 per MWh with net export forced to be positive;
- Variations to emissions constrained cases:
  - o Only carbon limit (−3% and +18%),
  - o Only local pollutant limit, and
  - o Carbon and local pollutant limits jointly with net export forced to be positive.

4. Results

4.1. Comparison of results of main scenarios

A high level comparison of the model results under the main scenarios is presented in Table 3. All of the parameters are aggregated/averaged over 2016–2035. Net system costs are presented in discounted terms. CAPEX or capital expenses are not discounted and these are the total overnight capital costs of all new builds.

A number of important observations arise:

- Net system cost over the next 20 years varies significantly between €3.2 billion to close to €4.8 billion. RE&EE represents the low end of net system costs, the IP the high end, and the unconstrained BASE scenario represents an interim point. The RE&EE scenario benefits immensely from the 9% EE-induced demand reduction, albeit we do *not* include in the net system costs the investment or other costs of implementing the EE program.[2] The net system cost of the IP

[2] There is currently no cost estimate available for the investments needed to meet the stated EE policy objectives in BiH. Nevertheless, discounted costs of

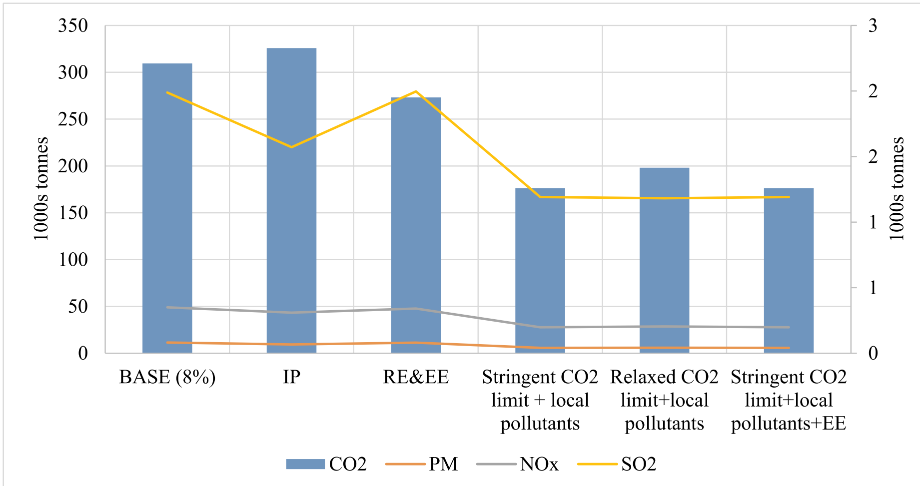


Fig. 3. Comparison of carbon and local pollutant (SO2, NOx and Particulate matters).

scenario is almost 50% higher than the RE&EE scenario, and in fact, *higher* than even the most stringent emissions constrained scenario (without EE);

- CAPEX or total generation capital requirement varies between €2.2 and €3.9 billion over the same period. Net system cost is the highest for the Indicative Plan although it does not require meeting any of the policy constraints – it is driven mostly by relatively early build of coal plants. CAPEX in fact explains to a large extent why the IP scenario has the highest net system cost. Building four large coal plants fairly early in the planning period, Zenica gas plant and additional hydro renders the total CAPEX to be €437 million higher than in the optimized BASE scenario. Once built, these plants are also dispatched whenever there are opportunities to recover the short run marginal costs including export to other markets. Although the IP scenario has the highest export volume, it clearly has sub-optimality in the capacity plan that is not offset by the higher export revenue;
- Net export (export less import as a % of domestic demand) volumes vary significantly:[3]
  - o The Base case has 36% net export indicating economically efficient export opportunities in an unconstrained scenario. This would by and large support the aspiration of BiH to become a significant net exporter in the region. Net exports are higher in the BASE than ~23% observed on average over the last decade. This is driven mostly by higher regional electricity prices post 2025, which in turn support part of the new build coal in later years;
  - o The Indicative Plan has the highest net export albeit at the expense of the highest OPEX and significantly higher capital outlay. However, as we have noted already – the net system cost for the scenario suggests part of the capacity – specifically Zenica gas plant – is sub-optimal;
  - o Following RE and EE target opens up significant export opportunities as domestic demand reduces. System cost reduces while export revenue remains largely unchanged, yielding a significantly lower net system cost;
- Exports drop drastically for the emissions constrained scenarios including almost no exports (if EE measures are not implemented (to meet the stringent (3% below 1990 level) CO_2 target. This is expected as the carbon constraints in particular discourage some of the coal plants that would otherwise be economic (in the BASE).
- The System LCOE figures are also useful to appreciate why exports are such a significant aspect of the unconstrained scenarios – at a System LCOE of €42/MWh (in BASE), BiH coal-based generation is highly competitive in the region given our assumptions on the regional prices.

Fig. 3 shows emissions levels for carbon and local pollutants for the main scenarios. Aggregate CO_2 emissions (2016–2035) exceed 300 million tonnes (mt) for the unconstrained scenarios. This implies a significant increase in emissions from ~11 mtpa (million tonnes per annum) currently (for the power sector only) to ~15 mtpa on average over the next 20 years. CO_2 limits (for the 3% below 1990 or Stringent limit scenario) according to the INDC tighten over the years to bring it down to 7.7 mtpa by 2030. As a result the total CO_2 emissions require to fall well below 200 mt to around 177–180 mt for the constrained scenarios. It holds significant implications for new coal build, introduction of additional hydro and RE relative to the BASE, and hence for other local pollutant emissions too.

Fig. 4 shows the capacity mix for the six main scenarios. Total capacity is the highest for the IP scenario because it includes Zenica gas plant (385 MW) and wind (350 MW) that are not selected by the model as part of the BASE. All four policy constrained scenarios include wind up to the 350 MW limit. Coal capacity is constrained significantly in the emissions constrained scenarios, but the hydro capacity is considerably higher at 753 MW for these three scenarios. New HPP capacity needed in all CO_2 scenarios is larger than the required coal-fired TPP capacity.

Table 4 shows the selection of coal projects across the scenarios. The significant points to note are:

1. The gas plant is never selected unless it is forced into the mix as we do to simulate the IP. This reiterates the point on sub-optimality of the gas project. It is interesting to note that even in the Stringent emissions target scenario, gas is not picked, suggesting high cost of gas and distribution network expansion does not render it to be part of the emissions constrained solution. Gas costs have to drop very significantly before it is rendered economic;
2. All four coal projects are selected in BASE, but they come in much later (6–15 years) than in the IP in three out of four cases, with one

(footnote continued)
the needed EE investments, assuming a cost of 2.68 Euro cents/kWh (based on a World Bank estimates of public building EE investment costs in BiH) would represent €327 million over 2016–2035. This cost estimate suggests the EE program is likely to have a strong net benefit. This is probably at the high end of the cost estimates as the levelized EE costs according to the same study are typically lower in the region (1.7–2.1 Euro c/kWh for Serbia, Montenegro and Kosovo, WB 2016); assuming these cost levels would yield a much lower EE cost estimate for BiH.

[3] Historically too net exports have been highly variable from 5% to 54% over 2005–2015 and averaged around 23.4% over this period.

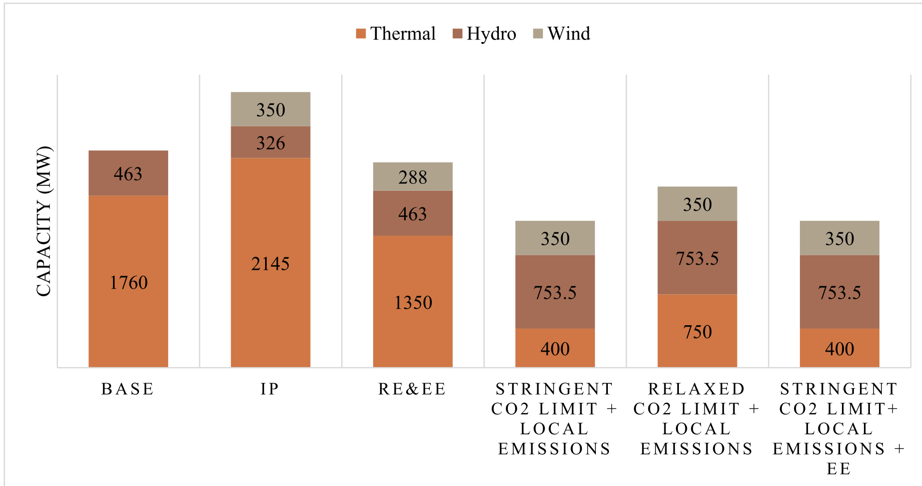


Fig. 4. Capacity mix (MW).

Table 4
Selection of thermal projects by commissioning year.

	Banovici (350)	Tuzla 7 (410)	Kakanj 8 (320)	Ugljevik 3 (600)	Zenica (385)
BASE	2030	2035	2024	2025	
IP	2020	2020	2024	2019	2020
RE&EE	2035		2024	2029	
Stringent CO_2 limit + local pollutants			2026		
Relaxed CO_2 limit + local pollutants	2028		2024		
Stringent CO_2 limit + local pollutants + EE			2026		

of them coming in the very last year of the planning period in our analysis;

3. Introduction of RE&EE obviate the need for one coal plant. Stringent carbon limits eliminate two more coal plants, although a Relaxed (18% above 1990 level) retains two coal plants in the mix.

It should be noted that the number and timing of coal projects rather than the selection of specific power plant is important in this context.

4.2. Other scenarios and sensitivities

Fig. 5 compares BASE with the sensitivities performed around it in a policy/emission unconstrained paradigm. These give useful insights into the nature of variation in net system cost and CAPEX, namely:

- Low demand (1.1%) growth rate reduces capacity costs by €748 million. If demand is further reduced by 9% due to EE measures, the CAPEX costs drop by €1273 million while system costs drop by €939 million, in part because of significantly more headroom to export (which increases to 44%);
- Higher demand (2.9%) growth rate leaves capacity cost unchanged, but increases OPEX by €372 million. There is no need for additional thermal units (and Zenica is not economic under a higher demand growth rate either), but the export volume reduces to 32% (as compared to 36% in BASE); and
- Capacity costs increase in the variable hydro availability scenario as a more variable but higher overall availability of hydro attracts higher investment in hydro. As a result, the net system costs drop by €680 million and leaves less room for dispatch from the thermal units.

4.2.1. Benefits of energy efficiency

The difference between two scenarios without and with EE represents the reduced capital and operating cost of the system due to a reduction in demand delivered through the EE program. We calculate the difference in net system cost between BASE and BASE + EE scenarios, i.e., without any emissions constraints. This difference represents an estimated benefit of the EE policy at €552 million. The discounted investment cost of EE (even with relatively high cost of investments in EE options) is estimated at around €327 million. These benefits further increase in an emissions constrained world. A comparison of the Stringent CO_2 limit scenarios show EE benefits increase to €768 million (in discounted terms). As the value of EE to the system *increases* while that of the thermal projects significantly diminish, it is clear that the EE program adds significant flexibility and has "option value" that should also be considered in evaluating the investment costs and benefits of the EE policy.

4.2.2. Interaction among carbon & local pollutants

Similarly, a comparison of system costs for BASE with BASE + Local Pollutants Limit, yields the incremental cost of meeting the NERP limits *only*. This incremental cost is compared to that of a joint CO_2 and local emissions cap scenario to understand if there is any added value ('co-benefit') of jointly optimizing carbon and local emissions control.

The interaction between carbon and local emissions constraints is important. Adding the local emissions constraint on top of the Relaxed CO_2 target increases the net system cost by €277 million. In fact, adding just the local emissions constraint to BASE, absent installation of emissions control equipment at existing plants would have a higher (discounted) cost impost for several years of €385 (see section below). Adding the Relaxed carbon limit on top of BASE in comparison adds a more modest €220 million. There are two important messages associated with these two numbers that are worth understanding in more detail:

- The discounted cost of the Relaxed/lower carbon cap at €220 million is more manageable and is almost half of that of the Stringent

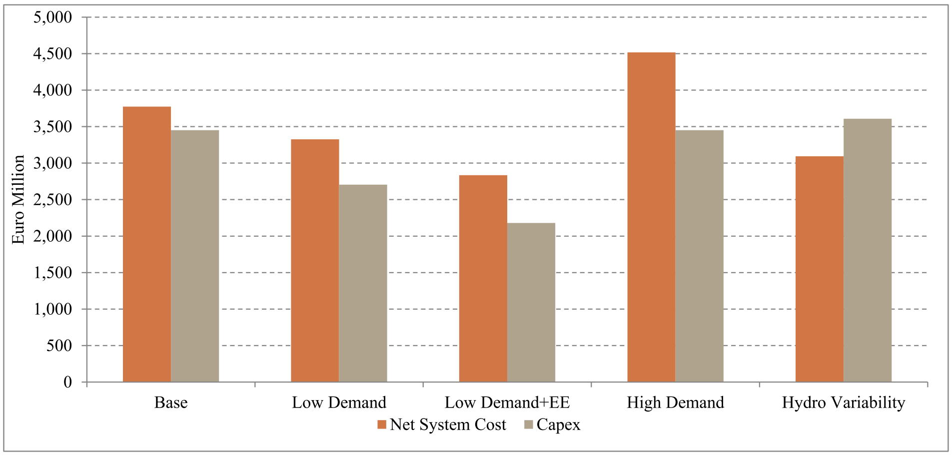
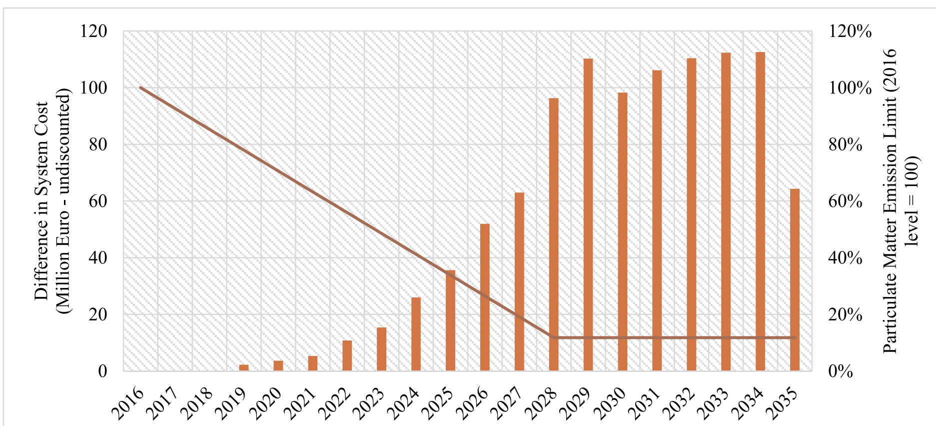


Fig. 5. Net system cost and CAPEX for sensitivities around BASE (€m): Unconstrained.



Note: This scenario compares BASE with BASE+Local Emission Limit scenario.

Fig. 6. Annual benefits of local emissions control equipment.
Note: This scenario compares BASE with BASE + Local Emission Limit scenario.

CO_2 limit (€426 million). The Relaxed scenario would leave open a greater prospect for thermal generation and export for BiH, as more coal based generation is possible before the more relaxed CO_2 cap is met.

- The addition of local pollutant constraint adds €277, i.e. more than that for a Relaxed carbon limit. If we were to consider adding only the local pollutant limit the cost impost is greater at €385 million. Although there are some co-benefits of addressing these two limits together of (€385-€277) €98 million by switching to non-coal based options, installation of local emissions control equipment (FGD, filters and low NOx burners) on existing units is a more economic option as we discuss in the next sub-section. Nonetheless, a judicious mix of all options to jointly address carbon and local emissions needs to be done in more detail to assess the type of controls, their location and timing - an important task to ensure the overall cost is minimized.

4.2.3. *Benefits of local emissions control equipment*

The analysis done on the benefits of local emission control equipment seeks to compare the cost of the investments needed to meet the NERP objectives and emissions limits (estimated at around €350 million) with the costs of not installing the emission controls and, instead, decommissioning old coal TTPs early and investing in new, less emitting TPP generation capacities.

The difference in system costs between a local emissions constrained scenario and the BASE therefore represents the additional costs that would be incurred *if* emissions control equipment are not installed on the existing units. In other words, the difference in system costs is essentially the 'benefits' of emissions controls that can be compared with the NERP program cost of emissions control equipment.

Fig. 6 provides further important insights into the benefit of local emissions control following on from the discussion we had in the preceding sub-section. It shows the undiscounted cost difference between BASE and BASE + Local Pollutant/Emission constraint scenarios. Installing controls renders the dispatch to be the same as the BASE as there is no need to adjust dispatch or invest in cleaner generation. We also plot dust or particulate matter emission limits (expressed as a % of the 2016 level) to indicate how the benefits grow much larger in later years as the limit binds significantly. These benefits are very significant, namely:

- Discounted value of all benefits is €385 million. One way to interpret is that if BiH were to invest in controls in all power plants (other than those that are in the opt-out list) *today* – the immediate pay-off is this amount; but
- If these investments are spread out over the years to match the NREP obligation, i.e., install controls closer to when the limits bind – the total undiscounted benefits are €1024 million; and
- Hence, considering the program cost is estimated at approximately €350 million – it is very likely that the program cost incurred over the next 10–15 years will be comfortably recovered rendering it to be significantly economic. As we have alluded to before – the location, timing of controls and a broader consideration including carbon, EE and RE policies should be borne in mind to optimize the

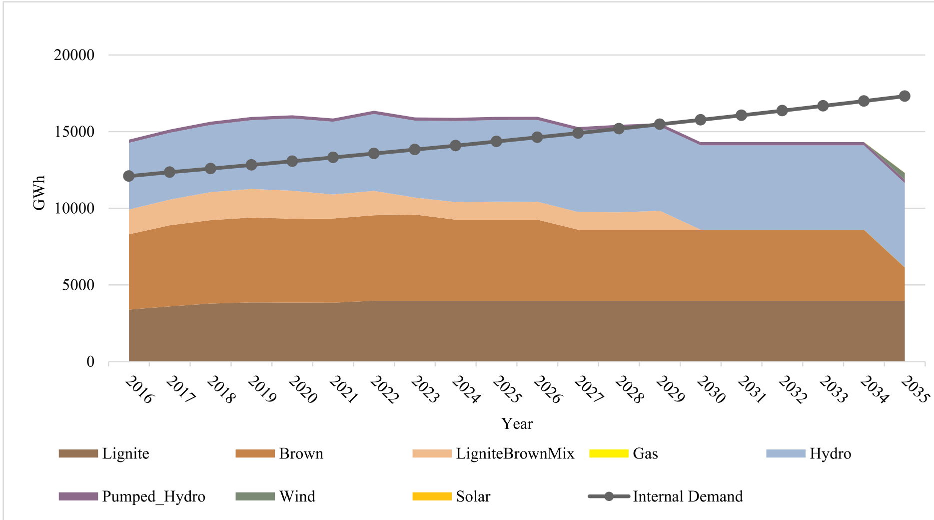


Fig. 7. Generation mix: BASE with higher cost for new coal.

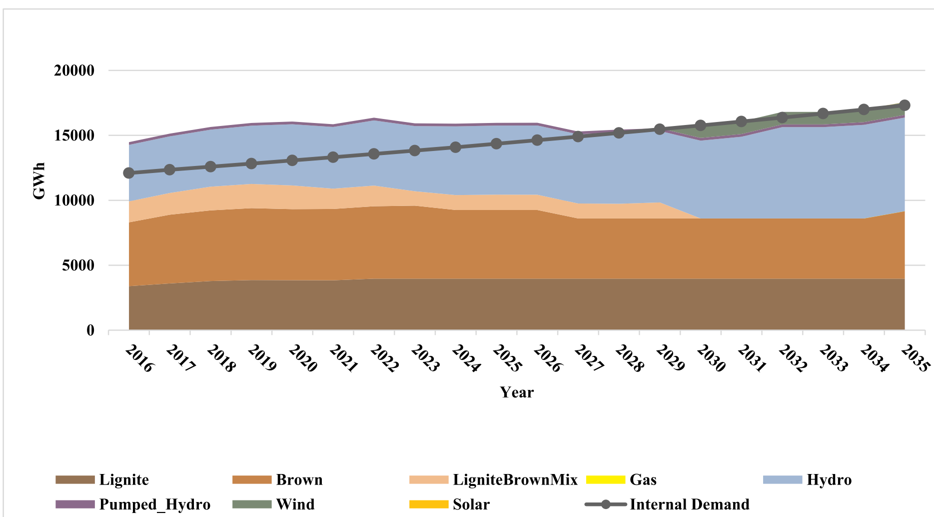


Fig. 8. Generation mix: BASE with higher cost for new coal and national energy security.

set of options that economically meet all of these policy objectives.

4.3. Implication of potentially higher costs for new coal

There are two additional issues that we explore around this scenario, namely:

1. What happens if the cost of new coal projects turn out to be higher than assumed in our BASE case? As the discussion around unconstrained BASE and other scenarios have highlighted prominently – export revenue is a key driver of the new coal projects with LCOE of these projects typically below €50/MWh. However, plant costs can differ, and may well turn out to be higher as has been the experience in the region for relatively small-size units similar to those being planned in BiH. We have therefore constructed a scenario where all four coal projects are assumed to be more expensive, offering PPAs in the range of €55–60 per MWh. In our analysis, we test *if* these projects would be economic for BiH or not. This includes the possibility that none of these projects may be selected if BiH has cheaper options to supply, including import. In other words, we do not assume these projects will be able to secure PPAs at that cost, and ask instead if these projects are worthwhile at the higher cost bracket; and
2. Since the above scenario as well as some of the emissions constrained scenarios leave BiH potentially as a net importer for an extended number of years, we have also analyzed what would be the cost of meeting a national energy security objective. We have simulated energy security by imposing the constraint that BiH must have at least a balanced position for each of the planning years, i.e., net export for BiH annually has to be greater than zero. If this restriction is binding, it would generally imply an additional cost that can be attributed to the price for following a national energy security policy.

Fig. 7 shows the generation mix and domestic/internal demand for BiH for 2016–2035. None of the coal projects is selected with BiH becoming heavily dependent on import post 2030. This leads to €212 million in higher costs relative to BASE. Since the coal projects require a baseload operation at high utilization factor (e.g., 85%) and regional prices (Fig. 2) even during the later years do not go beyond €56/MWh on average – it is not surprising to see the coal projects not being selected in this case.

Fig. 8 shows the outcome for the second sensitivity when we enforce BiH to be energy secure. Net system cost go up in this case by €285 million relative to BASE or €73 million (i.e. €285 less €212 million) higher than the previous sensitivity. This additional €73 million is the cost of national energy security that is met primarily through selection of additional hydro and wind.

5. Conclusions

BiH has significant opportunities to invest over €3 billion in new power plants over the coming two decades to form a robust and highly competitive generation system. That said, aspirations to build up to four new lignite/brown coal plants and a gas plant in the next ten years (as per the IP) require closer scrutiny keeping in view the policy objectives on renewable energy and energy efficiency (as part of the Energy Community obligations and the forthcoming National Energy Efficiency Action Plan), CO_2 reduction commitment as per the INDC (2015), and local pollution reduction as per the NERP (2015). All of these policies would require reduction in fossil fuel generation and/or substantial investment to install emission controls, and improved efficiency.

Our analysis aims to develop a balanced view of capacity/generation mix keeping in view both opportunities (including export opportunities) and risks. Combining and pursuing both the RE and EE policies present significant upside opportunities that can reduce net system cost by €541 million (excluding EE investment costs estimated at €327 million), boost export volume, and reduce generation investment requirements by €393 million (excluding EE investment). Optimized emission constrained scenarios reduce the number of coal projects from four down to a maximum of two. In fact, the viable coal projects are reduced to just one if we consider the Stringent (3% below 1990 level) carbon target. Considering a) the current development of coal projects in the region (for example the 350 MW Kostolac unit in Serbia), and proposals for additional coal capacity (the 225 MW Pljevja II lignite unit in Montenegro, and 500 MW Plomin C unit in Croatia; and b) the EU environmental obligations of BiH, the least-cost plan developed and presented in this Case Study would reduce the risk of new coal investments presented in the country's IP becoming stranded assets.

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