Bosnia and Herzegovina Power Sector Note: Least-cost Power Development Plan

FINAL REPORT

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ABBREVIATIONS AND ACCRONYMS

BiH	Bosnia and Herzegovina
CAPEX	Capital Expenditure
CO2	Carbon Dioxide
DH	District Heating
EE	Energy Efficiency
EP	Elektroprivreda
EPBiH	Elektroprivreda Bosne i Hercegovine
EPHZHB	Elektroprivreda Hrvatske Zajednice Herceg Bosne
EPRS	Elektroprivreda Republike Srpske
ESMAP	Energy Sector Management Assistance Program
FBiH	Federation of Bosnia and Herzegovina
HPP	Hydro Power Plant
IEA	International Energy Agency
INDC	Intended Nationally Determined Contributions
IP	Indicative Plan
ISO	Independent System Operator
LCOE	Levelized Cost of Electricity
LDC	Load Duration Curve
LP	Linear Programming
MIP	Mixed Integer Programming
MOFTER	Ministry of Foreign Trade and Economic Relations
NEEAP	National Energy Efficiency Action Plan
NERP	National Emissions Reduction Plan
NREAP	National Renewable Energy Action Plan
OPEX	Operational Expenditure
O&M	Operational and Maintenance
RE	Renewable Energy
TPP	Thermal Power Plant
VRE	Variable Renewable Energy
Wh	Watt-hour (TWh = Terra Watt hour GWh = Giga Watt hour

1. EXECUTIVE SUMMARY

Context

This report presents the findings of the Bosnia and Herzegovina (BiH) Power Sector Note that focuses on a least-cost planning analysis of the BiH power sector over the next two decades (2016-2035). This World Bank ESMAP-funded study was developed in association with the Independent System Operator (ISO or NOSBiH) and other BiH stakeholders, including governmental entities and the generation utilities in BiH.

Currently, BiH has about 4,000 MW of installed power generation capacity. Three government owned power utilities, or Elektroprivredas (EPs), are the most relevant players in the power sector. These are "JP Elektroprivreda Bosne i Hercegovine - d.d." (EPBiH) in Sarajevo, "MH Elektroprivreda Republike Srpske a.d." (EPRS) in Trebinje, and "JP Elektroprivreda Hrvatske Zajednice Herceg Bosne d.d." (EPHZHB) in Mostar. 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 EPs.

The analysis is intended to gain insights into strategic issues that are pivotal to the power sector in BiH that had many promising developments over the last 15 years, but also face significant challenges. At one level, BiH power sector has already made significant strides. For instance, (a) power generation in the country increased by 50% between 2001 and 2013 and per capita generation reached that of other Eastern European countries, (b) distribution losses halved between 2007 and 2010, (c) exports more than quadrupled between 2001 and 2011. Electricity exports have accounted for 23% of domestic consumption over 2005-2015 – a fact that has encouraged the generation companies to adopt plans for export-oriented generation projects to exploit the low-cost resources in the country. That said, there is also a long list of challenges that the sector needs to address, not the least of which is a lack of strategic planning in the country to properly address generation investment requirements keeping in view several policy objectives that must be met over the next two decades. The need for such planning analysis is exacerbated by the fact that at least 30% of the thermal capacity in the country is scheduled to close down in the short term. There has also been very little progress on harnessing hydro and other renewable energy (RE) resources that are central to *inter alia* BiH's Indicative Nationally Determined Contribution (INDC) for carbon reduction as well as local pollution reduction.

The analysis presented in this report is done in this context to ameliorate on the fragmented planning processes, and to form a clear direction that the sector needs to take in deciding the best mix of thermal and renewables. The analysis takes a critical look at the demand-supply balance in Bosnia and Herzegovina over the next 20 years (2016-2035) to identify generation investments that are most economical for a number of alternative scenarios, including scenarios around BiH's policy objectives on carbon emissions, local emissions control, renewable energy and energy efficiency. It also compares and contrasts an optimized/least-cost plan with the Indicative Plan (IP) that has been prepared by the ISO,

collating a wide range of projects proposed primarily by two of the main Elektroprivreda (EP) generation companies in BiH, namely EPBiH and EPRS. There is no regulatory mandate or capacity in the existing regulatory body at present to undertake a national power system planning exercise. Our review of the IP suggests that the IP is by and large a 'wish list' of all the projects considered by the two major EPs and not necessarily the 'least-cost' plan. This is confirmed from the discussions we had with the stakeholders including the ISO. The IP does include a notional contribution of generation from these projects to show that the maximum generation from these projects can be in excess of domestic demand. A major objective of the current analysis is therefore to optimize the portfolio of projects subject to different policy constraints to see how such an optimized plan may differ from the IP in terms of cost and other performance indicators (e.g., emissions, export and investment requirements).

The optimization analysis considers a number of significant lignite/brown coal projects, multiple small to medium scale hydro projects, wind, solar and a major gas project. The total investment requirement among those projects is around €5 billion according to the IP (2016) for the next 10 years. One of the main goals of this study is to analyze whether the IP plan is in line with the efficient/least cost plan of the sector. The study also aims at quantitatively addressing the major policy issues for the power sector, including those pertaining to:

a) 9% Energy Efficiency (EE) target included in BiH's Energy Community Treaty obligations;
b) 40% renewable energy target (as per the National Renewable Energy Action Plan, NREAP);
c) Carbon reduction commitment as per the INDC; and
d) Local emissions reduction as per the NERP.

In addition to the above mentioned the model considers the energy exchange with the neighboring countries, Serbia, Croatia and Montenegro. Of major importance in this study is the amount of energy trade across the borders of BiH and the economic implications associated with the revenues and costs from selling and importing electricity, respectively, as well as the energy security issues arising under scenarios where BiH becomes a netimporter of electric power

Methodology

A state-of-the-art linear/mixed integer programming based planning model developed by the World Bank planning team has been used for the analysis. The model produces a leastcost long term plan by minimizing the net system cost defined as:

Net system costs for BiH = Total system costs – Export revenue

Total system costs include: annualized cost of new build, fuel costs, fixed and variable O&M, cost of import, and cost of unserved energy (if any). It should be noted that export revenue is calculated using exogenously defined prices for other regions. The analysis considers system constraints that include:

- Demand and Reserve Requirement;
- Generation (maximum and minimum) and Transmission Limits;
- Joint capacity limit on transmission lines to carry energy and reserve;
- DC approximation of load flow constraints including piecewise linear losses;
- Transmission security constraints;
- Any applicable constraint on demand side response; and
- Policy constraints including CO_2 and local emissions limits and EE and RE targets.

Key assumptions around demand, supply, import/export and other miscellaneous issues are discussed below:

- **Demand**. Growth rates for three scenarios (pessimistic, central and optimistic) were adopted from the IP using annual growth rates of 1.1%, 1.9% and 2.9% respectively;
- **Supply**. The assumptions on major existing and candidate thermal and hydro projects were made based on the IP plan and discussions with the major electricity producers (EPs). The portfolio of projects that the model chooses from includes four (Banovici, Tuzla 7, Kakanj 8 and Ugljevik 3) lignite based projects and Zenica, a gas project, that form the main supply options in the IP;
- **Import export and regional trade**. Wholesale electricity prices for neighboring countries are based on a regional least-cost planning analysis (IFC, 2015);
- **CO_2 constraints** are based on INDC (Stringent: 3% below 1990 levels or 7.7mt per annum by 2030; and Relaxed: 18% above 1990 levels or 9.4mt per annum by 2030);
- **Local emissions constraints** are based on the NERP (780 t for dust/particulate matters, 7,446 t for NOx and 14,243 t for SOx by 2028);
- **RE penetration** needs to be 40% of internal demand starting 2020 as per the Energy Community Secretariat (2016) analysis; and
- **Other assumptions**: Discount rate of 8%, real 2016 Euro, EE reduction on load has been assumed to be 9% annually compared to the central load growth rate scenario, a maximum cap of 350 MW was applied for wind generation due to transmission constraints.

This study investigates a total number of 15 scenarios that considered different combinations of demand, policy (e.g., RE and EE with and without emissions constraints),

hydrology etc. A "Base" case, which included a central view on demand growth (1.9% pa) and no policy constraints, is compared with alternative policy scenarios. Specifically, a comparison of the Base with the IP is of interest in order to see if the fragmented planning in BiH might lead to sub-optimal outcomes, including in terms of requiring excessive capital. Furthermore, the analysis also explores the implications of an increase in cost of the proposed coal projects assuming these investments occur by private developers with an expected Power Purchase Agreement (PPA) price of €55-60/MWh, which is marginally higher than the levelized cost of €48-57/MWh.

Key Findings from the Modeling Analysis

Table 1 summarizes some of the key outputs complemented by Table 2 that lists the selection of five major thermal projects.

Table 1. Comparison of various system wide metrics among main scenarios

		Net System Cost	CAPEX	OPEX	System LCOE	Total Generation	Net Exports*	Coal consumption
		€m	€m	€m	€/MWh	(GWh)	(GWh)	mt
1	BASE	3,774	3,451	4,221	42	397,851	36%	273
2	IP	4,772	3,888	4,589	53	427,373	47%	292
3	RE&EE	3,232	3,058	3,956	41	370,134	39%	250
4	Stringent CO_2 limit+local pollutants	4,200	2,235	3,010	40	291,216	0%	161
5	Relaxed CO_2 limit+local pollutants	3,994	2,760	3,254	39	315,522	8%	176
6	Stringent CO_2 limit+local pollutants+EE	3,433	2,235	3,010	38	291,216	9%	161

** As % of internal demand*

Table 2. Year of commissioning of candidate thermal projects

	Banovici (350)	Tuzla 7 (410)	Kakanj 8 (400)	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		

Following are the key observations that can be made:

- **BiH has significant opportunities (and needs) to invest over €3 billion in new power plants over the coming two decades** to renew and build a robust and highly competitive generation system – a major share of it can be in the form of lignite/brown coal-fired power plants with very low operating costs;
- 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, CO_2 reduction commitment as per the INDC, and local pollution reduction;
- Our base case (BASE) that assumes none of these policy interventions, does support building all four coal plants. **However, in the BASE scenario the timing of these builds is delayed by 6-15 years for three out of four projects**. Also, the gas plant (Zenica 385 MW) is not selected in the BASE. These delays and exclusion of Zenica in the BASE scenario imply, **compared to the IP, significant savings to BiH making the overall system cost about a €1 billion (or 21%) lower in terms of discounted net system cost over 2016-2035**.
- Combining and pursuing both the RE and EE policies present significant upside opportunities that:

1. **Reduce net system cost by €541 million** (excluding EE investment costs);
2. Boost export volume to 39%; and
3. Reduce generation investment requirements by €393 million (excluding EE investment); but
4. **These two policies are not sufficient to ensure meeting the carbon and local emissions limits** included in the INDC and NERP.

- Optimized emission constrained scenarios in general:
  1. **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;
  2. **Emphasize the need for construction of significantly more hydro capacities.** Moreover, required new HPP capacity in all constrained scenarios over the planning period is larger than the required new coal-fired TPP capacity;
  3. **Drop export volume below 10%** - in fact it goes down to 0% for the most stringent scenario; but still
  4. Does not include gas based generation.
- Given the thin margin between delivered cost of coal-based electricity in BiH and forecasted regional prices (and risk of cost escalation of coal projects), **higher costs for four new coal projects were considered ('High PPA').** In this case:
  - **None of the coal projects are selected by the model**; As a result, BiH becomes a significantly reliant on imports post 2030, with a €212 million increase in cost relative to the BASE.
- While new thermal projects face the risk of being uneconomic/stranded, from a policy constraint or cost escalation perspective, **the benefits of installing local emissions control equipment is likely to be strongly positive**:
  - There is an **absolute minimum benefit of €385 million** (compared to the cost of trying to meet the local emission limits without installing control equipment) if all of the controls are installed today to start meeting the 2030 emissions standard;
  - **The benefits can be as high as €1,024 million** if the controls are installed closer to the 2030 period; and
  - Therefore, an emissions control program in the vicinity of €350 million (i.e. at level indicated by the NERP) spread over the next 10 years is likely to be economic.
- **Coal consumption varies significantly under the various scenarios,** being about 3540% lower in the emission constrained scenarios than in the Base scenario.

Key Messages

The first key message that emerges from the analysis is that the BiH power sector holds significant opportunity to exploit its ability to develop relatively low-cost generation resources including lignite, hydro and other renewables. There are economic opportunities of at least €3 billion over the next two decades to meet domestic demand and export. Absent any carbon emissions target, exports can substantially increase from 23% observed in the past decade to 36% over 2016-2035. Average annual export revenues over this period can amount to 3% of the GDP in 2015. There are however significant risks associated with an export-oriented strategy. Firstly, as the Indicative Plan scenario outcome clearly demonstrates, an overinvestment in thermal projects may cost BiH €1 billion, although excess uneconomic generation does boost the export share to 46%. Secondly, if the carbon and other emissions are mandated, some of the thermal projects may be rendered uneconomic and export share will as a result drop drastically to less than 10% of domestic consumption.

A second key message that emerges from the analysis is for BiH to re-focus on hydro and wind development to offset the risks associated with a carbon/emission constrained scenario. The findings of the policy constrained clearly suggest that BiH should develop 753 MW of new hydro and at least 350 MW of wind over the coming two decades under all carbon/emission constrained scenarios. The hydro capacity requirements in fact exceed that of new coal under these scenarios.

Third, given the significance of these outcomes and a relatively scarce level of information and fragmented state of planning, BiH needs to first put together a decision making framework that integrates the individual project plans – primarily from the EPs – and the policy objectives to form a coherent national energy plan. The framework also enables the policy makers and regulators to gain valuable insights into major programs such as energy efficiency, local emissions control, viability of commercial agreements with independent power producers, renewable portfolios and national energy security.

The planning process initiated through this exercise needs to continue, enhancing and expanding data and resolution as planning capacity improves over the years. We recommend that the ISO, or another suitable organization, obtains appropriate planning software and other tools to support this process.

The analysis that we have done casts light on the priority, timing and economics of the proposed investments, leading to the following specific conclusions and recommendations that should be considered in revising the current Indicative Plan:

On Thermal Power:

- The timing of all of the new thermal projects in the Indicative Plan requires a closer scrutiny because a least-cost plan (even without any policy constraint) delays several

of them by more than 5 years and up to 15 years; policies around carbon can eliminate at least two if not three of these projects (with corresponding implications on coal consumption);

- Cost escalation of these projects to even €55-60/MWh – which happens to be at the low end of PPAs in the region – would risk these projects being uneconomic, pointing to a need for a careful review and analysis of the costs of the plants being considered;
- Zenica gas plant is not needed in any of the scenarios including extreme ones that consider emissions constraints and no new coal projects.

On Renewable Energy, Energy Efficiency and CO_2 targets:

- Both RE and EE projects exhibit excellent economics to lower OPEX and boost export, and complement carbon and NERP local emission reduction policies. Energy efficiency in particular can significantly lower the cost of reaching CO_2 targets. It is therefore important to pursue the implementation of these policies in a coordinated manner.
- All emission constrained scenarios would require 750+ MW of new hydro and 350 MW of wind. A systematic framework to encourage the development of these projects is essential.

On Local Emissions Control:

- The investments in the emission controls envisaged in the NERP are likely to have a strong economic case, freeing up significant generation potential from existing projects to support export (as the TPPs can be operated more before hitting emission target levels);
- Adding emissions control would also typically involve extension of the life of the plant that in turn may reduce the need for new thermal capacity. The current analysis already considers one such life extension (for Ugljevik 279 MW unit), but further considerations will need to be given to such extensions for the other plants; and
- There should be a thorough examination of the specific controls and life extensions, and timing of these in line with all other policy objectives to optimize across all of the objectives.

2. INTRODUCTION

2.1. Report Background

This report presents the findings of the Bosnia and Herzegovina (BiH) Power Sector Note that focuses on a least-cost planning analysis of the BiH power sector over the next two decades (2016-2035). This World Bank ESMAP-funded study was developed in association with the Independent System Operator (ISO or NOSBiH) and other BiH stakeholders, including governmental entities and the generation utilities in BiH.

The analysis presented in this report takes a critical look at the demand-supply balance in Bosnia and Herzegovina over the next 20 years (2016-2035) to identify generation investments that are most economical for a number of alternative scenarios, including policy scenarios around BiH's policy objectives on carbon emissions, local emissions control, renewable energy and energy efficiency. In particular, the analysis compares and contrasts an optimized/least-cost plan with the Indicative Plan that has been prepared by ISO, collating a wide range of projects proposed primarily by two of the main Elektroprivreda (EP) generation companies in BiH, namely EPBiH and EPRS. A significant part of the work involved active consultations with all stakeholders to develop inputs, modelled scenarios, and vetting initial rounds of model results to refine and revise inputs/scenarios.

2.2. Country Context

It is useful to understand the country context at the outset as BiH's development stage and complex governance arrangements have a bearing on how infrastructure investment decisions, including power generation, are made in the country. BiH is a small country of close to 3.8 million people, which is yet to create a foundation for sustainable economic growth after a period of successful post-conflict recovery. BiH today is an upper middleincome country with per-capita income of US$ 4,200 (2015 data), which is less than half the global average, and only 26% of the average income in the European Union. Although the BiH economy remains smaller than before the war, the improved capture of the informal economy through a tighter tax enforcement suggests that progress is being made towards restoring the economic activity to pre-conflict levels.

The country's governance structure comprises two entities, each with a high degree of autonomy: the Federation of Bosnia and Herzegovina (FBiH) and Republika Srpska (RS). The Brcko District was added to the structure in 1999. The complex governance system poses significant challenges in developing coherent sectoral policies and efficiently tackling emerging development priorities. Nonetheless, the authorities in BiH have been pursuing a jointly authored medium term Reform Agenda. It represents a broad consensus among all levels of government on the key priorities of economic and social development that would take BiH to a more sustainable growth trajectory. The Reform Agenda implementation progress will underpin the country's application for EU membership. With public sector spending close to 50% of GDP, ensuring efficiency of public expenditures is critical. The

choices made by public institutions can therefore significantly influence economic growth. These choices are important to ensure efficient use of public resources toward faster economic growth, poverty alleviation and shared prosperity. In the energy sector, in line with the country's aspiration to become an EU country, the development of policies, regulations and investment is underpinned by the obligations of the Energy Community Treaty, which BiH signed in 2005.

2.3. Overview of the Power Sector in BiH

BiH has about 4,000 MW of installed power generation capacity and has experienced a 55% growth in electricity generation since 2000 to 16,300 GWh pa in 2013. Three government owned power utilities, or Elektroprivredas (EPs), are the most relevant players in the power sector. These are "JP Elektroprivreda Bosne i Hercegovine - d.d." (EPBiH) in Sarajevo, "MH Elektroprivreda Republike Srpske a.d." (EPRS) in Trebinje, and "JP Elektroprivreda Hrvatske Zajednice Herceg Bosne d.d." (EPHZHB) in Mostar. All three EPs perform generation, distribution, trade and supply in their respective license areas.

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 EPs. The privately owned 300 MW thermal power plant (TPP) Stanari in the RS was commissioned in September 2016. All TPP blocks are designed to operate with domestic coal (lignite/brown coal), supplied mostly from open-cast mines. These mines are also mainly owned and operated by the three main utilities.

The transmission system consists of about 6,300 km of 400 kV, 220 kV and 110 kV lines, 36 interconnections, over 140 substations and over 250 transformers. The system is owned by the transmission company "Elektroprenos Bosne i Hercegovine a.d." (Elektroprenos BiH) based in Banja Luka and operated by the ISO. The 10(20) kV distribution network has a total length of almost 22,000 km. The low voltage network is over 62,000 km long, and transformation from medium to low voltage is conducted in close to 20,000 transformer stations (World Bank, 2008).

In RS, five companies operate within the structure of EPRS as distribution system operators and suppliers to tariff customers. In FBiH, EPBiH and EPHZHB perform electricity distribution and supply to tariff customers. There are about 1.3 million registered electricity users in BiH; EPBiH serves 48%, EPHZHB 13%, ERS 37% with the remaining 2% is served by the distribution company of the Brcko District. Energy sector policy and regulatory development is largely driven by the EU accession process and the obligations under the Energy Community Treaty.

The electricity market regulatory framework includes a structure with a State Electricity Regulatory Commission (SERC), a Regulatory Commission for Energy in FBiH, and a Regulatory Commission for Energy of RS each having their own roles and mandates. SERC has jurisdiction and responsibility over the transmission of electricity, transmission system

operation and international trade in electricity. The Entity Regulatory Commissions' mandates include e.g., regulating the relations between power generation, distribution and electricity customers including power traders, tariff setting for non-eligible customers, permits and licenses for facilities (except transmission), distribution tariffs etc. As for intrastate trade of electricity, the trading licenses issued in one Entity are valid in the other Entity as well. Both Entities also have their own separate Renewable Energy Regulators and their own FITs. In terms of investment planning, Elektroprenos (which is shareholding by the Entities) develops its transmission system investment plan which SERC approves. The Entity level EPs (majority owned by the Entity governments) develop their own investment plans that are approved by the EPs shareholders' assemblies.

The current energy system requires minimal government financial interventions, with generation, distribution and transmission in no need for direct government financing. However, there was some deterioration of the financial results of two EPs in 2015. Mines remain partially supported by the EPBiH, mostly due to modernization needs. All three EPs are self-sustaining, an example of which is that their flood recovery needs after the 2014 floods were for most part covered internally, without substantial governmental support.

2.4. BiH Energy Sector Challenges

There are several encouraging headline numbers that underline significant achievements in the BiH energy sector. 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. However, this positive 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 no BiH wide energy strategy and the strategic planning efforts of FBiH and RS have not been harmonized, reflecting the fragmented BiH governance structure and energy markets. Tendering procedures in the sector are complicated and non-transparent. An electricity market liberalization planned for January 1, 2015, was not fully implemented, and there is no genuine platform to determine electricity prices by the market. Energy tariffs are below cost recovery. Large electricity exports observed 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 € cent per kilo-Watthour (kWh) at the end of 2013[1], energy tariffs are also too low to encourage the private sector to finance the construction of many new power plants. There is no regulatory mandate or capacity in the existing regulatory body at present to undertake a national power system planning exercise. Our review of the Indicative Plan (IP) suggests that the IP is by and large a 'wish list' of all the projects considered by the two major EPs.

[1] Albeit, current tariffs have slightly increased since then.

This is confirmed from the discussions we had with the stakeholders including the ISO. It is not necessarily the 'least-cost' plan. The IP does include a notional contribution of generation from these projects to show that the maximum generation from these projects can be in excess of domestic demand. A major objective of the current analysis is therefore to optimize the portfolio of projects subject to different policy constraints to see how such an optimized plan may differ from the IP in terms of cost and other performance indicators (e.g., emissions, export and investment requirements).

Furthermore, there are delays in implementing gas sector legislative reform, a National Energy Efficiency Action Plan has not been adopted, and low energy efficiency is consuming public and private resources, as well as harming firms' export competitiveness due to higher energy inputs compared to other countries. Electricity consumption is also estimated to increase significantly. Power consumption per capita increased by 53% between 2001 and 2011, but still remained just 86% of the SEE average. Some estimates place total energy demand increases at a total of 20% over 2010 to 2030, under a scenario of little manufacturing growth. Faster economic growth, including that in the manufacturing sector, could however result in more than 50% power demand increase over the period.[2]

If no significant power generation facilities are brought on-line in the next 10 years, BiH could 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 30% of the country's thermal capacity (470 MW out of about 1900 MW net capacity), exclusively servicing baseload power needs. The aging existing thermal capacity also does not comply with EU emission standards, resulting in polluted cities. While the overall carbon emissions of BiH are relatively small in the context of global CO_2 emissions, BiH per capita emissions are second highest in the region and the CO_2 intensity of GDP is the highest in the region and 6 times that of the EU average.[3]

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 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.

[2] If the high demand growth scenario of 2.9% per annum were to realize – a scenario that has been considered in our analysis as discussed later.

[3] Source: World Development Indicators - the primary World Bank collection of development indicators, compiled from officially-recognized international sources. It presents the most current and accurate global development data available, and includes national, regional and global estimates.

In large part thanks to the wide use of woody biomass for heating, the renewable energy sector is slowly 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, and comprehensive and reliable assessments of wind or solar potential do not exist. Estimates for hydro potential date back to the Yugoslav period, and may not be reliable as they do not take into account developments on environmental and social requirements, new riparian issues or institutional issues related to the creation of the political Entities after the war. Nonetheless, the available estimates indicate a technical hydropower potential of 23,396 GWh pa, with utilized hydropower potential amounting to 9,000 GWh pa (approximately 40% of the technical potential) which includes part of the hydro utilized outside BiH (EPBiH, 2006) in Croatia and Serbia. Actual utilization of hydro within BiH has been 4,500-6,000 GWh pa depending on the hydrology.

Notwithstanding the significant potential, addition of substantial new hydropower capacity appears unlikely without considerable new efforts and 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. At the BiH level, no competencies exist related to project development. The BiH Council of Ministers can only approve the projects being developed on rivers with neighboring countries. Several concessions and similar water rights that were granted in the past – in some cases to renowned international companies – were ultimately not implemented. In general, the reasons for the failure to develop HPP into investments in BiH were a combination of political instability, lack of adequate consultations and readiness for concessions with the other Entity, administrative capacity issues and lengthy procedures, or concerns and fee sharing demands by the local community. Some companies faced their own internal problems, or pulled out of their investments in the region as a whole. The fact that there are only a couple of medium-size hydropower plants currently being developed indicates that only a limited number of companies are able to successfully develop their projects in such an environment. The rare success stories include in the FBiH HPP Mostarsko Blato (60 MW) and HPP Pec Mlini (30 MW) that are now in operation and HPP Vranduk (20 MW) where construction is expected to start soon, and in the RS HPP Ulog (35 MW) with preparatory construction works already initiated. A number of additional projects are currently being developed by the EPs, but the participation of the private sector remains limited to development of only small scale hydro. Indeed, the FBiH government has never granted a concession for an HPP with a size of more than 10 MW to a private company.

2.5. Past Demand and Supply Balance

Table 3 shows the gross electricity consumption growth rate and export share over the last decade. The growth rate (expressed as a simple average of year on year growth) over the last decade has been low at around 1% pa but extremely variable over the period. There has

been little correlation between GDP growth rate and the electricity consumption growth rate. The share of export has been significant and also highly variable over the years averaging around 23% of domestic consumption for this period. Supply mix exhibits the same variable trend as the share of hydro in the mix has varied depending on hydro availability.

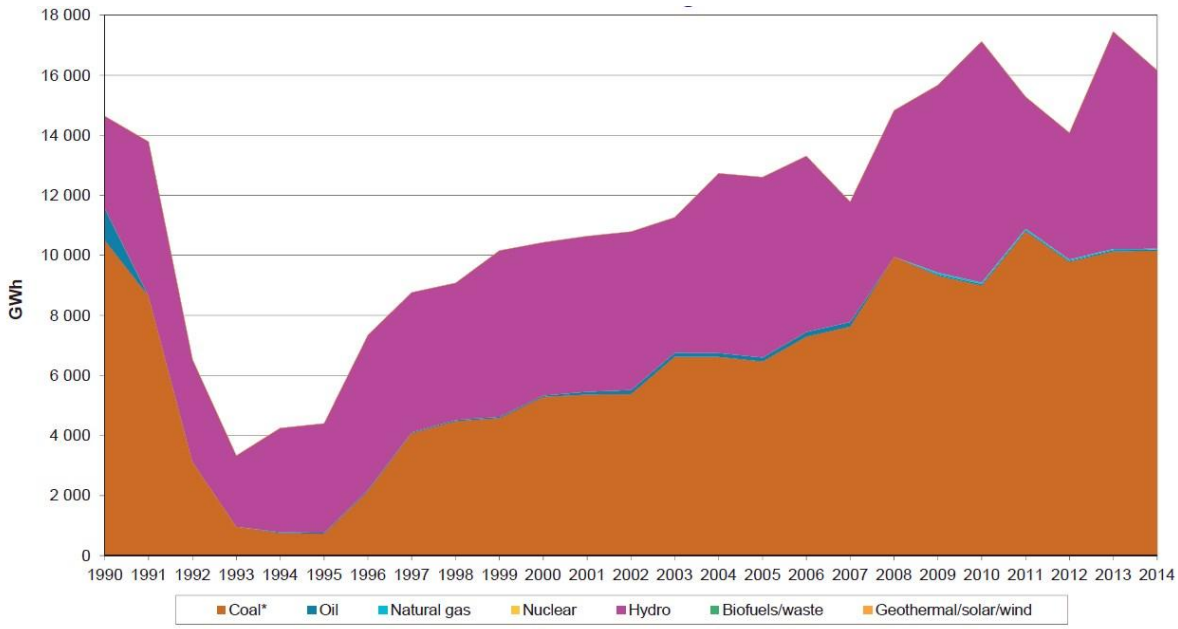
Figure 1 shows the gross generation by fuel type since 1990. Growth in coal generation over the years have led to the share of coal generation accounting for nearly two-thirds of the generation in 2014.

Table 3 Gross consumption and net export (GWh) 2005-2015

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Avg
Gross Consumption (GWh)	11,046	11,107	11,195	11,665	11,092	11,809	12,203	12,227	12,075	11,649	12,092	11,711
Growth Rate of Consumption		0.6%	0.8%	4.2%	-4.9%	6.5%	3.3%	0.2%	-1.2%	-3.5%	3.8%	1.0%
Export (GWh)	1,347	2,169	605	1,605	2,902	3,744	1,491	6,618	3,636	2,822	2,072	2,766
Export Share of Consumption	12%	20%	5%	14%	26%	32%	12%	54%	30%	24%	17%	23.4%

Source: NOSBiH Indicative Plan 2016, Table 4.1

Figure 1: Generation by fuel mix – gross GWh



Source: IEA. Note: Low power generation/demand during 1992-1995 was because of the BiH war over this period.

3. LEAST COST PLANNING ANALYSIS

3.1. Scope and Objective

The objective of the current planning study 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.

The scope of the study covers the following range of issues and questions:

(a) What is the least-cost generation expansion plan for the BiH power sector assuming no policy driven constraints around RE, EE, emissions, etc.?

(b) What should be the optimum configuration of generation mix to meet potentially high but unpredictable demand growth over the years, including higher than past demand growth?

(c) What is the impact of putting constraints on local pollutants (as per the BiH National Emission Reduction Plan, NERP) and/or carbon limits (as per the BiH Intended Nationally Determined Contribution, INDC, to the UNFCCC Paris Agreement)?

(d) What are the benefits of installing of local emissions control equipment?

(e) What role can be played by improved supply and demand side energy efficiency projects?

(f) Can wind/solar play a significant role?

(g) Is there room for gas-based generation under certain conditions?

(h) What are the opportunities for export of electricity going forward for (policy) unconstrained and constrained scenarios?

   i. Are there plausible scenarios under which the country becomes a net importer?
   ii. What would be the costs associated with enforcing a national energy security objective?

BiH is currently considering a several generation development possibilities that include a number of 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 IP (2016) for the next 10 years, i.e., more than 30% of the country's GDP in 2015. The discussions with the stakeholders conducted as part of this planning study suggests that the IP put in place by the ISO based on inputs from BiH stakeholders, is likely to be ambitious and requires a scrutiny. *Is the IP for instance in line with the efficient/least-cost plan for the sector?* This is therefore one of the central

questions that is being answered through this analysis and the need for creating an efficient benchmark plan is one of the major motivating factors for this study.

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:

- 9% Energy Efficiency target included in BiH's Energy Community Treaty obligations;[4]
- 40% renewable energy target (as per the National Renewable Energy Action Plan, NREAP);
- Carbon reduction commitment as per the INDC; and Local emissions reduction as per the NERP.

It is very likely that no single plan will meet these policy objectives simultaneously. The analysis of changes in selection of candidate projects and underlying generation mix for plans that are compliant with these policies, or their combinations therein, is also a major objective of the study.

3.2. Discussion on Methodology

The main objective of the planning exercise is to ensure that peak load and energy demand up to 2035 is met reliably and securely in line with the government's policies at the most efficient cost. The analysis takes into consideration a range of risks (e.g., high, medium and low load and hydro variability) to identify a plan that can best deal with the various possible outcomes and avoids building excessive capacity requiring massive investments. It requires a detailed analysis of many plausible combinations of investment choices that can be made to meet future demand. The level of details that such a model needs to consider typically requires representation of all existing and future power generation projects, distribution of demand over the years, across the months and even during typical days.

A powerful optimization tool is required to systematically assess many of these combinations – potentially millions of them over a 20 year period – and to identify the least cost plan. The assessment needs to consider not merely a selection of investment projects, but also how these plants will be dispatched for different hours of each month over the next 20 years. Put differently, a model that is capable of optimizing the capacity plan and the underlying dispatch is needed for the analysis.

The model used for the analysis has the following key characteristics:

1. Since mathematical programming based optimization models (such as linear/mixed integer programming models or LP/MIP) have been the most popular choice for dispatch

[4] BiH has not yet adopted a National Energy Efficiency Action Plan (NEEAP); the target of EE by 9% by 2020, included in the obligations of BiH in the Energy Community Treaty, was used. The 9% EE target was furthermore assumed, in consultation with BiH stakeholders, to be extended beyond 2020 for the whole planning period of this study.

and capacity optimization, a state-of-the-art mixed integer programming model was chosen for the analysis.

2. The investment and dispatch optimization in the model achieve the fundamental goal of maximizing societal benefit by mimicking the market operation in the long term, while keeping the model computationally tractable. It contains a set of equations, representing the possible physically consistent dispatches in terms of the logical, physical and energy security policy constraints. In addition, an LP/MIP model has an objective function, which seeks the most efficient dispatch from among these feasible candidates. One of 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.

3. The specific 'objective function' that the mathematical optimization employs for this analysis is:

Net system costs for BiH = Total system costs – Export revenue

Total system costs include: annualized cost of new build, fuel costs, fixed and variable O&M, cost of import, and cost of unserved energy (if any).

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 leastcost planning analysis (IFC, 2015) and reflects system marginal costs. The analysis therefore is consistent with least-cost principles.[5]

4. System constraints relevant to investment and dispatch optimization include:
   - Demand and Reserve Requirement, namely:
     - Meeting the MW demand for each load block; and
     - Meeting the reserve requirement for all classes for each load condition;
   - Generation (maximum and minimum) and Transmission Limits;
   - Joint capacity limit on transmission lines to carry energy and reserve;
   - DC approximation of load flow constraints including piecewise linear losses;
   - Transmission security constraints;
   - Any applicable constraint on demand side response; Risk-Reserve-Generation Interaction Constraints:

[5] While this assumption retains the economic principles, it is nonetheless a simplification. Our assumption effectively implies BiH is a price taker, i.e., to the extent export/import levels vary from those implicit in IFC's analysis, we assume these variations do not have any impact on regional prices. This is not necessarily true, although considering the relatively small size of the BiH power system in the regional market, it is not an unreasonable assumption.

- Risk is defined as the loss of a designated set of 'at risk' generators and any reserve that these generators carry;
- In addition, there is also a system minimum MW risk that has to be satisfied;
- The risk (defined by both the 'at risk generators' and 'system minimum MW' criteria) must be met from available reserve offers; and ○ Generation and reserve from a unit is jointly restricted by the unit's capacity.

- Policy constraints including ○ Limit on carbon emissions corresponding to the INDC; ○ Limit on SOx, NOx and dust; ○ Energy efficiency target represented as negative demand; and ○ Renewable energy generation target as a minimum share of total generation.

5. The key input data for the pool price projection model includes:
   - *Cost/Offer:* Simulated/representative bid and offer data of market participants, or fuel costs and specific fuel consumptions;
   - *Load:* Load forecasts in the form of load duration curves (LDC) for the planning years; and
   - *Generation:* Operational characteristics of generation plants.

3.3. Key Assumptions

The planning study covers the period 2016-2035. Key assumptions around demand, supply, import/export and other miscellaneous issues are discussed below.

Demand

Figure 2 shows the peak demand energy projections adopted from the IP (ISO, 2016). There are divergent views among BiH stakeholders on likely level of demand growth. There are two broad opinions that emerged from our discussions with the stakeholders, namely:

1. A low demand growth rate in line with past demand growth rates. As Table 3 shows, demand growth rate in the past has been highly volatile (including some years when demand fell sharply), and as a consequence a modest growth rate of 1% pa on average over 2005-2015 was realized. One of the reasons demand growth has been low over the last decade is due to a relatively small and stagnant base of large industrial customers. It is evident from the share of Large Customers that remains almost static at only 15%-17% over 2005-2015 (SERC, 2015).[6] This is reasonably aligned with the Low demand growth scenario of 1.1% pa in the Indicative Plan (referred to as the "Pesimisticni" scenario in the IP); and

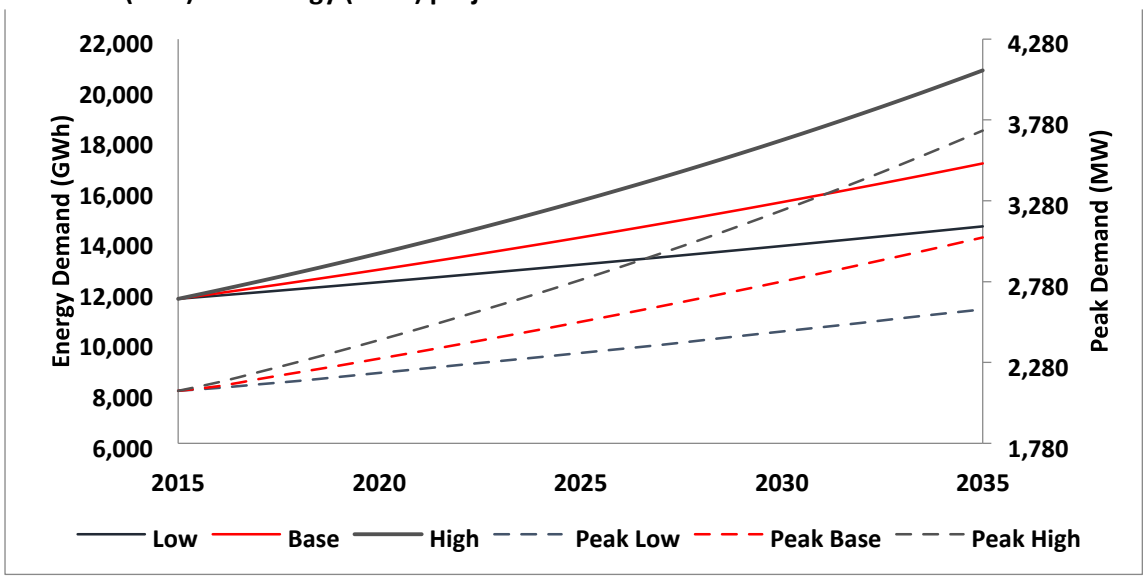
2. A more positive outlook that assumes the demand growth rate will nearly double (1.9% pa) from the past trend (i.e., the 1.0% in the past 10 years), or be even higher

[6] Figure 6 of the State Electricity Regulatory Commission Annual Report, p.26.

with a strong growth in industrial activity. The positive outlook is aligned with two additional scenarios in the Indicative Plan, i.e. the Central ("Realisticni") case of 1.9% pa and a High ("Optimisticni") (2.9% pa).[7]

Discussions with the BiH stakeholders during the preparation of this study, on the balance, suggest that 1.9% pa as the Central scenario in the IP may be most suited for the purpose of the analysis. It is considered to be a balanced scenario that takes into account the country's long term development objectives. The Central scenario's 1.9% pa demand growth rate was therefore adopted as the Base scenario ('BASE') assumption for the purposes of the analysis. However, the Low and High 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. Figure 2 below summarizes the peak (MW) and energy (GWh) projections contained in the IP.

Figure 2 Peak (MW) and energy (GWh) projections for BiH based on the IP scenarios



Supply

Tables 4 and 5 list the assumptions on major existing thermal and hydro generation plants, and thermal candidate projects (existing plants are listed in green, candidate plants in yellow). Bulk of the existing coal capacity (1,334 MW) is expected to be retired by 2035 with the exception of the Ugljevik plant (279 MW), which is currently undergoing investments in pollution control and rehabilitation of the generation equipment. There is, however, a portfolio of 2,408 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.

[7] The ISO develops an additional (fourth) GDP-correlated demand scenario, with an average growth rate of 2% over 20182026. For the purpose of development of this scenario, the ISO, among others, uses the World Bank GDP growth projection rates (Indicative Plan, 2016, p. 22).

In addition, the model also considers as part of its portfolio of candidate projects significant hydro and other renewable energy projects including (Table 6 below):

1. An array of small and medium size hydro projects (including Dabar – 160 MW) totaling 1,830 MW;[8]
2. 350 MW of wind;[9] and
3. 150 MW of solar PV.

Table 4 Key assumptions on major thermal generation projects

Unit	Fuel Price (€/GJ)	Earliest comm. Year	Retire Year	Capacity (MW)	Efficiency	Capital Cost (€/kW)
Tuzla 3	2.55	1966	2021	90	30%	
Tuzla 4	2.55	1971	2023	180	29%	
Tuzla 5	2.55	1974	2030	180	29%	
Tuzla 6	2.55	1978	2035	200	34%	
Kakanj 5	2.53	1969	2024	100	31%	
Kakanj 6	2.53	1977	2027	100	31%	
Kakanj 7	2.53	1988	2035	208	32%	
Gacko	2.07	1983	2031	276	31%	
Ugljevik	1.98	1985	>2035	279	31%	
Stanari	2.07	2016	>2035	263	39%	
Banovici	2.30	2020	>2035	350	41%	1,500
Zenica	9.4-15.0	2020	>2035	385	55%	928
Tuzla 7	2.30	2020	>2035	410	42%	1,823
Kakanj 8	2.30	2024	>2035	400	42%	1,490
Ugljevik 3	1.98	2019	>2035	600	40%	1,416

Note: (a) Zenica 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.

[8] With regards to hydro projects we have followed available estimates of hydro potential and a list of hydro projects, which are in different stages of development based on discussions with the EPs. An updated and detailed estimate of hydro potential would have been useful for this study, but developing such an estimate was not possible within the scope of this study.

[9] 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 (NOSBiH 2014) which lead to a conclusion that higher capacities of variable RE could indeed be integrated (Analiza integracije vjetroelektrana u elektroenergetski sistem i tržišna pravila", NOSBiH 2014; available online: http://www.nosbih.ba/bh/korporativneAktivnosti/elaborati-i-studije/21). 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 5 Key assumptions on major existing hydro generation projects

Unit number	Unit name	Start year*	Derated Power [MW]	Forced outage rate [%}	Estimated capacity factor [%]	FOM per MW of installed capacity [€/MW-year]	VOM [€/MWh]
1	Jablanica	1955	180	5.0%	45%	14,292	5.43
2	Grabovica	1981	114	5.0%	29%	14,292	5.43
3	Salakovac	1981	210	5.0%	22%	14,292	5.43
4	Small HPP EPBiH	1960	13	5.0%	58%	14,292	5.43
5	PSP Capljina	1968	400	5.0%	6%	14,292	5.43
6	Rama	1955	170	5.0%	49%	14,292	5.43
7	Mostar	1987	71	5.0%	50%	14,292	5.43
8	Jajce I	1957	58	5.0%	49%	14,292	5.43
9	Jajce II	1954	28	5.0%	64%	14,292	5.43
10	Pec Mlini	2005	30	5.0%	31%	14,292	5.43
11	Visegrad	1989	315	5.0%	40%	14,292	5.43
12	Bocac	1981	110	5.0%	32%	14,292	5.43
13	Trebinje I	1968	171	5.0%	26%	14,292	5.43
14	Trebinje II	1975	8	5.0%	25%	14,292	5.43
14	Dubrovnik	1965	108	5.0%	68%	14,292	5.43
15	Small HPP EPRS	1980	15	5.0%	30%	14,292	5.43
16	Mostarsko Blato	2010	60	5.0%	32%	14,292	5.43
17	Ustipraca	2016	7	5.0%	57%	14,292	5.43

*Retirement year for all existing hydro projects is after the end of the optimization period and thus is not being taken into account

Table 6 Key assumptions on major future hydro and generic wind and PV projects

Unit #	Unit name	Earliest start year*	Derated Power [MW]	Forced outage rate [%}	Estimate d capacity factor [%]	FOM per MW of installed capacity [€/MWyear]	VOM [€/MWh]	CAPEX [€/MW]
1	Unac	2024	72	5.0%	11%	14,292	5.43	1.39
2	Ustikolina	2028	59	5.0%	46%	14,292	8.86	1.53
3	Vranduk	2019	20	5.0%	55%	14,292	7.29	3.67
4	Glavaticevo	2024	28	5.0%	44%	14,292	5.43	2.19
5	Han Skela	2025	8.5	5.0%	48%	14,292	5.43	1.90
6	Vrletna Kosa	2023	25	5.0%	29%	14,292	5.43	1.80

Unit #	Unit name	Earliest start year*	Derated Power [MW]	Forced outage rate [%}	Estimate d capacity factor [%]	FOM per MW of installed capacity [€/MWyear]	VOM [€/MWh]	CAPEX [€/MW]
7	Small HPP Rivers	2024	20	5.0%	72%	14,292	5.43	2.18
8	Small HPP Cetina	2022	13	5.0%	24%	14,292	5.43	1.91
9	Bjelimici	2023	100	5.0%	25%	14,292	4.79	1.40
10	Small HPP Rivers	2019	282	5.0%	30%	14,292	5.43	2.03
11	Foca	2023	56	5.0%	41%	14,292	5.43	1.74
12	Dabar	2022	160	5.0%	19%	14,292	5.43	1.13
13	Bileca	2024	36	5.0%	37%	14,292	5.43	1.62
14	Dubrovnik II	2025	152	5.0%	12%	14,292	5.43	1.28
15	Nevesinje	2023	60	5.0%	19%	14,292	5.43	2.50
16	Krupa	2025	49	5.0%	33%	14,292	5.43	1.80
17	Banja Luka	2029	37	5.0%	58%	14,292	5.43	2.80
18	Novoselija	2029	16	5.0%	50%	14,292	5.43	1.90
19	Janjići	2021	13	5.0%	60%	14,292	6.62	4.33
20	Kovanići	2025	10	5.0%	53%	14,292	18.48	3.90
21	Babino Selo	2026	5	5.0%	57%	14,292	6.82	5.52
22	Neretvica I	2019	9	5.0%	52%	14,292	6.82	2.10
23	Neretvica II	2025	15	5.0%	46%	14,292	5.43	2.10
24	Una Kostela	2019	6	5.0%	40%	14,292	16.67	2.65
25	Ulog	2020	35	5.0%	50%	14,292	7.00	1.66
26	HPP Mrsovo	2020	43	5.0%	50%	14,292	7.00	2.00
27	Dub	2018	9	5.0%	50%	14,292	7.00	1.36
28	Buk Bijela	2024	94	5.0%	50%	14,292	7.00	2.06
29	Paunci	2020	46	5.0%	50%	14,292	7.00	2.80
30	Generic Wind	1018	350	5.0%	35%	37,292	5.43	1.23
31	Generic PV	2020	150	5.0%	15%	16,700	0.00	1.10

*Retirement year for all future projects is after the end of the optimization period and thus is not being taken into account

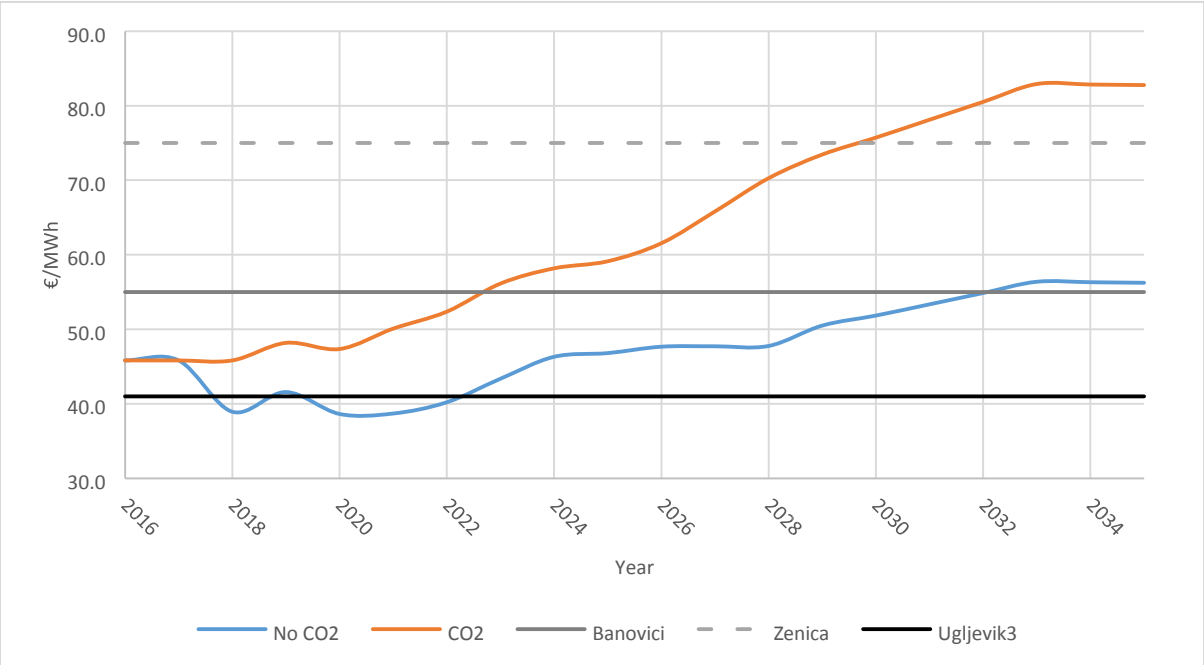
Import/Export and Regional Price

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

It should be noted that internal transmission constraints are not being modeled since based on discussions with ISO BiH it was understood that there are no significant internal transmission bottlenecks. Import/export is driven by regional electricity prices shown in Figure 3. The model considers prices for individual trading partners using a price duration curve. Figure 3 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 plants 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.

Figure 3 Average regional electricity price with and without carbon prices (€/MWh)



Source: IFC study (December, 2015)

Note: Coal prices are assumed to remain constant over the study period; TPP LCOEs do not account for financing costs and do not include any carbon cost component.

Other assumptions

In addition, the analysis was based on the following other 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 (EIA, 2015);
- 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). 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.[10] 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 (UNFCC, 2016);
- Local pollutant emissions caps are based on the National Emissions Reduction Plan (NERP, USAID, 2015) and are the following for 2030 (in tons): 780 t for dust/particulate matters, 7,446 t for NOx and 14,243 t for SOx;[11]
- RE limit is set to 40% based on the National Renewable Energy Action Plan dated
- March 2016 (Energy Community Secretariat, 2016). We assume that the RE targets will be achieved mainly through the contribution of hydro, solar and wind sources.12
- Variable hydro resource modeled based on historical data;
- Renewable energy (solar & wind) modelled using detailed/hourly data from neighboring countries in the region;
- Maximum capacity limit of 350 MW is imposed on wind; and
- EPBiH's plan to provide District Heating through Kakanj 8 and Tuzla 7 units are modelled as a minimum loading restriction for the relevant heating periods, ensuring the plants are kept on to meet heating load.

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[10] UNFCC (2016) statement: "*Emission reduction that BiH **unconditionally** might achieve, compared to the BAU scenario, is 2% by 2030 which would mean **18% higher emissions compared to the base year 1990**. Significant emission reduction is only possible to achieve **with international support, which would result in emission reduction of 3% compared to 1990**, while compared to the BAU scenario it represents a possible reduction of 23%*."

[11] In comparison, annual emissions in 2016 are estimated to be 6,616 t for dust/particulate matters, 20,511 t for NOx and 273,577 t for SOx.

[12] Our review of the Bosnian energy sector from an energy efficiency and biomass heating perspective suggests that, although there is significant economic potential to use biomass in BiH, this potential is primarily for heating. CHP is in most cases unlikely to be economic, and currently the FIT allocation is extremely small. As of this moment there is one biomass (0.24 MW) and one biogas (0.99 MW) online, with an additional 1 MW capacity in the pipeline.

3.4. Scenarios and Sensitivities

The analysis considers:

1. A set of **main scenarios** that include a 'Base' case constructed around the medium economic growth of 1.9% pa without any policy constraints. A number of variations around the Base are considered including:

    a. A simulation of the Indicative Plan (IP) (i.e., if we were to consider all of the projects as committed and the investments incurred as per the plan). The Indicative Plan is a long-term generation expansion study prepared by the independent system operation of BiH (ISO BiH). The results of the study are not the outcome of least-cost optimization. In that respect it makes sense to compare the results of the current study with the IP to identify if the IP is reasonably priced. The scenario tested is called in this report the "IP scenario".

    b. Addition of policy constraints that also form part of the main scenarios. Such policy constraints include energy efficiency (EE) measures/targets, renewable energy (RE) targets, CO_2 emissions constraints and local emissions constraints. The scenarios tested can be seen below (main scenarios 3 to 6).

2. A number of supporting scenarios and sensitivities around the Base.

Main Scenarios

The analysis considers the following 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[13] and NERP limits (NERP limits can be seen on Figure 10);

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 7 summarizes the specification of the main scenarios.

[13] The annual 1990 CO_2 emissions in the BiH power sector have been estimated at around 7.8 million tonnes

Table 7 Main scenarios

	Capacity	RE&EE	CO_2 cap	Local pollutant cap
1.Base	Optimal	No	No	No
2.Indicative Plan (IP)	Enforced as per the IP	No	No	No
3.RE&EE	Optimal	Yes	No	No
4.Stringent CO_2 Limit* + Local Pollutants	Optimal	No	Yes	Yes
5.Relaxed CO_2 Limit** + Local Pollutants***	Optimal	No	Yes	Yes
6.Stringent CO_2 Limit + Local Pollutants +Energy Efficiency	Optimal	Yes	Yes	Yes

* 3% below 1990 level ** 18% above 1990 level *** As per NERP

Note: Scenarios with CO_2 limits use regional electricity prices inclusive of carbon costs, i.e., the higher prices in Figure 3. We have used the terms 'pollutants' and 'emissions' interchangeably to describe the emissions scenarios.

Other scenarios and sensitivities

The following variations and sensitivities on the Base Case have a target to answer some BiH specific issues like:

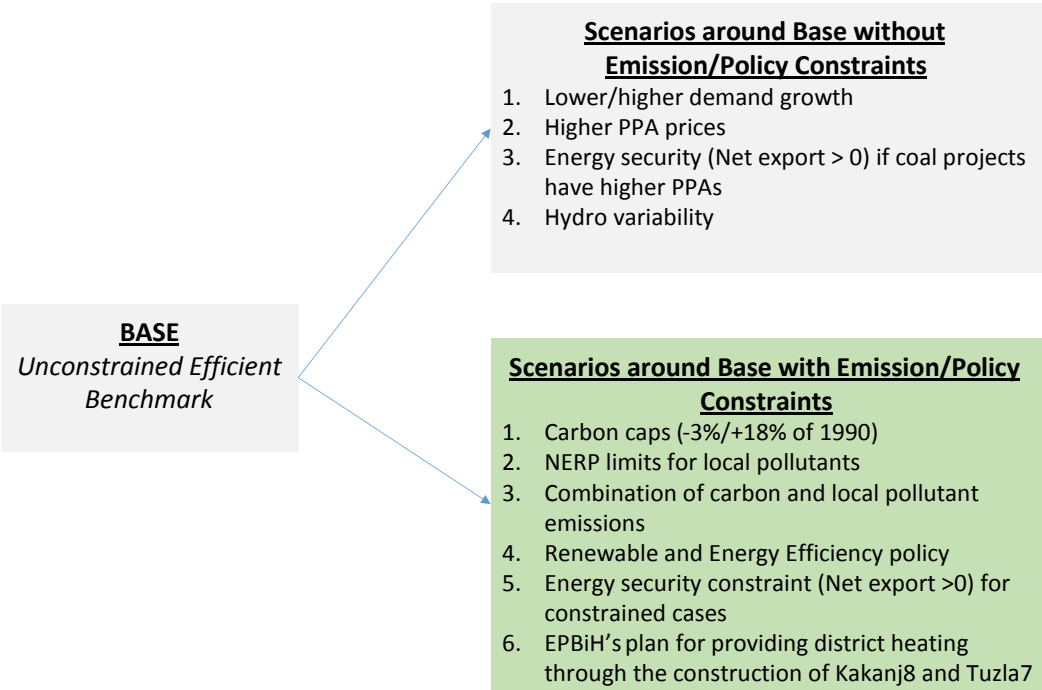
1. **High and low demand scenarios "(HD) and (LD) scenarios".** HD and LD investigate changes on the investment plan if the ISO BiH's high and low demand growth projections are given as inputs (1.1% and 2.9% respectively).
2. **"High PPA scenario".** Data from the EPs suggest LCOEs for coal projects in the range of €48/MWh to €57/MWh. However, new projects in the region suggest higher PPAs. The High PPA scenario assesses the risk of generation assets becoming stranded if the coal prices and CAPEX of respective plants end up being higher than the projected (€55/MWh to €60/MWh).
3. **"High PPA+energy security scenario".** It was noticed during the analysis that under specific circumstances (like higher than expected PPAs for coal) BiH became a net importer of electricity. This scenario was created to investigate the additional cost on investments to assure energy independence from third countries.
4. Varying hydrology **"VH scenario".** The scenario identifies changes on the capacity plan considering random variations on total annual hydrology based on historical data.
5. District heating **"DH scenario".** The DH scenario considers the heating requirement for the operation of the district heating networks in major cities. The scenario considers significant heat requirement additions after 2020 will be satisfied mainly by new thermal capacity installed by EPBiH. More specifically it is assumed that additional 30 MWt will be committed into Tuzla-Zivinice network, 40 MWt into the Tuzla-Lukavac network and around 400 MWt into the Kakanj-Zenica and

KakanjSarajevo networks. As a result, new projects like Kakanj 8 and Tuzla 7 are imposed into the plan.

6. Finally, a number of combinations on the above mentioned scenarios are investigated to bring out cost impacts of specific policy interventions.

Figure 4 provides an overview of the scenarios and sensitivities, and Table 8 describes these. In essence, the scenarios can be grouped into a Base or policy 'unconstrained' scenarios that present a continuation of *status quo* albeit with variations around demand growth rate, hydro availability and different cost assumptions around (coal) projects. The policy constrained scenarios are compared and contrasted against these to bring out some of the impacts on the generation projects – specifically the risks associated with coal projects. A comparison across the two groups also puts in perspective the role that may be played by renewables, energy efficiency and (local) emissions control programs.

Figure 4 Overview of scenarios



Note: There are additional combinations such as Base with Energy Efficiency, emissions constrained scenarios with only local emissions cap (with or without energy efficiency), etc. considered to understand specific impacts of energy efficiency, incremental cost of meeting a local emissions cap over and above a carbon limit. These additional scenarios are discussed at the relevant parts of the discussion on model results section that follows.

Table 8 Description of scenarios and sensitivities

Scenario Attribute	Key Parameters	Purpose
Electricity demand	Low (1.1% pa), Base (1.9% pa) and High (2.9%)	Performed mainly to check the impact on CAPEX requirements
Capacity plan	Optimized plan versus the Indicative Plan (IP)	Compare the IP to a theoretically efficient benchmark (least-cost)
Renewable (RE) and Energy Efficiency (EE) policy	40% RE target 9% EE target	Understand the cost and capacity implications of the EE policy targets
CO_2 emission target	3% below 1990 level 18% above 1990 level	Understand the impact of the CO_2 target on costs, generation mix
Local pollutant target	NERP limits for 2030	How do NERP targets impact cost and generation mix
Energy security	Net export > 0, or the restriction is removed to allow net positive import	Performed to assess the cost of energy security (i.e. that domestic generation can always meet demand if needed)

4. PLANNING MODEL 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 9. 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.

Table 9 Comparison of main scenarios (2006-2035)

	Net System Cost	CAPEX*	OPEX	System LCOE**	Total Generation	Net Exports as % of internal demand
	€m	€m	€m	€/MWh	(GWh)	(%)
BASE	3,774	3,451	4,221	42	397,851	36%
Indicative Plan	4,772	3,888	4,589	53	427,373	47%
RE&EE* **	3,232	3,058	3,956	41	370,134	39%
Stringent CO_2 limit+local pollutants	4,200	2,235	3,010	40	291,216	0%
Relaxed CO_2 limit+local pollutants	3,994	2,760	3,254	39	315,522	8%
Stringent CO_2 limit+local pollutants+EE	3,433	2,235	3,010	38	291,216	9%

* 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. ** Resource costs only (excludes carbon costs).
*** Specific EE investment costs are NOT included; demand is reduced to meet EE policy targets.

A number of important observations can be made based on the results in Table 9:

- 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.[14] The net system cost of the IP scenario is almost 50% higher than the RE&EE scenario, and in fact, higher than even the most stringent emissions constrained scenario (without EE);

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

- 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, the 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:
    - 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 the ~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;
    - The Indicative Plan has the highest net export albeit at the expense of the highest OPEX and significantly higher capital outlay. This is evident from the breakdown of the net system cost shown in Figure 5. 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;
    - Following RE and EE target opens up significant export opportunities as domestic demand reduces. As Figure 5 also shows, 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 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).

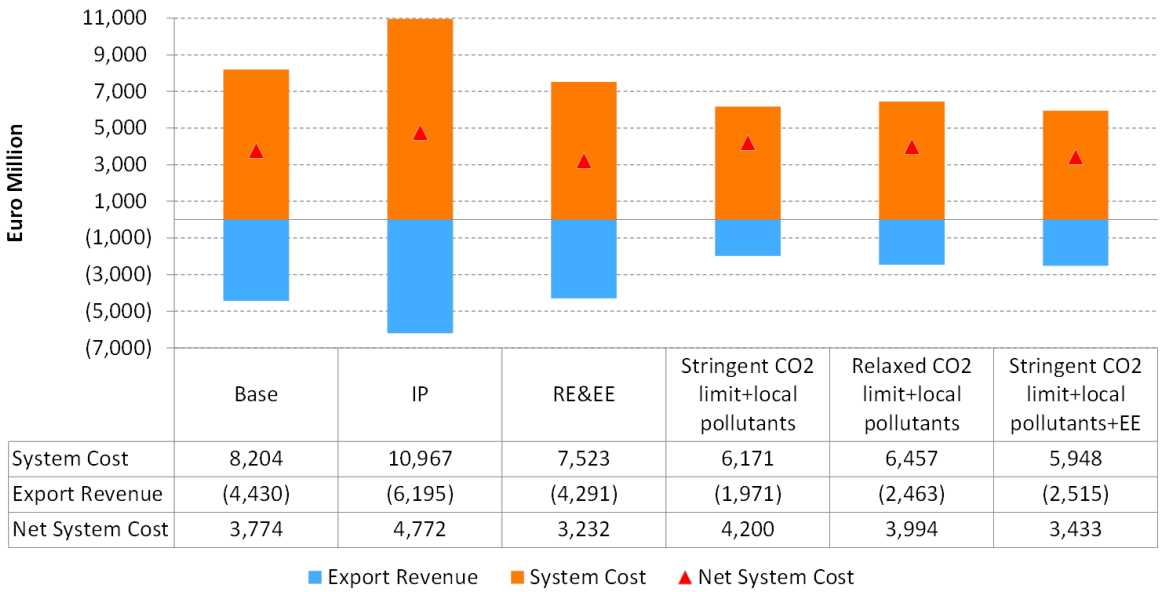
A more general observation from Figure 5 is also that export revenue component is a very significant part of the overall system cost. For instance, the total system cost for BASE is

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.

€8.2 billion[15], but export revenue offsets as much as €4.4 billion yielding a net system cost of €3.7 billion.

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 coalbased generation is highly competitive in the region given our assumptions on the regional prices.[14]

Figure 5 System cost and export revenue*



	Base	IP	RE&EE	Stringent CO2 limit+local pollutants	Relaxed CO2 limit+local pollutants	Stringent CO2 limit+local pollutants+EE
System Cost	8,204	10,967	7,523	6,171	6,457	5,948
Export Revenue	(4,430)	(6,195)	(4,291)	(1,971)	(2,463)	(2,515)
Net System Cost	3,774	4,772	3,232	4,200	3,994	3,433

*Total system costs ('System Cost') comprises the discounted annualized CAPEX costs as well as discounted OPEX costs and cost of imported electricity. Export revenue is the discounted revenues from electricity exports. Please note that Net System Cost (in the third row of the data table) is calculated as Total System Cost less Export Revenue.

Figure 6 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

[15] This is the discounted value of total system cost that includes *annualized* capital costs, operational costs, unserved energy costs and the cost of import. [14]

System LCOE is calculated using discounted system costs and generation. It should be noted that the emissions constrained scenarios do not include carbon costs and are calculated using resource costs. They are lower than that of the unconstrained scenarios due to lower fuel costs associated with hydro and other RE resources. We do not exogenously specify a carbon cost, but instead impose a limit on carbon emissions corresponding to the INDC. In other words, the carbon prices are implicitly reflected through a shadow price on the carbon constraint. Since there are multiple emissions constraints including local emission limits – our approach of relying on a quantity target rather than an exogenous cost impact makes sense as the different quantity limits may bind at different point in time. For instance, carbon constraints may be more stringent than others in later years, which has the co-benefit of reducing local pollutants as well, but NOx or dust emissions may be more stringent in the earlier years. As a consequence, shadow price of carbon may be very significant in outer years but are essentially zero in the early years (and vice versa for local pollutants).

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.

Figure 6: Comparison of carbon and local pollutant (SO_2, NO_x and Particulate matters)

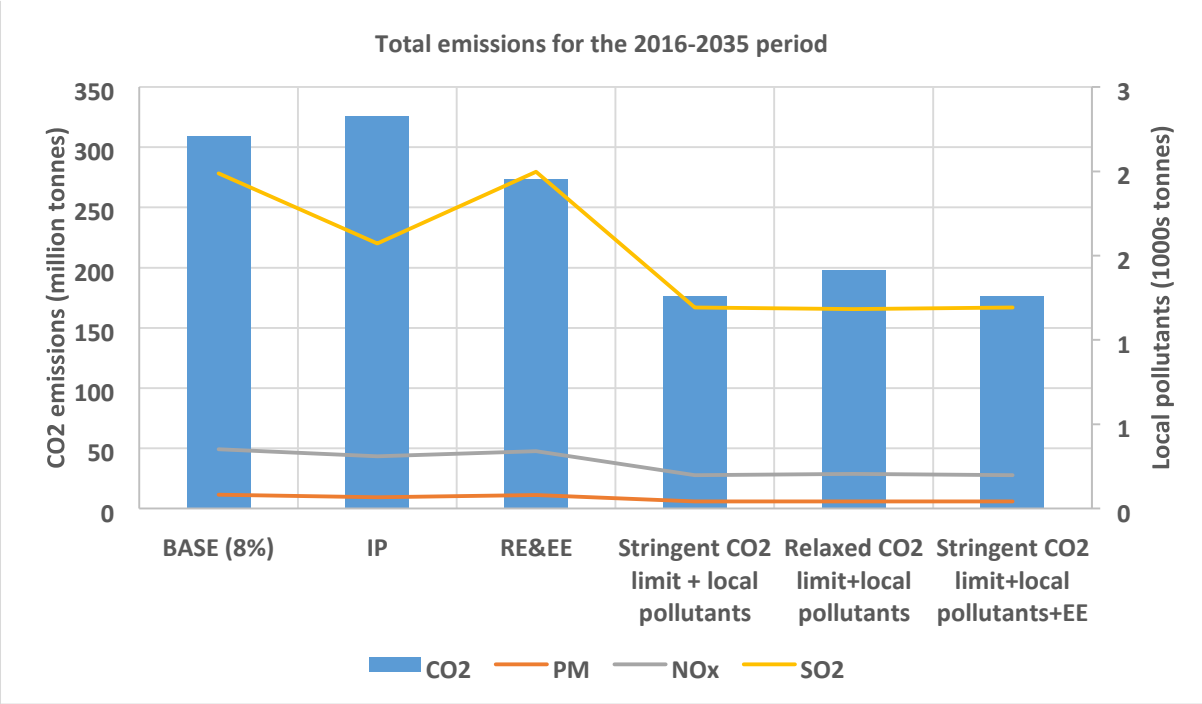


Figure 7 shows the capacity mix additions for the six main scenarios. Total capacity is the highest for the IP scenario because it includes Zenica gas plant (385 MW) and wind (350 MW) that are not selected by the model as part of the BASE. All four policy constrained scenarios include wind up to the 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.

Figure 7 Capacity mix (MW)

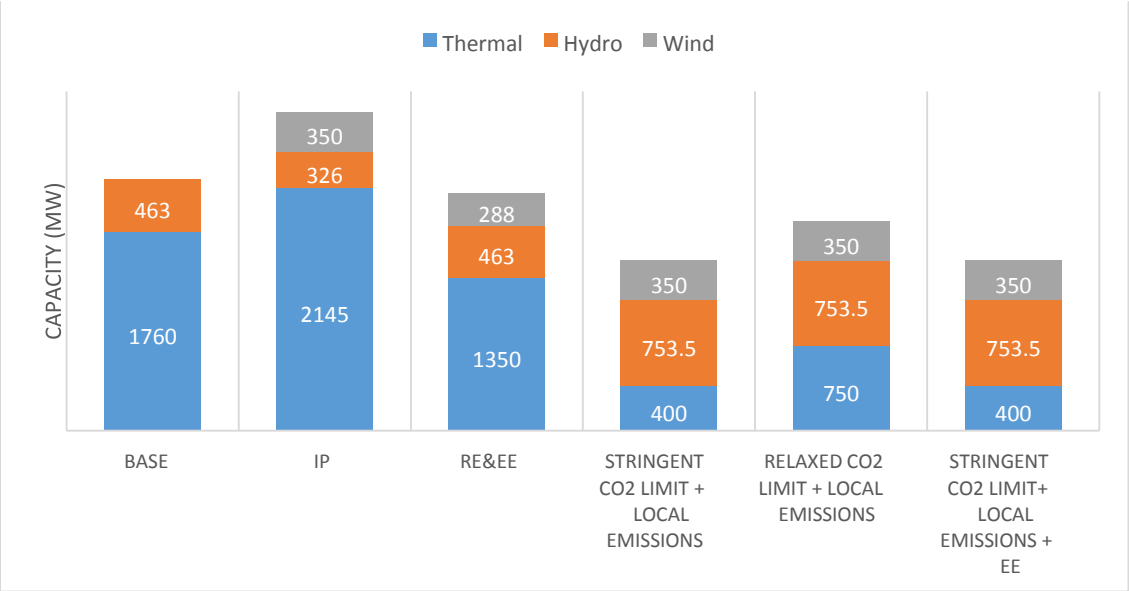


Table 10 shows the selection of coal projects across the scenarios. The significant points to note are:

1. Zenica 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, Zenica 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 than in the IP in three out of four cases. Tuzla 7 is delayed most by 15 years and comes in the very last year of the planning period in our analysis;
3. Introduction of RE&EE obviate the need for Tuzla 7. Stringent carbon limits also eliminate Banovici and Ugljevik 3, although a Relaxed (18% above 1990 level) retain Banovici in the mix.

Table 10 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		

It should be noted that the number of coal projects rather than the selection of specific power plant is important in this context. In other words, the modeling suggests that BiH should support:

- Only one coal project in the most stringent emissions reduction scenario (Stringent CO_2 limit + local pollutant caps + EE), or
- Two if the carbon limit is less stringent, or
- Three if the RE&EE policies are implemented (without imposing the CO_2 and local pollution caps), or
- All four only if none of the carbon, local emissions, RE or EE policies were to be in place.

It is important to note that the specific selection of one project over another is driven in the least-cost optimization primarily by a combination of capital cost and size of the unit. Kakanj 8 is selected in all scenarios because it is the second cheapest unit – marginally more expensive than Ugljevik 3 (600 MW) – *and* it is also a smaller unit that allows it to be utilized more heavily than a 600 MW unit. In some cases, the choice of one over the other is very marginal that can change with the slightest change in *inter alia* cost/size assumption. For instance, Banovici and Kakanj 8 are in fact very close in terms of their costs and unit size. We have tested the difference in net system cost selecting one over the other, and the difference is well below 1% of the system cost. The outcomes of the analysis therefore should be seen in the light of the fact that these outcomes are obtained based on the cost estimates that were provided for the analysis. Even a slight change in the combination of cost and sizing of the units can very well change their selection. Changes in other parameters in the model can also impact on the selection. Selection of a larger unit (e.g., Ugljevik 3) would be more economic if we assume a slightly higher demand growth rate and/or assume the existing Ugljevik unit's life is not extended.

4.2. Discussion on Other Scenarios and Sensitivities

Unconstrained scenarios and sensitivities

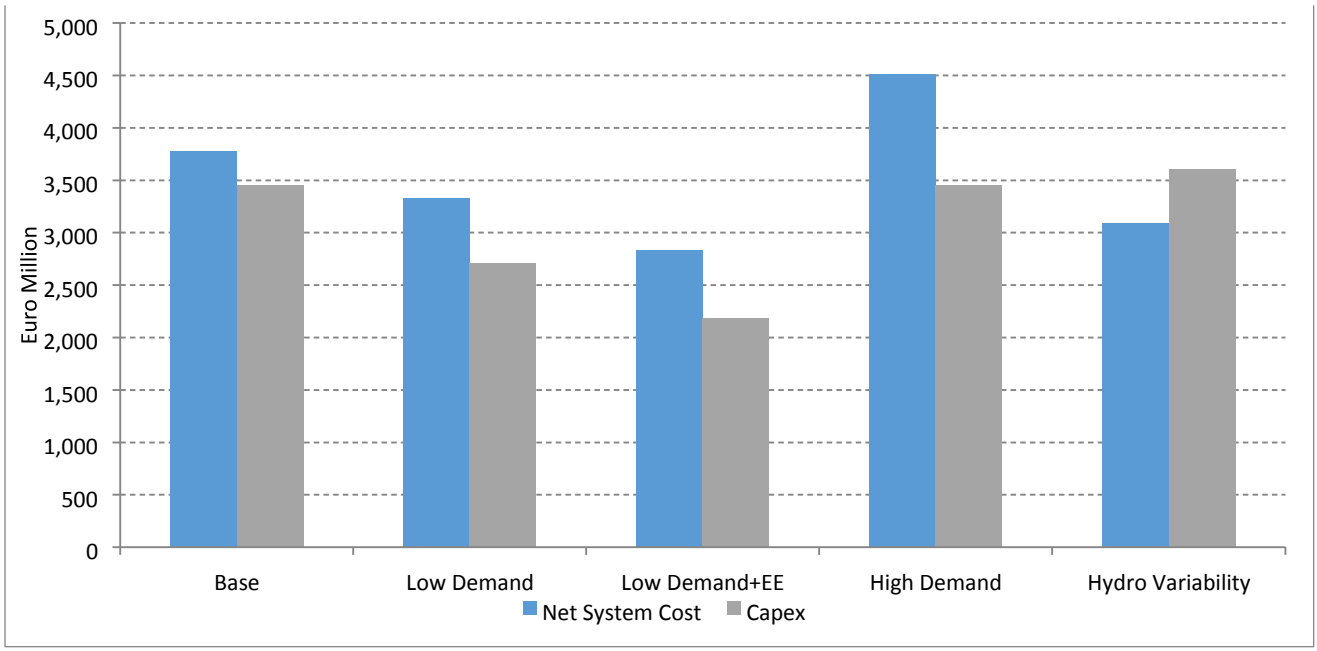
Figure 8 compares BASE with the sensitivities performed around it in a policy/emission unconstrained paradigm. These give useful insights into the nature of variation in net system cost and CAPEX, namely:

- 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 €1,273 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.

Figure 8 Net system cost and CAPEX* for sensitivities around BASE (€m): Unconstrained



*Net system cost is the annualized discounted total system cost including OPEX and CAPEX. The CAPEX figures represent the overnight total CAPEX cost.

Policy constrained scenarios and sensitivities

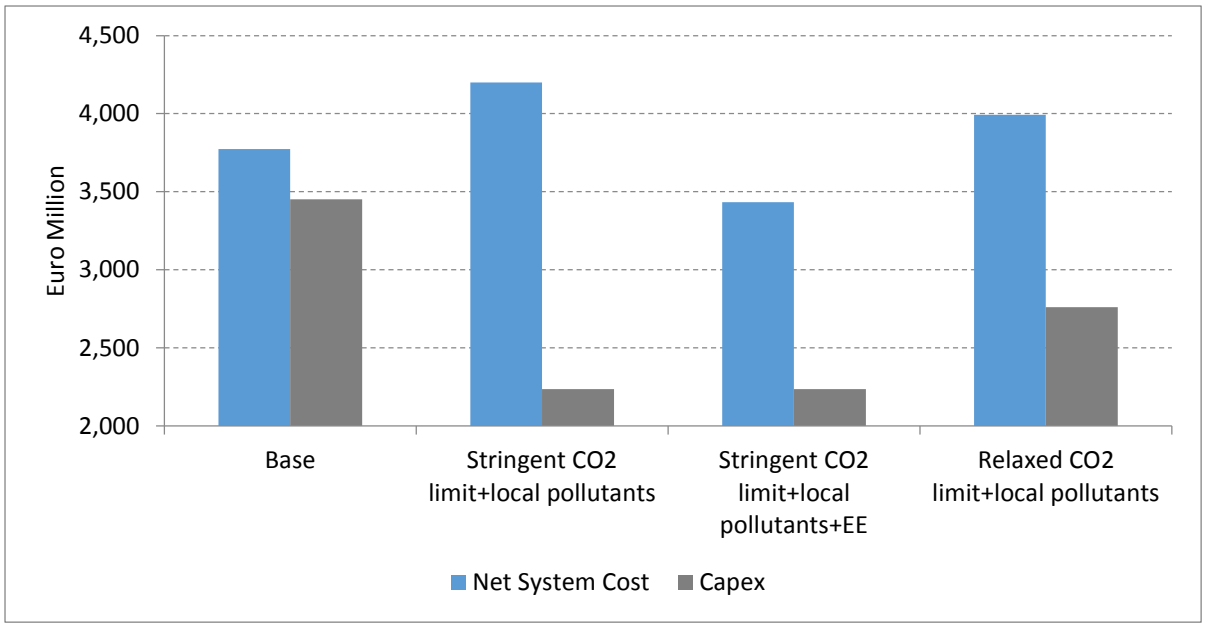
Figure 9 presents a similar comparison of BASE with the CO_2, local emissions and EE policy constrained scenarios. The difference in system costs generally represents the costs of reducing emissions and, in the variants with EE, implications of also meeting EE policy targets.

The local emissions constrained scenarios reflect the increase in system costs and other implications of meeting the NERP specified overall emission limits on local pollutants, without installation of emissions controls for the *existing*[16] coal plants. Emissions controls are considered, however, to be included in new TPP plants, as per the EU directives. Absent any local emissions control equipment on the existing plants, the model is effectively left with the choice to reduce/adjust dispatch for these units until the emission limits are met. The model will therefore adjust dispatch among the (existing and new) generators, including

[16] Existing coal plants that are not on the 'opt-out' list as per: Ministry of Foreign Trade and Economic Affairs, 2015, List of Limited lifetime derogation (opt-out) LCPs in BiH, December 2015.

the option to reduce generation from the existing units to the point of the retiring some of them early, build new coal plants (equipped with controls), forego export opportunities or invest in cleaner forms of generation including gas, hydro, other renewables.

Figure 9 Net system cost and CAPEX for sensitivities around BASE (€m): CO_2 and Local Emissions Constrained



A second issue that merits some attention is the interaction between local and CO_2 emissions constraints. If both NERP limits and carbon INDCs are to be honored, there is room for jointly optimizing the options to meet *both* at the lowest possible cost. Meeting the carbon constraint would typically require switching to a cleaner generation mix (and/or reduce generation/export) that also reduces emissions of local pollutants. Therefore, we also explore the *incremental* cost of meeting the NERP limits when combined with CO_2 limits, to see if emissions controls are still justifiable in a carbon constrained world.

Finally, we also recognize that while energy efficiency (EE) measures may be valuable even in an emission unconstrained scenario, their value may be substantially enhanced in the presence of NERP/INDC obligations because they can obviate the need for investment in substantially more expensive supply options.

Benefits of Energy Efficiency, and interaction among carbon & local pollutants

In this subsection, we firstly discuss the benefits of EE, followed by the interaction among NERP and INDC limits. In order to fully discuss these two issues, our analysis includes four additional sensitivities that includes a BASE+EE scenario, BASE+local pollutants/emissions constraint only, the Relaxed CO_2 limit (without any local emissions constraint or EE) and Stringent CO_2 limit with local emissions limits (but without EE). These four sensitivities provide us additional insights into the costs and benefits of various options. For instance,

the difference between BASE and BASE+EE shows the reduction in generation capital and operating costs that can be attributed to the EE program. 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 following specific points are useful for forming EE and emissions control policy analysis:

- **Benefits of EE:** Firstly, we calculate the difference in net system cost between BASE and BASE+EE scenarios. This difference represents an estimated benefit of the EE policy at €552 million. As discussed before (footnote 10), 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; and

- **The interaction between carbon and local emissions constraints is important**. As a comparison of the two Relaxed CO_2 target scenarios with and without the local emissions constraint in Figure 9 shows, 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 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 €98 million (€385-€277) 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.[17] Nonetheless, a judicious mix of all options to

[17] We note that there are existing plants that have opted out as per Ministry of Foreign Affairs and Trade derogation in 2015.

jointly address carbon and local emissions needs to be done in more detail to assess the type of controls, their location and timing is an important task to ensure the overall cost is minimized.

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 is 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.[18]

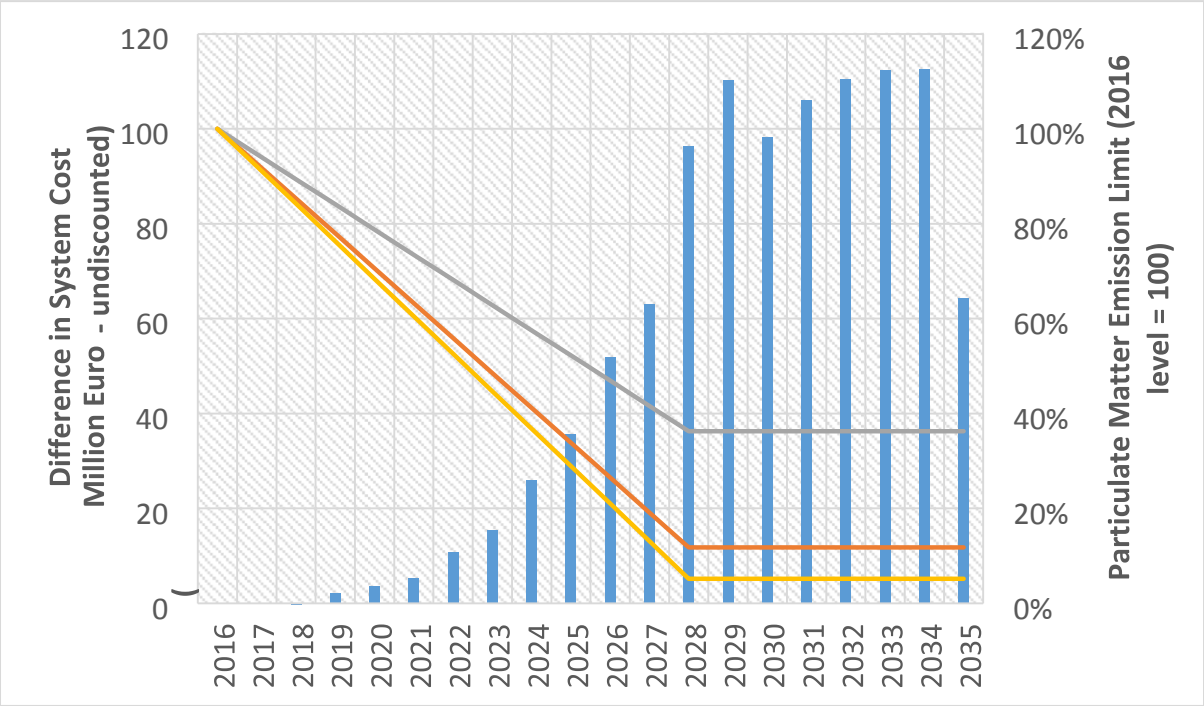
Figure 10 provides further important insights into the benefit of local emissions control following on from the discussion we had in the preceding sub-section. It shows the undiscounted cost difference between BASE and BASE+Local Pollutant/Emission constraint scenarios. Installing controls renders the 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.[19] 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 optout 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 €1,024 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

[18] We also implicitly assume here that the NERP limits must be met, i.e., the cost of allowing emissions to exceed the NERP limits has a cost of damage that exceeds either the cost of control equipment or any other alternative to it (e.g., lowering generation/export, etc.).

[19] Albeit it is not necessarily just the dust limit that binds but it provides a good indication of how all limits decrease over the years.

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 set of options that economically meet all of these policy objectives. **Figure 10 Annual benefits of local emissions control equipment***



Note: This scenario compares BASE with BASE+Local Emission Limit scenario.
*The 100% refers to local emissions in year 2016. The absolute values for the same year are: 6,616 tonnes PM, 20,511 tonnes NOx and 273,577 tonnes SOx.

Sensitivities on District Heating

The analysis also considered two sensitivities on District Heating (DH) by adding a minimum generation limit to existing Kakanj and Tuzla units and enforcing the commissioning of the new Tuzla 7 and Kakanj 8 units as per the current plans of the EPBiH.[20] These two sensitivities consider adding these constraints to (a) BASE and (b) Stringent CO_2 Limit + Local Pollutants +EE scenarios to understand the added cost implication to the electricity system of operating these two units at a higher utilization rate than might otherwise be the case. We find that:

1. Adding a District Heating obligation to BASE increases the cost by €211 million; and

[20] As per discussion with EPBiH. EPBiH envisions providing district heating (DH) services to Zivinice and Lukavac (total 200 MWt) through Tuzla units. In addition, EPBiH envisions providing about 400 MWt in Sarajevo and Zenica through the Kakanj units. Adding this heating constrain to the model enforces commissioning of both Tuzla 7 and Kakanj 8 plants in 2020 and 2024, respectively.

2. Adding this in a Stringent CO_2 Limit + Local Pollutants + EE case doubles the cost impost to €426 million, mainly because a significant part of the coal dispatch from these two units would otherwise be uneconomic.

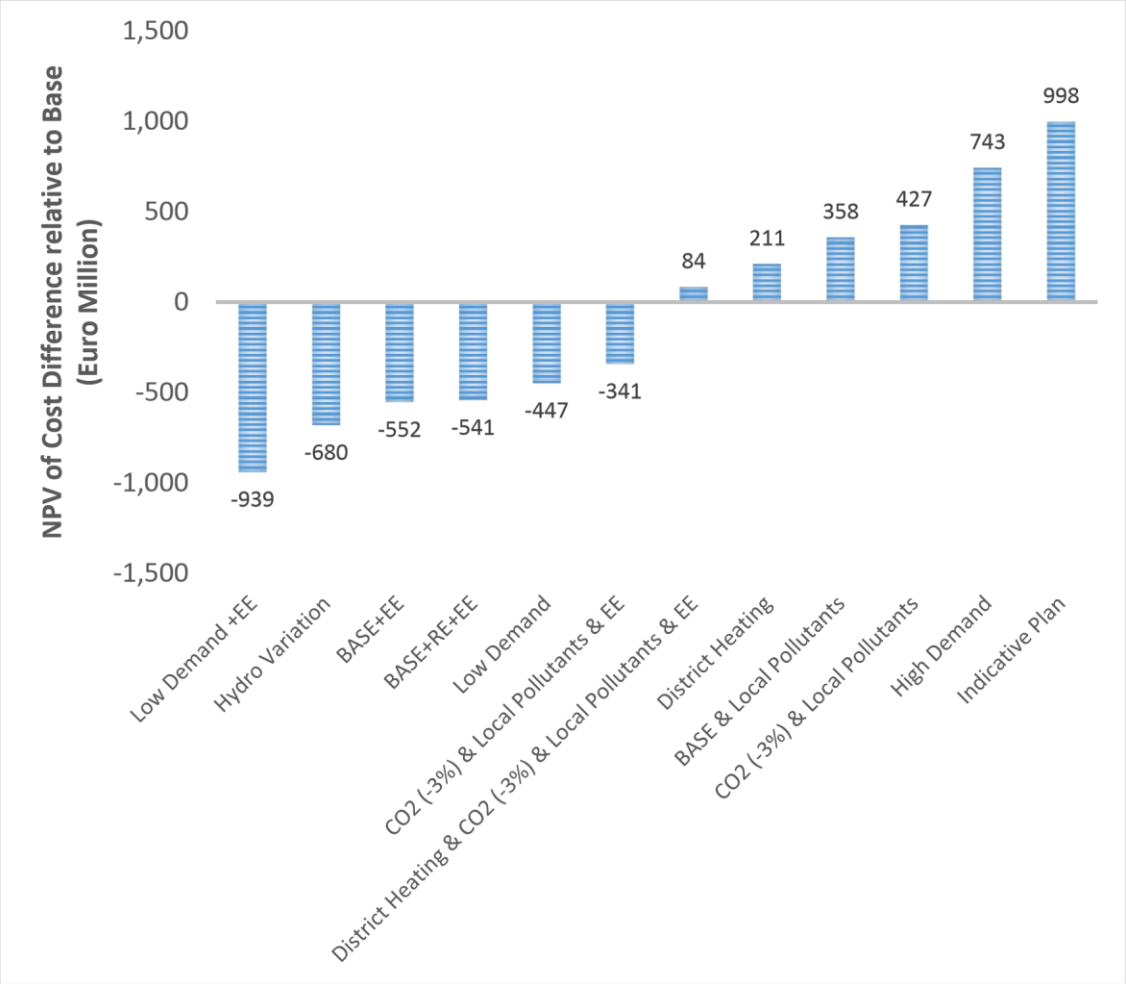
While these cost imposts are very significant and in fact comparable to the costs of meeting the carbon and local pollutant obligations, these need to be compared with alternative forms of providing the heating services. If other heating alternatives, for instance, cost more than €211 million (in an unconstrained scenario) or €426 million (in an emissions constrained scenario) – it may still be worthwhile keeping the District Heating option. However, a detailed cost-benefits analysis of alternative options to provide heating service including stand-alone heating boilers and usage of biomass for district heating were not possible to do within the scope of this analysis.

Cost impact of alternative scenarios and sensitivities

It is useful to conclude the discussion on system cost by looking at Figure 11 that presents the deviation of all scenario/sensitivity costs discussed in the preceding sections.

Negative numbers indicate costs that are lower than in the BASE scenario. Lower demand with EE prominently features in that list with €939 million cost savings that could be achieved from BiH implementing its EE policy targets, and continuing with a 1.1% pa growth rate over the next 20 years. High Demand (2.9%), on the other hand, can raise the cost by €743 million. Again, we note that the Indicative Plan even with 1.9% pa demand growth rate has a cost almost €1 billion higher than BASE.

Figure 11 Deviation of net system cost from BASE scenario cost (€3,774 million)



4.3. Implication of Potentially Higher Costs for New Coal

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

1. What happens if the costs 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.[21] 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 <u>not</u> assume these projects will be able to

[21] For instance, the RWE report for Republic of Kosovo in June 2016 noted capital cost for similar lignite based plants over €2,000/kW. (RWE, CAPEX & OPEX ANALYSIS AND REPORT FOR A LIGNITE FIRED BREF 2013 BAT COMPLIANT POWER PLANT, June 2016.). This translates into a cost of supply from a 300 MW sub-critical unit substantially above €60/MWh closer to €70/MWh for a merchant plant.

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.[22] 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.

Figure 12 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 (Figure 3) 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.

Figure 13 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 security that is met primarily through selection of additional hydro and wind.

[22] That is, import has to be less than export for the year as a whole. BiH can still import cheaper power during some periods (e.g., off-peak) as long as it exports at least as much during other periods.

Figure 12 Generation mix: BASE with higher cost for new coal

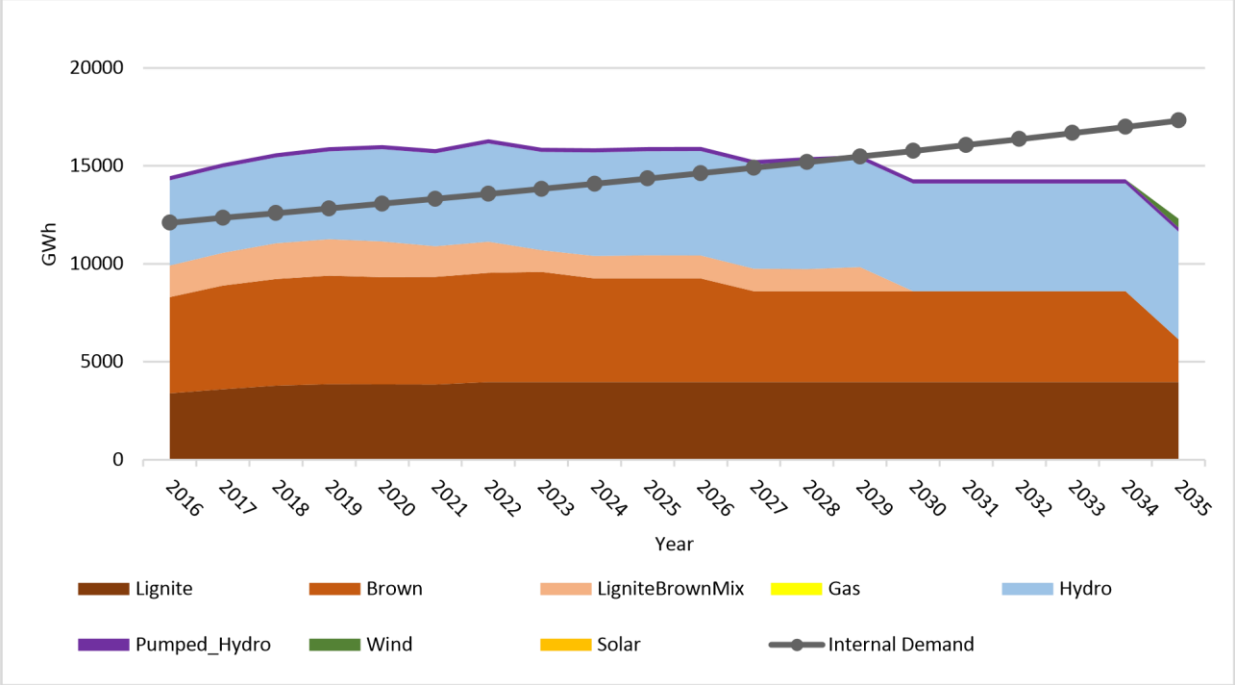
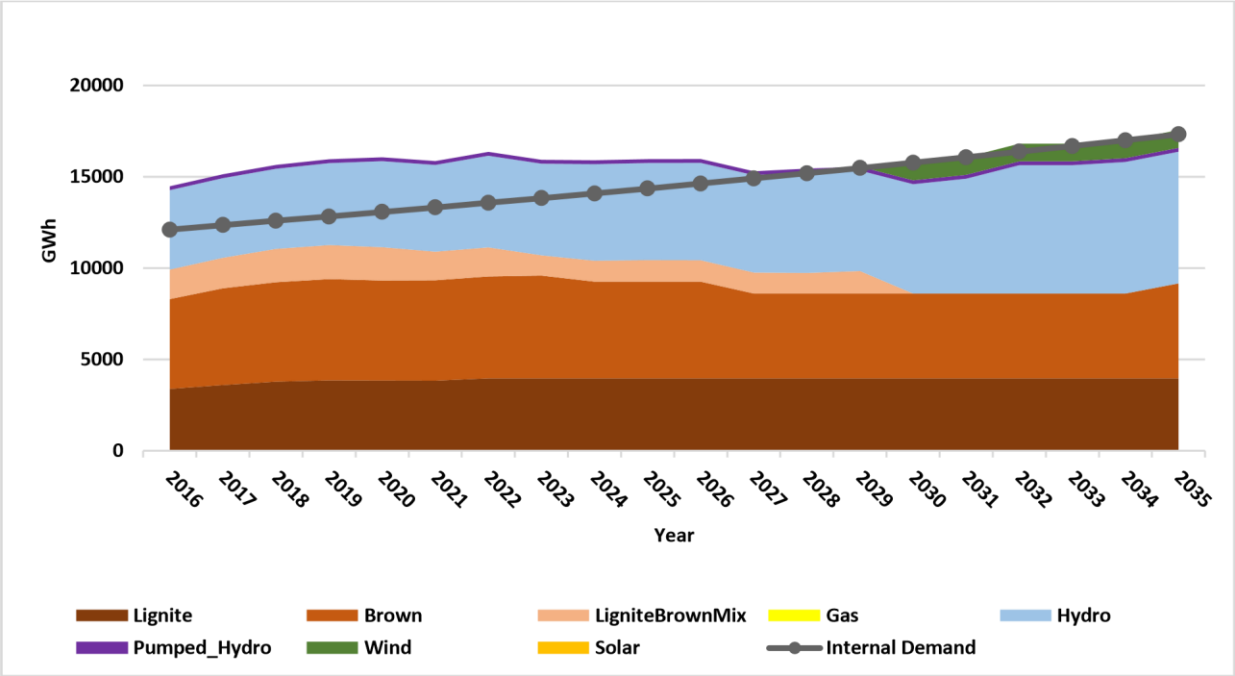


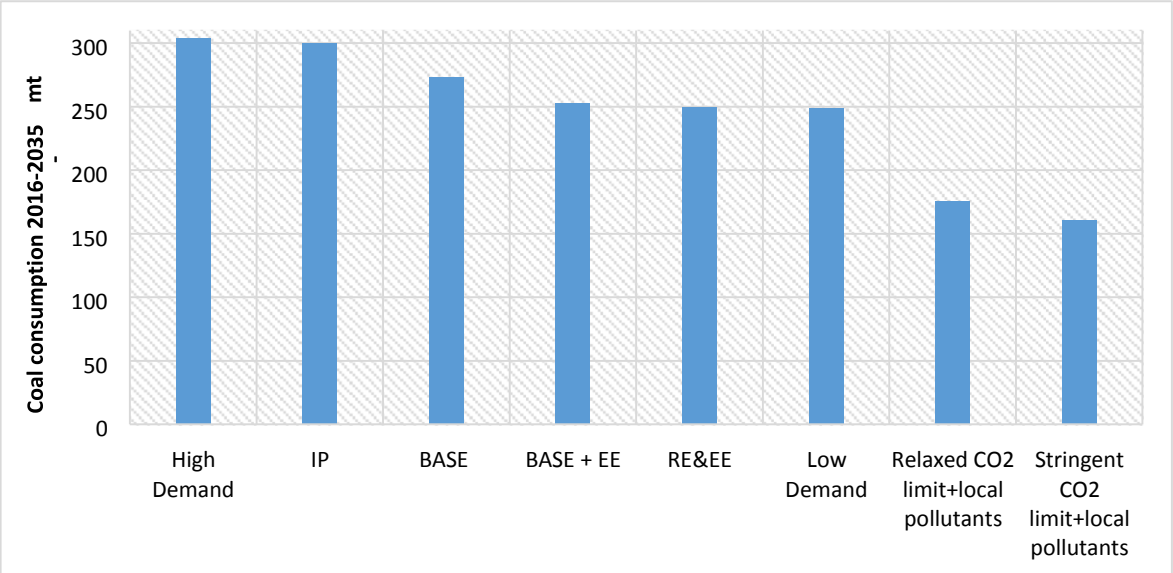
Figure 13 Generation mix: BASE with higher cost for new coal and national energy security



4.4. Comparison of Coal Consumption under Different Scenarios

Figure 14 shows a comparison of coal consumption[23] across some of the key scenarios and sensitivities that have a major bearing on dispatch of existing coal units and selection/dispatch of new ones. As the plot shows, coal consumption over the 20-year period can vary widely from 161 mt (or ~8 mt per year) in an emissions constrained world to over 300 mt (or 15+ mt per year) in a High Demand (2.9%) growth rate scenario. The BASE case represents a coal consumption of 13.65 mt per year on average, indicating a policy/emission unconstrained future of BiH would see an uptake of coal generation with existing ones retiring and new efficient ones replacing them.

Figure 14 Total coal consumption over 2016-2035 (million tonnes)



5. SUMMARY AND CONCLUDING REMARKS

The analysis presented in this report takes a critical look at the demand-supply balance in Bosnia and Herzegovina over the next 20 years (2016-2035) to identify generation investments that are most economical for a number of alternative scenarios, including policy scenarios around BiH's policy objectives on carbon emissions, local emissions control, renewable energy and energy efficiency. In particular, the analysis compares and contrasts an optimized/least-cost plan with the Indicative Plan that has been prepared by the Independent System Operator (ISO or NOS BiH), collating a wide range of projects proposed primarily by two of the main generation companies in BiH, namely EPBiH and EPRS.

[23] Coal consumption calculations are based on the heat rates of coal power plants (GJ/MWh), dispatch forecasts (MWh) for each of the scenario and the (inverse of) heating value of coal (tons/GJ) as disclosed by the EPs. Coal consumption = [Heat Rate * Dispatch] / Heating Value.

The work was done through active collaboration with the major stakeholders including the ISO, EPs, MOFTER, Ministry in FBiH and RS, and USAID. A significant part of the work involved active consultations with all stakeholders to develop inputs, modelled scenarios, and vetting initial rounds of model results to refine and revise inputs/scenarios. This process in itself was one of the most valuable aspects of the analysis. A national level power system planning optimization exercise to unify projects being, on one hand, planned by the EPs and policy goals being pursued at a state level, on the other, has never been done in the past. Many of the BiH issues that we revisited from the Bank's Systematic Country Diagnostics (SCD) including the dominant role of the public sector and a fragmented governance structure resonated well during the process.

While BiH power system as one of the lowest cost suppliers in the region does have major opportunities, including lucrative export potential, there are also significant risks that underlie many of its coal and gas generation investments. There are in fact deep conflicts, as well as potential synergies, among different investment and policy objectives that have not been understood, much less analyzed, to date. Imparting a better understanding of these trade-offs is at the heart of the analysis as we discuss the analytical findings and key recommendations in the next two sub-sections to conclude this report.

5.1. Summary of Analytical Findings

The key analytical findings of the study can be summarized as follows:

- BiH has significant opportunities (and needs) to invest over €3 billion in new power plants over the coming two decades to renew and build a robust and highly competitive generation system – a major share of it can be in the form of lignite/brown coal-fired power plants with very low operating costs;
- 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 (as part of the NREAP, 2015) and energy efficiency (as part of the Energy Community obligations and the forthcoming NEEAP), CO_2 reduction commitment as per the INDC (2015), and local pollution reduction as per the NERP (2015). All of these policies in one form or another would require reduction in fossil fuel generation and/or substantial investment to install emission controls, improve efficiency and extend life of such plants;
- Our base case (BASE) that assumes none of these policy interventions, does support building all four coal plants. However, the timing of these builds – even assuming almost twice the annual growth rate over the next two decades compared to the actual growth rate in the past decade (i.e., 1.9% pa assumed in BASE, as opposed to ~1% pa in the past decade) – is delayed by 6-15 years for three out of four projects. Also, the gas plant (Zenica 385 MW) is not selected in the BASE. These delays and exclusion of Zenica in the BASE scenario imply, compared to the IP, significant

savings to BiH making the overall system cost about a €1 billion (or 21%) lower in terms of discounted net system cost over 2016-2035. **This is a significant finding that points first and foremost to a need for a suitable decision making framework such as a least-cost optimization based planning model to systematically analyze a number of alternative supply (and demand) scenarios under different policy settings.**

- Although the difference of the IP and the least-cost (BASE) plan is primarily the Zenica gas plant – there are other risks of stranded assets (including coal) from the perspective of:

    1. CO_2 and/or NERP commitments;
    2. RE generation and EE that reduces thermal generation needs to meet domestic demand;
    3. Risk of higher costs for new coal plants that are not necessarily competitive in regional electricity market already exhibiting surplus capacity and depressed prices; and
    4. Intrinsic variability in hydro (including significant potential upsides).

  Our analysis aims to develop a balanced view of capacity/generation mix keeping in view both opportunities (including export opportunities) and these risks. We have systematically analyzed these issues through a set of scenarios.

- The overinvestment in the IP scenario would allow BiH to maximize electricity exports, which would reach 46% of domestic demand over 2016-2035. The BASE plan, even with the delay in the build of three coal plants and exclusion of the Zenica gas plant, would still achieve high levels of exports averaging 36% over 2016-2035;

- Combining and pursuing both the RE and EE policies present significant upside opportunities that:

    1. **Reduce net system cost by €541 million** (excluding EE investment costs)[24];
    2. Boost export volume to 39%; and
    3. Reduce generation investment requirements by €393 million (excluding EE investment); but
    4. Meeting the current RE and EE policy targets of 40% share of RE and 9% EE improvement alone is not sufficient to ensure meeting the carbon and local emissions limits included in the INDC and NERP.

- Optimized emission constrained scenarios in general:

[24] We do not have estimates of EE program costs, but based on the WB estimates for smaller EE programs in BiH done in the recent past suggest a program cost in the vicinity of €327 million.

1. **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 (both with and without any energy efficiency policy targets included)**;
2. Emphasize the need for construction of significantly more hydro capacities. Moreover, required new HPP capacity in all constrained scenarios over the planning period is larger than the required new coal-fired TPP capacity;
3. Drop export volume below 10% - in fact it goes down to 0% for the most stringent scenario; but still
4. **Does not include gas based generation**.

- Stringent carbon commitment (3% below 1990) together with the NERP local emission limits:
    - Increases net system cost by €427 million in NPV terms over 2016-2035; ○ Renders BiH to be a zero net exporter overall; and ○ Demonstrates that energy efficiency policy is an excellent complement as it can reduce net system cost by €768 million, giving EE potentially a very high benefit-to-cost ratio.

- A more relaxed carbon commitment (18% above 1990 level) with NERP limits:
    - Keeps the net system cost increase to a more manageable €220 million; ○ Keeps BiH net export positive (and thus energy secure), albeit at a modest 8% level; and
    - Keeps two coal projects viable even without energy efficiency.

- Given the thin margin between delivered cost of coal-based electricity in BiH and forecasted regional prices (and risk of cost escalation of coal projects), **higher costs for four new coal projects were considered. In this case: ○ None of the coal projects are selected by the model**;
    - As a result, BiH becomes a significantly reliant on imports post 2030, with a €212 million increase in cost relative to the BASE; ○ If BiH were to pursue a national energy security objective by keeping a balanced net export position, it would cost an additional €73 million requiring additional hydro and wind projects to fill the gap between import and export; but
    - Zenica gas is still not needed even at gas prices of €9.4/GJ (which is significantly lower than the current gas prices paid by the industrial customers).

- While new thermal projects face the risk of being uneconomic/stranded, from a policy constraint or cost escalation perspective, **the benefits of installing local emissions control equipment is likely to be strongly positive**:

- There is an **absolute minimum benefit of €385 million** (compared to the cost of trying to meet the local emission limits without installing control equipment) if literally all of the controls are installed today to start meeting the 2030 emissions standard;
- **The benefits can be as high as €1,024 million** if the controls are installed closer to the 2030 period; and
- Therefore, an emissions control program in the vicinity of €350 million (i.e. at level indicated by the NERP) spread over the next 10 years is likely to be economic.
- Given that the installation of emission control equipment may be combined with refurbishments to the generation technologies (as is the case in Ugljevik TPP) that extend the useful life of the plant, this puts further impetus on carefully considering which new TPPs, and when, to build.

5.2. Key Messages and Summary of Recommendations

The first key message that emerges from the analysis is that the BiH power sector holds significant opportunity to exploit its ability to develop relatively low-cost generation resources including lignite, hydro and other renewables. There are economic opportunities of at least €3 billion over the next two decades to meet domestic demand and export. Absent any carbon emissions target, exports can substantially increase from 23% observed in the past decade to 36% over 2016-2035. Average annual export revenues over this period can amount to 3% of the GDP in 2015. There are however significant risks associated with an export-oriented strategy. Firstly, as the Indicative Plan scenario outcome clearly demonstrates, an overinvestment in thermal projects may cost BiH €1 billion, although excess uneconomic generation does boost the export share to 46%. Secondly, if the carbon and other emissions are mandated, some of the thermal projects may be rendered uneconomic and export share will as a result drop drastically to less than 10% of domestic consumption.

A second key message that emerges from the analysis is for BiH to re-focus on hydro and wind development to offset the risks associated with a carbon/emission constrained scenario. The findings of the policy constrained clearly suggest that BiH should develop 753 MW of new hydro and at least 350 MW of wind over the coming two decades under all carbon/emission constrained scenarios. The hydro capacity requirements in fact exceed that of new coal under these scenarios. Notwithstanding the significant potential, addition of substantial new hydropower and wind plant capacity appears unlikely without considerable new efforts and increased participation by the private sector.

Third, given the significance of these outcomes and a relatively scarce level of information and fragmented state of planning, BiH needs to first put together a decision making framework that integrates the individual project plans – primarily from the EPs – and the policy objectives to form a coherent national energy plan. The framework also enables the

policy makers and regulators to gain valuable insights into major programs such as energy efficiency, local emissions control, viability of commercial agreements with independent power producers, renewable portfolios and national energy security.

The planning process initiated through this exercise needs to continue, enhancing and expanding data and resolution as planning capacity improves over the years. We recommend that the ISO, or another suitable organization, obtains appropriate planning software and other tools to support this process.

The analysis that we have done casts light on the priority, timing and economics of the proposed investments, leading to the following specific conclusions and recommendations that should be considered in revising the current Indicative Plan:

On Thermal Power:

- The timing of all of the new thermal projects in the Indicative Plan requires a closer scrutiny because a least-cost plan (even without any policy constraint) delays several of them by more than 5 years and up to 15 years; policies around carbon can eliminate at least two if not three of these projects (with corresponding implications on coal consumption);
- Cost escalation of these projects to even €55-60/MWh – which happens to be at the low end of PPAs in the region – would risk these projects being uneconomic, pointing to a need for a careful review and analysis of the costs of the plants being considered;
- Zenica gas plant is not needed in any of the scenarios including extreme ones that consider emissions constraints and no new coal projects.

On Renewable Energy, Energy Efficiency and CO_2 targets:

- Both RE and EE projects exhibit excellent economics to lower OPEX and boost export, and complement carbon and NERP local emission reduction policies. Energy efficiency in particular can significantly lower the cost of reaching CO_2 targets. It is therefore important to pursue the implementation of these policies in a coordinated manner.
- All emission constrained scenarios would require 750+ MW of new hydro and 350 MW of wind. A systematic framework to encourage the development of these projects is essential, including:
    - Improved/updated resource assessments for hydro
    - Strengthened coordination within the country and with neighboring countries
    - Improved and clarified institutional capacities and concessions process
    - Greater involvement of the private sector

On Local Emissions Control:

- The investments in the emission controls envisaged in the NERP are likely to have a strong economic case, freeing up significant generation potential from existing projects to support export (as the TPPs can be operated more before hitting emission target levels);
- Adding emissions control would also typically involve extension of the life of the plant that in turn may reduce the need for new thermal capacity. The current analysis already considers one such life extension (for Ugljevik 279 MW unit), but further considerations will need to be given to such extensions for the other plants; and
- There should be a thorough examination of the specific controls and life extensions, and timing of these in line with all other policy objectives to optimize across all of the objectives.

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