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Task 3: Network Reinforcement and Investment Planning

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1 Introduction

This Task 3 report forms part of a series of 3 reports in an assignment examining the potential for wind power development in Bosnia and Herzegovina (BiH). This report focuses on the network and investment planning and covers three key areas:

- Additional network reinforcements for different penetration of wind power into the BiH transmission system;
- Estimation of investment costs necessary to accept wind power into the BiH transmission system;
- Additional requests and requirements (P/f and Q/U control).

Task 2 identified bottlenecks in the transmission system that need to be removed in order to increase the capacity of the network to handle wind power.

In this report network reinforcements that ensure secure take off of all electricity produced by wind power capacity in BiH in the short to medium term (up to 2020) are prioritised and fully costed[1]. This is based on five previously agreed scenarios (marked with A, B, C, D1 and D2), together with one subscenario marked with A1 that represents possible construction of WPP 50 MW in wide area of Trebinje.. Estimation of costs has been done according to present unit prices of high-voltage equipment in the BiH estimated by Elektroprijenos BiH[2].

In accordance to the Terms of Reference the further sections of the report cover the following:

- Section 2 gives an overview of critical transmission elements, based on findings from Task 2, and gives comments about unofficially planned investments over the medium term and their benefit for wind power integration
- Section 3 identifies additional investments required in transmission system developments for different scenarios of wind power integration
- Section 4 provides an estimation of network reinforcement investment costs resulting from wind power integration
- Section 5 identifies additional requests in P/f and Q/U control

[1] Calculation of costs was done with assumptions of having FiT applied on all WPP projects, since at the moment there is no FiT limitation for WPPs.

[2] Blueprint of the transmission system development plan 2011 – 2020, Elektroprenos BiH, November 2010; Since there is no officially adopted transmission development plan till 2020, the Blueprint directions are used here. It is not expected to have singificant impact on this study results.

- Section 6 presents the results of analysis of the impact of wind integration on conventional generation and an assessment of the expected costs providing reserve generation to cover for wind

- Section 7 summarises the key findings of the report.

Environmental and social considerations and possible constraints are incorporated into proposed investment plan, reflecting the requirements set out in Bank's Environmental and Social Policy (2008).

2 Critical transmission system elements with respect to wind power plants integration

In Section 6 of the Task 2 report, network bottlenecks in the transmission system of BiH have been identified for different scenarios of wind power plant integration. Network bottlenecks are located in the South-western part of the country, spreading to the middle part of the country with wind power plants installed capacity increase.

Network bottlenecks are primarily caused by large concentration of wind farms at relatively small geographical area.

Five critical geographic network areas can be identified and bottlenecks for each will be identified in the following.

2.1 Area of Mostar

A critical line in the existing transmission system configuration for integration of wind farms under all scenarios is OHL 110 kV Mostar 4 – Siroki Brijeg. This line is planned for grid connection of WPP Velika Vlajina (see Figure 1).

Basic parameters of this line are given in Table 1.

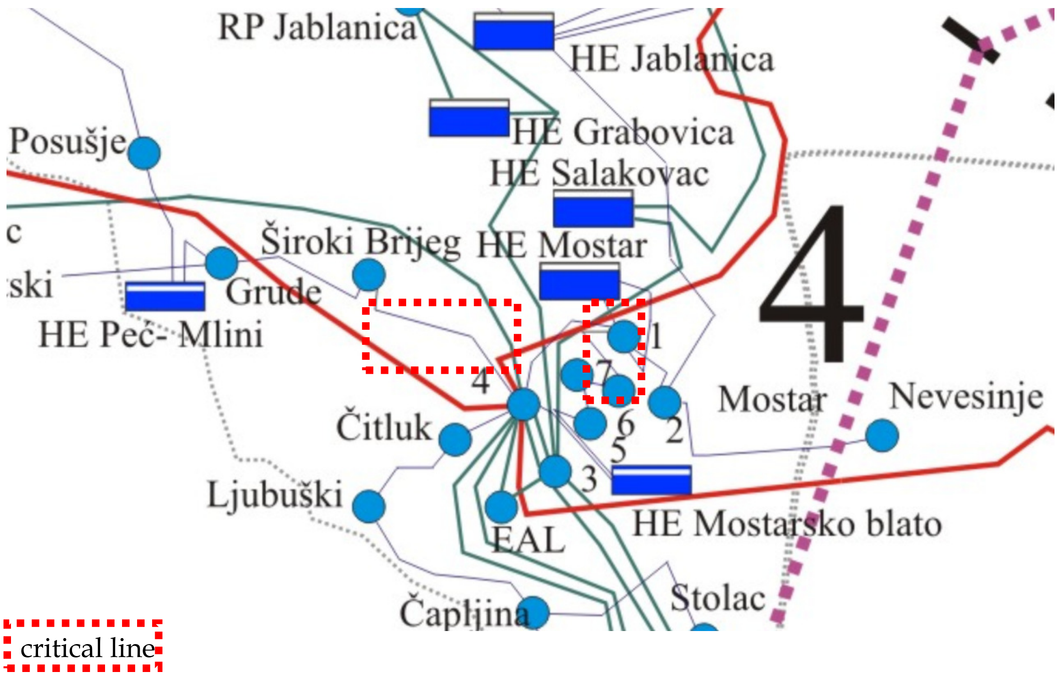
Table 1 Basic parameter of Mostar 4 – Siroki Brijeg

Transmission line and voltage:	**OHL 110 kV Mostar 4 – Siroki Brijeg**
*Length (km)**	a) 16,8 b) 16,8
Node 1	SS Mostar 4
Node 2	SS Siroki Brijeg
Year of commission/revitalization	1955/88/99
Towers	Concrete, steel
Conductors	Copper 95 mm², ACSR 240/40 mm²
Protection wire	Iron 50 mm², OPGW
Owner	Elektroprijenos BiH
Transmission capacity (MVA)	72
Permitted permanent current	380 A (Summer) / 380 A (Winter)
Permitted short-duration current	-
Transmission capacity limitation (A)	380 A (~68 MW); Reason: conductors cross section

* Line length : a) length within BiH transmission system b) total length

The critical line is equipped partially by conductors made of Copper 95 mm² that decreases its transmission capacity significantly. These conductors, together with concrete towers, are located across a line section that is 10.8 km long. Elektroprijenos BiH considers to replace critical conductors with standard ones (ACSR 240/40 mm²) and concrete towers with steel ones.

Figure 1 Critical lines in the area of Mostar



A critical line for future transmission system configuration for integration of wind farms for all scenarios is OHL 110 kV Mostar 1 – Mostar 6 (see Figure 1). Basic parameters of this line are given in Table 2.

Table 2 Basic parameter of Mostar 1 – Mostar 6 line

Transmission line and voltage:	**OHL 110 kV Mostar 1 – Mostar 6**
*Length (km)**	a) 4,3 b) 4,3
Node 1	SS Mostar 1
Node 2	SS Mostar 6
Year of commission/revitalization	1955/79/95
Towers	Concrete, steel
Conductors	ACSR 240/40 mm², ACSR 150/25 mm²
Protection wire	OPGW
Owner	Elektroprijenos BiH
Transmission capacity (MVA)	89
Permitted permanent current	470 A (Summer) / 470 A (Winter)
Permitted short-duration current	700 A
Transmission capacity limitation (A)	470 A (~85 MW); Reason: conductors cross section

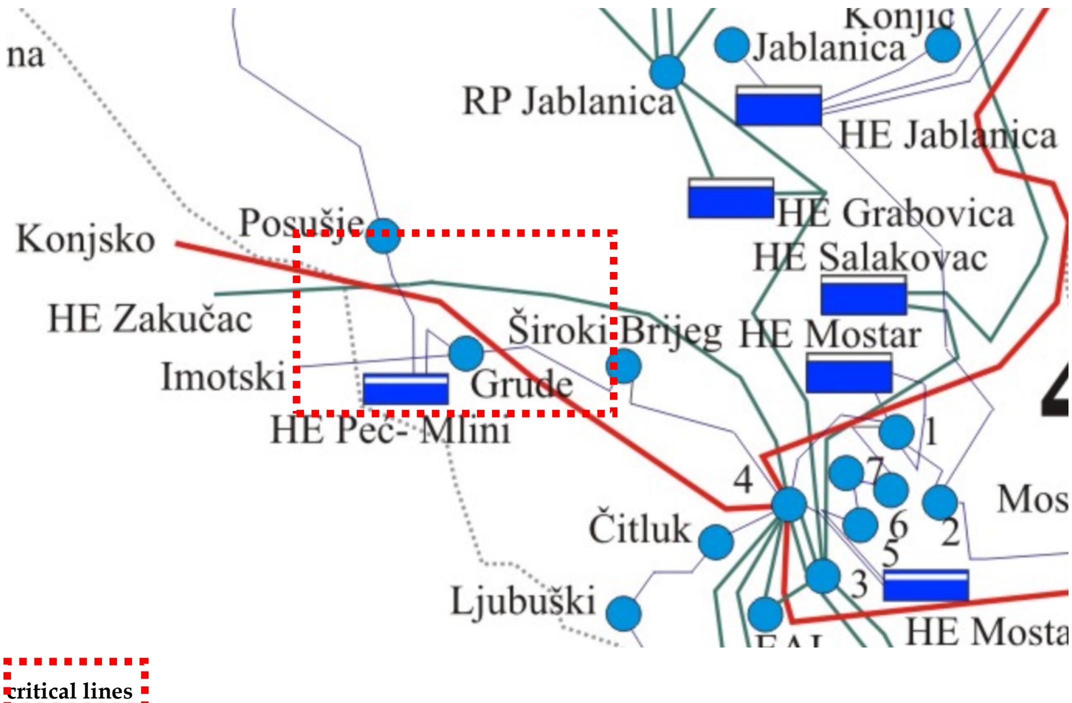
* Line length : a) length within BiH transmission system b) total length

The critical line was constructed more than 50 years ago and it is partially equipped with small cross-section conductors placed on concrete towers. Elektroprijenos BiH considers to replace critical conductors with standard ones (ACSR 240/40 mm²) and concrete towers with steel ones.

2.2 Area of Grude and Posusje

Critical lines in this area are OHL 110 kV Grude – Siroki Brijeg, Grude – Imotski, Grude – HPP Pec Mlini and Posusje – HPP Pec Mlini, in fact all lines 110 kV connected with substation Grude and HPP Pec Mlini. All four lines appear to be critical in scenario B of WPPs construction (total installed capacity 300 MW – see Figure 2).

Figure 2 Critical lines in the area of Grude and Posusje



Furthermore, 110 kV transmission infrastructure in this area is missing to connect some large wind power plants projects which are planned for construction.

Basic parameters of critical lines in observed area are shown in Table 3.

Lines Grude – Siroki Brijeg and Grude – Imotski appear to be critical mostly due to their decreased transmission capacity while lines around HPP Pec Mlini appear to be critical due to unfavourable network topology. These two critical lines are made of standard conductors cross-section (ACSR 240/40 mm²), but still with inadequate transmission capacity to integrate wind power plants in the scenario B and more.

Elektroprijenos BiH considers to replace critical conductors with standard ones (ACSR 240/40 mm²) and concrete towers with steel ones (Grude – Siroki Brijeg, Grude – Imotski).

Table 3 Basic parameter of critical lines in area of Grude and Posusje

Transmission line and voltage:	**OHL 110 kV Grude – Siroki Brijeg**
*Length (km)**	a) 15,5 b) 15,5
Node 1	SS Grude
Node 2	SS Siroki Brijeg
Year of commission/revitalization	1955
Towers	Concrete, steel
Conductors	Copper 95 mm², ACSR 240/40 mm²
Protection wire	OPGW
Owner	Elektroprijenos BiH
Transmission capacity (MVA)	89
Permitted permanent current	380 A (Summer) / 380 A (Winter)
Permitted short-duration current	-
Transmission capacity limitation (A)	380 A (~68 MW); Reason: conductors cross section

* Line length : a) length within BiH transmission system b) total length

Transmission line and voltage:	**OHL 110 kV Grude – Imotski**
*Length (km)**	a) 12,9 b) 20,85
Node 1	SS Grude
Node 2	SS Imotski (Croatia)
Year of commission/revitalization	1951/82
Towers	Concrete, steel
Conductors	Copper 95 mm², ACSR 240/40 mm²
Protection wire	Iron 50 mm²
Owner	Elektroprijenos BiH / HEP
Transmission capacity (MVA)	89
Permitted permanent current	380 A (Summer) / 380 A (Winter)
Permitted short-duration current	-
Transmission capacity limitation (A)	380 A (~68 MW); Reason: conductors cross section

* Line length : a) length within BiH transmission system b) total length

Transmission line and voltage:	**OHL 110 kV Grude – HPP Pec Mlini**	
*Length (km)**	a) 10,2	b) 10,2
Node 1	SS Grude	
Node 2	HPP Pec Mlini	
Year of commission/revitalization	1982/2004	
Towers	Steel	
Conductors	ACSR 240/40 mm²	
Protection wire	OPGW	
Owner	Elektroprijenos BiH	
Transmission capacity (MVA)	123	
Permitted permanent current	645 A (Summer) / 645 A (Winter)	
Permitted short-duration current	950 A	
Transmission capacity limitation (A)	645 A (~117 MW); Reason: conductors cross section	
* Line length : a) length within BiH transmission system b) total length		

Transmission line and voltage:	**OHL 110 kV Posusje – HPP Pec Mlini**	
*Length (km)**	a) 21,0	b) 21,0
Node 1	SS Posusje	
Node 2	HPP Pec Mlini	
Year of commission/revitalization	2004	
Towers	Steel	
Conductors	ACSR 240/40 mm²	
Protection wire	OPGW, Iron 50 mm²	
Owner	Elektroprijenos BiH	
Transmission capacity (MVA)	123	
Permitted permanent current	645 A (Summer) / 645 A (Winter)	
Permitted short-duration current	950 A	
Transmission capacity limitation (A)	645 A (~117 MW); Reason: conductors cross section	
* Line length : a) length within BiH transmission system b) total length		

2.3 Area of Livno

Critical lines in this area are OHL 110 kV Livno – Busko Blato and Livno – Tomislavgrad for scenario B of wind power plants integration, and Busko Blato – Kraljevac and Busko Blato – Peruca for higher scenarios of WPPs integration (scenarios C and D), in fact all 110 kV lines connected with substations Livno and Busko Blato. Basic parameters of critical lines in observed area are shown in Table 4 and Figure 3. 110 kV line Livno – Tomislavgrad is planned for grid connection of WPP Borova Glava.

Figure 3 Critical lines in the area of Livno

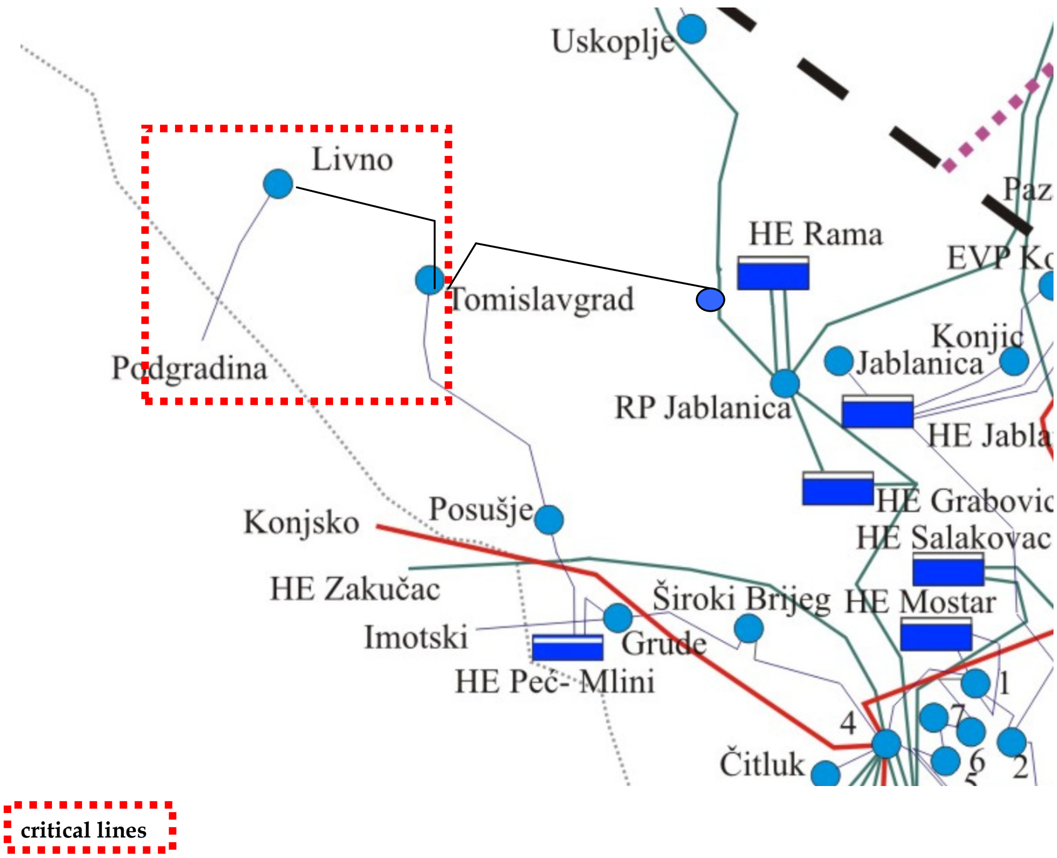


Table 4 Basic parameter of critical lines in area of Livno

Transmission line and voltage:	**OHL 110 kV Livno – Tomislavgrad**
*Length (km)**	a) 27,0 b) 27,0
Node 1	SS Livno
Node 2	SS Tomislavgrad
Year of commission/revitalization	2000/2011
Towers	Steel
Conductors	ACSR 240/40 mm²
Protection wire	OPGW
Owner	Elektroprijenos BiH
Transmission capacity (MVA)	123
Permitted permanent current	645 A (Summer) / 645 A (Winter)
Permitted short-duration current	950 A
Transmission capacity limitation (A)	645 A (~117 MW); Reason: conductors cross section

* Line length : a) length within BiH transmission system b) total length

Transmission line and voltage:	**OHL 110 kV Livno – Busko Blato**
*Length (km)**	a) 12,39 b) 12,40
Node 1	SS Livno
Node 2	SS Busko Blato
Year of commission/revitalization	1980
Towers	Steel
Conductors	ACSR 240/40 mm²
Protection wire	Iron 50 mm²
Owner	HEP
Transmission capacity (MVA)	123
Permitted permanent current	645 A (Summer) / 645 A (Winter)
Permitted short-duration current	950 A
Transmission capacity limitation (A)	645 A (~117 MW); Reason: conductors cross section

* Line length : a) length within BiH transmission system b) total length

Transmission line and voltage:	**OHL 110 kV Busko Blato – Kraljevac**
*Length (km)**	a) 23,6 b) 36,4
Node 1	SS Busko Blato
Node 2	SS Kraljevac (Croatia)
Year of commission/revitalization	1982
Towers	Steel
Conductors	ACSR 240/40 mm²
Protection wire	Iron 50 mm²
Owner	HEP
Transmission capacity (MVA)	120
Permitted permanent current	605 A (Summer) / 605 A (Winter)
Permitted short-duration current	605 A
Transmission capacity limitation (A)	605 A (~115 MW); Reason: conductors cross section

* Line length : a) length within BiH transmission system b) total length

Transmission line and voltage:	OHL 110 kV Busko Blato – Peruca
*Length (km)**	a) 13,2 b) 35,3
Node 1	SS Busko Blato
Node 2	SS Peruca (Croatia)
Year of commission/revitalization	1969/72
Towers	Steel
Conductors	ACSR 150/25 mm^2
Protection wire	Iron 50 mm^2
Owner	HEP
Transmission capacity (MVA)	90
Permitted permanent current	470 A (Summer) / 470 A (Winter)
Permitted short-duration current	470 A
Transmission capacity limitation (A)	470 A (~85 MW); Reason: conductors cross section

* Line length : a) length within BiH transmission system b) total length

All critical lines are equipped with standard conductors' cross-section, except the Busko Blato – Peruca line that is made of ACSR 150/25 mm^2. 110 kV lines around SS Busko Blato are owned by the Croatian power supply company HEP.

2.4 Area of Bugojno and Kupres

110 kV lines located in the wider area of Bugojno, Kupres, Jajce and D. Vakuf become critical in scenario C of wind power plants integration once new 110 kV lines Tomislavgrad – Kupres and Rama – Uskoplje are constructed allowing wind production to be transmitted in the direction of central Bosnia and Herzegovina (see Figure 4).

Critical 110 kV lines are Bugojno – D. Vakuf, D. Vakuf – Jajce 2, Tomislavgrad – Kupres (not been constructed yet) and Bugojno – Kupres.

Basic parameters of critical lines in observed area are shown in Table 5.

New 110 kV line Tomislavgrad – Kupres will be equipped with conductors ACSR 240/40 mm^2 with 123 MVA of transmission capacity. Around 20 km of this line should be constructed in a near future (8 km has already built).

Lines Bugojno – D. Vakuf and D. Vakuf – Jajce 2 are equipped with small cross-section conductors. Line sections with inadequate cross-sections are 21.2 km for D. Vakuf – Jajce 2 line and 5,7 km for Bugojno – D. Vakuf line.

Elektroprijenos BiH considers to replace critical conductors of Bugojno – D. Vakuf and D. Vakuf – Jajce 2 lines with standard ones (ACSR 240/40 mm^2).

Table 5 Basic parameter of critical lines in areas of Bugojno and Kupres

Transmission line and voltage:	**OHL 110 kV Bugojno – D. Vakuf**
*Length (km)**	a) 8,6 b) 8,6
Node 1	SS Bugojno
Node 2	SS Donji Vakuf
Year of commission/revitalization	1965/85/96
Towers	Steel
Conductors	ACSR 240/40 mm², ACSR 120/20 mm²
Protection wire	Iron 35 mm² and 50 mm²
Owner	Elektroprijenos BiH
Transmission capacity (MVA)	73
Permitted permanent current	385 A (Summer) / 385 A (Winter)
Permitted short-duration current	-
Transmission capacity limitation (A)	385 A (~62 MW); Reason: conductors cross section

* Line length : a) length within BiH transmission system b) total length

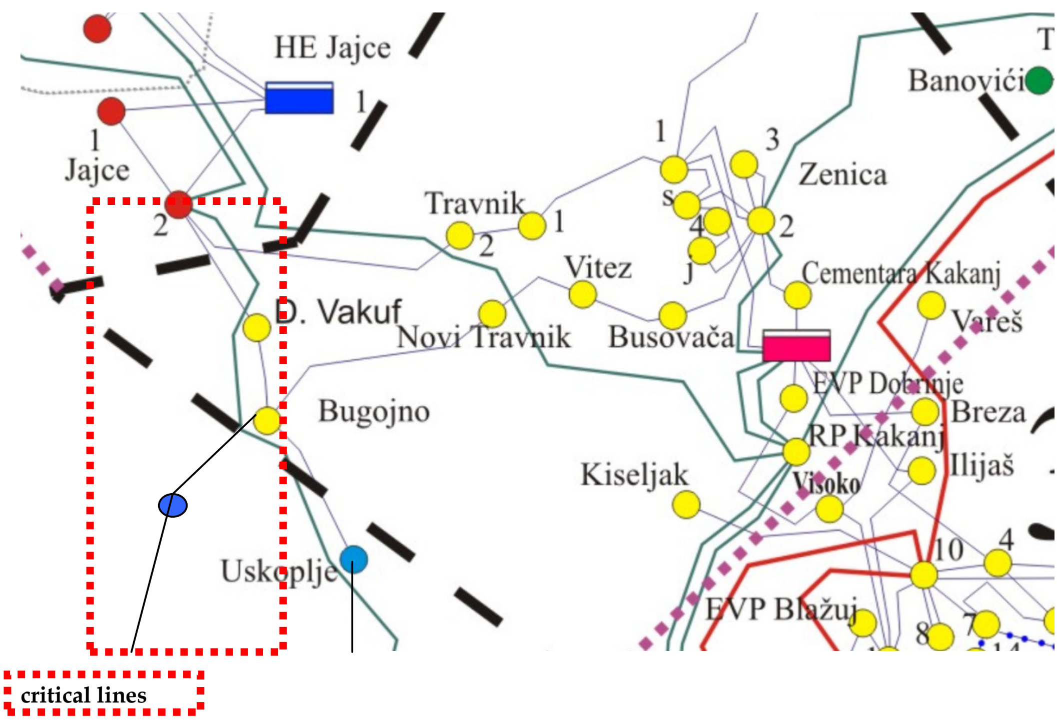
Transmission line and voltage:	**OHL 110 kV D. Vakuf – Jajce 2**
*Length (km)**	a) 26,7 b) 26,7
Node 1	SS Donji Vakuf
Node 2	SS Jajce 2
Year of commission/revitalization	1965/85
Towers	Steel
Conductors	ACSR 240/40 mm², ACSR 120/20 mm²
Protection wire	Iron 35 mm² and 50 mm²
Owner	Elektroprijenos BiH
Transmission capacity (MVA)	73
Permitted permanent current	385 A (Summer) / 385 A (Winter)
Permitted short-duration current	-
Transmission capacity limitation (A)	385 A (~62 MW); Reason: conductors cross section

* Line length : a) length within BiH transmission system b) total length

Transmission line and voltage:	**OHL 110 kV Bugojno – Kupres**	
*Length (km)**	a) 15,9	b) 15,9
Node 1	SS Bugojno	
Node 2	SS Kupres	
Year of commission/revitalization	1985	
Towers	Steel	
Conductors	ACSR 240/40 mm²	
Protection wire	EAlMG 95 mm²	
Owner	Elektroprijenos BiH	
Transmission capacity (MVA)	123	
Permitted permanent current	645 A (Summer) / 645 A (Winter)	
Permitted short-duration current	950 A	
Transmission capacity limitation (A)	645 A (~117 MW); Reason: conductors cross section	

* Line length : a) length within BiH transmission system b) total length

Figure 4 Critical lines in the area of Bugojno and Kupres



2.5 Area of Novi Travnik and Zenica

110 kV lines located in the wider area of Novi Travnik and Zenica become critical in the scenarios D1 and D2 of wind power plants integration (total installed capacity 900 MW), once when new 110 kV lines Tomislavgrad – Kupres, Bugojno – Kupres and Rama – Uskoplje are constructed allowing wind production to be transmitted in the direction of central Bosnia and Herzegovina (see Figure 5).

Critical 110 kV lines (path) are Bugojno – N. Travnik, N. Travnik – Vitez, Zenica – Busovaca and Busovaca – Vitez. Using this path electricity produced by wind power plants in Herzegovina flows to large consumer centre of Zenica (for smaller scale wind power plants integration this path is not jeopardized because electricity produced by WPPs is consumed in Herzegovina and wider Bugojno area). Basic parameters of critical lines in observed area are shown in Table 6.

All critical lines are equipped with standard conductors' cross-section with adequate transmission capacity in normal circumstances, but obviously inadequate transmission capacity for large wind power plants integration.

Figure 5 Critical lines in the area of N. Travnik and Zenica

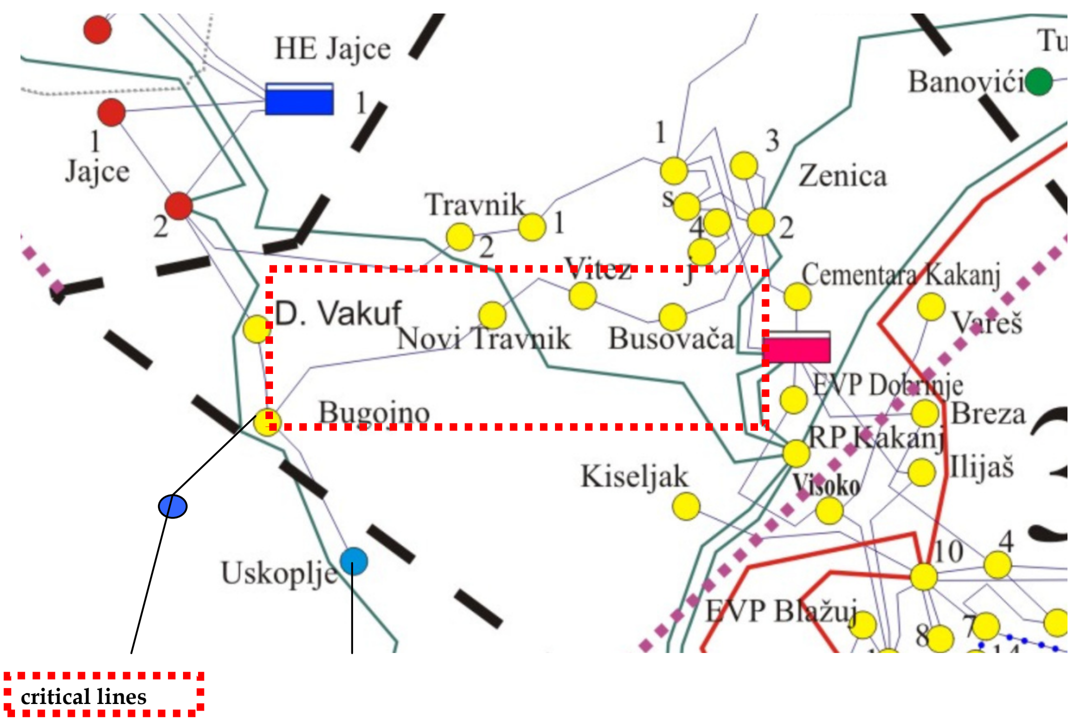


Table 6 Basic parameter of critical lines in areas of N. Travnik and Zenica

Transmission line and voltage:	**OHL 110 kV Bugojno – N. Travnik**
*Length (km)**	a) 25,03 b) 25,03
Node 1	SS Bugojno
Node 2	SS Novi Travnik
Year of commission/revitalization	1980
Towers	Steel
Conductors	ACSR 240/40 mm²
Protection wire	OPGW
Owner	Elektroprijenos BiH
Transmission capacity (MVA)	123
Permitted permanent current	645 A (Summer) / 645 A (Winter)
Permitted short-duration current	950 A
Transmission capacity limitation (A)	645 A (~117 MW); Reason: conductors cross section

* Line length : a) length within BiH transmission system b) total length

Transmission line and voltage:	**OHL 110 kV N. Travnik – Vitez**
*Length (km)**	a) 8,83 b) 8,83
Node 1	SS Novi Travnik
Node 2	SS Vitez
Year of commission/revitalization	1980
Towers	Steel
Conductors	ACSR 240/40 mm²
Protection wire	OPGW
Owner	Elektroprijenos BiH
Transmission capacity (MVA)	123
Permitted permanent current	645 A (Summer) / 645 A (Winter)
Permitted short-duration current	950 A
Transmission capacity limitation (A)	645 A (~117 MW); Reason: conductors cross section

* Line length : a) length within BiH transmission system b) total length

Transmission line and voltage:	**OHL 110 kV Zenica 2 – Busovaca**
*Length (km)**	a) 11,1 b) 11,1
Node 1	SS Zenica 2
Node 2	SS Busovaca
Year of commission/revitalization	1978
Towers	Steel

Conductors	ACSR 240/40 mm²
Protection wire	OPGW
Owner	Elektroprijenos BiH
Transmission capacity (MVA)	73
Permitted permanent current	385 A (Summer) / 385 A (Winter)
Permitted short-duration current	950 A
Transmission capacity limitation (A)	385 A (~62 MW); Reason: current metering transformers in Zenica 2 and/or Busovaca

* Line length : a) length within BiH transmission system b) total length

Transmission line and voltage:	**OHL 110 kV Busovača – Vitez**
Length (km)*	a) 10,6 b) 10,6
Node 1	SS Busovaca
Node 2	SS Vitez
Year of commission/revitalization	1980/82
Towers	Steel
Conductors	ACSR 240/40 mm²
Protection wire	OPGW
Owner	Elektroprijenos BiH
Transmission capacity (MVA)	123
Permitted permanent current	645 A (Summer) / 645 A (Winter)
Permitted short-duration current	950 A
Transmission capacity limitation (A)	645 A (~117 MW); Reason: conductors cross section

* Line length : a) length within BiH transmission system b) total length

3 Additional investments in transmission network

As mentioned in the Task 2, it is important to point out that these network calculations were done in order to identify network bottlenecks. In that sense verified power system model is used, along with WPP connection nodes and criteria given in the Task 1. But, neither NOS nor authors do not evaluate or prefer any of WPP projects. Accordingly, we don't analyze detailed WPP connection issues, but only expected overall WPP impact to network bottlenecks.

3.1 Additional investments for scenario A of WPPs integration (150 MW)

The wind power plants in Scenario A are located in Regions 2, 3 and 4 (according to Task 1). To integrate these wind power plants we suggest two network reinforcement investments:

- Revitalization of the 110 kV line Mostar 4 – Siroki Brijeg in order to increase its transmission capacity up to standard value (123 MVA), by Copper 95 mm² conductors and concrete towers replacement (construction of ACSR 240/40 mm² conductors and steel towers in length of 10,8 km)

- Revitalization of the 110 kV line Mostar 1 – Mostar 6 in order to increase its transmission capacity up to standard value (123 MVA), by ACSR 150/25 mm² conductors and concrete towers replacement (construction of ACSR 240/40 mm² conductors and steel towers in total length of the line).

These two investments allow wind power plants of 150 MW total installed capacity to be fully integrated into the transmission system.

Existing and future transmission network topology, comprising 110 kV lines Mostar 4 – Siroki Brijeg and Mostar 1 – Mostar 6 with transmission capacity of 123 MVA, were checked in scenario A of WPP construction and they fully satisfy planning criteria prescribed by the Grid code (no additional overloads, loss of load and voltage problems due to WPPs integration).

3.2 Additional investments for scenario A1 of WPPs integration (200 MW)

To integrate WPP with installed power 50 MW at wide Trebinje area it is necessary to construct planned line 110 kV Nevesinje – Gacko, especially if WPP connection will be established by using this line.

3.3 Additional investments for scenario B of WPPs integration (300 MW)

Additional wind power plants in Scenario B are located in Regions 1, 2 and 3 (Task 1). To integrate these wind power plants, the following additional investments should be made:

- Construction of new 2x110 line kV Poklecani – Posusje (ACSR 240/40 mm², 15,1 km) with enlargement of SS Posusje (two 110 kV line bays)
- Construction of new 2x110 kV line Poklecani – Tomislavgrad/Rama (ACSR 240/40 mm², 31,6 km), eg introduction of existing line 110 kV Tomislavgrad – Rama to WPP Poklecani
- Enlargement of SS Jablanica with one 110 kV line bay and operation of Rama – Jablanica line under 110 kV
- Finalization of Tomislavgrad – Kupres 110 kV line construction (20 km)

These investments allow wind power plants of total installed capacity 300 MW to be fully integrated into the existing transmission system.

Regarding future transmission system, additional critical contingences due to wind power plants integration will appear overloading critical 110 kV line HPP Pec Mlini – Grude (following a loss of Livno – Busko Blato line or Livno – Borova Glava line) so additional investment should be initiated:

- Enlargement of SS Rama and SS Uskoplje with one 110 kV line bay and construction of new 110 kV line Rama - Uskoplje.

Existing and future transmission network topology, comprising previously numbered investments, were checked in scenario B of WPP construction and we may conclude that new network topology satisfy planning criteria prescribed by the Grid code (no additional overloads, loss of load and voltage problems due to WPP integration).

110 kV line HPP Pec Mlini – Grude may still be highly loaded in some operational regimes. Construction of new 220/110 kV SS Posusje 2 or Poklecani[3] would relieve critical parts of 110 kV network around Grude and Posusje, so this investment may be applicable even for this scenario of WPPs construction. It is definitely suggested for scenario C (600 MW) of WPPs construction, that is explained in the next subsection.

[3] 220/110 kV SS Posusje 2 was planned by JP EP HZHB but construction of 220/110 kV SS at the location of WPP Poklecani may be a better solution. Exact location could be a subject for further analysis and discussions.

3.4 Additional investments for scenario C of WPPs integration (600 MW)

Additional wind power plants in Scenario C are located in Regions 2 and 3. To integrate these wind power plants, the following additional investments should be made:

- Construction of new 220/110 kV SS Poklecani or Posusje 2 (1x150 MVA)
- Construction of new 110 kV line HPP Pec Mlini – Grude 2 or Grude – Posusje (31 km)
- Construction of new 110 kV line Livno – WPP Borova Glava 2.

New 220/110 kV SS around Posusje and Poklecani redirects wind power plants output to the 220 kV network, thus relieving jeopardized sections of 110 kV network. Because of this, a new 220/110 kV SS is absolutely necessary for integration of 600 MW of WPPs. The 110 kV line between HPP Pec Mlini and SS Grude stays overloaded in certain conditions (for example after line Livno – Borova Glava outage) so this path should be reinforced also by constructing a new 110 kV line between Grude and HPP Pec Mlini or Posusje. In 2020, the 110 kV path between WPP Borova Glava and SS Livno may be jeopardized, so construction of new 110 kV line between WPP Borova Glava and Livno is suggested.

Future transmission network topology, comprising previously numbered investments, were checked in scenario C of WPP construction and we may conclude that network topology with new 220/110 kV SS Poklecani or Posusje 2 satisfy planning criteria prescribed by the Grid code (no additional overloads, loss of load and voltage problems due to WPPs integration).

3.5 Additional investments for scenario D1 and D2 of WPPs integration (900 MW)

Additional wind power plants in Scenario D1 are located mostly in Regions 1, 2 and 3. To integrate these wind power plants, the following additional investments should be made:

- Construction of SS (110 kV busbars) Glamoc
- Enlargement of SS Livno with one 110 kV line bay and operation of Livno – Glamoc line under 110 kV, together with a revitalization of this line (transmission capacity increase by ACSR 150/25 mm^2 conductors replacement)
- Enlargement of SS Kupres with two 110 kV line bays and construction of 2x110 kV line Slovinj – Kupres (with new 110 kV line Slovinj – Glamoc)

- ❑ Enlargement of SS Kupres with additional two 110 kV line bays and SS Bugojno with two 110 kV line bays and construction of new 2x110 kV line Bugojno – Kupres (circuits 2 and 3)

- ❑ Revitalization of the 110 kV line Bugojno – D. Vakuf in order to increase its transmission capacity up to standard value (123 MVA), by ACSR 120/20 mm² conductors replacement (construction of ACSR 240/40 mm² conductors in length of 5,7 km)

- ❑ Revitalization of the 110 kV line Jajce 2 – D. Vakuf in order to increase its transmission capacity up to standard value (123 MVA), by ACSR 120/20 mm² conductors replacement (construction of ACSR 240/40 mm² conductors in length of 21.2 km)

- ❑ Enlargement of SS Livno and SS Busko Blato with one 110 kV line bay each, and construction of new 110 kV line Livno – Busko Blato 2

- ❑ Reinforcement of 110 kV network in Mostar[4] (construction of new 2x110 kV line Mostar 9 – Mostar 4/Mostar 5 and introduction of 110 kV line Mostar 2 – Capljina in SS Mostar 9).

Having in mind that wind power plants around SS Kupres in analyzed scenario have significant installed capacity (WPP Glamoc – Slovinj and WPP Kupres) additional analysis with new 220/110 kV SS Kupres was performed, but it was concluded that this option wouldn't remove bottlenecks in the 110 kV network, so previously listed investments have to be conducted anyway.

New 220/110 kV substation Kupres may be necessary by 2020 when new contingences could appear jeopardizing revitalized 110 kV lines Bugojno – D. Vakuf and D. Vakuf – Jajce 2. A new 220 kV line between SS Kupres and SS Jajce 2 may also be necessary in this case.

In scenario D2 additional wind power plants were located in all five analyzed regions. To integrate these wind power plants, the following additional investments should be made:

- ❑ Enlargement of SS Busko Blato with one 110 kV line bay and construction of new110 kV line WPP Orlovaca – Busko Blato 2

- ❑ Revitalization of the 110 kV line Mostar 2 – Jablanica (section from WPP Plocno to SS Jablanica) in order to increase its transmission capacity up to standard value (123 MVA), by ACSR 150/25 mm² conductors replacement (construction of ACSR 240/40 mm² conductors)

- ❑ Reinforcement of 110 kV network in Mostar (construction of new 2x110 kV line Mostar 9 – Mostar 4/Mostar 5 and introduction of 110 kV line Mostar 2 – Capljina in SS Mostar 9)

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[4] Following 110 kV lines in Mostar may be jeopadized: Mostar 1 – Mostar 4, Mostar 1 – Mostar 6, Mostar 5 – Mostar 7, Mostar 6 – Mostar 7, Mostar 1 – Mostar 2.

This scenario requires better understanding of the 110 kV network in Mostar because all lines in the town may be jeopardized. A new double circuit line from SS Mostar 9 (Buna) to SS Mostar 4 and SS Mostar 5, and connection of existing 110 kV line Mostar 2 – Capljina to SS Mostar 9 may solve this problem.

3.6 Summary of additional investments for WPPs integration

A summary of additional investments recommended for each scenario and for transmission system developments for wind power plant integration is given in Table 7.

Table 7 Additional investments in transmission network

Project / investment	Scenario				
	A	B	C	D1	D2
OHL 110 kV Mostar 4 – Siroki Brijeg revitalization	+	+	+	+	+
OHL 110 kV Mostar 1 – Mostar 6 revitalization	+	+	+	+	+
OHL 2x110 kV Poklecani – Posusje	-	+	+	+	+
OHL 2x110 kV Poklecani – Tomislavgrad/Rama	-	+	+	+	+
enlargement of SS Jablanica with one line bay 110 kV and operation of Rama – Jablanica line under 110 kV	-	+	+	+	+
OHL 110 kV Tomislavgrad – Kupres	-	+	+	+	+
OHL 110 kV Rama - Uskoplje	-	+	+	+	+
SS 220/110 kV Poklecani or Posusje 2 (1x150 MVA)	-	-	+	+	+
OHL 110 kV Grude – Posusje	-	-	+	+	+
OHL 110 kV Livno – WPP Borova Glava 2	-	-	+	+	+
SS 110/x kV Glamoc	-	-	-	+	-
enlargement of SS Livno and operation of Livno – Glamoc line under 110 kV, together with a revitalization of this line	-	-	-	+	-
OHL 2x110 kV Slovinj - Kupres	-	-	-	+	-
OHL 2x110 kV Bugojno – Kupres	-	-	-	+	-
OHL 110 kV Bugojno – D:Vakuf revitalization	-	-	-	+	-
OHL 110 kV Jajce 2 – D:Vakuf revitalization	-	-	-	+	-
OHL 110 kV Livno – B. Blato 2	-	-	-	+	-
SS 220/110 kV Kupres (2x150 MVA)	-	-	-	+	-
OHL 2x110 kV Mostar 9 – Mostar 4/Mostar 5 with introduction of line Mostar 2 – Capljina in Mostar 9	-	-	-	- (+)	+
OHL 110 kV WPP Orlovaca – Busko Blato 2	-	-	-	-	+
OHL 110 kV Mostar 2 – Jablanica revitalization	-	-	-	-	+

\+ recommended for the scenario
\- not needed for the scenario
\- (+) not necessary but highly welcomed

3.7 Environmental and social policy

We have analysed the specifics of these investment plans and can confirm that they are consistent with the EBRD Environmental and Social Policy (2008).

4 Additional transmission cost estimation

4.1 Unit prices

The following unit prices of high-voltage equipment shown in Table 8 have been used in order to estimate network reinforcement costs for wind power plants integration into the BiH transmission system. Unit costs are based on the report made by Elektroprijenos BiH.

Table 8 Unit costs used for cost calculation

Transmission asset	Costs	
	KM/km(unit)	€/km(unit)
Lines (new)		
Single circuit 400 kV line (ACSR 490/65 mm²)	531.000	271.472
Double circuit 400 kV line (ACSR 490/65 mm²)	780.000	398.773
Single circuit 220 kV line (ACSR 360/60 mm²)	266.000	135.992
Double circuit 220 kV line (ACSR 360/60 mm²)	390.000	199.387
Single circuit 110 kV line (ACSR 240/40 mm²) - Type 1	135.000	69.018
Single circuit 110 kV line (ACSR 240/40 mm²) - Type 2	155.000	79.243
Single circuit 110 kV line (ACSR 240/40 mm²) - Type 3	175.000	89.468
Double circuit 110 kV line (ACSR 240/40 mm²) - Type 1	205.000	104.806
Double circuit 110 kV line (ACSR 240/40 mm²) - Type 2	230.000	117.587
Double circuit 110 kV line (ACSR 240/40 mm²) - Type 3	265.000	135.481
Lines (reconstruction and transmission capacity increase)		
Single circuit 110 kV line (ACSR 240/40 mm²) - Type 1	110.000	56.237
Single circuit 110 kV line (ACSR 240/40 mm²) - Type 2	125.000	63.906
Single circuit 110 kV line (ACSR 240/40 mm²) - Type 3	135.000	69.018
Bays and transformers		
Line bay 220 kV	798.612	408.288
Transformer bay 220 kV	720.589	368.399
Connection bay 220 kV	493.605	252.354

Metering bay 220 kV	85.127	43.521
Line bay 110 kV	380.783	194.674
Transformer bay 110 kV	365.381	186.800
Metering bay 110 kV	64.265	32.855
Transformer 220/110 kV, 150 MVA	3.209.948	1.641.078

Type 1 - no spatial problems

Type 2 - with spatial problems

Type 3 - urban area

The Connection costs of individual wind power plants, consisting of internal wind power plants mid-voltage network, x/110 kV substations at WPPs locations and connection lines to existing 110 kV lines (substations) were not included in the additional investment cost calculation.

4.2 Additional investment costs in scenario A of WPPs integration

Table 9 shows the estimated investment costs for wind power integration of WPPs into the transmission network for Scenario A. The costs are calculated on the basis of our recommended investments as outlined in the previous section and summarised in Table 7 and the unit costs presented in Table 8.

Table 9 Additional investments in transmission system for scenario A

Project / investment	Units or length in km	Costs (€)
OHL 110 kV Mostar 4 – Siroki Brijeg revitalization	10,80	690.184
OHL 110 kV Mostar 1 – Mostar 6 revitalization	4,30	296.779
Total additional costs (scenario A)		**986.963**

Total investment costs for wind power plants integration in scenario A are estimated at around 1 million €. The required investments consist of the revitalization of two 110 kV lines.

4.3 Additional investment costs in subscenario A1 of WPPs integration

❑ To integrate wind power plants in scenario A1 (200 MW) 110 kV line Nevesinje – Gacko should be constructed in addition to the above mentioned investment for Scenario A. Additional costs are estimated up to 7 millions KM (3,6 millions €).

4.4 Additional investment costs in scenario B of WPPs integration

Estimated additional investment costs for network reinforcements in Scenario B based on our recommendation are presented in Table 10.

Table 10 Additional investments in transmission system for scenario B

Project / investment	Units or length in km	Costs (€)
OHL 110 kV Mostar 4 – Siroki Brijeg revitalization	10,80	690.184
OHL 110 kV Mostar 1 – Mostar 6 revitalization	4,30	296.779
OHL 2x110 kV Poklecani – Posusje	15,10	2.164.911
OHL 2x110 kV Poklecani – Tomislavgrad/Rama	31,60	3.715.746
enlargement of SS Jablanica with one line bay 110 kV and operation of Rama – Jablanica line under 110 kV	1	194.674
OHL 110 kV Tomislavgrad – Kupres	20,00	1.584.867
OHL 110 kV Rama - Uskoplje	25,00	2.370.433
Total additional costs (scenario B)		**11.017.594**

The Total investment costs for wind power plants integration in scenario B are estimated at around 11.000.000 €. The costs are made up of two 110 kV lines revitalization, four new 110 kV lines construction and enlargement of several existing substations (Posusje, Jablanica, Uskoplje).

4.5 Additional investment costs in scenario C of WPPs integration

Estimated additional investment costs for network reinforcements for scenario C are presented in Table 11.

Table 11 Additional investments in transmission system for scenario C

Project / investment	Units or length in km	Costs (€)
OHL 110 kV Mostar 4 – Siroki Brijeg revitalization	10,80	690.184
OHL 110 kV Mostar 1 – Mostar 6 revitalization	4,30	296.779
OHL 2x110 kV Poklecani – Posusje	15,10	2.164.911
OHL 2x110 kV Poklecani – Tomislavgrad/Rama	31,60	3.715.746
enlargement of SS Jablanica with one line bay 110 kV and operation of Rama – Jablanica line under 110 kV	1	194.674
OHL 110 kV Tomislavgrad – Kupres	20,00	1.584.867
OHL 110 kV Rama - Uskoplje	25,00	2.370.433
SS 220/110 kV Poklecani or Posusje 2 (1x150 MVA)	-	6.818.358
OHL 110 kV Grude – Posusje	31,00	2.845.893
OHL 110 kV Livno – WPP Borova Glava 2	15,00	1.577.999
Total additional costs (scenario C)		**22.259.844**

Total investment costs for wind power plants integration under scenario C are estimated to approximately 22.000.000 €. Additional costs related to previous WPPs construction scenarios are made up of construction of one 220/110 kV SS and two new 110 kV lines.

4.6 Additional investment costs in scenario D1 of WPPs integration

Estimated additional investment costs for network reinforcements for scenario D1 are presented in Table 12.

Table 12 Additional investments in transmission system for scenario D1

Project / investment	Units or length in km	Costs (€)
OHL 110 kV Mostar 4 – Siroki Brijeg revitalization	10,80	690.184
OHL 110 kV Mostar 1 – Mostar 6 revitalization	4,30	296.779
OHL 2x110 kV Poklecani – Posusje	15,10	2.164.911
OHL 2x110 kV Poklecani – Tomislavgrad/Rama	31,60	3.715.746
enlargement of SS Jablanica with one line bay 110 kV and operation of Rama – Jablanica line under 110 kV	1	194.674
OHL 110 kV Tomislavgrad – Kupres	20,00	1.584.867
OHL 110 kV Rama - Uskoplje	25,00	2.370.433
SS 220/110 kV Poklecani or Posusje 2 (1x150 MVA)	-	6.818.358
OHL 110 kV Grude – Posusje	31,00	2.845.893
OHL 110 kV Livno – WPP Borova Glava 2	15,00	1.577.999

Project / investment	Units or length in km	Costs (€)
SS 110/x kV Glamoc (110 kV line bays)	3	817.632
enlargement of SS Livno and operation of Livno – Glamoc line under 110 kV, together with a revitalization of this line	33,20	1.128.212
OHL 2x110 kV Slovinj - Kupres	25,00	3.329.021
OHL 2x110 kV Bugojno – Kupres	15,90	2.648.329
OHL 110 kV Bugojno – D:Vakuf revitalization	5,70	364.264
OHL 110 kV Jajce 2 – D:Vakuf revitalization	22,60	1.444.274
OHL 110 kV Livno – B. Blato 2	12,40	1.181.782
SS 220/110 kV Kupres (2x150 MVA)	-	7.753.006
OHL 2x110 kV Mostar 9 – Mostar 4/Mostar 5 with introduction of line Mostar 2 – Capljina in Mostar 9	20,00	2.876.567
Total additional costs (scenario D1)		**43.802.931**

Total investment costs for wind power plants integration under scenario D1 are estimated to approximately 44.000.000 €. Additional costs related to previous WPPs construction scenarios are made up of one additional SS 220/110 kV construction, four new lines 110 kV construction, three lines 110 kV revitalization and enlargement of several existing and new substations.

4.7 Additional investment costs in scenario D2 of WPPs integration

Estimated additional investment costs for network reinforcements for scenario D2 are presented in Table 13.

Table 13 Additional investments in transmission system for scenario D2

Project / investment	Units or length in km	Costs (€)
OHL 110 kV Mostar 4 – Siroki Brijeg revitalization	10,80	690.184
OHL 110 kV Mostar 1 – Mostar 6 revitalization	4,30	296.779
OHL 2x110 kV Poklecani – Posusje	15,10	2.164.911
OHL 2x110 kV Poklecani – Tomislavgrad/Rama	31,60	3.715.746
enlargement of SS Jablanica with one line bay 110 kV and operation of Rama – Jablanica line under 110 kV	1	194.674
OHL 110 kV Tomislavgrad – Kupres	20,00	1.584.868
OHL 110 kV Rama - Uskoplje	25,00	2.370.433
SS 220/110 kV Poklecani or Posusje 2 (1x150 MVA)	-	6.818.358
OHL 110 kV Grude – Posusje	31,00	2.845.893
OHL 110 kV Livno – WPP Borova Glava 2	15,00	1.577.999

Project / investment	Units or length in km	Costs (€)
OHL 2x110 kV Mostar 9 – Mostar 4/Mostar 5 with introduction of line Mostar 2 – Capljina in Mostar 9	20,00	2.876.567
OHL 110 kV WPP Orlovaca – Busko Blato 2	10,00	987.108
OHL 110 kV Mostar 2 – Jablanica revitalization	41,50	2.652.096
Total additional costs (scenario D2)		**28.775.616**

Total investment costs for wind power plants integration under scenario D2 are estimated to approximately 29.000.000 €. Additional costs related to previous WPPs construction scenarios are made up of construction of three new 110 kV lines.

4.8 Summary of additional investment costs caused by WPPs integration

A summary of the additional investment costs needed for transmission system development for successful WPP integration is given in Figure 6 and Table 14.

Figure 6 Additional investments in transmission system for WPPs integration scenarios

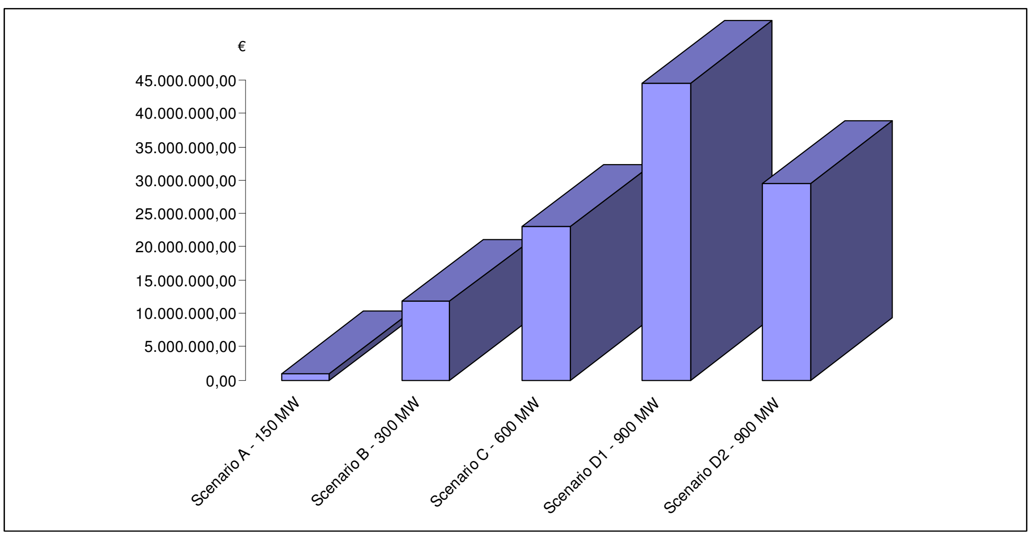


Table 14 Additional investments in transmission system for WPPs integration scenarios

Scenario	Costs (€)
Scenario A (150 MW)	986.963
Scenario B (300 MW)	11.017.594
Scenario C (600 MW)	22.259.844
Scenario D1 (900 MW)	43.802.931
Scenario D2 (900 MW)	28.775.616

An energy sector study in BiH[5] has estimated total transmission system development costs up to 2020 of 279 millions €. Transmission system additional development costs due to wind power plants integration are estimated as follows (as a percentage of total development costs):

- 0.35% - for integration of 150 MW in scenario A of WPPs construction
- 4.21% - for integration of 300 MW in scenario B of WPPs construction
- 8.24% - for integration of 600 MW in scenario C of WPPs construction
- 15.97% - for integration of 900 MW in scenario D1 of WPPs construction
- 10.58% - for integration of 900 MW in scenario D2 of WPPs construction.

Connection of individual wind power plants at 220 kV or 400 kV grid has not been analyzed in detail because of wind power plants predicted installed capacities (18 MW – 145 MW), which are relatively low and connection costs to 220 kV or 400 kV voltage level would be high (not economically feasible due to high connection costs). More realistic option is to connect individual WPP to the 110 kV grid, and if necessary to construct new substations 220/110 kV in order to transmit wind power production to this voltage level. Generally we may assume that necessity and locations of eventually needed SS 220/110 kV or 400/110 kV depends on new WPPs spatial distribution and their installed capacities, as well as vicinity of 220 kV and 400 kV lines. Similar investments may be needed if wind power plants spatial distribution is significantly different than assumed in this study.

[5] Energy Sector Study in BiH, Energy Institute Hrvoje Pozar, Soluziona, Economy Institute Banja Luka, Mining Institute Tuzla, 2008

5 Additional requests on P/f and Q/U control due to wind power integration

5.1 P/f control

In this subsection and in the following one we look at the operational factors that the ISO must consider in the day to day management of power flows when wind capacity is significant; this section concentrates on active power control techniques, while section 5.2 goes on to consider reactive power requirements. Both will have additional financial consequences for the ISO and/or wind investors.

As the amount of wind penetration increases on grid systems, the occurrence of large and rapid changes in wind power production becomes a significant grid management issue. ISO must ensure that there is a sufficient ramping capability from conventional generators in order to compensate for changes in wind output. Unexpected changes in wind generation can place additional stress on ancillary services.

Active power management assumes that the wind power plant production is adjusted depending on power system frequency. Power consumption significantly changes during the day and it has to be continuously equalised with adequate production, managing the system frequency within allowed boundaries for normal operation and with a requirement to limit inappropriate energy flows along interconnections with neighbouring systems. Thus, correct functioning of frequency regulation is of the highest importance for normal operation of the system.

The BiH power system is relatively small with a limited number of conventional power plants but with a significant share of hydro production in the generation mix. This means that power and frequency regulation abilities of existing hydro power plants could be significant and adequate to provide regulation support to new wind power plants.

Generally, hydro power plants have very fast secondary control response, while secondary control response of thermal power plants are much slower, especially coal fired power plants such as TPPs in BiH (Ugljevik, Gacko, Tuzla, Kakanj).

In BiH there are currently five hydro power plants which should provide secondary P/f regulation reserve (Jablanica, Trebinje, Visegrad, Rama, Bocac), and six hydro power plants which should provide tertiary P/f regulation reserve (Capljina, Grabovica, Salakovac, Visegrad, Bocac, Trebinje)[6]. For various reasons, NOS BiH can not provide total reserve from these hydro power plants, which leads to unsatisfactory imbalance of the BiH power system and large deviations in cross border flows compared to scheduled values.

[6] Regulation about ancillary services tariffs, DERK, 2010

This fact may limit future wind power plants integration into the BiH power system since they are an additional source of possible imbalance. It is of utmost importance that power supply companies in BiH provide secondary and tertiary control reserve to NOS BiH as stated in the DERK decision.

Under operational conditions that are typical for the last decade (including load fluctuations and agreed level of power exchanges within ENTSO-E that requires maximum power deviation of +/-20 MW compared to the planned and contracted exchanges) existing level of secondary P/f control may be sufficient to cover load forecast error, but is not enough for large wind power plants integration.

Necessary secondary and tertiary P/f control reserve, for different scenarios of WPP integration, is estimated under Task 1 of this Project.

It is estimated that additional hydro units should be included into secondary P/f control, including HPP Jajce 2, HPP Mostar, HPP Pec Mlini, HPP Mostarsko Blato, HPP Grabovica, HPP Salakovac etc. NOS BiH stated that secondary and tertiary P/f control reserve in BiH is not going to limit wind power plants integration, but power production companies have to provide such ancillary services. This could require further improvements to the tariff system for ancillary services because service providers should cover their costs in providing these types of ancillary services.

Annual variability of secondary P/f control reserve, especially expected low values during summer months, remains a crucial problem for WPPs integration. The ISO must solve this issue if this kind of ancillary service is going to be procurable in the region. If not, construction of at least one combined cycle power plant may be needed to provide this service when HPPs are unavailable.

Limited contribution of wind power plants to P/f control is possible, but efficiency of this is questionable because WPPs may not increase their prodution above related wind speed, they may only decrease their production in comparison with related wind speed. WPPs are not able to provide significant P/f regulation reserve for periods when consumption is larger than production.

5.2 Q/U control

The generators, transformers and other elements of an inductive nature consume reactive power that is to be produced or taken from the system. If the network user consumes reactive power from the system, the available line capacity for active power flow is reduced. In comparison to active power, reactive power cannot be efficiently transmitted across a large distance. It therefore has to be regulated locally with the aim of (i) satisfying protection requirements, (ii) maintaining active power transmission and (iii) maintaining appropriate voltage quality. A greater value of reactive power presumes a greater level of losses in the network. The flow of reactive power contributes to active power system losses. It is necessary to reduce reactive power flow in the network in order to reduce power losses. Reactive power control (Q/U control) can be realised using: synchronous generators, synchronous condensers, regulating transformers, static VAR systems, switched reactors and capacitor banks. The key point is that network voltages must be contained within defined limits and that the system voltage must be stable (avoidance of voltage collapse).

The BiH power system only has limited possibilities for Q/U control services. It is assured mainly by using synchronous generators and regulation transformers: 400/110 kV, 220/110 kV and 110/x kV.

As a consequence of this limited Q/U control, there can be intermittent occurrence of low voltages in some network nodes like Citluk, Capljina, Stolac etc. Also high voltages during low load conditions comprising the 400 kV, 220 kV and 110 kV network can occur.

Calculations conducted in Task 2 show that the expected voltage situation within the BiH transmission system will be mostly satisfactory, but low voltage and high voltage conditions are possible. In that sense some limited contribution from wind power plants in Q/U control may be welcomed. Furthermore, some large wind power plants like WPP Glamoc 1 – Slovinj, WPP Ljubusa, WPP Pakline and WPP Kupres have to be equipped to provide Q/U control services in order to avoid voltage collapse in the system. Bearing in mind that the expected transmission system development plan comprises some investments which will improve voltage condition within the transmission system (like new 220/110 kV SS Poklecani or Posusje 2), additional contributions could be directed to the wind power plants with the provision that WPPs must be able to operate within the power factor range of 0.95 inductive to 0.95 capacitive (lead/lag capability).

It is expected that wind power plants integration will cause no additional costs for the system in providing Q/U control service, especially if such provision is prescribed for wind investors.

6 Additional generation costs

Investment in transmission assets is only one part of the costs of operating the system with increased wind penetration. Other costs fall into two main categories:

- **Changes in the use of non-wind generation assets**. As wind will have priority in dispatch then other generation will either not be built or, more likely, will be used less. This will reduce revenue for these other generators.

- **Provision of reserves**. As noted elsewhere, the system operator must procure reserves against the intermittency of wind output – reserve generation must be available for when the wind does not blow. This needs to be procured using some form of ancillary service contract, with the costs charged to all customers through transmission charges.

In this section we analyse the revenue lost to conventional generation through increased wind penetration and then look at the additional costs needed to provide reserves for wind.

6.1 Impact of wind on conventional generation

Over time, as demand changes, it can be expected that new generation will be developed. Construction of wind farms may alter the development of new generation assets but is most likely to affect costs. In this sub-section, therefore:

- We develop a baseline scenario of how demand will grow and how new generation assets will be developed.

- We model how all generation will be dispatched in the baseline scenario and calculate the revenue and costs of the generation.

- We then compare scenarios of wind development against the baseline scenario and compare dispatch, costs and revenues against the baseline.

For this analysis, we use a single baseline scenario despite the fact that many variables (such as demand growth and generation investment) could change over time. However, we are only measuring the impact of wind development, which can be expected to be the same regardless of changes in other variables; ie the effect of building wind power plants can be determined provided the assumptions are consistent in all scenarios.

6.1.1 The generation dispatch model

We have developed a model of the BiH power system to determine how dispatch will change as new capacity is developed. The model is essentially a merit order dispatch model similar to traditional modelling tools such as the WASP model commonly used by utilities to plan generation development. Ours is a cut down model that limits the requirements for additional data. This is in keeping with the relatively simple options available in the small BiH power system.

A central assumption of our analysis is that wholesale prices can be simulated as if they were set in a competitive market. Although there is insufficient effective competition in the current market, this assumption remains useful in assessing the values of energy generated, which is the basis for calculating the relative impact of increasing wind development.

The model works as follows:

- Generation is stacked in merit order. This means that the generation with the lowest variable cost will always be dispatched first when available.
- Generation availability is adjusted seasonally to reflect likely outages. In the case of hydro power plants, outages are considerable at some times of the year. In a dedicated optimising tool, hydro would be dispatched at peak times when prices can be expected to be high and will not dispatch at night time in order to conserve water. To model this would require much additional information about hydro reservoir capability and seasonal inflows of water that is not readily available. We have therefore opted for a simplified approach with hydro dispatched at base load and limited by seasonal availability.
- Prices are assumed bid into the short term market with higher prices when capacity reserves are at their lowest. A quadratic function is used as follows:

$$P_t = f\left(\left(\frac{D_t}{C_t - D_t}\right)^2\right)$$

With:

$$\sum FC = \sum_{g=1}^{n} \sum_{t=1}^{8760} \left(\left(P_t - VC_{gt} \right) * D_{gt} \right)$$

Where:

P_t = Spot price of wholesale energy during time period t

D_t = Aggregate demand in time period t

C_t = Available capacity n time period t

FC = Total annual fixed costs that generators in aggregate seek to recover.

VC_{gt} = Variable cost of generator g in time period t

D_{gt} = Dispatch of generator g in time period t

In practical terms, price in the model are capped by the cost of imports, although this is seldom binding in BiH which has a surplus for export in most months. Import costs are modelled on the basis of costs reported in the region and EU Commission reports and forecasts of generally traded wholesale power in Europe. We estimate import prices as an average of peaking and off peak prices and do not actually model hourly import prices. The variations in import prices are therefore essentially seasonal.

6.1.2 Baseline scenario assumptions

Growth in demand

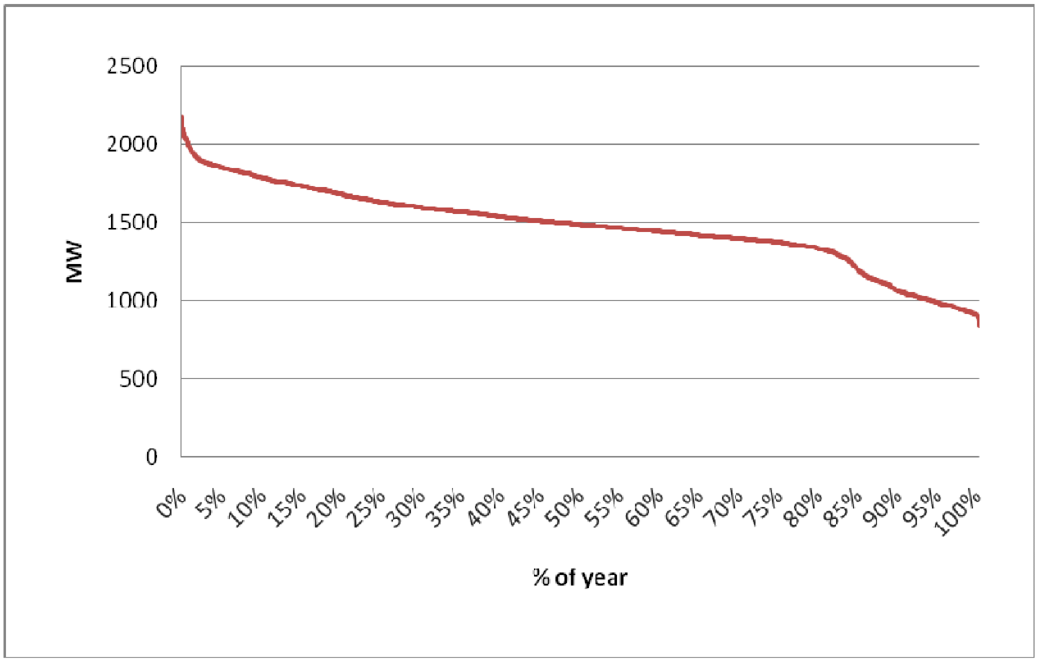
For demand growth, we have chosen a medium growth path with an assumed contant growth rate. The results of our projections are summarised in Table 15.

Table 15 BiH demand growth – baseline scenario

Year	Annual Demand (GWh)	Period	Annual growth rate
2010 (actual)	11,725	2008-2010	2.4%
2015	13,201	2010-2015	2.4%
2020	14,863	2015-2020	2.4%
2025	16,734	2020-2025	2.4%

Figure 7 shows the load duration curve for demand in BiH in 2010. We assume that there will be no change in the overall hourly shape of demand in future years.

Figure 7 Load duration curve for BiH, 2010

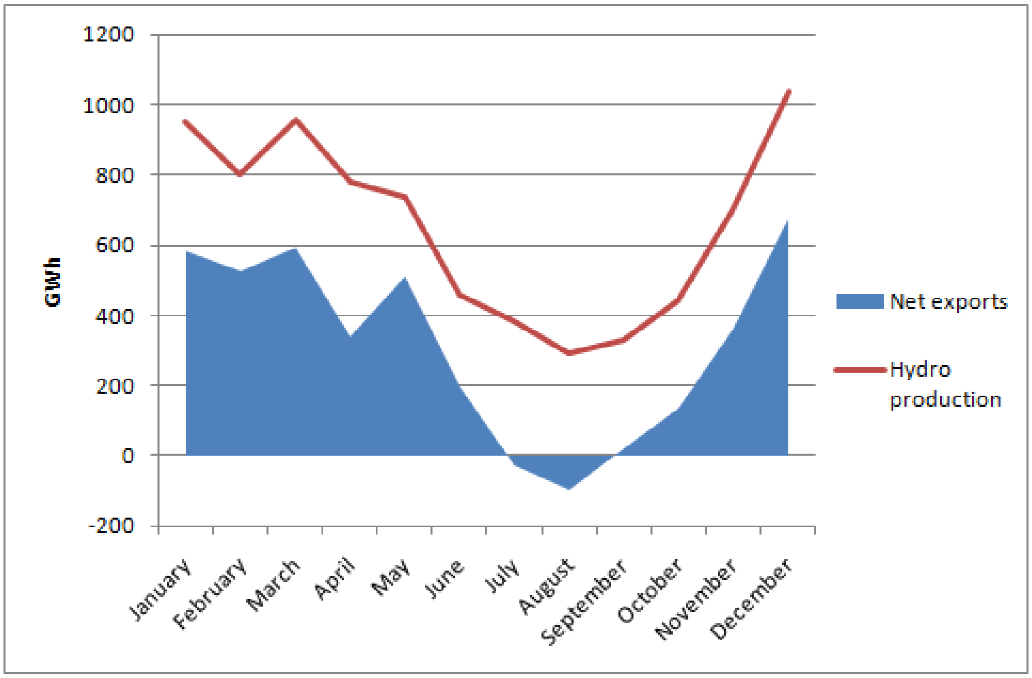


Source: ENTSO-E

Exports

BiH is a net exporter for most of the year, with interchanges with other countries reversing during the summer months when hydro availability is low (Figure 8). Exports are mainly of hydro. In 2010, hydro production and net exports were 97% correlated.

Figure 8 Hydro production and net exports from BiH in 2010



BiH is in a position to export its excess energy to its neighbours. Contracts for export are likely to be agreed in advance on a long-term basis with volumes set according to expected availability of hydro in a typical year. Any increases in BiH generating capacity over and above natural growth in local demand will be available to be added to export contracts.

In the baseline scenarios (no wind), a seasonal export contract profile is assumed based on the seasonal profile of exports in 2010. These assumed contracts do not match the actual 2010 profile exactly, reflecting the underlying reasoning that actual contracts would be based on long-term forecasts of *likely* availability. This may be a simplification, even in the absence of full regional balancing or short-term market since short-term cross-border trades are arranged currently depending on actual hydro conditions. However, the approach allows sufficient detail to provide a baseline to compare against for the purposes of this analysis.

The assumed profile of seasonal exports is maintained in the future years of the analysis. In the baseline scenario there is a large increase in capacity to 2015 (9.4% addition over five years) followed by a further large increase to 2020 (10.4%) and no further change to 2025. However, average growth in demand during each five-year period is still expected to be faster (12.6%) than the average rate of new capacity additions so that demand eats into the availability for export. To allow for this in the analysis, the level of exports was adjusted in future years to maintain the margin of peak generation capacity to peak local demand in each year.

Generation development

A large amount of new generation capacity is under consideration for installation up to 2020. However, much of this has not yet received the necessary government approvals and, more generally, the scale of mooted new capacity additions is too great to realistically be accommodated within the BiH system. With these considerations in mind, a total of 1,121.85 MW of new capacity is expected up to 2020, made up of 71.85 MW of hydro and 1,050 MW of thermal.

Not all the assumptions made will transpire but, as explained above, the most important requirement is that assumptions are consistent between the baseline scenario and the wind development scenarios.

Table 16 lists the key developments expected between 2010 and 2025, based on Tables 10 and 11 of the Task 2 report. The following points can be noted:

- The existing HPPs are listed in total by river system. This treatment does not affect the modelling since the HPPs have common cost characteristics.

- In the HPP Trebišnjica system the pumped storage plant (HPP Capljina) is included in the analysis. The capacity of HPP Dubrovnik I is set at the 50% that BiH is entitled to under the sharing agreement with Croatia

- The annual fixed costs given are estimated levelised annual costs of investment (plus O&M costs) for each plant type based on an assumed cost per MW. Fixed costs for existing plants are expected to be relatively low since these older plants have been fully or nearly fully depreciated. These costs are used in our model to check that the power plant will be viable.

- Variable costs are only applicable in the case of thermal power plants, with the majority of costs being fuel. New plants are assumed to have higher fuel efficiency than the existing older plants. Although the feed-in tariff for wind might be considered a 'variable cost' for the purposes of modelling, these plants are guaranteed their return and so their costs do not affect merit order – they will run whenever they can.

Table 16 Baseline Conventional generation characteristics

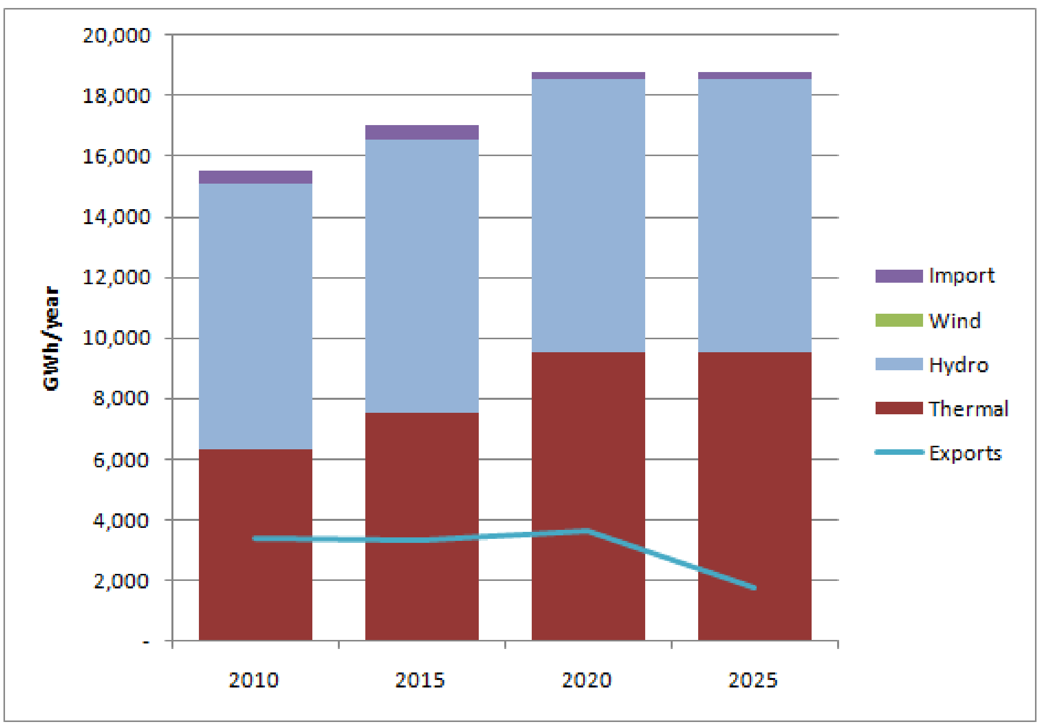
Year of commissioning	Power plant name	Type	Capacity (MW)	Annual fixed costs (€m)	Variable costs (€/MWh)
Up to 2010	HPP Trebišnjica	Hydro	240.5	46.3	0
	HPP Neretva	Hydro	804	56.3	0
	HPP Vrbas	Hydro	200	14.0	0
	HPP Drina	Hydro	515	36.1	0
	TPP Tuzla	Thermal	711	76.2	23.13
	TPP Kakanj	Thermal	524	56.2	23.13
	TPP Gacko	Thermal	276	29.6	23.13

	TPP Ugljevik	Thermal	279	29.9	23.13
	Interconnector	Export	1450	-	Seasona l
2011 to 2015	TPP Stanari	Thermal	300	41.4	20.23
	HPP Sutjeska	Hydro	19.15	3.6	0
	HPP Ustiprača	Hydro	8	1.5	0
	HPP Ulog	Hydro	34.7	6.6	0
	HPP Dub	Hydro	10	1.9	0
2016 to 2020	TPP Tuzla 7	Thermal	450	48.9	20.23
	TPP Kakanj 8	Thermal	300	32.6	20.23

In Figure 9, the modelled dispatch from all capacity is given for the baseline scenario. Imports supply only a small proportion of load in BiH, which remains a net exporter of energy under this and all other scenarios.

In this scenario all new investments are completed by 2020 and spare capacity is contracted for export. This results in a stable total dispatch situation between 2020 and 2025. Exports fall after 2018 as domestic load continues to grow while no further additions are made to capacity.

Figure 9 Development of dispatch – baseline scenario



6.1.3 Baseline scenario results

Figure 10 gives a snapshot of modelled dispatch for 2020 for the baseline (no wind) scenario. For most of the year the old thermal plants are marginal (Kakanj, Ugljevik and Gacko), with the new thermal and hydro plants coming in beneath these and at the bottom of the stack respectively. Imports (Interconnector) are used in only a few hours. The results for the marginal plants are similar in the other years.

Figure 10 Modelled dispatch – baseline scenario, 2020

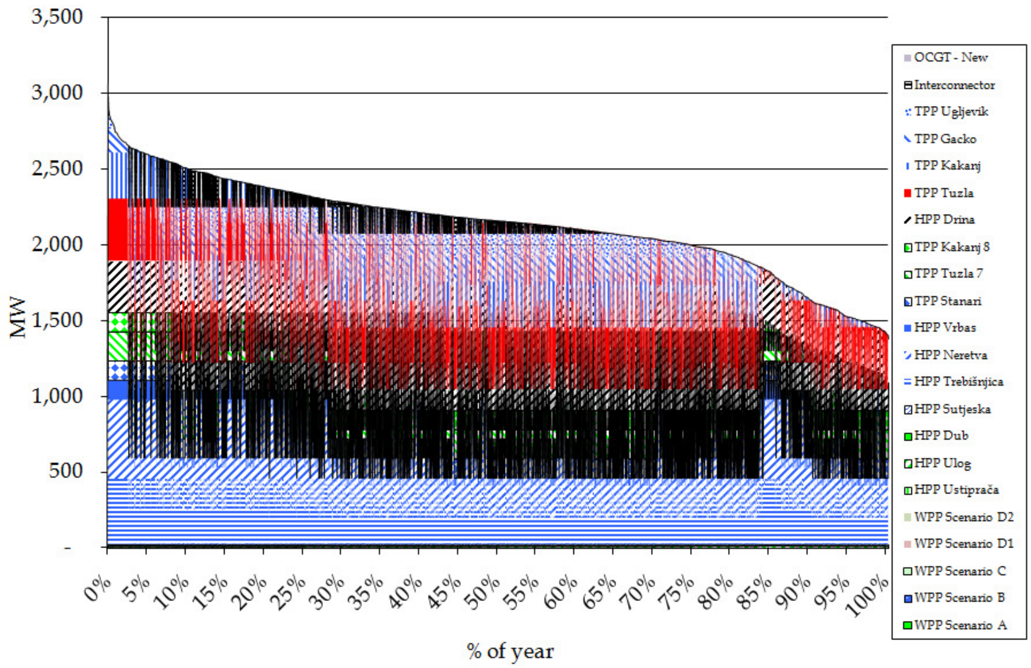


Table 17 shows some financial indicators derived from the model for the baseline scenario. The table shows the large increase in generation to 2015 and to 2020 as the major waves of new investments, most of which are in thermal capacity, come online. Imports decline over time as new firm thermal capacity becomes available, which fills in for hydro output during the low-lake (summer) season.

The small change in total costs in 2025, despite total load (including exports) and capacity remaining stable, is due to a slight increase in import prices over 2020.

It should be remembered that this is a scenario rather than a forecast; its main purpose is to be a baseline against which wind scenarios can be compared.

Table 17 Summary results - baseline scenario

		Thermal	Hydro	Wind	Total generation	Import	Total
2010	Dispatch (GWh)	6,338.7	8,758.1	-	15,096.8	435.3	15,532.2
	Total revenue (€m)	342.5	349.6	-	692.1	18.9	710.9
	(of which: variable cost (€m))	146.6	-	-	146.6	-	146.6
2015	Dispatch (GWh)	7,540.1	8,977.4	-	16,517.5	522.8	17,040.3
	Total revenue (€m)	409.4	365.0	-	774.5	23.4	797.9
	(of which: variable cost (€m))	171.2	-	-	171.2	-	171.2
2020	Dispatch (GWh)	9,541.5	8,978.0	-	18,519.5	230.0	18,749.5
	Total revenue (€m)	520.7	380.9	-	901.6	10.8	912.4
	(of which: variable cost (€m))	209.7	-	-	209.7	-	209.7
2025	Dispatch (GWh)	9,541.5	8,978.0	-	18,519.5	230.0	18,749.5
	Total revenue (€m)	523.7	382.2	-	905.9	10.9	916.8
	(of which: variable cost (€m))	209.7	-	-	209.7	-	209.7

6.1.4 Impact of wind generation – overview

Intermittent wind generation will have priority in dispatch and so will displace other generation when in operation. The model does not show the effects of intermittency; rather, it assumes a probability of wind blowing for up to 30% of the time and this is represented by a probability of 25-30% of available wind capacity being dispatched in any hour.

Similarly, the model does not show the effects on other generation of holding some capacity as reserve (this is estimated in section 6.2). Therefore, the model is limited to showing revenue for hydro and thermal generation (and imports) assuming a set percentage of wind dispatch in each hour. A snapshot result is shown in Figure 11.

Figure 11 Modelled dispatch – Scenario D1, 2020

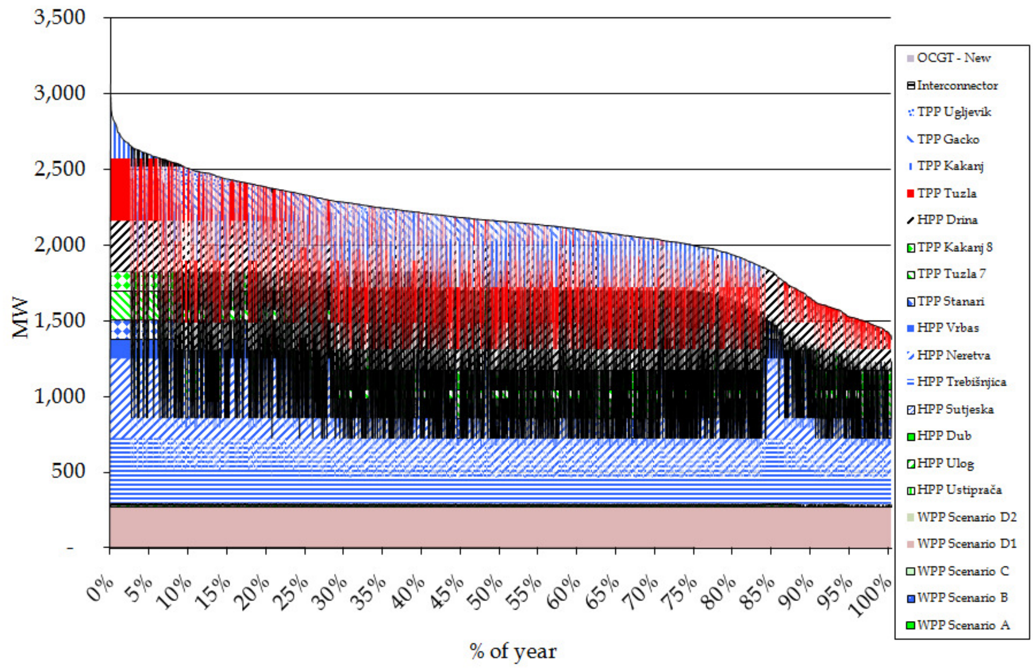
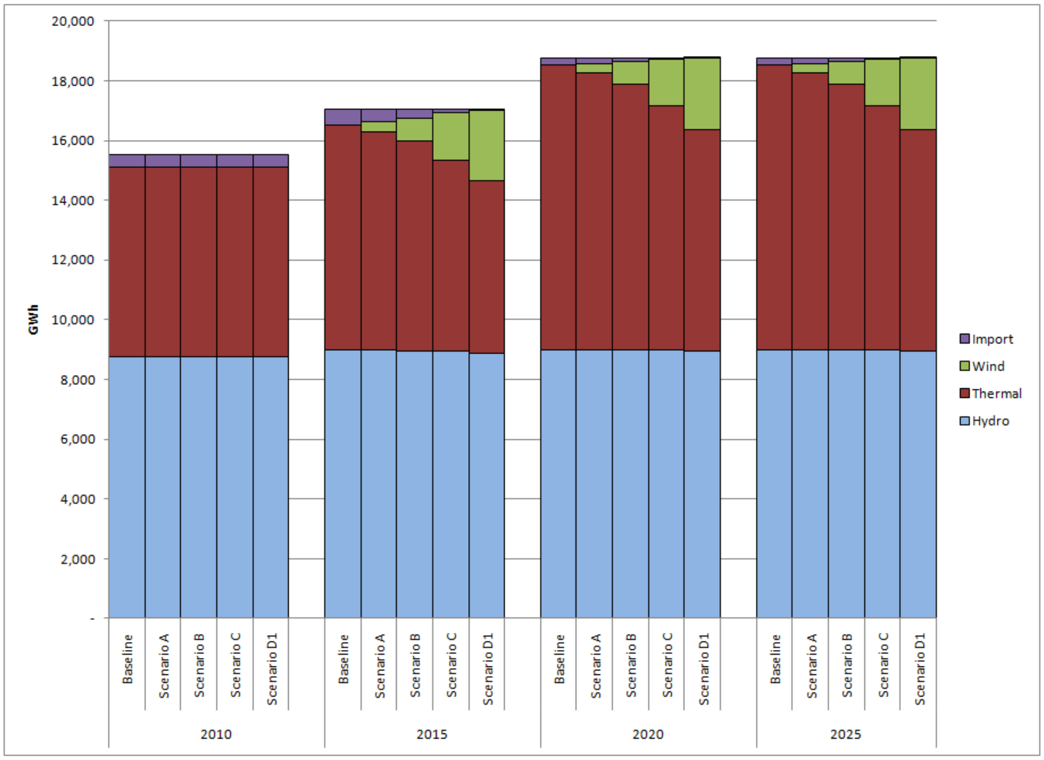


Figure 11 shows merit order dispatch for scenario D1 in 2020 and can be compared with the equivalent baseline figure (Figure 10 on page 39). Wind appears at the bottom of the stack in Figure 11 while, compared with Figure 10, some marginal thermal plant has been pushed off the stack at the top.

The effect of wind on annual dispatch is summarised in Figure 12. In all scenarios, wind output mainly displaces thermal plant. The implications of this on revenues and costs are discussed for each scenario in the next sections.

Figure 12 Impact of wind dispatch on conventional generation – all scenarios



The results for Wind Scenario D2 are not shown since, in this analysis, the dispatch results for Wind Scenario D1 (wide dispersion of wind farms) are the same as for D2 (concentrated).

6.1.5 Impact of wind on generation cost – Scenario A

Scenario A assumes that, following the construction of 4 WPPs[7] no further wind farms are constructed. As with all scenarios, there is no change in the construction programme for conventional generation and so the effect of these wind farms will be mainly to displace thermal generation.

Table 18 shows how the increase in wind dispatch is likely to affect output, revenues and costs of other types of generation and exports.

[7] WPP Mesihovina 44 MW, WPP Velika Vlajina 32 MW, WPP Kamena 42 MW, WPP Ivan Sedlo 40 MW

Table 18 Impact of wind on conventional generation - Scenario A[8]

		2010	2015	2020	2025
Wind	Output (GWh)		329	329	329
	Value at feed-in tariff price (€m)		29.6	29.6	29.6
Impact on imports	Total GWh imported in scenario A	435	413	164	164
	Wind impact (GWh)		*-110*	*-66*	*-66*
	Wind impact (%)		*-21%*	*-29%*	*-29%*
	Total cost in scenario (€m)	18.9	18.5	7.7	7.8
	Wind impact (€m)		*-4.9*	*-3.1*	*-3.2*
	Wind impact (%)		*-21%*	*-29%*	*-29%*
Impact on thermal	Total GWh thermal generated in scenario A	6,339	7,323	9,279	9,279
	Wind impact (GWh)		*-217*	*-262*	*-262*
	Wind impact (%)		*-3%*	*-3%*	*-3%*
	Total thermal revenue in scenario (€m)	343	395	497	499
	Wind impact (€m)		*-14.1*	*-24.0*	*-24.6*
	Wind impact (%)		*-3.4%*	*-4.6%*	*-4.7%*
	Fuel costs in Scenario A	147	166	204	204
	Wind impact (€m)		*-5.0*	*-6.0*	*-6.0*
	Wind impact (%)		*-2.9%*	*-2.9%*	*-2.9%*
	Margin in Scenario A	195.9	229.1	293.1	295.4
	Wind impact (€m)		*-9.1*	*-18.0*	*-18.6*
	Wind impact (%)		*-3.8%*	*-5.8%*	*-5.9%*
Impact on hydro	Total GWh hydro generated in scenario A	8,758	8,976	8,978	8,978
	Wind impact (GWh)		*-1.4*	*0*	*0*
	Wind impact (%)		*-0.0%*	*0.0%*	*0.0%*
	Total hydro revenue in scenario (€m)	350	362	375	376
	Wind impact (€m)		*-3.3*	*-5.9*	*-6.2*
	Wind impact (%)		*-0.9%*	*-1.6%*	*-1.6%*

[8] It should be noted that all comparison figures are by reference to the figures in Table 17 Baseline scenario. For example, imports in 2015 from Table 17 were 522.8 GWh so that the 110 GWh fall under scenario A brings this figure down to 412.7 GWh, a 21% fall.

It should be noted that, although hydro generation does not reduce in volume terms under this scenario, there is still a loss of revenue suggesting that average wholesale prices fall as a result of increased delivery of base load (wind) generation reducing the need for peaking generation.

Viewed from a consumer viewpoint the effects are shown below (negative values are costs to customers, positive values are benefits). Wind provides consumers with a large saving on themal generation costs as well as a saving on imports and hydro. Although consumers face an increase in net costs in 2015 due to the feed-in tariff paid to wind, from 2020 the combined savings on conventional generation more than compensate consumers for the additional cost of the feed-in tariff and they enjoy a net benefit from wind.

	2015	2020	2025
		€ million	
Increased cost of feed-in tariff	-29.6	-29.6	-29.6
Savings on imports	+4.9	+3.1	+3.2
Change in cost of thermal generation	+14.1	+24.0	+24.6
Change in cost of hydro generation	+3.3	+5.9	+6.2
Total	**-7.3**	**+3.5**	**+4.4**

6.1.6 Impact of wind on generation cost – Scenario B

Scenario B is a 300 MW wind scenario, with three new wind farms built in addition to those in Scenario A[9]. Table 19 shows how the increase in wind dispatch is likely to affect output, revenues and costs of other types of generation and exports under Scenario B, and how this compares to the baseline outcomes.

Table 19 Impact of wind on conventional generation - Scenario B

		2010	2015	2020	2025
Wind	Output (GWh)		775	775	775
	Value at feed-in tariff price (€m)		69.8	69.8	69.8
Impact on imports	Total GWh imported in scenario B	435	281	95	95
	Wind impact (GWh)		*-242*	*-135*	*-135*
	Wind impact (%)		*-46%*	*-59%*	*-59%*
	Total cost in scenario (€m)	18.9	12.6	4.4	4.5
	Wind impact (€m)		*-11*	*-6*	*-6*
	Wind impact (%)		*-46%*	*-59%*	*-59%*

[9] The additional plants are WPP Poklecani 72 MW, WPP Borova Glava 52 MW, WPP Gradina 70 MW

		2010	2015	2020	2025
Impact on thermal	Total GWh thermal generated in scenario B	6,339	7,014	8,902	8,902
	Wind impact (GWh)		*-526*	*-640*	*-640*
	Wind impact (%)		*-7%*	*-7%*	*-7%*
	Total thermal revenue in scenario (€m)	343	377	475	476
	Wind impact (€m)		*-32.8*	*-45.9*	*-47.2*
	Wind impact (%)		*-8%*	*-9%*	*-9%*
	Fuel costs in Scenario B	147	159	195	195
	Wind impact (€m)		*-12*	*-15*	*-15*
	Wind impact (%)		*-7%*	*-7%*	*-7%*
	Margin in Scenario B	195.9	217.5	279.7	281.4
	Wind impact (€m)		*-21*	*-31*	*-33*
	Wind impact (%)		*-9%*	*-10%*	*-10%*
Impact on hydro	Total GWh hydro generated in scenario B	8,758	8,969	8,978	8,978
	Wind impact (GWh)		*-8.1*	*-0.1*	*-0.1*
	Wind impact (%)		*-0%*	*-0%*	*-0%*
	Total hydro revenue in scenario (€m)	350	360	377	378
	Wind impact (€m)		*-5.3*	*-3.7*	*-4.2*
	Wind impact (%)		*-0.0*	*-0.0*	*-0.0*

The effects of Scenario B from a consumer viewpoint are shown below. There is a large saving in thermal generation costs as thermal plants are displaced by the increased wind generation. Import costs are also lowered as the new capacity moves the system further toward self-sufficiency. Although hydro output remains fairly stable there is a small change in the cost, which reflects the fall in average wholesale prices due to the displacement of thermal at the margin.

Consumers experience an increase in cost overall as the feed-in tariff paid to the larger fleet of wind generators exceeds the savings in other generation. However, the net cost is lower from 2020 as the thermal saving increases.

	2015	2020	2025
		€ million	
Increased cost of feed-in tariff	-69.8	-69.8	-69.8
Savings on imports	+10.8	+6.3	+6.4
Change in cost of thermal generation	+32.8	+45.9	+47.2
Change in cost of hydro generation	+5.3	+3.7	+4.2
Total	**-20.8**	**-13.8**	**-11.8**

6.1.7 Impact of wind on generation cost – Scenario C

Table 20 Impact of wind on conventional generation - Scenario C

		2010	2015	2020	2025
Wind	Output (GWh)		1,577	1,577	1,577
	Value at feed-in tariff price (€m)		141.9	141.9	141.9
Impact on imports	Total GWh imported in scenario C	435	114	29	29
	Wind impact (GWh)		*-409*	*-201*	*-201*
	Wind impact (%)		*-78%*	*-88%*	*-88%*
	Total cost in scenario (€m)	18.9	5.1	1.3	1.4
	Wind impact (€m)		*-18*	*-9*	*-10*
	Wind impact (%)		*-78%*	*-88%*	*-88%*
Impact on thermal	Total GWh thermal generated in scenario C	6,339	6,410	8,169	8,169
	Wind impact (GWh)		*-1,131*	*-1,373*	*-1,373*
	Wind impact (%)		*-15%*	*-14%*	*-14%*
	Total thermal revenue in scenario (€m)	343	340	436	437
	Wind impact (€m)		*-69.8*	*-84.5*	*-86.6*
	Wind impact (%)		*-17%*	*-16%*	*-17%*
	Fuel costs in Scenario C	147	145	178	178
	Wind impact (€m)		*-26*	*-31*	*-31*
	Wind impact (%)		*-15%*	*-15%*	*-15%*
	Margin in Scenario A	195.9	194.4	257.9	258.8
	Wind impact (€m)		*-44*	*-53*	*-55*
	Wind impact (%)		*-18%*	*-17%*	*-18%*
Impact on hydro	Total GWh hydro generated in scenario C	8,758	8,940	8,976	8,976
	Wind impact (GWh)		*-37.1*	*-2.4*	*-2.4*

		2010	2015	2020	2025
	Wind impact (%)		-0%	-0%	-0%
	Total hydro revenue in scenario (€m)	350	355	380	380
	Wind impact (€m)		-10.4	-1.0	-1.8
	Wind impact (%)		-0.0	-0.0	-0.0

Scenario C is a 600 MW wind scenario, with three new wind farms built in addition to those in Scenario B[10]. Table 20 shows how the increase in wind dispatch is likely to affect the outcomes compared with the baseline scenario.

The effects of Scenario C from a consumer viewpoint are shown below. The pattern is similar to the other scenarios, with the main saving in thermal generation that is displaced by wind while the cost of imports is also reduced in all three snapshot years. These cost savings mitigate, by as much as 70%, the impact on the consumer of the feed-in tariff that is paid to 600 MW of wind generation.

There is still a net cost to the consumer following the introduction of the new wind capacity. On a unit basis this wind-support cost is around €0.33c/kWh of BiH load in 2015 after adjusting for the savings made on other generation, and declines over time to €0.26c/kWh in 2025. This compares to an average total generation cost of €4.5-4.7c/kWh.

	2015	2020	2025
		€ million	
Increased cost of feed-in tariff	-141.9	-141.9	-141.9
Savings on imports	+18.3	+9.4	+9.6
Change in cost of thermal generation	+69.8	+84.5	+86.6
Change in cost of hydro generation	+10.4	+1.0	+1.8
Total	**-43.4**	**-47.0**	**-44.0**

6.1.8 Impact of wind on generation cost – Scenario D1

Scenario D1 is a 900 MW wind scenario, with four new wind farms built in addition to those in Scenario C[11]. Scenarios D1 and D2 differ in terms of the geographical dispersion of the wind farms. However, since the total installed capacity is the same in D1 and D2 the results are equivalent in the analysis here (which is unaffected by

[10] The additional plants in Scenario C are WPP Ljubusa 110 MW, WPP Pakline 145 MW, WPP Podvelezje 30 MW

[11] The additional plants in Scenario D1 are WPP Kupres 77 MW, WPP Glamoc 1 – Slovinj 130 MW, WPP Podvelezje 1 46 MW, WPP Luka Krusevljani 60 MW.

location of individual plants). Given this, the results reported below can be treated as for D1 and D2.

Table 21 shows how the increase in wind dispatch is likely to affect the outcomes compared with the baseline scenario.

Table 21 Impact of wind on conventional generation - Scenario D1

		2010	2015	2020	2025
Wind	Output (GWh)		2,365	2,365	2,365
	Value at feed-in tariff price (€m)		212.9	212.9	212.9
Impact on imports	Total GWh imported in scenario D1	435	32	6	6
	Wind impact (GWh)		*-491*	*-224*	*-224*
	Wind impact (%)		*-94%*	*-97%*	*-97%*
	Total cost in scenario (€m)	18.9	1.4	0.3	0.3
	Wind impact (€m)		*-22*	*-10*	*-11*
	Wind impact (%)		*-94%*	*-97%*	*-97%*
Impact on thermal	Total GWh thermal generated in scenario D1	6,339	5,753	7,419	7,419
	Wind impact (GWh)		*-1,787*	*-2,123*	*-2,123*
	Wind impact (%)		*-24%*	*-22%*	*-22%*
	Total thermal revenue in scenario (€m)	343	302	398	399
	Wind impact (€m)		*-107.7*	*-122.8*	*-125.1*
	Wind impact (%)		*-26%*	*-24%*	*-24%*
	Fuel costs in Scenario D1	147	130	161	161
	Wind impact (€m)		*-41*	*-49*	*-49*
	Wind impact (%)		*-24%*	*-23%*	*-23%*
	Margin in Scenario D1	195.9	171.6	236.8	237.4
	Wind impact (€m)		*-67*	*-74*	*-77*
	Wind impact (%)		*-28%*	*-24%*	*-24%*
Impact on hydro	Total GWh hydro generated in scenario D1	8,758	8,890	8,960	8,960
	Wind impact (GWh)		*-87.3*	*-18.4*	*-18.4*
	Wind impact (%)		*-1%*	*-0%*	*-0%*
	Total hydro revenue in scenario (€m)	350	351	379	380
	Wind impact (€m)		*-13.6*	*-1.5*	*-2.4*
	Wind impact (%)		*-0.0*	*-0.0*	*-0.0*

The pattern of effects on the consumer under Scenario D1 is similar to that under scenario C. Overall, there is a net cost of increased wind, although this is mitigated by savings on other generation sources.

	2015	2020	2025
		€ million	
Increased cost of feed-in tariff	-212.9	-212.9	-212.9
Savings on imports	+22.0	+10.5	+10.6
Change in cost of thermal generation	+107.7	+122.8	+125.1
Change in cost of hydro generation	+13.6	+1.5	+2.4
Total	**-69.6**	**-78.1**	**-74.7**

6.1.9 Impact of wind on generation costs - summary

In all four scenarios, wind capacity increases in 2015 along with most conventional capacity developments. This leads to the results illustrated in Figure 13. The most ambitious scenarios (Scenarios D1 and D2) entail wind accounting for more than 20% of all generating capacity in 2015. This is in the face of nearly 10% increase in conventional capacity to 2015. Wind retains a large proportion of installed capacity in these scenarios, even with futher increases in conventional capacity prior to 2020. It is likely that BiH will be heavily reliant on the new conventional capacity to provide reserve for managing the new wind farms; the potential costs of this are explored in the next section.

Figure 13 Wind farm share of total capacity – all scenarios

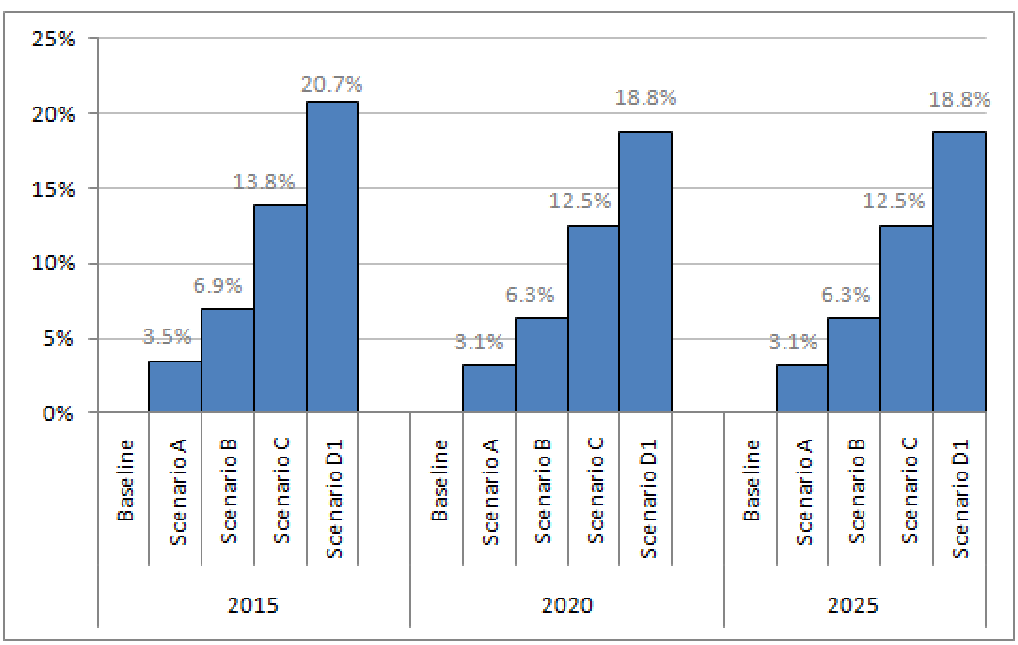


Figure 14 shows the impact that increasing wind penetration has on thermal generation and imports. In all years the result is a reduction in generation from these sources as wind displaces them. Hydro output, which is able to sell any surplus energy into the export market, remains stable.

Figure 14 Impact of wind on GWh from conventional sources

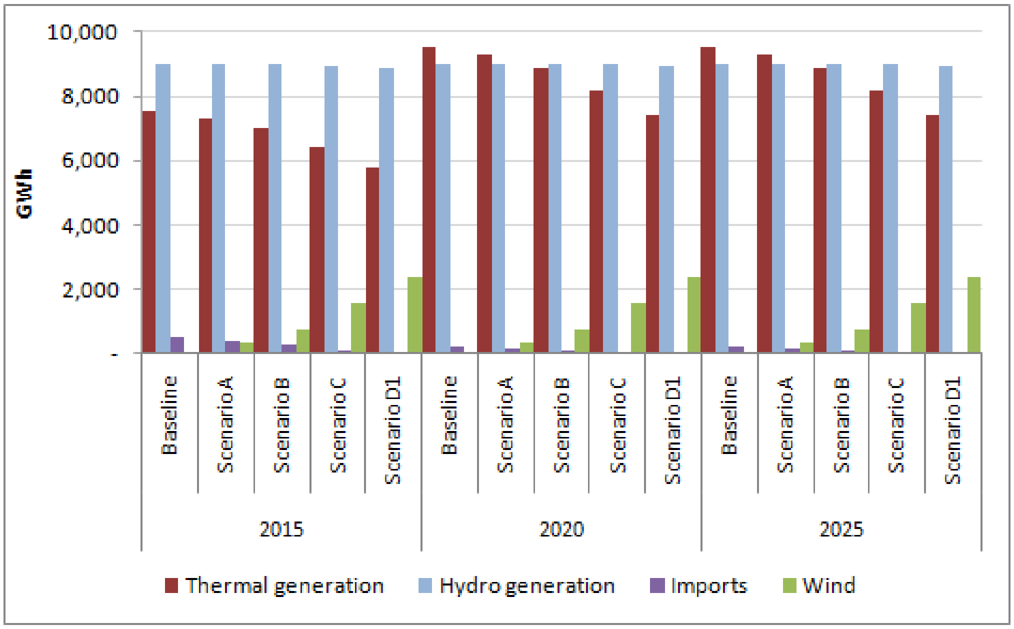
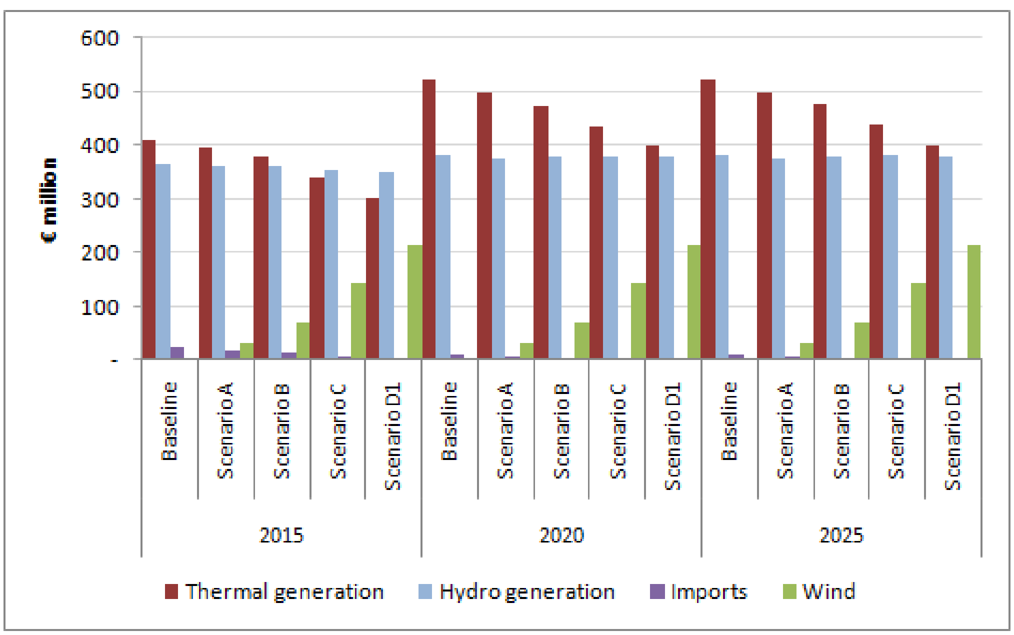


Figure 15 shows the impact that increasing wind has on the revenues earned by the conventional sources. As would be expected given the production results in Figure 14, most of the revenue reduction is experienced by thermal generation.

Figure 15 Impact of wind on annual revenue to conventional sources



The overall impact on total cost of generation to the consumer in each scenario is summarised in Table 22 below. The net cost increases in all cases except the later years under scenario A. The additional cost reflects the higher cost of supporting wind generation through the feed-in tariff.

Although the € million total costs may seem high, it is useful to put them in context. The net cost of wind as a percent of the total cost of generation in each scenario is also shown below. The addition to cost is less than 1% in Scenario A and rises to just over 5% in Scenario C. The highest it gets as a proportion of generation cost is 8% when there are 900MW of wind added (Scenario D1).

Table 22 Summary of net cost to the consumer of wind additions

	2015	**2020**	**2025**
	Net cost to consumers, € million		
Scenario A	-7.3	+3.5	+4.4
Scenario B	-20.8	-13.8	-11.8
Scenario C	-43.4	-47.0	-44.0
Scenarios D1, D2	-69.6	-78.1	-74.7
	Net cost as % of total cost to consumers		
Scenario A	0.9%		
Scenario B	2.5%	1.5%	1.3%
Scenario C	5.2%	4.9%	4.6%
Scenarios D1, D2	8.0%	7.9%	7.5%

The impacts on conventional generation discussed above are the first part of the cost of adding wind to the system. The second part, the cost of providing reserve for wind, is discussed next.

6.2 Reserve provision

Determining the extent of reserve that must be provided is a complex undertaking. In a hydrothermal system, reserve is provided against the risk of failure of generating units and against mis-forecasting of demand levels.

The intermittency of wind adds a new degree of complexity. Two forms of additional reserve need to be considered: reserve against wind failing to deliver when scheduled to do so, but equally important is a need for downward flexibility on other generating units when wind delivers unscheduled energy onto the system. This sub-section looks at both of these in turn.

It should be noted that reserve against wind intermittency is different to reserving against generation failure and demand mis-forecast because, with non-wind uses there is a correlation between demand level and need for reserve (ie when demand is high then more generators are operating, which increases the chances of one of those generators failing and, when demand is high, a percentage error in demand forecast will have a greater effect measured in MW). Wind variability can happen at any time and so the incremental need for reserve is essentially independent of demand level. This increases the potential total cost of reserving against wind variability.

6.2.1 Valuing reserve capacity

BiH has the following options for providing reserve against wind variability:

- ❑ **Imports** currently provide some reserve energy. However, increased reliance on cross-border flows would not be reasonable in the absence of a full scale regional balancing agreement. Therefore, the bulk of cross-border energy would need to be via contracts nominated one or two days ahead at the latest and not the necessary near-instantaneous flows required for reserve. Most interconnector flows can be expected to remain substantially base load. ***This is not a practical option in the current regional market***.

- ❑ **Use existing lignite generators**. The existing and planned lignite generators are not sufficiently flexible in operation to provide reliable secondary and tertiary reserve. ***This is not a practical option***.

- ❑ **Construction of specialist thermal reserve plants** would need to rely on open cycle plants burning imported distillate fuels because the alternative fuel, natural gas, may not be sufficiently reliably available in the near future; operation of such plants on distillate would be very expensive even though the capital costs would be relatively low. ***This is discussed below***.

- ❑ **Hydro generators** can operate flexibly provided there is adequate reservoir capacity and provided there is sufficient water held in the reservoir that can be released. The main difficulty with hydro is almost certainly going to be seasonality of water supply and this will be the main limiting factor on reserve provision. ***This is discussed below***.

Construction of specialist reserve capacity

The costs of a distillate open cycle generator are based on the following international cost factors[12]:

Fixed costs:

Investment cost	612,000	EUR/MW
Discount rate	10%	real
Technical lifetime	30	years

[12] Sources of data is IEA ETSAP - Technology Brief E02, Gas fired power, April 2010 (assumed FX rate $/EUR=0.68)

O&M Costs	25,000	EUR/MW/Year
Variable costs:		
Distillate[13]	885	USD/tonne – this leads to:
Distillate	270	EUR/MWh generated

Calculating fixed cost we get an annual cost of paying off the investment of about €65,000 per MW so that, after inclusion of O&M costs, the cost per MW per year is €90,000.

The levelised cost per MWh will depend on the operating regime of the plant, and this is discussed below.

Valuing water reserved against wind non-delivery

The marginal cost of using water to generate electricity is close to zero. However, the value of water in a reservoir is actually much higher. The basis for valuing water held as reserve is the revenue that could be gained by generating with that water. Therefore, the water is valued against the energy displaced if the water is used. Reviewing the dispatch profiles in section 6.1 (see the examples in Figure 10 and Figure 11 on pages 39 and 41) it can be seen that the main energy displaced will be thermal generation.

Each MW held as reserve could have been sold at the wholesale market price. In some hours it will be utilised to replace wind and the generator will earn the revenue from delivering energy to the system operator at an agreed price; in the remaining hours, an availability payment will need to be made that compensates for lost revenue from being held in reserve. Reserved hydro capacity could be used to displace missing wind delivery for 75% of the year and this lost opportunity to sell the water will need to be compensated for at the market price.

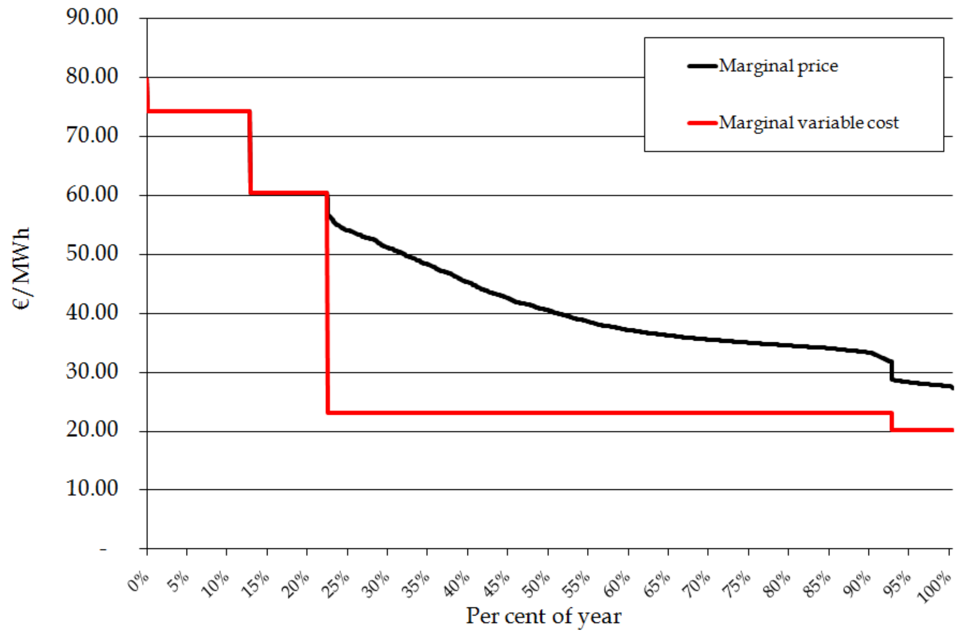
However, any water not actually delivered in order to replace the missing output from wind farms will accumulate, and this water must eventually be delivered to avoid overflow of the reservoir. Therefore, the sold water should be valued at its eventual delivered value, which should be the spill energy price.

It is therefore reasonable to value reserve held against wind non-delivery based on the marginal prices delivered from the model used in the analysis in section 6.1 for all energy held in reserve and not utilised less the value of spill energy for when that energy is eventually released.

Figure 16 shows an example of the modelled wholesale price curve for each hour of a sample year (2020) in the baseline. It can be noted that the marginal price is capped by the import price in peak periods. During the rest of the year the marginal variable cost is set at the fuel cost of thermal plants, which are marginal. The difference between this and the marginal price represents fixed cost recovery.

[13] Based on a recent ICE forward market snapshot for delivery into Europe

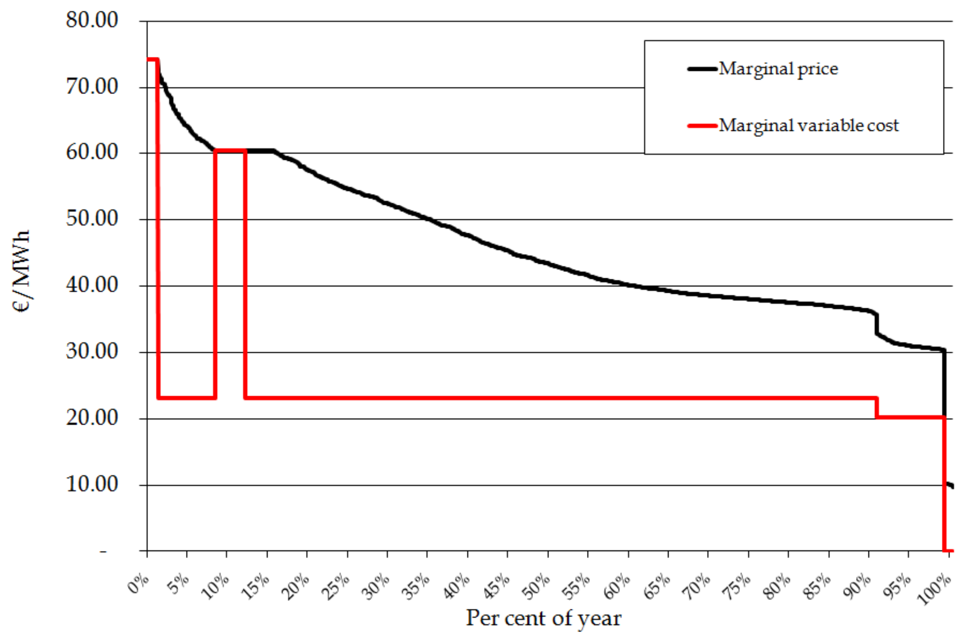
Figure 16 Modelled wholesale prices and costs, 2020 baseline



For contrast, Figure 17 shows the modelled wholesale price curve for 2020 in scenario C. Consistent with the results in section 6.1, the addition of wind to the system reduces the need for imports and lowers the marginal price in peak periods. Imports now cap the price in just a few peak periods (corresponding to when hydro availability is low). Hydro sets the price in a few hours when demand is at its lowest. The analysis that produced Figure 17 is run for each scenario and each year of analysis.

Figure 17 also shows the modelled marginal variable costs in the market, which is the price at which unused reserve energy will eventually be spilled onto the market.

Figure 17 Modelled wholesale prices and costs, 2020 scenario C



Valuing hydro reserve contracts held against unscheduled wind delivery

Wind is approximately as likely to deliver energy onto the system when not expected as to fail to deliver when scheduled. This requires units that are already in operation to reduce output. Where output is reduced, the cost to the generator is usually small: the generator will already have sold the energy scheduled for generation and so cutting back output will be profitable to the generator if it pays the value of fuel saved. Therefore, the value of energy displaced when unscheduled wind is spilled onto the system is the marginal variable cost of production in the time period when the energy was displaced.

To model the value to the system operator of ability to deload plants when unscheduled wind is spilled onto the system, the system operator can reasonably consider that it will earn average variable costs for hours when spilled energy from wind must be balanced.

Figure 17 shows an example of the modelled marginal variable costs in the market on the assumption that unscheduled wind delivery will be sold by the system operator to a generator at approximately this price in order to balance the system.

However, there remains a cost to the consumer. The supplier had already purchased energy from the generator at a price based on the wholesale marginal price of energy and so the true balancing cost to the consumer is this price less the revenue paid by generators to deload plants.

In other words, whether reserve is needed because of a shortfall in wind delivery or due to surplus wind delivery, the cost to the consumer against which this reserve should be valued is the difference between the wholesale marginal price and the market spill price.

Reserve operation models

The cost of reserve could depend on the way it is operated. The following operation modes could be considered.

- **Treat all wind output as spilled energy**. Given the uncertainty of wind output and possibly a complete lack of scheduling information for wind farms, it may be reasonable to schedule the system on the assumption that no wind will be delivered. Any wind that is delivered will be surplus energy, which is then balanced by deloading the most expensive plant on the system (be it coal, import or a hydro equivalent). If this is done then the cost of reserve management is the spill price for every MWh of wind delivered onto the system. This is one extreme treatment of wind.

- **Treat all wind output as firm**. This is only a realistic proposition with wind generation schedules based on good forecasting. However, at an extreme, reserve would be held against any outage of wind from full load operation.

- **Hybrid model**. This is the more normal model whereby reserve is only held against statistical potential of the full wind portfolio to over-deliver against expectation or under-deliver against expectation[14]. In sub-section 6.2.2 we make an assessment of the reserve capacity requirements for this third model.

6.2.2 Reserve capacity assessment

In this section we summarise the total additional reserve capacity needed to regulate the variability of WPP.

Existing reserve capacity

The current reserve capacity available in BiH is sufficient to meet the reserve requirements of the system. It is likely that this will remain sufficient to both provide additional output in times of shortage, and reduce output in times of oversupply.

Additional reserve capacity needed for WPP

The amount of maximum reserve needed under each WPP scenario is summarised in Table 23. It is assumed that variation in wind output is symmetric, so that positive and negative variations are equally likely (see Task 1 report for descriptions of the distribution of expected deviations). It should also be stressed that these values refer to a situation without wind forecasting techniques applied by the system operator or any other person.

[14] However, in our analysis, it must be remembered that we use potential of wind to vary between time periods as a proxy measure of wind variation from forecast

Table 23 Additional maximum reserve capacity needed				
	Scenario A	**Scenario B**	**Scenario C**	**Scenario D1**
Total installed WPP capacity	150 MW	300 MW	600 MW	900 MW
Max variations (%)	21.3%	40.0%	34.5%	31.9%
Max variations (MW)	**32 MW** ready to decrease or increase	**120 MW** ready to decrease or increase	**207 MW** ready to decrease or increase	**287 MW** ready to decrease or increase
Expected annual GWh from wind	329.9 GWh	776.3 GWh	1568.8 GWh	2377.3 GWh
Expected cumulative total change in hourly output per year (GWh)	±18.67 GWh	±43.00 GWh	±77.27 GWh	±112.65 GWh
Implicit load factor on reserve for wind	**6.7%** on reserved capacity	**4.1%** on reserved capacity	**4.3%** on reserved capacity	**4.5%** on reserved capacity

Source: Task 1 report

The Table 23 calculations are based on the reserve needed to regulate hourly changes in WPP (commonly referred to as tertiary reserve). This is a conservative approach given that, since the possible changes in WPP output in an hour are usually higher than those possible in a 15 minute period (commonly referred to as secondary reserve).

6.2.3 Cost of providing reserve capacity

Provision of reserve assuming all wind energy is spill

Table 24 shows the net cost of wind balancing in each scenario modelled. In this methodology:

- ❑ The cost of provision of reserve for each MWh of wind dispatched (item 5 on the table) is:
- ❑ The cost of the energy that was bought by suppliers at the wholesale price (item 3); *less*
- ❑ The revenue earned by the system operator in selling the wind energy that was all spilled onto the system (item 4).
- ❑ This amount is passed on to consumers for every MWh of wind dispatched; the net cost to consumers is given on the table at item 6 (calculated by multiplying cost per MWh from item 5 by the GWh of wind dispatch from item 2).

Table 24 Net reserve cost to consumers if all wind is treated as spill

		Scenario A	Scenario B	Scenario C	Scenario D1
(1)	MW wind	150	300	600	900
(2)	GWh wind per year	329.9	776.3	1568.8	2377.3
(3)	**Average system marginal price (€/MWh)**				
	2015	44.2	43.7	42.7	42.1
	2020	44.8	44.7	44.7	44.7
	2025	45.0	44.9	44.8	44.7
(4)	**Average system spill price (€/MWh)**				
	2015	36.4	33.7	28.5	23.8
	2020	31.0	28.3	24.7	22.7
	2025	31.2	28.4	24.8	22.7
(5)	**Net cost to consumer (€/MWh)**				
	2015	7.9	10.0	14.2	18.3
	2020	13.8	16.5	20.0	22.0
	2025	13.8	16.5	20.0	22.0
(6)	**Net cost to consumer (€m)**				
	2015	2.60	7.74	22.31	43.40
	2020	4.56	12.77	31.41	52.19
	2025	4.56	12.78	31.45	52.28

Table 24 shows that the cost per MWh increases between 2015 and 2020 as a result of falling spill prices (as thermal generation is displaced by wind) while marginal prices remain stable on average. This cost is high, particularly in the more ambitious wind scenarios.

Provision of reserve treating all wind as firm

As previously explained, treating all wind as firm and then reserving against all possible wind unavailability is likely to prove very expensive because wind is unavailable for up to 75% of the time. This option is not costed here.

The hybrid model using hydro provision only

In this model, a more limited amount of reserve is held on hydro plants against a statistical estimation of *likely* wind outage. The capacity required is that indicated in Table 23 on page 57. This accounts for wind non-availability; the reserve for wind that was not expected is essentially treated as spill. The results of this analysis are given in Table 25.

Table 25 Net cost of reserve to consumers using a hybrid model with hydro as reserve against wind non-availability

		Scenario A	Scenario B	Scenario C	Scenario D1
(1)	MW wind	150	300	600	900
(2)	GWh wind per year	329.9	776.3	1568.8	2377.3
(3)	**Net cost to consumer (€/MWh)** (*from* Table 24, *item 5*)				
	2015	7.9	10.0	14.2	18.3
	2020	13.8	16.5	20.0	22.0
	2025	13.8	16.5	20.0	22.0
(4)	MW reserved against wind non-availability	32	120	207	287
(5)	**Net cost to be compensated by reserve contracts (€m)** (*to cover energy purchased when wind not available*)				
	2015	0.7	8.1	40.5	109.1
	2020	1.3	13.4	57.0	131.2
	2025	1.3	13.4	57.0	131.4
(6)	Expected spill energy per year (GWh)	18.67	43.00	77.27	112.65
(7)	**Net spill cost to consumers (€m)** (*lost opportunity to sell energy at full price*)				
	2015	0.15	0.43	1.10	2.06
	2020	0.26	0.71	1.55	2.47
	2025	0.26	0.71	1.55	2.48
(8)	**Total net cost to consumers under this hybrid methodology (€m)**				
	2015	0.87	8.56	41.55	111.16
	2020	1.54	14.14	58.51	133.69
	2025	1.54	14.14	58.57	133.93
(9)	**Cost to consumers €/MWh wind dispatched**				
	2015	2.65	11.03	26.49	46.76
	2020	4.66	18.21	37.29	56.24
	2025	4.66	18.22	37.34	56.34

The calculations used in Table 25 are as follows:

- The net cost to consumers per MWh of reserve (item 3) are as set out in Table 24 (page 58, see the explanation at item 5 of that table)
- The MW reserved against wind non-availability (item 4) are as set out in Table 23 (page 57)

- ❑ The net cost to be compensated by consumers (item 5) is calculated by deriving the MWh not sold at the wholesale price (the MW from item 4 times 8760) and multiplying them by the net consumer cost (item 3) and the dividing by 1,000,000)
- ❑ Net spill cost to consumers (item 7) is calculated by multiplying the cost per MWh (item 3, which is actually the same cost to consumers whether the energy is treated as spill or as top-up due to unavailability) by the expected spill energy (item 6), which has been taken from Table 23 and dividing by 1,000 (to get the result in €m)
- ❑ Total cost to consumers (item 8) is the sum of items 5 and 7
- ❑ Cost to consumers per MWh of wind dispatched (item 9) is calculated by dividing item 8 by item 2 and multiplying by 1,000.

The results of this analysis suggest that it is slightly more expensive to use this methodology than to simply treat all wind dispatch as spill.

Hybrid model using thermal capacity for top-up

Table 26 shows the cost using reserve against non-delivery of wind. The following apply:

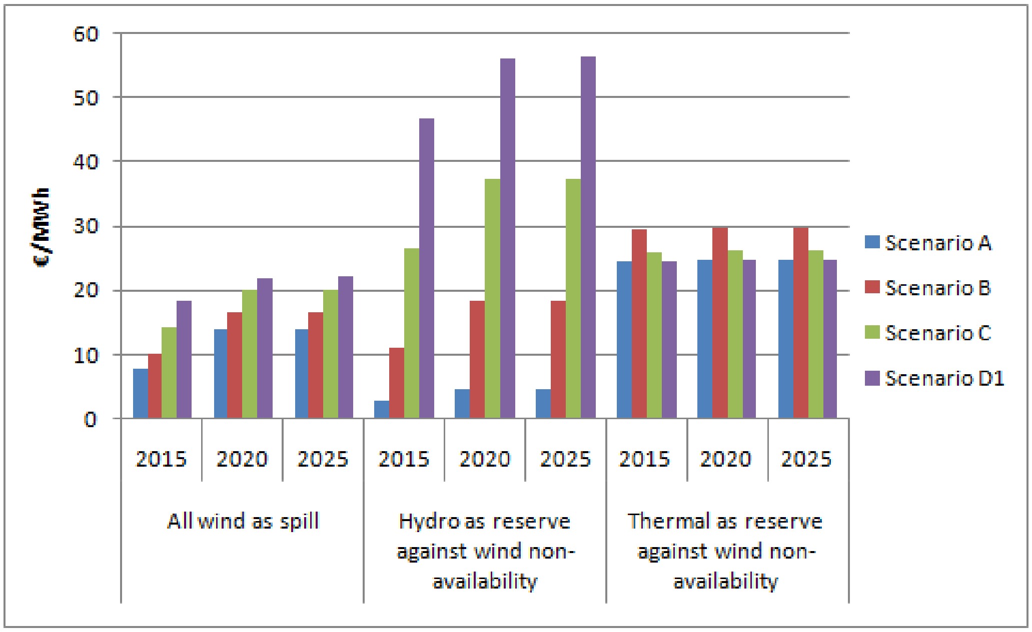
- ❑ MW reserved against wind non-availability (item 3) and GWh of reserve dispatched against wind non-availability (item 4) are taken from Table 23 (page 57)
- ❑ Thermal reserve costs (per MW or per MWh) are given in items 5 and 7, which are taken from section 6.2.1 (se page 52)
- ❑ Total annual fixed costs of thermal reserve (item 6) are calculated by multiplying fixed cost per MW (item 5) by the MW reserved (item 3) and dividing by 1,000
- ❑ Total variable cost of thermal reserve (item 8) is cost per MWh (item 7) multiplied by GWh reserve dispatched (item 4) divided by 1,000
- ❑ Total cost of using thermal reserve (item 9) is item 6 plus item 8
- ❑ Net spill cost to consumers (item 11) is calculated in the same way as item 7 on Table 25 (page 59) and uses the same data
- ❑ Total net cost to consumers (item 12) is the sum of items 9 and 11
- ❑ Cost to consumers per MWh of wind dispatched (item 13) is calculated by dividing item 12 by item 2 and multiplying by 1,000.

Table 26 Net cost of reserve to consumers using a hybrid model with thermal reserve against wind non-availability

		Scenario A	Scenario B	Scenario C	Scenario D1
(1)	MW wind	150	300	600	900
(2)	GWh wind per year	329.9	776.3	1568.8	2377.3
(3)	MW reserved against wind non-availability	32	120	207	287
(4)	GWh reserve dispatched against wind non-availability	18.67	43.00	77.27	112.65
(5)	Annual fixed cost per MW of thermal reserve (€000)	89.92	89.92	89.92	89.92
(6)	Total annual fixed cost of thermal reserve (€m)	2.88	10.79	18.61	25.81
(7)	Variable cost (€/MWh) of thermal reserve	270	270	270	270
(8)	Total annual variable cost of using thermal reserve (€m)	5.04	11.61	20.86	30.42
(9)	**Total annual cost of using thermal reserve (€m)**	7.92	22.40	39.48	56.22
(10)	GWh reserved against non-scheduled wind delivery (*from Table 25, item 6*)	18.67	43.00	77.27	112.65
(11)	**Net spill cost to consumers (€m)** (*from Table 25, item 7*)				
	2015	0.15	0.43	1.10	2.06
	2020	0.26	0.71	1.55	2.47
	2025	0.26	0.71	1.55	2.48
(12)	**Total net cost to consumers under this hybrid methodology (€m)**				
	2015	8.07	22.83	40.58	58.28
	2020	8.18	23.11	41.02	58.70
	2025	8.18	23.11	41.03	58.70
(13)	**Cost to consumers €/MWh wind dispatched**				
	2015	24.45	29.41	25.86	24.51
	2020	24.79	29.77	26.15	24.69
	2025	24.79	29.77	26.15	24.69

As with other methodologies for reserving against wind variability, the cost to consumers in this methodology remains high. Figure 18 summarises the cost per MWh of the three support methodologies in this sub-section.

Figure 18 Comparison of reserve provision methodologies



6.2.4 Key lessons on reserve costs

The analysis in this section presents a worst case cost of reserve provision. This is because it assumes that there is no short term forecasting of wind output. Experience from Europe shows that considerable savings can be made by forecasting wind availability a few hours ahead. Without such forecasting, the costs of reserving against wind variability in BiH are very high. This is because there is a lack of flexible thermal capacity in BiH and, in particular, limited options in the provision of open-cycle plants that have relatively low fixed costs due to a limits of gas supply.

7 Summary

7.1 Critical areas for wind power plants integration

Several critical areas are identified with respect to wind power plants integration and existing topology of transmission system:

- Town of Mostar,
- Area around Grude and Posusje,
- Area of Livno,
- Area of Bugojno and Kupres,
- Area of Novi Travnik and Zenica.

The transmission system in these areas will have to be reinforced to allow wind power plant integration into the power system of BiH. Individual reinforcements have been identified, and investment costs have been estimated in this Report.

7.2 Integration of 150 MW of wind power plants (Scenario A)

To integrate wind power plants in scenario A1 (150 MW) two network reinforcement investments are suggested:

- Revitalization of the 110 kV line Mostar 4 – Siroki Brijeg in order to increase its transmission capacity up to standard value (123 MVA), by Copper 95 mm^2 conductors and concrete towers replacement (construction of ACSR 240/40 mm^2 conductors and steel towers in length of 10,8 km)
- Revitalization of the 110 kV line Mostar 1 – Mostar 6 in order to increase its transmission capacity up to standard value (123 MVA), by ACSR 150/25 mm^2 conductors and concrete towers replacement (construction of ACSR 240/40 mm^2 conductors and steel towers in total length of the line).

Network reinforcement costs in this scenario are estimated at 1.000.000 €.

7.3 Integration of 200 MW of wind power plants (subscenario A1)

To integrate wind power plants in scenario A1 (200 MW) one network reinforcement investment is suggested:

- Construction of 110 kV line Nevesinje – Gacko.

Additional network reinforcement costs in this scenario are estimated at 3,6 millions €.

7.4 Integration of 300 MW of wind power plants (Scenario B)

To integrate wind power plants in scenario B (300 MW), the following network reinforcement investments are suggested:

- ❑ Construction of new 2x110 kV line Poklecani – Posusje (ACSR 240/40 mm^2, 15.1 km) with enlargement of SS Posusje (two 110 kV line bays)
- ❑ Construction of new 2x110 kV line Poklecani – Tomislavgrad/Rama (ACSR 240/40 mm^2, 31.6 km)
- ❑ Enlargement of SS Jablanica with one 110 kV line bay and operation of Rama – Jablanica line under 110 kV
- ❑ Finalization of Tomislavgrad – Kupres 110 kV line construction (20 km)
- ❑ Construction of 110/x kV SS Kupres
- ❑ Enlargement of SS Bugojno with one 110 kV line bay and operation of Bugojno – Kupres line under 110 kV
- ❑ Enlargement of SS Rama and SS Uskoplje with one 110 kV line bay and construction of new 110 kV line Rama - Uskoplje.

Network reinforcement costs in this scenario are estimated to 11.000.000 €.

7.5 Integration of 600 MW of wind power plants (Scenario C)

To integrate wind power plants in scenario C (600 MW), the following network reinforcement investments are suggested:

- ❑ Construction of new 220/110 kV SS Poklecani or Posusje 2 (1x150 MVA)
- ❑ Construction of new 110 kV line HPP Pec Mlini – Grude 2 or Grude – Posusje (31 km)
- ❑ Construction of new 110 kV line Livno – WPP Borova Glava 2.

Network reinforcement costs in this scenario are estimated to 22.000.000 €.

7.6 Integration of 900 MW of wind power plants (Scenario D1)

To integrate wind power plants in scenario D1 (900 MW, concentrated distribution), the following network reinforcement investments are suggested:

- Construction of SS 110 kV Glamoc
- Enlargement of SS Livno with one 110 kV line bay and operation of Livno – Glamoc line under 110 kV, together with a revitalization of this line (transmission capacity increase by ACSR 150/25 mm^2 conductors replacement)
- Enlargement of SS Kupres with two 110 kV line bays and construction of 2x110 kV line Slovinj - Kupres
- Enlargement of SS Kupres with additional two 110 kV line bays and SS Bugojno with two 110 kV line bays and construction of new 2x110 kV Bugojno – Kupres line (circuits 2 and 3)
- Revitalization of the 110 kV line Bugojno – D. Vakuf in order to increase its transmission capacity up to standard value (123 MVA), by ACSR 120/20 mm^2 conductors replacement (construction of ACSR 240/40 mm^2 conductors in length of 5.7 km)
- Revitalization of the 110 kV line Jajce 2 – D. Vakuf in order to increase its transmission capacity up to standard value (123 MVA), by ACSR 120/20 mm^2 conductors replacement (construction of ACSR 240/40 mm^2 conductors in length of 21.2 km)
- Enlargement of SS Livno and SS Busko Blato with one 110 kV line bay each, and construction of new 110 kV line Livno – Busko Blato 2
- Reinforcement of 110 kV network in Mostar (construction of new 2x110 kV line Mostar 9 – Mostar 4/Mostar 5 and introduction of 110 kV line Mostar 2 – Capljina in SS Mostar 9)
- Construction of 220/110 kV SS Kupres (2x150 MVA).

Network reinforcement costs in this scenario are estimated to 44.000.000 €.

7.7 Integration of 900 MW of wind power plants (Scenario D2)

To integrate wind power plants in scenario D2 (900 MW, wide distribution), the following network reinforcement investments are suggested:

- Enlargement of SS Busko Blato with one 110 kV line bay and construction of new 110 kV line WPP Orlovaca – Busko Blato 2

- Revitalization of the 110 kV line Mostar 2 – Jablanica (section from WPP Plocno to SS Jablanica) in order to increase its transmission capacity up to standard value (123 MVA), by ACSR 150/25 mm^2 conductors replacement (construction of ACSR 240/40 mm^2 conductors)

- Reinforcement of 110 kV network in Mostar (construction of new 2x110 kV line Mostar 9 – Mostar 4/Mostar 5 and introduction of 110 kV line Mostar 2 – Capljina in SS Mostar 9).

Network reinforcement costs in this scenario are estimated to 29.000.000 €.

7.8 Additional requests on P/f control

The power and frequency regulation abilities of existing hydro power plants could be significant and adequate to provide regulation support to new wind power plants.

For various reasons, NOS BiH can not provide total reserve from these hydro power plants, which leads to unsatisfactory imbalances in the BiH power system and large deviations of cross border flows relative to scheduled values.

This fact may limit future wind power plants integration into the BiH power system since they are an additional source of possible imbalance. It is of utmost importance that power supply companies in BiH provide secondary and tertiary control reserve to NOS BiH as stated in the DERK decision.

It is estimated that additional hydro units should be included into secondary P/f control.

NOS BiH stated that secondary and tertiary P/f control reserve in BiH is not going to limit wind power plants integration, but power production companies have to provide such ancillary services.

Annual variability of secondary P/f control reserve, especially expected low values during summer months, remains a crucial problem for WPP integration.

7.9 Additional requests on Q/U control

A limited contribution from wind power plants in Q/U control may be welcomed. Furthermore, some large wind power plants like WPP Glamoc 1 – Slovinj, WPP Ljubusa, WPP Pakline and WPP Kupres have to be equipped to provide Q/U control services in order to avoid voltage collapse in the system. Additional contributions could be directed to the wind power plants with the provision that WPPs must be able to operate within the power factor range of 0.95 inductive to 0.95 capacitive (lead/lag capability).

It is expected that wind power plants integration will cause no additional costs for the ISO in providing Q/U control service.

7.10 Impact of wind integration on conventional generation

As wind capacity increases its main impact is to displace thermal sources and imports. Thermal generation currently provides the largest share of generation in BiH and tends to be the marginal generation source. This means that the introduction of new baseload generation (wind) has the greatest impact on thermal, which is pushed out of the dispatch order. Thermal generation sees a reduction in revenues in all wind scenarios.

Hydro output, which is able to sell any surplus energy into the export market, remains stable in all wind scenarios.

The impact on consumers is an increase in net cost in all cases except the later years under wind Scenario A. The additional cost reflects the higher cost of supporting wind generation through the feed-in tariff. However, the net cost of wind as a percent of the total cost of generation in each scenario is less than 1% in Scenario A and rises to just over 5% in Scenario C. The highest it gets as a proportion of generation cost is 8% when there are 900 MW of wind added (Scenario D1).

7.11 Impact of wind integration on reserve costs

With the introduction of wind to a power system two forms of additional reserve need to be considered: reserve against wind failing to deliver when scheduled to do so, but equally important is a need for downward flexibility on other generating units when wind delivers unscheduled energy onto the system. Different approaches can be taken to valuing reserve for wind. In the analysis here three approaches were used and in all cases the cost of providing reserve for wind is relatively high.

The analysis assumes that there is no short term forecasting of wind output and this results in a conservative view on the required reserve. It is possible, following the experience in Western Europe, that considerable savings could be made through the introduction of techniques to forecast wind availability a few hours ahead.

8 Bibliography

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