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SUMMARY

This paper presents electricity power generation capacities in South East Europe (SEE). Due to a high share of hydro power generation, hydrology has a major influence on energy balance and power markets in SEE. Power markets are facing the impact of a rising number of renewable energy generation facilities. This paper describes influences of energy availability on power markets and energy generation within three hydrological scenarios (dry, normal and wet scenario). Short-term electricity prices are analyzed in terms of production and consumption on three major power exchanges in Romania, Hungary and Slovenia. Findings demonstrate influences of weather conditions on power markets in SEE through energy production, security of supply and risks facing power producers.

Key words: hydro power generation, SEE power market, hydrological scenarios

1. INTRODUCTION

Power system planning sector has always been a great challenge due to the complexity of the power system and its most important characteristics; simultaneity of production and consumption. Considering the time horizon, there are three types of planning: long-term, medium-term and short-term planning. There is no explicit definition of the time interval for each of the planning type. In general, long-term planning deals with strategic guidelines of the county energy policy. Medium-term planning defines guidelines of the energy policy in the near future up to 5 years which are needed to provide finances for the implementation of projects and changes in the electricity market. Short-term planning refers to time horizon up to a month. Generally, short-term planning determines the future demand for electricity and plans how to secure it, taking into account criteria of safety and feasibility.

Load forecasting is the oldest problem in the power sector, very popular in professional and scientific community. Nowadays, load forecasting methods and models ensure the forecast error below 3% [2]. The second part of the planning process relates to production planning and purchase or sale of electricity. The costs of production are made of fixed and variable costs. Fixed costs are related to financing and operation of power plants while the variable costs are related to the cost of fuel. Share of fixed and variable costs for various types of power plants are shown in Figure 1.

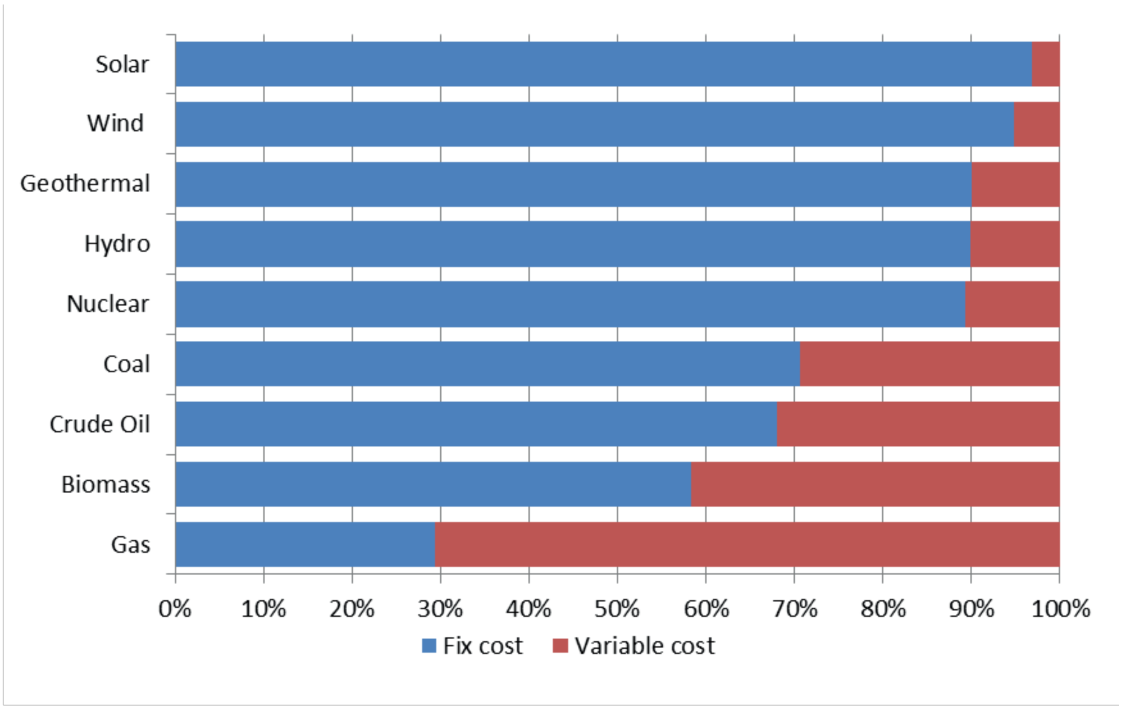

Figure 1. Share of fixed and variable costs in electricity production by technology

Optimization of the production portfolio for energy companies needs to meet several criteria: maximum safety, availability and profitability. Criteria refer to the security of supply for electricity consumers, maximum availability of production facilities and maximizing revenue in market conditions. Disregarding the rules can lead to adverse social and economic consequences that may cause serious economic damage. The production is planned according to the so-called merit order list (MOL). It represents the distribution of power plants by variable cost for production of an additional MWh. Example of MOL is shown in Figure 2.

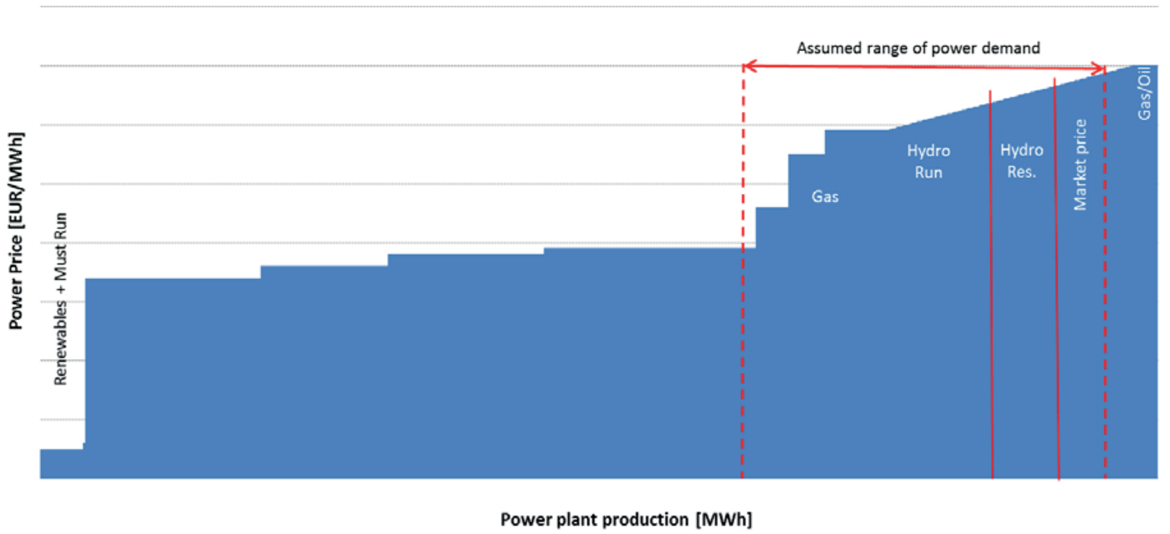

Figure 2. Merit order list for a power system

For power plants on the MOL, the general rule is that the electricity should be imported if the market price is lower than the production cost of additional MWh. It is used for economic optimization of the power plant schedule (considering the above mentioned criteria). Another problem is how to valorize production for hydro power plants (HPP). There are two categories, run-of-river and storage HPP. Run-of-river power plants must produce energy depending on water inflows due to inability to store water. The value of this energy can be evaluated by the current market price. Unlike run-of-river power plants, storage HPP can produce energy at the time of arrival of water inflows and sell it at the current market price or store water in reservoirs and produce energy at another point in time when the market price is estimated to be higher. One way of valorizing the price of energy produced from HPP is presented in paper [1].

However, all criteria in portfolio management don't have equal importance; there are parts of production that are not included in the economic criterion. Those parts are called must run units (MR). They include power plants that must remain in operation for the safety reasons. Power plants (that generate electricity for maintaining the stability of the transmission network) or a combined heat and power plant (CCGT) (which supplies a large population with heat while producing electricity as a derivative throughout the cycle) are included in the MR. Run-of-river HPPs can be added in MR since their exclusion from the production process can lead to unwanted overflow. Renewable energy sources (RES) are also MR because they belong to protected category of environmentally acceptable energy production and have an advantage over other energy sources.

Liberalization and restructuring of the electricity market introduced additional variables to production planning. Competition has brought in new opportunities in the power sector in terms of flexibility and possibilities for a more efficient planning, introducing increasingly complex market mechanisms such as cross-border capacities trading as well as volatile production from renewable energy sources. The primary focus of this paper will be the management of electricity produced in different market scenarios. The analysis will be performed on the data for South Eastern Europe (SEE), characterized by a large share of HPP with seasonal production characteristics. The actual data will show cases of extreme market deviations accompanied by descriptions of the conditions under which they occur. The first two chapters describe the power characteristics of the SEE. Afterwards, different hydrological scenarios will be analysed as well as their impact on price movements in power markets. Analysis will show the risks that occur in the SEE power sector.

2. ENERGY CHARACTERISTICS OF SEE REGION

The SEE Region consists of the following countries: Slovenia, Hungary, Croatia, Bosnia and Herzegovina, Serbia, Bulgaria, Romania, Macedonia, Albania, Montenegro, Kosovo and Greece. Some of those, formed by a disintegration of larger countries, have power systems developed for energy needs of their former countries. Today, these countries are independent facing the consequences of their historical development. GDP per capita ranges from 3.800 USD to 24.500 USD. GDP has fallen compared to 2011 for all countries in the region [9]. Development of new projects in those countries has been further reduced by the economic crisis as well as the socio-economic situation and the economic decline, which caused a further reduction in foreign investment due to financial instability and indebtedness. The economic structure of the countries in the region is shown in Figure 3. There is equal ratio between high, medium and low developed countries.

Figure 4 shows the monthly load dynamics in the region during the 2012 and the average daily load. Total load of the region in a year amounted to about 227 TWh [12]. Annual load ranges from 1,9 TWh in Montenegro to 53,8 TWh in Romania. Load value is highest in winter, a little lower in summer and lowest in spring and autumn. Changes in load during the year depend on weather conditions, temperature and the length of day. During the last decade, summer consumption increased, which can be explained by low prices of cooling systems, and partly by tourism, as some countries have sea access. The exceptionality of the load in 2012 was in February. Extremely low temperatures have resulted in a deviation from normal load values, i.e. in load reduction compared to January. The impact of such "anomaly" will be analyzed in detail in later chapters.

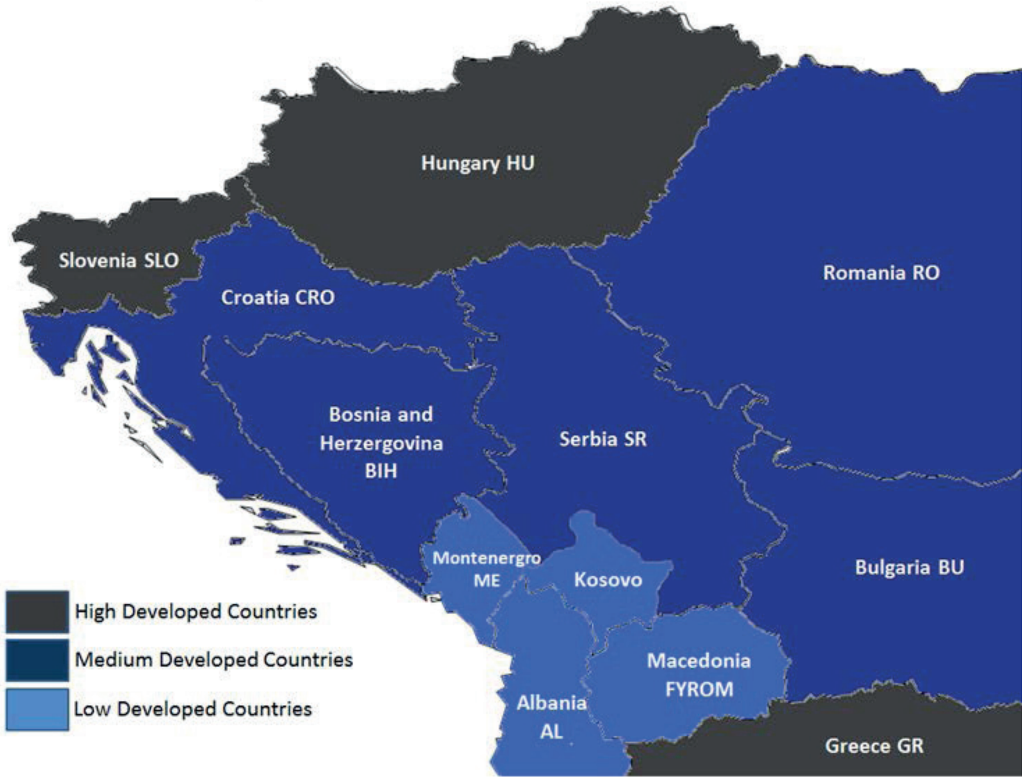

Figure 3. Economic characteristics of the countries in the SEE region

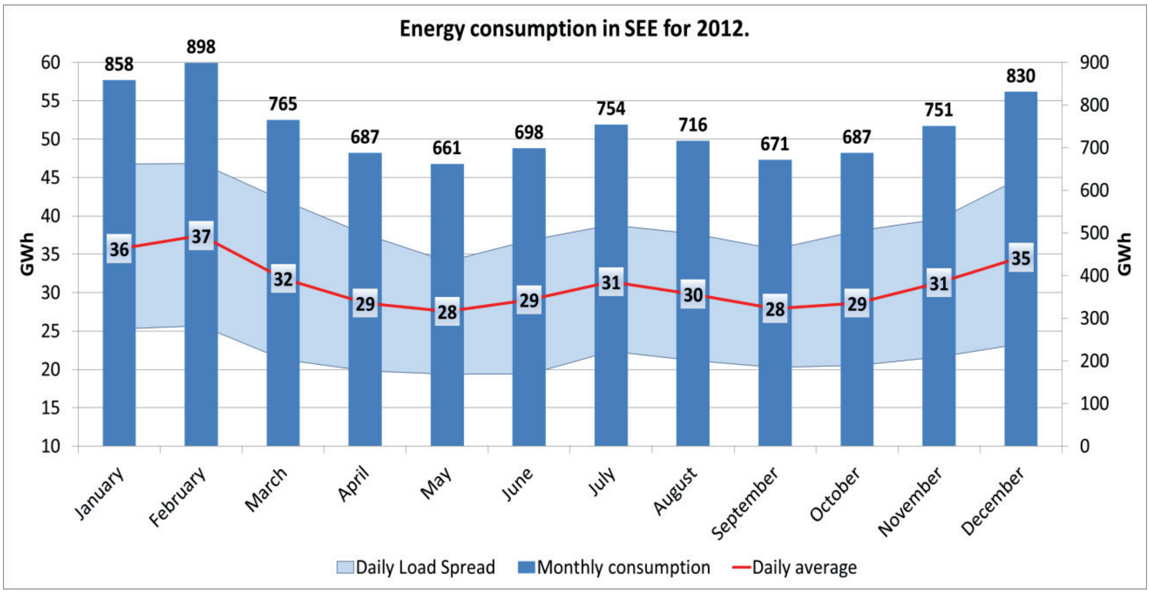

Figure 4. Load dynamics in the SEE region - 2012

Maximum hourly demand of 47 GWh/h in the region in 2012 was on February 2nd (19th hour). Minimum hourly load of 19 GWh/h was recorded on May 1st (6th hour). Those are the days with maximum (984 GWh) and minimum (571 GWh) regional daily loads in the year. During the winter, the peak load is usually achieved earlier (19th hour), and in the summer, the peak load occurs during later hours (22th hour) because of a longer day.

The average load curve is the mean hourly value of load in the 2012. Table 1 shows the minimum and maximum values of the average load curve by countries.

Table I. Load parameters in SEE for 2012.

Load (MWh/h)	RO	GRE	SER	HU	BUG	CRO	BIH	SLO	MK	MNE
Min daily load	5.122	4.490	3.415	3.406	3.382	1.377	1.043	1.061	751	339
Max daily load	6.865	6.906	5.279	4.881	4.881	2.315	1.652	1.579	1.100	516
Ration max/min	134%	154%	155%	143%	144%	168%	158%	149%	146%	152%

Also, the percentage difference is shown between the maximum and minimum load value (percentage describes load growth during the day compared to the night). Smaller increase is desirable, because high differences between a nightly minimum and a daily maximum can cause problems for the power system management. For example, in Croatia, for a nightly load of 1.300 MWh/h, it's necessary to have an additional average production of 1.000 MWh/h, of which a large part of power plants would have to work only a few hours a day. This kind of load curve would be covered by import. Romania is in the most favourable situation since it does not need to activate a lot of peak power plants and is in a better position to plan the power system production.

Table II. Share of installed power capacity in SEE for 2012.

Country	HPP (%)	NPP (%)	TPP (%)	RES (%)	Sum (MW)
Romania	33%	7%	49%	11%	17.750
Greece	22%	0%	66%	12%	16.499
Bulgaria	23%	16%	52%	9%	12.167
Hungary	1%	23%	71%	5%	8.775
Serbia	35%	0%	65%	0%	8.179
Croatia	48%	8%	39%	5%	4.267
BiH	52%	0%	48%	0%	3.700
Slovenia	46%	9%	43%	2%	3.656
Albania	91%	0%	6%	3%	1.570
Macedonia	41%	0%	57%	2%	1.409
Montenegro	75%	0%	24%	1%	882
SEE	30%	8%	55%	7%	78.855

Table 2 shows the installed power capacity (according to data collected from all available sources: power system operators, market operators, owners of power plants) in the region. Total installed capacity is 78,86 GW, of which a share of nuclear power plants (NPP) is 8%, thermal power plants (TPP) 55%, hydro power plants (HPP) 30%, with annually more installed capacities that use renewable energy sources (RES) which 2012 had a share of 7%. The highest share of renewable energy sources is installed in Greece (12%), the smallest in Serbia and BIH. NPP plants are installed in 5 of the 11 countries. Variety of installed power sources is essential for any power system. Albania is a country that is almost entirely dependent on the hydrological situation and has 91% of its installed capacities in HPP, Montenegro 75% and around 50% in Croatia, BIH and Slovenia. These countries are hydro dependent and in case of dry periods they have to import electricity. TPP share is the largest in Hungary, 71% of total installed capacity, 66% in Greece and 65% in Serbia while about 50% TPP is used in BIH, Bulgaria, Romania and Macedonia.

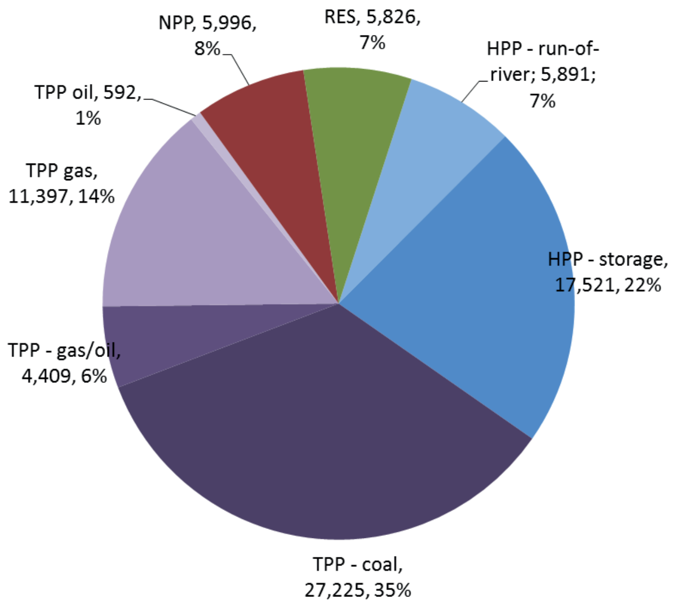

Figure 5. Installed production capacities in the SEE region 2012

From installed TPP, 62% are coal-fired, 26% gas-fired while the other TPPs use crude oil (older TPPs) and TPP that are either gas or oil-fired (can run on both fuels and are older and usually less effective). Coal can be declared as the most important energy source, because coal-fired TPPs amount to 35% of the total installed capacity in the region. Of installed HPPs, a quarter of them are run-of-river, while others are HPPs with storage.

Engaging the production of electricity from a specific source depends on its technical and financial characteristics. NPPs and coal-fired TPPs have low variable costs and thus are technically designed as baseload power plants. Gas-fired TPPs have higher variable costs, but due to their flexibility and fast start-up time they are used for the regulation of power a system. RES are the most variable sources of electricity because they depend entirely on the weather. HPPs, whose share of installed capacity is approximately 30%, also depend on the weather, but because of the seasonality of hydrological phenomena their production can be stochastically predicted and in that way are maneuverable. Given the large share of HPPs and RES in the region, it can be concluded that the region is exposed to a high risk of extreme weather conditions (drought/extremely high precipitation level).

When the country cannot produce sufficient electricity to meet demand, it is necessary to import it. Usually, electricity is traded bilaterally or through power exchanges. Trading may be a few hours up to several years in advance. Countries that can't meet the demand by their own production usually conclude an annual contract. Any surplus or shortage of energy is traded on daily, weekly or monthly bases. With development of the electricity market in the region, the amount of energy traded on power exchanges is constantly growing and bilateral trade is decreasing. There are three power exchanges in the SEE region: OPCOM (Romania), Southpool (Slovenia) and HUPX (Hungary). Volume traded on OPCOM in 2012 averaged to 1.120 MWh/h (total: 10,7 TWh), on Southpool 500 MWh/h (total: 4,4 TWh) and on HUPX 720 MWh/h (total: 7,2 TWh). In summary, traded volumes on power exchanges represent 10% of the total load in the region. At the end of 2012 HUPX expanded (by Hungary) in Slovakia and the Czech Republic ("Market coupling"), leading to an increase in trading volume, which at the beginning of 2013 amounted to more than 1.000 MWh/h. By developing power exchanges, a further increase in trading volume is expected. Earlier, the SP connected to the Italian market resulting in the increase of the trading volume above 720 MWh/h. Before market coupling, trading volume on Southpool and HUPX was lower by 50%. Increased market liquidity resulted in more market participants turning to power exchanges since volatility of electricity prices is lower with increase in traded volumes.

For importing or exporting electricity into and out of the country it is necessary to ensure cross-border transfer capacity (CBTC). It is common for transmission system operators to have auctions for allocating CBTC on yearly, monthly and daily basis. Capacity auctions are called explicit auctions. As noted, power exchanges don't have to be related to a particular country and, in market coupling CBTC is already included in the price of electricity (implicit auction). Lately, auction platforms have been joining at explicit auctions. One example is the CAO ("Central Allocation Office") – currently organizes CBTC auctions for Slovenia, Hungary and Croatia (among many other countries in Europe). It is expected that in the future the CAO (or similar platforms) will organize auctions for even more countries instead of all operators independently running auctions. This allows a simpler and a more transparent trading. The main entrances to the region are borders of Austria with Hungary and Slovenia. These borders are particularly interesting since trade volumes range between 25.000 – 35.000 MWh/h on the German power exchange EEX, and the situation on that power exchange affects the prices on the power exchanges in the SEE region.

3. ELECTRICITY PRODUCTION IN SEE REGION

Energy position of the SEE region over the last five years is shown in Figure 6, which endorses the aforementioned quantitative risk associated with the HPP production. In overall, 2012 was an extreme year, which means that it alternated periods of extreme drought and above-average precipitation as well as periods of extreme temperatures.

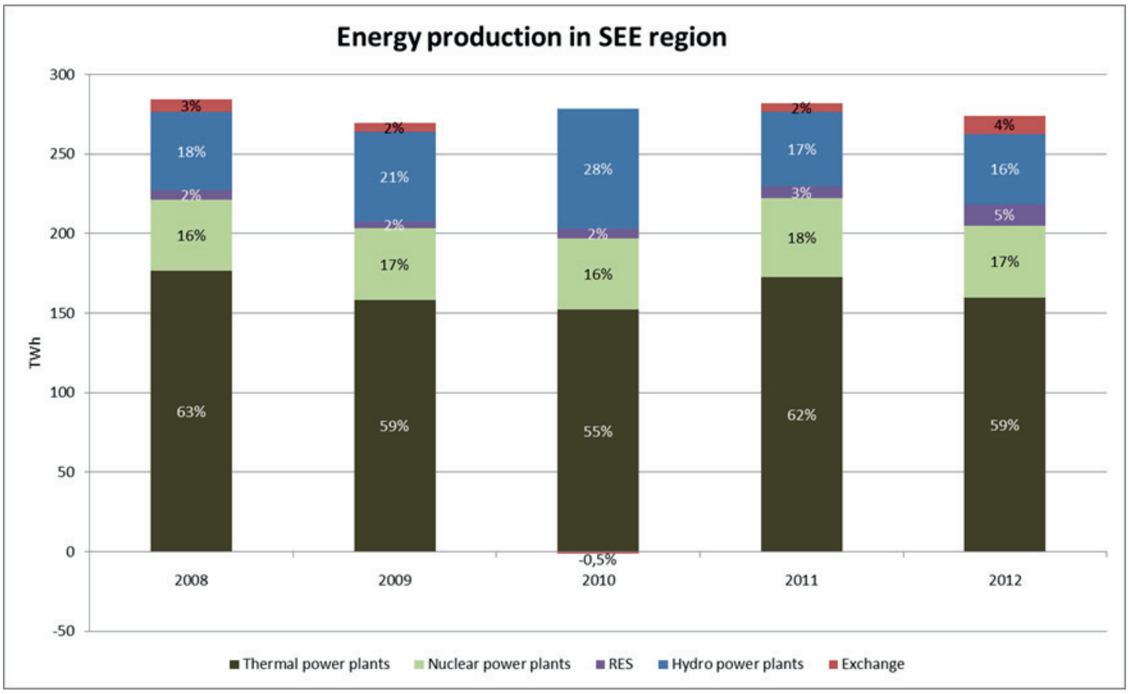

Figure 6. Production in the SEE region 2008 to 2012.

HPP production had significant variations (lowest production in the last 5 years was recorded in 2012). On the other hand, 2010 was a record year for HPP production and the region exported electricity. That year was followed by the unfavorable hydrological period (2011) which extended early 2012. For comparison, the production of HPPs in 2012 was up to 4 TWh lower on a monthly basis than the production in 2010. As a result, the increase in imports occurred in the region at a total of 5% (the largest volume of imports in the last 5 years).

HPP production in the region in the first quarter of 2012 was the lowest for that period in the last 15 years [10]. Although hydrologically just a little weaker than the 2011, another unfavorable circumstance was an unusual cold in early 2012 (February 2012 temperatures were below -25°C). This period recorded a high production of TPPs, which on a monthly basis amounted to 16 TWh, representing about 63% of a total share in covering the load diagram. In February, production of storage HPPs increased due to an increase in market prices. Because the import is limited by CBTC, all available sources of electricity were used to cover an extremely high load. Some countries in the region were forced to put their TPPs with lower efficiency into operation, in order to cover their electricity needs. Adding import to that amount, it turns out that 69% of the load curve was covered with TPP production and imports.

The HPP production covered only 16% of the total load. Throughout the spring, run-of-river HPPs increased their production, but because of the maintenance of TPPs and NPPs, imports continued to cover a large part of the load in the whole region. After extremely cold winter and poor hydrology, came a period of extreme heat (temperatures over 40°C). During this period, the HPP production is low and countries again turn to import and production from expensive TPPs, which together reached 64% of the total load. As the year went by, the hydrological conditions improved and the total load was lower than previous years. The region was able to recover and even achieve above-average HPP production (last 5 years). Increased hydrology caused a decline in imports, especially in November. Last quarter was marked by the highest production from RES, primarily from wind power plants (30% of annual production).

Production by sources (GWh) for the region in 2012 is given in Table 3. Share of coal TPPs reached 45%. Other TPPs have participated with 13%, NPPs with 17% and HPPs with 16% also participated in covering the load diagram, while the RES have participated with the 5%.

Table III. Production in the SEE region by sources

TPP				HPP		RES			NPP	Exchange
159.766				44.016		11.489			45.297	11.571
Coal	Gas	Oil	Gas/oil	Storage	Run of river	Wind	Biomass	Solar		
122.617	29.955	385	6.809	22.798	21.219	8.091	1.977	1.421		
45%	11%	0%	2%	8%	8%	3%	1%	1%	17%	4%

As mentioned in the previous chapter, the share of HPPs is 30% of the total installed generating capacity in the region, which is explained by the fact that the whole region has a great hydropower potential. Large rivers combined with natural and artificial lakes make this region very suitable for the construction of HPPs. Five countries have the largest share of installed capacity in HPPs. Figure 7 shows the dependence on energy production from HPPs over the last five years and how the influence of hydrology reflects on energy import into the region. It is obvious that 2008, 2009 and 2011 were years with the average hydrology with fluctuations through various periods. Import to the region had a share from 1,9 to 3% in covering the total load of the region. To understand this dependence, it's necessary to while the total exchange was negative, which means that consider years with very wet and very dry hydrology. Production of HPP plants in the region in 2010 totalled to 75,51 TWh the region exported electricity [11]. Just two years later, production was as much as 30 TWh lower, thus automatically making countries in the region importers of electricity.

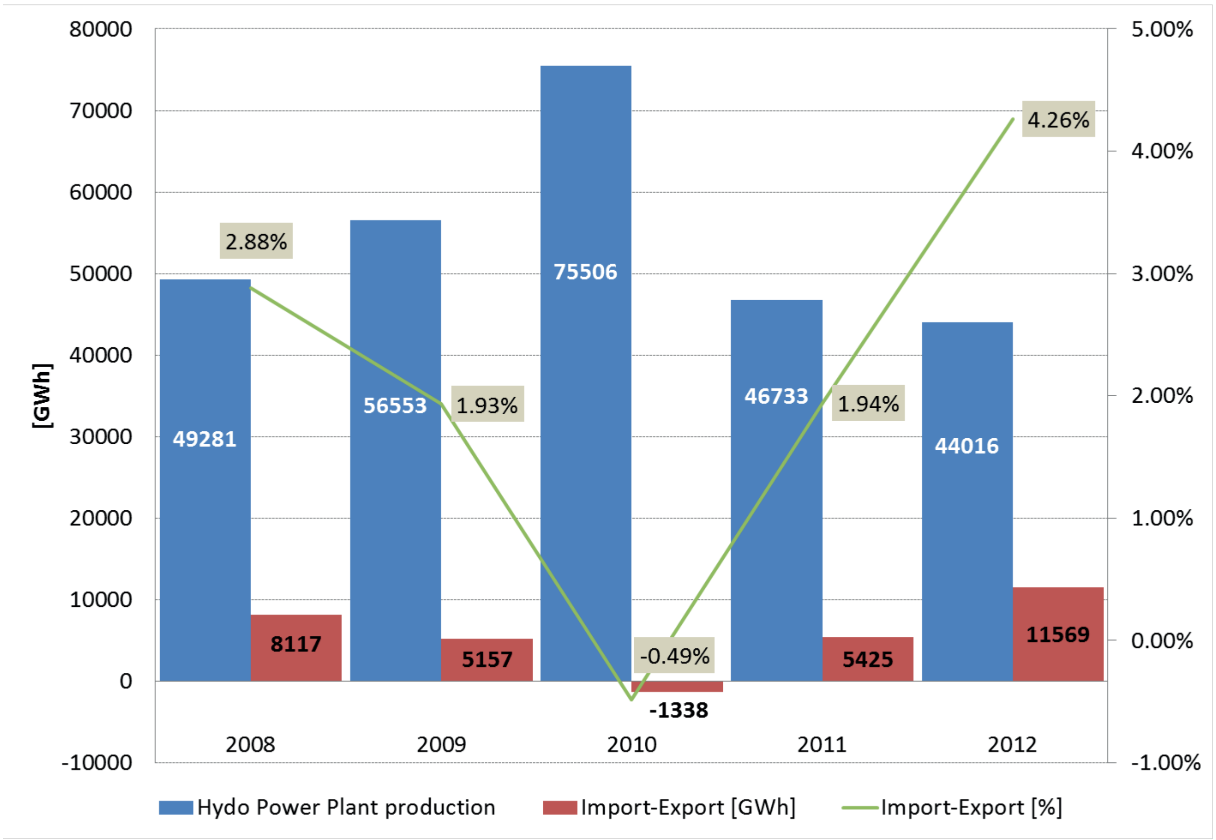

Figure 7. Dependence on hydropower production

Good hydrological conditions in 2010 had the biggest impact in Bulgaria, BIH, Romania and Albania as these countries ended the year as exporters of electricity, while Slovenia, Montenegro and Serbia were very close to becoming one. Two years later the situation in the region turned upside down. Despite the long drought through 2011 and 2012, the only countries that were net exporters at the end of year were Bulgaria and BIH. It is interesting to note that Albania, a country which production capacity is 91% in HPPs, in 2010 had a total export of 730 GWh, and a year later imported 3.167 GWh. Even Hungary, a country whose HPPs account for only 1% of total production capacity, failed to become an exporter of electricity, regardless of the 71% share in TPPs, due to problems such as the cost of fuel, maintenance, outages, load etc.

Share of import in the region's total electricity consumption in 2012 was 4,25%. This percentage averaged to about 5% in the first nine months, but as already mentioned, extreme hydrological conditions in the last quarter greatly reduced this percentage. The largest import was in February (6,3 %), and the lowest in November (1,6 %) of the total load curve.

On hourly basis, in 2012 the region imported 61,6% of the time, and exported 38,4% of the time. If we observe only the installed power, all countries except Macedonia (no data for Kosovo) had enough of their own generation capacity installed to cover peak loads in 2012. However, unavailability of generating units (failures, maintenance) and the need capacity margins in the power system must be taken into account in production process. Serbia would need 93% of installed capacity to cover peak load, Albania 82%, Montenegro 80%, and Croatia 75% [12]. Most countries in the region were dependent on import due to unfavorable conditions. Some countries have achieved a record of their peak loads. For example, in Croatia the maximum peak load amounted to 3.193 MWh/h. For comparison, in 2013 the maximum peak load in the same period amounted to 2.813 MWh/h, which is a big difference on an hourly basis. Among the countries in the region, only Bulgaria was independent from import throughout the year. Bosnia and Herzegovina was also an exporter at the end of the year, thanks to its HPP production, which totalled to more than 1 TWh in the last quarter of the year. Other countries that were exporters in certain months were Serbia, Slovenia, Romania and Croatia (if NPP Krško does not count as import since its 50% is owned by Croatia and located in Slovenia), while net importers were Macedonia, Greece and Hungary.

4. SIMULATION

Considering the structure of the installed HPPs in the region, it is important to notice how their production affects the market trends in the region. Weather conditions that affect the HPP production are stochastic and are very hard to predict. Based on available data for the past 17 years [10], Figure 8 shows the distribution of HPP production. It is interesting to note in Figure 8, that there are two ranges of production which cover about 82% of the production value (54-65 TWh) which means that the average annual production may only exceed the mean value about 18%.

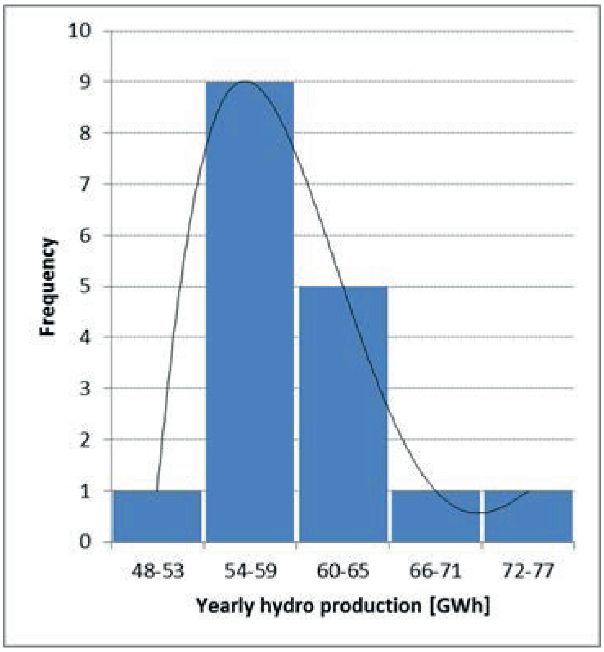

Figure 8. Distribution of HPP production

Hydrology in the region is seasonal, which is shown in Figure 9. (statistics for the past 17 years [10]). The range is higher in the first and fourth quarter of the year (production depends mostly on precipitation), and the middle of the year depends more on the snow from the mountains melting and the use of reservoirs. Average HPP production in 2012 was 13% lower than the mean value. Especially critical was the first quarter in which the lowest production in the last 17 years was recorded.

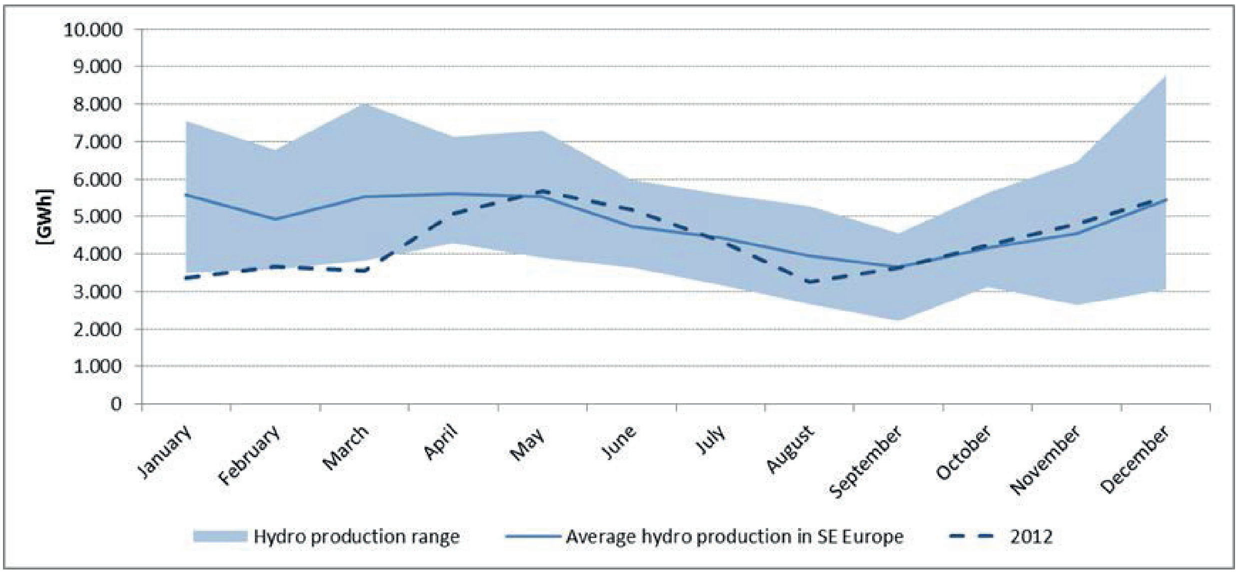

Figure 9. The range of monthly HPP production in the SEE region

Considering this fact, simulations of market price trends depending on the variable costs of TPPs and HPP production are shown below. To confirm the hypothesis about the high influence of hydrology on price movements in the region, the 2012 data will be used.

To prove the impact HPP production on the electricity price on the market, a fundamental analysis is made, which is based on the merit order list (MOL) with average production price for available power plants in the region. When creating the MOL and calculating the cost of production from individual power plants, some of the assumptions shown in Table 4 are taken into account. Fuel prices are taken according to data from [13], assuming that the fuel purchased is 70% from long-term contract and 30% from short-term contract, so that the prices have been assumed as a weighted percentage of forward and spot contracts**.**

Table IV. Assumed characteristics of TPP and fuel prices

Fuel	Power Plant Efficiency	Fuel Caloric Value	Fuel price
Coal	(35-41)%	24.800 kJ/kg	(85-120) USD/t
Gas	(41-59)%	33.338 kJ/m^3	(28-34) EUR/MWh
Crude Oil	(25-35)%	39.774 kJ/kg	(100-116) USD/bbl

Figure 10. shows the achieved balance by countries in the region for 2012. The most volatile parameter was import, which in February was equal to the maximum possible value, while at the end of the year fell down to 4 times lower value

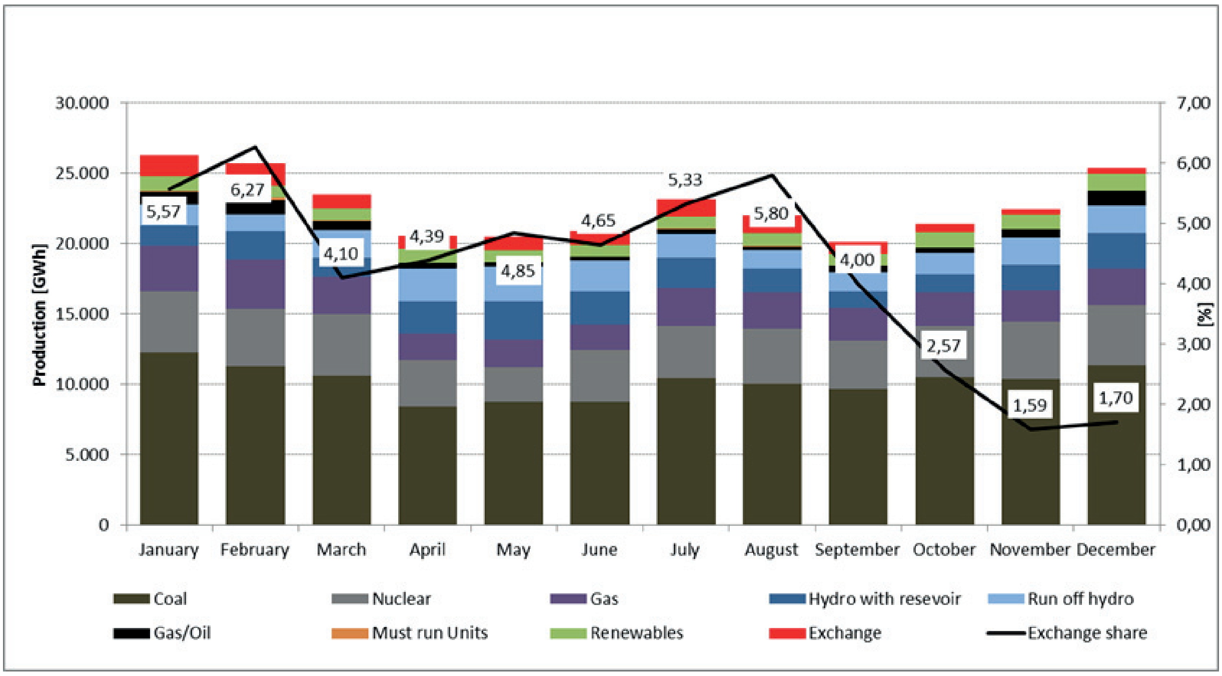

Figure 10 Energy balance - SEE region 2012

Import has a limit (like each energy source), while HPP production depends on water inflows and use of the reservoirs. Correlation between HPP production and share of import is shown in Figure 11.

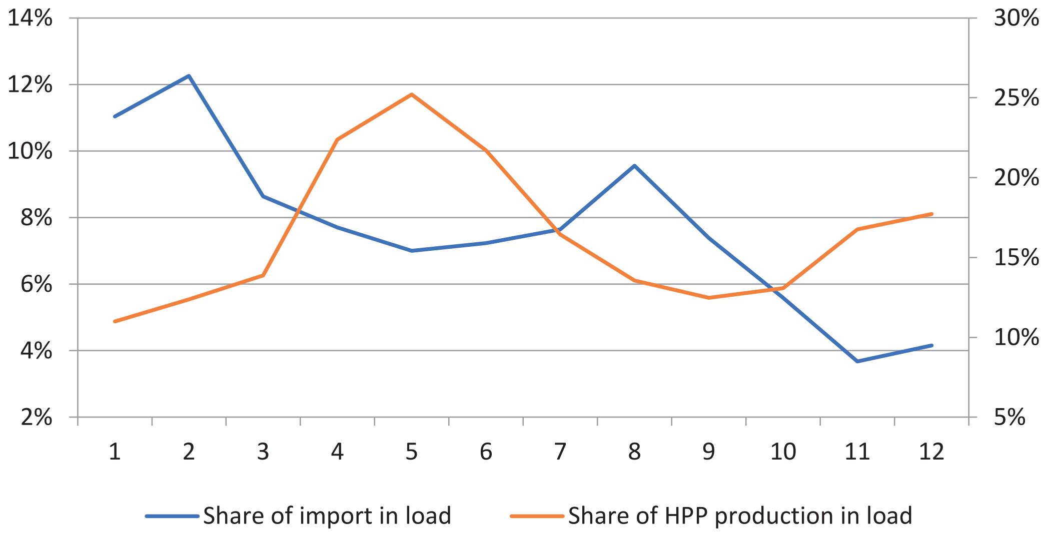

Figure 11. Correlation of share of HPP production and import volumes

HPP production ranges from 2.500 GWh to 5.000 GWh per month. As mentioned in previous chapters, reduced HPP production directly affects the increase in imports and vice versa. Regarding prices, market position of the SEE region depends heavily on the production of HPPs (as well as the load). Market players are well aware of the situation in the power systems of the region and they try to take advantage of their position. For example, if it is evident that the HPP production is (or will be) below the average, it is expected that the market will react (maybe more than it really should), and market players will try to make a higher profit. February and November will be specifically analyzed (February as a month of a very high load and low hydrology and November as the month of a lower load and high hydrology).

Two selected months have been observed because they were completely opposite (hydrologically). All mentioned conditions have had great impact on the electricity price on the market (caused by changes in price of producing additional MWh). Marginal cost of production (MOL) for February 2012 is shown in Figure 12.

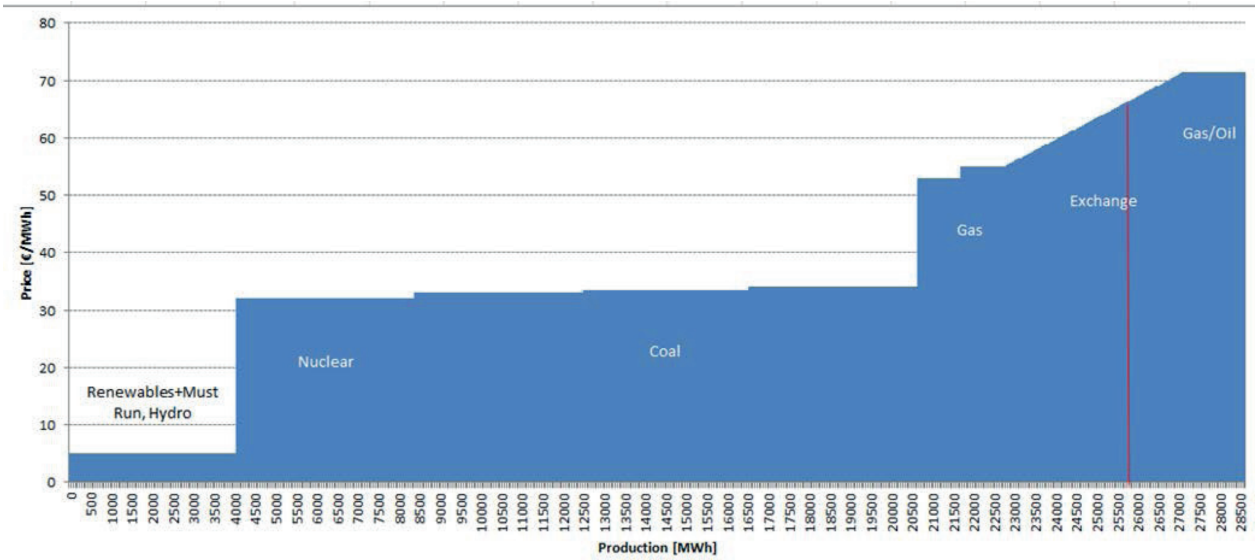

Figure 12. MOL for the SEE region - February 2012

MR power plants for February are renewable energy sources, run-of-river HPPs and CCGTs. NPPs are the cheapest ones and therefore are used as baseload power plants (98% of installed capacities in operation). Coal-fired TPPs have a slightly higher price of production and 80% of maximum possible capacities were in operation. From other TPPs, only inefficient and the most expensive ones weren't in operation. Gas-fired TPPs are considerably more expensive than coal-fired TPPs (depending on the efficiency of the plant and the price of fuel). One part of gas-fired TPPs were in the must run category, while the other part was in operation because the price of production was similar to the market price. The gap between the cost of production of gas-fired TPPs and the price of producing additional MWh (mostly gas and crude oil-fired TPPs) is filled with import at a corresponding price.

Regions dependence on import caused price movements: an increase in the CBTC price (import in the region) and the price on the power exchanges. The red vertical line in Figure 12 indicates the total load of the SEE region in February. The level of load directly affects electricity price. Higher load means that red line goes more to the right on the MOL. As a result, price determined with MOL is higher (possibly affecting market price). In addition to these reasons, unfavorable situation in the region suggests the same situation in the rest of Europe. Energy (outside the SEE region) is practically produced from expensive sources and therefore the import has to be more expensive. Cost of additional MWh was around 70 EUR.

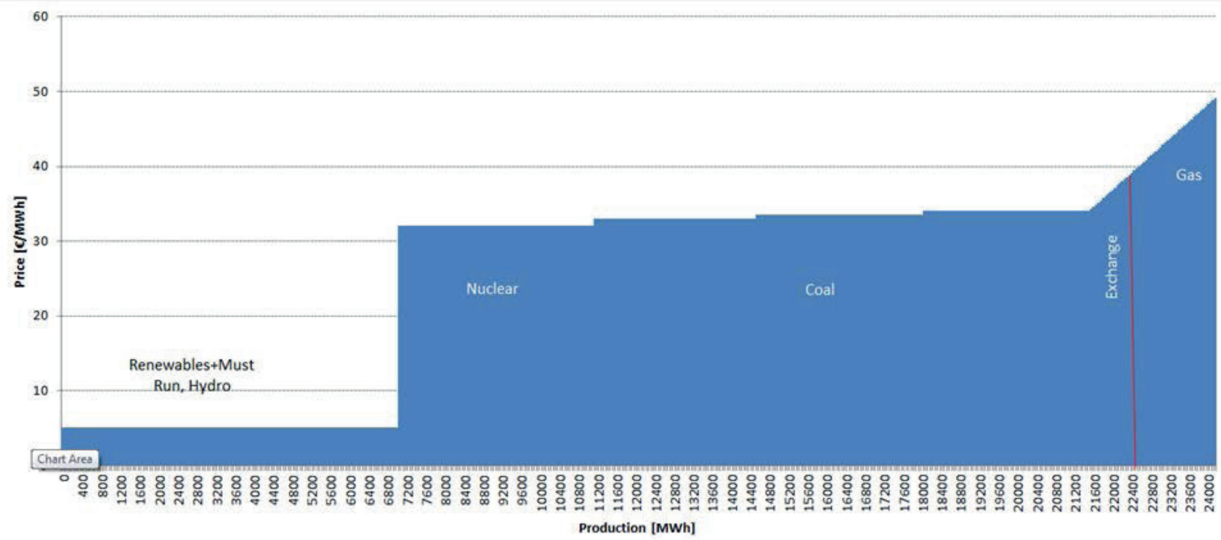

Figure 13. MOL for the SEE region - November 2012

In November, total load was 13% lower than in February (below average for that month) [12]. The same power plants as in February were used as MR. Production of run-of-river HPPs increased by 65% (storage HPPs produced 9% less), while the total HPPs produced 20% more energy. The assumption is that all reservoirs were filling up as they entered the rain season almost empty. The plan was to fill reservoirs to a certain limit and have that energy available later on. Expensive power plants were not in operation (reduction of gas-fired TPP production by 38% and gas/oil-fired TPPs by 40% compared to February). As a result there was a change in the market - the region could meet its energy demand (changes which market players were well aware of). Also, favourable hydrology in the region indicates that in other parts of Europe the situation is also improving which could affect the price as well (as in February). The result is a reduction in imports to 1,6% of total load, and a very large reduction in the price on the market (to less than 40 EUR/MWh).

Determination of the price with different graphical and computational methods led to the following results shown in Figure 14. The red curve represents the weighted price of three power exchanges in the region and a blue line represents calculated price of the merit order list. The price of electricity import practically depends on the possibility to cover the load in the SEE region, which is directly related to the HPP production.

Figure 14. Correlation of market and MOL price

5. CONCLUSION

This paper shows that although energy balance in the SEE region depends on global energy trends and market prices in the rest of Europe, hydro production has major impact on energy balance of the SEE region. The SEE region has necessary installed production capacities to cover the load from various power sources, but part of the power plants are old and with low efficiency. These factors directly influence the high price of energy production for the SEE region. The price of producing an additional MWh which is related to the market price can be determined with the merit order list. The arrangement of power plants depends on their production availability and the power system requirements. This paper has shown that good hydrological periods result in increases hydro production in the SEE region, reducing the electricity prices on energy markets. On the other hand, dry periods mean lower share of hydro production, which results in increased imports and prices on energy markets.

The solution to short-term planning can be found in further development of the electricity market, by increasing the amount of trading volume on the power exchange. Additional products like long-term contracts with and without physical delivery and options could reduce the existing risks. Combination of different contract types could decrease the exposure to statistically hardly predictable circumstances caused by weather conditions. With a rising share of renewable energy sources, the SEE region will become even more exposed to risk of weather dependent power plant production. Regional energy exchange might be one of the solutions for incoming challenges.

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