Balkans and Regional Energy Market Partnership Program: PSSE/OPF Regional Model Construction Report

Black Sea Regional Transmission Planning Project Phase III
Cooperative Agreement EEE-A-02-00054-00

September 30, 2012

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Black Sea Regional Transmission Planning Project Phase III

Prepared for:

United States Agency for International Development
and United States Energy Association

Cooperative Agreement EEE-A-02-00054-00

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ABBREVIATIONS

General
TSO - Transmission System Operator
TEN-E - Trans-European Energy Networks
CIGRÉ – International Council on Large Electric Systems
UCTE - Union for the Coordination of Transmission of Electricity
ENTSO-E – European Network of Transmission System Operators for Electricity (former UCTE)
ACER - Agency for the Cooperation of Energy Regulators
NRA - National Regulatory Authority or Agency
IEM - Internal Energy Market
REM - Regional Energy Market
LOLE - Loss of Load Expectation
SAF - System Adequacy Forecast
SoS - Security of Supply
VOLL - Value of Lost Load
ETS - Emission Trading System
EWIS - European Wind Integration Study
CENTREL - Association of TSOs of Czech Republic, Hungary, Poland and Slovakia
SEE - South East Europe
SECI - South East European Cooperation Initiative
BSTP - Black Sea Transmission Project
FIT - feed-in tariff
LF - Load flow
OPF - Optimal power flow
FGC, UNEG – Federal Grid Company, Unified National Electric Grid
IPS/UPS – Interregional Power System/Unified Power System

Transmission
AC - Alternating Current
DC - Direct Current
HV - High Voltage
MV - Medium Voltage
LV - Low Voltage
HVAC - High Voltage AC
HVDC - High Voltage DC
EMF - Electromagnetic Field
ED - Electricity Distribution
SS – Substation
OHL - Overhead Lines
UC - underground cable
SC - submarine cable
TR - Transformer
OLTC – On Load Tap Changer
PST - Phase Shifting Transformer
SCR – Short Circuit Ratio
ESCR – Effective Short Circuit Ratio

CCT – Critical Clearing Time
LCC - Line Commutated Converter
FACTS - Flexible AC Transmission System
VSC - Voltage Source Converter
STATCOM – Static Synchronous Compensator
NTC - Net Transfer Capacity
TTC - Total Transfer Capacity
TRM - Transmission Reliability Margin
RC - Remaining Capacity
RAC - Reliable Available Capacity

Generation
HPP – Hydro Power Plant
PHPP – Pumping Hydro Power Plant
TPP – Thermal Power Plant
NPP - Nuclear Power Plant
CCGT - Combined cycle gas turbine
CCS - Carbon Capture and Storage
CHP - Combined Heat and Power Generation
RES - Renewable Energy Sources
NGC - Net Generation Capacity
VAR - Volt-Ampere-Reactive, reactive power
BTU - Brithish Thermal Unit = 1055J = 0.293Wh = 252cal, mBTU = 1000000BTU
tcm - thousand cubic meter $1000m^3$
RGC – Regional Generation Company
TGC - Territorial Generation Company
WGC – Wholesale Generation Company

Countries

	ISO	Country	Car
Austria	AT	AUT	A
Albania	AL	ALB	AL
Bosnia and Herzegovina	BA	BIH	BiH
Bulgaria	BG	BUL	BG
Croatia	HR	CRO	CRO
Germany	DE	GER	D
Greece	GR	GRE	GR
Hungary	HU	HUN	HU
Italy	IT	ITA	I
FYR of Macedonia	MK	FYRM	MAK
Montenegro	ME	MNE	MNE
Romania	RO	ROM	ROM
Serbia	RS	SRB	SRB
Slovenia	SI	SLO	SLO
Switzerland	CH	SUI	CH
Turkey	TR	TUR	TUR
Ukraine	UA	UKR	UKR

Armenia	AM	ARM	ARM
Georgia	GE	GEO	GEO
Moldova	MD	MLD	MLD
Russia	RU	RUS	RUS
Azerbaijan	AZ	AZB	AZB
Belorussia	BY	BLR	BLR

1 INTRODUCTION

The BSTP was established by the United States Agency for International Development, the United States Energy Association and the transmission system operators of the Black Sea region in 2004 to build institutional capacity to develop and analyze the region's first common transmission planning model. Members of the project working group represent the transmission system operators (TSO) of Armenia, Bulgaria, Georgia, Moldova, Romania, Russia, Ukraine and Turkey.

The Power System Simulator for Engineers (PSS/E) software was selected as the common planning software platform for the project. The project supplied each TSO with the software and has provided ongoing training in its use and application to build capacity in the region to construct national and regional models of the Black Sea high voltage electric power transmission network.

The BSTP Working Group developed the first detailed national and regional load flow and dynamic models of the high voltage network for the 2010, 2015 and 2020 planning horizons. These models are used to identify bottlenecks to regional trade of electricity; model the impact of the transmission network on energy security initiatives; determine the potential to integrate renewable energy resources; and identify network investment requirements.

Phase III of the BSTP is currently underway. The objectives of this phase of the project are to:

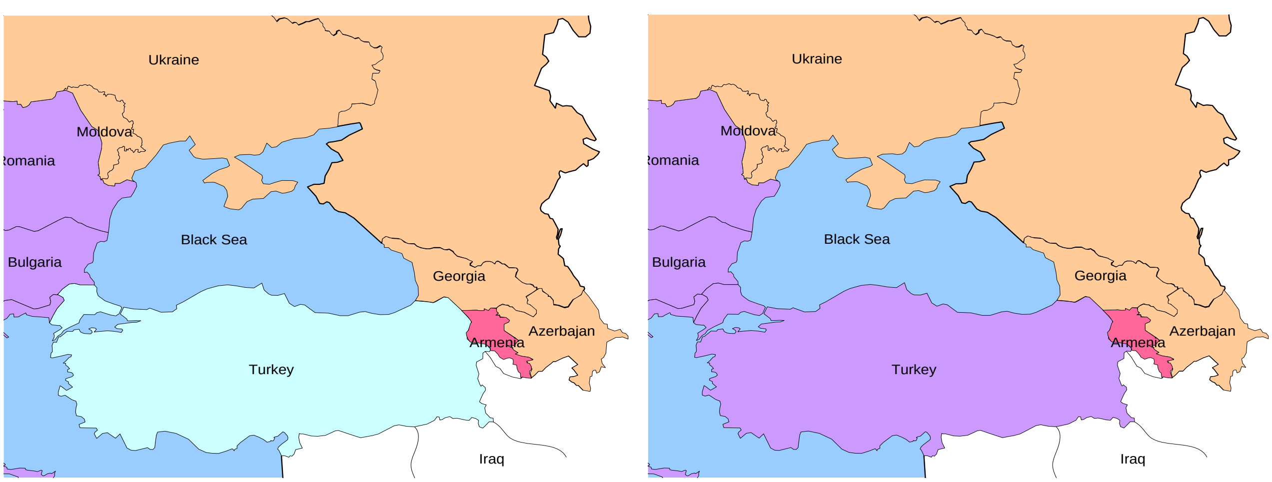
- Integrate projected wind, solar and hydroelectric generating capacity forecasted and being developed in Armenia, Bulgaria, Georgia, Moldova, Romania, Russia, Ukraine and Turkey into the regional models;
- Develop a cost based planning model of the Black Sea network using the Optimal Power Flow (OPF) feature of PSS/E that will simulate economic dispatch of the Black Sea generation fleet;
- Utilize the OPF model and its economic dispatch to determine the most likely trading patterns for 2015 and 2020, taking into account the integration of renewable energy generation capacity; and
- Test the transmission network using the OPF, load flow and dynamic models to determine its capacity to support trade under the most likely economically based trading scenarios.

To date, the project has collected and compiled renewable energy generation forecasts for each country and has published a complementary Renewable Energy Integration report. This report provides investors, regulators and policy makers with a summary of the renewable energy strategy for each country; renewable energy feed-in tariffs and other fiscal incentives offered; and interconnection procedures for renewable projects. Data from this report has now been used to populate the 2015 and 2020 OPF and load flow models to provide the most accurate estimates of renewable energy generation capacity available in the region.

Development of the OPF model marks a significant achievement and milestone for the regional TSOs and the BSTP. In previous phases of the BSTP, the models were used to evaluate system stability and reliability during one hour of a maximum or minimum load period. With the development of the generic cost curves and the regional OPF model discussed in this report, regional planners are able to simulate economic dispatch of the Black Sea generation fleet over the entire regional transmission network. With the inclusion of projected renewable energy generation capacity taken from the Renewable Energy report that complements this study, this model provides the most comprehensive simulation of the network available today. The addition of the OPF model to the suite of BSTP planning tools gives regional planners a platform to couple economic and efficiency parameters to reliability criteria for the first time. As such, it is following the path of regional planning efforts in North America and Europe, which have incorporated market based economic dispatch in their planning models as their electricity markets matured over time.

The goal of this Report is to review the initial OPF regional study methodology and results and to draw preliminary conclusions based on the predicted economic trade of electricity in this region. Figure 1.1 below shows existing interconnecting lines between the countries in the region and Figure 1.2 illustrates the evolution of synchronous operations in the region from 2010 through 2012. Currently Bulgaria, Romania and Turkey are synchronous with the ENTSO-E while Ukraine, Moldova, Russia and Georgia are synchronous within the IPS/UPS; Armenia is presently not synchronous with any of its BSTP neighbors.

Figure 1.1– Interconnection lines in Black Sea Region (status 2012)



2010 2012

Figure 1.2 – Black Sea region – synchronous operation

2 MODELING COST ASSUMPTIONS

In a previous phase of this BSTP project the regional 2010, 2015 and 2020 static and dynamic models developed by the TSOs revealed certain system deficiencies and weak points and quantified the fact that every TSO in this region has a surplus of energy. In this phase of the project, further analysis is performed to determine the capacity of the regional network to support enhanced trade and exchange of electricity while maintaining security and reliability and taking into account regional economic factors. For these studies new OPF national models were developed and were combined to create a regional OPF model for the planning years of 2015 and 2020. However, in this first attempt to use OPF to study economic trade on a regional level, this study and report are for 2015 summer and winter maximum hours.

In this study, power plant technology is differentiated based on the type of prime mover employed; fluid that moves a turbine that runs a generator that converts mechanical energy into electricity. The efficiency of a conversion process from fuel to electricity for fossil and nuclear fueled plants is quantified by the Heat Rate of the power plant.

The cost of production of electricity depends on numerous factors that are described as follows:

- **Overnight Costs**

  Overnight costs are the cost of a construction project if no interest is incurred during construction; as if the project was completed "overnight". An alternate definition is: the present value cost that would have to be paid as a lump sum up front to completely pay for a construction project. The overnight cost is frequently used when describing power plants. The unit of measure typically used when citing the overnight cost of a power plant is $/kW. For example, the overnight cost of a nuclear plant might be $1200/kW, so a 1000MW plant would have an overnight cost $1.2 billion.
- **Capital Costs**

  A power plant's capital costs include the purchase of the land the plant is built on, permitting and legal costs, the equipment needed to run the plant, the cost of the plant's construction, the cost of financing and the cost of commissioning the plant incurred prior to commercial operation of the plant. Unlike operating costs, capital costs are one-time expenses, although payment may be spread out over many years in financial reports and tax returns. Capital costs are fixed and are therefore independent of the level of output.
- **Operational and Maintenance Costs**

  Operational and maintenance costs include all costs that are a consequence of power plant operation during its operational life. These costs are usually divided into fixed and variable costs. Fixed costs are not dependent on operation of the power plant. These usually include labor used to run the plant and the labor and supplies needed for maintenance.
- **Variable Operational Costs – Fuel Costs**

  These costs include all costs related to production, primarily fuel and fuel transportation costs. Figure 2.1 below shows the recorded dependency of electricity costs on the fuel used for production from 1995 through 2010.

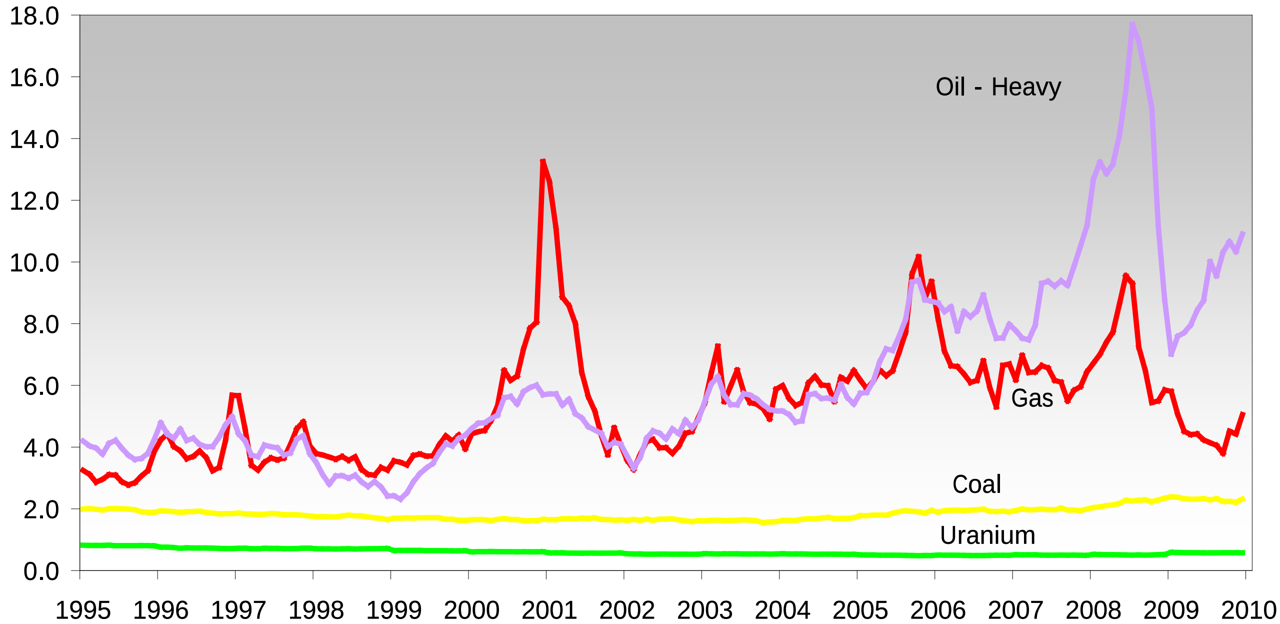


Figure 2.1– Electricity costs depending on Fuel ($/MWh)

- **Overhead Costs**

  Overhead cost refers to an ongoing expense of operating a business and it is usually used to group expenses that are necessary for the continued functioning of the business but cannot be immediately associated with the products/services being offered. Overhead expenses are all costs on the income statement except for direct labor, direct materials & direct expenses. Overhead expenses include accounting fees, advertising, depreciation, insurance, interest, legal fees, rent, repairs, supplies, taxes, telephone bills, travel, utilities costs and rent.
- **Decommissioning Costs**

  These costs are all costs that occur after power plant life time (dismantling, clearing the land, waste disposal…)
- **Transmission Costs**

  All costs associated with the connection of the power plant to the transmission grid such as connection lines and substations.

Using these definitions of costs, Nominal Costs for each cost category relating to each power plant type were developed. The term "Nominal Costs" relates to the estimated costs that will result when the power plant is operating at the nominal or most efficient operating point. When a power plant is not operating at its most efficient nominal output, the cost of generation is determined by the generation cost curves that have been developed in this BSTP project and are an important input to the OPF software. The construction of these generation cost curves and how they are utilized in this study is the subject of the next section of this report.

The following Table 2.1 presents the nominal costs data for each type of generating plant represented in this study.

Table 2.1 – Electricity production nominal costs by source

	CAPA CITY	HEAT RATE	EFF	UTIL	LIFE	ENERGY	OVER NIGHT	CAPITAL	O&M			OVER HEAD	DECO MMISSI ON	TRANS MISSI ON	CO2 EMIS.	LEVEL IZED COST	PRO DU CTIO N COST
									FIXED	VARIABLE	FUEL						
TYPE	MW	mBTU/ MWh	%	%	year	GWh	MI$/M W	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MW h	$/MW h	$/MW h	$/MWh	$/MW h
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
CONVENTIONAL																	
NUCLEAR	1000	10.4	40	90	40	7884.0	2.75	40.40	12.00	8.24	7.49	4.00	7.80	3.00	0.00	75.44	32.04
NUCLEAR	500	10.4	40	90	40	3942.0	2.75	40.40	20.00	8.24	7.49	4.00	5.20	3.00	0.00	80.84	37.44
COAL	1000	8.9	45	85	30	7446.0	1.70	26.40	8.00	39.34	30.26	4.00		3.60	12.00	93.34	63.34
COAL ADV	600	8.9	45	85	30	4467.6	2.00	31.10	11.00	34.80	30.26	3.50		3.60	10.50	94.50	59.80
COAL ADV CCS	1000	8.9	45	85	30	7446.0	2.30	35.80	12.00	36.31	30.26	3.50		3.60	5.00	96.21	56.81
HYDRO DAM	500			50	30	2190.0	2.20	58.20	3.50	7.10				5.70	0.00	74.50	10.60
HYDRO PENSTOCK	150			50	30	657.0	2.00	52.90	3.50	7.10				5.70	0.00	69.20	10.60
HYDRO RUN	150			50	30	657.0	1.20	31.70	3.10	7.10				5.70	0.00	47.60	10.20
GAS CCGT	786	7	58	85	25	5852.6	0.90	14.00	5.04	51.23	48.79	2.70		3.60	5.40	81.97	64.37
GAS CCGT NEW	786	6.75	58	85	25	5852.6	0.95	14.80	4.70	49.40	47.05	2.70		3.60	5.40	80.60	62.20
GAS CONV	160	10.8	40	85	25	1191.4	0.60	9.30	6.85	79.04	75.28	1.50		3.60	8.10	108.39	95.49
GAS CONV CHP	500	10.8	40	85	25	3723.0	0.93	14.50	5.51	79.04	75.28	1.50		3.60	8.10	112.25	94.15
GAS CONV CHP	50	10.8	40	85	25	372.3	1.20	18.70	7.25	79.04	75.28	1.50		3.60	8.10	118.19	95.89
GAS CONV CHP	10	10.8	40	85	25	74.5	1.25	19.40	8.33	79.04	75.28	1.50		3.60	8.10	119.97	96.97
RENEWABLES																	
SOLAR PV	5		45	21.7	20	9.5	6.00	365.50	6.40					13.00		384.90	6.40
SOLAR TH	100		45	31.2	20	273.3	5.00	211.90	21.80					10.40		244.10	21.80
GEOTHERMAL	50	34.6		85	30	372.3	1.70	26.40	22.90			3.50		4.80		57.60	26.40
BIOMASS	10	9.6		85	30	74.5	2.76	42.90	19.00	12.60		29.40		3.80		107.70	61.00
SMALL HYD. BASE	2	9.05		65	30	11.4	1.40	28.50	2.80	7.10				6.00		44.40	9.90
SMALL HYD. PEAK	1	10.07		65	30	5.7	1.65	33.60	2.80	7.10				6.00		49.50	9.90
WIND	50			30	20	131.4	2.00	75.50	11.70			6.10		8.40		101.70	17.80
WIND OFFSHORE	100			35	20	306.6	2.40	79.30	24.40			5.70		9.00		118.40	30.10

1 - Type of power plant
2 - Capacity
3 - Heat rate (nominal)
4 - Efficiency
5 - Utilization
6 - Life time
7 - Yearly Energy production
8 - Overnight costs
9 - Capital costs (20year loan, 10% discount rate)
10 - Fixed O&M costs
11 - Variable O&M costs (includes fuel costs)
12 - Fuel costs
13 - Overhead costs
14 - Decommissioning
15 - Transmission costs
16 - CO2 emissions (rate 20$/ton of CO2)
17 - Levelized costs = 9+10+11+13+14+15+16
18 - Production costs (related only to production) =10+11+13+14+16

All costs in table 2.1 are based on a 20 year payment period so that comparisons between different generation sources can be made. Capital costs are also calculated based on a 20year payment period and are not dependent on the age of the equipment. This means that for all power plants older than 20 years, capital costs are assumed to be zero. For power plants that are less than 20 years old, the annual capital costs are assumed to be the straight line depreciation costs taken over a 20 year period.

The data presented in table 2.1 is the foundation of this study because the generation cost curves used by OPF to produce these study results are based on these nominal costs and the calculated heat rates. Because these assumptions could be critical in determining the study results, the contents of the table 2.1 have been reviewed and approved by each TSO. In addition, it is planned that a sensitivity analysis will be performed to determine which assumptions have the largest impact on the study results. The subject of performing a sensitivity analysis is discussed in more detail later in this report.

3 GENERIC GENERATION COST CURVES

As mentioned above, a key input to the OPF model is a generation cost curve for each generator on the electric transmission system. These curves define the fuel costs at varying levels of generation output. For each type of power plant in the Black Sea region, appropriate generic generation cost curves have been developed based on typical technological characteristics. These generic cost curves have been implemented in the Regional OPF model after making adjustments according to available plant specific data.

Because generation cost curves are a critical input to the OPF software and yet TSOs do not have full access to all of the cost curve data, the decision was made to use Generic Cost Curves that were developed for various types and vintages of generating plants, taking into consideration differences in fuel characteristics such as the type of coal burned in the plant.

Generating costs are typically represented by one of the following four curve types: input/output (I/O) curve, fuel-cost curve, heat-rate curve or incremental cost curve. In the scope of this study, ***fuel cost curves*** are used which give the costs for a given production level Pg of the respective generating unit as show in Figure 3.1 below.

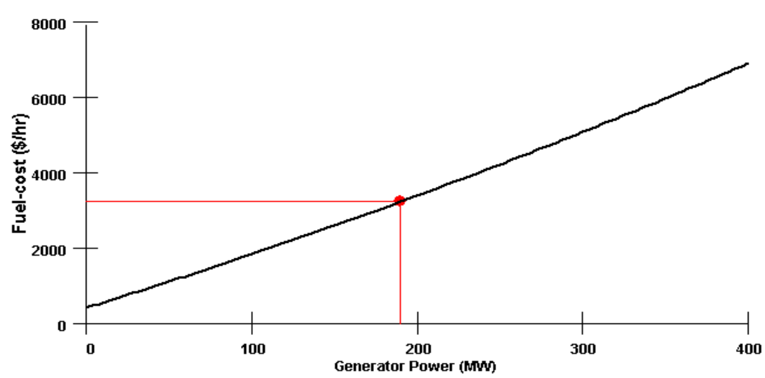


Figure 3.1 – Fuel-cost curve

In reality, generator cost curves are not smooth and in most cases are quite discontinuous. The most common way to handle this issue is to approximate the actual curve with a smooth, convex curve. This is done by using linear piece-wise smoothing functions where the entire curve is divided into linear sections as shown in Figure 3.2 below.

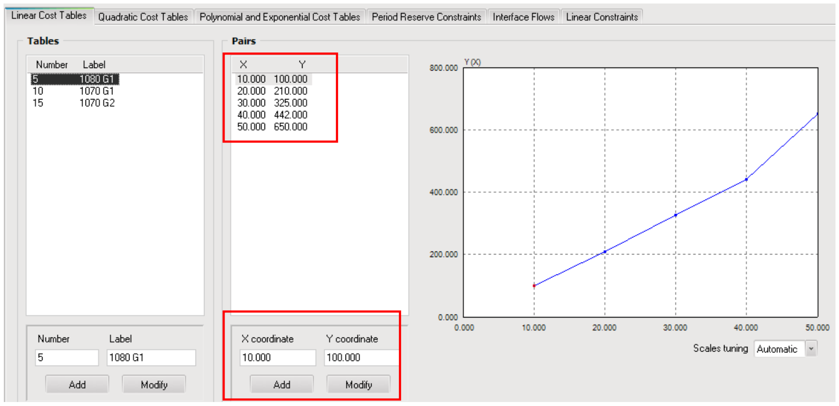


Figure 3.2 – Piece-wise linear cost curve

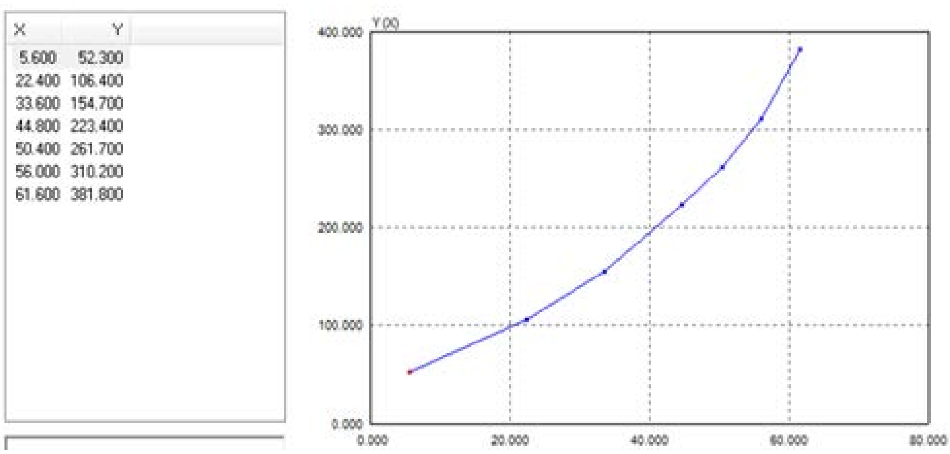
Data are entered in coordinate pairs (x,y) which define segments of the linear cost curve

- x: active power generation (MW)
- y: generator fuel cost ($/h)

Gen. Fuel cost = [Fuel Cost Scale Coef.] x generator fuel cost [$/h]

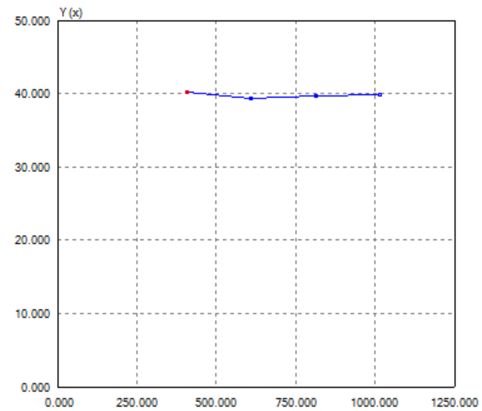
Actual generation cost curves developed and used in this study are provided in the OPF Final Report Annex for each power plant in each country. From this long list of generation cost curves, the following examples are presented:

Armenia – Cost curve and table for HPPs on Sevan-Hrazdan cascade



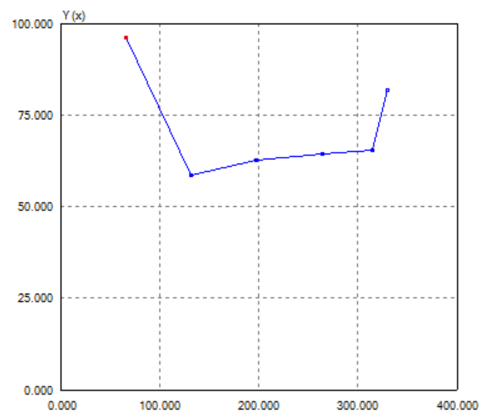
Bulgaria – Cost curve and table for NPP Kozloduy 1000MW units

X	Y
406.300	40.243
609.500	39.306
812.600	39.681
1015.800	39.868



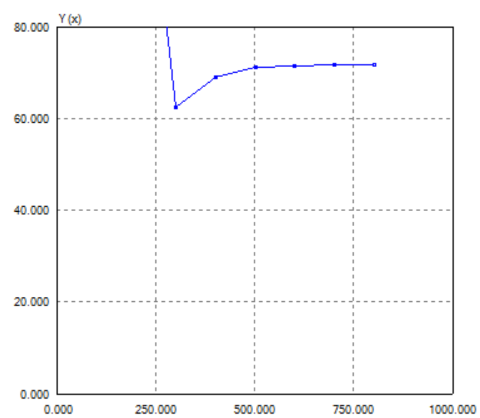
Romania – Cost curve and table for TPP Turceni, Rovinari, Isalnita

X	Y
66.000	96.171
132.000	58.671
198.000	62.671
264.000	64.271
315.200	65.397
330.000	81.727



Turkey – Cost curve and table for new CCGT Ada Pazari-Gebze

X	Y
200.700	139.199
301.100	62.316
401.400	69.059
501.800	71.222
602.100	71.320
702.500	71.578
802.800	71.743



4 OPF MODEL CONSTRUCTION

The Optimum Power Flow (OPF) feature of the PSS/E software is a powerful tool that all TSOs in the region use for transmission planning and to facilitate market based analysis. OPF solves optimization problems involving system operational costs, losses, system performance, system exchange opportunities and congestion management. It is important to understand that PSS/E and OPF are tools that study one snapshot hour at a time and that these study results are for a winter peak load hour and a summer peak load hour in 2015. The OPF regional model has been used in this project to calculate average generation costs in each country and to optimize those costs under various synchronous scenarios. OPF automatically adjusts the participating machines' active power generation, within capability limits, to reduce the total variable cost.

The OPF model data set consists of transmission network data and generation data. The transmission portion of the model consists of data describing network limitations according to respective country grid codes and rules of engagement such as voltage limits and line and transformer load ratings. The generation portion of the model deals with all the machines connected to the high voltage network and represented in the load flow model. Each generator is modeled individually with an appropriate data set consisting of generation dispatching data, generator reserve data and generation cost curves as discussed in the previous section of this report. For all new generator units and units where data is not available, typical parameters or production unit construction data are used.

The first stage of model construction was to build national OPF models using generic cost curves. Each TSO tested their own national model and made adjustments so that modeling results corresponded to real system behavior. When all national models were tested and approved by the TSOs, a regional OPF model was constructed by integrating the national models into one regional model. This regional model was used to produce the study results presented in this report.

The regional OPF model and data base has been prepared based on the Load flow model for winter peak and summer peak regimes for 2015. The OPF Regional model consists of:

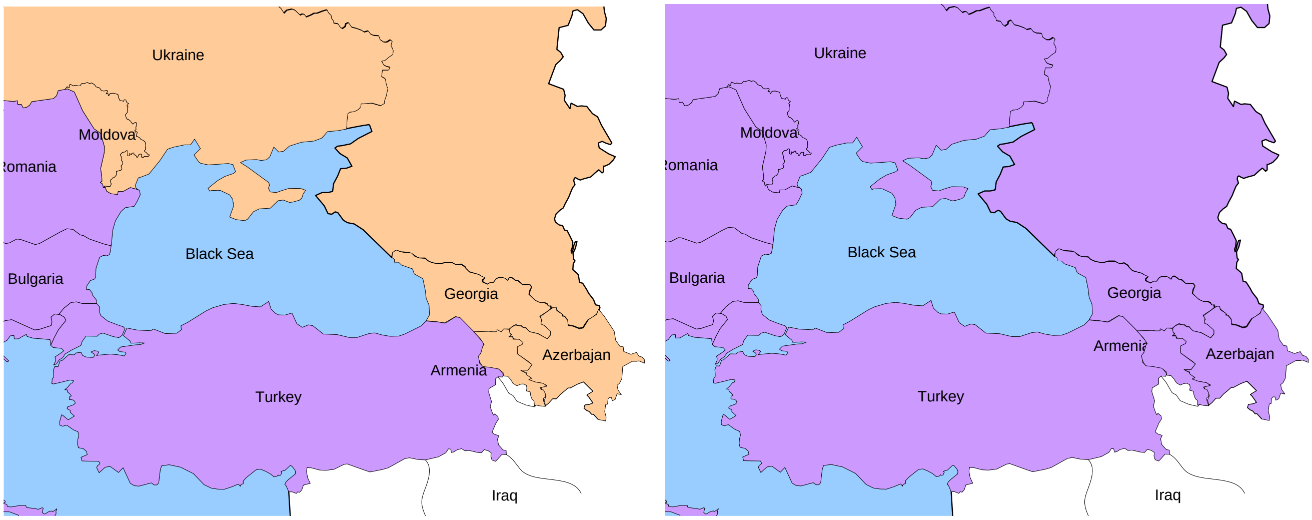
- Load flow model in PSS/E format (*.sav file)
- OPF model data base (collected questionnaires from TSOs)
- OPF model in PSS/E format (*.rop file) that corresponds to the Load flow file

5 LOAD FLOW, SECURITY AND OPF ANALYSIS

Load flow analysis has been performed to check the security margins of the network for peak conditions and various generation patterns, with special attention to voltage profiles and power flows in the network in N and N-1 conditions.

Security analysis has been performed taking into consideration the thermal capacity or protection settings of the network elements for winter and summer conditions. The definition of a summer rating is taken from the Grid Code that is in force in each respective electric power system in the BSTP region and from the ENTSO-E Operational Handbook [1].

The effects of various generation patterns have been investigated through multiple PSS/E - OPF simulation runs, with various calculation options and synchronous modes investigated. As Figure 5.1 illustrates, two synchronous modes were investigated; (1) ENTSO-E and IPS/UPS systems split and (2) ENTSO-E and IPS/UPS systems operating in a parallel mode. The split option (1) is similar to the way the region operates today except that Armenia has been added to the IPS/UPS synchronous mode. The combined parallel mode option (2) is not considered a realistic mode for synchronous operation in the study year of 2015 but, is studied in this way to provide insights into where future interconnections could increase trade opportunities; these interconnections might be synchronous or could be DC or Island connections.



(1) Split (2) parallel

Figure 5.1 – Black Sea region – synchronous operation modes for analyses

Three simulation scenarios have been analyzed as follows:

I Simulation-Split Mode

In this first simulation run, levels of production are analyzed as they presently are in the 2015 regional model assuming synchronous mode (1) when the systems are split. By using the developed PSSE/OPF model, average costs of production (AVG) and the price of the last unit engaged to cover demand (generation marginal price GMP) for each country have been calculated in a non optimized way and then compared to OPF optimized calculations to demonstrate the value in fuel cost savings when all generating plants in the region are optimally dispatched. The interconnecting lines between TSOs assume no imposed constraints in this scenario so that the exchanges are based solely on differences in average production costs and the optimization performed by OPF.

II Simulation-Parallel Mode

In this simulation run, all interconnection lines between synchronous areas are put into operation, so that synchronous mode (2) parallel is obtained. The interconnecting lines between TSOs have no imposed constraints so that the exchanges are based solely on differences in average production costs and the optimization performed by OPF. Again, by using the developed PSSE/OPF model, average costs of production and generation marginal prices for each country have been calculated in a non optimized way and then compared to OPF optimized calculations to show the value in fuel cost savings when all generating plants in the region are optimally dispatched.

III Simulation-Parallel Mode Constrained

This third simulation run is the same as *II Simulation-Parallel Mode* described above, with one important difference; in this simulation, constraints on interconnection lines between areas have been taken into consideration. These interface flows are limited by the net transmission capacity (NTC) values for winter and summer peak hours in 2015 calculated by the TSOs under the BSTP project and these NTCs are illustrated in Figures 5.2 and 5.3 below.

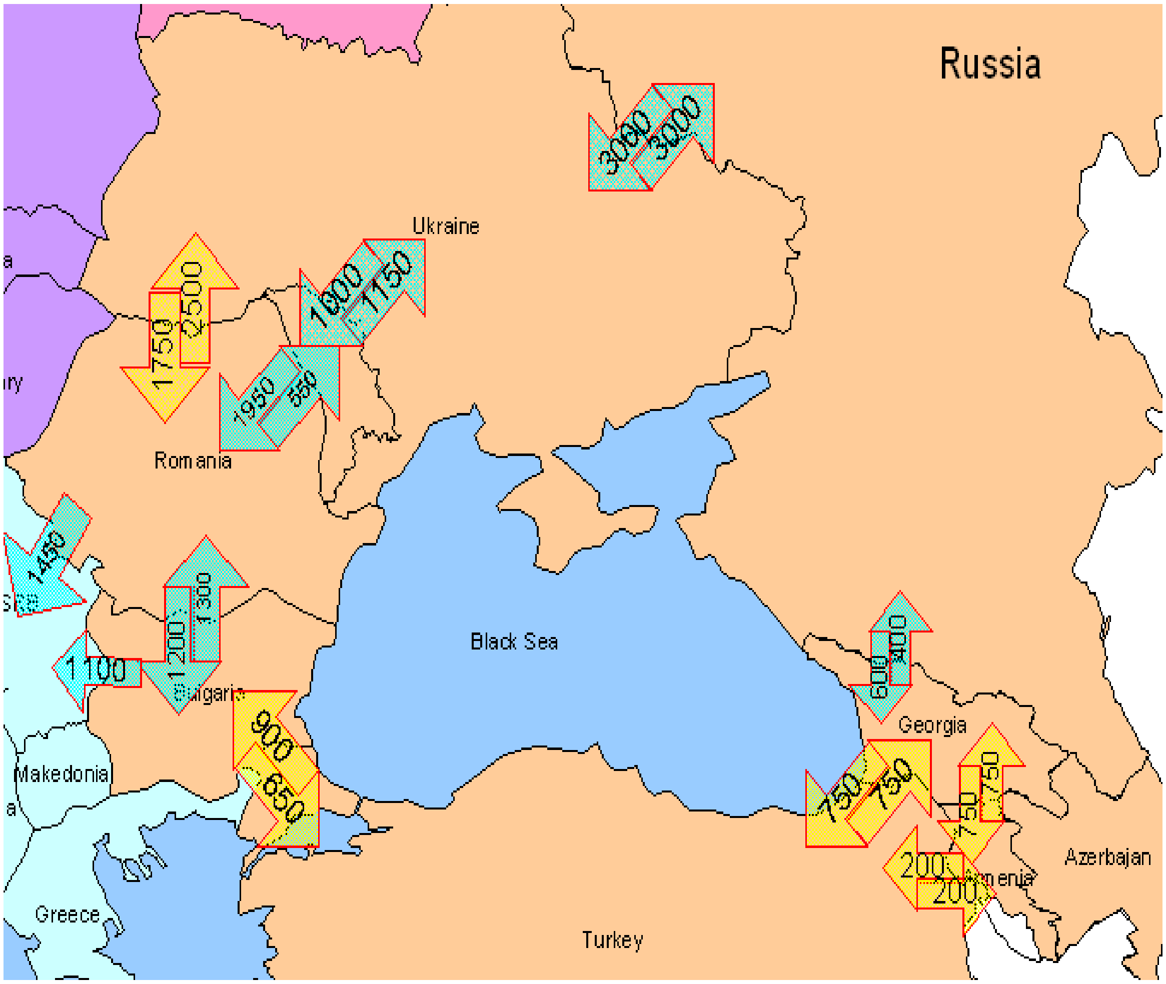


Figure 5.2 – Black Sea region – Border capacities for winter peak

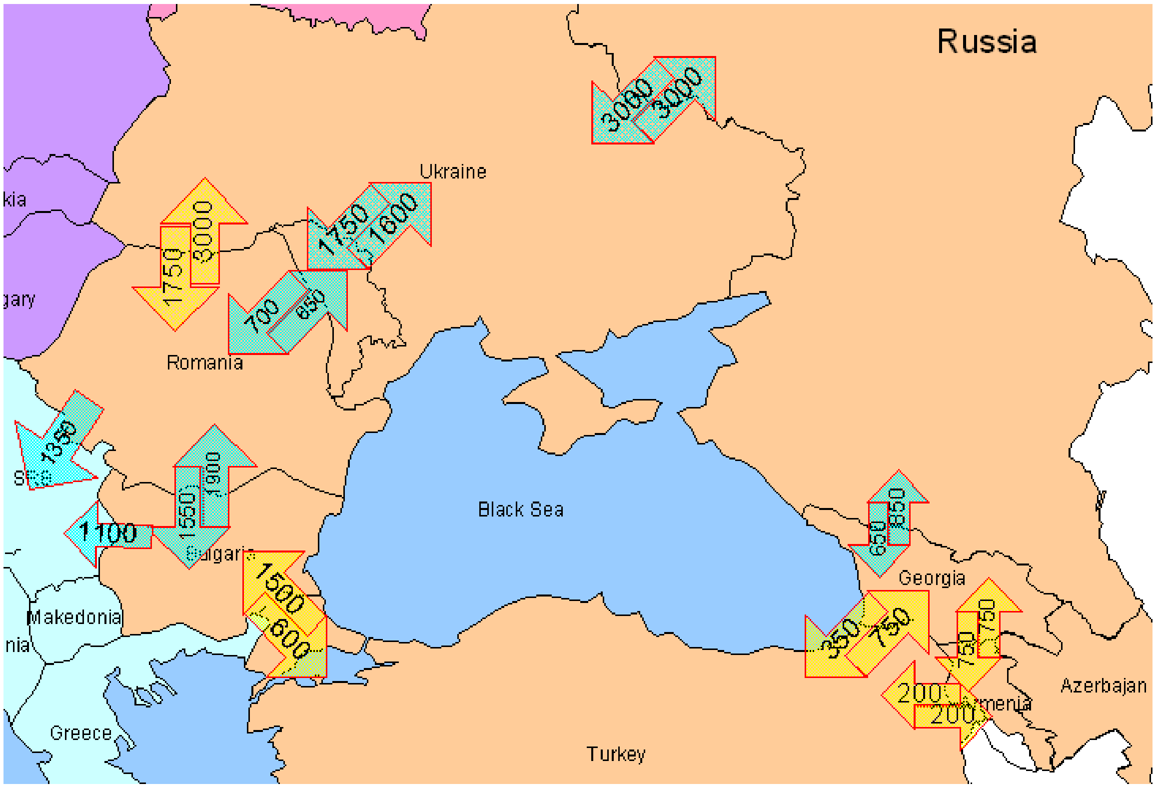


Figure 5.3 – Black Sea region – Border capacities for summer peak

6 ANALYSIS RESULTS

The following analysis results are presented showing the average system electricity cost (AVG), the price of the last unit engaged to cover demand (generation marginal price GMP), the transmission tariff for each TSO and the amount of available export (+) or required import (-) for each TSO. All calculations are based on 2015 winter and summer peak hours. The values for the Tariffs represent whole sale prices in the fourth quarter of 2011 on high voltage transmission lines. For systems where a market based approach is implemented, the tariff represents the wholesale market average price for electricity; for all others the tariff represents the average wholesale tariff.

Table 6.1 and Table 6.2 below present the power balances in MW in the regional models for 2015 for the winter and summer regimes. This data confirms that all countries in the region have excess power production capacities most of the year and most of them have export capability even on winter and summer peak hours. The Exchange figures in these charts are used as the "Not Optimized" starting point for exchanges in each of the simulations.

Table 6.1 – Black Sea region – Power balance of systems in regional model winter peak 2015

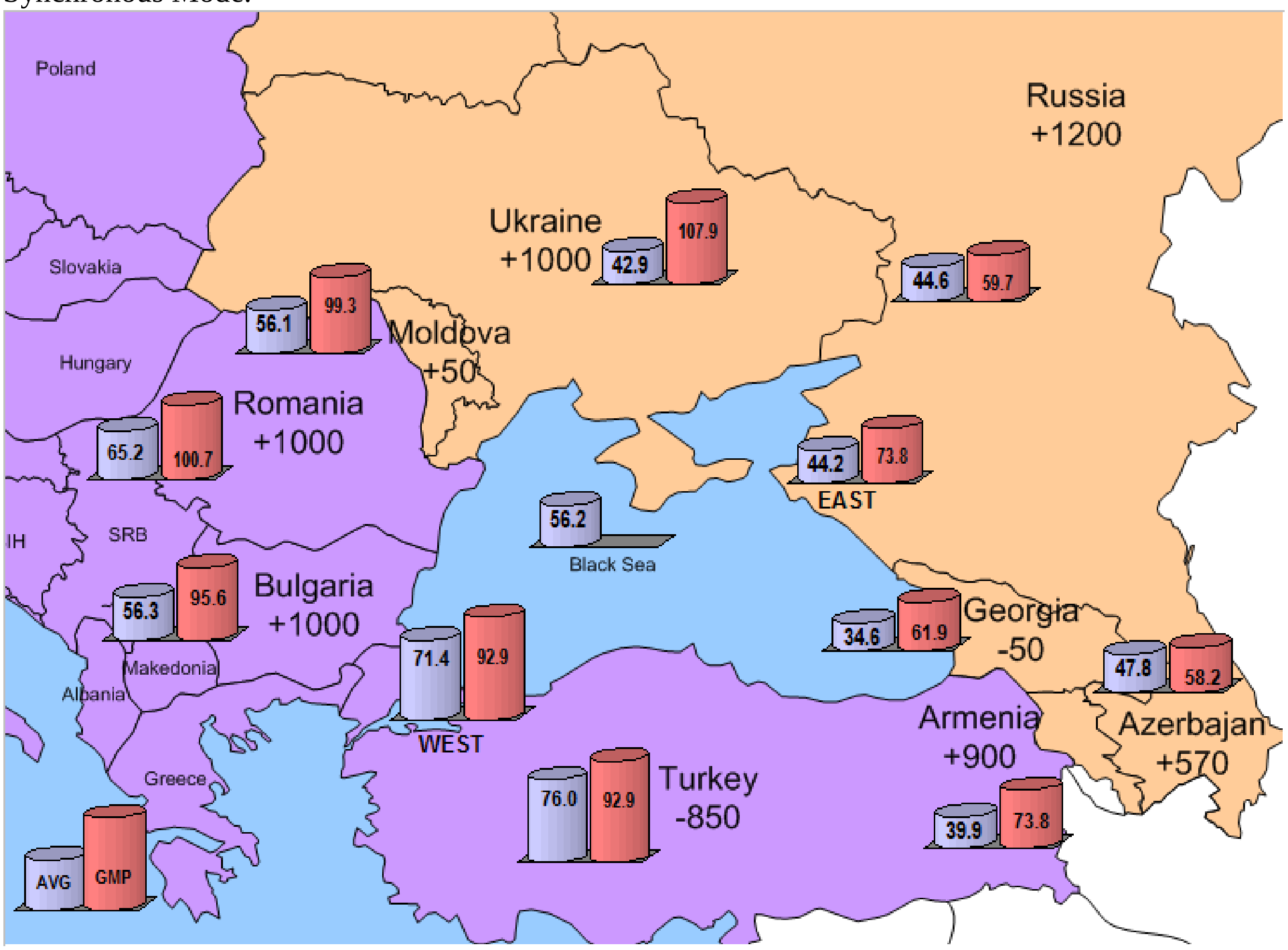
Winter 2015	Generation [MW]	Consumption [MW]	Losses [MW]	Exchange [MW]
Armenia	2210	1287	20	900
Bulgaria	8501	7317	185	1000
Georgia	2022	2024	48	-50
Moldova	1272	1201	21	50
Romania	10985	9666	319	1000
Russia	104054	101661	1195	1200
Turkey	41860	41555	1155	-850
Ukraine	32592	30873	719	1000
Black Sea - total	**203496**	**195584**	**3662**	**4250**

Table 6.2 – Black Sea region – Power balance of systems in regional model summer peak 2015

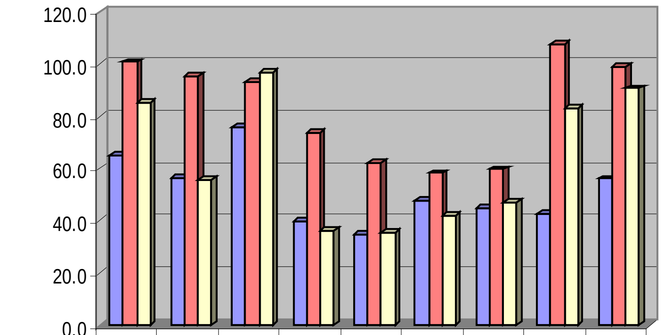
Winter 2015	Generation [MW]	Consumption [MW]	Losses [MW]	Exchange [MW]
Armenia	1711	944	17	750
Bulgaria	6601	5420	131	1050
Georgia	1597	1561	36	0
Moldova	816	806	10	0
Romania	9387	8104	283	1000
Russia	104227	101681	1182	1365
Turkey	41831	41521	1160	-850
Ukraine	22371	21313	467	590
Black Sea - total	**188541**	**181350**	**3286**	**3905**

Split Mode - Not Optimized

In this first simulation run, levels of production are analyzed as they exist in the 2015 winter peak regional model when the generation dispatch **is not optimized** and the region is operating in the Split Synchronous Mode.



AVG – Average system electricity cost $/MWh
GMP – Generation marginal price $/MWh

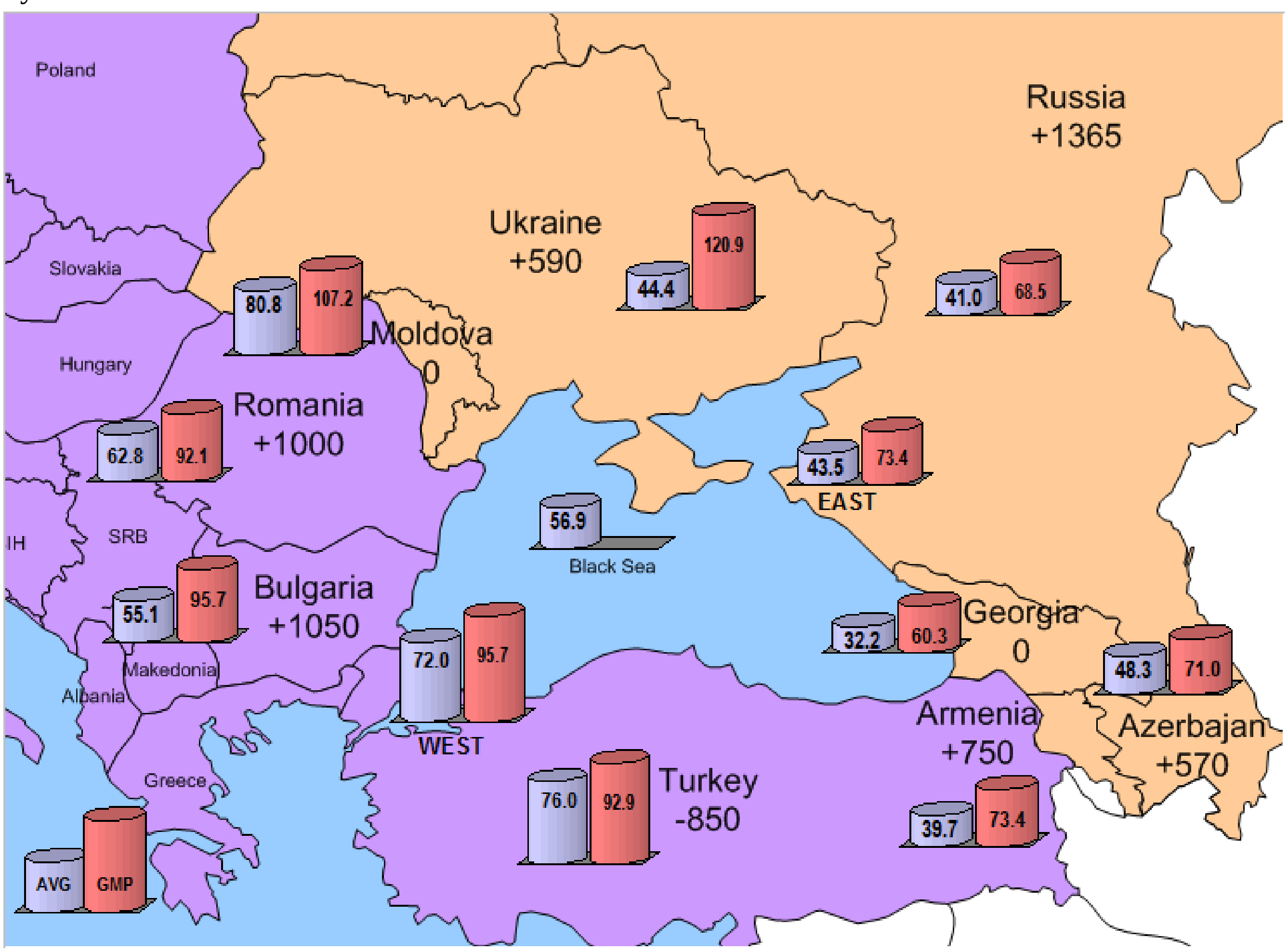


	RO	BG	TR	AM	GE	AZ	RU	UA	MD
AVG	65.2	56.3	76.0	39.9	34.6	47.8	44.6	42.9	56.1
GMP	100.7	95.6	92.9	73.8	61.9	58.2	59.7	107.9	99.3
TARIF	85.3	55.6	96.6	35.9	35.6	42.1	47.2	83.2	90.6

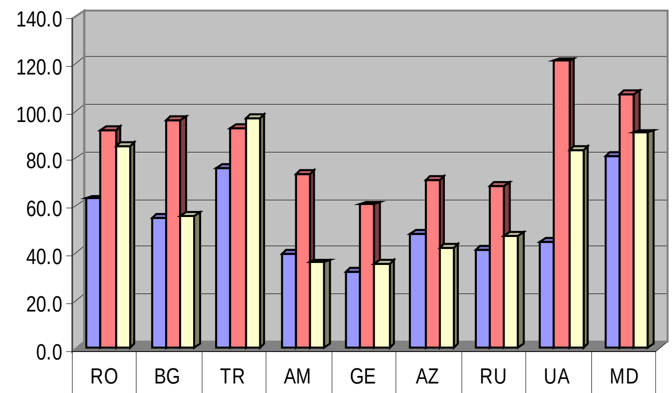
AVG GMP TARIF

Figure 6.1 – Black Sea region – OPF results first iteration for winter peak 2015 – split, non-optimized

In this simulation run, levels of production are analyzed as they exist in the 2015 summer peak regional model when the generation dispatch **is not optimized** and the region is operating in the Split Synchronous Mode.



***AVG** – Average system electricity cost $/MWh*
***GMP** – Generation marginal price $/MWh*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
AVG	62.8	55.1	76.0	39.7	32.2	48.3	41.0	44.4	80.8
GMP	92.1	95.7	92.9	73.4	60.3	71.0	68.5	120.9	107.2
TARIF	85.3	55.6	96.6	35.9	35.6	42.1	47.2	83.2	90.6

AVG GMP TARIF

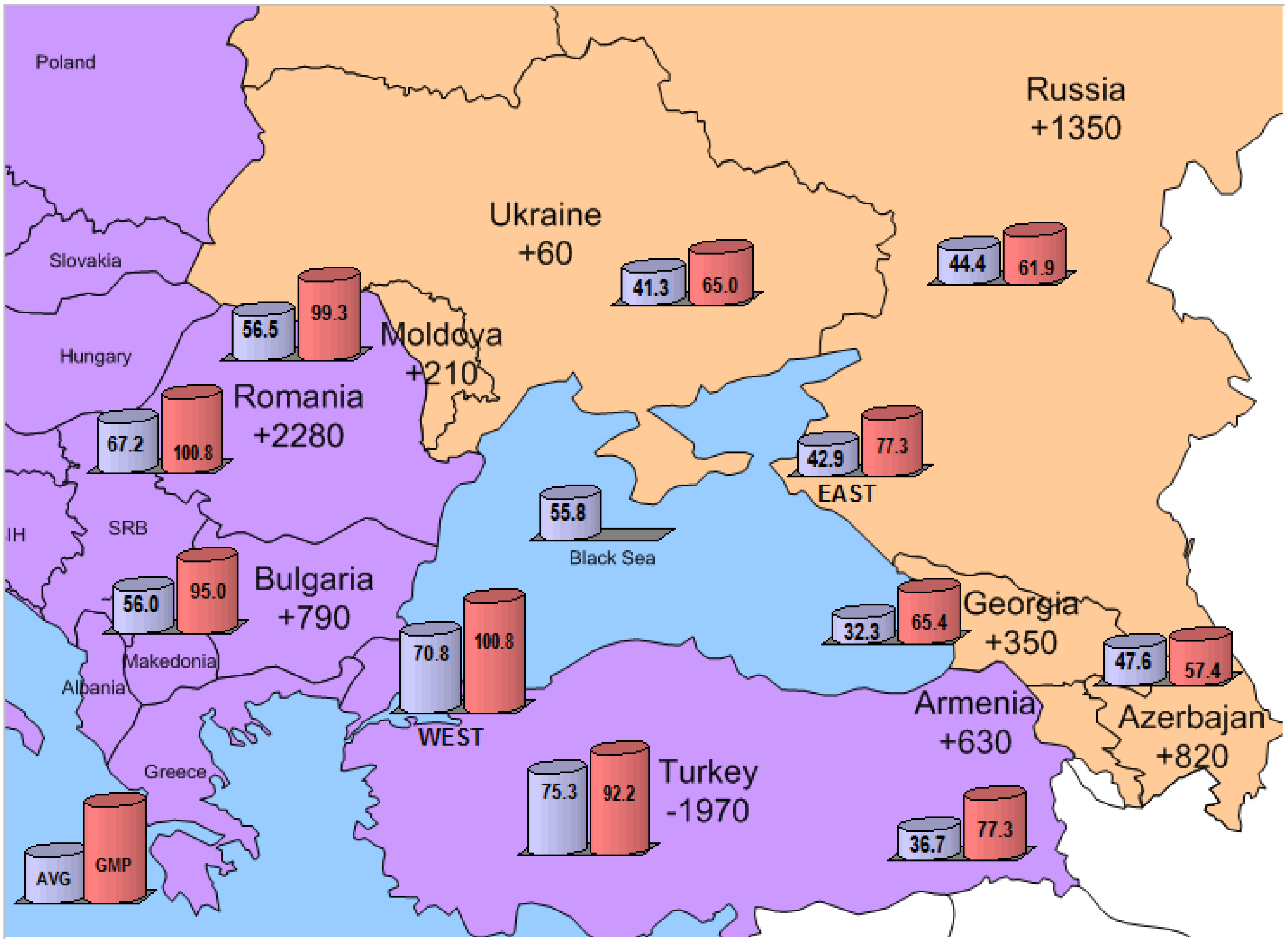
Figure 6.2 – Black Sea region – OPF results first iteration for summer peak 2015 – split, non-optimized

From Figures 6.1 and 6.2 we can see that AVG prices in the IPS/UPS region are consistently lower than in the ENTSO-E region on both winter and summer peak hours. We also see consistently high GMP values in both regions because the calculations are made on the summer and winter peak hours when the price of the last unit engaged to meet demand will be the high cost generator in the system. In addition, we see that in some countries the price of the last unit engaged (GMP) is higher than the tariff or market price. This is explained by the presence of CHP or Industrial generation units that, in addition to producing electricity, are producing steam for other purposes and the economical effect of cogeneration is not taken into consideration in these calculations. All of these thermal units are treated as must run units in winter when they supply district heating and all renewables such as wind and small hydro are must run in summer and winter because they depend on wind and water and are not dispatchable.

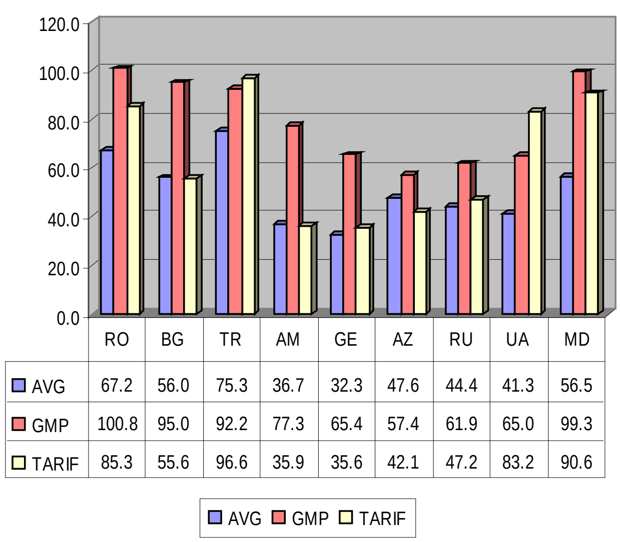
Split Mode - Optimized

In these next simulation runs, the levels of production are analyzed as they exist in the 2015 winter and summer peak regional model when the generation dispatch **is optimized** and the region is operating in the Split Synchronous Mode. The following assumptions are made for optimization calculations:

- Hydro units do not participate in optimization because it is assumed that engagement of hydro in the model is done according to the availability of water (except in Georgia where hydro production is optimized).
- All nuclear and thermal units are used for optimization except the ones that are switched off because of overhaul or decommissioned or confirmed out of operation.
- RES units such as small hydro and Wind power are treated as must run units and will not change their engagement for optimization since they are not engaged by price but by the availability of water and wind.

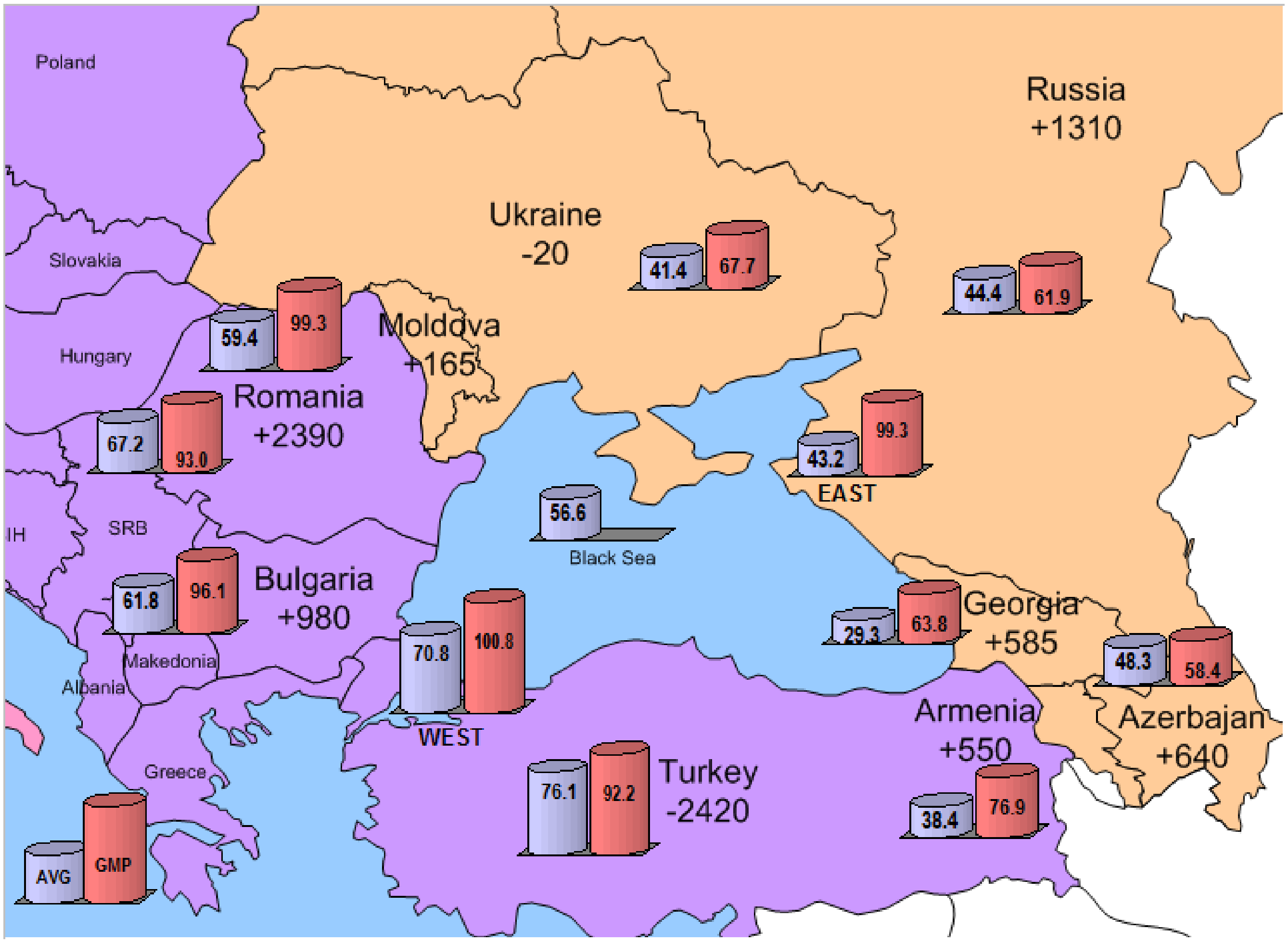


AVG – Average system electricity cost $/MWh
GMP – Generation marginal price $/MWh

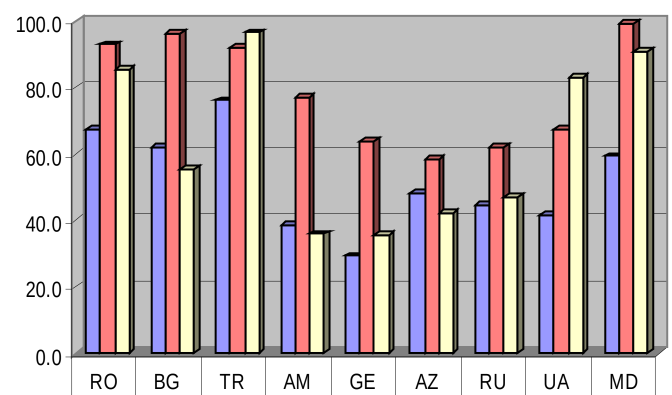


	RO	BG	TR	AM	GE	AZ	RU	UA	MD
AVG	67.2	56.0	75.3	36.7	32.3	47.6	44.4	41.3	56.5
GMP	100.8	95.0	92.2	77.3	65.4	57.4	61.9	65.0	99.3
TARIF	85.3	55.6	96.6	35.9	35.6	42.1	47.2	83.2	90.6

Figure 6.3 – Black Sea region – OPF results for winter peak regime - split, optimized



***AVG** – Average system electricity cost $/MWh*
***GMP** – Generation marginal price $/MWh*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
AVG	67.2	61.8	76.1	38.4	29.3	48.3	44.4	41.4	59.4
GMP	93.0	96.1	92.2	76.9	63.8	58.4	61.9	67.7	99.3
TARIF	85.3	55.6	96.6	35.9	35.6	42.1	47.2	83.2	90.6

AVG GMP TARIF

Figure 6.4 – Black Sea region – OPF results for summer peak regime – split, optimized

The results of OPF dispatch optimization shown in Figures 6.3 and 6.4 above are compared to the non-optimized results in Figures 6.1 and 6.2 and are summarized as follows:

ENTSO-E Continental Europe - WEST

In the winter maximum regime, after optimization of the ENTSO-E Continental European part of the system, the Romanian system increase production and export while production levels in Bulgaria and Turkey are reduced. Comparing the overall costs of production due to optimization, savings are calculated to be 52,610 $/hour, or 1.38%. The average cost of production for the Western region before optimization was 71.44$/MWh, and after 70.76$/MWh.

Optimized Results in Split Mode-Not Constrained

Winter 2015 - Balance [MW]	RO	Burstin	BG	TR	Average production cost [$/MWh]
Non-optimized	1,000	750	1,000	-850	71.44
Optimized	2,280	600	800	-1,970	70.76
Generation Delta	**1,280**	**150**	**-200**	**-1,120**	**-1.38% / -52,610 $/h**

Similarly, in the summer maximum regime, after optimization of the ENTSO-E Continental European part of the system, the Romanian and the Burstin Island portion of the Ukrainian system increase production and export while production levels in Bulgaria and Turkey are reduced. Comparing the overall costs of production, savings are 48,610 $/hour, or 1.37%.

Optimized Results in Split Mode-Not Constrained

Summer 2015 - Balance [MW]	RO	Burstin	BG	TR	Average production cost [$/MWh]
Non-optimized	1000	350	1,050	-850	72.00
Optimized	2,390	430	980	-2,420	70.80
Generation Delta	**1,390**	**80**	**-70**	**-1,570**	**-1.37% / -48,610 $/h**

These optimized results are based on unconstrained transmission system capacities and represent what could be accomplished based on average prices in 2015 if transmission system capacities were not an issue. As we will see when we present the constrained results, the border capacity limit (NTC) between Bulgaria and Turkey is 650MW (see Figure 5.2) so that even the non-optimized 850 MW import to Turkey is not possible in the Split Synchronous Mode. The winter and summer optimized import to turkey of 1,970 MW and 2,420 MW are certainly not possible without significant transmission system upgrades in Turkey. Optimized results that are constrained by transmission NTCs are presented later in this report.

IPS/UPS - EAST

In the winter maximum regime, after optimization of the eastern portion of the Split Mode, large shifts in production patterns occur as presented in the following table. Comparing the overall costs of production, optimization savings are $98,060 per hour, or 3.5%. Average costs of production for the Eastern region before optimization was $44.2/ MWh, and after optimization was $42.9/ MWh.

Optimized Results in Split Mode-Not Constrained

Winter 2015 - Balance [MW]	UA	AM	RU	MD	GE	AZ	Average production cost [$/MWh]
Non-optimized	250	900	1,200	50	-50	570	44.2
Optimized	-540	630	1,350	210	350	820	42.9
Generation Delta	**-790**	**-270**	**150**	**160**	**400**	**250**	**-3.5% / -98,060 $/h**

In the summer maximum regime, after optimization of the eastern portion of the Split Mode, large shifts in production patterns also occur as presented in the following table. If we compare the overall optimized costs of production, savings are $43,380 per hour, or 1.85%.

Optimized Results in Split Mode-Not Constrained

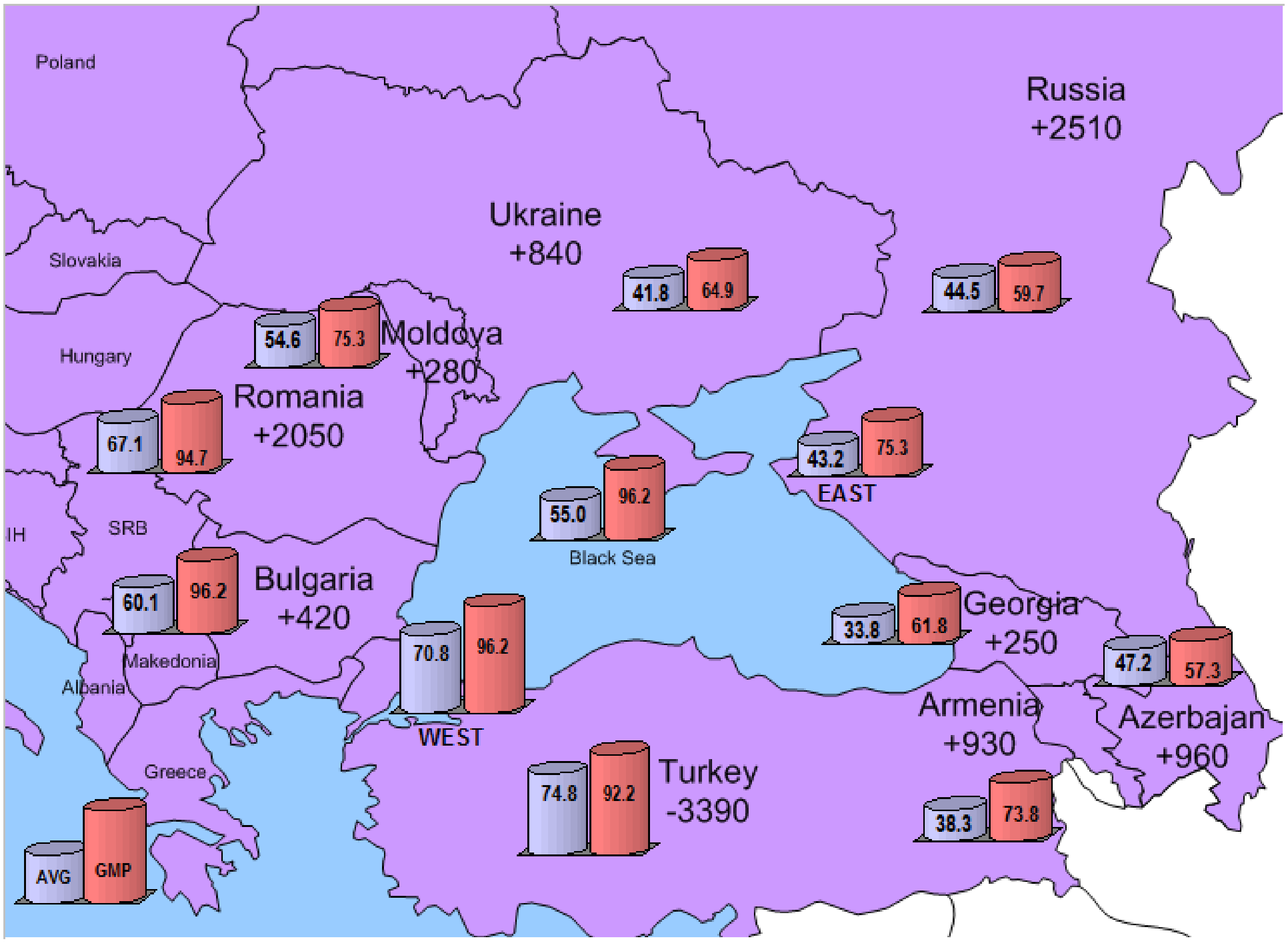
Summer 2015 - Balance [MW]	UA	AM	RU	MD	GE	AZ	Average production cost [$/MWh]
Non-optimized	240	750	1,365	0	0	570	44.40
Optimized	-450	550	1,310	165	585	640	41.40
Generation Delta	**-690**	**-200**	**-55**	**165**	**585**	**70**	**-1.85% / -43,380 $/h**

From these winter and summer IPS/UPS Split Mode optimized results and supporting detailed data, we find that mostly thermal gas fired units in Armenia and Ukraine have been replaced with low cost coal fired units in Moldova, hydro units in Georgia, and thermal gas fired units in Azerbaijan.

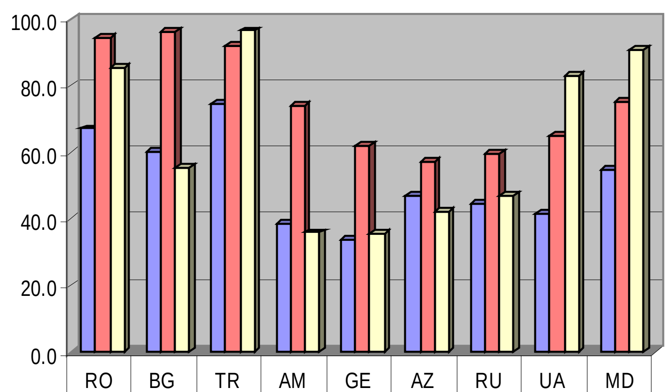
Security N-1 analyses shows that this regime is feasible.

Parallel Mode - Optimized

In these next simulation runs, the levels of production are analyzed as they exist in the 2015 winter and summer peak regional model when the generation dispatch is optimized and the region is operating in the Parallel Synchronous Mode.



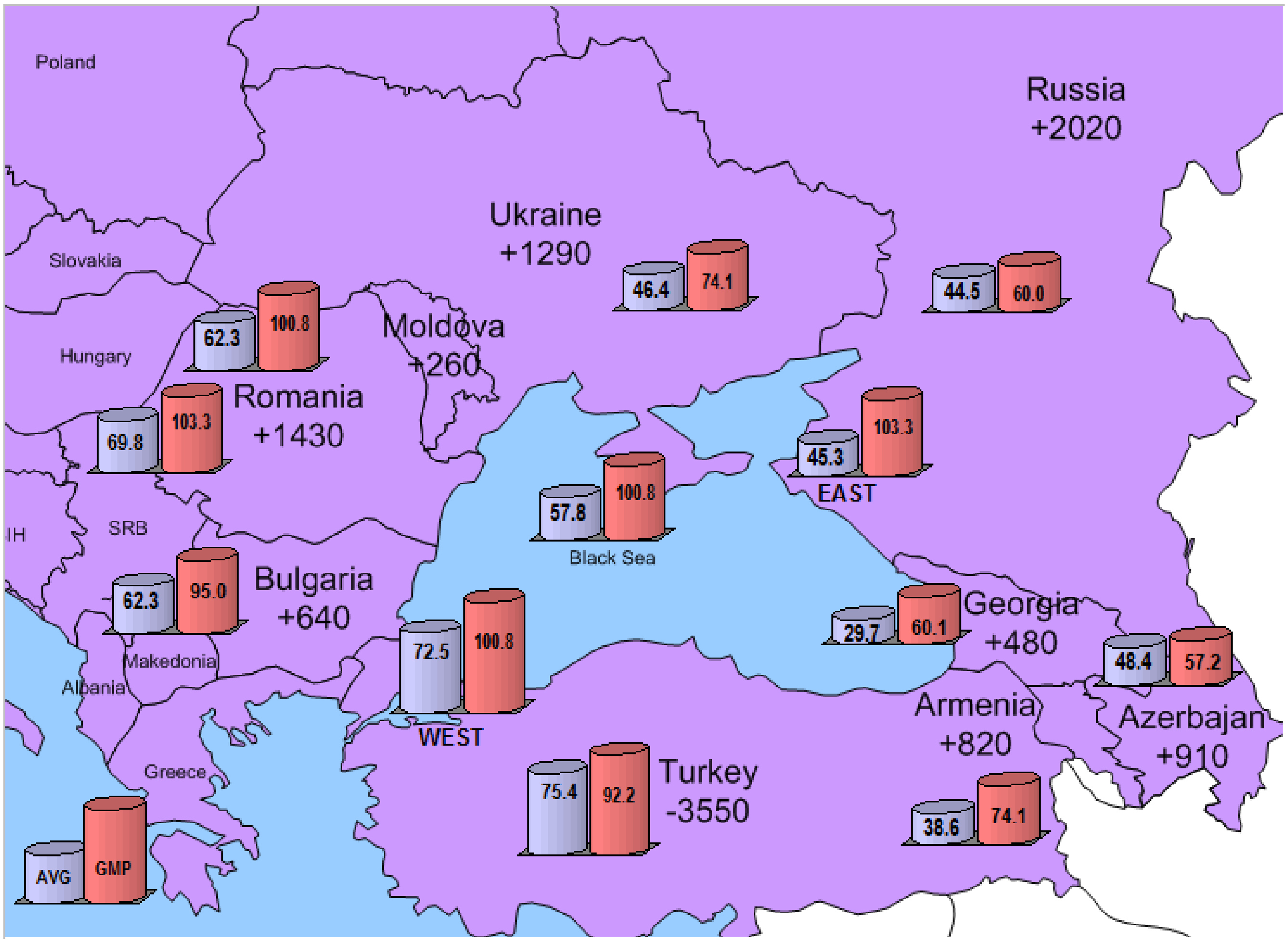
***AVG** – Average system electricity cost $/MWh*
***GMP** – Generation marginal price $/MWh*



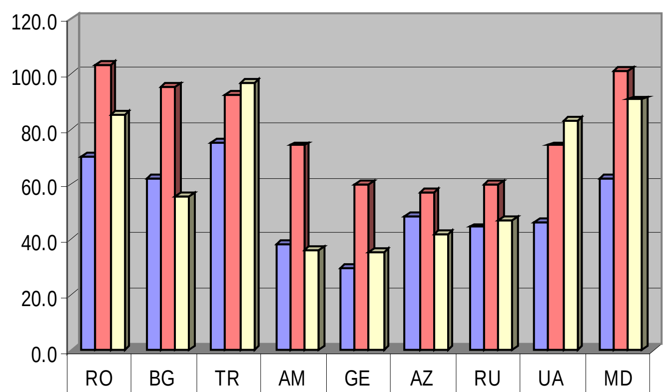
	RO	BG	TR	AM	GE	AZ	RU	UA	MD
AVG	67.1	60.1	74.8	38.3	33.8	47.2	44.5	41.8	54.6
GMP	94.7	96.2	92.2	73.8	61.8	57.3	59.7	64.9	75.3
TARIF	85.3	55.6	96.6	35.9	35.6	42.1	47.2	83.2	90.6

AVG GMP TARIF

Figure 6.5 – Black Sea region – OPF results for winter peak 2015 – parallel, optimized, non-constrained



AVG *– Average system electricity cost $/MWh*
GMP *– Generation marginal price $/MWh*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
AVG	69.8	62.3	75.4	38.6	29.7	48.4	44.5	46.4	62.3
GMP	103.3	95.0	92.2	74.1	60.1	57.2	60.0	74.1	100.8
TARIF	85.3	55.6	96.6	35.9	35.6	42.1	47.2	83.2	90.6

AVG GMP TARIF

Figure 6.6– Black Sea region – OPF results for summer peak 2015 – parallel, optimized, non-constrained

The results of OPF dispatch optimization shown in Figures 6.5 and 6.6 above are compared to the non-optimized results and are summarized as follows:

In the winter maximum regime, after optimization of the entire region in Parallel operation, large shifts in production patterns occur as presented in the following table. Average cost is reduced from 56.2 to 55.0 $/MWh, and total savings for the optimized regime are 112,000 $ per hour, or 1.7%.

Optimized Results in Parallel Mode-Not Constrained

Winter 2015 - Balance [MW]	RO	BG	TR	UA	AM	RU	MD	GE	AZ	Average production cost [$/MWh]
Non-optimized	1,000	1000	-850	1,000	900	1,200	50	-50	570	56.2
Optimized	2,050	420	-3390	840	930	2,510	280	250	960	55.0
Generation Delta	**1,050**	**-580**	**-2540**	**-160**	**30**	**1,310**	**230**	**300**	**390**	**-1.7% / -112,000 $/h**

In the summer maximum regime, after optimization of the entire region in parallel operation, large shifts in production patterns are again observed as presented in the following table. Average cost is reduced from 56.9 to 56.0 $/MWh and total savings for the optimized regime are 58,900 $ per hour, or 1.01%.

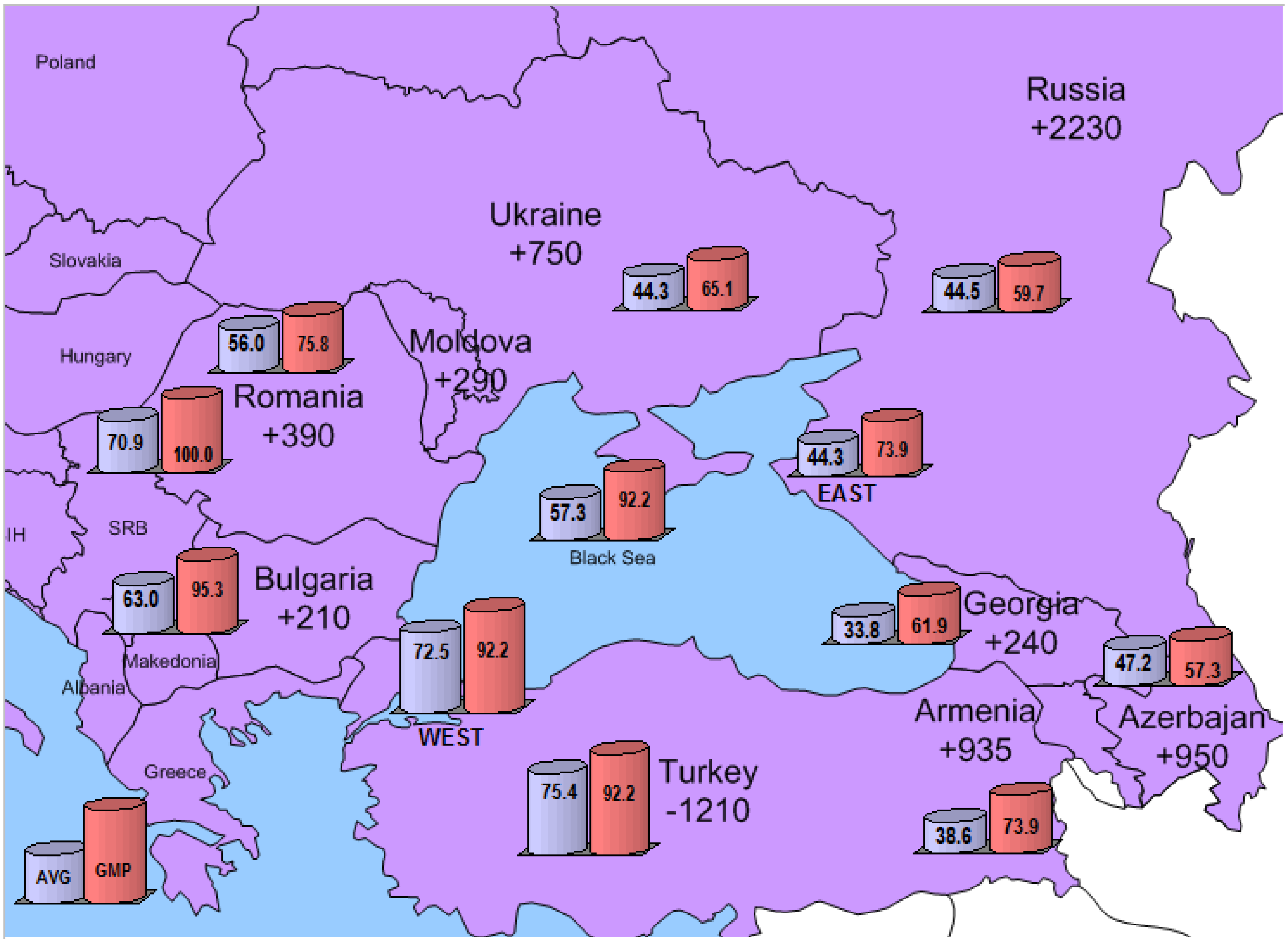
Optimized Results in Parallel Mode-Not Constrained

Summer 2015 - Balance [MW]	RO	BG	TR	UA	AM	RU	MD	GE	AZ	Average production cost [$/MWh]
Non-optimized	1,000	1,050	-850	590	750	1,365	0	0	570	56.9
Optimized	1,430	640	-3,550	1290	820	2,020	260	480	910	56.0
Generation Delta	**430**	**-410**	**-2,700**	**700**	**70**	**655**	**260**	**480**	**340**	**-1.01% / -58,900 $/h**

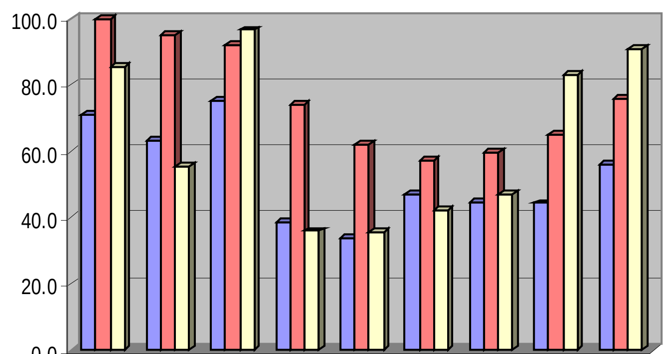
These optimized results are based on unconstrained transmission system capacities and represent what could be accomplished based on average prices in 2015 if transmission system capacities were not an issue. As we will see when we present the constrained results, the border capacity limit (NTC) between Bulgaria and Turkey is 650MW (see Figure 5.2) so that even the non-optimized 850 MW import to Turkey is not possible in this Parallel Synchronous Mode. The winter and summer optimized import to Turkey of 3,390 MW and 3,550 MW are certainly not possible without significant transmission system upgrades in Turkey and between Turkey and its neighbors. Optimized results that are constrained by transmission NTCs are presented in the following section of this report.

Parallel Mode – Optimized and Constrained

In these last simulation runs, the levels of production are analyzed as they exist in the 2015 winter and summer peak regional model when the generation dispatch is optimized, the region is operating in the Parallel Synchronous Mode and the NTC constraints are activated on transmission system interconnections. This analysis checks the feasibility of the optimized unconstrained exchanges presented in the previous sections of this report and provides some insight into needed transmission system upgrades and further detailed studies to facilitate economical trade between the TSOs of the region.



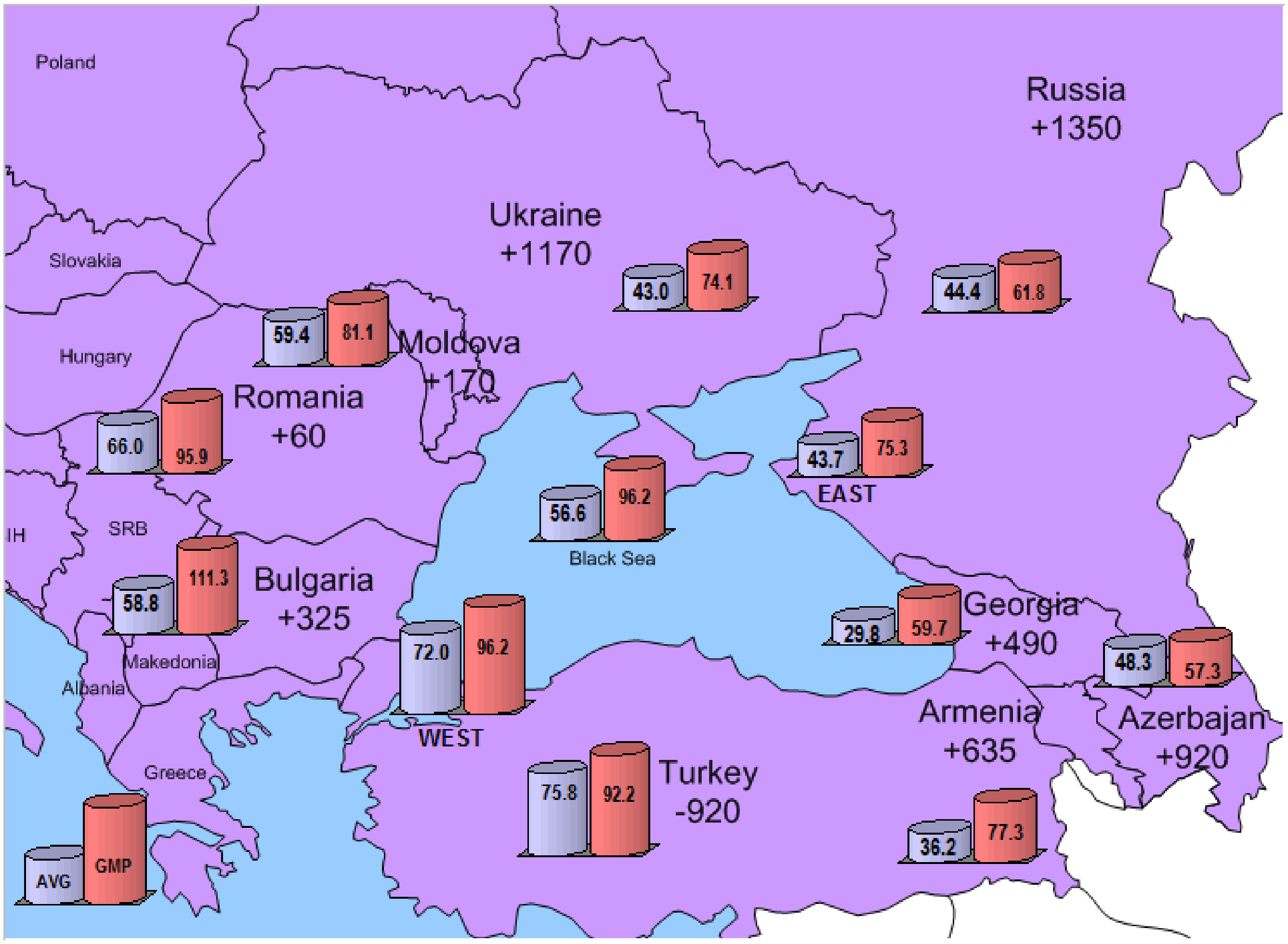
AVG – Average system electricity cost $/MWh
GMP – Generation marginal price $/MWh



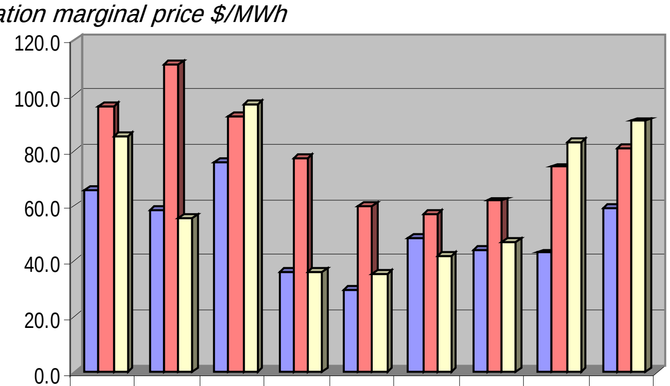
	RO	BG	TR	AM	GE	AZ	RU	UA	MD
AVG	70.9	63.0	75.4	38.6	33.8	47.2	44.5	44.3	56.0
GMP	100.0	95.3	92.2	73.9	61.9	57.3	59.7	65.1	75.8
TARIF	85.3	55.6	96.6	35.9	35.6	42.1	47.2	83.2	90.6

AVG GMP TARIF

Figure 6.7 – Black Sea region – OPF results for winter peak 2015 – parallel, optimized & constrained



***AVG** – Average system electricity cost $/MWh*
***GMP** – Generation marginal price $/MWh*



	RO	BG	TR	AM	GE	AZ	RU	UA	MD
AVG	66.0	58.8	75.8	36.2	29.8	48.3	44.4	43.0	59.4
GMP	95.9	111.3	92.2	77.3	59.7	57.3	61.8	74.1	81.1
TARIF	85.3	55.6	96.6	35.9	35.6	42.1	47.2	83.2	90.6

AVG GMP TARIF

Figure 6.8 – Black Sea region – OPF results for summer peak 2015 – parallel, optimized & constrained

The results of OPF dispatch optimization for parallel synchronous operations and NTC constrained interconnections as shown in Figures 6.7 and 6.8 above are compared to the non-optimized results and are summarized as follows:

In the winter maximum regime after the constrained optimization has been performed, countries in the west significantly reduce exports while countries in the east are increasing them. Since the border between Bulgaria and Turkey is congested with an NTC of 650 MW, Turkey is importing 560 MW from the Caucasus region to meet its optimized import of 1,210 MW. The analysis shows that most of the 560 MW comes from Azerbaijan and Georgia. There is additional capacity on the Georgia-Turkey border, but there is no reserve of generation left in the Caucasus region in 2015 winter and summer peak hours. In addition, it is important to note that Russia is able to export up to 2,230 MW in winter even when all transmission constraints are considered.

Optimized Results in Parallel Mode-Constrained

Winter 2015 - Balance [MW]	RO	BG	TR	UA	AM	RU	MD	GE	AZ	Average production cost [$/MWh]
Non-optimized	1000	1000	-850	1000	900	1200	50	-50	570	56.20
Optimized	390	210	-1210	750	935	2230	290	240	950	55.30
Generation Delta	**-610**	**-790**	**-360**	**-250**	**35**	**1030**	**240**	**290**	**380**	**-1.0% / -54,200 $/h**

In the summer maximum regime after the constrained optimization, similar to the winter case, countries in the west significantly reduce exports while countries in the east are increasing them. Compared to the non-optimized results, savings are 0.2% or 13,800 $ per hour. So despite congestion and limited transfer capacity there is still some room for profitable trade.

Optimized Results in Parallel Mode-Constrained

Summer 2015 - Balance [MW]	RO	BG	TR	UA	AM	RU	MD	GE	AZ	Average production cost [$/MWh]
Non-optimized	1000	1050	-850	590	750	1350	50	0	570	56.90
Optimized	60	325	-920	1170	635	1350	170	490	920	56.60
Generation Delta	**-940**	**-725**	**-70**	**580**	**-115**	**0**	**120**	**490**	**350**	**-0.2% / -13,800 $/h**

These winter and summer constrained and optimized summaries of the parallel synchronous mode demonstrate that, even though economic considerations would indicate large exports from Romania and Bulgaria to Turkey as reported in the un-constrained sections of this report, the constraints that exist on the Bulgaria-Turkey interconnection line and many internal transmission lines in Turkey significantly limit such exports. These study results also show that Russia has large economically justified exports and can deliver them even considering known transmission constraints in both winter and summer periods.

7 FINDINGS AND CONCLUSIONS

Black Sea Transmission Planning TSO Capacity Building

This project, to evaluate economic opportunities for trade in the BSTP region using the OPF feature of the PSS-E software, began with the training of the TSO engineers on the use of OPF and the updating of the load flow and dynamic models to include current projections on new generation and transmission system infrastructure including the latest projection for renewable energy source (RES) integration. TSOs then collected the data that is required to perform an OPF analysis and participated in the construction of the OPF national models including assisting in the creation of generic generation cost curves. Once the national models were tested and verified by the TSOs, the national models were integrated into one regional model that was used in this project. TSOs now have a new tool, the PSSE/OPF national and regional models for winter and summer maximum demand hours in 2015 and 2020 that will continue to perform technical load flow and dynamic analysis and now can facilitate market based analysis and simulate potential future regional markets.

Average Costs of Production (AVG) Calculations

Utilizing the OPF 2015 winter and summer peak regional models that include the developed generation cost curves representing the relationship between generator output and fuel costs for every generator in the region, average production costs (AVG) and generation marginal prices (GMP) have been calculated and presented in this report for two synchronous modes and various scenarios considering OPF optimization and transmission system constraints. It is important to remember that these results are for a one hour peak demand period in winter and a one hour peak demand period in summer and that further calculations would be required to predict average production costs and exchange opportunities in other periods of the year.

The basic finding concerning the average production costs in the BSTP region, as presented in Section 6 of this report, is that the ENTSO-E countries of Romania, Bulgaria and Turkey have generally higher average production costs than the IPS/UPS countries of Georgia, Armenia, Azerbaijan, Russia, Ukraine and Moldova. The detailed explanations for this are outside the scope of this study but all explanations involve the mix in each country of generation types, the age of the generation fleet and that impact on capital costs, the cost of fuel and plant fuel efficiency.

The highest average production costs are in Turkey where the AVG is $75/ MWh or higher in every scenario in winter and summer peak hours. Even though Turkey has adequate internal generation capacity to cover demand in 2015, Turkey is an importer of energy because import prices are lower than internally generated costs. One of the major reasons for these high generation costs is that Turkey is mainly importing primary fuels (coal, natural gas) used to produce electricity.

The lowest average production costs are in Georgia where the AVG is $35/ MWh or lower in every scenario in winter and summer peak hours. In 2015, Georgia will not be a large exporter of energy; study results indicate 240 MW of export in winter and 490 MW in summer in the constrained Parallel Mode. However, Georgia has ambitious hydro expansion plans that would provide a different result in a 2020 OPF study. Other low cost producers in the Caucuses region are Armenia ($40/ MWh) and Azerbaijan ($48/ MWh), each having 600-950 MW of export available in 2015. The exporter with the biggest impact in the region is Russia with an AVG of $45/ MWh or less in every scenario and, in the constrained Parallel Mode, has the capability to export 2,230 MW at winter peak and 1,350 MW at summer peak.

Export and Import Calculations

As discussed above, Turkey has a large demand for imports due to its high generation costs and the rest of the BSTP region has available exports at significantly lower costs. In this study two synchronous modes were selected for study; the Split Mode that reflects how the region will probably operate in

2015 and the Parallel Mode that may never become a reality but reveals where energy would flow if all needed infrastructure was in place. Parallel Mode results are meant to be preliminary signals to the investment community concerning where future generation and transmission system infrastructure may be needed.

The study results presented in section 6 of this report and summarized in the table below show that Turkey has a demand for imports in summer and winter peak periods and every other country in the region has export capacity. This table shows MW exports as positive numbers and MW imports as negative numbers for the summer and winter Parallel Mode. The "Not Optimized" number for each country is the amount of power that each TSO has determined is available from its energy balance, not considering prices or demand. In this study, OPF has been utilized to optimize exports and imports based on the cost of production in each country; this value with no constraints is shown as "Optimized". Finally, the OPF model was run as optimized and with NTC transmission constraints and these values are referred to as "Constrained".

2015 Exports (+) and Imports (-) in MW

Synchr. Mode	RO	BG	TR	AM	GE	AZ	RU	UA	MD
Winter Parallel									
Not Optimized	1000	1000	-850	900	-50	570	1200	1000	50
Optimized	2050	420	-3390	930	250	960	2510	840	280
Constrained	390	210	-1210	935	240	950	2230	750	290
Summer Parallel									
Not Optimized	1000	1050	-850	750	0	570	1365	590	0
Optimized	1430	640	-3550	820	480	910	2020	1290	260
Constrained	60	325	-920	635	490	920	1350	1170	170

Before this study was completed, the Turkey BSTP PSS/E model for 2015 anticipated 850 MW of imports from Romania and Bulgaria and the rest of ENTSO-E. Now this study has shown that, if no transmission system constraints existed in the Parallel Mode, Turkey would economically import 3,390 MW in winter and 3,550 MW in summer. However, when transmission system constraints that include both internal and interconnection capacity limitations are considered, the Turkey imports are limited to 1,210 MW in winter and 920 MW in summer. These imports are supplied to Turkey by Romania and Bulgaria through Bulgaria-Turkey and Greece-Turkey interconnection and by Georgia, Armenia and Azerbaijan through a Georgia-Turkey interconnection.

Russia is one of the low production cost producers in the region ($45/ MWh) and OPF has calculated that Russia would economically (without constraints) export 2,510 MW in winter and about 2,020 MW in summer; the largest export in the region. An important finding is that in the winter peak hour Russia can export up to 2,230 MW when transmission system constraints are applied and becomes the largest exporter by over 2 times the next largest exporter, Azerbaijan.

When reviewing the export opportunities for Armenia, Georgia and Azerbaijan in 2015, it is important to consider the ambitious generation and transmission system expansion plans that exist in all three countries. By the year 2020 this picture could look quite different with new hydro development in Georgia, new gas fired generation in Azerbaijan and added nuclear capacities in Armenia.

A general conclusion from these findings is when export/import plans are optimized by OPF according to calculated average production costs and constrained by actual transmission system capacity limitations, exports from Romania and Bulgaria are significantly decreased while exports from Russia, Georgia and Azerbaijan are increased. Also, when exports are reduced in Romania and Bulgaria, the AVG productions costs are significantly increased; from $67.1/ MWh to $70.9/ MWh in Romania and from $60.1/ MWh to $63.0/ MWh in Bulgaria. These increases are due to the must run requirement of higher cost wind power plants and CHP plants (in winter regime) that exist in these two countries.

Calculated Savings from Optimization

The PSSE/OPF program module is a powerful tool for optimizing tradeoffs on the transmission system. OPF uses an objective function that is an expression of cost in terms of a power system variable (example, the fuel cost incurred to produce power is a function of the active power generation among participating machines). OPF automatically adjusts the participating machines active power generation, within capability limits, to reduce the total fuel cost or losses or other goal. In Section 6 of this study we have presented non-optimized results compared to optimized results including the change in average production costs ($/MWh) for the region as well as the total saving due to optimization ($/hour).

When optimization replaces high cost production with lower cost production in an unconstrained manner, the savings can be substantial. For example, when the IPS/UPS was optimized in the winter Split Mode, the average production costs were reduced from $44.2/ MWh to $42.9/ MWh; a savings of $98,060/hour (3.5%) for the IPS/UPS region. When the entire BSTP region was optimized in the winter Parallel Mode, the savings were $112,000/hour (1.7%) for the region. If increased trading as a result of the optimization process was only 2,000 hours per year, savings in the region could amount to $200 million per year.

Sensitivity Analysis

In the course of this study several innovations were required such as the creation of a new OPF data base, the development of nominal production costs (Table 2.1) and the preparation of generic generation cost curves. In every step of this process assumptions were made that ultimately impacted these study results. In order to understand the sensitivity of these reported results to the input data assumptions, a Sensitivity Analysis is proposed to determine which assumptions significantly impact the study results. Examples of assumptions that can be tested are;

- The 20 year payment period assumption that impacts the capital costs and gives a cost advantage to plants 21 years old and older.
- The assumptions made on the cost of fuel in 2015; especially natural gas and oil.
- The shape of the cost curves for each plant type.
- The assumed cost of CO_2 emissions.
- The calculated values of NTCs in the region including the impact of Dynamic Stability in some areas of the region.

These and other assumptions can be varied in a determined range of probable values to measure the impact of the changed variable on the calculated results. When the variables with the largest impact on study results are identified, more research and study can proceed in order to fine tune these inputs and ultimately increase the probability that the results are reliable.

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