BLACK SEA REGIONAL TRANSMISSION PLANNING PROJECT: PSSE/OPF Regional Model Construction Report

Black Sea Regional Transmission Planning Project Phase III

Balkans and Regional Energy Market Partnership Program
Cooperative Agreement EEE-A-00-02-00054-00

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Black Sea Regional Transmission Planning Project Phase III Prepared for:

United States Energy Association and
United States Agency for International Development Office of Energy and Infrastructure Bureau for Europe and Eurasia

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CONTENTS

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
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	- British 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
Iran	IR	IRN	IRN

I. 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 Ukraine, Armenia, Georgia, Romania, Bulgaria 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;
- Using the OPF model and its economic dispatch determine the most likely trading patterns for 2015, 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 is publishing a complementary report titled, BSTP Renewable Energy Compendium Report. It 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 the report is being 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. The initial runs of the economic dispatch model are set to be complete by September 2012. These will provide first results indicating the ability of the network to support economically based trade of electricity. Based on the initial results the model will be refined and additional analysis will be conducted based on subsequent model runs.

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 when the maximum available power was pushed through interconnections in the simulated system. With the development of the generic cost curves 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 models gives regional planners a platform to couple economic and efficiency parameters to reliability criteria for the first time. As such, it mirrors regional planning efforts in North America and Europe, which have incorpated market based economic dispatch in their planning models as their electricity markets matured over time.

The goal of this Report is to review the necessary technical data for the Black Sea countries and the region as a whole used for the Regional Transmission Planning Project.

Figure 1.1 – Interconnection lines in Black Sea Region

Chapter 2 presents characteristic power systems data for all analyzed countries.

Chapter 3 gives review of Load Flow Model development, model characteristics and base case scenarios.

Chapter 4 gives review of Dynamic Model development, model characteristics and main production features for each system modeled.

Chapter 5 presents main Findings and Conclusions of this phase of Black Sea Project.

The Black Sea region operates in four synchronous parts (Figure 1.2)

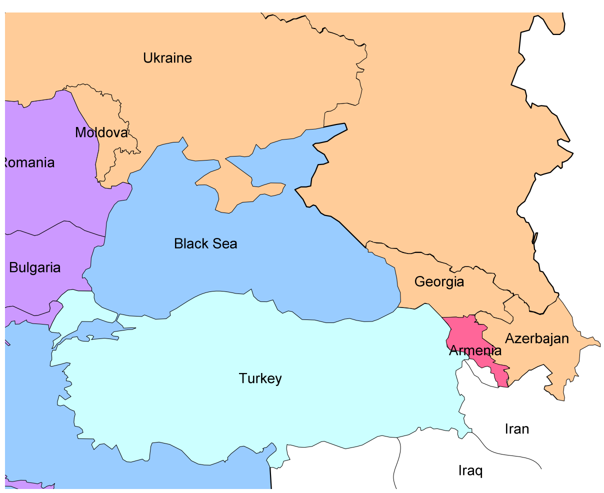


Figure 1.2 – Black Sea region – synchronous operation 2010

Threes synchronous scenarios were developed for study. (see Chapter 2 of the SRIE Technical Report) Section 2.1 presents each synchronous scenario and Table 2.1 presents the line diagrams for each scenario in 2015 and 2020. It is important to realize that the power system of Armenia is presently isolated from all of the power systems presented in Table 2.1 (Georgia, Azerbaijan, Russia and Turkey) except for island connections with Georgia and Turkey. During project year #1, only scenario #3 (synchronous operation of the Power Systems of Armenia, Georgia, Azerbaijan and Russia by 2015) has been studied.

II. METHODOLOGY

In the previous phase of the project, the 2010 static and dynamic model developed by the TSOs revealed certain system deficiencies and weak points. Currently the region has a surplus of energy, to further analyze the capacity of the regional network to support enhanced trade and exchange of electricity while maintaining security and reliability, and incorporating economical factors too, adequate regional Optimal Power Flow model is necessary. So, upon realization of Load flow and Dynamic model upgrade of this regional model, the OPF analysis has been performed.

1.1 Electricity Production

Electricity generation is the process of generating electric energy from other forms of energy. Electricity is most often generated at a power station by electromechanical generators, primarily driven by heat engines fueled by chemical combustion or nuclear fission, and by other means such as the kinetic energy of flowing water and wind. There are many other technologies that can be and are used to generate electricity such as solar photovoltaics and geothermal power.

Electricity is produced by using an electrical generator that converts mechanical power to electrical power and energy. All generators are run by a turbine, and all turbines are driven by a fluid acting as an intermediate energy carrier. This fluid is the primary energy source (water, steam, wind…). Depending on the type of primary energy source, total produced electricity in the world looks is shown in Table 2.1 and Figure 2.1 with an increase of other sources to reduce pollution and green gas emissions.

Table 2.1– Produced Electricity by Source (World total year 2008 data source IEA/OECD)

Source of Electricity (World total year 2008)							
-	Coal	Oil	Natural Gas	Nuclear	Hydro	other	Total
Electricity (TWh/year)	8,263	1,111	4,301	2,731	3,288	568	20,261
proportion	41%	5%	21%	13%	16%	3%	100%

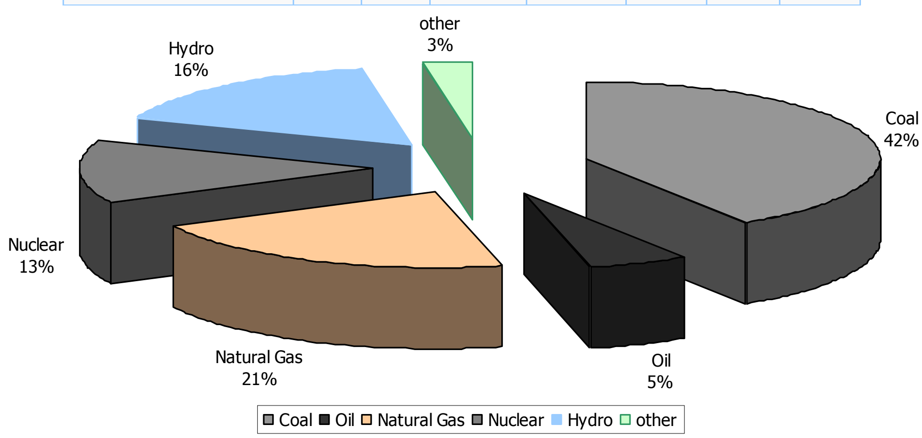


Figure 2.1 - Produced Electricity by Source (World total year 2008 data source IEA/OECD)

1.1.1 Power Plants

In this subchapter small analysis of power plants and primary sources is done as main input to electricity production by type, and also influence on overall pricing of electricity is explained.

Power plants are installations that produce electricity. Technology is differentiated based on the type of prime mover (fluid that moves turbine that runs generator that converts mechanical energy into electricity). Usually efficiency of conversion process from fuel to electricity is described through Heat rate of power plant (for fossil fuel power plants). Figure 2.2 shows recorded dependency of electricity cost on technology used for production.

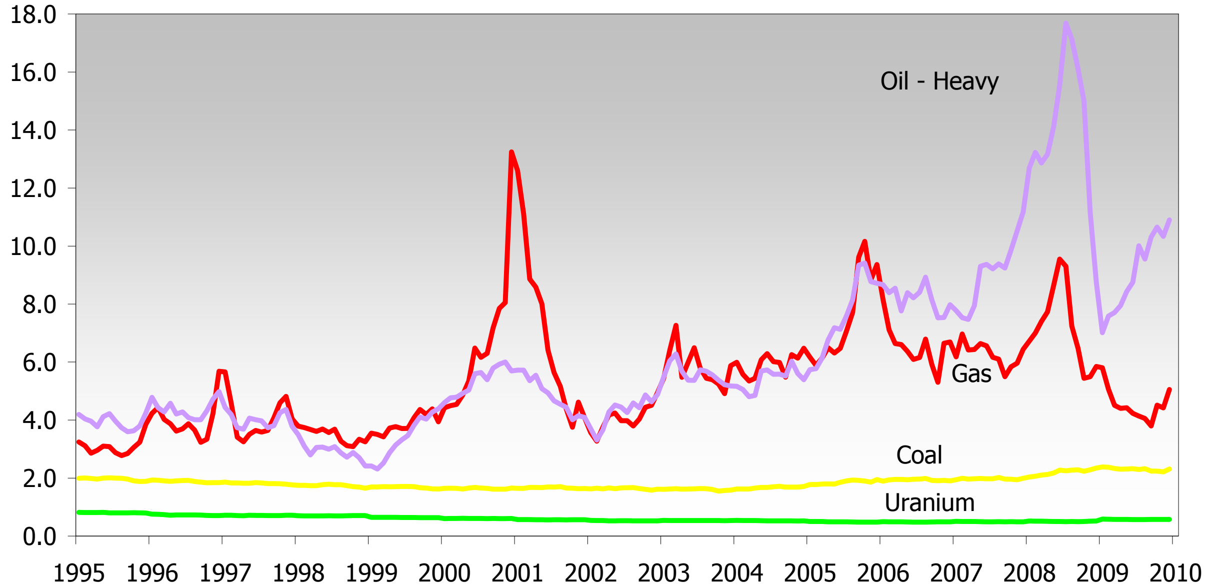


Figure 2.2 – Electricity costs depending on Fuel ($/MWh)

Cost of production of electricity depends on numerous factors, including the power plant type and technology. Costs of power plants can be divided into following categories:

- **Overnight costs**

Overnight cost is the cost of a construction project if no interest was 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**

Capital costs are costs incurred on the purchase of land, buildings, construction and equipment to be used in the production of goods or the rendering of services, in other words, the total cost needed to bring a project to a commercially operable status. For example, the purchase of a new machine that will increase production and last for years is a capital cost. Capital costs do not include labor costs except for the labor used for construction. 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. 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. They do not include the cost of fuel and labor used to run the plant or the labor and supplies needed for maintenance. These values are calculated based on Overnight costs, payment period of 20years, and discount rate 10%.

- **Operational and maintenance costs**

Operational and maintenance costs include all costs that are a consequence of power plant operation during operational life. They are usually divided into fixed and variable costs. Fixed costs do not dependent on operation of the power plant regardless if the plant is running or not. These usually include labor used to run the plant and supplies needed for maintenance.

- **Variable Operational costs (fuel costs)**

These costs include all costs related to production, such as fuel costs and fuel transportation costs. Usually they are referred to as fuel costs.

- **Overhead costs**

Overhead cost or overhead expense refers to an ongoing expense of operating a business and it is usually used to group expenses that are necessary to 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 and utilities costs, rent etc...

- **Decommissioning costs**

These costs are all costs that occur after the power plant life time (dismantling, clearing the land, waste disposal etc…). It is usually referred to nuclear facilities (decommissioning is the dismantling of a nuclear power plant and decontamination of the site to a state no longer requiring protection from radiation for the general public).

- **Transmission costs**

Are all costs connected to connection of the power plant to the transmission grid (connection lines, substations etc…).

In this chapter all economical characteristics of power plants will be explained and compared between each other. Costs by type of power plant are shown in
Table Table 2.2. All costs described in next subchapters are related to nominal operating point, or to values when power plant is operated most efficiently. Influence of different operation is given through heat rate and cost curves explained in later subchapters.

Table 2.2– Electricity production costs by source

TYPE	CAPA CITY	HEAT RATE	EFF	UTIL	LIFE	ENERGY	OVER NIGHT	CAPITAL	O&M			OVER HEAD	DECO MISSION	TRANS MISSION	CO2 EMIS.	LEVEL IZED COST	PRODU CTION COST
									FIXED	VARIABLE	FUEL						
	MW	mBTU/MWh	%	%	year	GWh	MI$/MW	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
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 - Leveled costs = 9+10+11+13+14+15+16
18 - Production costs (related only to production) =10+11+13+14+16

Hydro Power Plants

Hydro power plants use water as the prime mover. The kinetic energy of water running the blades of turbine is used (Turbine blades are acted upon by flowing water). To utilize this source, hydro power plants are built. Depending on the type of water usage, hydro power plants can be divided into three groups:

- Run of river

  These power plants are built on large rivers, and use natural flow and mass of water to produce electricity.
- Reservoir or Storage

  These power plants have high dams, so behind the dam large reservoir lake is formed to utilize water and to store water.

Another type of hydro power plant is a pumping station. These facilities are always reservoir type and have the ability to pump water in the upper reservoir and store energy as water.

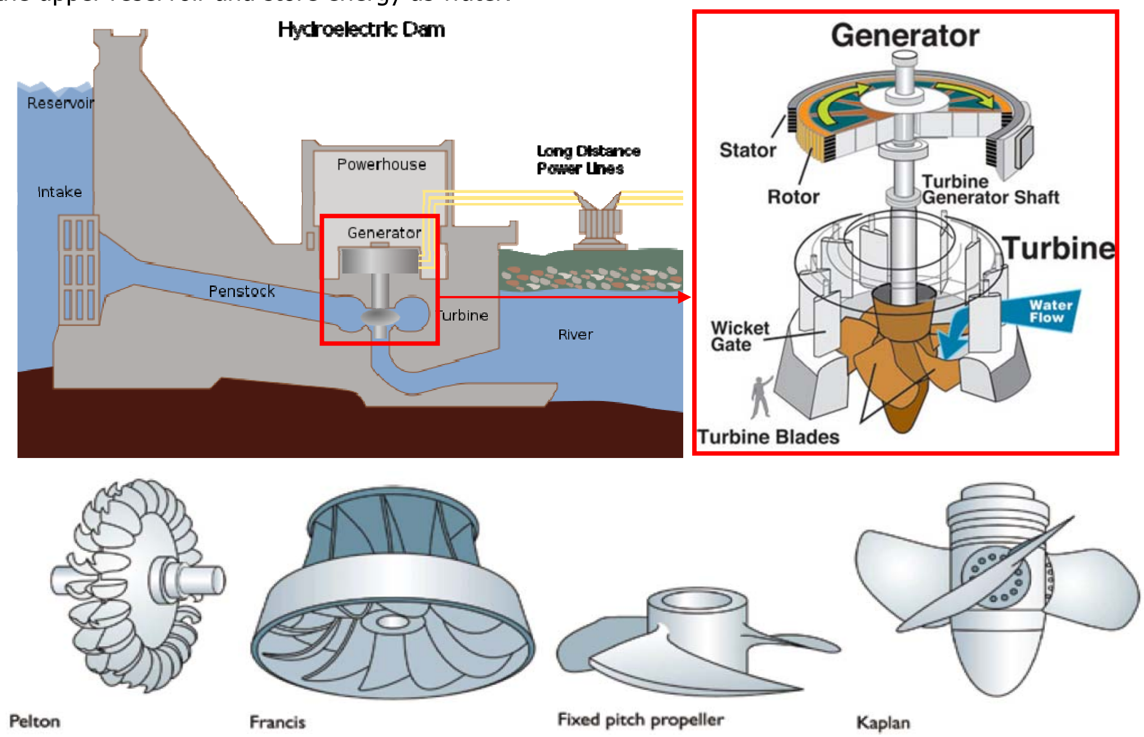


Figure 2.3 – Hydro power plants – dam cross section, turbine cross section, types of turbines

Depending on the height difference between upper and lower water level (water column length) **Net head**, shows different type of turbines (Figure 2.3):

- Pelton turbines (500m<Net Head)
- Francis turbines (<Net Head)
- Kaplan turbines (low Net Head and run of river)
- Propeller (Bulb) turbines (run of river)

Water is treated as renewable source, and there is no price tag on it, but still these facilities have some expenses:

Overnight costs for hydro power plants are quite large since there is a lot of infrastructure that needs to be built for its operation (dam, inlet channels and penstock, machine building, outlets...). Depending on the type of power plant, these costs vary from $1.2 mil/MW to $2.2mil/MW.

Capital costs are connected to overnight costs, and can range from $30-60/MWh. Large capital costs are also influenced by the time needed to build one hydro power plant. This time period of about 4-5 years, has associated costs such as land acquisition and land preparation.

Operational and maintenance costs depend on the type of hydro power plant and vary from $3.1-3.5/MWh. They are low, since the operation of a hydro power plant requires less labor. The operation crew is small and in smaller facilities there are none. Maintenance costs are not included in hydro plants since they are depend on level of operation.

Variable Operational costs (fuel costs) are zero, but to utilize water there are some expenses that are related to maintenance like clearing the derivation channels, reservoir, and penstocks. Also in this group is labor and supply expenses needed for maintenance, since most parts are changed depending on the power plant usage. These costs are usually around $7.1/MWh.

Overhead costs for hydro power plants are usually very low and can be neglected.

Decommissioning costs for hydro actually are zero, since these power plants are not decommissioned.

Transmission costs for hydro power plant highly depend on power plant location, and these plants are usually in remote places relative to consumption areas. They average around $5.7/MWh.

Thermal Power Plants

Thermal power plants use steam as the prime mover of the turbine. Steam turbines utilize a fuel (coal, natural gas, petroleum, or uranium) to create heat which, when applied to a boiler, transforms water into high pressure superheated (above the temperature of boiling water) steam. The steam is directed through a valve-controlled nozzle over turbine blades, which spins the turbine to drive a synchronous generator. Boiler can be different construction depending on the how steam is generated and which fossil fuel is used for water heating to steam:

- coal fired
- natural gas fired
- oil fired

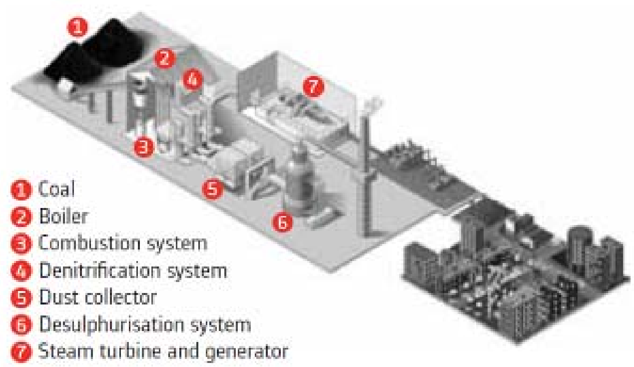


Figure 2.4 – Thermal power plant

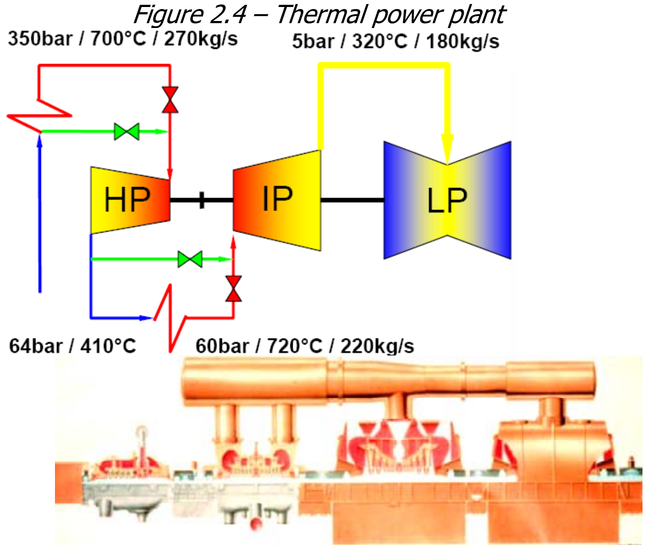


Figure 2.5 – Steam turbine (High Preasure+Intermediate pressure+Low pressure)

High pressure steam requires strong, bulky components (Figure 2.5). High temperatures require expensive alloys made from nickel or cobalt, rather than inexpensive steel. These alloys limit practical steam temperatures to 655 °C while the lower temperature of a steam plant is fixed by the boiling point of water. With these limits, a steam plant has a fixed upper efficiency of 35 to 42% (higher the working temperatures higher the efficiency rate). Described in Heat rate, typical for steam units is around 10mBTU/MWh, but for the modern large coal fired units it goes up to 8.5-9.0 mBTU/MWhr. It has to be pointed out that smaller the unit lower the efficiency, and also, if the unit is run on gas or oil heat rate increases up to 11mBTU/MWh, and even higher for Combined Heating and Power units (for oil up to 15mBTU/MWh). This is because boiler is more simplified, and also there is no special fuel preparation as it exists for coal. For this reason capital costs are much lower than for equivalent coal fired power plant as well as some operational costs.

Overnight costs for thermal power plants depend on the type of fuel used, because different infrastructure is needed. For coal fired power plants it ranges from $1.7mil/MW to $2.3mil/MW (costs of mines are not included). For gas or oil fired prices range from $0.6-1.2mil/MW. Larger size plants are less costly than smaller units.

Capital costs are connected to overnight costs and range from $26-36/MWh for coal fired units and $15-20/MWh for oil and gas fired units depending on size.

Operational and maintenance costs depend on the type. For coal fired units fixed costs are from 8-12$/MWh, and for oil and gas fired $5.5-8.3/MWh. Costs are higher for coal fired because of more complicated storage and transport facilities, and more people are employed in coal fired plants than for oil or gas.

Variable Operational costs (fuel costs) depend on the fuel used. Fuels used for thermal power plants are coal, oil or gas. Coal is the main fuel used for electricity production. There are four types of coal (first three are used for electricity production and also referred to as steam coal):

- Brown coal (Lignite) <18.5mBTU/ton
- Bituminous 18.5-24mBTU/ton
- Subbituminous 24-35mBTU/ton
- Anthracite >35mBTU/ton

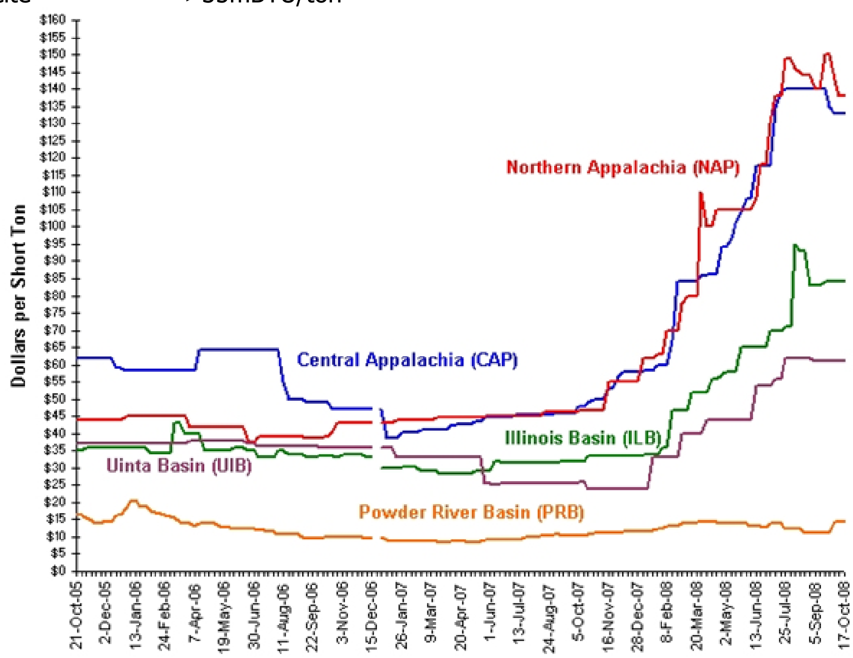


Figure 2.6 – Coal prices $/ton for different types of coal in US (1stone = 0.91ton)

Present average prices are 155$/ton for sub-bituminous, 100$/ton of bituminous and 65$/ton of lignite, or referenced to caloric heat value:

- Brown coal (Lignite) 3.5$/mBTU
- Bituminous 4.2$mBTU
- Subbituminous 4.4$mBTU

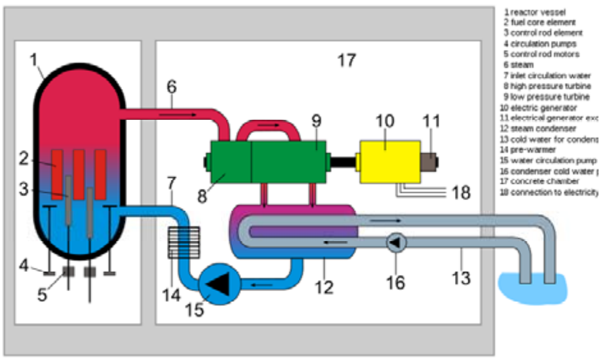
Overhead costs for coal fired units are $3.5-4/MWh, and for oil and gas $1.5/MWh.

Decommissioning costs for thermal power plants is neglected, since usually there are none. In the future it will probably be taken into consideration. These facilities are usually modernized or converted into new units, and these costs are included as capital costs for new units.
Transmission costs for a thermal power plant highly depend on the power plant location and size, but they can be estimated at \$3.6/MWh.

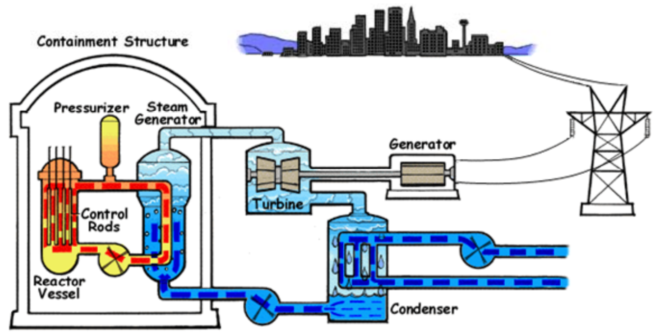
Nuclear Power Plants

Nuclear power plants are thermal power plants that use nuclear reactor generated heat to produce steam. The nuclear reactor uses Uranium as a fuel, and in process of nuclear fission, heat is produced that heats water up to high temperature steam that the runs turbine.

There are two types of reactors in use today: BWR – boiled water reactor and PWR – pressurized water reactor (Figure 2.7). In first case water is run as a coolant through the system by using pumps, and in second high pressure is used as moving force for coolant. Also, nuclear units do not have re-heater and intermediate stage in turbines (Figure 2.8)



BWR



PWR

Figure 2.7 – Types of Nuclear reactors (BWR and PWR)

Figure 2.8– Cross section of Nuclear turbine (HP stage and three LP stages)

Since the nuclear plants work with smaller steam temperatures than fossil fuel run thermal power plants and do not have re-heater, efficiency rate is a little bit lower 35-40%, and heat rate is usually at 10.5mBTU/MWh.

Control of these units is achieved in similar fashion as for thermal units run on fossil fuels. One control loop is through steam valves, and second by controlling the nuclear reactor by using control rods to reduce nuclear fission. These units are usually run as base load units to avoid using control rods, and in some cases running the unit on lower rate than nominal can be risky (reducing the load of unit means increasing the temperature and reduction of cooling efficiency).

Overnight costs for nuclear power plants are quite large since there are a lot of infrastructure that needs to be built for its operation and they go in range from 2-4mil$/MW depending on the producer and type of technology. Also, policy of country that wants to build these types of facilities is influencing dearly the costs.

Capital costs are connected to overnight costs, and range from 35-60$/MWh, and the investment can contribute about 70-80% of the costs of electricity. But 40$/MWh can be taken as a reference.

Operational and maintenance costs depend on type of technology used, but because of high safety measures they are higher than for similar size fossil fuel units. Included are costs related to labor, material & supplies, contractor services, licensing fees, and miscellaneous costs such as employee expenses and regulatory fees. On the other hand, labor costs are lower (less employees) but workers are more expensive since they require special skills and education. These costs also highly depend on the size of the plant. For smaller power plants (up to 800MW) costs are higher, but for large ones (more than 2000MW) they are around 12$/MWh.

Variable Operational costs (fuel costs) for nuclear power plants are fuel related costs, and there are two main factors: price of fuel and transportation, and waste disposal and transportation. Price of nuclear fuel was quite stable for a long period, and usage of old uranium based decommissioned nuclear warheads (mainly in Russia) contribute to this relatively low prices. For a typical 1,000 MWe BWR or PWR, the approximate cost of fuel for one reload (replacing one third of the core) is about $40 million, based on an 18-month refueling cycle, or roughly 0.7$/mBTU. These costs increased for 10% for waste management (in US it is 0.1$/MWh) gives total around 8$/MWh. These costs represent around 20-25% of total costs, compared to fossil fuel plants at 80%.

Overhead costs for nuclear power plants can be high, and main reason being the additional safety measures that are necessary for the facilities compared to fossil fuel ones which are around 4$/MWh.

Decommissioning costs for nuclear units can be significant. At the moment, they exist only for nuclear units. Usual costs per plant are $300-500 million, and these include estimated radiological ($300 million), used fuel ($100-150 million) and site restoration costs ($50 million).

Transmission costs for nuclear power plant depend on power plant location, and these plants are in remote places (to consumption areas) for the safety reason. On the other hand, high utilization of these facilities reduces transmission costs to $3/MWh.

Gas Turbine Power Plants

As a special group of thermal power plants are ones that use gas turbines. Primary driving force is the exhaust gas from burned mixture of air and gas in the combustion chamber. These machines are actually Jet engine technology fixed to the ground. Fuel (can be either liquid or gas) mixed with compressed air is ignited (Figure 2.10). The combustion increases the temperature and volume of the gas flow, which when directed through a valve-controlled nozzle over turbine blades, spins the turbine which drives a synchronous generator. A combustion turbine is also referred to as a simple cycle gas turbine generator. They are relatively inefficient with net heat rates at full load of over 15 mBTU/MWhr per kilowatt-hour (Figure 2.10). Consequently, simple cycle gas turbine generators are relatively inefficient, combined with high natural gas prices, make the gas turbine expensive. Yet, they can ramp up and down very quickly, so as a result, combustion turbines have mainly been used only for peaking or standby service.

Combined cycle units are another type of gas fired plants that utilize both gas turbines and steam turbines (Figure 2.9). A combined cycle power plant combines gas turbine (also called combustion turbine) generator(s) with turbine exhaust waste heat boiler(s) (also called heat recovery steam generators or HRSG) and steam turbine generator for the production of electric power. The waste heat from the combustion turbine is fed into the boiler and steam from the boiler is used to run steam turbine. Both the combustion turbine and the steam turbine produce electrical energy. Generally, the combustion turbine can be operated with or without the boiler. The gas turbine exhausts relatively large quantities of gases at temperatures over 540 °C, In combined cycle operation, then, the exhaust gases from each gas turbine will be ducted to a waste heat boiler. The heat in these gases, ordinarily exhausted to the atmosphere, generates high pressure superheated steam. This steam will be piped to a steam turbine generator. The resulting combined cycle heat rate is in the 8.5 to 10.5 mBTU/MWh range, significantly less than a simple cycle gas turbine generator.

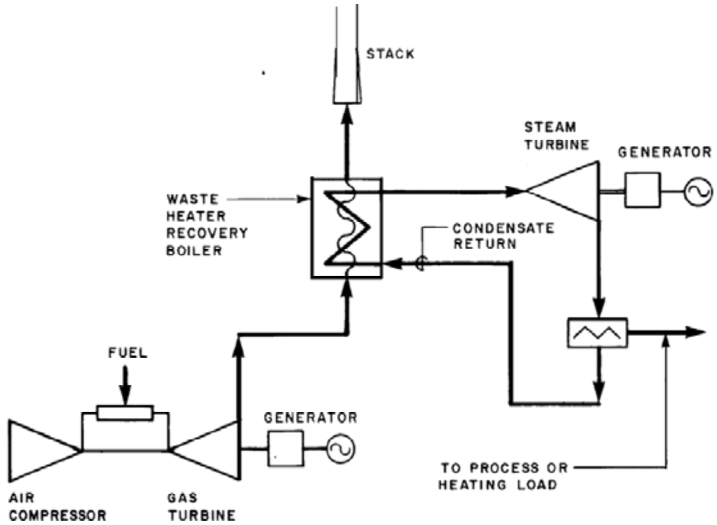


Figure 2.9 - Single Gas Turbine with Single HRSG

This process is much more effective than standard usage of burned gas in the boiler to generate steam described in previous section and these plants offer efficiencies of up to 60%. In addition to the good heat rates, combined cycle units have flexibility to utilize different fuels. This flexibility, together with the fast ramp rates of the combustion turbines and relatively low heat rates, has made the combined cycle unit the unit of choice for a large percentage of recent new power plant installations.

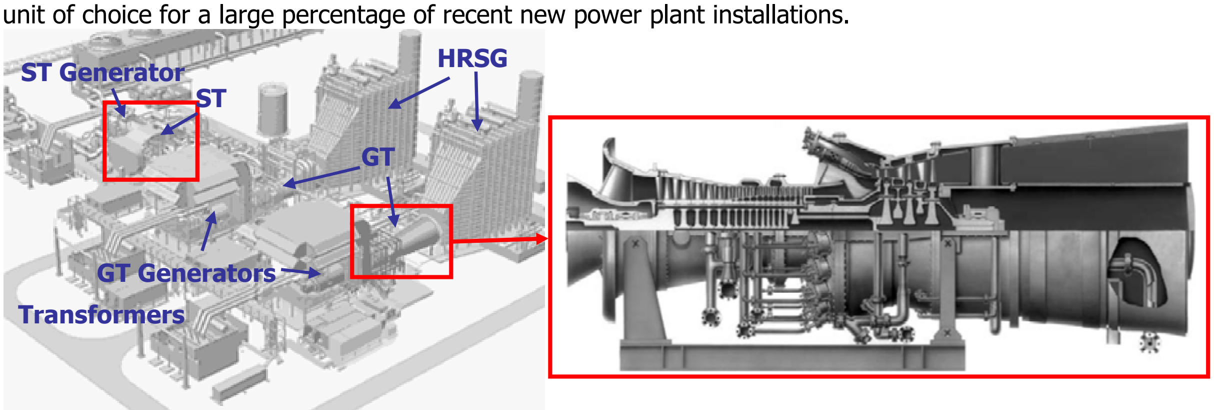


Figure 2.10 – Multi-shaft system 2GT+ST and Gas Turbine

Figure 2.9Figure shows the simplest kind of combined cycle arrangement, where there is one combustion turbine and one HRSG and corresponding steam turbine, but other combinations are possible:

- Single shaft units (GT and ST are mounted on the same shaft and running one generator)
- Multi shaft units (typically 2xGT+1xST but other arrangements are possible)

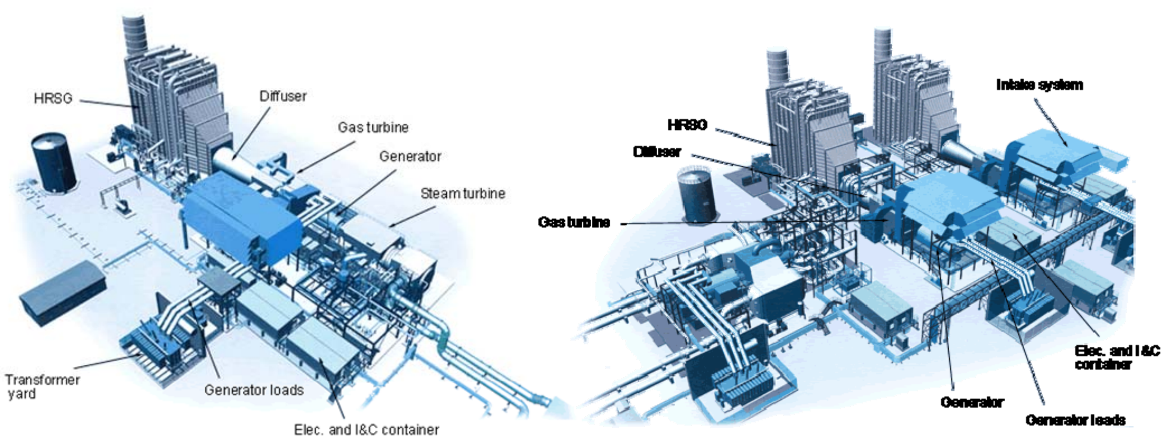


Figure 2.11 – Single shaft GT+ST+1generator and Multi-shaft system 2GT+ST

For large scale power generation, a typical set would be a 270 MW gas turbine coupled to a 130 MW steam turbine giving 400 MW. A typical power station might comprise of between 1 and 6 such sets. Plant size is important in the cost of the plant. The larger plant sizes benefit from economies of scale (lower initial cost per kilowatt) and improved efficiency. Typical Combined cycle block sizes offered by three major manufacturers (Alstom, General Electric and Siemens) are roughly in the range of 50 MW to 500 MW and costs are about $600/kW.

Control of power is achieved through control fuel injection and not through flow of working fluid (water or steam) like with classical fossil fuel fired units. This makes the units useful for fast control, and suitable for ancillary services.

Overnight costs for CCGT are relatively low and goes in range from 0.85-0.95mil$/MW, which make these facilities quite interesting from this point of view.
Capital costs are connected to overnight costs, so as explained here are they relatively low in range from 14-15$/MWh. Also, period of commissioning is up to three years. Due to these qualities, there is more investment in the combined cycle units in the world.
Operational and maintenance costs depend on type of technology that is used, but compared to other fossil fueled power plants they are considerably lower and vary from 5-7$/MWh. Main reason for this is simple technology and low labor costs.
Variable Operational costs (fuel costs) are highly dependent on fuel costs, which price has changed a lot in recent period (Figure 2.12). Heat rate of LNG as fuel is taken as 39mBTU/tcm. Recent price development shows that average gas price is 8.2$/mBTU, although in recent history it achieved 10$/mBTU. There is opinion that price of 12$/mBTU would make power production from gas totally without profit. Projections are that natural gas prices will decline in the next few years, but so far they haven't, largely as a result of the increased power plant use and increased demand.

Figure 2.12 – LNG prices ($/mBTU) on different market hubs

It has to be pointed out that these facilities have relatively low carbon emission, so they become interesting sources even from ecological point of view. So, despite the high price of natural gas as a fuel relative to coal, the past 10 years have seen new combined cycle gas-fired plants far outpace new coal-fired plants, with gas accounting for over 99% of new capacity in this time period. The reason for this has been that natural-gas-fired combined cycle plants have:

- lower capital costs,
- higher fuel efficiency,
- shorter construction lead times, and
- lower emissions.

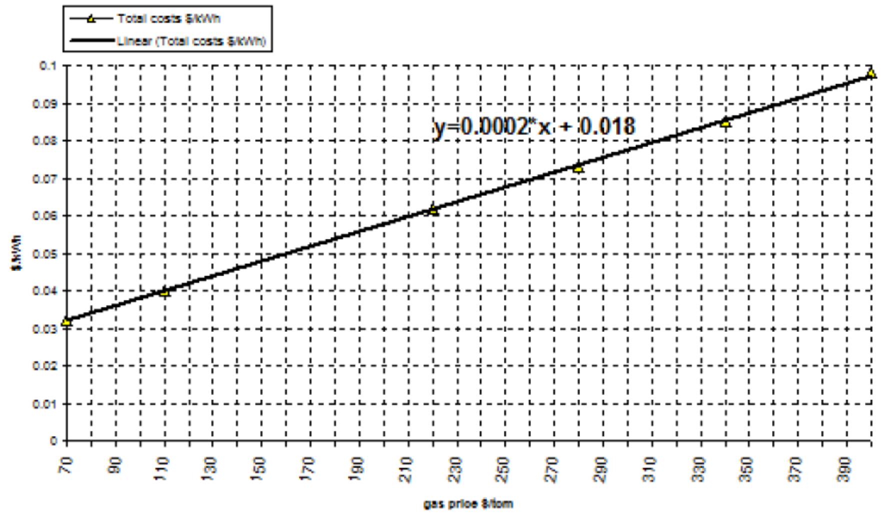


Figure 2.13 – Gas price ($/tcm) influence to CCGT generation cost

Figure Figure 2.13 shows influence of price of gas on price of electricity produced in CCGT. The information on current gas price for the generators in 2011 varies, from 297-360 $/tcm. According to the graph above, this gas price returns the total generation cost of about 77-90 $/MWh.
Overhead costs for these type of power plants are relatively low around 2.7$/MWh, but they can go up to 4$/MWh depending on the regulations.
Decommissioning costs for these units are zero, usually old fossil fired units are replaced with these ones, but there have been cases in which power plants have been dismantled but only to be replaced with new more efficient units.
Transmission costs for these units are usually lower than for other types, because these facilities are build close to consumption areas (which is one of major advantages) and in lot of cases they are used to replace old fossil fired units, so transmission capacity already exist. These costs are estimated to 2.6$/MWh.

Renewables

Renewable energy sources RES are all sources that do not use conventional approach in generating electricity (described before). Following types of RES can be differentiated:

Small hydro is the development of hydroelectric power on a scale serving a small community or industrial plant. The definition of a small hydro project varies but a generating capacity of up to 10 megawatts (MW) is generally accepted as the upper limit of what can be termed small hydro. These power plants are actually very similar to large ones, only difference is their size.

Biomass*,* a renewable energy source, is biological material from living, or recently living organisms, such as wood, waste, (hydrogen) gas, and alcohol fuels. Biomass is commonly plant matter grown to generate electricity or produce heat. In this sense, living biomass can also be included, as plants can also generate electricity while still alive. The most conventional way in which biomass is used, however, still relies on direct incineration, and usage of similar technology as for thermal power plants. As a special form of Biomass is usage of **Biofuel** which is a type of fuel which is in some way derived from biomass. The term covers solid biomass, liquid fuels and various biogases. In both cases, technology to get electricity is as conventional power plants, the only difference is how you get fuel.

Waste power is electricity gained through process of waste incineration and disposal. These are conventional thermal power plants that use waste as fuel (construction of incinerator is different) and there is preparation of waste as fuel that is different.

Solar power means usage of sun as energy source, directly through photovoltaic conversion (PV panels) or usage of sun as the heat source: solar parabolic troughs and solar power towers concentrate sunlight to heat a heat transfer fluid, which is then used to produce steam like in conventional thermal power plant.

Geothermal, power means usage of either steam under pressure that emerges from the ground and drives a turbine or hot water evaporates a low boiling liquid to create vapor to drive a turbine. In other words these are like conventional thermal power plants.

Tidal power, also called tidal energy, is a form of hydropower that converts the energy of tides into useful forms of power - mainly electricity. Usually these facilities are constructed in ocean bays and demand special type of turbines.

Wind power is electricity generated from kinetic energy of wind by using a wind turbine. Most wind turbines generate electricity from naturally occurring wind. Solar updraft towers use wind that is artificially produced inside the chimney by heating it with sunlight, and are more properly seen as forms of solar thermal energy. Standard wind turbines are able to convert up to 59% of wind energy to power.

Costs of RES are relatively difficult to accommodate since they depend on lot of factors, and one of main is policy in some country as well as subsidies.
Overnight costs for RES highly depend on type of technology that is used. Usage of Solar energy is most expensive and also tidal, since they use special technology for electricity production. Other RES use conventional technology which lowers their costs. Exception is wind power, but level of production of wind turbine decreased the overall prices for wind equipment.
Capital costs are connected to overnight costs, but it has to be said that they are highly dependable on state subsidies for RES (either through lower discount rates or special bank policies). In these analyses these effects are neglected.
Operational and maintenance costs depend on type of technology used, but they tend to be quite high since special technologies and labor is necessary for maintenance and operation. These costs are especially high if there is large uncertainty in energy production, like for wind, because they include significant costs for wind prediction.
Variable Operational costs (fuel costs) for all RES are treated as zero, although for some type of RES there are fuel costs related to fuel used (waste, biomass…). These costs do not include eventual costs of balancing the production (ancillary services).
Overhead costs for RES are quite dependant on state policy, but usually they can be neglected for most of RES type.
Decommissioning costs for RES are treated as zero.
Transmission costs for RES are significantly high and depend on technology used. Usually these facilities are in remote places where you have to build transmission capacity in other to utilize the power plant. In other words, significant transmission related investments have to be made in other to utilize the source. For some type, these costs are not that high (biomass, waste and even small hydro in some cases).

1.1.2 Generation Cost Curves

Generation costs are typically represented by one of the following four curves:

- input/output (I/O) curve
- fuel-cost curve
- heat-rate curve
- incremental cost curve

Input/output (I/O) curve

The cost of fuel input to a generation plant does not reflect the actual costs of producing electrical energy as output from the plant because substantial losses occur during production. Some power plants have overall efficiencies as low as 35%. Additionally, the plant efficiency varies as a function of the generation level Pg.

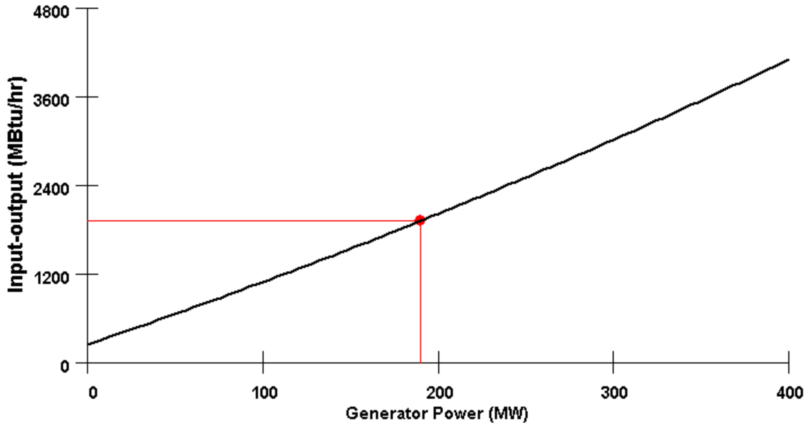


Figure 2.14 – Input/output (I/O) curve

By measuring the energy output to obtain Pg, MW output, over a given period of time, for example an hour, and the energy input can be obtained by measuring the fuel used during the hour and then multiplied by the coal energy content in MBTU/ton. The resulting plot demonstrates fuel input in MBTU/hr as a function of the power output Pg in MW. This type of plot (Figure 2.14) is called an input-output curve, and it is denoted as R.

Fuel-cost curve

If I/O is multiplied by the fuel cost, it is called a fuel-cost curve (Figure 2.15) The curve shows the cost for the given production level Pg.

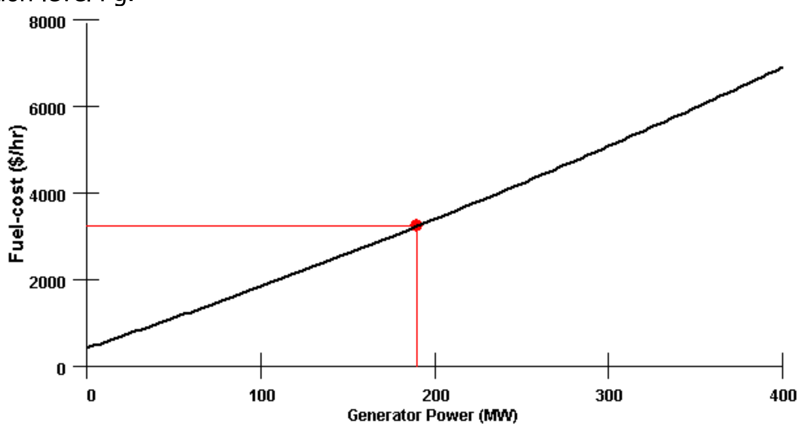


Figure 2.15 – Fuel-cost curve

In a fuel cost curve, if the fuel input is increased, the power output per unit fuel input begins to decrease. The furnace, boiler and the steam pipes leak a larger percentage of input heat as temperatures increase (energy losses are higher). This is characteristic for almost all processes, the rate of increase in output decreases as the input increases, assuming other inputs are fixed.

Heat-rate curve

Since the heat rate (Energy Efficiency) depends on operating point, is represented as H=H(Pg). The heat-rate curve is the I/O curve divided by MW. The heat rate H=H(Pg) is the amount of input energy required to produce a MWhr, at the generation level Pg. Figure 2.16 indicates that there is less efficiency for low generation levels and increases with generation, but at some optimum level it begins to diminish. Most power plants are designed to have the optimum level close to the rated output.

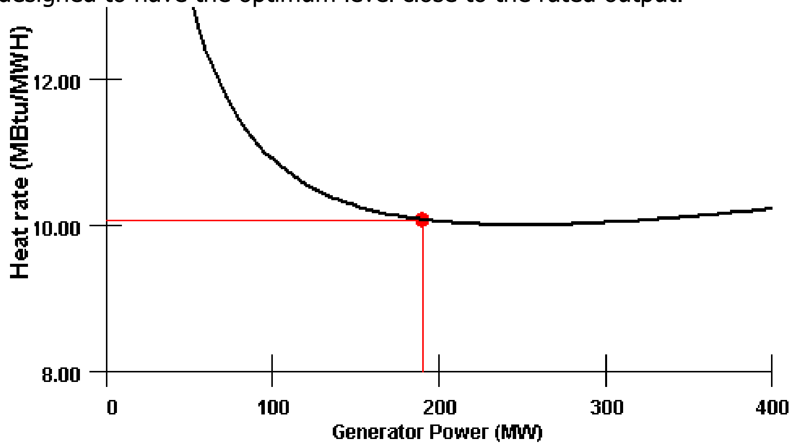


Figure 2.16- Heat rate curve

Some typical heat rates for units at maximum output are (in MBTU/MWhrs) 9.5-10.5 for fossil-steam units and nuclear units, 13.0-15.0 for combustion turbines, and 7.0-9.5 for combined cycle units. Future combined cycle units may reach heat rates of 6.5-7.0. It is important to understand that the lower the heat rate, the more efficient the unit.

Incremental cost curve

Figure 2.15 hows that the cost per hour increases with generation, a feature that one would expect since higher generation levels require greater fuel intake per hour, but this increase is not linear as efficiency of generation increases. This cannot be clearly seen from the curve, so the desired $/MWh characteristic, called the incremental cost curve for the plant, is obtained by differentiating the fuel cost curve. In this curve it is evident that the costs decrease as efficiency increases. Figure 2.17 shows an incremental cost curve derived from the fuel cost curve shown on Figure 2. 15.

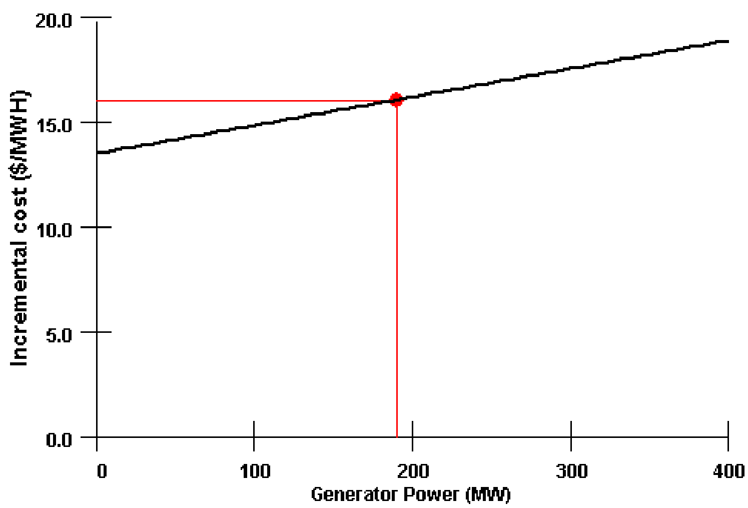


Figure 2.17– Incremental cost curve

$$C_i(P_{Gi}) \quad = \quad \alpha_i + \beta P_{Gi} + \gamma P_{Gi}^2 \quad \text{\$/hr (fuel-cost)}$$

$$IC_i(P_{Gi}) \quad = \quad \frac{dC_i(P_{Gi})}{dP_{Gi}} = \beta + 2\gamma P_{Gi} \ \text{\$/MWh}$$

Smoothing cost curves

Generator cost curves are usually not smooth. In some cases the curves are discontinuous. The discontinuity in the cost curve of Figure 2.18 occurs due to the multiple steam valves. There are 5 different steam valves shown on the diagram. Large steam power plants are operated so that valves are opened sequentially, i.e., power production is increased by increasing the opening of only a single valve, and the next valve is not opened until the previous one is fully opened. So the discontinuities of Figure 2.18 represent where each valve is opened. The cost curve increases at a greater rate with power production just as a valve is opened. The reason for this is that the so-called throttling losses due to gaseous friction around the valve edges are greatest just as the valve is opened and taper off as the valve opening increases and the steam flow smoothens.

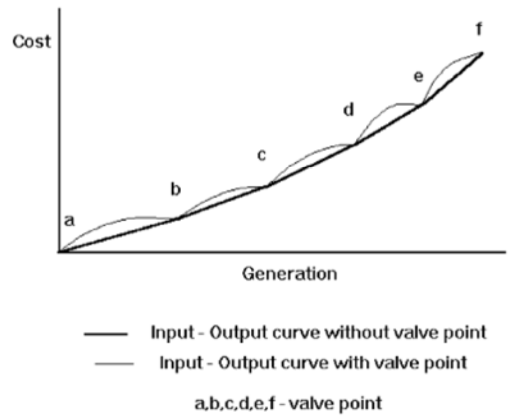


Figure 2.18 – Cost curve for large steam power plant

The significance of this effect is that the actual cost curve function of a large steam plant is not continuous, but even more important, it is non-convex. A simple way to handle these two issues is to approximate the actual curve with a smooth, convex curve, similar to the dark line of Figure 2.18. This is done by using adequately estimated piece-wise smooth functions.

There are three predominant approximations:

- piece-wise linear functions
- quadratic or cubic piece-wise functions
- polynomial functions

"Piece-wise linear" cost curve, means that whole curve is divided in linear sections (Linear relation between cost and generation in MW), point by point (Figure 2.19). This approach is extremely good if we are modeling Fuel cost curves.

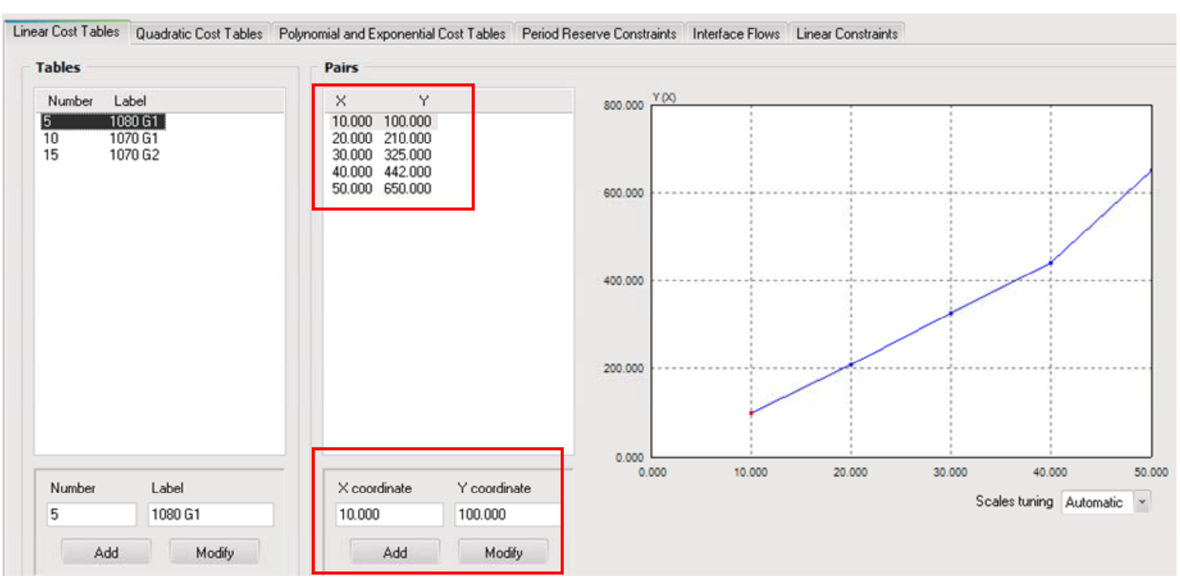


Figure 2.19 – Piece-wise linear cost curve

Data are entered in coordinate pairs (x,y) which define segments of 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]

"Piece-wise quadratic" cost curve, means that the incremental cost curve is represented with linear sections. Since incremental cost curve is a derivate from fuel cost curve, a set of quadratic curves show the fuel cost curve.

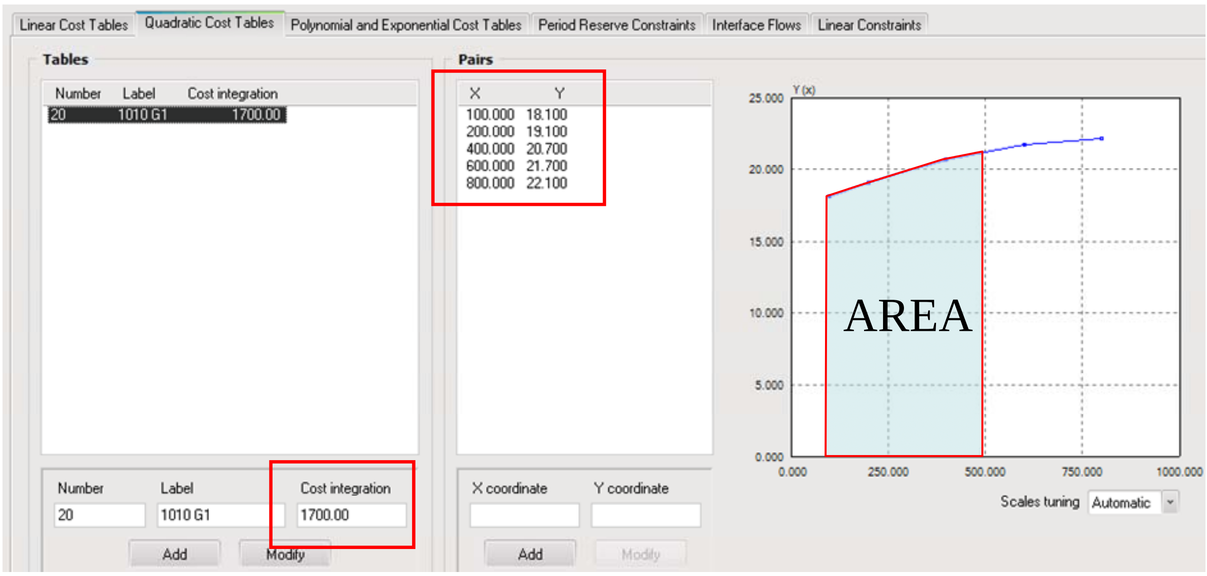


Figure 2.20 – Piece-wise quadratic cost curve

Data are entered in coordinate pairs (x,y)
- x: active power generation (MW)
- y: generator incremental fuel cost (€/MW)
- Integration constant – used to calculate final fuel cost (€/h)

Gen. fuel cost = [Fuel Cost Scale Coef.] x (Integ. Constant + AREA)

"Polynomial and Exponential" cost curve, means "fitting of polynomial function according to calculated values for generation costs.

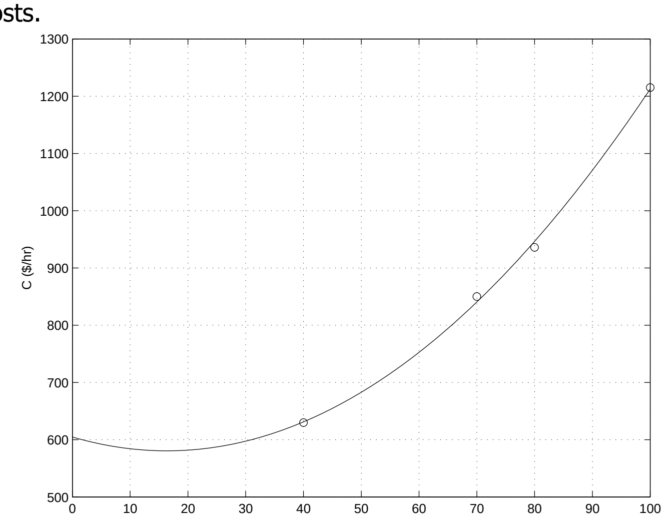


Figure 2.21 – Polynomial Curve Fit for Cost Rate Curve

*Gen. fuel cost = [Fuel Cost Scale Coef.] x (Integ. Constant + A*Pgen + B*Pgen² + C*e^{D*Pgen})*

1.1.3 Generic Generation cost curves

For each type of power plant, EKC has developed generic generation cost curves based on general technological characteristics. These generic cost curves are implemented in the Regional model but adjusted according to the available data and real power plant characteristics. For all power plants older than 20 years, transmission costs and capital costs are assumed to be zero, and for new power plants are fully included.

Hydro Power Plants

Depending on the type of hydro power plant and hydraulic turbine used, there can be three types of cost curves:

- high head long penstock (Pelton turbine)
- high head medium penstock (Francis turbine)
- low head no penstock (Kaplan turbine)

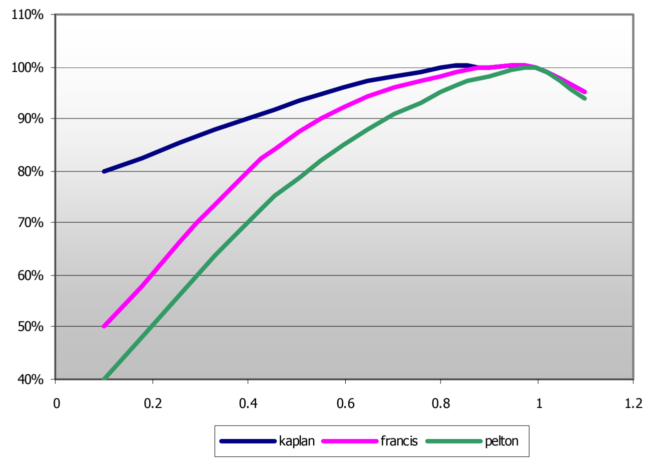


Figure 2.22 – typical efficiency rates for hydraulic turbines depending on power output (p.u.)

These three types of turbines have different efficiencies and therefore there are three types of cost curves.

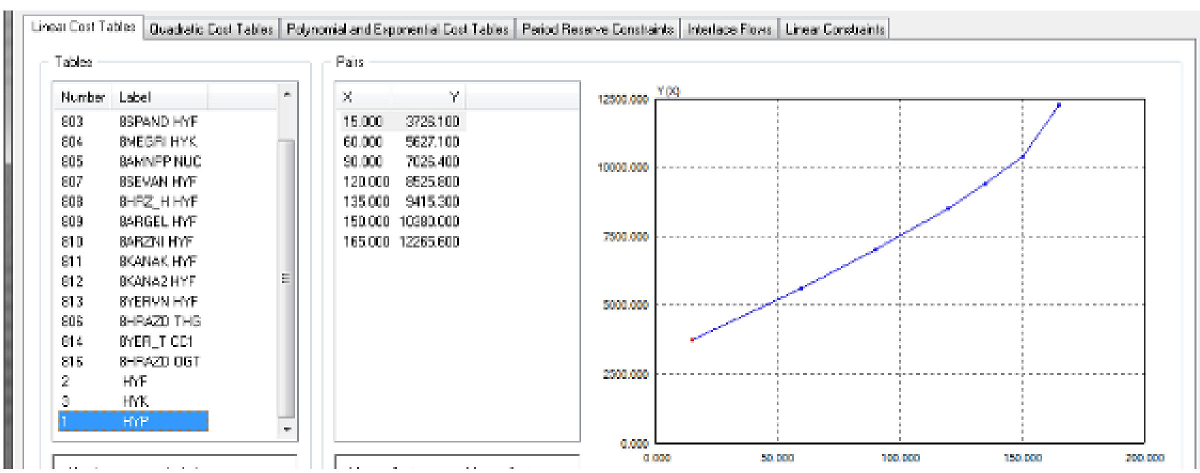


Figure 2.23– Cost curve and table for HPP with Pelton turbine 160MW (curve HYP)

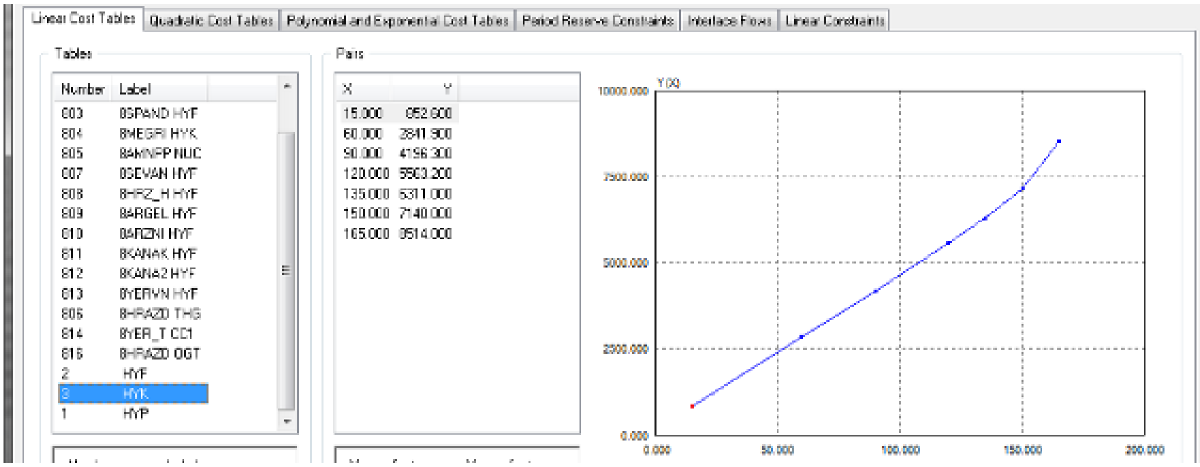


Figure 2.24– Cost curve and table for HPP with Kaplan turbine 160MW (curve HYK)

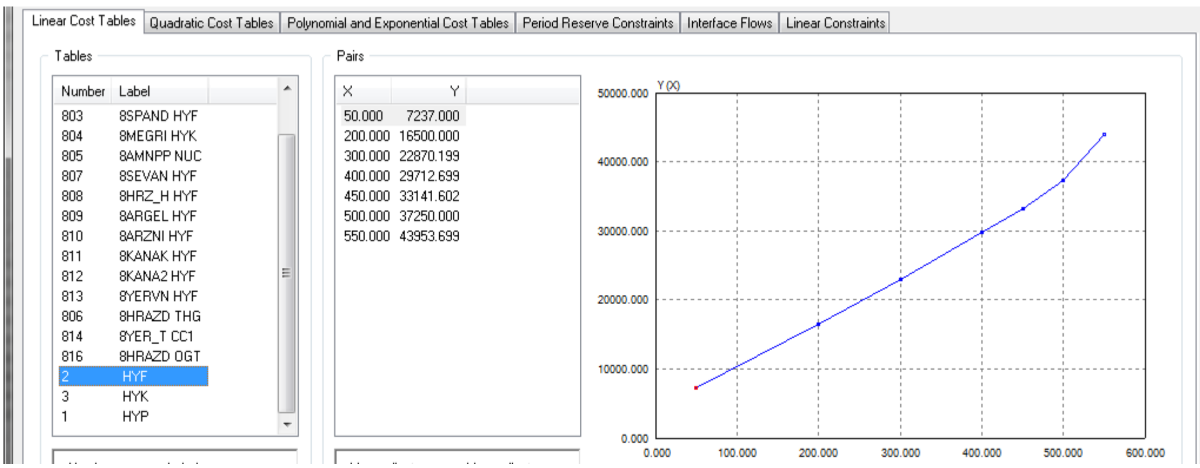


Figure 2.25 – Cost curve and table for HPP with Francis turbine 500MW (curve HYF)

Another important factor for hydro power plants is that variable costs depend on the operation point. If a turbine is operated near the technical minimum it causes greater fatigue on the turbine blades, and therefore the costs are higher. These regimes are avoided by modeling the technical minimum parameter for hydro power plants.

Variable Costs for all three types of curves at nominal capacity is the same 7.1$/MWh, and fixed costs according to the cost of labor (related to GDP value) and whether capital costs are taken into consideration or not. Same approach is taken for all types of power plants.

Power plants on the same river-cascade should have similar curves and the same cost ratio, to avoid illogical engagement (all downstream plants are engaged according to the engagement of the first one in the cascade). It is not possible to model this effect in PSS/E OPF and the only way to follow this effect is by defining the limits of engagement of a power plant and by using similar cost curves. Different costs between these plants are achieved by changing the fuel cost coefficient.

Thermal Power Plants

Thermal power plants that use steam as the prime mover for a turbine, are grouped by size. Two models are developed, 300 MW unit and 1000MW unit (the larger the unit better the efficiency). Based on these two models other fuel type models (gas and oil) are derived.

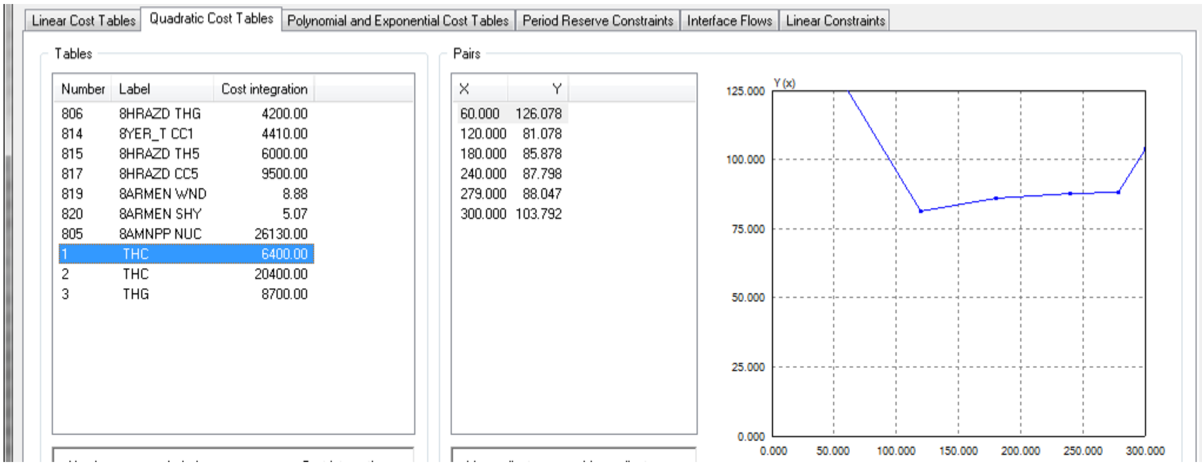


Figure 2.26– Cost curve and table for 300MW coal fired unit (curve THC)

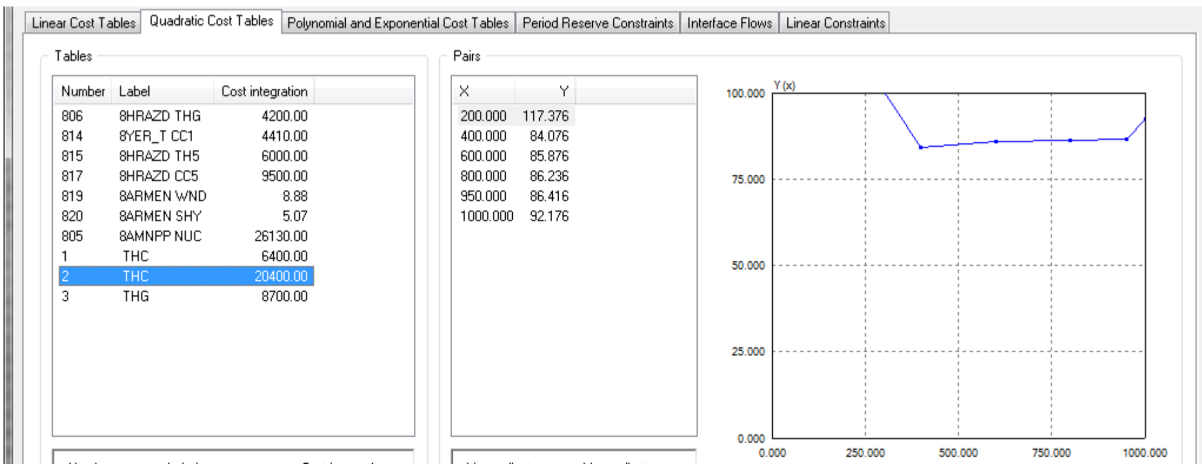


Figure 2.27 – Cost curve and table for 1000MW coal fired unit (curve THC)

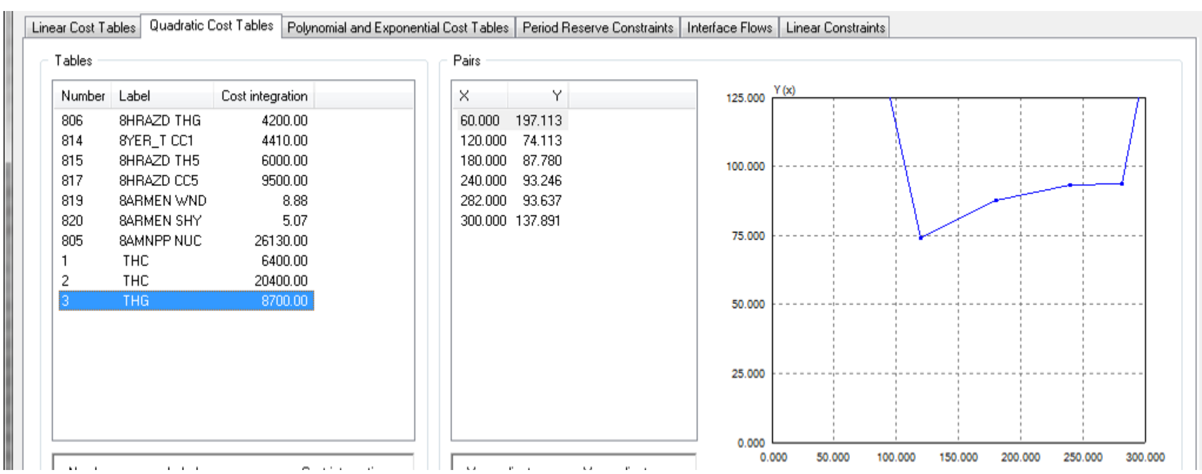


Figure 2.28 – Cost curve and table for 300MW gas fired unit (curve THC)

Cost curves that correspond to real units are gained through scaling of these curves according to real machine data (size of the unit, heat rate, fuel costs etc…).

Gas Turbine Power Plants

Figure 2.29 shows a typical cost curve for Open cycle gas turbine units (OGT).

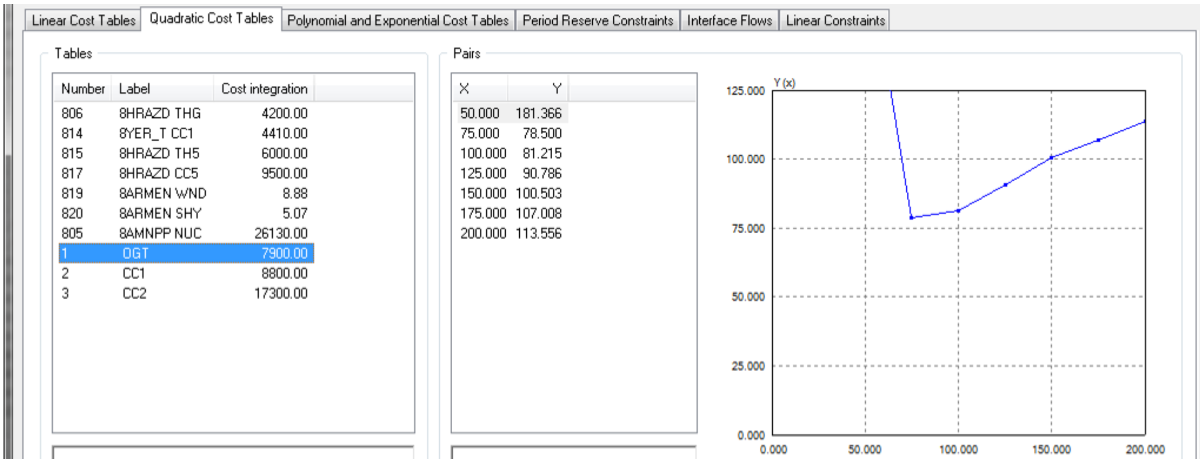


Figure 2.29 – Cost curve and table for OGT 200MW (curve OGT)

Combined cycle GT units (CCGT) use exhaust gases to heat up steam for ST units. One additional level of complexity would have two GT (GT A and B) and one ST unit (2GT+ST). In this design, the following six combinations are possible:

1. GT A alone
2. GT B alone
3. GT A and GT B together
4. GT A and ST
5. GT B and ST
6. GT A and B and ST

The modes with the ST are more efficient than the modes without the ST (since the ST utilizes GT exhaust heat that is otherwise wasted), with the last mode listed being the most efficient. Each of these six combinations will have their own unique cost-curve characteristic. Therefore, in performing economic dispatch, shifting between these various cost curve characteristics is important. But there is another more serious problem. Consider the transition between the combined cycle power plant operations just as the HRSG is ramped up. Prior to the HRSG start-up, only the GT is generating, with a specified amount of fuel per hour being consumed, as a function of the GT power generation level. After the HRSG start-up, the fuel input remains almost constant, but the MW output of the two generation units has increased by the amount of power produced by the steam turbine driven by the HRSG. A typical cost curve for this situation is shown in Figure 2.30.

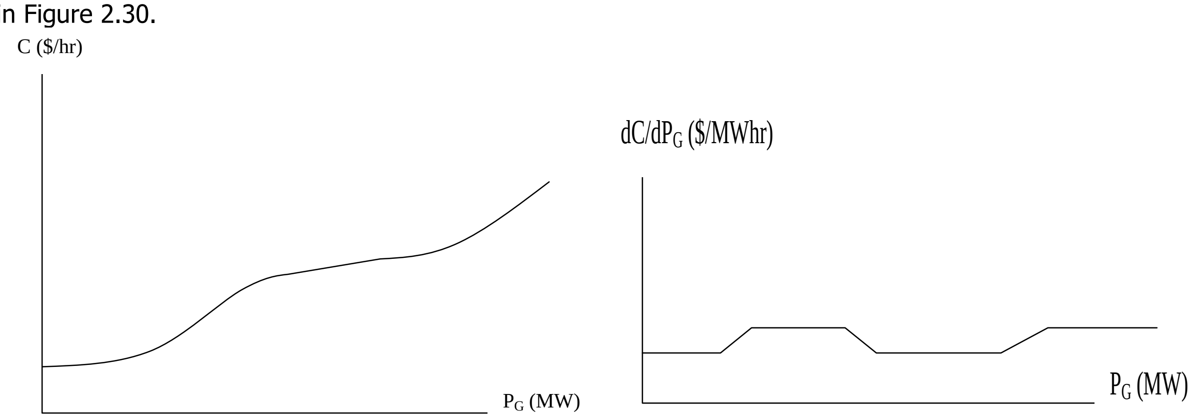


Figure 2.30– Cost curve and Incremental cost curve for a combined cycle plant

An important feature of this curve is that it is not convex, which means its slope (i.e., its incremental cost) does not monotonically increase with P_G. and that is something that cannot be modeled in PSS/E. So for these power plants equivalent curve is constructed, and this one takes into consideration that all units are always operational (both GTs and ST) in Figure 2.31 (for GT+ST single and multi-shaft units) and Figure 2.32 (2GT+ST).

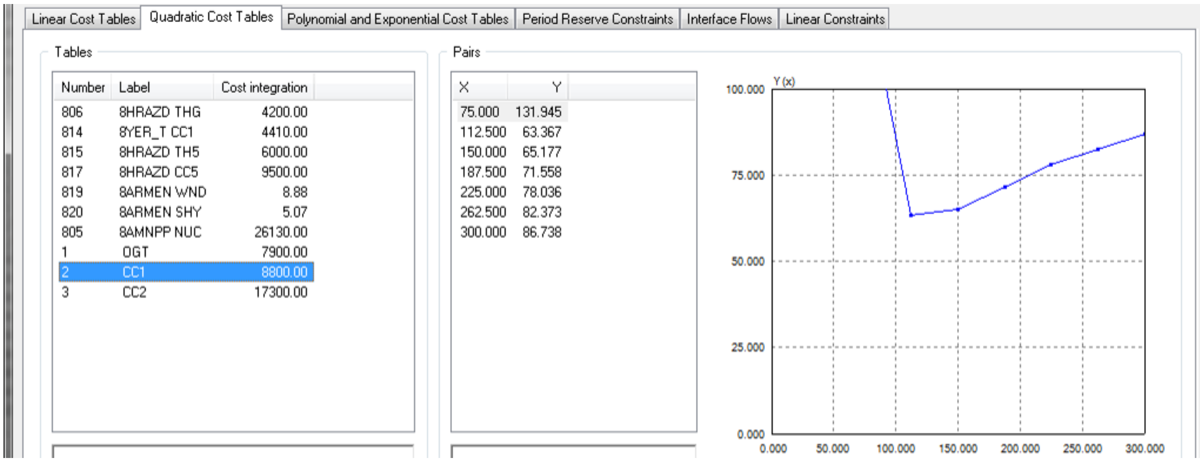


Figure 2.31 – Cost curve and table for CCGT 200MW GT+100MW ST (curve CC1)

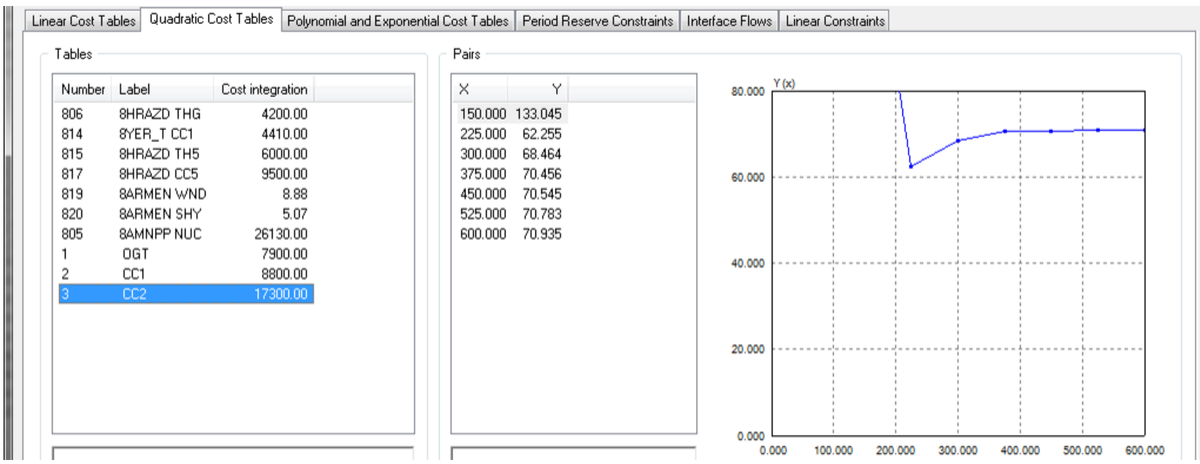


Figure 2.32 – Cost curve and table for CCGT 2x200MW GT+100MW ST (curve CC2)

Cost curves that correspond to real units are gained through adequate scaling of these curves according to real machine data (size of the unit, heat rate, fuel costs etc…).

Nuclear Power Plants

Nuclear power plants are actually thermal power plants, but with one significant difference, they use nuclear reactor generated heat to produce steam. A similar approach is taken, meaning the two models are developed, 500 MW unit (to represent older units) and 1000MW unit (larger the unit better the efficiency).

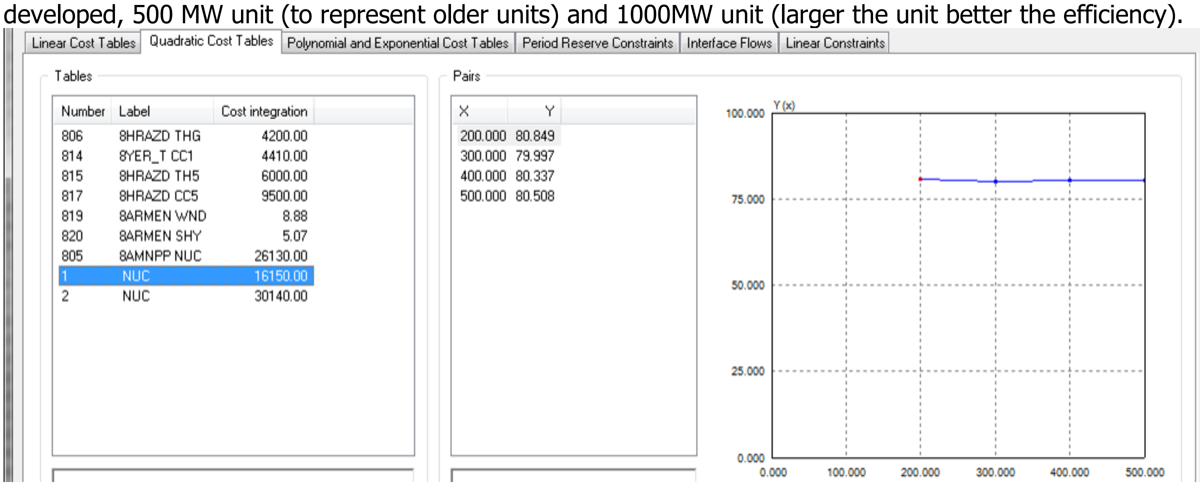


Figure 2.33 – Cost curve and table for 300MW coal fired unit (curve THC)

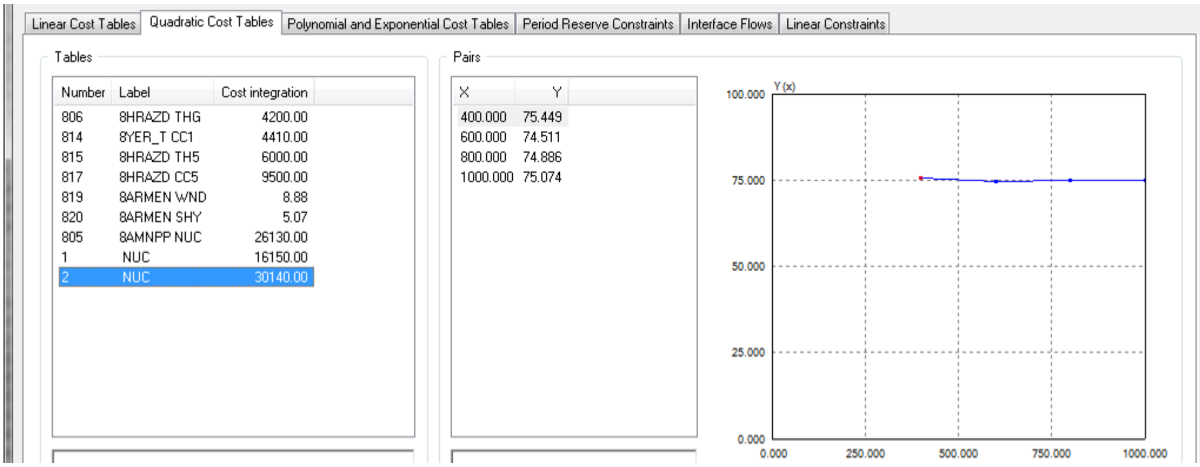


Figure 2.34 – Cost curve and table for 1000MW coal fired unit (curve THC)

Again, cost curves that correspond to real units are gained through adequate scaling of these curves according to real machine data (size of the unit, heat rate, fuel costs etc…).

Renewables

Specific RES models are not developed, but depending on the real system situation adequate model is derived based on classical models described before. Most commonly used ones are feed in tariff models shown in Figure 2.35 for Wind power plant and Figure 2.36 for small hydro power plants.

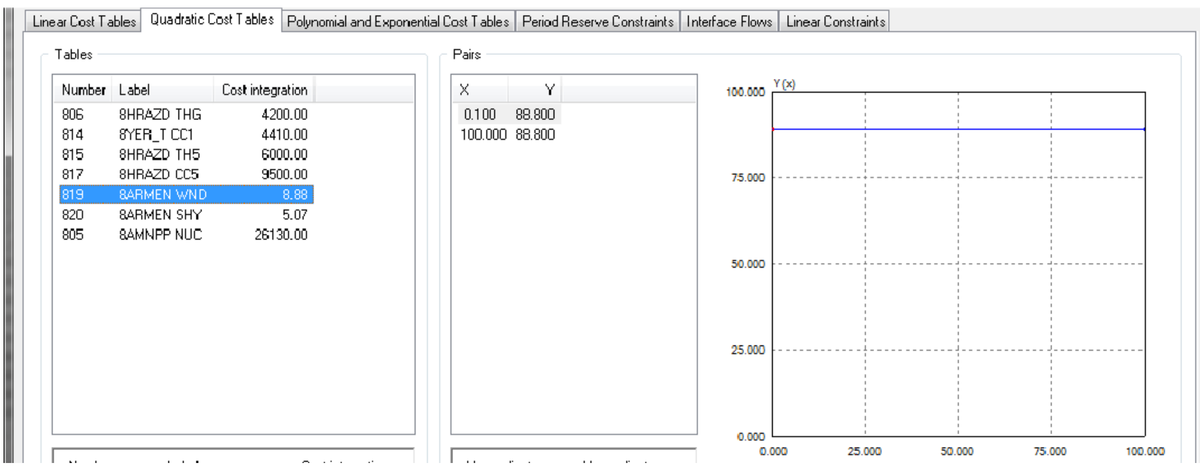


Figure 2.35 – Cost curve and table for Wind power plants (curve WND)

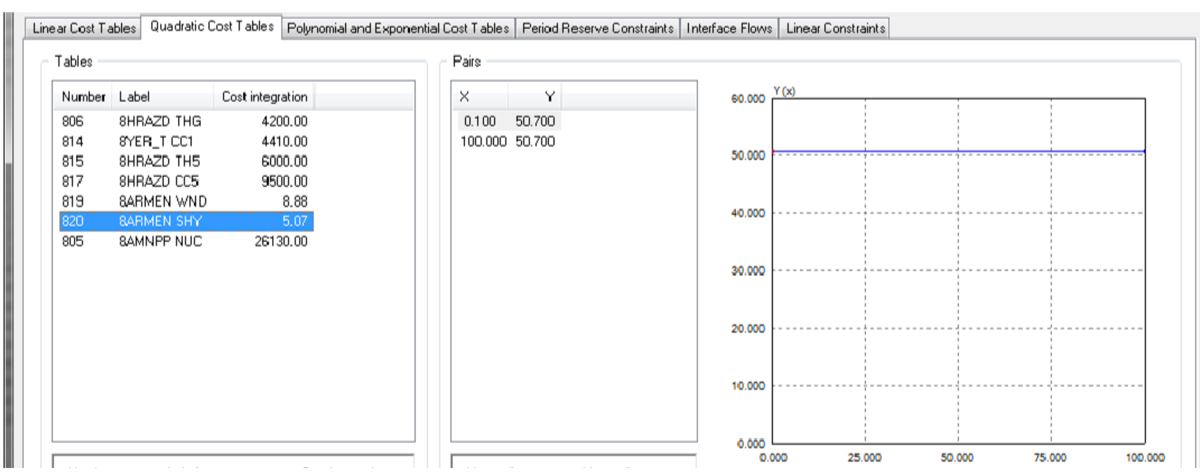


Figure 2.36 – Cost curve and table for Small Hydro units (curve SHY)

These curves should be used for production costs calculation instead of generation engagement optimization, since these units are engaged based on energy availability and not on economics, so in optimization calculations they should be disabled (dispatch value should be set to zero).

1.2 Prerequisites and Assumptions

1.2.1 Optimal Power Flow

In previous phases of this project a PSS/E network model and the data base have been developed as a tool for detailed transmission network analyses of technical nature. But PSS/E as a software package also has the ability to do optimization, and in this phase of the BST project, the goal is to develop a database that enables experts to develop a detailed economical and more cost wise analyses.

PSS/E program description

Professional software package PSS/E™ version 33.0.0 is used for all calculations performed in this project. The PSS/E package is a set of computer programs and structured data files designed to handle the basic functions of power system performance simulation work, namely:
Data handling, updating, and manipulation

- Power Flow
- Optimal Power Flow
- Fault Analysis
- Dynamic Simulations + Extended Term dynamic Simulations
- Open network Access and Price calculation
- Equivalent Construction

Since its introduction in 1976, the PSS/E tool has become the most comprehensive, technically advanced, and widely used commercial program of its type. It is widely recognized as the most fully featured, time-tested and best performing commercial product available in the market. The program employs the latest technology and numerical algorithms to efficiently solve large and small networks.

PSS/E is comprised of the following modules:

- PSS/E Power Flow
- PSS/E Optimal Power Flow (PSS/E OPF)
- PSS/E Balanced or Unbalanced Fault Analysis
- PSS/E Dynamic Simulation

PSS/E Power Flow module is basic PSS/E program module and it is powerful and easy-to-use for basic power flow network analysis (Figure 2.37) as well as short circuit and dynamic analyses. Besides analysis tool this module is also used for data handling, updating, and manipulation.

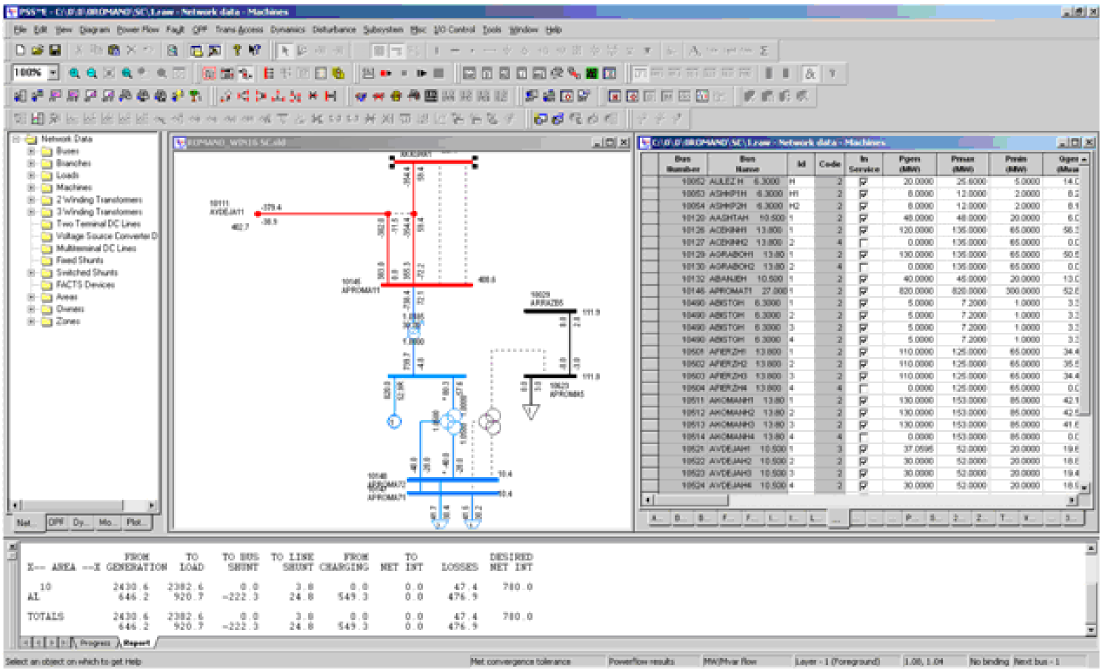


Figure 2.37- PSS/E model Graphical interface

PSS/E Optimal Power Flow (PSS/E OPF) module is advanced PSS/E program module and it is main purpose are advanced "constraint" analyses, deriving solutions by considering constraints and limitations such as voltage limits, transmission line capacities and economical factors for generation engagement.

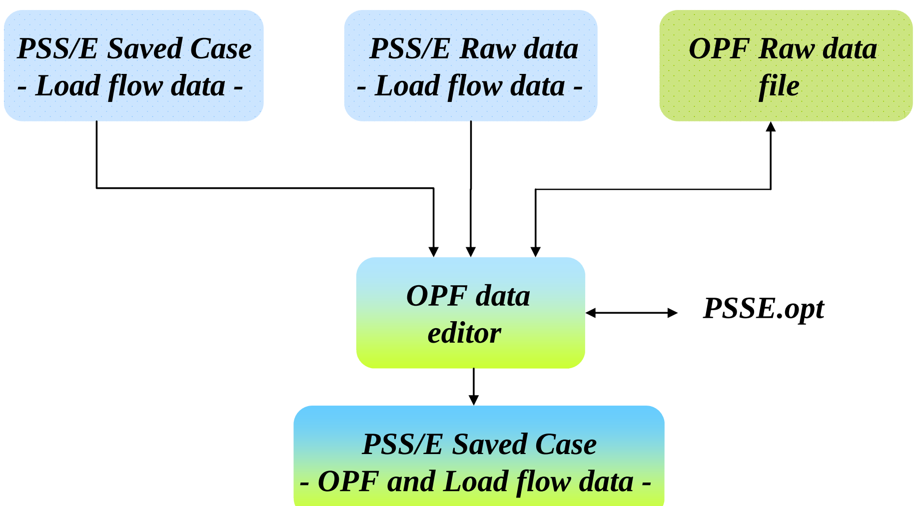


Figure 2.38 PSS/E model – PSS/E OPF data organization

This enables you to perform so called "optimization" of network, or in more detail:

- System operation optimization
  - o Reduction of system operational costs
  - o Reduction of losses
  - o Feasibility of regimes (technical and economical)
- Optimization of system performance (transformer tap ratios, voltage profile, reactive power plant engagement etc...)
- Series and Shunt compensation requirements
- Identification of load shed strategy to resolve system problems
- Limited economical aspect analyses
  - o Marginal price calculations
  - o System exchanges opportunities (export/import)
  - o Congestion related costs

Objective functions are expressions of cost in terms of the power system variables (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. Optimization is achieved through the minimization of the objective function that can be to:

- Minimize fuel costs
- Minimize Active Power Slack Generation
- Minimize Reactive Power Slack Generation
- Minimize Active Power Loss ($/pu MW)
- Minimize Reactive Power Loss ($/pu Mvar)
- Minimize Adjustable Branch Reactance
- Minimize Adjustable Bus Shunts
- Minimize Adjustable Bus Loads
- Minimize Interface Flows
- Minimize Reactive Generation Reserve

OPF model data set can be divided into two main parts: transmission network and generation.

PSS/E OPF transmission system modeling

As it was said, PSS/E is formidable tool for transmission and distribution network analyses, and networks are usually presented with buses and connection links-network elements (lines, cables, transformers, etc…). In a way the whole PSS/E model represents the model of a transmission grid (Figure 2.39).

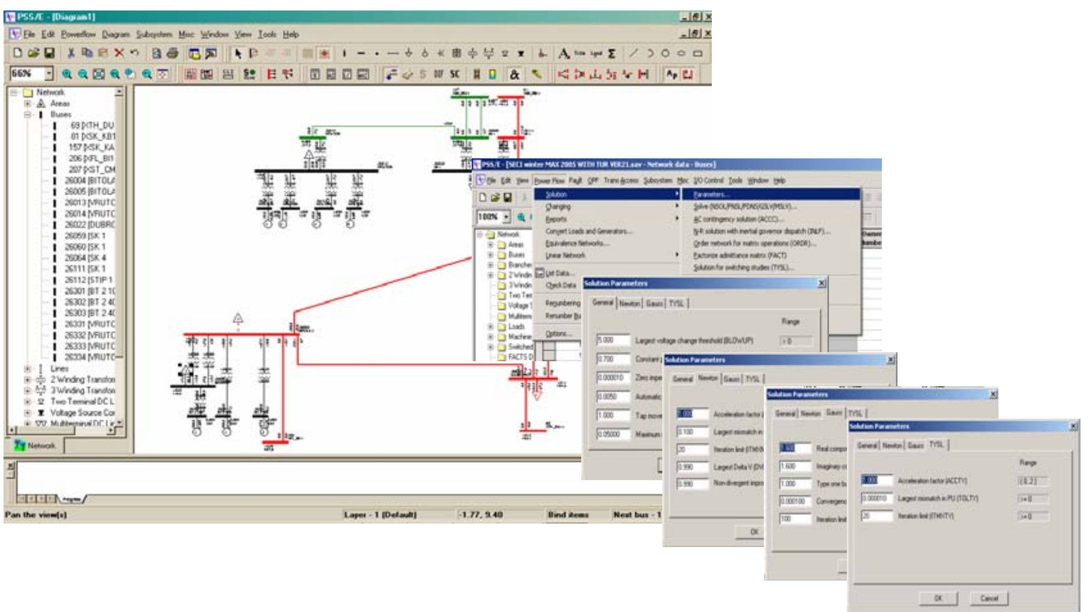


Figure 2.39- PSS/E model – transmission network and calculation parameters

The first part consists of data describing network limitations, according to respective country grid codes and rules of engagement like voltage limits, line and transformer load ratings.

PSS/E OPF generation modeling

Generation in PSS/E is usually modeled as it is in reality (generator+step up transformer) to model adequately all effects that can happen in machine. Figure 2.40 shows sheet in PSS/E with generator data.

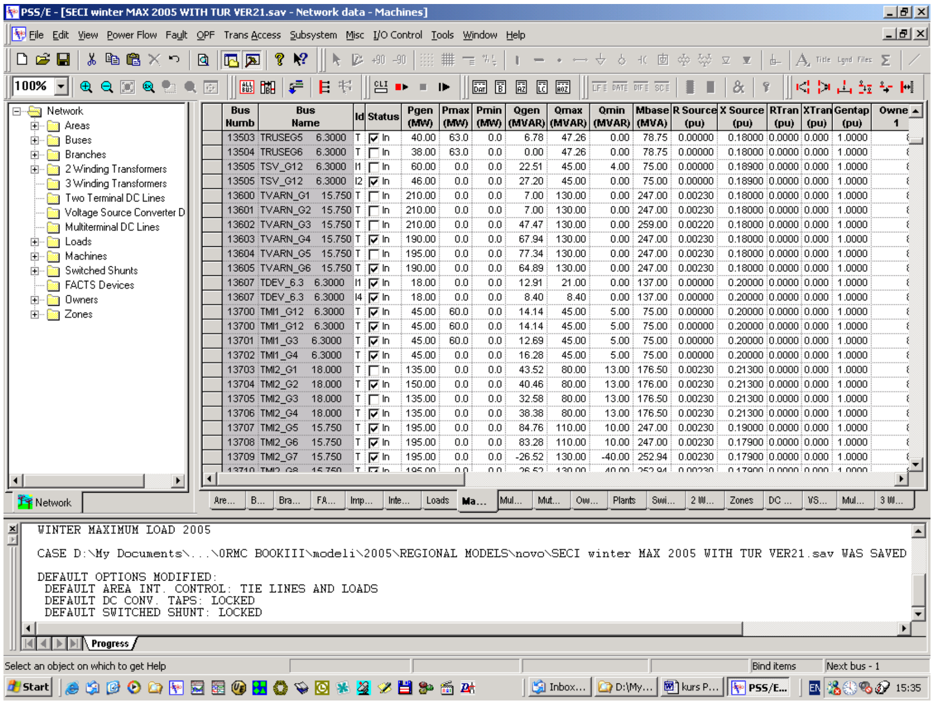
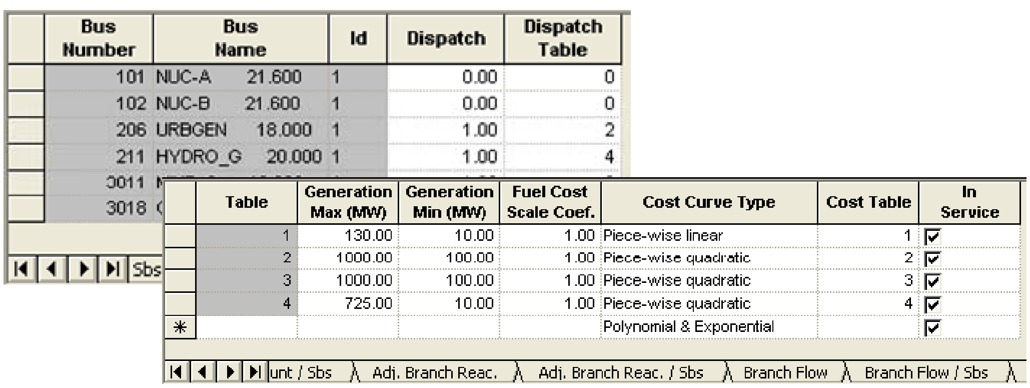


Figure 2.40- PSS/E model – generation modeling

The other part of data is stored in OPF module of PSS/E as Active Power Dispatch Tables with the following data:

- Generation Max
- Generation Min
- Fuel Cost scale coef, scaling of cost curve
- Cost curve type
- Cost table
- In service, defining that data are enabled



Bus Number	Bus Name	Id	Dispatch	Dispatch Table
101	NUC-A 21.600	1	0.00	0
102	NUC-B 21.600	1	0.00	0
206	URBGEN 18.000	1	1.00	2
211	HYDRO_G 20.000	1	1.00	4
3011				
3018				

Table	Generation Max (MW)	Generation Min (MW)	Fuel Cost Scale Coef.	Cost Curve Type	Cost Table	In Service
1	130.00	10.00	1.00	Piece-wise linear	1	☑
2	1000.00	100.00	1.00	Piece-wise quadratic	2	☑
3	1000.00	100.00	1.00	Piece-wise quadratic	3	☑
4	725.00	10.00	1.00	Piece-wise quadratic	4	☑
*				Polynomial & Exponential		☑

Figure 2.41- PSS/E model – generation modeling OPF

Most important data for optimization are generation cost tables. If the cost curve table coordinate value has units of MBTU/hour, then the fuel cost scale coefficient should be entered with units of (cost units)/MBTU, and final cost tables are product between these values and the associated Fuel cost (for specific unit defined in dispatch tables) curve coordinate value produces a result that has cost units of (cost units)/hour (Figure 2.42).

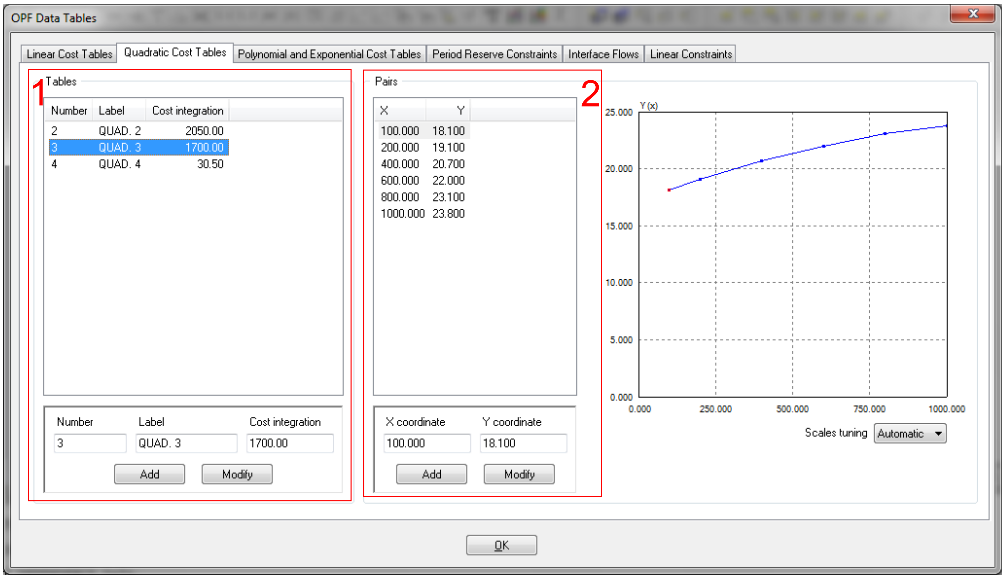


Figure 2.42 PSS/E model – generation modeling cost curve

Biding values, as way to model market behavior (market behavior is usually different then cost curves):

- Minimum production level is usually offered at low price (just to cover expenses)
- Real market offer price is after minimum engagement, usually higher than costs, that includes profits (profit based approach)

1.3 OPF Models Construction Procedure

OPF model data set can be divided into two parts: transmission network and generation. First part consists of data describing network limitations, according to respective country grid codes and rules of engagement such as voltage limits, line and transformer load ratings.

The second part deals with generation and all the machines connected to the high voltage network and represented in Load flow model. Machines are represented individually with appropriate data sets that consist of following parts:

- Generation dispatching data
- Generator reserve data
- Generation cost curve

Model integrator, EKC, has prepared a questionnaire for OPF data collection that each project participant has populated with the required data. With this data, the model integrator constructed a data base that is used for the OPF model preparation. Based on the data provided, the model integrator has constructed generic generator models.

For all new generator units and units for which data is not available, the model integrator has utilized common parameters and/or production units of construction.

For this procedure, the model integrator has the following responsibilities:

- Review the collected data and confirm that the format is according to the agreed numbering systems for areas, zones and busses
- Review and test the operation of respective isolated models for each system
- Merge all the model data to form one regional model
- Test the operation of the regional model
- Prepare a regional model report that consists of:
  - Summary data for the regional model
  - Characteristics of the regional model
  - OPF Data base
- Distribute the verified and accepted regional model to all participants

The model integrator was responsible for the distribution of the OPF models for each corresponding country for review and verification. Each project participant was responsible for updating the generic OPF models to correspond to their system behavior and to return it to model integrator to be incorporated in the regional model.

The Regional dynamic model and data base is prepared based on the Load flow model for Winter peak and Summer peak regimes for the following years:

- 2010
- 2015
- 2020

The OPF Regional model consists of following parts:

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

The OPF model was developed in latest version of PSS/E v33. USAID and USEA provided the full PSS/E program support for the project participants to complete this model.

1.4 Training for OPF Model construction

To develop the OPF model, it was necessary to increase the capacity of the working group members, which required training in the use of the PSS/E software for OPF modeling and the construction of detailed technical databases.

In scope of the project, EKC experts prepared and organized a four day training session on the use of the PSS/E software for the development of national transmission models for OPF analyses. (Annex 7.1)

Following the training, the TSOs began a discussion on the parameters of the model, data collection and the development of a common technical data base. This further advanced to the development of a common OPF model.

One of the project goals is to establish a technical database necessary to support OPF modeling. It is expected that draft national and regional models will be developed by the conclusion of this stage of the Project and detailed analysis would be performed in the following project stages.

III. POWER SYSTEMS DATA

By Paul Gipe (*Wind Works, 2010*) the tariffs in some of countries differ between EURO 7.8 cent/kWh to EURO 12 cent/kWh.

Country	Tariff in EURO cent/kWh
Germany	9.2
Ontario, Canada	9.6
France	8.2
Spain	7.8
South Africa	11.8
Vermont, USA	9.2
Austria	10
Brazil	8
Czech Republic	12
Portugal	11
Belgium	10
Bulgaria	9
Croatia	9
Finland	8
Hungary	9
Slovakia	8
Slovenia	9
Switzerland	12
Ukraine	11

1.5 Armenia

1.5.1 General Information

The Republic of Armenia is located in the north-east of the Armenian Highland. The terrain is mostly mountainous, with fast flowing rivers and few forests. The climate is highland continental, making the country subject to hot summers and cold winters. The land rises to 4090 m above sea-level at Mount Aragats, and no point is below 390 m.

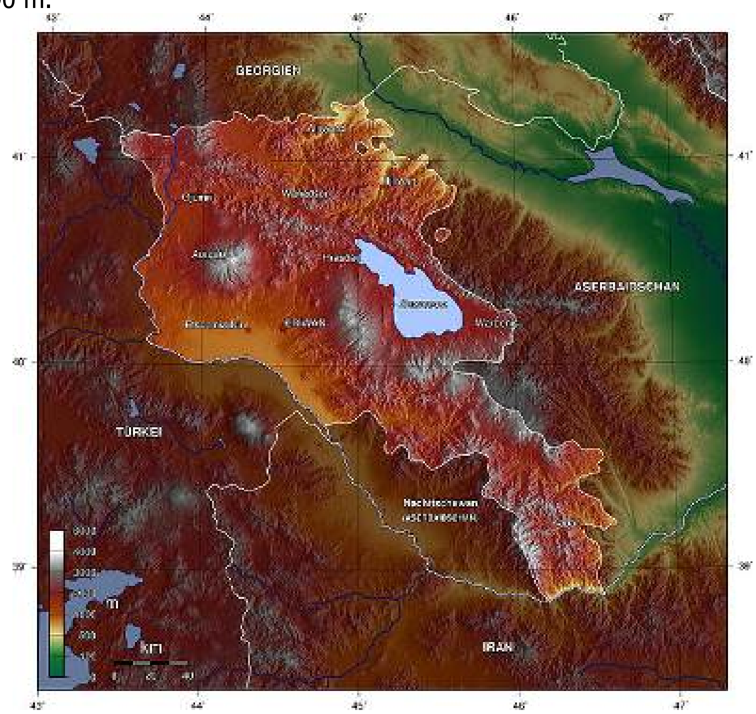


Figure 3.1 *– Armenia – Topography*

Area: 29743 sq. km
Arable land: 71 %
Forest area: 12 %
Population (Million): 3.256 (2010)

GDP ppp (Billion $): 15.63
GDP ppp (per capita): 5074 (2009)

GDP composition per sector:

- agriculture: 19.8 % (2010)
- industry: 33.5 % (2010)
- services: 46.7 % (2010)

Per-Capita Electricity Cons. (kWh-gross):

- 2006 1612 KWh
- 2007 1733 KWh
- 2008 1578 KWh
- 2009 1551 KWh
- 2010 1600 KWh

1.5.2 Transmission Network

Figure 3.2 shows the transmission system of Armenia, together with new planned network elements. The power transmission network of Armenia consists of 220 kV and 110 kV lines. The main plan for an upgrade is building a 400kV network through the country, from North (new interconnection with Georgia) to South.

Table 3.1 shows main data about Armenian transmission network.

Table 3.1 – Armenia - network overview

Lines		Transformers	
Voltage level	Length of the overhead lines and cables	Voltage level	Installed capacities
(kV)	(km)	(kV/kV)	(MVA)
220	1527	220/x	2715
110	3083	110/x	5700
total	4610		8415

Table 3.2 – Armenia - Interconnection overview

Countries	Name	From-To nodes	Status	Comment
AM-GE	Alaverdi 220 kV	OHL 220 kV Alaverdi (AM)-Tbilisi (GE)	Existing	Island, to be put synchr.
AM-GE	Lalavar 110	OHL 110 kV Alaverdi 2 (AM)-Sadakhlo (GE)	Existing	Island
AM-GE	Ahotsk 110	OHL 110 kV Ahotsk (AM)-Ninotsminda (GE)	Existing	Island
AM-TR	Kars 220 kV	OHL 220 kV Gymri (AM)-Kars (TR)	Existing	Island
AM-GE	Marneuli 400 kV	OHL 400 kV Hrazdan (AM)- Marneuli (GE)	Planned	By 2015
AM-TR	New 400 kV AM-TR	HVDC 400 kV ANPP (AM)-Horasan (TR)	Idea	By 2020

Table 3.1, Table 3.5 and Table 3.6 show planed network reinforcements and generation capacities in the forthcoming period.

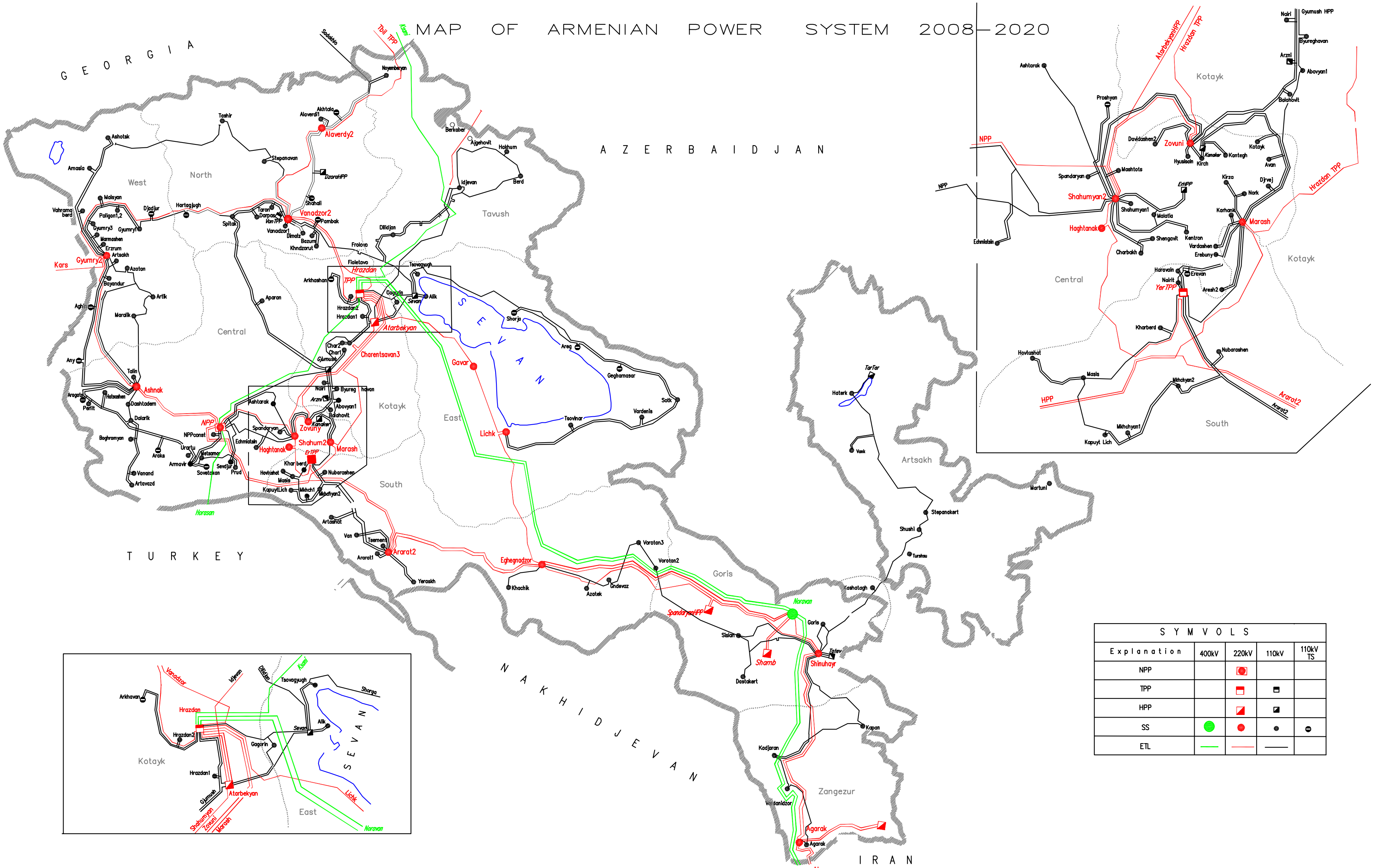


Figure 3.2 – Armenia – transmission network geographical map

Table 3.3 – Armenia - Planned network reinforcements

TYPE	SUBSTATION1		SUBSTATION2		VOLTAGE LEVEL	number of circuits /units	CAPACITY		MATERIAL OR TRANSFORMER TYPE	CROS SECTION	LENGTH			DATE OF COMMISSION
								limited			BR1	BR2	TOTAL	
					kV/kV		A or MVA	A or MVA		mm2	km	km	km	
1	2	3	2	3	4	5	6	7	8	9	10	11	12	13
SS	AM	Hrazdan TPP			400/220	2	2x500	2x500						2015
OHL	AM	Hrazdan TPP	IR	Tavriz	400	2	2x1800	2x1900	ACSR	2x(2x500)	332	100	432	2015
OHL	AM	Hrazdan TPP	GE	Marneuli	400	1	1100	1400	ACSR	2x500	70	20	90	2014
SS	AM	Noravan			400/220	2	2x200							2015
OHL	AM	Noravan	AM	Hrazdan TPP	400	2	1445		ACSR	2x500				2015
OHL	AM	NPP Medzamor	AM	Hrazdan TPP	400	2	1445		ACSR	2x500				2015

1 Type of project (OHL - overhead line, K - cable, SK - submarine cable, SS - substation, BB - back to back system...)
2 Country (ISO code)
3 Substation name
4 Installed voltage (for lines nominal voltage, for transformers ratio in voltages)
5 number of circuits/units
6 Conventional transmission capacity of elements for OHL in Amps, for transformers in MVA
7 Conventional transmission capacity limited by transformers or substations
8 Type of conductor or transformer (ACSR - Aluminum Cross section Steel Reinforced, or code of conductor, PS - phase shift transformer...)
9 Cross section (number of ropes in bundle x cross section/cross section of reinforcement rope)
10 Length till border of first state
11 Length till border of second state
12 Total length
13 Date of commissioning (estimate)

1.5.3 Generation

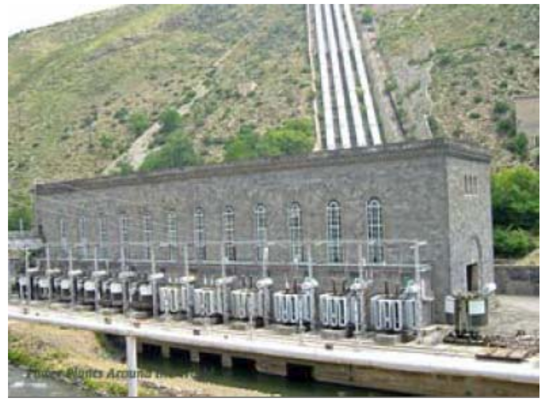
Majority of the Armenian generation capacity, about 1650MW (53%), comes from thermal power plants that run on imported natural gas. Hydro power plants make up 1020MW(33%) of installed capacity, and nuclear 440MW (14%).

Figure 3.3 *– Armenia – Generation capacities and transmission network*

TPP Hrazdan
Location: Armenia
Operator:
Configuration: 4 X 210 MW, 2 x 100MW, 2x 60MW
Operation:
T/G supplier: Kharkov, Electrosila
EPC:
Quick facts: Largest power plant in Armenia, run on natural gas.

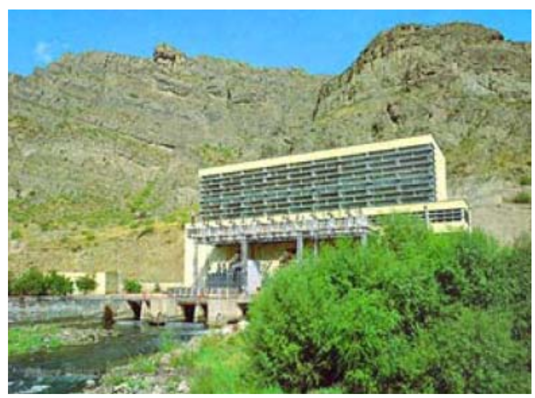
NPP Medzamor
Location: Armenia
Operator: Armenian Nuclear Power Plant CJSC
Configuration: 2 X 408 MW PWR
Operation: 1977-1980
Reactor supplier: Atomstroyexport
T/G supplier: Kharkov, Electrosila
EPC: Atomstroyexport
Quick facts: The Armenian NPP has two VVER-440/270 reactors. For safety reasons, the USSR Ministers Council decided to shut the plant down and Units 1 and 2 were shut down on 25 Feb 1989 and 18 Mar 1989, respectively. After the collapse of the Soviet Union, Armenia's energy situation worsened and in Apr 1993, the Armenian government decided to re-start Unit-2. After reviews of recommendations from a variety of international organizations and contractors including IAEA, WANO, Framatome, Bechtel, and Rosenergoatom, a restart program was developed. On 5 Nov 1995, Unit-2 came back online.

HPP Argel
Location: Kotayk
Operator: International Energy Corp CJSC
Configuration: 4 X 56 MW Francis
Operation: 1953
T/G supplier: LMZ
EPC: Armhydroenergyproject
Quick facts: This is a high-head plant a drop of 285m through the penstocks.



HPP Kanaker
Location: Yerevan
Operator: International Energy Corp CJSC
Configuration: 4 X 12.5 MW, 2 X 25 MW Francis
Operation: 1938-1941
T/G supplier: LMZ
EPC: Armhydroenergyproject
Quick facts: After more than 50 years of operation, Kanaker-5 was taken offline in 1995 for rehabilitation followed by Unit-6 in 2000.

Tatev HPP
Location: Syunik
Operator: Vorotan Hydroelectric Plants CJSC
Configuration: 3 X 52 MW Pelton
Operation: 1953
T/G supplier: LMZ, Electrosila
EPC: Armhydroenergyproject
Quick facts: This is the first power station in the Vorotan cascade and is supplied by an 18km tunnel. The design head is 552m, the highest in Armenia. Average annual output is about 580 GWh



Generation capacities planned

Nuclear Power Plants: There is a plan to replace existing obsolete units in Medzamor NPP, or ANPP, with 1000MW PWR block. A new block is planned to be operational by 2017.

Hydro Power Plants: Hydro power is an important energy source in Armenia. Currently there are three large hydro power stations planned to be constructed:

- Megri (in south close to Armenian border) 140MW
- Loriberd (in north close to Georgian border) 65MW
- Snokh 75MW

By 2020, 275-300MW of new capacities in large hydro stations are planned to be developed through new units and through reconstruction of old ones.

Thermal Power Plants: Thermal power plants are planned to be retrofitted, replacing aging equipment, especially in obsolete CHP power plants in Hrazdan TPP and Yerevan TPP. On the other hand, old units will not be decommissioned but kept in cold reserve (particularly 200MW units in Hrazdan), while old units in Yerevan TPP would be dismantled and replaced by new Combined Cycle units run on imported natural gas.

Renewables: Plans for 2015 and 2020 include significant levels of hydro power and an aggressive plan for wind power development by 2020. The summary data is shown in the following table.

Table 3.4 – Armenia - Renewable generation

Renewable	Spring 2015 MW	2015 Million kWh/yr	Spring 2020 MW	2020 Million kWh/yr
Hydro Power	704	2,030	763	2,560
Wind Power	36	100	280	625
Total	**740**	**2,130**	**1,043**	**3,185**

This program results in 2,130 million kWh/yr of renewable energy in 2015 out of total generation in 2015 of 11,100 million kWh/yr. Renewables are planned to make up 19.2% of total generation. By 2020, the plan is to produce 3,185 million kWh/yr of energy out of the total generation of 16,200 million kWh/yr, making renewables 19.7% of total generation. Even though total generation that includes a new ANPP growth by 46% from 2015 to 2020, Armenia continues to produce nearly 20% of all generated power utilizing renewable resources. There are also plans to install other type of renewable sources (biomass, solar etc.), but size of these is for now negligible and these will not have large impact on the network.

Table 3.5 – Armenia - Planned new generation units

TYPE		SUBSTATION1	VOLTAGE LEVEL kV	kV	CAPACITY MW	MVA	DATE OF COMMISSIONING year
1	2	3	4	5	6	7	8
CCHP	AM	Yerevan TPP new unit	18	110	208	240	2009
TPP	AM	Hrarzdan TPP unit 5	15.75	220	440	510	2009
NPP	AM	NPP Medzamor	24	400	1000	1111	2017
HPP	AM	Shnoch			75	85	2017
HPP	AM	Megri			140	165	2017
HPP	AM	Loriberd			65	71	2017
SHPP	AM				140	189	2010
WPP	AM				200	220	2012

1 Type of plant (HPP - Hydropower plant, TPP - Thermal power plant, PSHPP - Pump Storage Hydro Power Plant, CCHP - Combined Cycle Heating Plant...)
2 Country
3 Substation name
4 Generator voltage level
5 Network voltage level
6 Installed active power
7 Installed apparent power
8 Date of commissioning (estimate)

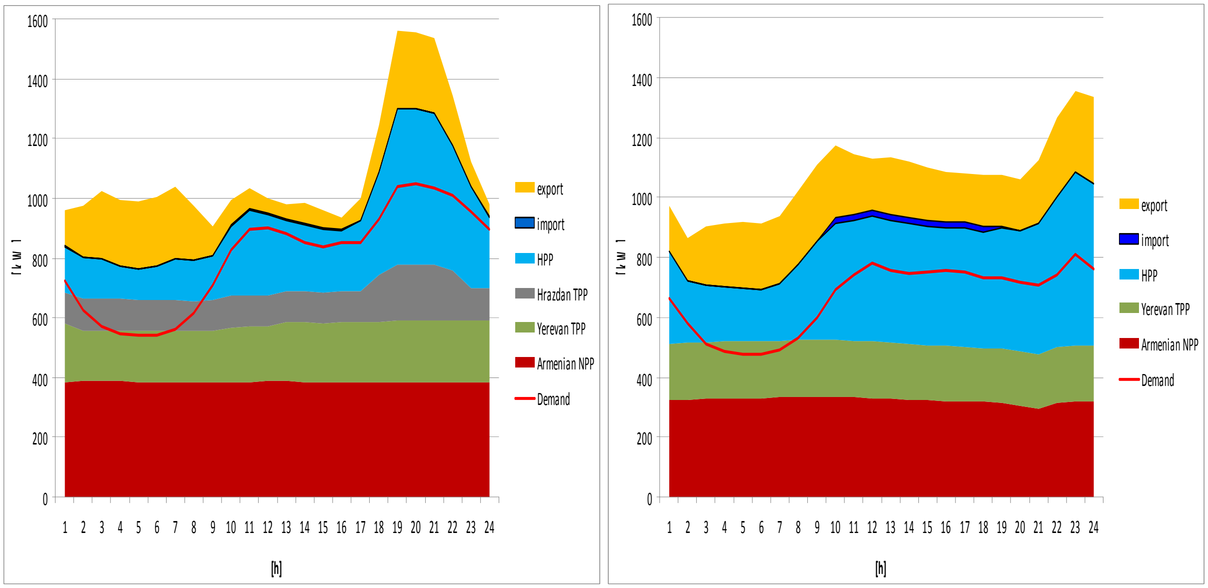
Table 3.6– Armenia – Existing and Planned RES and connection to the network

Plant/Identification name	Name in BS RTSM	Type [wind/solar/biomass]	Existing /Planned	Requests [MW]	Potential [MW]	Epotential [MWh/year]	Pinst2015 [MW]	Pinst2020 [MW]	Location [area, region]	Connection point
SHPP region Aragatsotn	8AMNPPSH	water	Existing	2.9	2.9	18670	18.7	19.2	Aragatsotn	substation Ashtarak110/35/10
SHPP region Armavir	8DALARSH	water	Existing	9	9	17500	10	10	Armavir	substation Armavir 110/35/10
SHPP region Ararat	8ARARTSH	water	Existing	3.5	3.5	5340	3.5	8.6	Ararat	substation Ararat 110/35/10
SHPP region Gegharkunik	8LICHKSH	water	Existing	1.1	1.1	4730	10.3	12.5	Gegharkunik	substation Lick 110/35/10
SHPP region Lori	8VANDZSH	water	Existing	22.5	22.5	63520	28	34.6	Lori	substation Vanadzor 110/35/10
SHPP region Kotaik	8ABOVYSH	water	Existing	6.4	6.4	17030	9.6	11.9	Kotaik	substation Abovyan 110/35/10
SHPP region Ширак	8GYUMR5	water	Existing	10.7	10.7	35720	14.9	15.9	Shirak	substation Gyumri 110/35/10
SHPP region Siunik	8SHINUSH	water	Existing	23.2	23.2	79720	38.2	40.5	Siunik	substation Shinuayr 110/35/10
SHPP region Vayots Dzor	8EXEGNSH	water	Existing	21.8	21.8	52340	30.6	38.5	Vayots Dzor	substation Ehegnadzor 110/35/10
SHPP region Tavush	8HRAZDSH	water	Existing	7.1	7.1	17800	14.4	19.1	Tavush	substation Hrazdan 110/35/10
Karaxach	8GYUMRW	wind	Planned				20	140	Shirak	substation Gyumri 110/35/10
Zod	8LICHKW	wind	Planned				20	20	Gegharkunik	substation Lick 110/35/10
Pushkin+East Pambak	8VANDZW	wind	Planned				-	75	Lori	substation Vanadzor 110/35/10
Fontan	8CHARNVW	wind	Planned				-	75	Kotaik	substation Charencavan 110/35/10
Megri	8AGARK2	water	Planned	140	140		140	140	Siunik	substationn/c Mergi 220/35/10
Snokh	8SHNOKHH	water	Planned	76	76		76	76	Lori	substation Alaverdi 110/35/10
Loriberd	8LORIBH	water	Planned	60	60		60	60	Lori	substationn/c Lori 110/35/10

1.5.4 Demand

Demand behavior

Figure 3.4 and Figure 3.5 show demand behavior for characteristic winter and summer peak regimes and participation of different types of consumption in total energy consumed.



Winter peak 27.12.2010 Summer peak 08.07.2010

Figure 3.4 – Armenia – Daily demand curve for winter and summer peak 2010

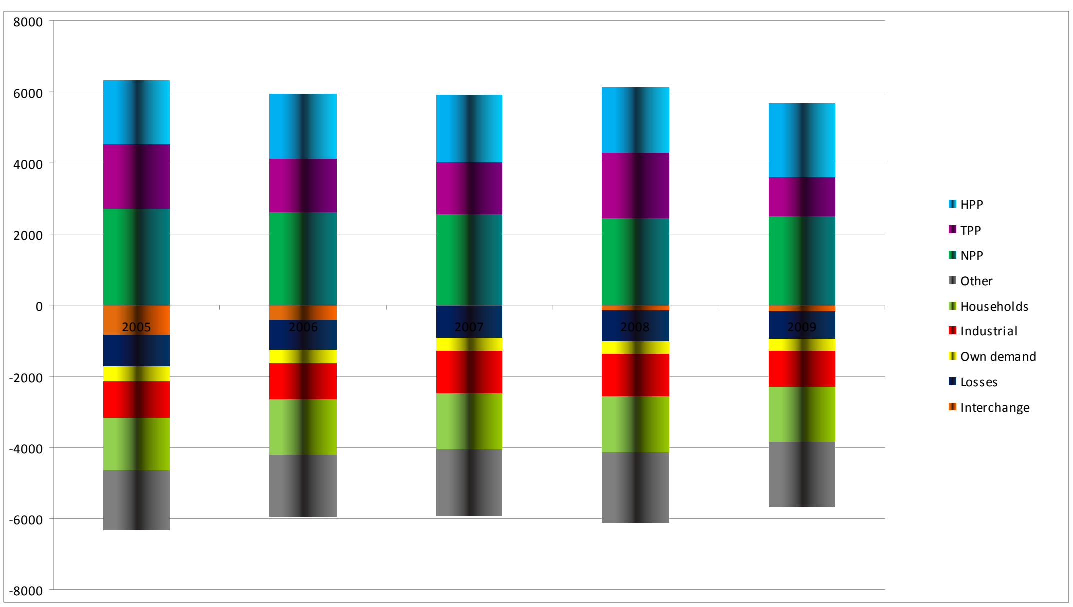
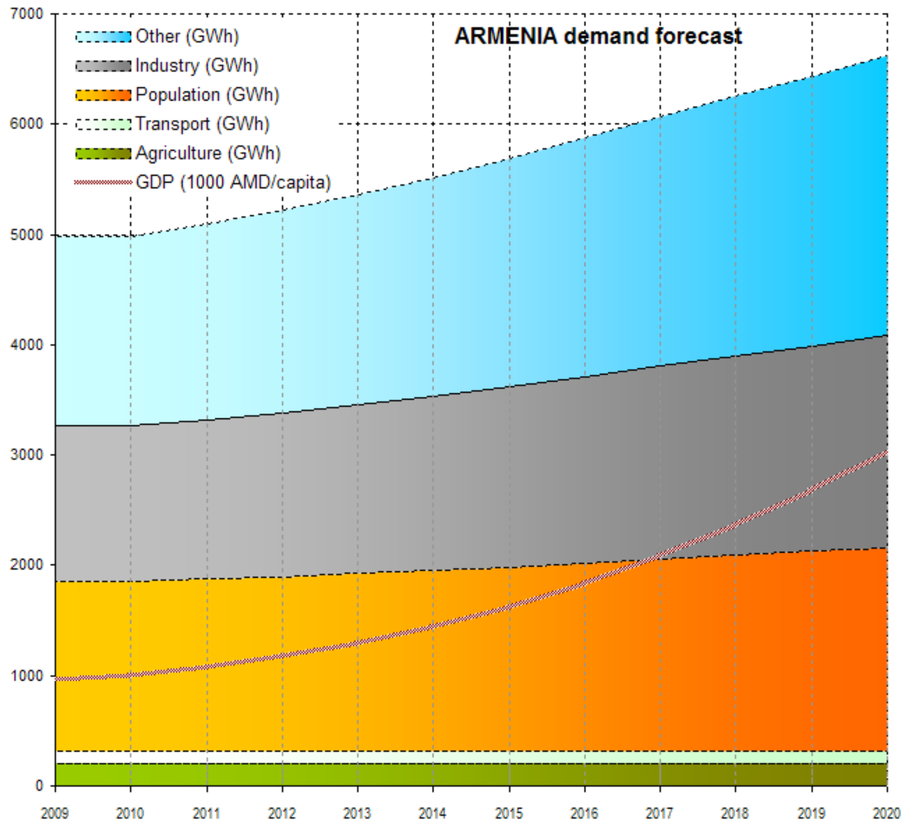


Figure 3.5 – Armenia – Participation of different demand type in total energy in 2010

Demand forecast

Figure 3.6 shows demand forecasts up to 2020. This forecast is done according to the type and relation of GDP projections, and Figure 3.7 and Figure 3.8 show daily demand curves for characteristic regimes in 2015 and 2020. Based on the figures, if NPP Medzamor is reconstructed, Armenia will have large surplus of electricity.



Y	Total GWh	Demand growth%
2009	4977	
2010	4988.1	0.20%
2011	5094.2	2.10%
2012	5218.2	2.40%
2013	5355.6	2.60%
2014	5517.7	3.00%
2015	5686.7	3.10%
2016	5875.2	3.30%
2017	6063.7	3.20%
2018	6249.8	3.10%
2019	6434.7	3.00%
2020	6614.2	2.80%
		Average% 2.71%

Figure 3.6 – Armenia – Demand Forecast

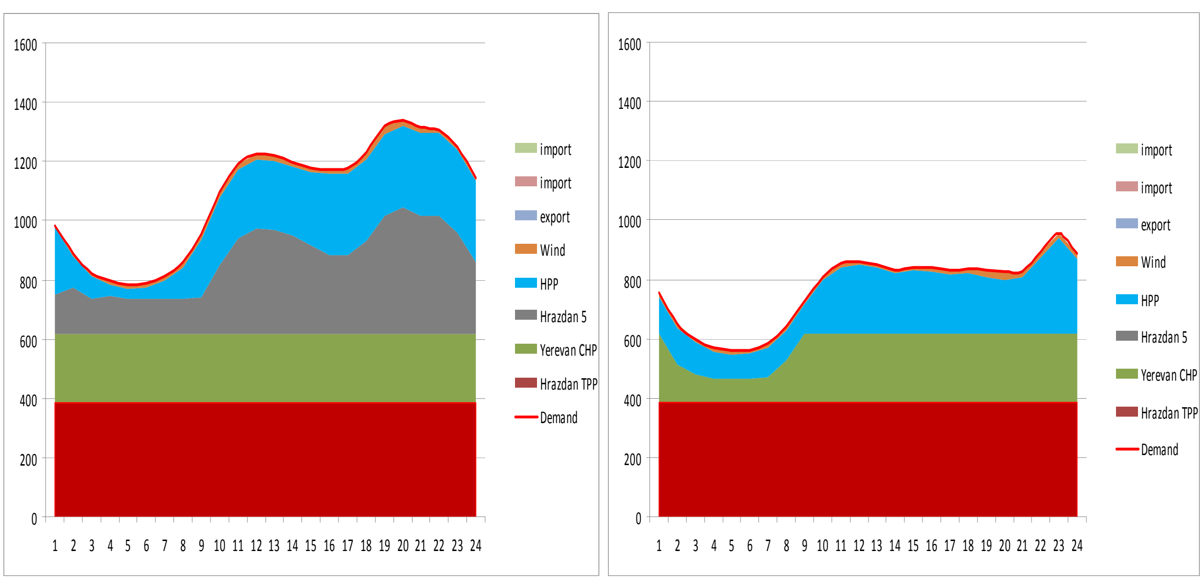


Figure 3.7 – Armenia – Daily demand curve for winter and summer peak 2015

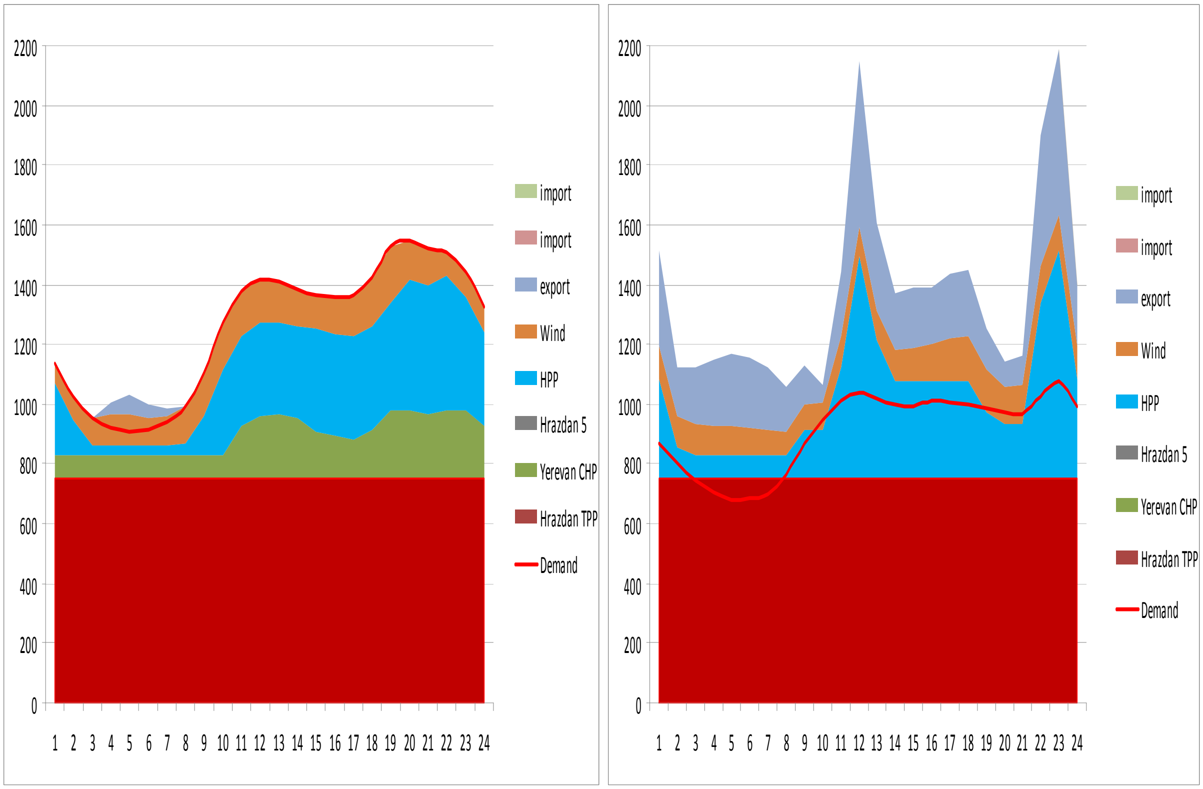


Figure 3.8 – Armenia – Daily demand curve for winter and summer peak 2020

Tariff

Table 3.7 shows prices of electricity for end consumers, and Table 3.8 and Table 3.9 show prices for electricity produced from different types of power plants. This data was taken into consideration for building the OPF model for Armenia.

Table 3.7 – Armenia – tariffs for consumers

Voltage kV	Price (including VAT)			
	Day		Night	
	AMD/kWh	$c/kWh	AMD kWh	$c/kWh
≥35	21	5.50	17	4.50
6(10) direct	25	6.60	17	4.50
6(10) not direct	30	7.90	17	4.50
0.38	30	7.90	20	5.30

Table 3.8– Armenia – tariffs for power plants

	Electricity AMD/kWh	Power AMD/kW	Electricity $/MWh	Power $/MW
Armenian NPP	3.84	2590.35	10.10	68.17
Hrazdan TPP	27.16	427.25	71.48	11.24
For export	27.16		71.48	0.00
Yerevan TPP	25.77	484.53	67.82	12.75
For export	25.77		67.82	0.00
Vorotan Cascade of HPPs	0.96	178.81	2.53	4.71
Sevan-Hrazdan Cascade of HPPs	0.98	418.92	2.57	11.02
Hrazdan 5			43.00	
Yerevan CHP			36.70	
New NPP			100.00	
High Voltage Network (for service)	0.71		1.87	0.00
For export	0.71		1.87	0.00
Power System Operator (for service)	**92.65**		2.44	0.00
For export	0.28		0.74	0.00
Settlement Center (for service)	**10.92**		0.29	0.00
For export	0.03		0.07	0.00

Table 3.9 – Armenia – tariffs for RES (before taxes)

	category	AMD/KWh	EURc/KWh	USDc/KWh
I	Small HPP on the rivers	19.28	3.60	5.07
II	Small HPP on the irrigation system	12.85	2.40	3.38
III	Small HPP on the drinking water	8.57	1.60	2.26
IV	Wind Farm	33.76	6.31	8.88
V	Biomass	36.93	6.90	9.72

Price of natural gas imported from Russia is 210$/tcm for large scale consumers like power plants including transportation costs.

1.5.5 Export Potential in 2015 and 2020

From figures presented in the previous chapter, if NPP Medzamor is reconstructed Armenia will have large surplus of electricity. Armenia forecasts that in the Winter Max, 705 MW will be available for export to Georgia in mostly a synchronous mode and to Turkey in an island mode. In 2020 winter max, the power and energy balance includes the addition of the new ANPP of 1050 MW and 280 MW of wind power. With the addition of the 400 kV HVDC connection to Turkey, Armenia forecasts that 1,340 MW will be available for export to Georgia in mostly a synchronous mode and to Turkey through the HVDC connection as well as the Kars 220 kV island connection. It is important to emphasize that this export potential is a technical maximum and does not include any economic or market considerations.

1.5.6 Analyses results and renewables balancing and control

Based on detailed analyses performed in other studies, and taking into consideration numerous scenarios following conclusions can be drawn:

- Primary reserves for Armenia have been calculated assuming an emergency disconnection of the largest UES Russia generator of 1200 MW is accepted as a design-based failure. The calculated reserves are **15 MW in 2015** and **20 MW in 2020**. These primary reserves are maintained by the Hrazdan TPP.
- Secondary reserves for Armenia have been calculated for automated compensation of normative irregular power flow fluctuations and are **30 MW** in both 2015 and 2020. These secondary reserves are maintained by the Tatev HPP.
- Tertiary reserves for Armenia have been calculated to meet the following three requirements:

  (1) Manual compensation for the largest generator in Armenia that could fail in 2015 (Hrazdan TPP 440 MW) and in 2020 (ANPP 1050 MW) in proportion to the total power in the Transcaucasia region and secondary reserves calculated above. These calculations results in 2015 = 65 MW and in 2020 = 240 MW.

  (2) Manual compensation of disconnections of power from wind power plants due to changes of wind velocity according to monitoring data. These calculations results in 2015 = 30 MW and in 2020 = 230 MW.

  (3) Manual compensation of simultaneous emergency disconnection of all wind power in Armenia due to impermissible increase of wind velocity (considered with low probability). These calculations results in 2015 = 40 MW and in 2020 = 280 MW.

  Therefore, the highest levels of reserves are selected from these calculations so that the tertiary reserves for **2015 = 65 MW** (maintained by Hrazdan TPP) and for **2020 = 240 MW** (maintained by Shamb HPP, Spandaryan HPP, and Hrazdan TPP). These tertiary power reserve amounts meet all three requirements in 2015 and the first two requirements in 2020. The lacking reserve in 2020, which is 280-240=40 MW, can be compensated by the cold power reserve or the tertiary reserve purchased on the regional market of system services.
- Cold Reserves are provided to restore the used tertiary reserves and to compensate for the generator that is disconnected due to an emergency. In 2015 all needed cold reserves for Hrazdan TPP No. 5 (440 MW) will come from various combinations of units at Hrazdan TPP. In 2020 all needed cold reserve for the new ANPP (1,050 MW) will not be available so that some portion will be purchased from the regional market.

The table below summarizes these power reserve findings.

Table 3.10 – Calculated reserve levels

Reserve, MW	W2015		W2020	
AM primary reserve	15	OK	20	OK
AM secondary reserve	30	OK	30	OK
AM tertiary reserve	65	OK	240	280 MW required; -> 40 MW from cold reserve, or bought on regional market
AM cold reserve	OK, for outage Hrazdan TPP g5, 440 MW		NOK for outage ANPP, 1050 MW; -> use old capacities, or regional reserve	

1.5.7 Remarks and Comments

The interconnection to Georgia is on an existing 220 kV line that passes near the prospective wind plant sites. Future increase in capacity with the construction of a new 400kV connection, will enable Armenia to export power through the Georgian network and access to regulating power in Georgia, if there is a need for that.

Steady state load flow and dynamic models for the region were reviewed by the BSTP group. One result was the assessment of the maximum transfer capacity of synchronous interconnection between Armenia and Georgia. Its analysis revealed that the net transfer capacity between the two countries if operated synchronously amounts to 800 MW. This large transfer capacity can accommodate the balancing energy demand between the two countries especially during winter months when winds are strongest and most hydro resources are sequestered in ice and snow.

1.6 Bulgaria

1.6.1 General Information

With a territory of 110,994 square kilometers (42,855 sq. mi), Bulgaria ranks as the 16th-largest country in Europe. Several mountainous areas define the landscape, most notably the Stara Planina (Balkan) and Rodopi mountain ranges, as well as the Rila range, which includes the highest peak in the Balkan region, Musala. In contrast, the Danubian plain in the north and the Upper Thracian Plain in the south represent Bulgaria's lowest and most fertile regions. The 378-kilometer Black Sea coastline covers the entire eastern bound of the country. Bulgaria's capital city and largest settlement is Sofia.

Area: 110994 sq. km
Arable land: 29.94 % (2005)
Forest area: 33 % (2005)
Population: 7,351,234 (2011)

GDP: purchasing power parity - $96.8 billion (2010 est.)
GDP per capita: purchasing power parity - $12850 (2010 est.)

GDP composition per sector:

- agriculture: 7.1 % (2009)
- industry: 35.2 % (2009)
- services: 57.7 % (2009)

1.6.2 Transmission Network

Power transmission network of Bulgaria consists of 400 kV, 220 kV and 110 kV lines. Figure 3.9 shows the map of Bulgarian network and Table 3.11 shows the main data about Bulgarian transmission network. Interconnection lines between the Bulgarian EPS and neighboring countries are shown in Table 3.12

Table 3.11– Bulgaria - network overview

lines		transformers	
Voltage level (kV)	Length of the overhead lines and cables (km)	Voltage level (kV/kV)	Installed capacities (MVA)
400	2451	400/x	-
220	2805	220/x	-
110	9954	110/x	-
total	15210		15888

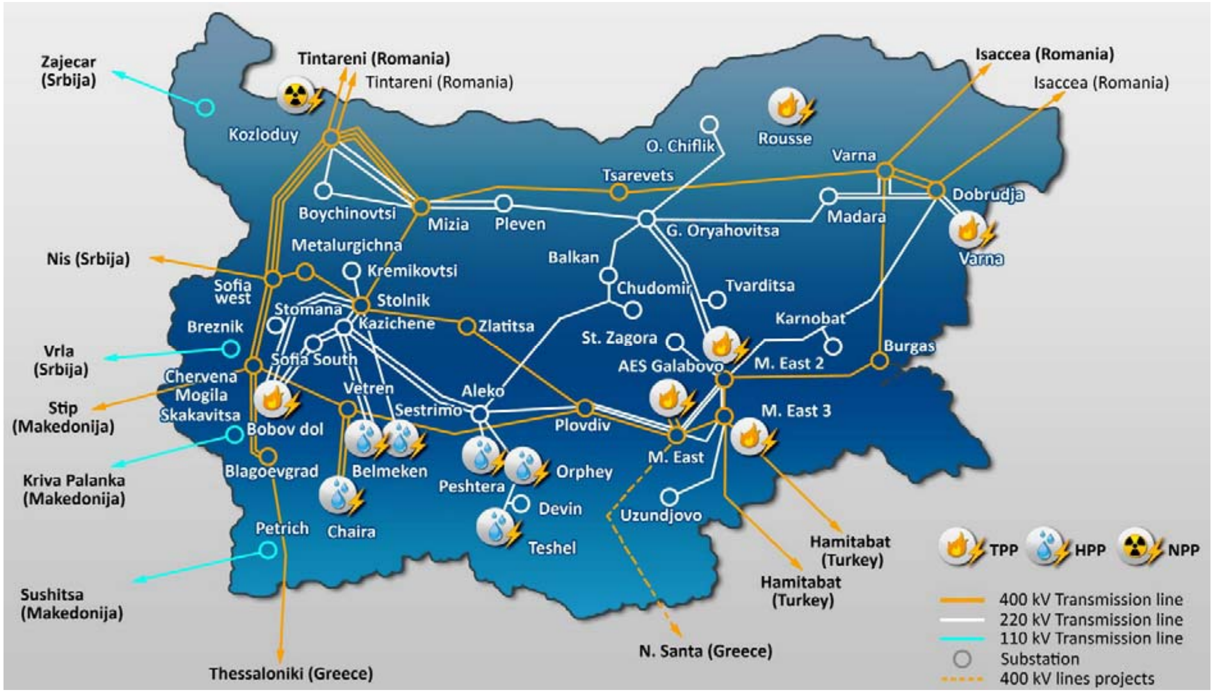


Figure 3.9 – Bulgaria - network map

Table 3.12 Bulgaria – interconnection lines

Nominal Voltage, kV	Neighbor country	Bulgarian S/S	Neighbor S/S	Neighbor TSO	Length, km	Parallel operation	Cross section	Thermal rating, A
400 kV	Romania	Dobrudzha	Isaccea	TEL	230,6	Yes	3 x ACO 400	2475
400 kV	Romania	Kozloduy	Tintareni	TEL	115,7	Yes	2 x ACO 500	1890
400 kV	Romania	Kozloduy	Tintareni	TEL	115,7	Yes	2 x ACO 500	1890
400 kV	Serbia	Sofia West	Nis	EMS	122,5	Yes	2 x ACO 500	1890
400 kV	FYROM	Chervena Mogila	Stip	MEPSO	150,1	Yes	2 x ACO 500	1890
400 kV	Greece	Blagoevgrad	Thessaloniki	HTSO	176,8	Yes	2 x AC 500	1890
400 kV	Turkey	Maritsa East 3	Hamitabat	TEIAS	148,8	Yes	3 x ACO 400	2475
400 kV	Turkey	Maritsa East 3	Hamitabat	TEIAS	158,8	Yes	2 x ACO 500	1890
110 kV	Serbia	Kula	Zajecar	EMS	20,2	No	AC 185	510
110 kV	Serbia	Breznik	Vrla	EMS	64,1	No	AC 185	510
110 kV	FYROM	Skakavitsa	Kriva Palanka	MEPSO	18,1	No	ACO 400	825
110 kV	FYROM	Petrich	Susica	MEPSO	32,6	No	ACO 400	825
400 kV	Romania	Varna	Isaccea	TEL	236,6	No	5 x ACO 300	2835
400 kV	Greece	Maritsa East	Nea Santa	HTSO	140,0	Project	3 x ACO 400	2475

Table 3.13– Bulgaria - Planned network reinforcements for RES connection to the network

TYPE	SUBSTATION1		SUBSTATION2		VOLTAGE LEVEL kV/kV	Number Of Circuits /units	CAPACITY A or MVA	CAPACITY limited A or MVA	MATERIAL OR TRANSFORMER TYPE	CROSS mm2	LENGTH BR1 km	LENGTH BR2 km	LENGTH TOTAL km	DATE OF COMMISSIONING	STATUS
1	2	3	2	3	4	5	6	7	8	9	10	11	12	13	14
OHL	BG	M.East	GR	Nea Santa	400	1	1890	-	ACSR	2X500	-	-	-	2015	Project
OHL	BG	M.East1	BG	M.East3	400	1	1890	-	ACSR	2X500	-	-	-	2015	
OHL	BG	M.East1	BG	Burgas	400	1	1890	-	ACSR	2X500	-	-	-	2015	
OHL	BG	M.East1	BG	Plovdiv	400	1	1645	-	ACSR	2X500	-	-	-	2015	
SS	BG	Belene			400/110	2	275		OTC					2015	
OHL	BG	Belene	BG	Carevec	400	2	1645	-	ACSR	2X400	-	-	-	2015	
OHL	BG	Belene	BG	Mizia	400	2	1645	-	ACSR	2X400	-	-	-	2015	
SS	BG	Karlo			400									2015	
OHL	BG	Carevec	BG	Karlo	400	2	1645	-	ACSR	2X400	-	-	-	2015	
OHL	BG	M.East3	BG	Karlo	400	2	1645	-	ACSR	2X400	-	-	-	2015	
OHL	BG	HPP Aleko	BG	Plovdiv	220	1	1890	-	ACSR	500	-	-	-	2015	
OHL	BG	Karnobat	BG	Dobrudja	220	1	945	-	ACSR	500	-	-	-	2015	
SS	BG	Majak			110/20	2								2015	Project
OHL	BG	Majak	BG	Dobrich		2							58	2015	Project
OHL	BG	Majak	BG	Shabla		2							12	2015	Project
OHL	BG	Majak	BG	Kavarna		2							12	2015	Project
OHL	BG	Varna Sever	BG	Kavarna		1							50	2015	Project
OHL	BG	Varna Zapad	BG	Kavarna		1							55	2015	Project
OHL	BG	Dobrudja	BG	Dobrich		1							34	2015	Project
SS	BG	Svoboda			400/110	2		300	OTC					2020	Project
OHL	BG	Svoboda	BG	Varna(BG)–Issacea(RO)	400	2	1890	-	ACSR	2X500			10	2020	Project
SS	BG	Vidno			400/110	2		300	OTC					2020	Project
OHL	BG	Svoboda	BG	Vidno	400	2	1890	-	ACSR	2X500			115	2020	Project

1 Type of project (OHL - overhead line, K - kable, SK - submarine kable, SS - substation, BB - back to back system...)
2 Country (ISO code)
3 Substation name
4 Installed voltage (for lines nominal voltage, for transformers ratio in voltages)
5 number of circuits/units
6 Conventional transmission capacity of elements for OHL in Amps, for transformers in MVA
7 Conventional transmission capacity limited by transformers or substations
8 Type of conductor or transformer (ACSR - Aluminum Cross section Steel Reinforced, or code of conductor, PS - phase shift transformer...)
9 Cross section (number of ropes in bundle x cross section/cross section of reinforcement rope)
10 Length till border of first state
11 Length till border of second state
12 Total length
13 Date of commissioning (estimate)
14 Status of project (Idea, Feasibility study, Construction, Damaged, out of service, Decommissioned...)
**reconstruction in network connected to new RES installation*

Table 3.14 – Bulgaria - Planned new generation units

TYPE 1	2	SUBSTATION1 3	VOLTAGE LEVEL kV 4	kV 5	CAPACITY MW 6	MVA 7	DATE OF COMMISSIONING year 8	STATUS 9
NPP	BG	Belene	24	400	2x1000	2x1111	2014	Project
CCGT	BG	TPP Varna New unit 1	?	220	280	?	2010	Project
CCGT	BG	TPP Varna New unit 2	?	220	280	?	2011	Project
CCGT	BG	TPP Varna New unit 3	?	110	312	?	2012	Project
TPP	BG	TPP Maritsa East1, U1	?	400	300	?	2010	Commissioning
TPP	BG	TPP Maritsa East1, U2	?	400	300	?	2011	Commissioning
TPP	BG	TPP Maritsa East4	?	400	700	?	2015	Project
HPP	BG	HPP Cankov Kamak, U1	?	110	40	?	2010	Commissioning
HPP	BG	HPP Cankov Kamak, U2	?	110	40	?	2010	Commissioning
HPP	BG	HPP Gorna Arda	?	110	174	?	2016	Project
TPP	BG	TPP Ruse	?	110	100	?	2011	Project
HPP	BG	HPP Nikopol	?	110	440	?	2018	Project
HPP	BG	HPP Silistra	?	110	130	?	2019	Project
CHPP	BG	GPP Haskovo	?	110	256	?	2012	Project
CHPP	BG	GPP Mramor	?	110	250	?	2012	Project
WPP	BG	Valtchi Dol	?	110	100		2011	connection point V_VDOL5
WPP	BG	Kavarna	?	110	150		2011	connection point VKAVAR5
WPP	BG	Baltchik	?	110	45		2015	connection point VBALTC5
WPP	BG	Widno	?	110	350		2015	connection point VVIDNO5
WPP	BG	Majak	?	110	360		2015	connection point VMAJAK5
WPP	BG	General Toshevo	?	110	50		2020	connection point VG_TOS5
WPP	BG	Svoboda(Krushari)	?	110	400		2020	connection point VSVOBO5
WPP	BG	Dobrich	?	110	50		2020	connection point VDOBRI5
WPP	BG	Borovo	?	110	70		2020	connection point VBOROV5
WPP	BG	Binkos	?	110	70		2020	connection point VBINKO5
WPP	BG	Rechica	?	110	50		2020	connection point VRECHI5
WPP	BG	Burgas	?	110	100		2020	connection point VBURGA52
WPP	BG	Trastenik	?	110	50		2020	connection point VTRAST51
WPP	BG	Guljanci	?	110	50		2020	connection point VGULJA5
WPP	BG	Jeravica	?	110	100		2020	connection point VJERAV5
WPP	BG	Martinovo	?	110	50		2020	connection point VMARTI5
WPP	BG	Berkovica	?	110	50		2020	connection point VBERKO5
SPP	BG	Carevec	?	110	20		2020	connection point VCAREV5

1 Type of plant (HPP - Hydropower plant, TPP - Thermal power plant, PSHPP - Pump Storage Hydro Power Plant, CCHP - Combined Cycle Heating Plant...)
2 Country
3 Substation name
4 Generator voltage level
5 Network voltage level
6 Installed active power
7 Installed apparent power
8 Date of commissioning (estimate)
9 Status of the project (Idea, Feasibility study, Construction...)

1.6.3 Generation

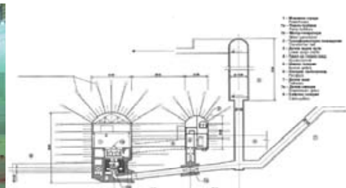
Installed generation capacity is about 5400 MW of thermal units, 2000 MW of nuclear units, and 2600 MW of hydro units. Thermal power plants produce about 50 % of the total energy, nuclear units produce about 40 and hydro units cover 10 %.

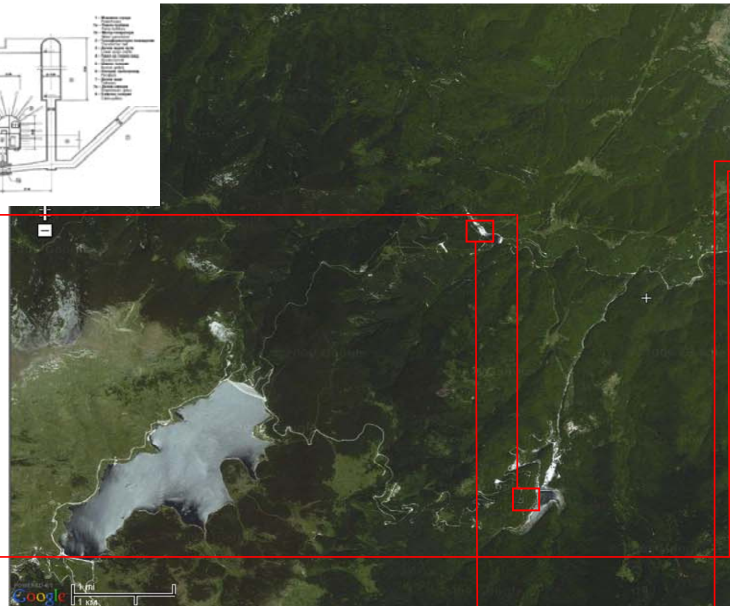
Major production capacities are described in following paragraphs:

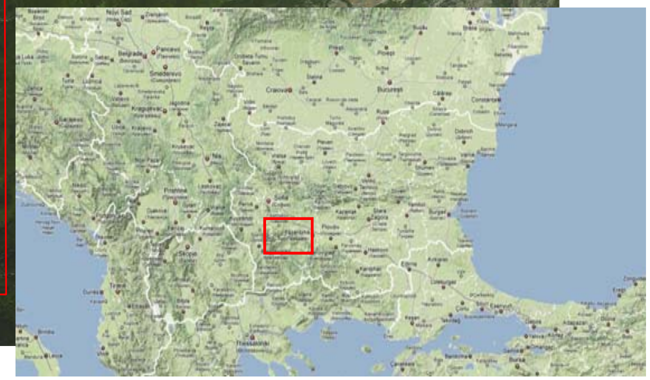
NPP Kozloduy
Location: Bulgaria
Operator: NEK
Configuration: 2 X 440 MW, 2 X 1,000 MW PWR
Operation: 1974-1993
Reactor supplier: AEE
T/G supplier: Kharkov, Electrosila
Quick facts: Reactor Units 1&2 retired in 2006.

TPP Maritza East-2
Location: Bulgaria
Operator: Maritsa East-2 TPP plc
Configuration: 4 X 150, 2 X 210 MW, 2 X 215 MW
Fuel: lignite
Operation: 1969-1996
Boiler supplier: Podoloski
T/G supplier: Kharkov, LMZ, Electrosila
Quick facts: This is the largest thermal power plant Bulgaria and one of three power plants in the Maritsa East complex in the southeastern part of the country. The plant has a 512ha site near Radetski Villare and Lake Ovcharitsa 60km from the town of Stara Zagora. Units 7&8 are scrubbed and Units 1-6 are in the midst of major rehabilitation and scrubber retrofits. The two 325m stacks are the tallest structures in Bulgaria.

TPP Maritza East-3
Location: Bulgaria
Operator: Maritza East III Power Company AD
Configuration: 4 X 210 MW
Fuel: lignite
Operation: 1978-1980
Boiler supplier: Podoloski
T/G supplier: LMZ



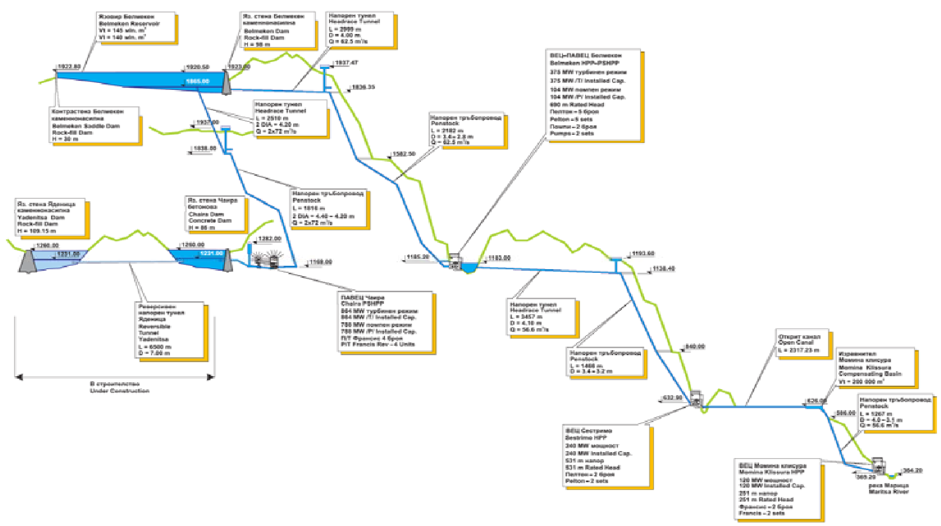




CHAIRA PHPP
Location: Marica, Bulgaria
Operator: NEK
Configuration: 4 X 211 MW Francis,197MW pump
Operation:
T/G supplier: Toshiba
EPC:
Quick facts: 701m head

BELMEKEN PHPP
Location: Marica, Bulgaria
Operator: NEK
Configuration: 5 X 74.7 MW Pelton,2x52MW pump
Operation:
T/G supplier:
EPC:
Quick facts:

SESTRIMO
Location: Marica, Bulgaria
Operator: NEK
Configuration: 2 X 130MW Pelton
Operation:
T/G supplier:
EPC:
Quick facts:



MOMINA KLISURA
Location: Marica, Bulgaria
Operator: NEK
Configuration: 2 X 60MW Francis
Operation:
T/G supplier:
EPC:
Quick facts:

Bulgaria

Generation capacities planned

Nuclear Power Plants: The NPP Belene, power plant that is a long time in construction, is expected that at least one unit will be operational by 2015.

Hydro Power Plants: Hydro power is an important energy source for system regulation. Development plans in this field are concentrated mainly in finishing projects that already started some time ago, and refurbishment of old power plants. Most of refurbishment plans are already finalized in Batak and Arda cascades.

Thermal Power Plants: Large number of thermal capacities in Bulgaria are old, and there many plans for replacing these obsolete units with new ones, like the recent power plant Galabovo, Maritsa East 1 entered operation replacing old units. There are similar plans for power plant Maritza East 3 and Varna. It is also expected that construction of a new gas pipeline "south stream" will create opportunities for construction of CCGT units, to replace the aging CHP plants.

Renewables: The promotion of renewable energy is a an important part of the National Energy Strategy. It is anchored in the Bulgarian Energy Act, as well as in the Energy Efficiency Act. Chapter 11 of the Energy Act covers the promotion of production of electricity from renewable energy sources and cogeneration. The current national renewable energy sources target to be achieved by 2010 is 11% of electric energy consumption, and 20% by 2020. (Table 3.15).

Table 3.15 – Bulgaria – Planned RES by 2020

	installed		Energy produced	
	MW	%	GWh	%
Gross consumption 2020		100.00%	42090	100.00%
HPP large		6.41%	2700	6.41%
Small HPP (private)	550	1.94%	815	1.94%
Wind PP	1800	8.55%	3600	8.55%
Solar PP	600	1.61%	676.2	1.61%
Biomass PP	160	1.52%	640	1.52%

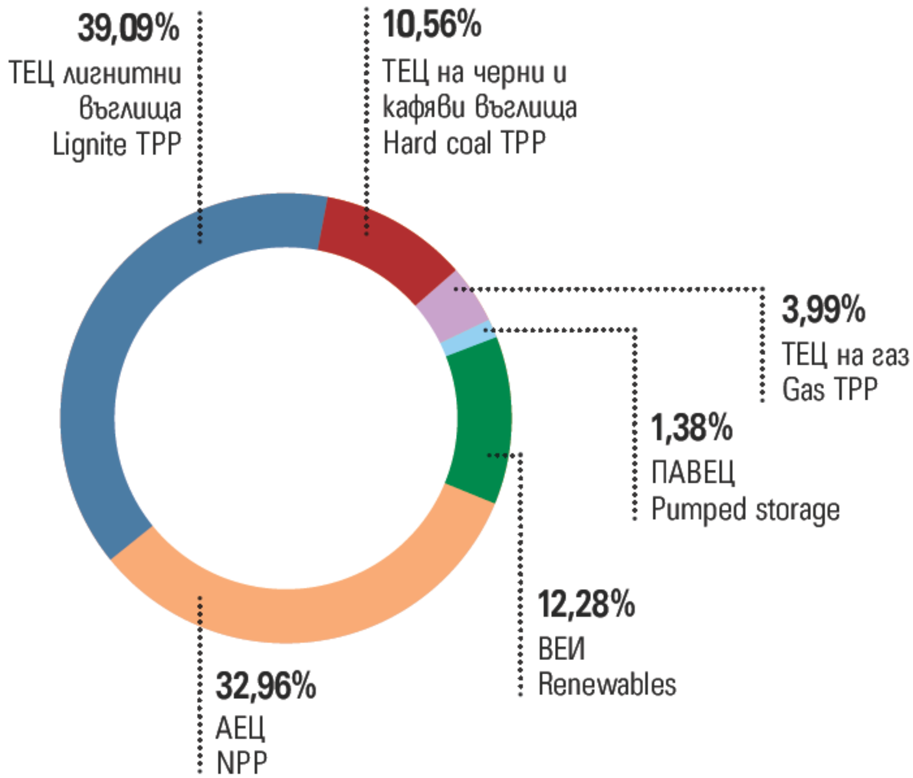
Large scale hydro power is by now the main part of the renewable energy, but its technical and economic potential is almost fully exploited. As a result, one goal is to increase the amount of energy generated from non-hydroelectric sources. Table 3.16 shows the planned development of RES in 2010-2020 period, taking into consideration ENTSO-E standards and network constraints.

Table 3.16 – Bulgaria – Planned RES 2010-2020 in MW

DEVEELOPMENT PLAN OF RENEWABLES –INSTALLED CAPACITY [MW]												
Type /Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	SUM[MW]
HPP(no pumps)	2170					25			170			2365
WPP	488	312	300	300	200	100			100			1800
SOLAR	25	125	125	125	100	100						600
BIOMASS	5	30	30	30	30	20	10	5				160
SUM[MW]	2688	467	455	455	330	245	10	5	270	0	0	4925

1.6.4 Demand

Demand Behavior



Demand Forecast

Figure 3.10 shows planed demand forecast and distribution of demand by type.

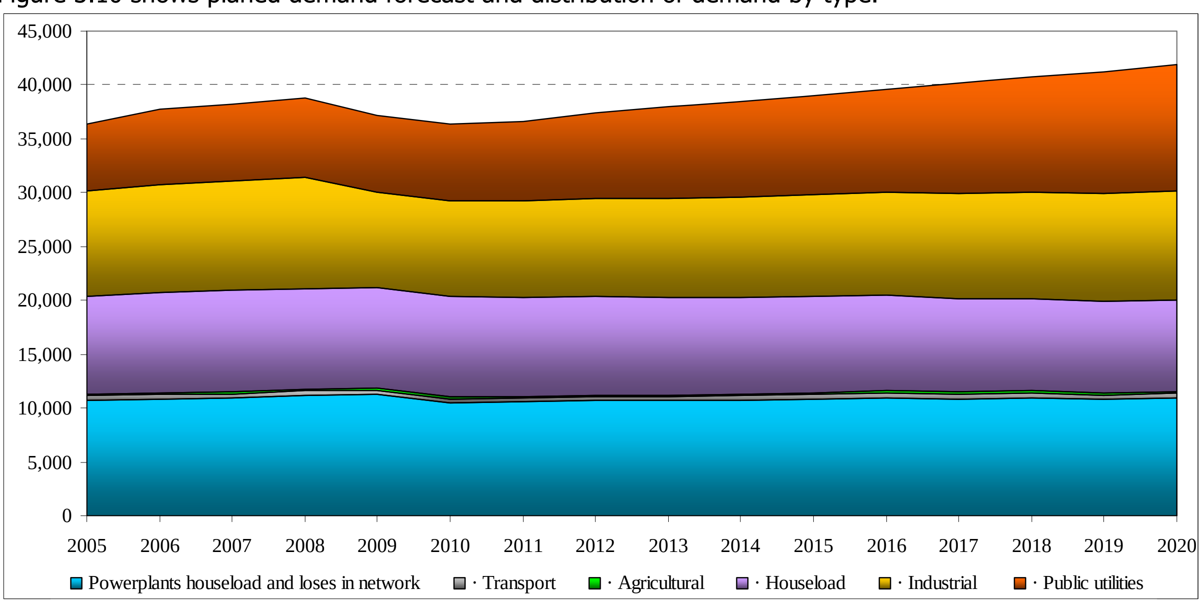


Figure 3.10 – Bulgaria – Demand Forecast and distribution by type

Tariff

This chapter shows the tariff system in Bulgaria. It is divided like in most of the countries by type of consumption and voltage level (all prices are before taxes):

- prices of electricity on HV level (for large industrial consumers and distribution companies) are around 72.24lev or approximately 37EUR/MWh (VAT is not included)/52.5$/MWh. The prices do not include transmission fees are market driven.
- prices of electricity on MV and LV level (residential and commercial)

Table 3.17 – Bulgaria – tariffs for residential and commercial on MV and LV level (before taxes)

Type of measuring	Time zones	$/MWh Voltage level MV	LV
3 time Zones	peak	93.04	98.51
	day	49.25	51.45
	night	19.32	24.74
2 time Zones	day	71.14	82.10
	night	19.16	27.37
NO time Zones		68.96	68.96

- Prices of electricity for residential customers (Low Voltage grid)

Type of measuring	Time zones	$/MWh
2 time Zones	Day	58.12
	Night	26.16
NO time Zones		58.12

- Additional fees:

For green energy 0.22 c$/kWh
For transportation of energy 0.7 c$/kWh
For access to the grid 0.65 c$/kWh

In Bulgaria a feed in system for renewables production is implemented and Table 3.18 shows these tariffs for different power producers, in local currency, in EUR and USD.

Table 3.18 – Bulgaria – tariffs for RES (before taxes)

	kategory	BGN/KWh	EURc/KWh	USDc/KWh
	Prices of energy from Hydro PP with installed capacity less than 10 MW, installed before19.06.2007	0.112	5.4	7.6
	Prices of energy from Hydro PP with installed capacity less than 200 kW	0.223	10.75	15.13
I.	Prices of energy from Hydro PP with installed capacity less than 10 MW	0.178	8.58	12.08
	Prices of energy from Wind PP with installed capacity more than 800 кW with:			
	Less than 2250 full effective hours for year	0.189	9.7	13.7
II.	More than 2250 full effective hours for year	0.172	8.8	12.5
III.	Prices of energy from Wind PP with installed capacity less than 800 кW with squirrel cage induction generator	0.145	7.4	10.5
	Solar with installed capacity less than 5kW	0.76	36.64	51.57
IV.	Solar with installed capacity more than 5kW:	0.699	33.7	47.43

The tariffs were approved on 30.03.2011 by State Energy and Water Regulatory Commission.

1.6.5 Export Potential in 2015 and 2020

Bulgaria's export potential largely depends on the NPP Belene project and installation of new thermal power plants, some of which run on imported coal. If these projects are realized, Bulgaria will have large quantities of power for export, if not, it will be balanced. There will be sufficient energy for domestic demand.

1.6.6 Remarks and comments

Regarding the frequency control of the EPS, the following requirements to the WPP are foreseen:

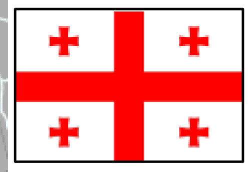
1. WPP with installed capacity 50MVA and more is obliged to have joint control of the produced active power with smooth change of active power according to the requirements of the system operator of ESO.
2. WPP with installed capacity 50MVA and more is obliged to work with decreased active power generation regardless of metrological conditions, when the system operator of ESO needs it.

For the 2020 time horizon, the technical potentials for control of the Bulgarian EPS with respect to the existing and planned development of generation, show that providing quality control and security of EPS, according to the ENTSO-E standard, is possible if the installed capacity of renewables does not exceed:

- WPP 1800MW
- Solar 600MW
- Biomass 160MW

ESO has a proposal for a renewables grid code, but has not yet been approved.

1.7 Georgia



1.7.1 General Information

Georgia is a sovereign state in the Caucasus region of Eurasia. Located at the crossroads of Western Asia and Eastern Europe, it is bounded to the west by the Black Sea, to the north by Russia, to the southwest by Turkey, to the south by Armenia, and to the southeast by Azerbaijan.

Area: 69700 sq. km
Arable land: 29.94 % (2005)
Forest area: 33 % (2005)
Population: 7,351,234 (2011)

GDP: purchasing power parity - $22.4 billion (2010 est.)
GDP per capita: purchasing power parity - $5114 (2010 est.)

GDP composition per sector:

• agriculture:	7.1 %	(2009)
• industry:	35.2 %	(2009)
• services:	57.7 %	(2009)

Figure 3.11 – Georgia - regions

1.7.2 Transmission network

Figure 3.19 shows the transmission system of Georgia. The 500 kV East-West line represents the backbone of Georgia's high voltage network. Together with 220 kV lines in parallel, 110kV and 35 kV in radial (spurs) operation, it forms the Georgian transmission system. Table 3.19 shows main characteristics of the Georgian network.

Table 3.19 – Georgia - network overview

lines		transformers	
Voltage level (kV)	Length of the overhead lines and cables (km)	Voltage level (kV/kV)	Installed capacities (MVA)
500	573	500/220	5995
330	21	330/x	480
220	1536	220/x	7275
110	3925	110/x	4125
total	6055		3200

Table 3.20 – Georgia - Interconnection overview

Countries	Name	From-To nodes	Status	Comment
AM-GE	Alaverdi 220 kV	OHL 220 kV Alaverdi (AM)-Tbilisi (GE)	Existing	Island
AM-GE	Lalavar 110	OHL 110 kV Alaverdi 2 (AM)-Sadakhlo (GE)	Existing	Island
AM-GE	Ahotsk 110	OHL 110 kV Ahotsk (AM)-Ninotsminda (GE)	Existing	Island
GE-RU	Kavkasioni – 500 kV	OHL 500 kV Enguri (GE)-Centralna (RU)	Existing	
GE-RU	Salkhino – 220 kV	OHL 220 kV Bzibi (GE)-Psou (RU)	Existing	
GE-RU	Java – 110 kV		Existing	
GE-RU	Dariali – 110 kV		Existing	
GE-TR	Ajara – 220 kV	OHL 220 kV Batumi (GE)-Hopa (TR)	Existing	
GE-AZ	Gardabani – 330 kV	OHL 330 kV Mukharani (GE)-AZGRES (AZ)	Existing	
AM-GE	Ksani 400 kV	OHL 400 kV Hrazdan (AM)- Marneuli (GE)	Planned	
GE-AZ	New 500 kV AZ-GE	OHL 500 kV Tbilgresi (GE) - Azerbaijan	Planned	
GE-TR	New 400 kV HVDC GE-TR	HVDC 400 kV Akhaltsikhe (GE) – Borcka (TR)	Planned	By 2013
GE-TR	New 220 kV HVDC GE-TR	HVDC 220 kV Batumi (GE) – Hopa (TR)	Planned	By 2015

Planned network reinforcements

The main guideline is to reinforce the Georgia-Russia-Azerbaijan loop, close the 500 kV loop internally and to build a new connection to Turkey to increase transfer capacity. Georgia's development plan is divided into three phases.

2013
An asynchronous interconnection between Georgia and Turkey is planned to be established via a line commutated back to back (B2B) HVDC Substation located in the Akhaltsikhe region of Georgia. The second end of the line will be tied to the substation located in the Borcka region of Turkey. Along with the Akhaltsikhe substation, new 500 kV substations Jvari and Marneuli are also planned. Other projects include the internal 500 kV lines connecting Akhaltsikhe B2B with 500 kV substations Zestafoni and Marneuli and 500 kV lines between substations Ksani -Marneuli, Gardabani - Marneuli and Enguri – Jvari. The reinforcement of the 220 kV power grid's western part of Georgia is also being considered (Figure 3.12).

2015
Another asynchronous interconnection between Georgia and Turkey is expected to be in service by 2015. The connection will include a B2B substation, which will be located in the Adjara region of Georgia, near Batumi. The second end of the tie line will be connected with a substation located in Muratli region of Turkey. There are also plans to build a 500 kV portion at the Tskaltubo substation, with a 500/220 kV autotransformer and 500 kV lines connecting with 500 kV substations Akhaltsikhe and Jvari. Additionally, the existing 500 kV line Imereti, between 500 kV substations Enguri and Zestafoni, will be split and will enter and exit from the Tskaltubo 500 kV substation (Figure 3.13).

2017.
The new power plants – Khudoni HPP, Namakhvani HPP Cascade, among others, with corresponding substations and OHLs connecting with system are planned to come on line by 2017 (Figure 3.14)

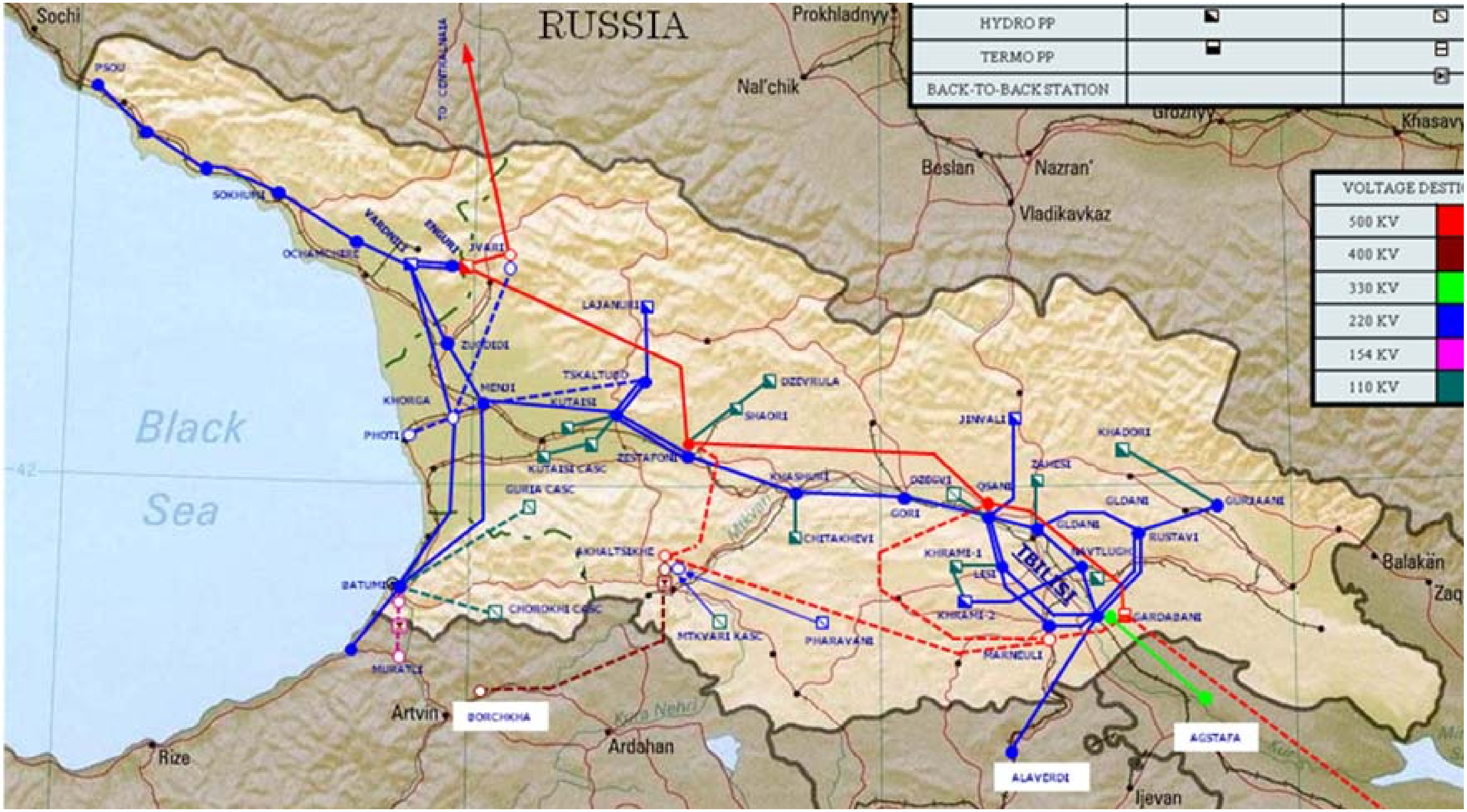


Figure 3.12 – Georgia - network map for 2013

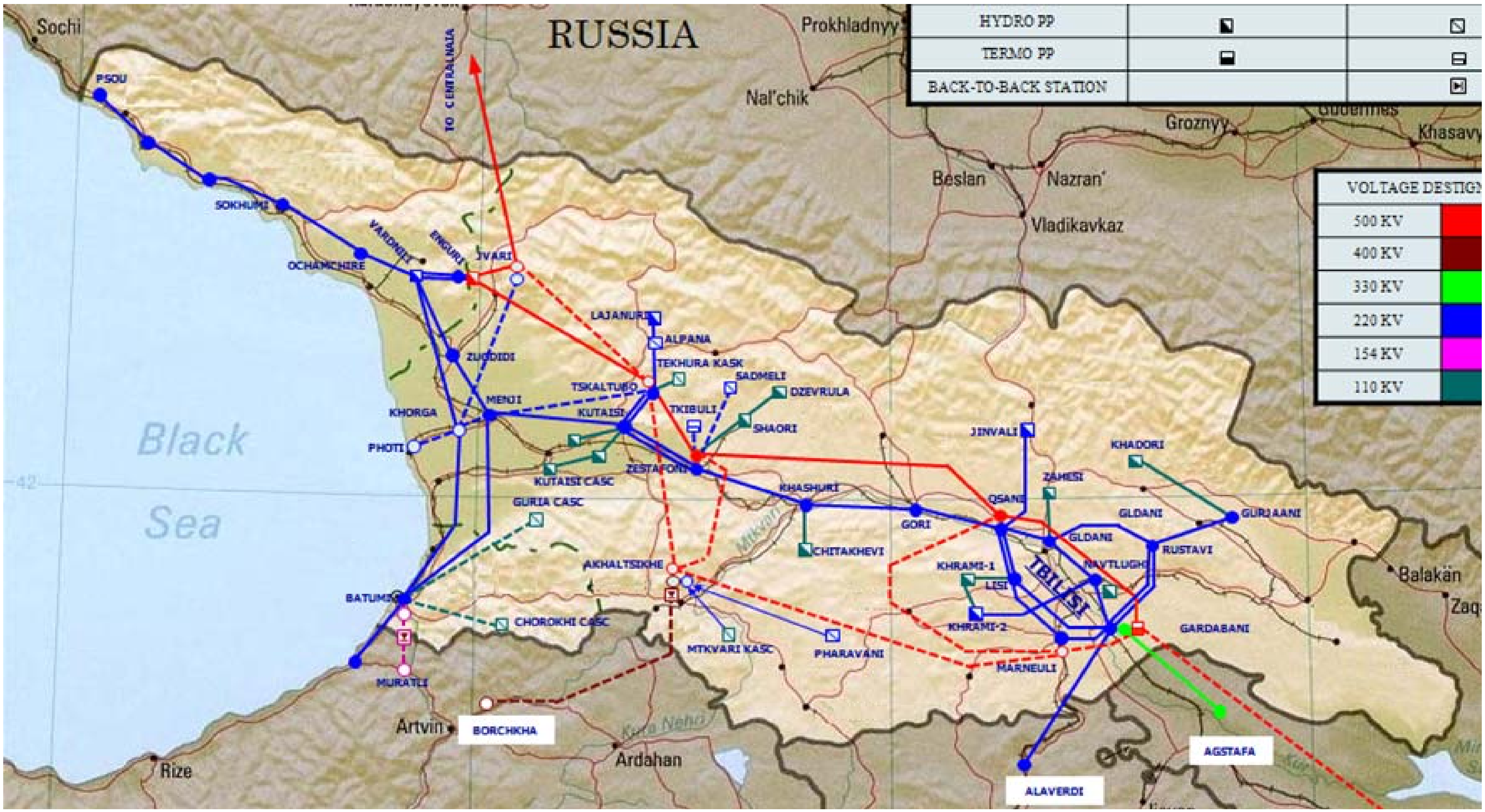


Figure 3.13 – Georgia - network map for 2015

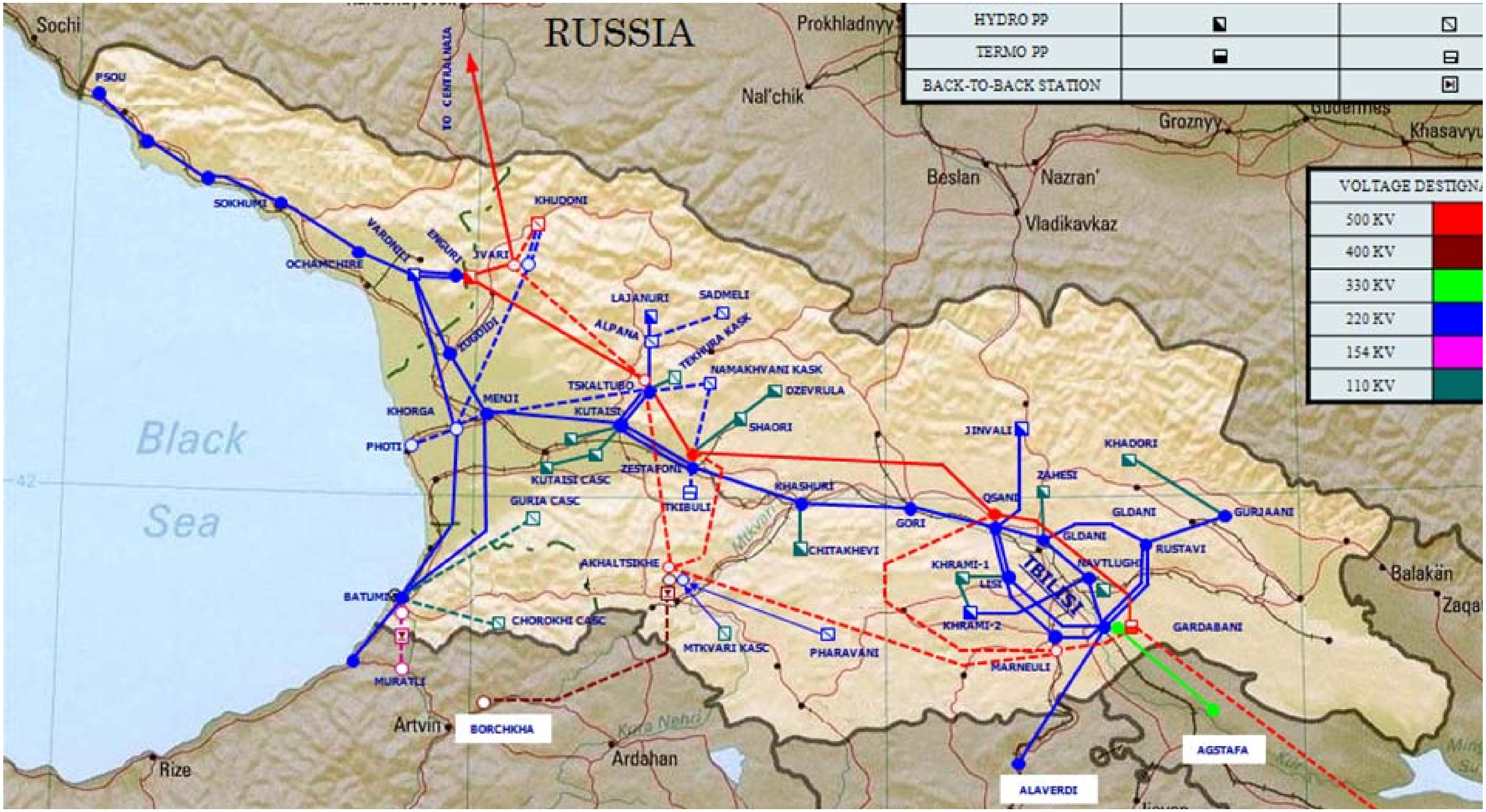


Figure 3.14 – Georgia - network map for 2017

Table 3.21 – Georgia - Planned network reinforcements

TYPE	SUBSTATION1		SUBSTATION2		VOLTAGE LEVEL kV/kV	number of circuits /units	CAPACITY A or MVA	CAPACITY limited A or MVA	MATERIAL OR TRANSFORMER TYPE	CROSSECTION mm2	LENGTH BR1 km	LENGTH BR2 km	LENGTH TOTAL km	DATE OF COMMISSION	STATUS
1	2	3	2	3	4	5	6	7	8	9	10	11	12	13	14
SS	GE	Qsani			500/400	1	3X267		LTC					2009	Feasibility study
OHL	GE	Qsani	AM	TPP Hrazdan	400	1	1100	1400	ACSR	2x300	80	90	170	2009	Feasibility study
OHL	GE	Mukharani	AZ	AZ TPP	330	1							283		
SS	GE	Akhaltske			500/400	1									
BB	GE	Akhaltske			400	1									
OHL	GE	Akhaltske		Marneuli	500	1									
OHL	GE	Marneuli		Gardabani	500	1									
OHL	GE	Akhaltske		Menji	500	1									
OHL	GE	Menji		Kudoni	500	1									
OHL	GE	Akhaltske		Zestaponi	500	1							71		
OHL	GE	Akhaltske	TR	Borcka	400	1							130		
OHL	GE	Gardabani	AR	Atarbeksan	330	1									
OHL	GE	Enguri	RU	Centralna(Sochi)	500	1							450		

1 Type of project (OHL - overhead line, K - kable, SK - submarine kable, SS - substation, BB - back to back system...)
2 Country (ISO code)
3 Substation name
4 Installed voltage (for lines nominal voltage, for transformers ratio in voltages)
5 number of circuits/units
6 Conventional transmission capacity of elements for OHL in Amps, for transformers in MVA
7 Conventional transmission capacity limited by transformers or substations
8 Type of conductor or transformer (ACSR - Aluminum Cross section Steel Reinforced, or code of conductor, PS - phase shift transformer...)
9 Cross section (number of ropes in bundle x cross section/cross section of reinforcement rope)
10 Length till border of first state
11 Length till border of second state
12 Total length
13 Date of commissioning (estimate)
14 Status of project (Idea, Feasibility study, Construction, Damaged, out of service, Decommissioned...)

1.7.3 Generation

Georgia's total nameplate generating capacity is about 5,000 MW. 2,088 MW are concentrated in three thermal power plants, Gardabani, Tkvarchelli and the Tbilisi CHP plant. About 2,700 MW is in hydro and about 5 MW are diesel units. The hydro-power capacity consists of 6 large storage plants, 17 large run-of-river plants and the rest are small run-of -river plants. Assets in Abkhazia, which hosts about one-third of the country's generation capacity, will not be privatized until full Georgian jurisdiction is restored. Assets include hydro-power plants, Vardinli cascade, the Sukhumi HPP, the country's largest hydro-power plant at Inguri (1,300 MW), and the Tkvarchelli thermal power station (220 MW).

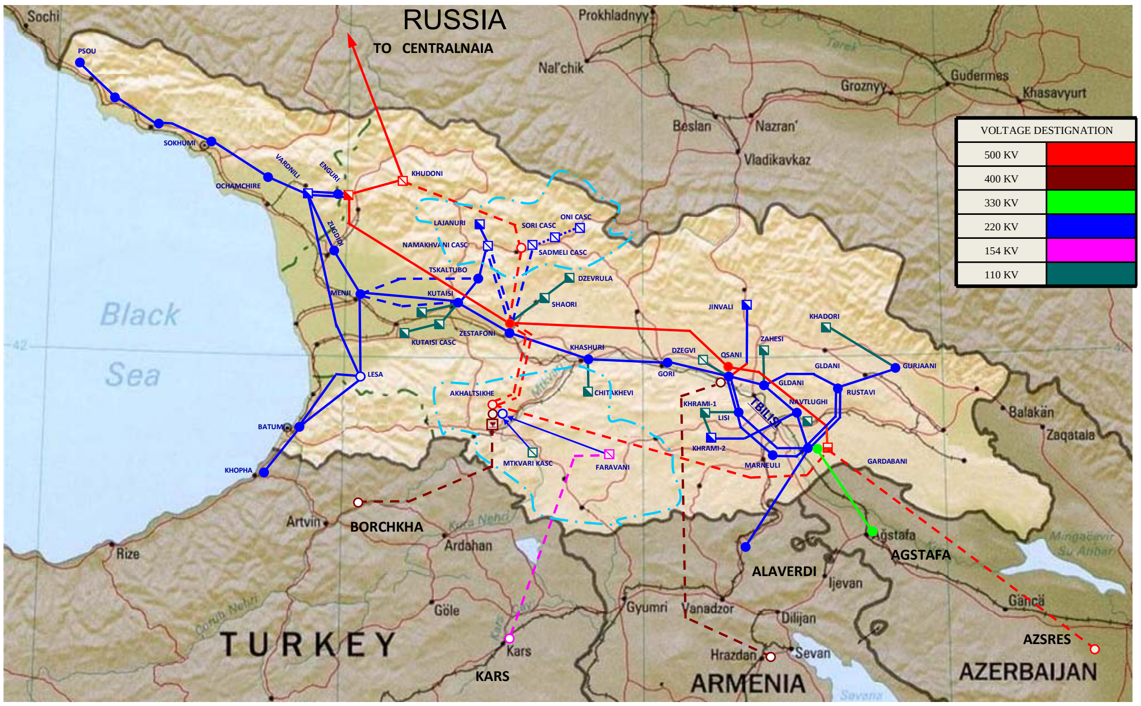


Figure 3.15 – *Georgia – Generation capacities and transmission network*

HPP Enguri

Location: Abhazia
Operator: ?
Configuration: 5 X 260 MW Francis
Operation: 1984
T/G supplier: HTGZ/ Sibelektrojazhmash Kharkov, Voith
Quick facts: With its installed capacity of 1300 MW/4430GWh, Enguri is the largest hydro-electric scheme in Georgia. The Enguri hydro-electric station including the 271.5 m high arch dam (the world's highest arch dam). Pressure tunnel, 15 km long and 9,5 m, in diameter the and underground power station. Reconstruction is on the way, units 2, 3 (in 2006) and 4 are finished, and units 1 and 5 expected to be finalized by 2012, financed from 20mil$ EBRD loan.

HPP Vardinli

Configuration: 3X73.3 MW Kaplan
Operation: 1971
T/G supplier: Turboatom/Sibelektrojazhmash Kharkov
Quick facts This is a hydroelectric power plant with seasonal regulation; its water reservoir is located nearby river Eristskali north to the city of Gali, with 146 million cub. meter of water reservoir. Its installed capacity is 220 (3X73,3) MW and rated average annual capacity - 663 million kW/h. It was put into operation in 1971. Water reservoir of Vardnili HPP is located on the river Eristskali, at the end of Enguri HPP water diversion canal.

TPP Gardabani - Tbilresi
Location: Georgia
Operator: Tbilsresi
Configuration: 1 X 130 MW, 5 X 142 MW
Fuel: natural gas
Operation: 1981-1991
Boiler supplier: Taganrog
T/G supplier: LMZ, Electrosila
Quick facts: This is the largest thermal plant in Georgia but only three units run regularly.

TPP Mtkvari
Location: Georgia
Operator: Telasi JSC
Configuration: 2 X 300 MW
Fuel: natural gas, oil
Operation: 1989-1994
Boiler supplier: Taganrog
T/G supplier: LMZ, Electrosila
Quick facts: Mtkvari power station (formerly Gardabani 9&10) has two 300-MW sets. This two supercritical sets are the largest steam-electric units in Georgia. One set was seriously damaged by accident in Dec 2001 and is deactivated and the second operates at 200-220MW.

CCGT Gardabani Power
Location: Georgia
Operator: Energo-Pro Georgia
Configuration: 2 X 55 MW FT8 TwinPacs
Operation: 2006
Fuel: natural gas
T/G supplier: P&W, BRUSH
EPC: Capital Turbines
Quick facts: In Jan 2006, Georgia's President opened this gas turbine plant developed by Enegy Invest, an obscure investment vehicle from Russia. The project was completed with loans from United Georgian Bank and Vneshtorgbank with two gas turbine ordered in Sep 2005. The project was acquired by Energo-Pro in Dec 2010. The original plan was to convert the machines to combined-cycle operation with 40MW steam unit.

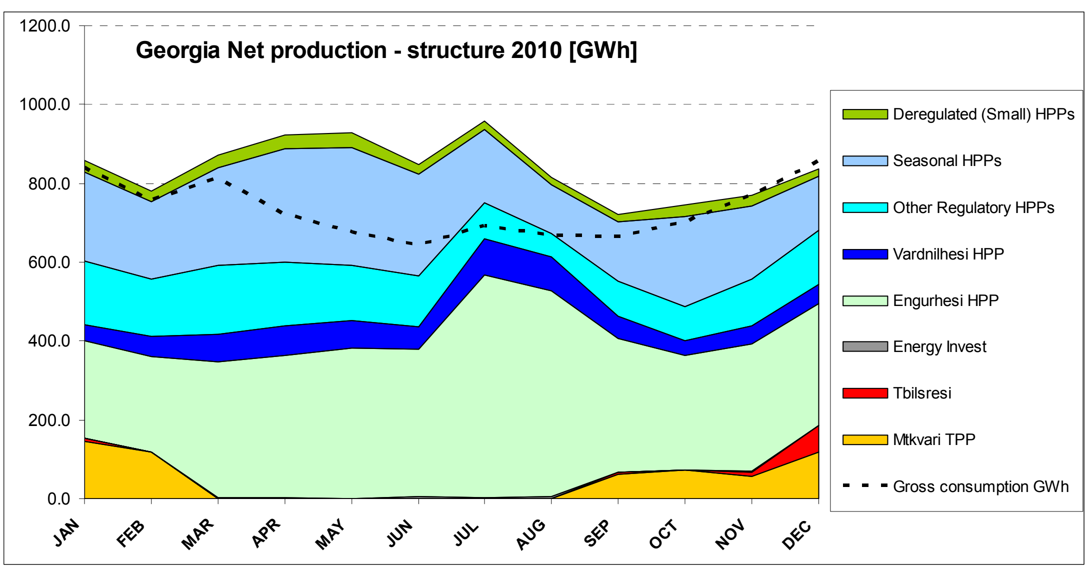


Figure 3.16 – Georgia – production structure 2010 monthly

Generation capacities planned

Hydro Power Plants: Hydro power sources in Georgia have the most potential and highest priority for development. There are more than 27000 rivers In Georgia. Technical potential of hydro resources of the country is up to 80-85 billion KWh, from which economically effective part amounts to 45-50 billion KWh. Currently only 10-15 % of the existing resources are used. In the future, a significant amount of hydro potential realization is anticipated (Table 3.22, Table 3.24), through construction of HPPs, with various types, capacities and reservoirs.

Table 3.22 – Georgia – Annual Generation and Total capacities of HPPS entered in system

Year	2012	2013	2014	2015	2016	2017	2018
Capacity (MW)	6	90	39	587	654	267	1582
Annual Generation (mln KWh)	35	499	247	2362	2546	1340	5399

Enguri – Nescra cascade: Hydro energy resources of the river Enguri are estimated to reach 3530 MW capacity with the power production potential amounting to 10.3 bln KWh. Out of the given amount 5.5 bln KWh has already been realized through the operation of Enguri and Vardnili HPPs Cascade. In order to utilize the remaining part of the economically feasible hydro energy potential, there is a proposal to construct the Khudoni HPP – 700MW and Tobari HPP – 600MW, Khaishi HPP – 700MW, Fari HPP – 200MW, as well as Nescra cascade 260MW on the river Nescra that flows into Enguri. There is an uncertainty whether or not all the proposed plants will be built. Currently, only Khudoni, Tobari and Nescra cascade are contracted for construction.

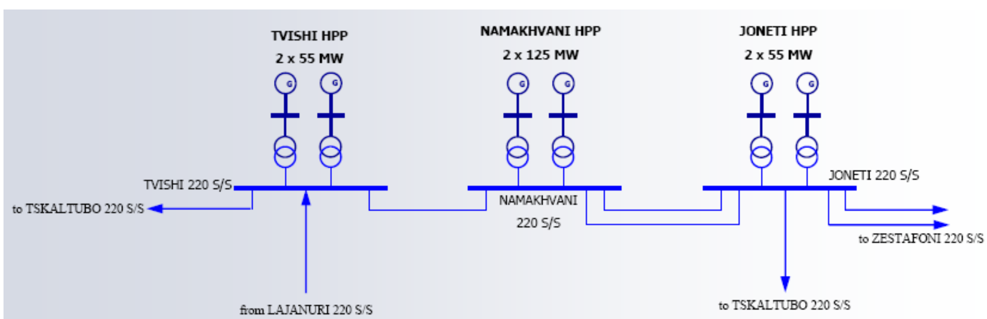


Figure 3.17– Georgia – Rioni cascade

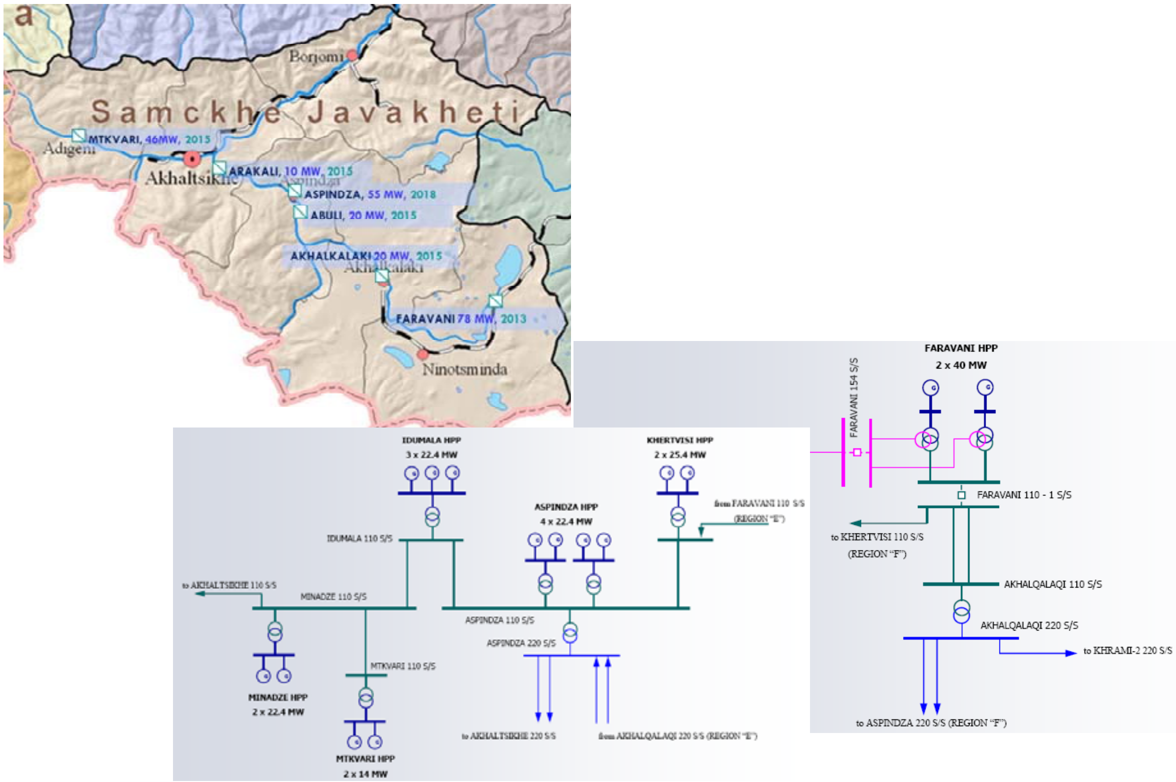


Figure 3.18 *– Georgia – Mtkvari cascade*

Rioni cascade: On the river Rioni : Namokhvani HPPs cascade of 450 MW (is made up of Joneti HPP - 100 MW, Namakhvani HPP - 250 MW and Tvishi HPP - 100 MW), Alpana HPP - 77 MW; These projects are ongoing and should be finalized by 2015.

Mtkvari cascade: On the river Mtkvari: Aspindza HPP - 88 MW, Idumala HPP - 65 MW, Khertvisi HPP - 50 MW, Minadze HPP - 41 MW, Paravani HPP - 80 MW; as well as other small and medium-size HPPs, except Paravani HPP, require investments. This projects will be finalized by 2020.

In total, projects adding up to 3225MW and 12.4TWh are under contracts and some have begun construction.

Thermal Power Plants: Thermal power plants in Georgia are expected to replace aging equipment, especially in obsolete CHP power plants in Gardabani-Tbilresi. The project estimates a construction of 300-450 MW Coal TPP on the basis of units V, VI and VII and through the use of "Tbilsresi" infrastructure. It is possible to install a Gas turbine Unit to of dismantled units I and II of "Tbilsresi", which in a combined cycle with the Unit III will generate 350-400 MW. After full scale implementation of the project it has the potential to generate up to 800 MW at the "Tbilsresi".

There are large coal deposits in Tkibuli and Vale region, and one of the plans is to build coal fired Tkibuli TPP 600MW and mine for exploitation of the coal. Nevertheless, all these projects are not on the top priority list due to large investment costs, and high price of natural gas, and are unlikely to be realized before 2020. Present capacities will be in operation until 2025.

Renewables: Georgia also plans to utilize ecologically pure energy resources - alternative, renewable, wind and solar energies, geothermal waters, biogases and etc. Favorable conditions for wind power exist along the Black Sea coast (Poti and Batumi areas), in Sabueti in central Georgia, in the suburbs of Tbilisi and in over 160 meteorological sights in Georgia used for measuring wind velocity. Tacis estimates the total economic potential of renewable energy is at 900 MW.

Table 3.23 – Georgia – Generation units renewables according to priorities

Type	Installed capacity MW	Energy potential GWh	Cost Ratio ($/kW)	Costs (M$)
New building of SHHP	1,300	6,700	1,525	610
Rehabilitation of SHHP	130	700	520	36.4
Wood and wood waste		2,530	1,500	210
Solar		18	2,500	1
Wind power	530	1,450	1,100	198
Other (biogas, waste)		2,054	1,500	129
Geothermal	100	700	700	14
Total	**2,060**	**14,152**	**1,198**	

Table 3.21 – Georgia – Planned HPPs

PLANT NAME	Name in BS RTSM	Type	Existing/planned	Prequests [MW]	Ppotential [MW]	Epotential [MWh/year]	Pinst2015 [MW]	Pinst2020 [MW]	Location [area, region]	Connection point
NESKRA	6NESKRH	HPP	planned	260	260	1200		260	Zemo Svaneti	
KHUDONI	6KHUDOH1	HPP	planned	700	700	1500		700	Zemo Svaneti	
KHOBI-1	6KHOBIY	HPP	planned	39	39	247	39	39	Zemo Svaneti	
KHOBI-2		HPP	planned	46	46	223		46	Zemo Svaneti	
TSKHENISTSKALI	6TSKHEH	HPP	planned	130	130	400		130	Kvemo Svaneti	
NOBULEVI	6TEKHUY	HPP	planned	25	25	107		25	Zemo Svaneti	
TSKHIMRA		HPP	planned	32	32	160		32	Zemo Svaneti	
ERJIA		HPP	planned	27	27	137		27	Zemo Svaneti	
LECHEKHA		HPP	planned	21	21	119		21	Zemo Svaneti	
TVISHI	6TVISHH1	HPP	planned	100	100	404		100	Kvemo Svaneti	
NAMAKHVANI	6NAMAKH1	HPP	planned	250	250	928		250	Kvemo Svaneti	
DZHONETI	6JONETH1	HPP	planned	100	100	346		100	Kvemo Svaneti	
ALPANA	6ALPANH1	HPP	planned	80	80	357		80	Kvemo Svaneti	
LUKHUNI-1	6LUKHUY	SHPP	planned	11	11	66		11	Kvemo Svaneti	
LUKHUNI-2		SHPP	planned	12	12	74	12	12	Kvemo Svaneti	
LUKHUNI-3		SHPP	planned	9	9	46		9	Kvemo Svaneti	
SADMELI	6SADMEH1	HPP	planned	90	90	467		90	Kvemo Svaneti	
SORI	6SORI-H1	HPP	planned	134	134	617		134	Kvemo Svaneti	
ONI	6ONI-HH2	HPP	planned	72	72	408		72	Kvemo Svaneti	
UTSERA	6UTSERH2	HPP	planned	170	170	486		170	Kvemo Svaneti	
KHRAMI-3	6KHRAM2	HPP	planned	25	25	150		25	Kvemo Kartli	
KHRAMI-4		HPP	planned	40	40	150		40	Kvemo Kartli	
KHRAMI-5		HPP	planned	25	25	150		25	Kvemo Kartli	
CHOROKHI	6CHOROHS	HPP	planned	48	48	182		48	Ajara	
CHOROKHI - 1		HPP	planned	24	24	152		24	Ajara	
CHOROKHI - 2		HPP	planned	24	24	152		24	Ajara	
VAIO	6AJARAY2	HPP	planned	40	40	196		40	Ajara	
KHELVACHAURI	6CHOROY	HPP	planned	22	22	144		22	Ajara	
ADJARISTSKALI - 1	6AJARAG1	HPP	planned	26	26	112		26	Ajara	
ADJARISTSKALI - 2		SHPP	planned	13	13	67		13	Ajara	
ADJARISTSKALI - 3		SHPP	planned	6	6	34		6	Ajara	
ASPINDZA	6ASP GG2	HPP	planned	55	55	294		55	Samche Javakheti	
FARAVANI	6FARAVG1	HPP	planned	78	78	425	78	78	Samche Javakheti	
MTKVARI	6MTKVAH	HPP	planned	46	46	200		46	Samche Javakheti	
ARAKALI	6MINADG0	SHPP	planned	10	10	63		10	Samche Javakheti	
ABULI	6ASP GY4	SHPP	planned	20	20	129		20	Samche Javakheti	
KHERTVISI	6KHERTG2	HPP	planned	81	81	420		81	Samche Javakheti	
AKHALKALAKI	6AKHALY	SHPP	planned	15	15	85		15	Samche Javakheti	
FARAVANI	6FARAVW	Wind	planned	50	50	0	5	50	Samche Javakheti	
KHUNEVI		SHPP	planned	11	11	62		62		
STEFANTSMINDA		HPP	planned	105	105	50		50		
KIRNATI		SHPP	planned	14	14	96		96		
ZOTI		HPP	planned	36	36	144		144		
ZOMLETI	6CHOKHY	HPP	planned	31	31	147		147	Guria	
BAKHVI		SHPP	planned	6	6	35	35	35	Guria	
KVIRILI		SHPP	planned	5	5	22		22	Guria	
KOROMKHETI		HPP	planned	21	21	113		113		
NIALA		HPP	planned	90	90	362		362		

Figure 3.44 – Georgia – Planned HPPs

1.7.4 Demand

Demand Behavior

Figure 3.20 shows typical demand behavior for an average Winter and Summer day. It is expected that in future demand will be similar.

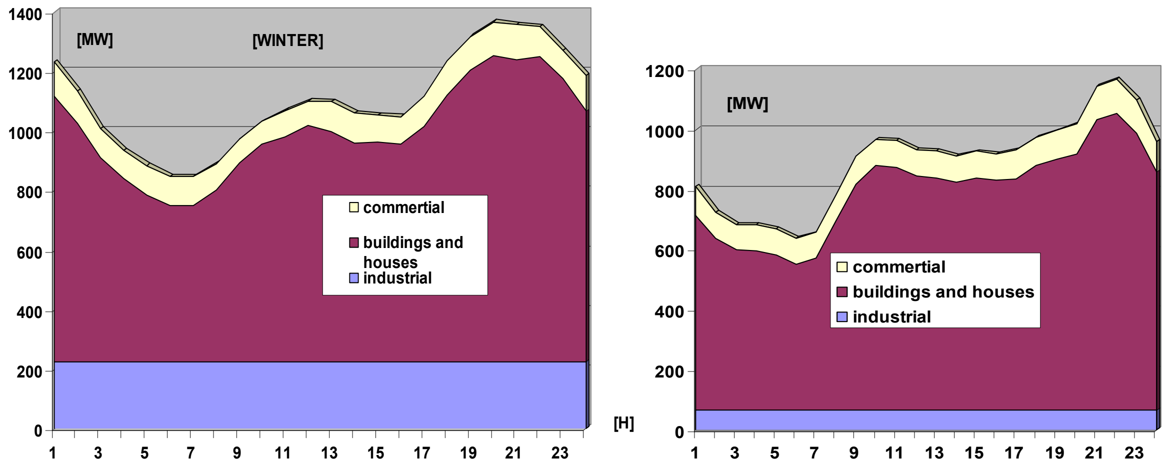


Figure 3.20– Georgia – Daily demand of typical Winter and Summer days [2010 year]

These curves also present the distribution of demand on based on the type of consumption. The same conclusion can be drawn that in future this distribution will remain the same. There are some estimates that the industrial demand share will grow in the future more rapidly than other types of demand, in relation to ambitions development plans for the Poti harbor and the industrial zone.

Demand forecast

Figure 3.21 shows the official demand forecast and generation development to cover this demand. Latest energy projections take into consideration effects of a worldwide crisis and predict more pessimistic results, especially concerning investments in new generation capacities (Figure 3.22).

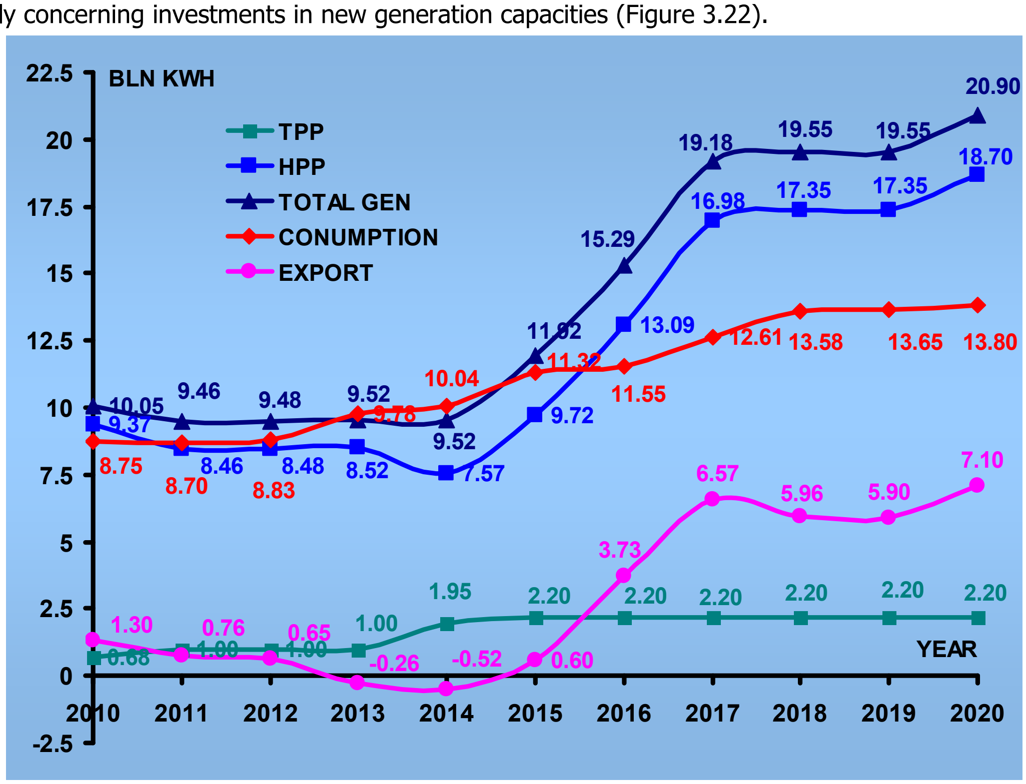


Figure 3.21 – Georgia – Generation-Demand Forecast

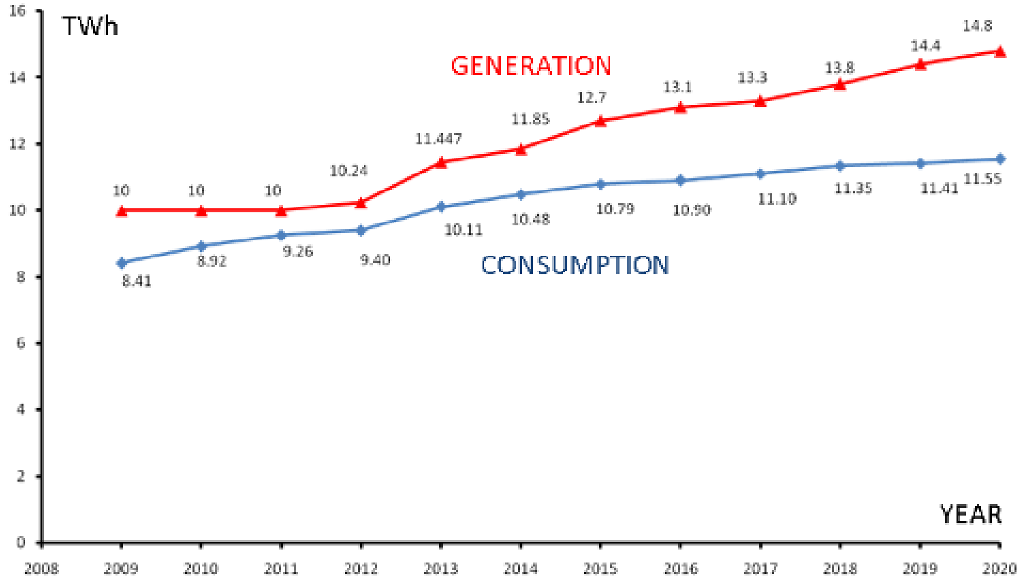


Figure 3.22 – Georgia - Demand forecasts (TWh) - Energy balance for whole year pessimistic

Tariff

The tariffs for power producers in Georgia are set by the independent regulator, GNERC. According to the document "Resolution 33" of the "Georgian National Energy and Water Regulatory Commission Decree on the Electricity Tariffs", on the electricity tariffs, the tariffs currently applied on the Georgian generation are as follows:

Table 3.25 - Georgia - Generation tariffs

Company/PP	PP name	Category	MW	GWh 2010	Tetri/kWh	$cents/kWh
JSC "Energy Invest"	Energy Invest	TPP	110	16	10.54	6.4
Ltd "International Energy Corporation of Georgia" (TbilSresi)	TbilsResi g38	TPP	270	96	9.801	6.0
Ltd "Mtkvari Energetica" (Tbilsresi Unit #9)	Tbilsresi g9 (Mtkvari)	TPP	300	570	9.11	5.6
Ltd "Eastern Energy Corporation" (Khadorhesi)	Khadori	HPP	26	141	8.75	5.3
JSC "Energo-pro Georgia" (DzevrulHesi)	Dzevruli	HPP	80	161	3.85	2.3
JSC "Energo-pro Georgia" (AtsHesi)	Atshesi	HPP	16	45	3.85	2.3
JSC "Energo-pro Georgia" (ShaorHesi)	Shaori	HPP	36	123	3.82	2.3
JSC "Energo-pro Georgia" (LajanurHesi)	Lajanuri	HPP	113	423	3.8	2.3
JSC "Energo-pro Georgia" (Cascade of Gumati HPPs)	Gumati	HPP	67	322	3.64	2.2
JSC "KhramHesi 2"	Khrami 2	HPP	110	385	3.5	2.1
JSC "Energo-pro Georgia" (RionHesi)	Rioni	HPP	48	319	3.5	2.1
Ltd "Ortachalahesi"	Ortachala	HPP	18	97	2.5	1.5
JSC "Energo-pro Georgia" (SatskhenisiHesi)	Satskhenisi	HPP	14	57	2.33	1.4
JSC "KhramHesi 1"	Khrami 1	HPP	113	297	2.3	1.4
Ltd "Tbili Water" (ZhinvalHesi)	Zhinvali	HPP	130	526	1.83	1.1
JSC "ZaHesi"	Zahesi	HPP	36	202	1.42	0.9
Ltd "Vartiskhe 2005" (Vartsikhehesi)	Vartsikhe	HPP	184	814	1.25	0.8
Ltd "VardnilHesebi Cascade"	Vardnili	HPP - regulatory	220	732	1.17	0.7
Ltd "EngurHesi"	Enguri	HPP - regulatory	1300	4301	1.128	0.7
		Sum:	3190	9629		$cents/kWh
					Average	2.5
					Average weighted by kWh	1.5

The average regulated generation tariff in Georgia is approximately 2.5 US Cent/kWh, although it fluctuates widely between Vardnilli and Enguri HPP at 0.7 Cents to Energy Invest at 6.4 Cent/kWh. Average tariff weighted by the kWh produced in 2010 is at the level of 1.5 US Cent/kWh.

The generation tariffs in Georgia are relatively low, but investors in new HPPs are allowed to negotiate the rate of return on equity with GNERC before committing to a project, which should ensure acceptable returns, especially if CDM credits are taken into account. GNERC is committed to facilitate private sector investment in the sector. The low tariffs for HPPs partly reflect the fact that most of the assets were built over 30 years ago and are fully depreciated.

Power producers have two options when selling their electricity: Entering into a direct contract with a customer or selling the electricity to the Electricity System Commercial Operator (ESCO). ESCO, is the market maker in the electricity system in Georgia and is responsible for balancing supply and demand. ESCO purchases electricity from the least-cost providers for the price set by the regulator GNERC. The price is averaged on a monthly basis, and ESCO sells the electricity on to distribution companies and direct customers, adding a small fee (currently 0.019 tetri/kWh i.e. about 0.01 US Cent/kWh).

Table 3.26 – Georgia - Monthly ESCO prices - sale to the distribution customers 2010

ESCO sale 2010	Tetri/kWh	$cents/kWh
Jan	8.49	5.18
Feb	7.69	4.69
Mar	5.92	3.61
Apr	6.85	4.18
Maj	1.25	0.76
Jun	1.96	1.20
Jul	1.69	1.03
Avg	1.62	0.99
Sep	4.28	2.61
Okt	9.14	5.58
Nov	7.15	4.36
Dec	6.68	4.07
Average	5.23	3.19

After amendments to the Electricity Market Rules in June 2007, ESCO guarantees the purchase of all electricity from newly built HPPs. Increasing demand will increase the average electricity generation cost in the system making it difficult to find customers that are interested in purchasing the electricity directly. Building new HPPs will most likely increase the average cost of generating electricity even though the government of Georgia would like to phase out expensive thermal power generation and replace it with cheaper domestically generated hydro resources. The expected average generation cost for new hydro in the first 7 years of operation would be in the range of 6-8 US c/kWh, falling to 2-3 US C after 7 years.

Additional amendments to the Electricity Market Rules were introduced in 2007, granting all HPPs with an installed capacity of less than 10 MW the right to operate without a license. The small HPPs (so-called "deregulated") are also free to sell their electricity directly to a buyer and agree to a price for the electricity bilaterally. In reality, the price of the electricity from the small HPPs is set by the average sales price from ESCO. At present, the feed in tariff system is set on a 50$/MWh from these resources.

1.7.5 Export Potential in 2015 and 2020

Figure 3.23 shows exchange structure of the Georgian system in 2010. Due to the large hydro production it depends on the seasons. (Figure 3.16)

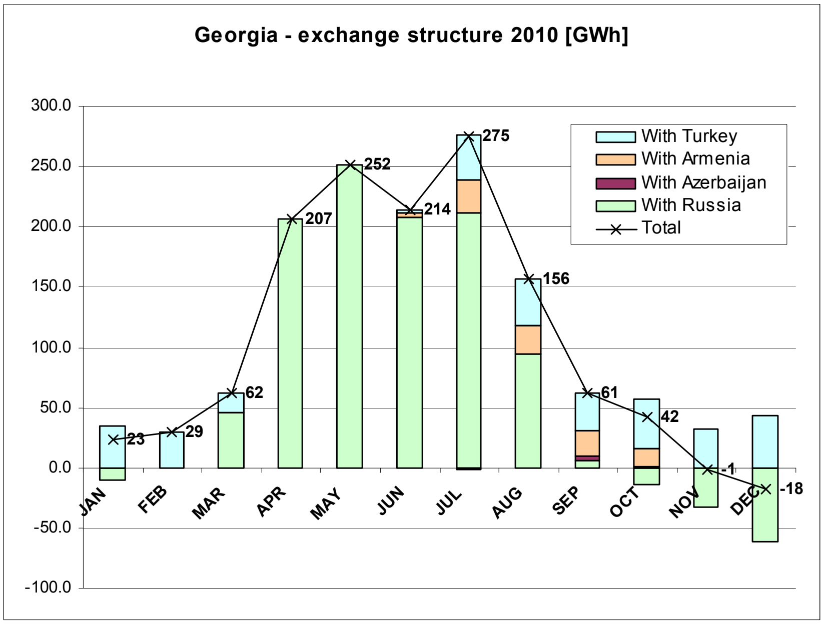


Figure 3.23 – Georgia – monthly exchanges 2010

It is expected that in the future this trend will continue until large hydro capacities like HPP Khudoni enter operation in 2017. After this, Georgia will have large export capabilities. Official demand and generation forecasts for 2020 are given on Figure 3.24 and Figure 3.25.

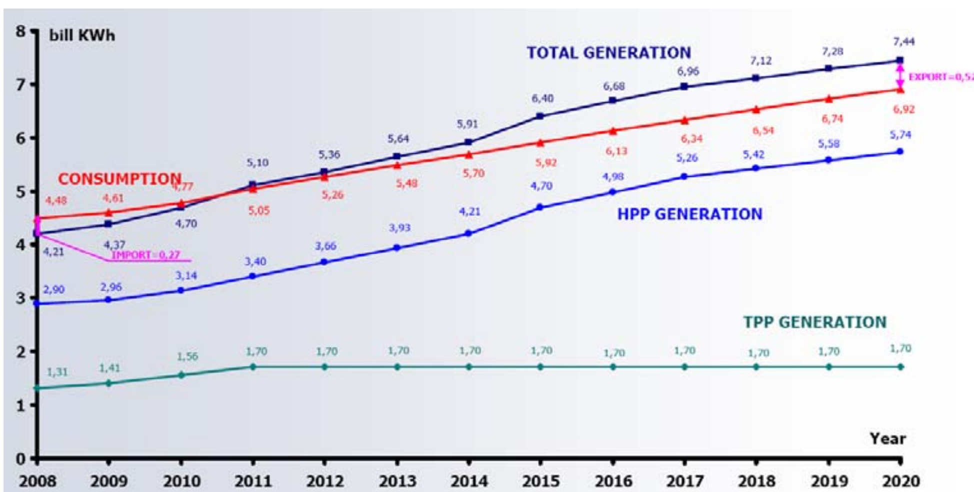


Figure 3.24 – Georgia - Demand forecasts (TWh) - Energy balance for Winter season (1 Nov –15 Apr)

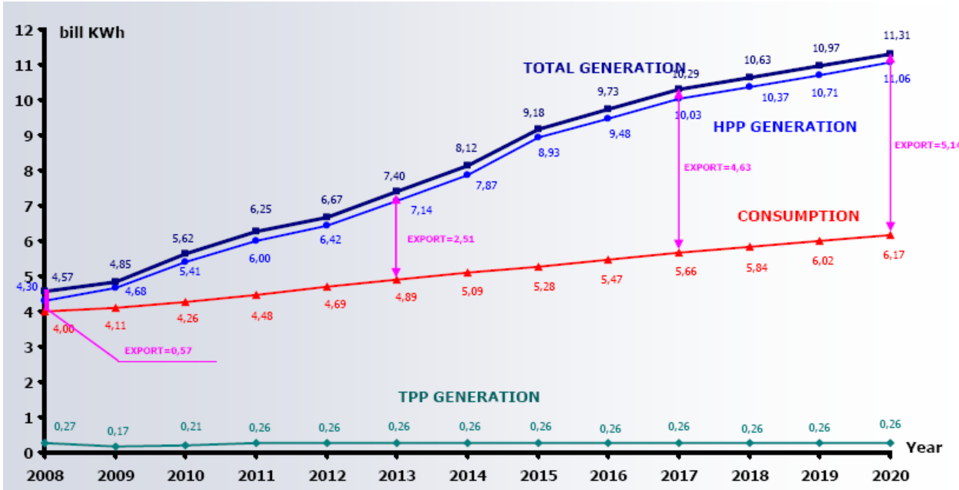


Figure 3.25 – Georgia - Demand forecasts (TWh) - Energy balance for Summer season(16 Apr –31 Oct)

Balance is presented for two characteristic seasons because this describes better behavior of Georgian demand and generation. In terms of generation, that is mainly hydro and seasonally dependent, Georgia has the ability to export large quantities of power during spring-summer seasons. Unlike this period during winter months, it is forced to import power. Total annual energy balance is presented in Figue 3.26

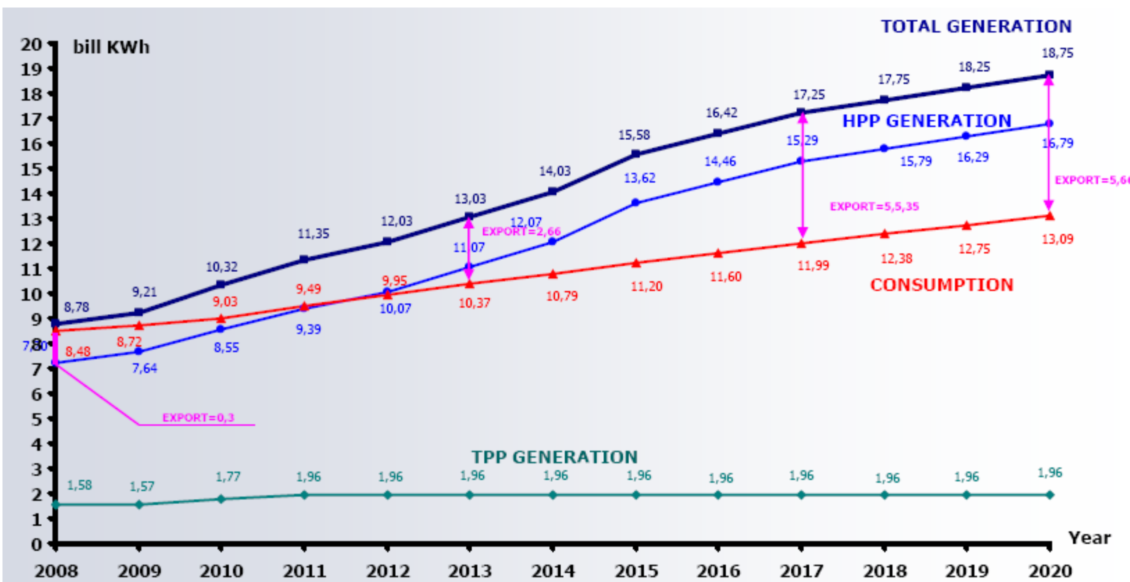


Figure 3.26 – Georgia - Demand forecasts (TWh) - Energy balance for whole year

So in 2020 Georgia can be treated as export country, depending on the prices. On the other hand, in 2015, Georgia can be treated as exporter in summer period only, which coincides with Turkeys peak consumption, and there is opportunity to export electricity to Turkey.

1.7.6 Remarks and comments

Georgia has a large hydro capacity and potential. It also has excess power of installed capacity compared to consumption, but high dependence on hydrology and seasons. This means that the country has low capacity in base load power plants. Their strategy is to buy base load power from another system like Azerbaijan and export peak power from Hydro into the regional system because peak power is more expensive than base load. This approach requires more investments, and requires a regional market development to achieve economical results.

The ESCO determines the amount of electricity that it will purchase based on demand forecasts approved by the Minister of Energy. According to the Electricity Market Rules, all wholesale purchasers of electricity are required to possess reserve capacity no less than a certain percentage of their hourly demand. The percentages are set out in the table below.

Table 3.27 Georgia - Reserve capacity requirements in Georgia 2006-2016

Period	Percentage	Source
2010-2012	10%	50% from local sources
2013-2015	10%	Local sources only
2016-2019	15%	Local sources only

1.8 Moldova

1.8.1 General Information

Moldova is a landlocked country in Eastern Europe, located between Romania to the west and Ukraine to the north, east and south.

Area: 33846 sq. km
Arable land: 54.52 % (2005)
Permanent crops: 8.81 % (2005)
Forest area: 9.9 % (2003)
Population: 4,320,490 (July 2007 est.)

GDP: purchasing power parity - $10.98 billion (2010 est.)
GDP per capita: purchasing power parity - $3082 (2010 est.)

GDP composition per sector:

- agriculture: 21.5 % (2006)
- industry: 22.0 % (2006)
- services: 56.5 % (2006)

GDP Real Growth Rate: 3 % (2007 est.)

1.8.2 Transmission Network

Moldova has an extensive power transmission and distribution system, but much of the equipment is obsolete and poorly maintained. The electricity grid operates in parallel with the Ukrainian electricity system; connected by six high voltage electric lines of 330 kV, while a 400 kV overhead power line connects it to the electricity systems of Romania and Bulgaria. Other three 110 kV overhead power lines provide an interconnection with the Romanian electricity system in an „insular regime". Strengthening links with the Romanian electricity system remains a continuous effort for the Republic of Moldova.

Table 3.28 – Moldova - network overview

lines		transformers	
Voltage level (kV)	Length of the overhead lines and cables (km)	Voltage level (kV/kV)	Installed capacities (MVA)
400	214	400/330	500
330	532.4	330/x	2525
110	5231.1	110/x	3687
total	5977.5		6712

At the moment, the country's electricity infrastructure can support the transit to the Balkan countries. The existing intersystem ties with Ukraine, Bulgaria and Romania and could ensure electricity transit at a level of 4-5 TWh /year. However, there is a need to strengthen the network of 330 kV lines in the Odessa region and in the northern part of the country: OHL 330 kV Novodnestrovsk (Ukraine), Balti (Moldova) and OHPL 400 kV Balti (Moldova), Suceava (Romania). Figure 3.27 presents the transmission grid of Moldova and Table 3.28 shows the main characteristics of its network.

Planned network reinforcements

Table 3.29 and the corresponding figure show the planned network reinforcements.

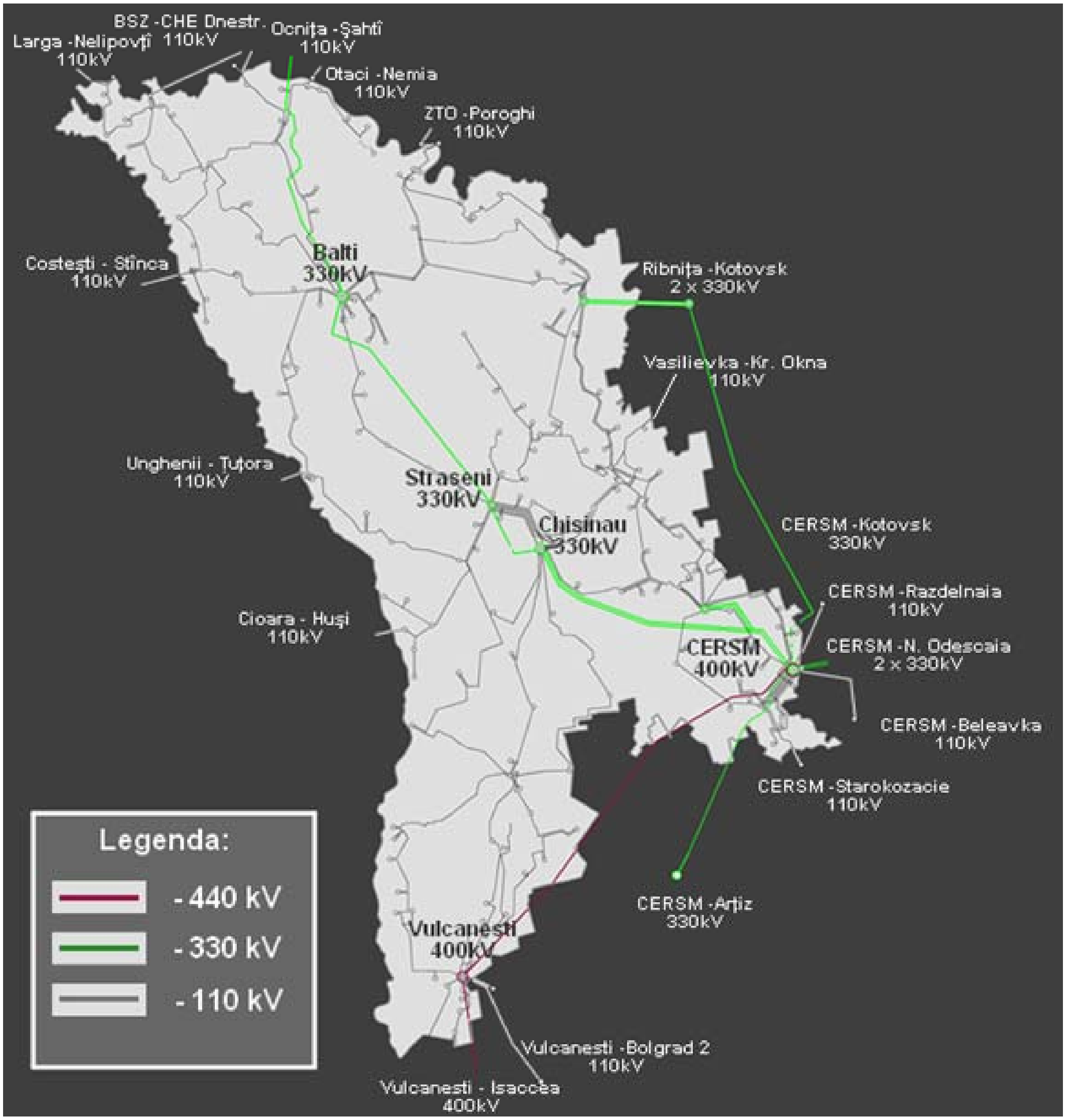


Figure 3.27– Moldova - network map

Table 3.29 – Moldova - Planned network reinforcements

TYPE	SUBSTATION1		SUBSTATION2		VOLTAGE LEVEL kV/kV	Number Of Circuits /units	CAPACITY A or MVA	CAPACITY limited A or MVA	MATERIAL OR TRANSFORMER TYPE	CROSSECTION mm2	LENGTH BR1 km	LENGTH BR2 km	LENGTH TOTAL km	DATE OF COMMISSIONING
1	2	3	2	3	4	5	6	7	8	9	10	11	12	13
OHL	MD	Balti	UA	Dnestrovska HPP	330	1	1670				88	32	120	2015
OHL	MD	Balti	MD	Straseni	330	1	1380				102.8		102.8	2015
OHL	MD	Straseni	MD	Chisinau	330	1	1380				36.4		36.4	2015
OHL	MD	Balti	MD	Ribnita	330	1	1380				82.5		82.5	2015
OHL	MD	Straseni	MD	Ribnita	330	1	1380				75		75	2015
SS	MD	Balti			400/330	1	630		IPC					2015
OHL	MD	Balti	RO	Suceava	400	1	1750				55			2015
SS	MD	Chisinau			400/330	1	630							2020
OHL	MD	Chisinau	RO	Iasi	400	1	1750							2020
SS	MD	Moldovskaya			400/330	1	2X630		IPC					2015
SS	MD	Pahoarna			110/x	2	??							2020
OHL	MD	Pahoarna	MD	Floresti	110	1								2020

1 Type of project (OHL - overhead line, K - kable, SK - submarin kable, SS - substation, BB - back to back system...)
2 Country (ISO code)
3 Substation name
4 Installed voltage (for lines nominal voltage, for transformers ratio in voltages)
5 number of circuits/units
6 Conventional transmission capacity of elements for OHL in Amps, for transformers in MVA
7 Conventional transmission capacity limited by transformers or substations
8 Type of conductor or transformer (ACSR - Aluminum Cross section Steel Reinforced, or code of conductor, PS - phase shift transformer...)
9 Cross section (number of ropes in bundle x cross section/cross section of reinforcement rope)
10 Length till border of first state
11 Length till border of second state
12 Total length
13 Date of commissioning (estimate)
14 Status of project (Idea, Feasibility study, Construction, Damaged, out of service, Decommissioned...)

*In red are network reinforcements connected to RES

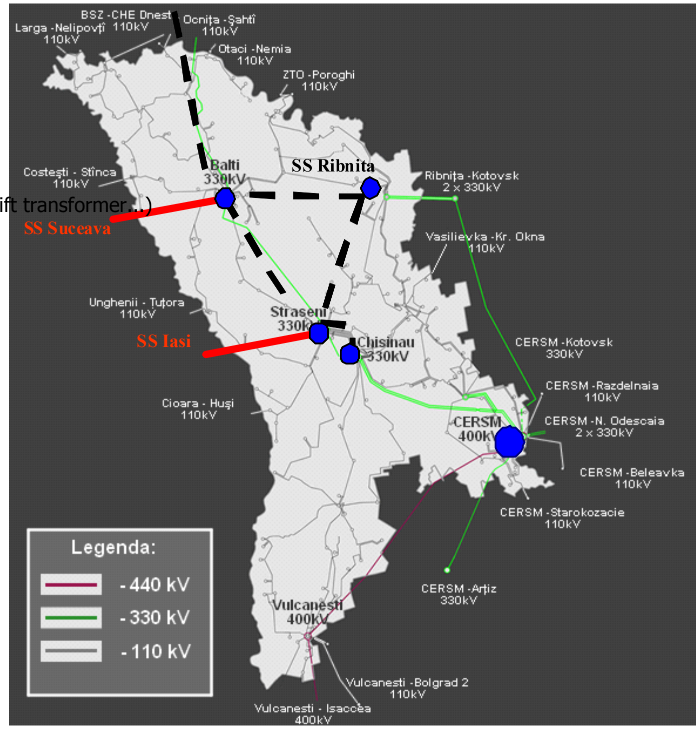


Table 3.30 – Moldova - Planned new generation units

TYPE	SUBSTATION1		VOLTAGE LEVEL kV	kV	CAPACITY MW	MVA	DATE OF COMMISSIONING year	STATUS	COMMENT
1	2	3	4	5	6	7	8	9	10
CCHP	MD	Balti	15.75	400	3x150	3x176	2015		2x150MW gas,1x150MW steam
CCHP	MD	Burlaceni	15.75	400	3x150	3x176	2015		2x150MW gas,1x150MW steam
CCHP	MD	Chisinau	15.75	110	540		2015		reconstruction and extension of existing plant
WPP	MD	Pahoarna	20	110	84	90	2020		
WPP	MD	Centru	20	110	140	150	2015		
WPP	MD	Carpineni	20	110	42	45	2015		

1 Type of plant (HPP - Hydropower plant, TPP - Thermal power plant, PSHPP - Pump Storage Hydro Power Plant, CCHP - Combined Cycle Heating Plant...)
2 Country
3 Substation name
4 Generator voltage level
5 Network voltage level
6 Installed active power
7 Installed apparent power
8 Date of commissioning (estimate)
9 Status of the project (Idea, Feasibility study, Construction...)

1.8.3 Generation

The electricity system of the Republic of Moldova includes one large thermal power plant Moldovska GRES that runs on Gas/Oil located in the Transnistrian region. Others include: three heat and power cogeneration (CHP) units, two hydropower plants and 10 CHP plants within sugar factories also run on gas or fuel oil.

TPP Moldavskaya GRES
Location: Moldova
Operator: CERS Moldova
Configuration: 7 X 200 MW, 5 X 210 MW
Operation: 1964-1980
Fuel: coal, natural gas, oil
Boiler supplier: Taganrog
T/G supplier: LMZ, Kharkov
Quick facts: This power station in Tiraspol, Transdneister region, has about 80% of Moldova's installed generating capacity.

There are only two major hydroelectric power plants, in spite of the fairly large number of rivers in Moldova. The largest of these is the Dubosari plant on the Dniester River. The power plant was built in 1954, and its installed capacity is 48 MW. The other significant hydro power plant with the installed capacity of 16 MW is located in Costesti, on the Prut river.

Generation Capacities Planned

Planned power plants in Moldova are shown in Table 3.30

Hydro Power Plants: There are no large hydro capacities planned in Moldova.

Thermal Power Plants: Planned thermal power plants in Moldova are the reconstruction of CHPP Chisianu to include new Combined Cycle units run on imported natural gas. The rest are two IPP CCGT plants that are planned to run on imported gas, and export electricity to Romania and the rest of the Europe. These plans will be realized much later due to the world crisis that has jeopardized these projects.

Renewables: Moldova hopes to cover a large portion of the internal consumption with renewable sources such as wind. Currently, the potential locations are under investigation, but no wind capacity is in operation. The request for grid connection of wind power has reached 500 MW. This accounts for about 40% of peak demand of a power plant. At moment there are three potential locations with 266MW installed capacity:

- Central wind farm with requested installed capacity of 140 MW
- Carpineni wind farm with requested installed capacity of 42 MW
- Pohoarna wind farm with requested installed capacity of 84 MW

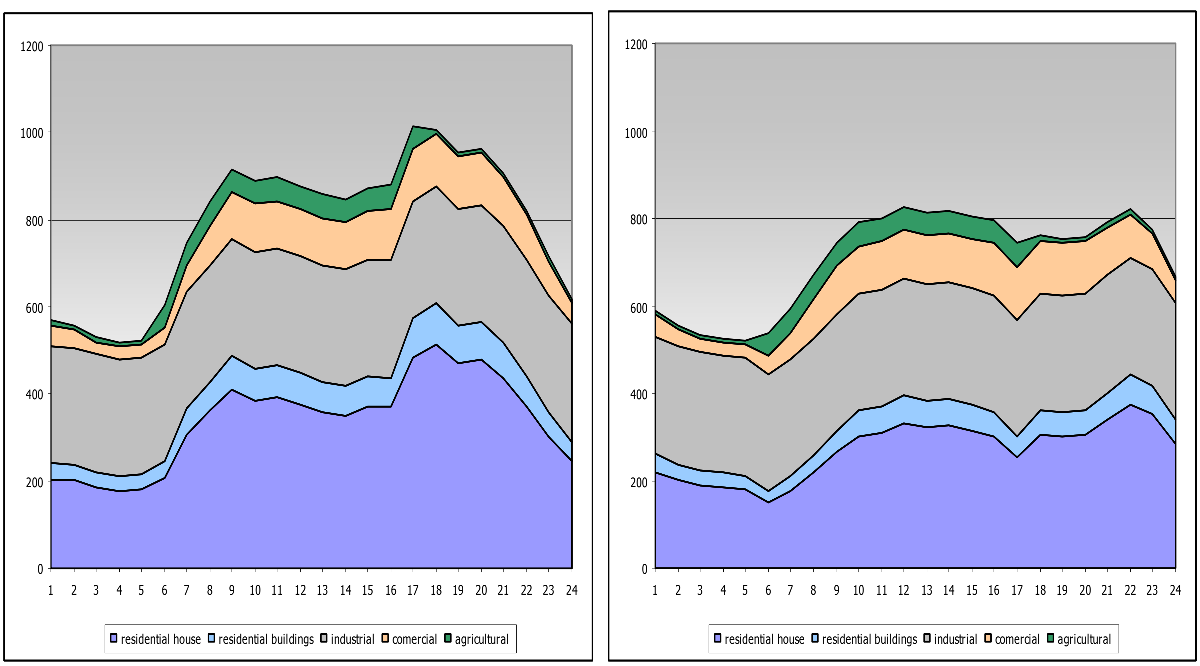
Energy potential of these 3 wind farms is estimated at 699048 MWh per year. This amount is about 11% from yearly consumption of Moldova.

Figure 3.28 – Moldova – Locations of Wind power plants

1.8.4 Demand

Demand behavior

Figure 3.4 and 3.5 show demand behavior for characteristic winter and summer peak regimes and participation of different types of consumption in total energy consumed.



Winter peak 15.12.2010. Summer peak 16.6.2010

Figure 3.29 – Moldova – Daily demand curve for winter and summer peak 2010

Demand forecast

Demand forecast is shown in Figure 3.30 as well as coverage of this diagram by domestic power production. If new gas fired installations are built, Moldova will most likely export this power to western markets.

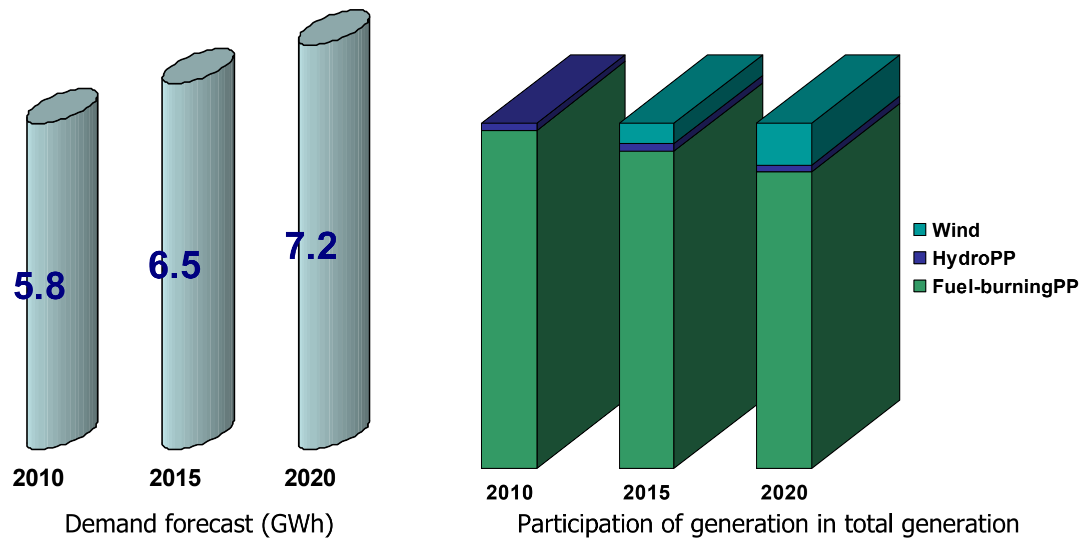


Figure 3.30– Moldova – Demand forecast and generation participation

Tariff

Renewable energy resources incentive schemes have not been set in Moldova. The country plans to stimulate investments through a national incentive scheme that includes the following: Tax privileges and tax crediting for physical persons and economic organizations, custom duties reduction in tax/tax-free and total income-tax reduction for a 3-year period.

1.8.5 Remarks and comments

Currently most of the ancillary power imported from Ukraine. The MGRES power plant can be used to balance renewables production on a day-ahead market. Another source would be from the Ukrainian energy system on real-time market. Present balancing mechanisms for the wind intermittence are possible through imports from Ukraine. This is a likely scenario for the future as well.

1.9 Romania

1.9.1 General Information

Romania is a country located at the crossroads of Central and Southeastern Europe, north of the Balkan Peninsula, on the Lower Danube, within and outside the Carpathian arch, bordering on the Black Sea. Romania shares a border with Hungary and Serbia to the west, Ukraine and Moldova to the northeast, and Bulgaria to the south.

Area: 238391 sq. km
Arable land: 39.49% (2005)
Permanent crops: 1.92% (2005)
Forest area: 27 %
Population: 21,466,174 (2010 est.)

GDP: purchasing power parity - $254.16 billion (2010 est.)
GDP per capita: purchasing power parity - $11860 (2010 est.)

GDP composition per sector:

- agriculture: 12.4 % (2009)
- industry: 35.0 % (2009)
- services: 52.6 % (2009)

1.9.2 Transmission Network

Romania has an extensive interconnected power transmission and distribution network with an overall length of about 600,000 km, and a total transformer capacity of about 172,000 MVA. Main characteristics of Romanian network are presented in Table 3.31 . The national grid operates on 750 kV, 400 kV, and 220 kV for transmission and 20 kV, 10 kV, 6 kV, 1 kV and 0.4 kV for distribution.

Table 3.31– Romania - network overview

Voltage (kV)	Transformer Substation			Length (km)
	Substation nr.	Transformers (T, AT) nr.	Nominal Power (T,AT) MVA	
750	1	2	1250	154,6
400	34	2 20 25	500 400 250	4740,3
220	42	2 1 80	400 100 200	4095,9
110	0			38
Total Number of Substation	77			
Total Length (km)				9028,8
Transformer Substation (T, AT)		132	34.65	

Romania has strong interconnections with Ukraine and Bulgaria, substantial interconnections with the former Yugoslavia, and weaker links to the Republic of Moldova and Hungary. The transmission network is interconnected with neighboring countries by 750 kV (4,000 MWe capacity), 400 kV (2,500 MWe capacity), and two 110 kV tie-lines with Ukraine; a 400 kV line with Hungary (currently operating at 220 kV, with a planned capacity of 1,200 MWe); 750 kV (4,000 MWe capacity), 400 kV (2,500 MWe capacity), and 220 kV (260 MWe capacity) lines to Bulgaria; and one 400 kV (1,200 MWe capacity) and two 110 kV lines with Serbia; and two 110 kV lines with Moldova.

Planned Network Reinforcements

Present development plan is to increase border line capacities by diverting Dobrudja (Bulgaria)-Vulkanesti (Moldova) line to the Isaccea (Romania) substation, rehabilitation of existing 750 kV line Isaccea (Romania)-Pivdenoukrainskaya (Ukraine) with installation of Back-to-Back system, building 400 kV lines Oradea (Romania) - Becescaba (Hungary) and Suceava (Romania)-Balti (Moldova) and to upgrade parts of Romanian network from 220 kV to 400 kV. These lines are already built for 400 kV but currently operate at 220 kV level. The construction of the new 400 kV lines will increase transmission and reserve capacity of the network. The goal is to close the 400kV ring in the Romanian network in addition to the Bucharest 400kV ring to increase the security of supply of main consumption region.

The Dobrudja region has a vast wind potential and a large number of WPP applications, but not enough transmission capacity to support it. To accommodate the connection of large wind parks in the Dobrudja region, separate 400/110 kV substations are planned to evacuate all the power produced. This approach can be costly but it proved to be more suitable then a connection to a local distribution network or to a lower voltage network, from both the transmission capacity, regulation and control point of view. Table 3.32 shows the planned network reinforcements to support WPP integration in transmission network.

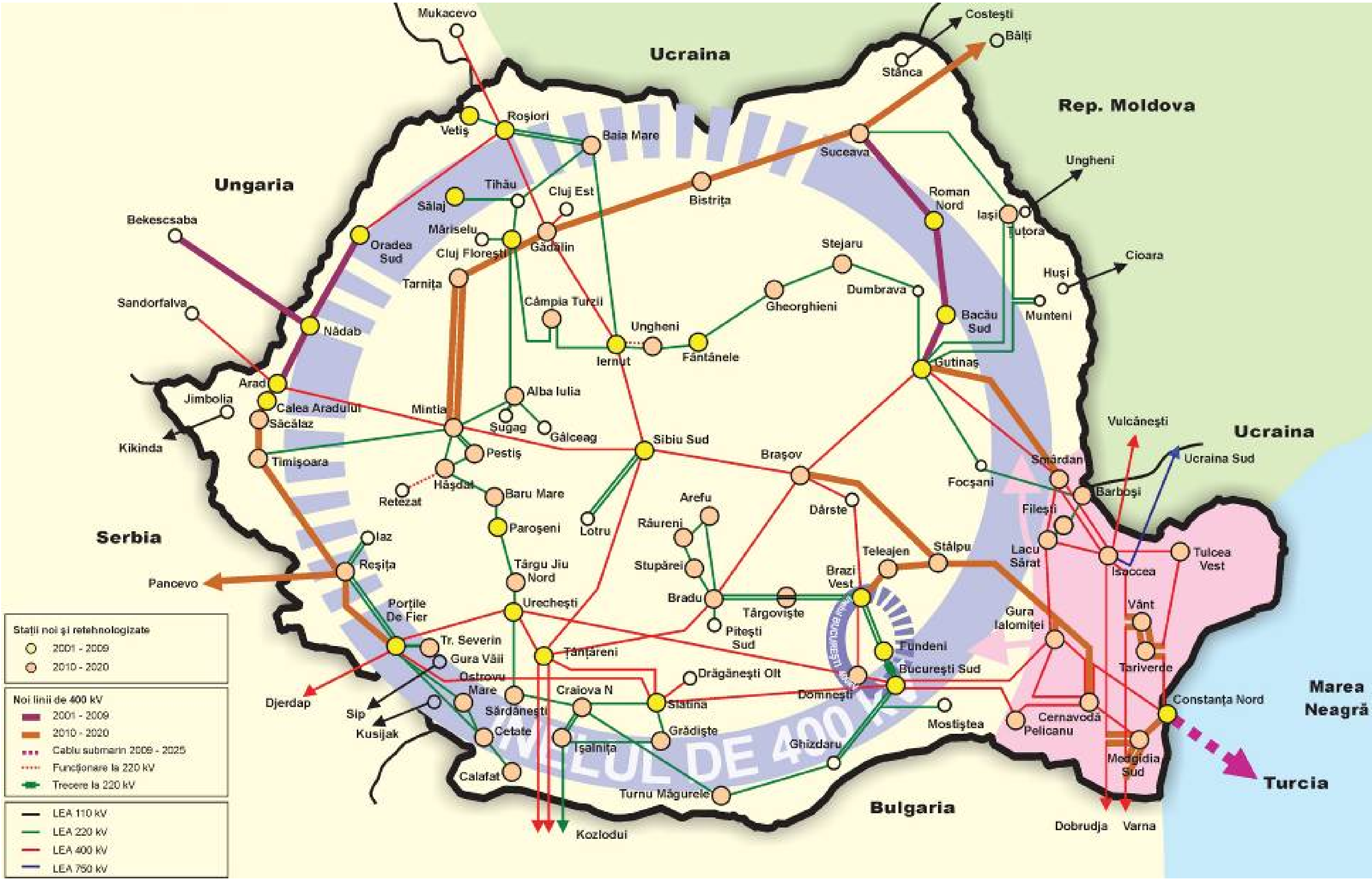


Figure 3.31 – Romania - network map

Table 3.32 – Romania - Planned network reinforcements for RES connection to the network

TYPE 1	2	SUBSTATION1 3	2	SUBSTATION2 3	VOLTAGE LEVEL kV/kV 4	Number Of Circuits /units 5	CAPACITY A or MVA 6	limited A or MVA 7	MATERIAL OR TRANSFORMER TYPE 8	CROSS mm2 9	LENGTH BR1 km 10	BR2 km 11	TOTAL km 12	DATE OF COMMISSION 13	STATUS 14	COMMENT 13
SS	RO	Resita			400/220	1	400		2 windings					2014		
SS	RO	Resita			400/110	1	250		2 windings					2014		
OHL	RO	Portile de Fier I	RO	Resita	400	1	1997		Ol-Al	3x300			117	2014		new 400kV OHL
SS	RO	Timisoara			400/220	1	400		2 windings					2014		
OHL	RO	Timisoara	RO	Resita	400	1	1997		Ol-Al	3x300			73	2014		upgrade from 220 kV
OHL	RO	Timisoara	RO	Arad	400	1	1997		Ol-Al	3x300			55	2014		upgrade from 220 kV
OHL	RO	Timisoara	RS	Pancevo	400	1	1750		Ol-Al	3x300			100	2014		
SS	RO	Suceava			400/110	2	250		2 windings					2010		
OHL	RO	Suceava	MD	Balti	400	1	1750		Ol-Al	3x300	40	55	95	2019		
SS	RO	Bacau			400/220	1	400		2 windings					2014		
SS	RO	Roman			400/220	1	400		2 windings					2014		
OHL	RO	Suceava	RO	Roman	400	1	1700		Ol-Al	3x300			100	2014		upgrade from 220 kV
OHL	RO	Roman	RO	Bacau	400	1	1700		Ol-Al	3x300			58.8	2014		upgrade from 220 kV
OHL	RO	Bacau	RO	Gutinas	400	1	1700		Ol-Al	3x300			55.3	2014		upgrade from 220 kV
SS	RO	Bistrica			400/110	1	250		2 windings					2020		
OHL	RO	Suceava	RO	Bistrica	400	1	1700		Ol-Al	3x300				2020		upgrade from 220 kV
OHL	RO	Gadalin	RO	Bistrica	400	1	1700		Ol-Al	3x300				2020		upgrade from 220 kV
SS	RO	Rahmanu			400/110	2	250		2 windings					2014		
OHL	RO	Isaccea	RO	Rahmanu	400	1	1800		Ol-Al	3x300				2014	Constr.	to line Isaccea-Dobrudja
OHL	RO	Medgidia	RO	Rahmanu	400	1	1800		Ol-Al	3x300				2014	Constr	to line Isaccea-Dobrudja
OHL	BG	Dobrudja	RO	Medgidia	400	1	1800		Ol-Al	3x300				2012	Constr	to line Isaccea-Dobrudja
SS	RO	Tariverde			400/110	2	250		2 windings					2011	Constr	
OHL	RO	Tulcea west	RO	Tariverde	400	1	1800		Ol-Al	3x300				2011	Constr	to line Tulcea-Constanta
OHL	RO	Constanta	RO	Tariverde	400	1	1800		Ol-Al	3x300				2011	Constr	to line Tulcea-Constanta
OHL	RO	Isaccea	RO	Medgidia	400	1	1800		Ol-Al	3x300				2014		to line Isaccea-Varna
OHL	BG	Varna	RO	Medgidia	400	1	1800		Ol-Al	3x300				2014		to line Isaccea-Varna
OHL	RO	Constanta	RO	Medgidia	400	1	1800		Ol-Al	3x300			21	2014		new 400kV OHL
DC	RO	Constanta			400		600 MW							2020		DC Converter station
SK	RO	Constanta	TR	Pasakoy	400	1	600 MW				200	200	400	2020		
SS	RO	Iasi			400/220									2020		
OHL	RO	Iasi	MD	Chisinau	400	1	1750		Ol-Al	3x300				2020		

SS	BG	Majak			110/20	2								2015	Project

OHL	BG	Majak	BG	Dobrich		2							58	2015	Project
OHL	BG	Majak	BG	Shabla		2							12	2015	Project
OHL	BG	Majak	BG	Kavarna		2							12	2015	Project
OHL	BG	Varna Sever	BG	Kavarna		1							50	2015	Project
OHL	BG	Varna Zapad	BG	Kavarna		1							55	2015	Project
OHL	BG	Dobrudja	BG	Dobrich		1							34	2015	Project
SS	BG	Svoboda			400/110	2		300	OTC					2020	Project
OHL	BG	Svoboda	BG	Varna(BG)–Issacea(RO)	400	2	1890	-	ACSR	2X500			10	2020	Project
SS	BG	Vidno			400/110	2		300	OTC					2020	Project
OHL	BG	Svoboda	BG	Vidno	400	2	1890	-	ACSR	2X500			115	2020	Project

1 Type of project (OHL - overhead line, K - cable, SK - submarine cable, SS - substation, BB - back to back system...)
2 Country (ISO code)
3 Substation name
4 Installed voltage (for lines nominal voltage, for transformers ratio in voltages)
5 number of circuits/units
6 Conventional transmission capacity of elements for OHL in Amps, for transformers in MVA
7 Conventional transmission capacity limited by transformers or substations
8 Type of conductor or transformer (ACSR - Aluminum Cross section Steel Reinforced, or code of conductor, PS - phase shift transformer...)
9 Cross section (number of ropes in bundle x cross section/cross section of reinforcement rope)
10 Length till border of first state
11 Length till border of second state
12 Total length
13 Date of commissioning (estimate)
14 Status of project (Idea, Feasibility study, Construction, Damaged, out of service, Decommissioned...)

**reconstruction in network connected to new RES installation*

Table 3.33 – Romania – Planned new generation units

TYPE	SUBSTATION1		VOLTAGE LEVEL kV	kV	CAPACITY MW	MVA	DATE OF COMMISSIONING year	STATUS	COMMENT
1	2	3	4	5	6	7	8	9	10
CCHP	RO	Brazi	20	400	2x305	4x288	2010	construction	
CCHP	RO	Brazi	20	220	315	4x288	2010	construction	
TPP	RO	Galati	24	400	800		2014	construction	
TPP	RO	Braila	24	400	880		2016	construction	
NPP	RO	Cernavoda	24	400	2x720	2x800	2016	construction	
HPP	RO	Tarnita	15.75	400	4x256	4x288	2016	Project	

1 Type of plant (HPP - Hydropower plant, TPP - Thermal power plant, PSHPP - Pump Storage Hydro Power Plant, CCHP - Combined Cycle Heating Plant...)
2 Country
3 Substation name
4 Generator voltage level
5 Network voltage level
6 Installed active power
7 Installed apparent power
8 Date of commissioning (estimate)
9 Status of the project (Idea, Feasibility study, Construction...)

1.9.3 Generation

Romania is in the process of modernizing and reconstructing of most of its generation capacities. About 55% of the electricity is produced in coal fired thermal power plants. Hydro units produce 25% and Nuclear facilities 15%. Independent producers and ever growing renewables make up 5% with tendency to grow fast.

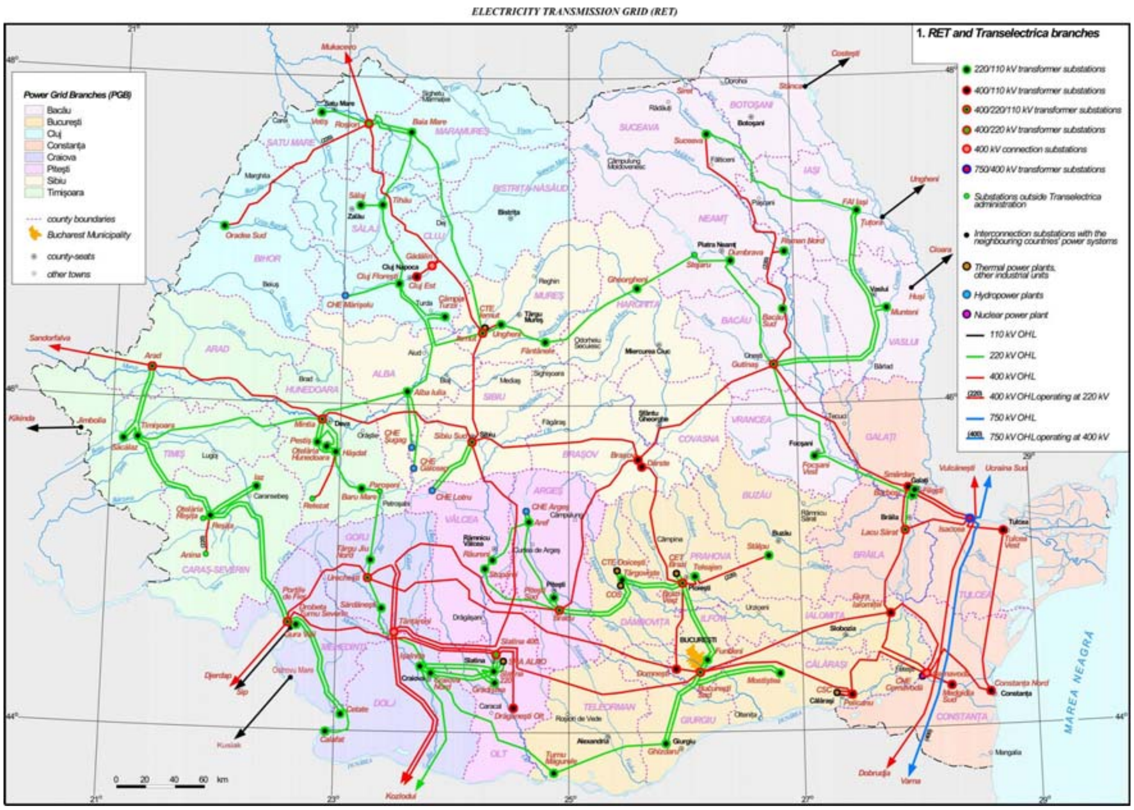


Figure 3.32 – Romania – Generation capacities and transmission network

NPP Cernavoda
Location: Romania
Operator: SN Nuclearelectrica SA
Configuration: 2 X 720 MW CANDU
Operation: 1996-2007
Reactor supplier: AECL
T/G supplier: GE
EPC: AECL, Ansaldo

Quick facts: In Dec 1978, an agreement was signed between AECL and Romenergo for the construction of Unit-1, followed in Jul 1981 by the agreement for Unit-2. Construction started on these two units in 1980 and 1982, respectively, while the civil works for three more units were started in 1984-86. The original agreements covered the licensing of the CANDU-6 design, equipment supply, and technical assistance. A consortium of Canadian equipment manufacturers and engineering contractors was formed to oversee construction while a number of different government agencies were responsible for project management. Completion of Cernavoda-1 was initially scheduled for 1985, however the construction schedule slipped repeatedly as local industries failed to produce needed materiel, imports were restricted, and foreign loans dried up. Finally, work was stopped completely in 1989 to fix large numbers of defective pipe welds. Following a visit from an IAEA mission in 1991, a new consortium of AECL and Italy's Ansaldo was formed to finish Cernavoda-1. Criticality was achieved in Apr 1996, grid connection in Jul, and commercial operation in Dec. Unit-2 went commercial on 5 Oct 2007.

TPP Rovinari
Location: Gorj, Romania
Operator: SC Complexul Energetic Rovinari SA
Configuration: 2 X 200 MW, 4 X 330 MW
Fuel: subbituminous coal, natural gas, oil
Operation: 1976-1979
T/G supplier: Skoda, Rateau, Alsthom, IMGB
Quick facts: Rovinari is in Gorj County on the Jiu River near Târgu Jiu. Largest Thermal power plant in Romania. Almost all machines are refurbished in 1990s and western build equipment is used now. 200-MW sets have been decommissioned and a new 500-MW group is planned.

TPP Turceni
Location: Gorj, Romania
Operator: SC Termoelectrica SA
Configuration: 7 X 330 MW
Fuel: lignite
Operation: 1978-1987
Boiler supplier: Babcock
T/G supplier: IMGB/Alstom
Quick facts: Although one set is deactivated, this remains the largest thermal power plant in Romania. The 1,293ha site is situated half-way between the cities of Craiova and Targu Jiu in southwest Romania. Turceni is essentially a minemouth plant with lignite supplied by rail from mines around 35km away, from Jilţ Coal Mine 1700kcal/kg and Tehomir underground mine 1900kcal/kg.

HPP Portile de Fier
Location: Romania
Operator: Hidroelectrica
Configuration: 6 X 171 MW Kaplan
Operation: 1972
T/G supplier: LMZ, Electrosila, Koncar
EPC:
Quick facts: Largest Hydroelectric power plant in Romania, as joint project with Yugoslavia. The plant is located in the Djerdap Gorge – the Iron Gate - on the Danube River. A second powerhouse has ten 26-MW LMZ bulb turbines completed in the late 1980s. Power plant is totally refurbished and capacity is increased to 6x200MW.

HPP Sugag
Location: Sebes river, Romania
Operator: Hidroelectrica
Configuration: 2 x 75 MW Francis
Operation: 1980s
T/G supplier: Resita
EPC:
Quick facts: The project was started and finished in the 1980s and it was made up by the construction of a double arched concrete dam 78 m high which was equipped with two vertical turbines, the Şugag Hydro Power Plant having

HPP Gilcegag
Location: Sebes river, Romania
Operator: Hidroelectrica
Configuration: 2 x 75 MW Francis
Operation: 1980s
T/G supplier: Resita
EPC:
Quick facts: The first and the greatest of reservoirs forming the cascade developed on river Sebes course is reservoir Oaşa. Situated at the foots of Sebeşului Mountains, it is a concentration of Sebeş river waters and its main affluents i.e. Valea Mare and Curpătul, as well as of other smaller water courses, through some secondary galleries. At the normal retension levels, Oaşa reservoir has a water volume of 136 mil.cu.m., while the surface is of 454 hectars. The dam is a reinforced concrete facing rockfill type and is 91 m high. The commissioning during the year of 1980 of the Gîlceag underground hydropower plant resulted in a capitalization of Oaşa power potential storage. Equipped with two vertical Francis turbine driven alternators, the hydropower plant has an installed power of 150 MW. Net Rated Head: 430 m, Installed discharge: 40 cu.m./s Project Energy: 260 GWh.

HPP Lotru
Location: Romania
Operator: Hidroelectrica
Configuration: 3 X 170 MW Pelton
Operation: 1970
T/G supplier: Resita
EPC:
Quick facts: The project was started and finished in the 1970s and it was made up by the construction of a rockfill with a clay core dam 140 m high and an underground power plant equipped with three hydro units, having an installed capacity of 510 MW. The Pelton type turbines operate under a net head of about 800 m. A 220 kV outdoor substation connects the plant to the Romanian electric grid. Together with HPP Bradisor it makes a cascade.

Most of the thermal power plants are run on domestic open pit lignite that is around 7.5mBTU/ton, a low grade coal. There is a higher quality domestic coal at 14.1mBTU/ton, and also some is imported from Ukraine that reaches 23.8mBTU/ton. Lower grade coal is mixed with fuel oil to increase heat value in some thermal power plants.

Romania uses more than half of its natural gas sources at 32mBTU/tcm, and imports the rest from Russia. In most cases the gas is used as the primary fuel for CHP, although depending on the market prices and availability of fuel, same facilities use fuel oil as well (37.7mBTU/ton).

Generation Capacities Planned

Nuclear Power Plants: Romania plans to finish two more 700MW units in NPP Cerna Voda by 2014 and 2015 respectively. Construction started for the unit 5, but has been put on hold.

Hydro Power Plants: Hydro power is already very developed in Romania, and locations for large HPPs are already used. Only large projects are reversible pumping stations PHPP Tarnita 1000MW and PHPP Olt (~400 MW). There is a large potential for developing small hydro power plants. There are many ongoing projects for refurbishment and reconstruction of existing facilities.

Thermal Power Plants: Only development plans for thermal power plants are replacing the obsolete and old units that run on gas or fuel oil with new more efficient ones. This is especially the case for CHP units in Bucharest and Constanca. There are plans for installing large CCGT units in Iernut-Ludus 400MW and

Borzesti 400MW, and to build large coal fired units in Isalnita 500MW and in TPP Braila 800MW that will be run on imported coal.

Renewables: One of the priorities for development of Romanian system is to increase the use of ecologically pure energy resources - alternative, renewable, wind and solar energies, geothermal waters, biogases and etc. Long term targets for Romania (according to the Law 220 / 2008) the generation on renewable sources (subject of green certificates support scheme) should cover the following quantities per year:

- 2011 – 10.00 %
- 2012 – 12.00 %
- 2013 – 14.00 %
- 2014 – 15.00 %
- 2015 - 16.00 %
- 2016 - 17.00 %
- 2017 - 18.00 %
- 2018 - 19.00 %
- 2019 - 19.50 %
- 2020 - 20.00 %

Figure 3.33 – Romania – Locations of the main wind power plants

Wind generation in Romania – significant aspects

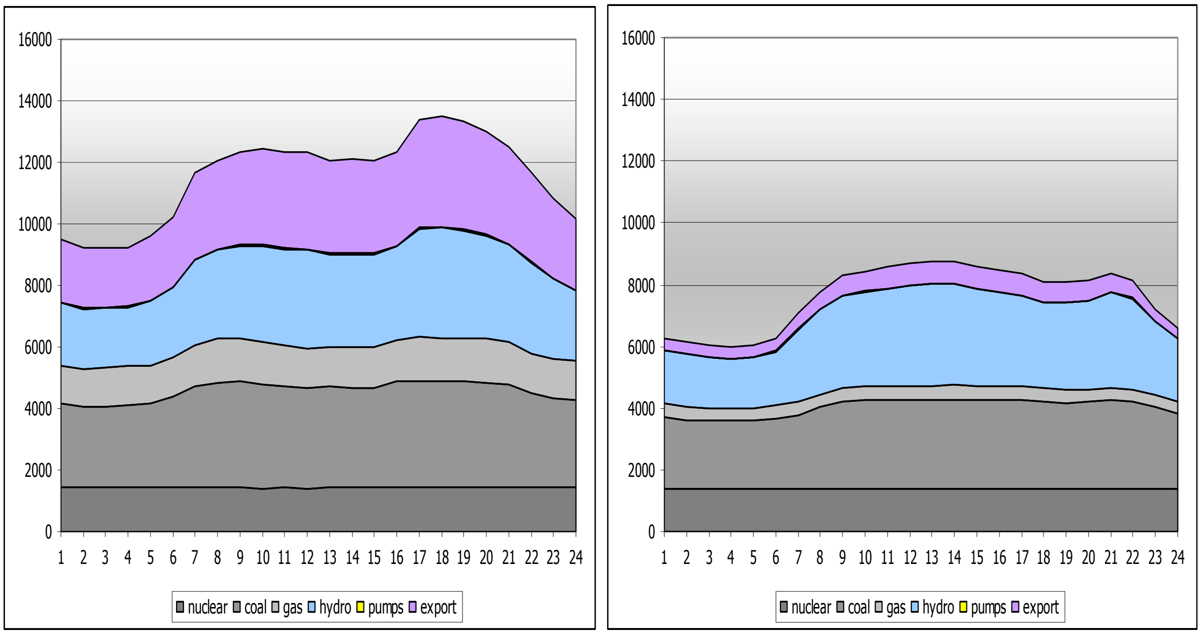
Forecasts for installed power (according to our National Plan NREAP):

- 2015 – 3200 MW
- 2020 – 4000 MW

1.9.4 Demand

Demand Behavior

Figure 3.34 shows the demand behavior for typical winter and summer peak regimes and the different generation types. Table 3.34 shows the distribution of demand by type in previous periods and forecasts.



Winter peak 15.12.2010 Summer peak 20.07.2010

Figure 3.34 – Romania – Daily demand curve for winter and summer peak 2010

Table 3.34 – Romania – Distribution of demand by type and demand forecast

		2006	2007	2008	2009	2010	2015	2020
Energy consumption gross	**TWh**	**53.02**	**54.14**	**55.22**	**50.64**	**53.66**	**60.0**	**68.0**
demand	**MW**	8151	8681	8589	8247	8464	9560	11020
pumping	**TWh**	0.15	0.15	0.12	0.12	0.27	0.30	0.65
	TWh	57.42	56.37	59.8	53.2	56.8	63.5	72.5
Generation	**MW**	8846	9285	9406	8762	9248	10560	12520
	TWh	4.25	2.09	4.43	2.47	2.92	3.20	3.86
export-import	**MW**	695	604	817	515	784	1000	1500
Consumption	**TWh**	**46.5**	**47.6**	**48.0**	**44.2**	**46.2**	**52.4**	**60.0**
	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0
agriculture	**%**	0.98	1.13	1.16	1.1	1.1	1.1	1.1
industry	**%**	62.83	61.97	60.87	57.9	57.9	57.8	56.5
transport	**%**	3.00	3.07	2.92	3.0	3.0	3.0	3.1
service	**%**	10.92	12.01	13.40	14.5	15.0	17.0	19.2
population	**%**	22.27	21.82	21.66	23.5	23.0	21.0	20.2

Demand Forecast

Table 3.34 shows the distribution of demand and demand forecasts for 2015 and 2020 and Figure shows the demand growth in the forthcoming period through 2020.

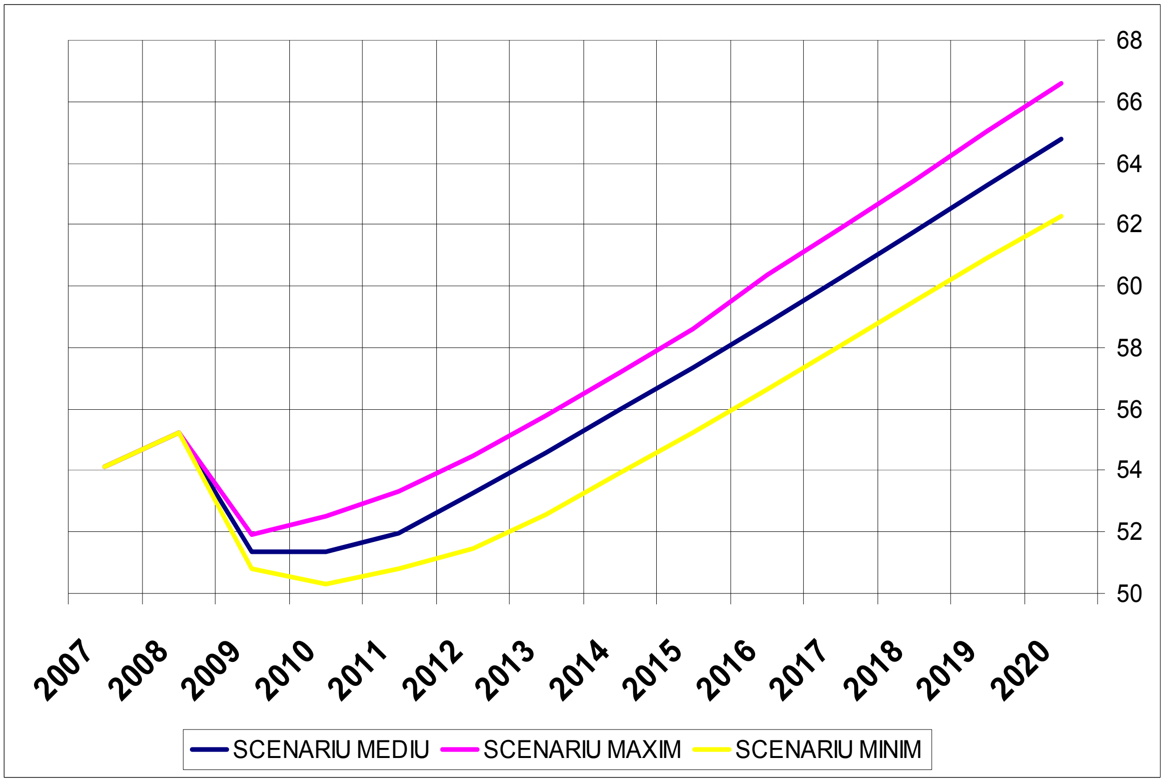


Figure 3.35 – Romania – Demand Forecast

Tariff

Currently the electricity supply tariffs for commercial customers are 8.5cEUR/kWh or 12.15c$/kWh and for households 8.56cEUR/kWh or 12.23c$/kWh, before taxes. The wholesale market in Romania is organized, but prices vary significantly due to the wide diversity of fuel used for electricity production.

The financial support scheme for RES is in form of Green Certificates (2 Euro/MWh for wind, 6 Euro/MWh for solar with a margin of 27÷55 euro/certificate). For the period 2005-2012, the annual maximum and minimum value for Green Certificates trading is 24 Euro/certificate, respective 42 Euro/certificate, calculated by the Romanian National Bank, on the last working day of the December of the previous year. This is reflected on the prices of electricity. A large price increase is expected but will remain lower than the value in other EU countries.

Gas prices in Romania are lower than market values than on majority of gas market Hubs, for electricity production price is around 320$/tcm, or 8.2$/mBTU.

1.9.5 Export Potential in 2015 and 2020

From previously shown tables and diagrams it can be concluded that Romania will have up to 1500MW surplus power for export, mainly due to a large increase in RES installed capacity.

1.9.6 Remarks and comments

Currently balancing in the system is done by HPPs and TPPs, and NPPs do not participate in this process. The new planned PSPP Tarnita 1000 MW should increase the control potential of the Romanian system and resolve most of the difficulties in this field. In addition, the installation of the New Pump Storage HPP Olt river (~400 MW) and modern gas and/or coal fired generation units in the future will enable larger penetration of renewables in Romania.

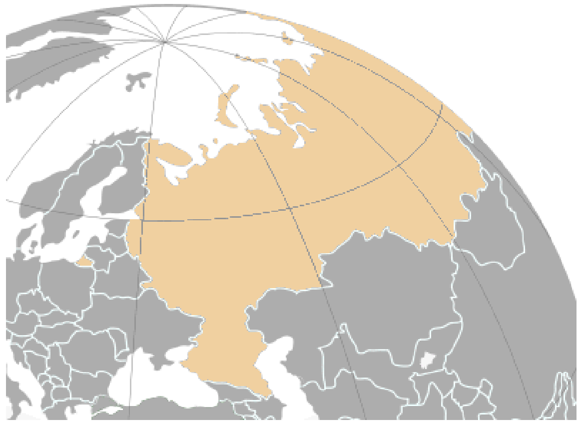
Main principles of balancing:

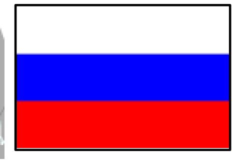
- balancing market has been developed according to the Commercial Code,
- all the available capacity should be notified, there is a cap price,

- day ahead schedule, intra-day schedule, hourly based notification, the system allows notifications at 15 min intervals,
- Scheduling Management System,
- BRP – balancing responsible parties (consumption/production responsible parties),
- According to the Commercial Code, WPPs must be part of BRP.

1.10 Russia

1.10.1 General Information





From northwest to southeast, Russia shares borders with Norway, Finland, Estonia, Latvia, Lithuania and Poland (both via Kaliningrad Oblast), Belarus, Ukraine, Georgia, Azerbaijan, Kazakhstan, the People's Republic of China, Mongolia, and North Korea. It also has maritime borders with Japan by the Sea of Okhotsk, and the United States by the Bering Strait. At 17,075,400 square kilometers, Russia is the largest country in the world, covering more than one eighth of the Earth's inhabited land area. Russia is also the ninth most populous nation with 143 million people. It extends across the whole of northern Asia and 40% of Europe, spanning nine time zones and incorporating a wide range of environments and landforms. Russia has the world's largest reserves of mineral and energy resources. It has the world's largest forest reserves and its lakes contain approximately one-quarter of the world's fresh water.

Area: 17075400 sq. km
Arable land: 39.49% (2010)
Water: 13 %
Forest area: 27 %
Population: 142,905,200 (2010)

GDP: purchasing power parity - $2222 billion (2010 est.)
GDP per capita: purchasing power parity - $15840 (2010 est.)

GDP composition per sector:

- agriculture: 12.4 % (2009)
- industry: 35.0 % (2009)
- services: 52.6 % (2009)

1.10.2 Transmission Network

The power industry in Russia gradually developed overtime. First, by incorporating regional power systems, working in parallel, and forming interregional electric power pools, which merged to form a single Power Grid that covers a vast area. The entire transmission network is controlled by the Federal Grid Company of Unified Energy System (JSC FGC UES) which operates the Unified National Electric Grid (UNEG). The company operates 121096km of transmission lines and 797 substations with installed capacity over 300000MVA of different voltage levels 110-1150kV.

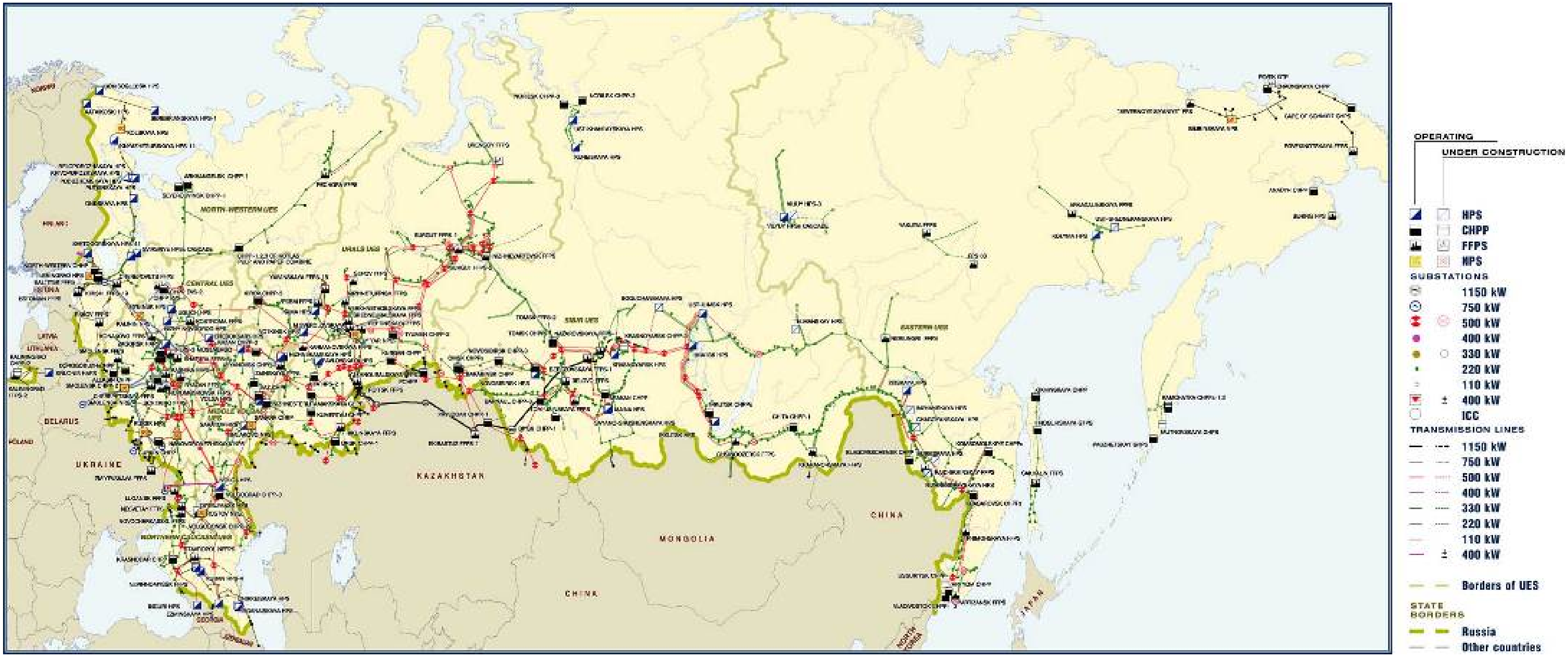


Figure 3.36 – Russia – network map

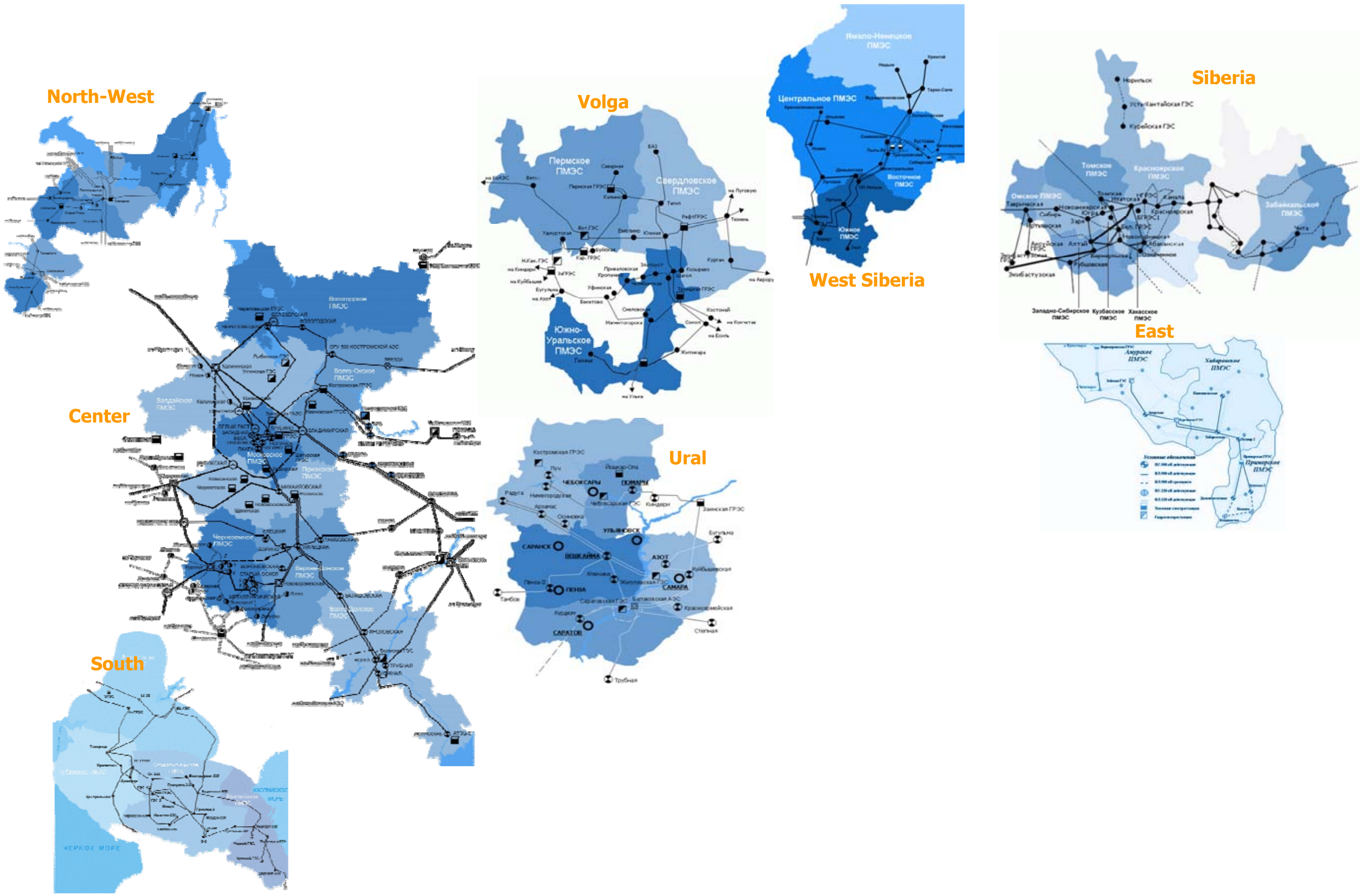


Figure 3.37 – Russia – network map and control regions

To manage such large network, it is divided into regional control centers that correspond to the system divisions. (Figure 3.37):

- North-West
- Center
- South
- Ural
- Volga
- West Siberia (Yakutia)
- Siberia
- East

Table 3.35 shows the characteristics of the network by control areas, and Figure 3.36 shows the entire network while Figure 3.38 presents only the European part.

Table 3.35 – Russia - network overview

					Lines				
Voltage	Center km	South km	Ural km	Siberia km	North-west km	West Siberia km	East km	Volga km	Total km
1150kV			129.5	817.6					947.1
800kV	169.7	206							375.7
750kV	2270.2				799.13				3069.33
500kV	7490.3	2384	5153	7073.99	74	4543	3095	4007.53	33820.82
400kV					126.5				126.5
330kV	1835.07	2681			6458.03				10974.1
220kV	14913.97	4539.1	10145	17566.2	6448.57	8591	9502	8098.62	79804.46
110kV	249.5	108	233.2	356.46	408.06	2			1357.22
35kV			3	125.48	144.8				273.28
									130475.2
					Substations				
Voltage	Center num	South num	Ural num	Siberia num	North-west num	West Siberia num	East num	Volga num	Total num
1150kV				2					2
800kV									0
750kV	6				2				2
500kV	24	6	19	16		18	8	13	80
400kV					1				1
330kV	14	17			32				49
220kV	135	43	76	87	50	64	64	73	457
110kV	9	3	8	9	7				27
35kV	1		2	1	3				6
									618
									624

Strategic objectives of UNEG development are accomplished by JSC FGC UES. The key development goals in JSC FGC UES are as follows:

- develop electric grids;
- provide power plants capacity;
- arrange conditions for reliable power supply of consumers;
- cope with fixed assets ageing;
- develop centralized technological control for electric grids;
- create grid and technological infrastructure;
- join participants of wholesale market to the electric grid;
- bring UNEG technical level to world standards;
- raise operating performance through reduction of costs, unit costs incidental to operation and losses in UNEG grids;
- implement unified strategy in area of investments and raising capital.

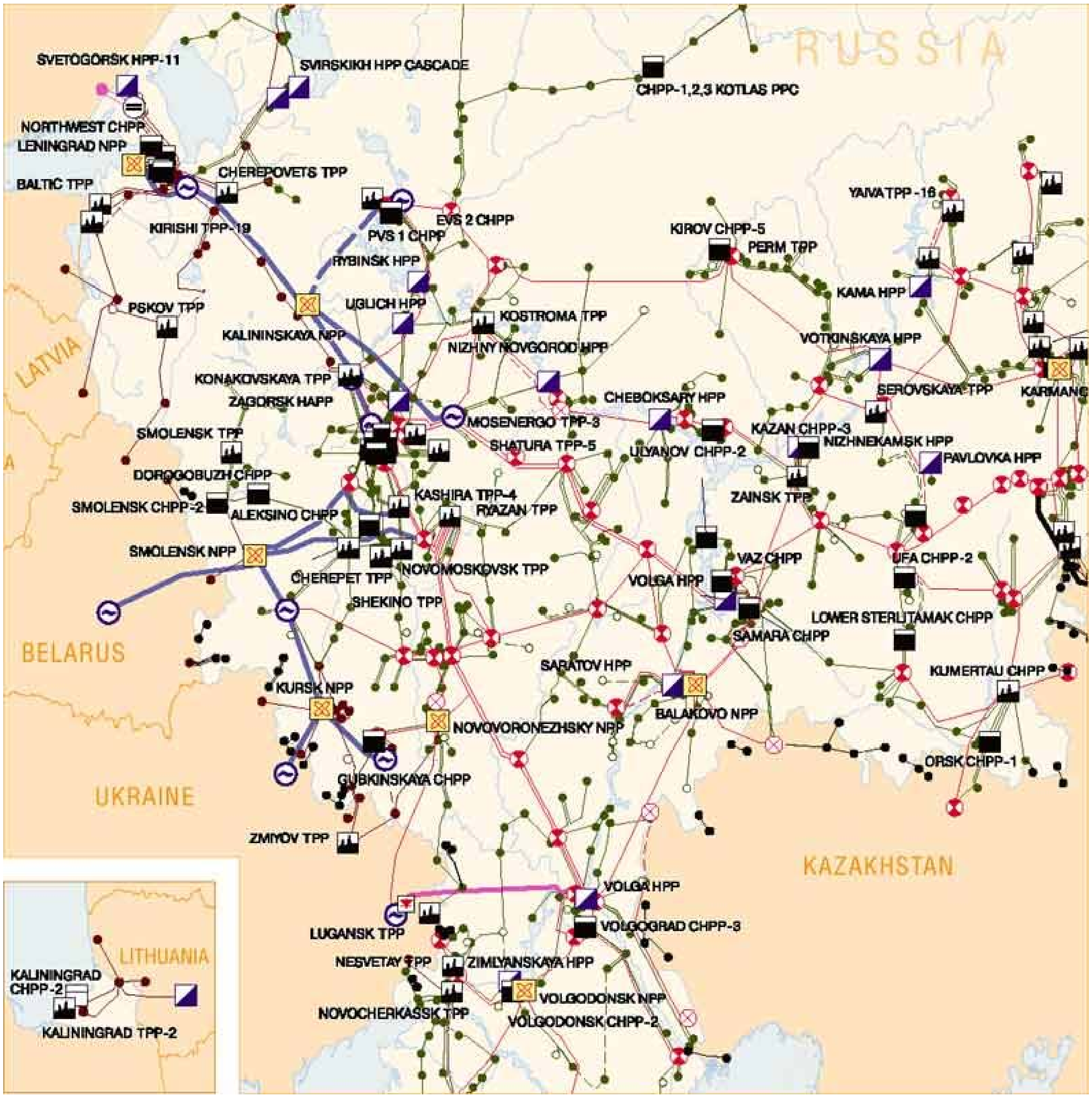


Figure 3.38 – Russia – network map (western part)

Planned Network Reinforcements

Development strategy for the Unified National Electric Grid (UNEG) for the decennial period is planned once every five years. The primary document in strategy is the UNEG Development Concept, which identifies fundamental problems in the grid development and conceptually outlines solutions for performance improvement and sustainable development.

Table 3.36 and Figure 3.39 show the planned network reinforcements in the Northern Caucasus part of the Russian grid.

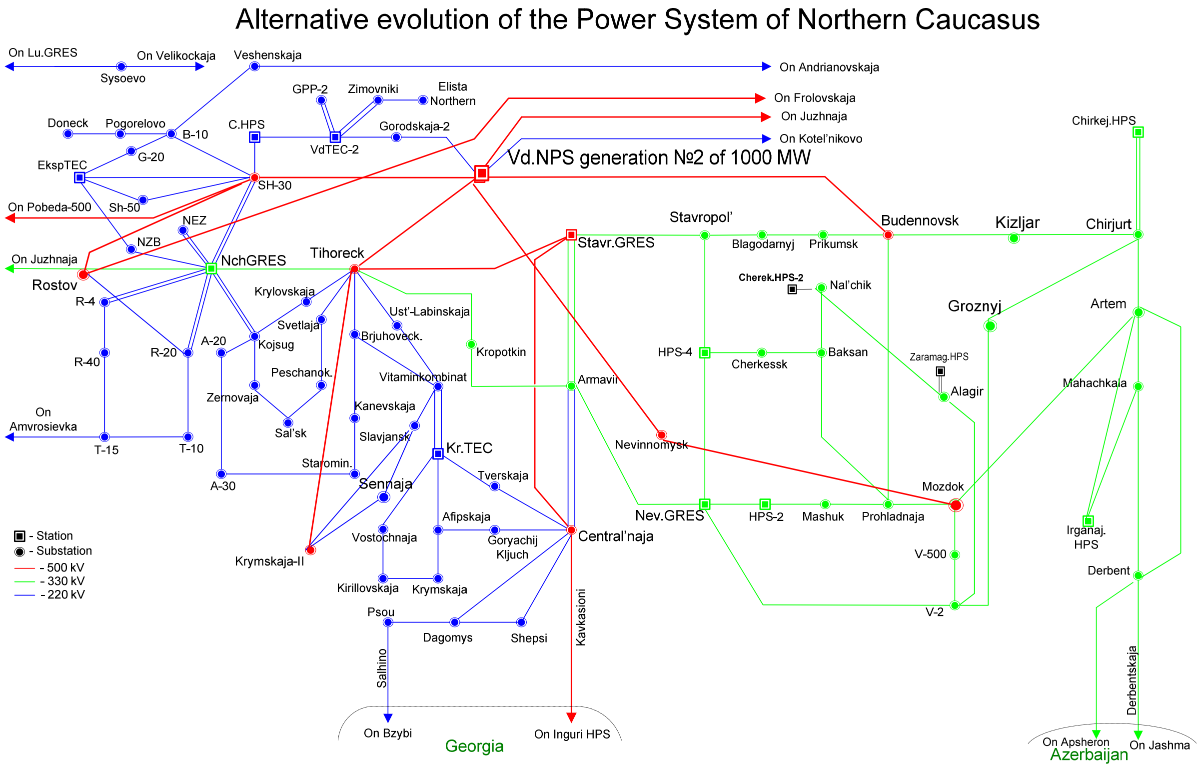


Figure 3.39 – Russia – Planned network topology in Northern Caucasus

Table 3.36 – Russia – Planned network reinforcements

TYPE		SUBSTATION1		SUBSTATION2	VOLTAGE LEVEL kV/kV	Number Of Circuits /units	CAPACITY A or MVA	CAPACITY limited A or MVA	MATERIAL OR TRANSFORMER TYPE	CROSS mm2	LENGTH BR1 km	LENGTH BR2 km	LENGTH TOTAL km	DATE OF COMMISS ION	STATUS	COMMENT
1	2	3	2	3	4	5	6	7	8	9	10	11	12	13	14	13
OHL	RU	Centralna(Sochi)	GE	Enguri	500									2015		450 km, single circuit
SS	RU	Rostov			500/220									2011		-
OHL	RU	Rostov		Sati 30	500									2011		single circuit
OHL	RU	Rostov		Frolovska	500									2011		single circuit
OHL	RU	Rostov		R20	220									2011		single circuit
SS	RU	Krimskaya II			500/220									2015		-
OHL	RU	Krimskaya II		Tihoreck	500									2015		single circuit
SS	RU	Senaya			220									2015		-
OHL	RU	Krimskaya II		Senaya	220									2015		single circuit
OHL	RU	Krimskaya II		Slavyansk	220									2015		single circuit
OHL	RU	Slavyansk		Senaya	220									2015		single circuit
SS	RU	Nevinomysk			500/220									2010		-
OHL	RU	Nevinomysk		Volgodonska	500									2010		single circuit
SS	RU	Mozdok			500/220									2012		-
OHL	RU	Nevinomysk		Mozdok	500									2012		single circuit
SS	RU	Alagir			330/110									2015		-
OHL	RU	Nalcik		Alagir	330									2015		single circuit
OHL	RU	V2		Alagir	330									2015		single circuit
SS	RU	Kizljar			330/110									2015		on 330 kV Budenovsk-Chirjurt
SS	RU	Grozniy			330/110									2015		on 330 kV V2-Chirjurt
SS	RU	Artem			330/110									2010		on 330 kV Mahachkala-Chirjurt
OHL	RU	Mozdok		Artem	330									2010		single circuit
OHL	RU	HPP Irganskaya		Artem	330									2010		single circuit
OHL	RU	Derbent		Artem	330									2010		single circuit
OHL	RU	Derbent	AZ	Apsheron	330									2010		single circuit

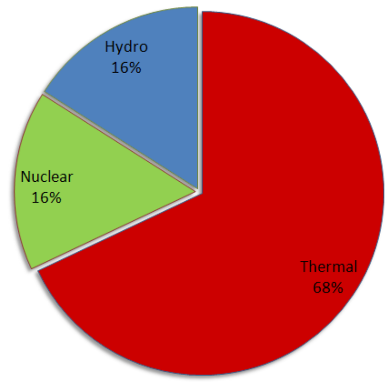
1 Type of project (OHL - overhead line, K - kable, SK - submarin kable, SS - substation, BB - back to back system...)
2 Country (ISO code)
3 Substation name
4 Installed voltage (for lines nominal voltage, for transformers ratio in voltages)
5 number of circuits/units
6 Conventional transmission capacity of elements for OHL in Amps, for transformers in MVA
7 Conventional transmission capacity limited by transformers or substations
8 Type of conductor or transformer (ACSR - Aluminum Cross section Steel Reinforced, or code of conductor, PS - phase shift transformer...)
9 Cross section (number of ropes in bundle x cross section/cross section of reinforcement rope)
10 Length till border of first state
11 Length till border of second state
12 Total length
13 Date of commissioning (estimate)
14 Status of project (Idea, Feasibility study, Construction, Damaged, out of service, Decommissioned...)

Table 3.37 – Russia – Planned new generation units

			VOLTAGE LEVEL		CAPACITY		DATE OF COMMISSIONING		
TYPE		SUBSTATION1	kV	kV	MW	MVA	year	STATUS	COMMENT
1	2	3	4	5	6	7	8	9	10
NPP	RU	Leningrad2	24	500	2x1150	2x1278	2010	CONSTR.	old plant decommissioned
NPP	RU	Leningrad2	24	750	2x1150	2x1278	2011	CONSTR.	old units decommissioned
NPP	RU	Novovoronez	24	500	2x1150	2x1278	2015	CONSTR.	
NPP	RU	Kostromska	24	500	2x1150	2x1278	2020	CONSTR.	
NPP	RU	Nizhegorodskaya	24	500	2x1150	2x1278	2020	CONSTR.	
NPP	RU	Kaliningrad	24	500	2x1150	2x1278	2015	CONSTR.	
NPP	RU	Kola2	24	500	1150	1278	2015	CONSTR.	
NPP	RU	Seversk	24	500	2x1150	2x1278	2020	CONSTR.	
HPP	RU	Boguchanskaya		330	3000		2020		Krasnoyarsk area
HPP	RU	Evenky		330	1000		2020		Krasnoyarsk area
HPP	RU	Motiginskaya		330	757		2020		Krasnoyarsk area
PHPP	RU	Leningrad		330	4x390		2015		Sankt-Petersburg area
PHPP	RU	Zagorsk-2		330	2x420		2015		Moscow region
PHPP	RU	Zelenchuk		330	1x140		2015		Karachay-Cherkessia
HPP	RU	Zaramagskaya		330			2010		
HPP	RU	Cherkeskaya II		330			2010		
NPP	RU	Volgodonskaya	24	500	1000	1111	2010	CONSTR.	unit 2
CCGT	RU	Stavropol	15.75	500	2x400	2x440	2012	PLANNING	
CCGT	RU	Nevinnomyssk	15.75	500	410	450	2010	CONSTR.	
CCHP	RU	Sochi	10.5	110	80	90	2010	CONSTR.	
CCHP	RU	Tuapce	15.75	110	150	170	2011	CONSTR.	
CCHP	RU	Tuapce	15.75	110	180	200	2012	CONSTR.	
CCHP	RU	Adler	15.75	110	2x180	2x200	2012	CONSTR.	
CCHP	RU	Olimpic	15.75	110	2x180	2x200	2012	CONSTR.	

1 Type of plant (HPP - Hydropower plant, TPP - Thermal power plant, PSHPP - Pump Storage Hydro Power Plant, CCHP - Combined Cycle Heating Plant...)
2 Country
3 Substation name
4 Generator voltage level
5 Network voltage level
6 Instaled active power
7 Instaled apparent power
8 Date of commissioning (estimate)
9 Status of the project (Idea, Feasibility study, Construction...)

1.10.3 Generation



Russia is one of the world's largest producers of energy, most of which it obtains from oil, natural gas and coal. Out of the 203 GW of electric generation capacity that it has, 21.2GW comes from Nuclear, 44GW comes from hydroelectricity, and less than 1% from renewable sources. In 2009, the Russian energy industry generated a total 992 TWh of electricity: Nuclear (16%), Hydro (16%) and Thermal (68%). Figure 3.40 shows how production units are connected to the transmission grid in the European part of the system. Power plants are operated by JSC RAO "UES of Russia". In order to address the problems of electricity sector and improve its efficiency, the government of Russia launched the power sector restructuring. The reform began on March 26, 2003 when a set of laws were signed by the president. It took several years to restructure 73 "Energos" of the RAO UES, a former monopoly, and approach the target configuration, to form generation and supply companies that would become private and compete on the wholesale market. The government retained control in all the network companies: the System Operator, nuclear (Rosenergoatom) and the hydro generation companies (RusHydro5). In the process of restructuring RAO's thermal power plants, 6 Wholesale Generation Companies WGC (formed of large-scale plants) and 14 Territorial Generation Companies TGC (rest of the power plants of several adjacent "Energos") were created (Figure 3.40).

Nuclear Power Plants

Nuclear power represents an important energy source in Russia. In 2005 nuclear energy supply in Russia amounted to 149 TWh, which is 15.7 % of total Russian electricity output and 5.4 % of global nuclear energy production. The total installed capacity of nuclear reactors is 21,244MW. All Russian civil reactors are operated by Atomenergoprom, a holding company for the entire Russian civil nuclear industry, including Energoatom, the nuclear fuel producer and supplier TVEL, the uranium trader Tekhsnabexport (Tenex) and nuclear facilities constructor Atomstroyexport.

Figure 3.40 – Russia – Generation capacities and major transmission lines

NPP Novovoronezh
Location: Voronezh
Operator: Rosenergoatom
Configuration: 1 X 210 MW, 1 X 365 MW, 2 X 440 MW, 1 X 1,000 MW PWR
Operation: 2001
Reactor supplier: Mintyazhmash
T/G supplier: Kharkov
Quick facts: The first VVER reactor unit was built at this site as well as the first 1,000-MW VVER.

NPP Kalinin
Location: Tver
Operator: Rosenergoatom
Configuration: 3 X 1,000 MW PWR
Operation: 1988-2004
Reactor supplier: Mintyazhmash
T/G supplier: Kharkov, LMZ
Quick facts: Kalinin-3 is Russia's newest nuclear unit and went into trial operation in Dec 2004. Kalinin-4 is under construction for service in 2011.

NPP Kursk
Location: Kursk
Operator: Rosenergoatom
Configuration: 4 X 1,000 MW PWR
Operation: 1976-1985
Reactor supplier: Mintyazhmash
T/G supplier: Kharkov, LMZ/ Electrosila
Quick facts:

NPP Smolensk
Location: Smolensk
Operator: Energoatom
Configuration: 3 X 1,000 MW RBMK
Operation: 1982-1989
Reactor supplier: Mintyazhmash
T/G supplier: Kharkov, Electrosila

NPP Volgodonsk-1
Location:Rostov
Operator:Rosenergoatom
Configuration:1X1,031MWPWR
Operation:2001
Reactorsupplier:Mintyazhmash
T/Gsupplier:Kharkov,Electrosila
EPC:Rosenergatom,Atomprojekt

NPP Volgodonsk-2
Location:Rostov
Operator:Rosenergoatom
Configuration:1X1,000MWPWR
Operation:2009
Reactorsupplier:Mintyazhmash
T/Gsuppli er:Kharkov,Electrosila
EPC:NIIAEP

Thermal Power Plants

Rest of the power produced in Russia comes from conventional thermal power plants run on coal or Combined Heating Power Plants mostly run on natural gas or oil (mazut).

CHPP Novocherkaska
Location: Rostov
Operator: OGK-6
Configuration: 6 X 300 MW
Operation: 1965-1972
Fuel: coal, natural gas, oil
Boiler supplier: Taganrog
T/G supplier: Kharkov
EPC: SEP-Electric
Quick facts: The decision to build this plant was made in 1952. The initial configuration was 3 X 100 MW, then 4 X 150 MW, and then 3 X 200 MW. Finally, the designers settled on building six 300-MW sets using supercritical technology, only the second such power station in the Soviet Union. Construction got underway in Mar 1956 and commissioning of Unit-1 began in Dec 1964. This took just over 6 months as final design and construction issues were resolved and Unit-1 went commercial on 30 Jun 1965.

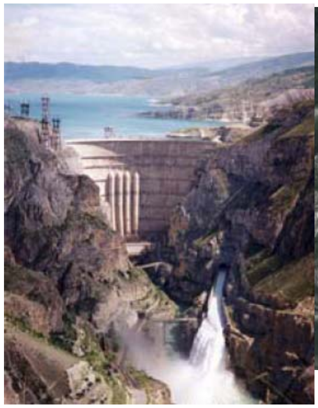
CHPP Surgut-1
Location: Khanty-Mansi AO
Operator: OGK-2
Configuration: 2 X 180 MW, 16 X 210 MW
Fuel: natural gas
Operation: 1973-1983
Boiler supplier: Taganrog
T/G supplier: LMZ, Electrosila
Quick facts: This plant was in the Top 100 for many years.

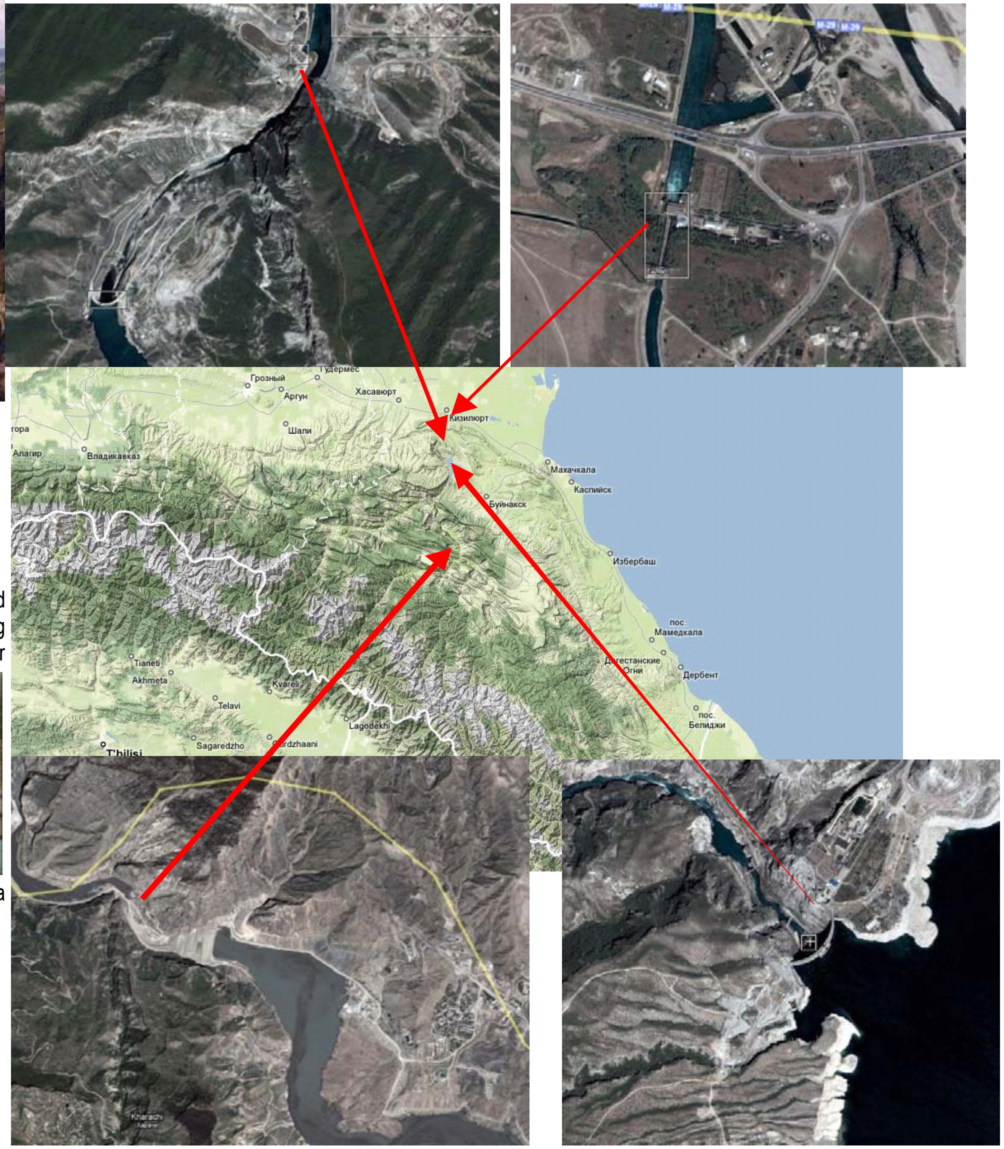
CHPP Ryazan
Location: Ryazan
Operator: OGK-6
Configuration: 4 X 300 MW, 2 X 800 MW
Operation: 1973-1981
Fuel: natural gas, coal, oil
Boiler supplier: Podolski, Taganrog
T/G supplier: LMZ, Electrosila

Hydro Power Plants

Russia has 102 hydropower plants in operation with a capacity of over 100 MW. The total installed capacity of HPP generator units in Russia today amounts to approximately 45 million kW (5th place in the world), with an output in the order of 165 billion kWh/year (also 5th place) – while HPPs account for no more than 21% of Russia's total electric power production (176 TWh). Hydropower is the key element in ensuring reliability of the country's Unified Energy System, possessing 90% of the capacity regulation reserves. Of all the existing types of electric power stations, HPPs are the most maneuverable and capable, if necessary, of substantially increasing their output in just a few minutes and thus covering peak loads. For thermal power stations, this indicator means hours and for nuclear ones several days. Hydro generation, including pumped-storage output in 2005 was 175 TWh, which represents 5.8% of world hydroelectricity generation. Russia ranks as the fifth largest hydroelectricity producer in the world. At the end of 2005 installed hydroelectric generating capacity was 45.7 GW.

HPP Chirkeyskaya
Location: Dagestan
Operator: Dagestan Regional Power Generation Co
Configuration: 4 X 250 MW
Operation: 1974-1976
T/G supplier: Kharkov, Electrovipryamitel
EPC: Hydropower Institute
Quick facts: This 232.5m dam on the Sulak River is the fifth tallest in Russia and the CIS.





HPP Irganskaya
Location: Dagestan
Operator: Sulakenergo
Configuration: 2 X 200 MW Francis
Operation: 1998-2001
T/G supplier: Kharkov, Elsib
EPC:Lenhydroproject, Chirkeygesstroy
Quick facts: This plant is on the the Avarskoie Koisu River, the main tributary of the Sulak River, at the head of the Chirkey Reservoir. Construction got underway in 1987. The complex includes a 101m high, 313m long earth-and-rock-fill dam, joined tunnel spillway, and two 7.5m diameter, 5km pressure tunnels to the power house. Two more units are planned.

HPP Miatlyska
Location: Dagestan
Operator: Dagestan Regional Power Generation Co
Configuration: 2 X 110 MW
Operation: 1986
T/G supplier: Kharkov, UETM
Quick facts: This is the third plant in the Sulak cascade and completes a development program initiated in 1932. Construction on Miatly started in 1970 but was interrupted by a landslide in 1977 which necessitated major redesign work.

HPP Chirut 1
Location: Dagestan
Operator: Dagestan Regional Power Generation Co
Configuration: 2 X 36 MW
Operation: 1961
T/G supplier: Kharkov, UETM

HPP Volzhinskaya

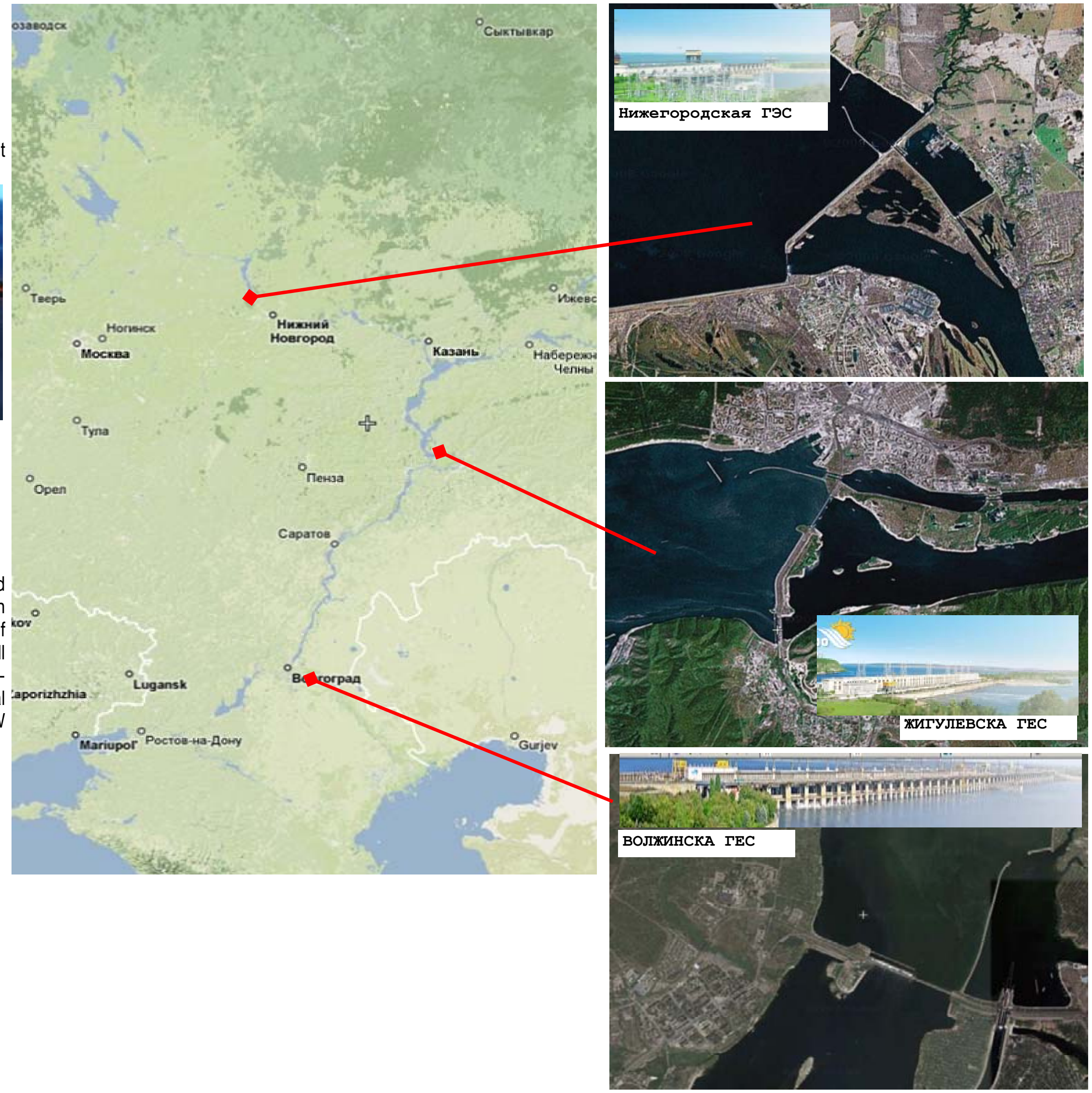
Location: Volgograd
Operator: RusHydro
Configuration: 22 X 115 MW Kaplan
Operation: 1958-1962
T/G supplier: LMZ, Electrosila
Quick facts: Construction started in 1951 and the total construction work force peaked at about 25,000. The dam and powerhouse complex is 5km long.

HPP Zhigulevskaya

Location: Volgograd
Operator: Volzhskaya Lenin GES
Configuration: 20 X 126 MW Kaplan
Operation: 1955
T/G supplier: LMZ, Electrosila
Quick facts: This is one of the two large hydro plants built on the Volga River in the mid-1950s. Formerly known as Volzhskaya Lenin.

HPP Nizhegorodskaya

Location: Nizhni Novgorod
Operator: RusHydro
Configuration: 8 X 65 MW
Operation: 1959
T/G supplier: LMZ, Electrosila
Quick facts: Construction started in 1948 and was completed in 1959. Complex consists of concrete spillway dam, 7 earth-fill dams and 3 dikes total 18.6 km long and up to 40 m high, power plant house, and two single-chamber two-lane locks with an intermediate pond. Installed power is 520 MW, average annual production is 1510 GWh. Power house has 8 generator units with Kaplan turbines, each 65 MW at 17 m head. The dam with total waterfront length of 13 km forms Gorky Reservoir.



Generation Capacities Planned

Nuclear Power Plants: There are plans to increase the number of commercial reactors from 31 to 59, including decommissioning of the old reactors and replacement with new ones.

Hydro Power Plants: Gross theoretical potential of the Russian hydro resource base is 2,295 TWh per year, of which 852 TWh is regarded as economically feasible. Most of this potential is located in Siberia and the Far East.

Thermal Power Plants: Thermal power plants that are planned in Russia are supposed to replace aging equipment, especially in obsolete CHP power plants that would be dismantled and replaced by new Combined Cycle units run on natural gas.

Renewables: One of the development priorities for Russia is to increase the use of ecologically pure energy resources - alternative, renewable, wind and solar energies, geothermal waters, biogases and etc.
Low prices of natural gas compared to the high price of renewables makes this goal harder to implement.

1.10.4 Demand

Demand Behavior

Figure 3.41 shows the demand behavior for a typical winter and summer day (upper left corner) and typical generation coverage for whole year month by month (upper right corner).

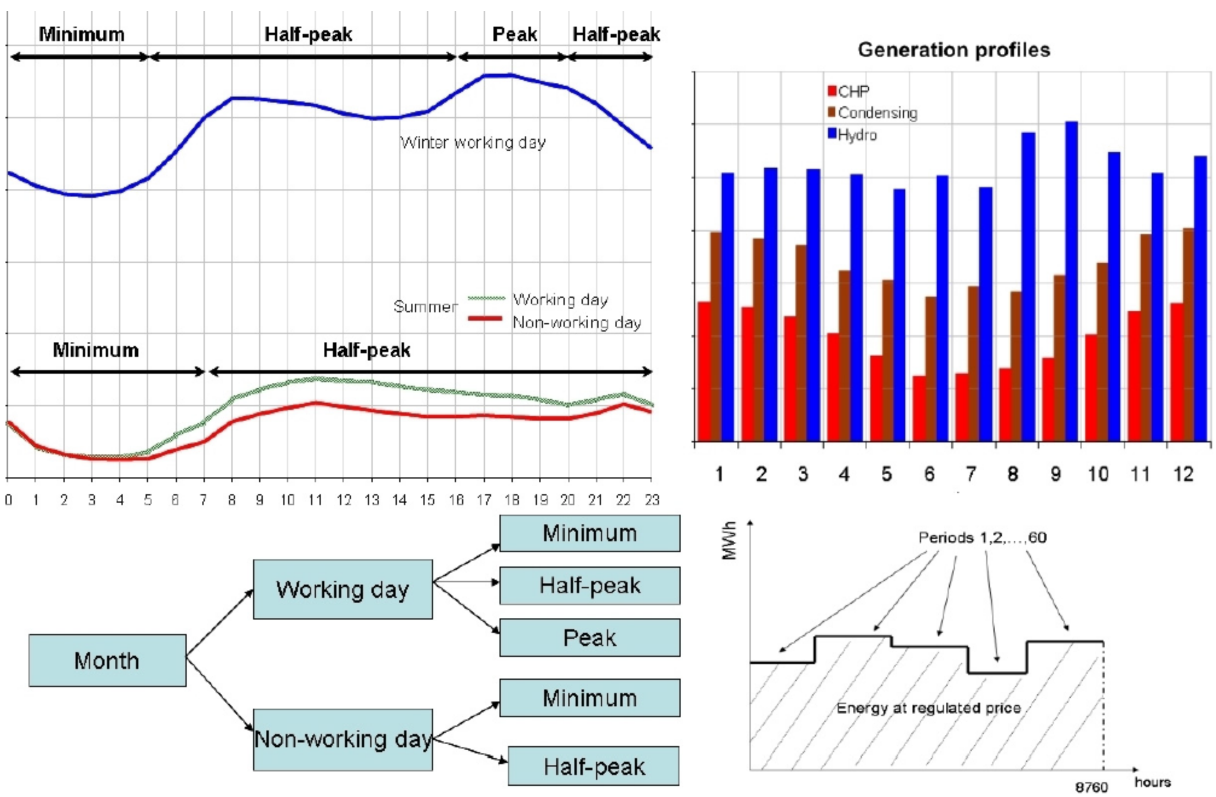
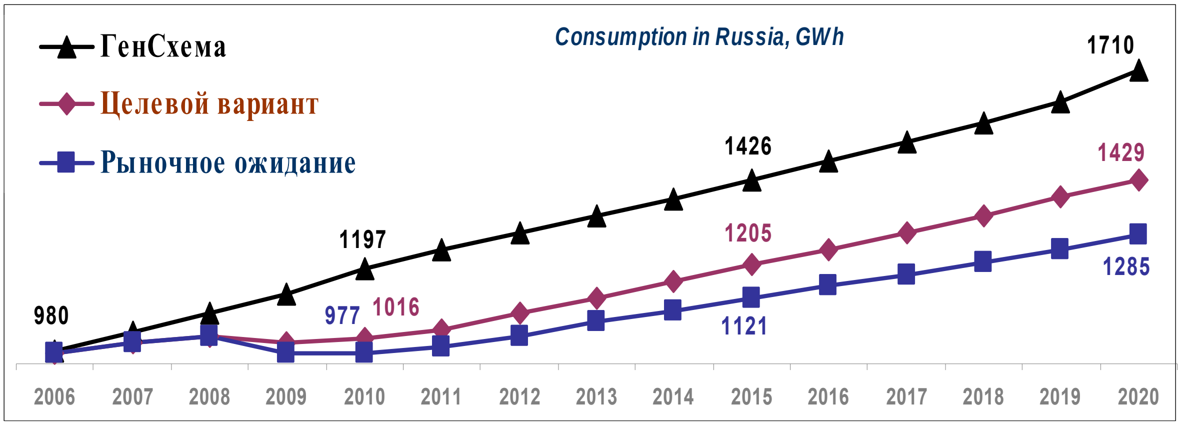


Figure 3.41– Russia – Demand behavior and generation coverage

Demand Forecast

Figure 3.42 shows demand forecasts for Russia's consumption for different scenarios with the correlating peak load. Table 3.38 shows the planned development for generation and coverage of peak load with installed capacities up to 2020.



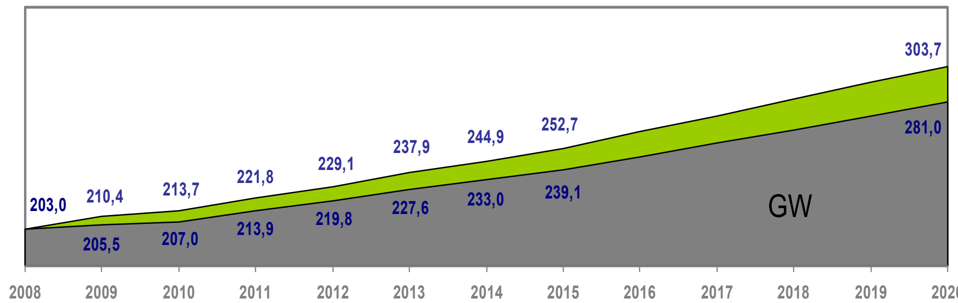


Figure 3.42 – Russia – Demand Forecast – Consumption TWh and Peak load in GW

Table 3.38 Russia – Generation development plan

Installed capacity / Years	2006	2010	2015	2020
Peak load	203.0	213.7	252.7	303.7
Total	210.8	243.8	297.5	347.4
1. Hydro	44.9	49.2	57.1	71.7
2. Nuclear	23.5	26.9	38.1	53.2
3. Total thermal power plants:	142.4	167.7	202.3	222.5
1) Total CHP plants	77.1	93.2	107.8	113.7
steam-turbine (gas-and-oil burning)	43.2	43	40.9	36.5
combined cycle and gas turbine	1.1	15.3	27.9	36
steam-turbine (hard fuels)	32.8	34.9	39	41.2
2) Condensing power plants	65.3	74.5	94.5	108.8
steam-turbine (gas-and-oil burning)	37.5	37.3	14.3	6.8
combined cycle and gas turbine	2.7	9.9	30.2	38.5
steam-turbine (hard fuels)	25.1	27.3	50	63.5

Tariff

Natural gas is the main fuel for Russian thermal power plants. Minimum regulated wholesale price for non-household consumers in 2008 on average amounts to 48 €/tcm or 68.6$/tcm, while the upper price limits are determined as minimum prices increase by a certain value. Average maximum value for whole 65 regions is around 109€/tcm or 155.7$/tcm. End-user prices also include payments for gas distribution and supply/sales services, which are regulated and together add about 5–10 €/tcm to consumers' bills. Average export price of natural gas was around 232.5€/tcm or 330$/tcm. No new nuclear units were commissioned since 2007, production of the "old" ones is capped by regulated tariff (4.68 €/MWh or 6.69$/MWh in 2009). Hydro power plants pay taxes on water use 0.15÷0.4€/MWh, or 0.21÷0.57$/MWh depending on water basin.

Russia utilizes a feed-in tariff system and calculates the RES energy tariff based on the average wholesale generation tariff in the system. It adds a premium rate close to three times the average generation tariff (*GretaEnergy Int'l, 2009*). As a result the current average generation tariff in the system is RUB 0.8/kWh the premium rate is at RUB 2.5/kWh making the wind generation tariff RUB 3.3/kWh or EURO 8.1 cent/kWh. Russia has yet to develop its first utility-scale wind power plant.

Table 3.39 – Russia – tariffs for RES (before taxes)

	kategory	PREMIUM VALID years	EURc/KWh	USDc/KWh
I.	Small hydro (<25 MW)	10	6.45	9.23
II.	Wind energy	10	12.21	17.44
III.	Geothermal energy	10	10.17	14.53
IV.	Biomass	7	12.8	7.89
V.	Tidal energy	15	5.52	20.64
VI.	Solar energy	15	47.39	67.70
VII.	Other	10	8.50	12.14

1.10.5 Export Potential in 2015 and 2020

Russia has a vast potential with the current energy supply and the future large surplus of electrical energy that is forecasted and shown on Table 3.38. The country is also the main supplier of nuclear fuel and natural gas for other countries.

1.10.6 References

[1] **"Russian electricity market - Current state and perspectives"**; Rinat Abdurafikov, VTT 2009.

1.11 Turkey

1.11.1 General Information

Turkey is a Eurasian country that stretches across the Anatolian peninsula in Western Asia and Thrace in the Balkan region of southeastern Europe. Turkey is bordered by eight countries: Bulgaria to the northwest; Greece to the west; Georgia to the northeast; Georgia, Azerbaijan (the exclave of Nakhchivan) and Iran to the east; and Iraq and Syria to the southeast. The Mediterranean Sea and Cyprus are to the south; the Aegean Sea to the west; and the Black Sea is to the north. The Sea of Marmara, the Bosporus and the Dardanelles (which together form the Turkish Straits) demarcate the boundary between East Thrace and Anatolia; they also separate Europe and Asia. Turkey's location at the crossroads of Europe and Asia makes it a country of significant geostrategic importance.

Area: 783 562 sq. km
Arable land: 35 %
Water: 1.3 %
Forest area: 27 %
Population (Million): 73.7 (2010)

GDP ppp (Billion $): 960.5 (2010 est.)
GDP ppp (per capita): $13464 (2010 est.)

GDP composition per sector:

- agriculture: 11.1 % (2007)
- industry: 29.7 % (2007)
- services: 60.1 % (2007)

Carbon intensity per capita (t); 3.3 (2004)

1.11.2 Transmission Network

The Turkish Power Grid consists of lines of 400, 220, 150, 66 kV. Table 3.40 shows total length of transmission lines by voltage levels and Table 3.41 shows the interconnection lines. Network of the 400 kV system is shown in Figure 3.44 The Turkish generation and transmission system is managed by 9 regional dispatching centers: Adapazarı, Çarşamba, Keban, İzmir, Gölbaşı, İkitelli, Erzurum, Çukurova and Kepez, coordinated by the National Dispatching Center in Ankara (Gölbaşı). The power system of Turkey has a service quality and reliability comparable to western European standards.

Table 3.40 – Turkey – network overview

lines		transformers		
Voltage level	Length of the overhead lines and cables	Voltage level	Installed capacities	
(kV)	(km)	(kV/kV)	numb	(MVA)
400	14622.9	400/x	184	35020
220	84.5	220/x	1	300
150	31932	154/x	1034	58015
66	508.5	66/x	54	637
400 cables	170.9			
150 cables	22.3			
total	47148		1272	93672

Hydro and lignite are one of the primary energy resources for the country. Large loads are concentrated in İstanbul, İzmir and Ankara. Most of the hydro resources and a large lignite fields are located in eastern Turkey. This power has to be transmitted across the country via 400 kV lines. The location of the generation and the long distances involved challenge the transmission grid during operation. Most of the power produced by the large HPPs in the East and has to be transferred to the North-West and South-West regions where the energy consumption is high at the maximum hydroelectric dispatch. Consequently, the planned lines connecting the western and eastern parts of country has an adequate power carrying capacity and stability margins. Concentrated small wind generations in one region are collected in one substation.

Table 3.41 – Turkey – Interconnection lines

Countries	Type	From-To nodes	Status	Comment
GE-TR	954 MCM, Rail - 28 km	OHL 220 kV Batumi (GE)-Hopa (TR)	Existing	Island
AM-TR	2X954MCM,Cardinal-80.7km	OHL 220 kV Gymri (AM)-Kars (TR)	Existing	Island
AZ-TR	2x477 MCM,Hawk-180 km	OHL 154 kV Iğdır (Turkey)-Babek(Nahcivan)	Existing	Island
TR-IR	2x954 MCM, Cardinal - 28km	400 kV Baþkale (TR) - Khoy (IR)	Existing	Island
TR-IR	954 MCM, Cardinal - 40 km	OHL 154kV Doðubeyazýt (TR)-Bazargan (IR)	Existing	Island
TR-GR	3x954 MCM, Cardinal-260km	OHL 400kV Babaeski (TR) - Phillipi (GR)	Existing	
BG-TR	2x954 MCM, Rail - 136 km	OHL 400kVBabaeski (TR) - Maritsa East (BG)	Existing	
BG-TR	3x954 MCM, Cardinal-150km	OHL 400kV Hamitabat (TR)-Maritsa East (BG)	Existing	
TR-SY	2x954 MCM, Cardinal-124 km	OHL 400kV HPP Birecik (TR) – Aleppo (SY)	Existing	Island
TR-IQ	2x954 MCM, Cardinal -28km	OHL 400Kv PS.3 (TR) - Zakho (IQ)	Existing	Island
AM-TR	New 400 kV HVDC AM-TR	HVDC 400 kV ANPP (AM)-Horasan (TR)	Idea	By 2020
GE-TR	New 400 kV HVDC GE-TR	HVDC 400 kV Akhaltsikhe (GE) – Borcka (TR)	Planned	By 2013
GE-TR	New 220 kV HVDC GE-TR	HVDC 220 kV Batumi (GE) – Hopa (TR)	Planned	By 2015
TR-RO	New 400 kV HVDC RO-TR	HVDC 400 kV Constanca(RO)-Alibeykoy(TR)	Planned	By 2020

Planned Network Reinforcements

Development plans for the transmission network are steered towards accommodating the large generation development plan that will enable a secure transfer of power from power plants to the consumption areas. Figure 3.45 shows the planned network development in the 400kV transmission network. There is also a plan to increase the interconnection capacities to neighboring countries. As Table 3.41 shows, four last lines represent further planning activities in developing interconnection capacities. For the first one, there is an interest from both sides, but no official documentation exists at this point. For the second one, there is an agreement to the increase capacity from 700MW to 1050MW (3x350MW) by 2020, and for third one feasibility studies showed that it is not economically feasible. This plan will most likely be replaced by a new project to increase the capacity of the connection between Romania, Bulgaria and Turkey. The idea is to build a 400kV triangle between these countries using a double circuit 400kV line.

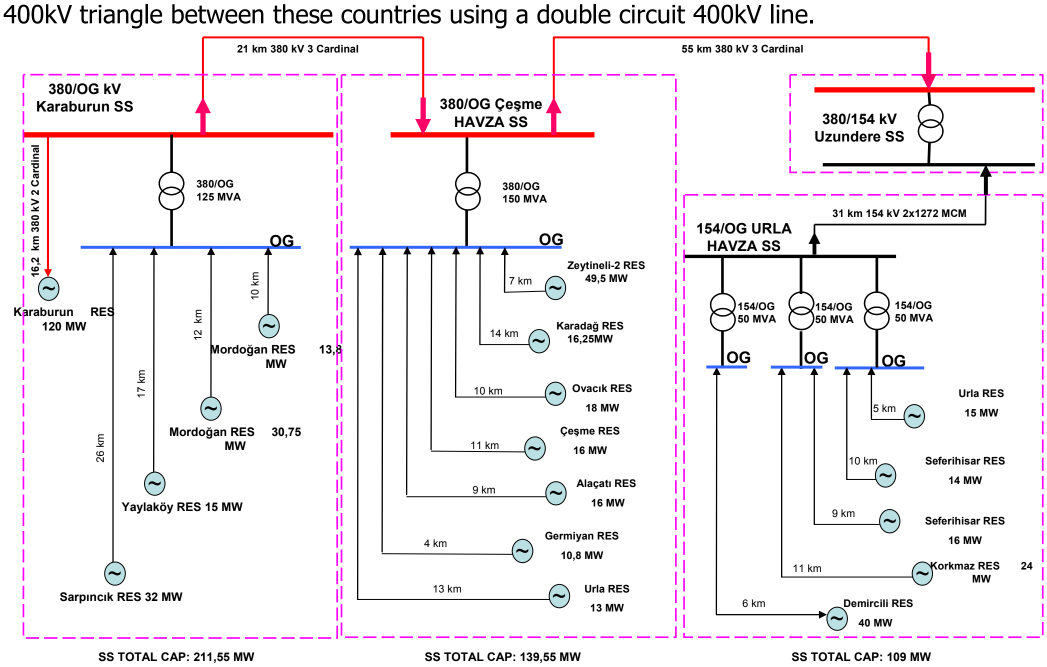


Figure 3.43 – Turkey – ÇEŞME REGION WIND PROJECTS: 460 MW

Figure 3.44 – Turkey – network map

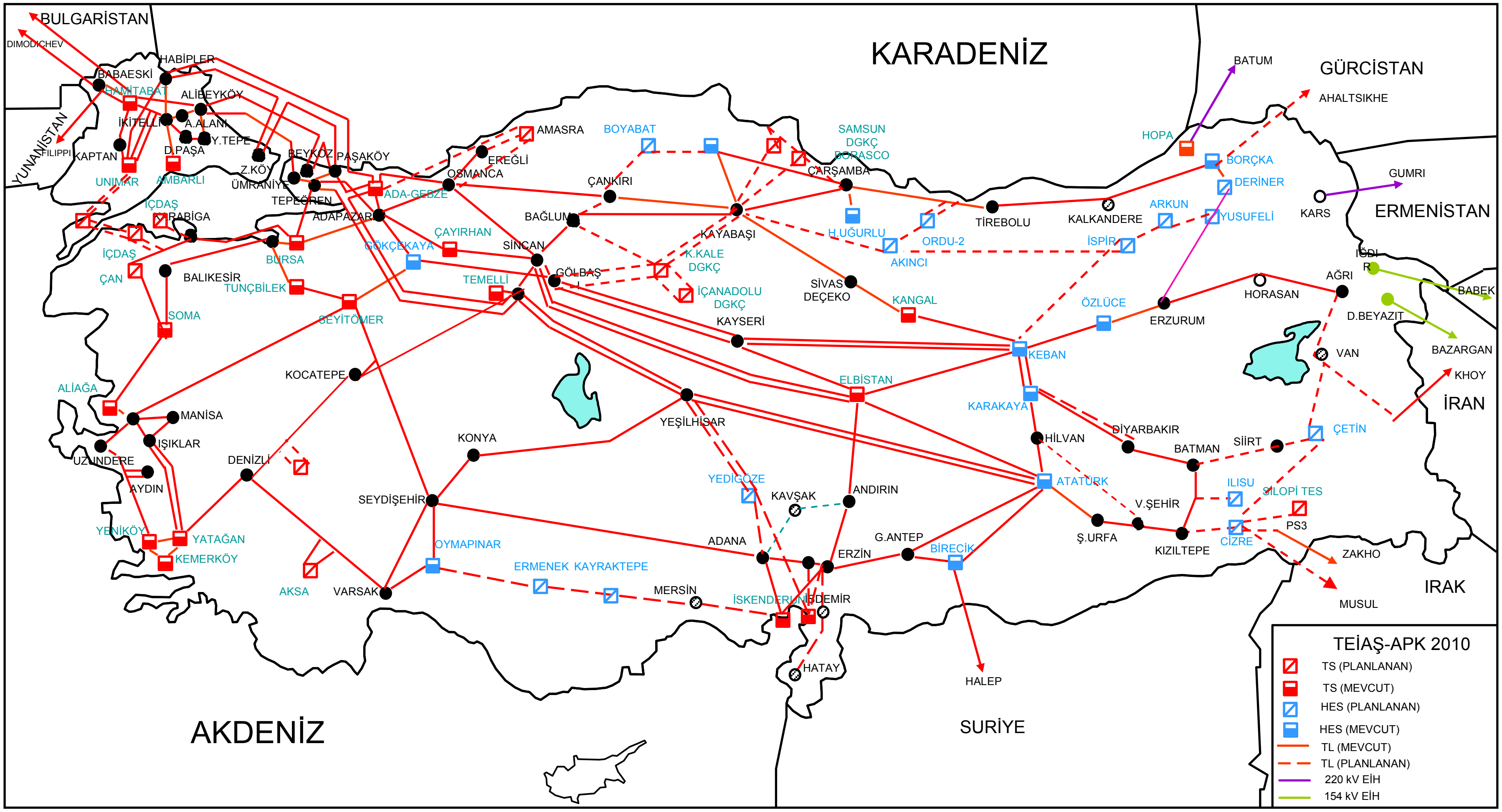


Figure 3.45– Turkey – 400kV network map

Table 3.42 – Turkey – Planned network reinforcements

TYPE		SUBSTATION1		SUBSTATION2	VOLTAGE LEVEL kV/kV	Number circuits /units	CAPACITY A or MVA	limited A or MVA	MATERIAL OR TRANSFORMER TYPE	CROSS mm2	LENGTH BR1 km	BR2 km	TOTAL km	DATE OF COMMISSION	STATUS	COMMENT
1	2	3	2	3	4	5	6	7	8	9	10	11	12	13	14	15
OHL	TR	HPP OYMAPINAR		HPP ERMENEK	400	1			ACSR	3BX1272			144		FINISHED	
OHL	TR	MERSIN		HPP ERMENEK	400	1			ACSR	3BX1272			145		CONSTR	
SS	TR	MERSIN			400/150		2x250								CONSTR	
OHL	TR	GERCUZ-ILISU		CIZRE-SINIR	400	2			ACSR	3BX954	30	100	130		PLANNING	PLANNING
OHL	TR	AGRI		VAN	400	1			ACSR	3BX1272			180		PLANNING	
OHL	TR	BATMAN-SİİRT		VAN	400	1			ACSR	3BX1272	65	205	270		PLANNING	
OHL	TR	VAN		BASKALE	400	1			ACSR	3BX954			105		FINISHED	Temporary 154kV
OHL	TR	HPP BOYABAT		HPP ALTINKAYA	400	1			ACSR	3BX1272			50		PLANNING	
OHL	TR	SEYDISEHIR		VARSAK	400	1			ACSR	3BX1272			130		FINISHED	
OHL	TR	TEMELLI		AFYON2	400	1			ACSR	3BX1272			214		FINISHED	
OHL	TR	AFYON2		DENIZLI	400	1			ACSR	3BX1272			180		FINISHED	
OHL	TR	BURSA NGCCPP		BURSA SAN	400	1			ACSR	2BX954			14		FINISHED	
OHL	TR	ICDAS-BAND. NGCCPP		BURSA NGCCPP	400	1			ACSR	3BX954	59	115	174		FINISHED	
OHL	TR	SOMA		MANISA	400	1			ACSR	3BX1272			50		CONSTR	
SS	TR	KONYA			400/150		150								CONSTR	CAPACITY ADD
SS	TR	AKDAM (KOZAN)			400/150		250								CONSTR	
SS	TR	ESKISEHIR			400/150		2X250								CONSTR	
SS	TR	CATALCA			400/150		2X250								PLANNING	
SS	TR	KUCUKBAKKALKOY GIS			400/150		2X250								FINISHED	
SS	TR	KUCUKBAKKALKOY GIS			400/33		2X125								FINISHED	
C	TR	UMRANIYE		KUCUKBAKKALKOY	400					2000mm2			6.3		FINISHED	
SS	TR	VAN			400/150		2x250								CONSTR	
SS	TR	UZUNDERE			400/33		125								PLANNING	
SS	TR	YENIBOSNA GIS			400/150		2X250								FINISHED	
SS	TR	YENIBOSNA GIS			400/33		2X125								FINISHED	
C	TR	YENIBOSNA GIS		DAVUTPASA	400					2000mm2			6.98		FINISHED	
SS	TR	AFYON2			400/150		2X250								CONSTR	CAPACITY ADD
SS	TR	VIRANSEHIR			400/150		250+150								CONSTR	
SS	TR	DIYARBAKIR			400/33		125								CONSTR	
SS	TR	USAK			400/150		250								PLANNING	

1 Type of project (OHL - overhead line, K - kable, SK - submarin kable, SS - substation, BB - back to back system...)
2 Country (ISO code)
3 Substation name
4 Installed voltage (for lines nominal voltage, for transformers ratio in voltages)
5 number of circuits/units
6 Conventional transmission capacity of elements for OHL in Amps, for transformers in MVA
7 Conventional transmission capacity limited by transformers or substations
8 Type of conductor or transformer
9 Cross section (number of ropes in bundle x cross section/cross section of reinforcement rope)
10 Length till border of first state
11 Length till border of second state
12 Total length
13 Date of commissioning (estimate)
14 Status of project (Idea, Feasibility study, Construction, Damaged, Decommissioned...)

Table 3.43 – Turkey – Planned generation units

TYPE	SUBSTATION1		VOLTAGE LEVEL kV	kV	CAPACITY MW	MVA	DATE OF COMMISSIONING year	STATUS	COMMENT
1	2	3	4	5	6	7	8	9	10
HPP	TR	Ermenek		400	320		2010	CONSTR	
HPP	TR	OBRUK		400	4x50		2010	CONSTR	
HPP	TR	Borçka		400	300		2010	FINISHED	
HPP	TR	Deriner		400	670		2010	CONSTR	In service end of 2011
TPP	TR	TEREN		400	2X600		2015	PLANNED	Coal fired TPP
HPP	TR	TIREB		400	300		2015	PLANNED	Equivalent of HPPs, most of them run of river type
HPP	TR	KALKANDERE		400	3X200		2015	PLANNED	Equivalent of HPPs, most of them run of river type
HPP	TR	YUSUFELI		400	4x135		2015	PLANNED	Equivalent of HPPs, most of them run of river type
CCGT	TR	TBANDRMA		400	1000		2015	PLANNED	NGCCPP(Private company)
CCGT	TR	AMBARLI		400	2X270		2015	PLANNED	NGCCPP. Extension of existing Ambarlı NGCCPP
CCGT	TR	AKSA ANTALIA		400	1000		2015	PLANNED	NGCCPP(Private company)
TPP	TR	SUGOZU		400	700		2015	PLANNED	Coal fired. Extension of existing Sugozu TPP
CCGT	TR	DENIZLI		400	1000		2015	PLANNED	NGCCPP(Private company)
HPP	TR	BOYABAT		400	3X180		2015	PLANNED	HPP(Private company)
TPP	TR	GALATA		400	2X135		2015	PLANNED	TPP (oil fired)
CCGT	TR	MAKINA		400	2X300		2015	PLANNED	NGCCPP(Private company)
HPP	TR	ALKUMRU		400	3X80		2015	PLANNED	HPP(Private company)
CCGT	TR	RASA		400	80		2015	PLANNED	NGCCPP(Private company)
TPP	TR	SILOPITES		150	135		2015	PLANNED	TPP (oil fired)
HPP	TR	INCIR		150	122		2015	PLANNED	HPP(Private company)
HPP	TR	AKDAM		400	300		2015	PLANNED	Equivalent of HPPs, most of them run of river type
CCGT	TR	EGEMER		400	6X300		2015	PLANNED	NGCCPP+ Coal fired(Private company)
WPP	TR	GELI		400	300		2015	PLANNED	Equivalent of lots of WPPs in the region
WPP	TR	CAN		400	300		2015	PLANNED	Equivalent of lots of WPPs in the region
TPP	TR	BASAT		400	2X150		2015	PLANNED	Coal fired TPP
TPP	TR	ORTA		400	2X150		2015	PLANNED	Coal fired TPP
TPP	TR	ATLAS		400	600		2015	PLANNED	Coal fired TPP
TPP	TR	KARASU		400	2X600		2015	PLANNED	Coal fired TPP
HPP	TR	ILISU		400	6x200		2015	PLANNED	
NPP	TR	Akkuyu Bay		400	5x1100		2020	PLANNED	

1 Type of plant (HPP - Hydropower plant, TPP - Thermal power plant, PSHPP - Pump Storage Hydro Power Plant, CCHP - Combined Cycle Heating Plant...)
2 Country
3 Substation name
4 Generator voltage level
5 Network voltage level
6 Instaled active power
7 Instaled apparent power
8 Date of commissioning (estimate)
9 Status of the project (Idea, Feasibility study, Construction...)

1.11.3 Generation

Turkey has a unique power plant displacement. The main fuel source is imported natural gas, and the largest installed capacities are run on gas fired CCGT power plants built next to large cities like Istanbul and Ankara, where the majority of the demand is. Additionally, there are some thermal capacities run on coal, vast hydro capacities in the east and Southeast of country, and new built hydro in the Northeast, distant from the demand centers located mostly in the West.

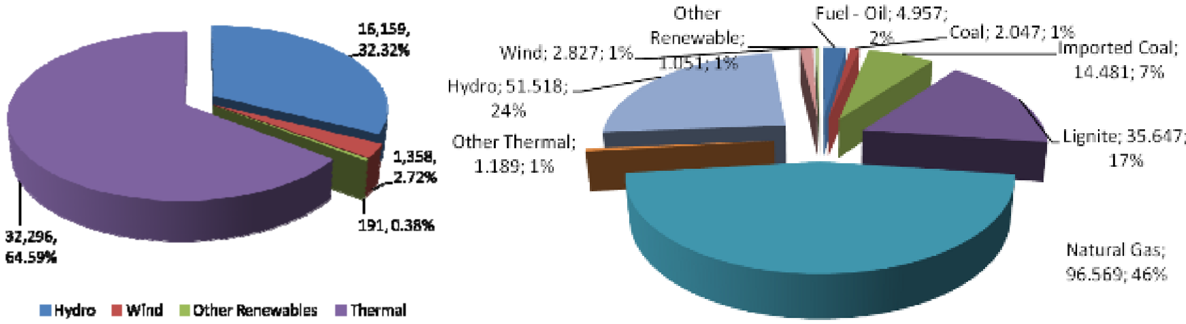


Figure 3.46 – Turkey – Installed capacity MW/% and total generation by source

The installed capacity in Turkey is 50.004 MW: 32% hydro, 65% thermal and 3% RES, mainly wind. Yearly generation in 2010 was at 210,286 GWh.

Renewable energy supply in Turkey is dominated by hydropower and biomass. More than two thirds of renewable energy supply is biomass. It is mainly used in the residential sector for heating. The remaining one-third of renewable energy supply is predominantly hydro-power. The contribution of wind and solar is limited but expected to increase. The large potential for geothermal, wind and solar have not been systematically developed until recently. In 2007, their combined share in TPES was only 1.5 % and in 2010 it reached 3%.

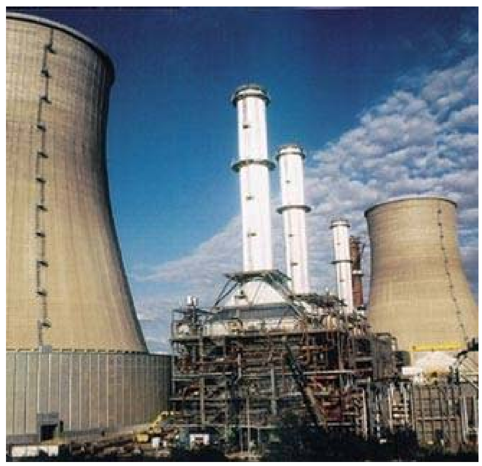
TPP Afsin Elbistan
Location: Kahramanmaras
Operator: Elektrik Uretim AS
Configuration: 4 X 360 MW, 4 X 360 MW
Operation: 2006
Fuel: lignite
Boiler supplier: BBP
T/G supplier: MHI, Melco
EPC: BBP, MHI, Gama-Tekfen-Tokar JV, ENKA
Quick facts: The region around the plant site has lignite reserves of as such as 3.4bn, about a third of Turkey's recoverable reserves. Further development on this site is expected.

TPP Sugozu
Location: Adana
Operator: Iskenerun Enerji (Isken)
Configuration: 2 X 660 MW
Operation: 2003
Fuel: hard coal
Boiler supplier: BBP
T/G supplier: Siemens
EPC: BBP, Siemens, Gama, Tefken
Quick facts: This €1.5bn power station near Iskenderun was a flagship project for private power development and has the largest individual generating units in Turkey. It is run on imported hard coal. This is offloaded in the world's largest floating trans-shipment facilities capable of handling 30,000 tons of coal per day.

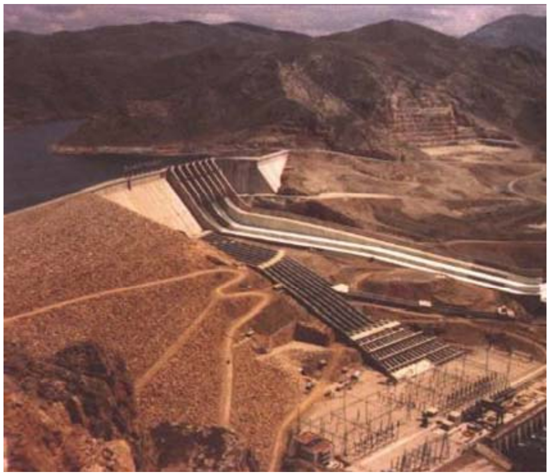
CCGT Baymina
Location: Ankara
Operator: Baymina Enerji AS
Configuration: 770-MW, 2+1 CCGT block with 9001FA+
Operation: 2004
Fuel: natural gas
HRSG supplier: CMI
T/G supplier: GE, Alstom
EPC: VA TECH, Yuksel
Quick facts: In Sep 2001, Tractebel acquired a controlling interest in the $500mn plant. The new plant connected to the main 380kV grid and is just 3km away from the main gas pipeline to Ankara.

CCGT Izmir
Location: Izmir
Operator: InterGen Enerji Ltd Sirketi
Configuration: Two 700-MW 2+1 CCGT blocks
Operation: 2003
Fuel: natural gas
HRSG supplier: CMI
T/G supplier: GE/Alstom
EPC: Bechtel Enka
Quick facts: Turkish construction company Enka had won the exclusive right to negotiate for 3x500-MW of CCGT capacity one of the largest private-power development schemes in the world. In Sep 2000 the partners signed $1.5bn of loan agreements for the project. Gas turbine purchase amounted to about $900mn the largest order for such equipment ever in Turkey and the largest single order for the 9FA+ machine to that date.

CCGT Bursa
Location: Bursa
Operator: InterGen Enerji Ltd Sirketi
Configuration: Two 700-MW 2+1 combined-cycle blocks with 9001FA+ gas turbines
Operation: 1999
Fuel: natural gas
HRSG supplier: CMI
T/G supplier: Mitsubishi
Quick facts: 1400MW CCGT Bursa plant was built by a consortium led by Mitsubishi Corporation that included the Itochu Corporation and ENKA a Turkish-based conglomerate. The plant the biggest turnkey project in Turkey produces 10 billion kWh of electricity a year. Bursa CCGT plant consumes about 1 700m3 of natural gas every year.



NPP Akkuyu
Location: Akkuyu
Operator:
Configuration: 4 X 1,200 MW PWR
Operation: 2019-2021
Reactor supplier: Mintyazhmash
T/G supplier: Kharkov, LMZ
Quick facts: Russian consortium led by Rosenergoatom won the contract to build first Turkeys nuclear power plant for US$ 20 bn. Turkish Electricity Trade and Contract Corporation (TETAS) has guaranteed the purchase of 70% power generated from the first two units and 30% from the third and fourth units over a 15-year power purchase agreement. Electricity will be purchased at a price of 12.35 US cents per kWh and the remaining power will be sold in the open market by the producer.



HPPs on Eufrat

HPP Keban
Location: Elazig
Operator: EUAS
Configuration: 4 X 157.5 MW, 4 X 175 MW Francis
Operation: 1974-1982
T/G supplier: Voest, Neyrpic, AEG
EPC: Ebasco , Sogea
Quick facts: The Keban Dam was the first of the large dams to be built on the Euphrates River. It created a reservoir extending 50km upriver and 100km uprive in the Murat River valley to the east. The Murat joined the Euphrates about 7km north of the dam.

HPP Karakaya
Location: Diyarbakir
Operator: EUAS
Configuration: 6 X 300 MW Francis
Operation: 1987-1989
T/G supplier: Sulzer Escher Wyss, ABB
EPC: Electrowatt
Quick facts: Located 166 km downstream of the Keban Dam and 180 km upstream of the Atatürk Dam the 173 m high arch gravity Karakaya Dam represents the second stage of the five dams series developing the Euphrates middle reach.

HPP Ataturk
Location: Sanliurfa
Operator: EUAS
Configuration: 8 X 300 MW Francis
Operation: 1992-1993
T/G supplier: SZEW, ABB
EPC: Dolsar, ATA Insaat
Quick facts: Ataturk Dam is the largest in a series of 22 dams and 19 hydroelectric plants built on the Euphrates and Tigris rivers as part of the GAP, a massive irrigation and hydroelectricity scheme. The dam is one of the world's largest earth-and-rock fill dams measuring 184m high and 1,820m.

HPP Birecik
Location: Sanliurfa
Operator: EUAS
Configuration: 6 X 112 MW Francis
Operation: 1994
T/G supplier: Neyrpic, ACEC, Sulzer
EPC: Philip Holzman, TemelsuGama, Strabag
Quick facts:This was the first large Turkish hydroelectric BOT project and it reached financial close in Nov 1995 about 7yrs from the time the
development process started. Construction on $1.64bn plant began in Mar 1996. Ownership of Birecik is to be transferred to the state in 2016.

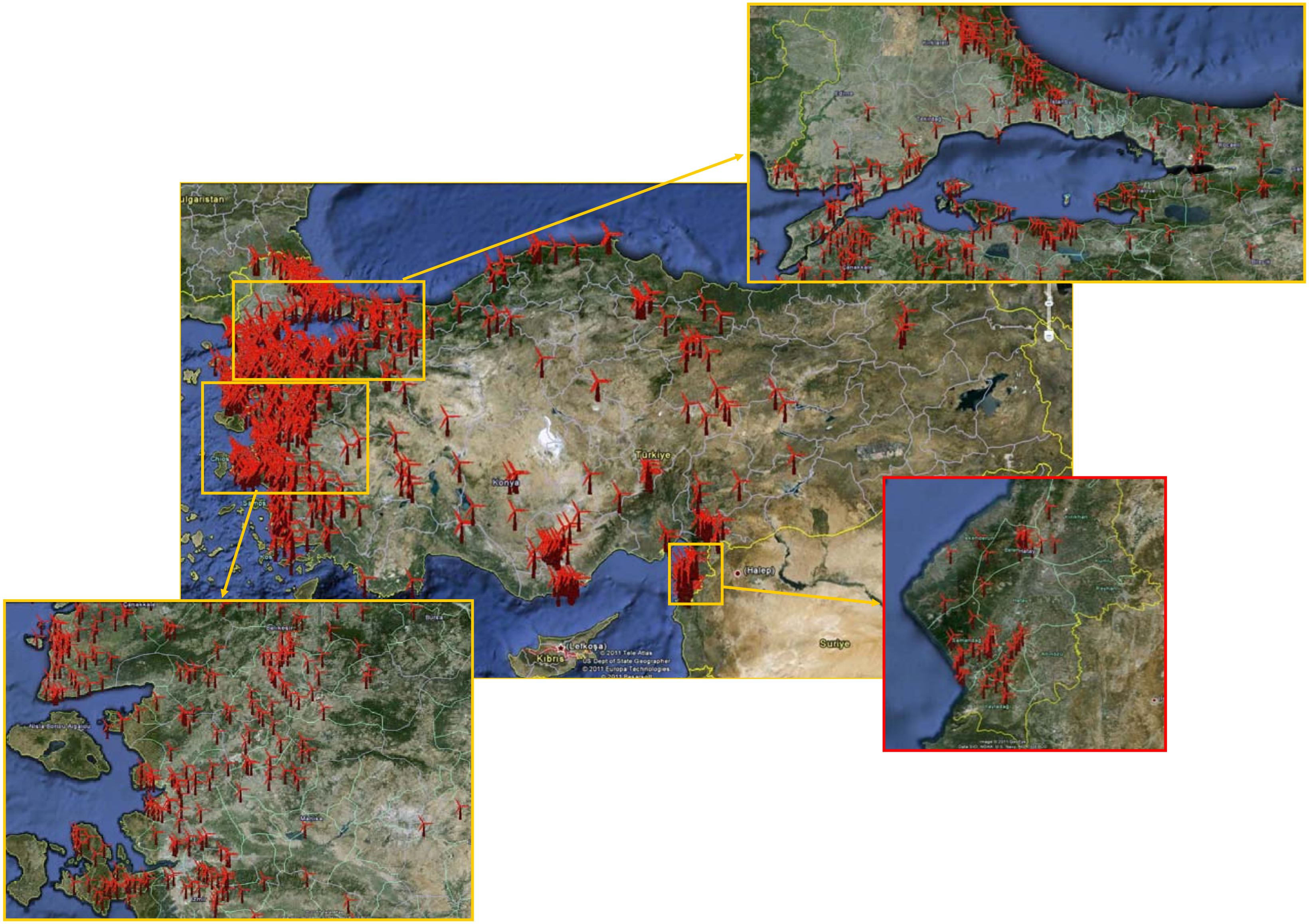


Figure 3.47 – Turkey – planed locations for wind power plants

Generation Capacities Planned

Turkey has limited domestic energy resources. Most of the generation expansion in last two decades has come through a rapid growth in gas based generation using imported gas mainly from Russia.

As of December 2009, installed capacity, project generation and firm generation data for power plants granted by license, under construction and expected to be in service are shown on Table 3.43. According to TEIAS's capacity projection for period 2010-2019, in 2009 the 4100.3 MW have been commissioned and 1156.4 MW decommissioned, which gave an increase of 2944 MW.

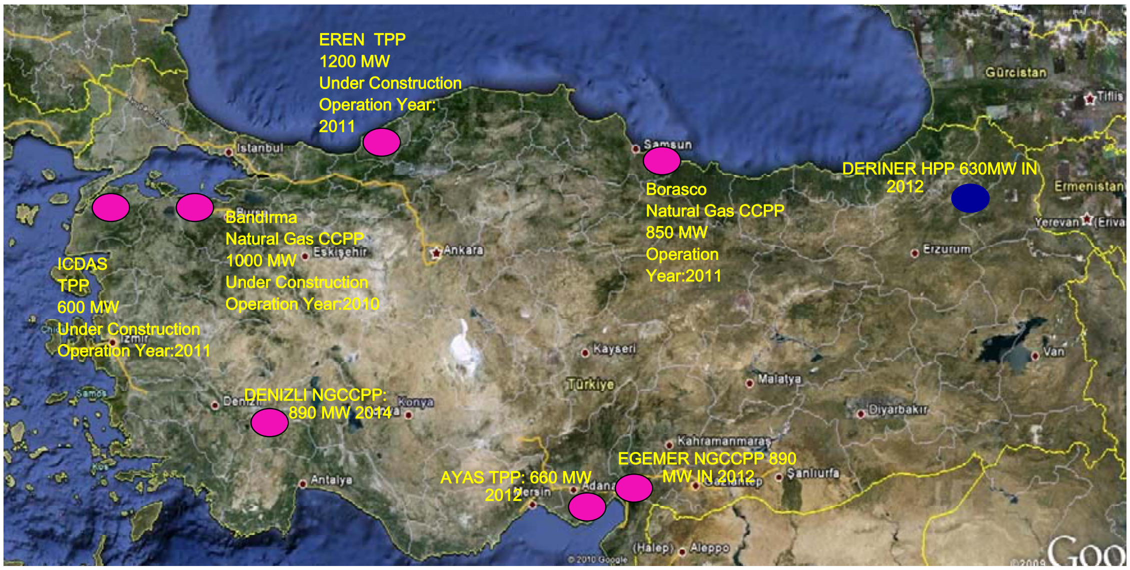


Figure 3.48 – Turkey – Large power plants to be commissioned in next 5 years

Nuclear Power Plants: The Turkish government wants to have substantial nuclear power resources operational in Turkey. It has begun negotiations with Russia's Rosatom State Nuclear Energy Corporation for the construction of a nuclear power plant in the Akkuyu district in the southern province of Mersin. Plans with Japan on the construction of another plant in the northern province of Sinop were suspended after the unfolding of a nuclear crisis in Japan on March 11. Its goal is to have a minimum of 5% of electricity production come from nuclear power plants by 2020. The latest year observed for Turkey is 2019. If in that period 15000 GWh of nuclear electricity is added creating approximately 2000 MW, it would represent 5% of total electricity production in Turkey.

Hydro Power Plants: Turkey is also pushing the agenda to maximize the country's hydroelectric potential and develop renewable energy production.

Thermal Power Plants: Turkey also anticipates further growth of the installed capacity of thermal power plants run on natural gas Combined Cycle units, and coal fired power plants in the North and in the Southeast parts of the country. The coal fired plants can be divided in two major groups. One runs on domestic lignite and an another on imported coal. Regardless, coal fired power plants are on schedule based on development plans. On the other hand, recent increase of natural gas and oil prices has caused many of the CCGT projects to be suspended or delayed.

Renewables: Wind power represents the main renewable energy source in Turkey. First WPP was commissioned in 1998. Present system available capacity for connecting wind generation reaches 8474 MW.

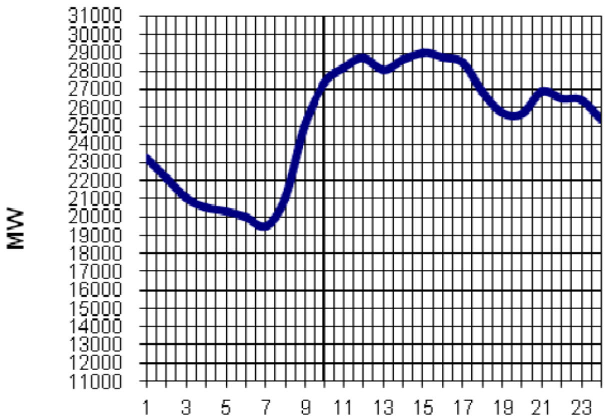
The current status of WPP is listed below:

- Number of the wind pp's in operation: 1626 MW (39 pp's)
- Current Licensed wind generation: 3483 MW
- Applications (Date: 1th November 2007) 78.000 MW (722 pp's)

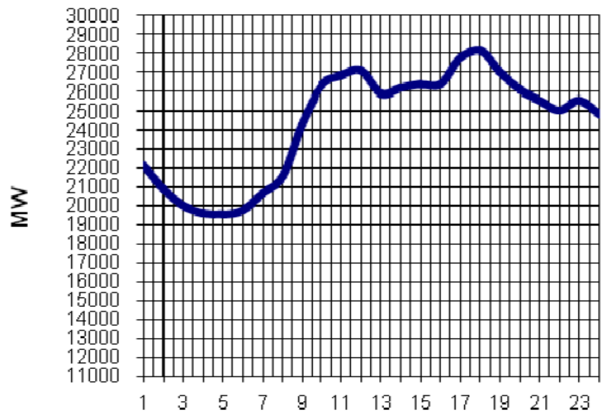
1.11.4 Demand

Demand Behavior

Turkey's yearly consumption in 2010 was at 209.4 GWh and peak load at 33,392 MW. Its consumption per capita is below the world and EU average. Based the Turkish market trends, power consumption is expected to have a steady high growth between 6.6–7.3% on average annually.



Summer peak
29.25GW, 603.2MWh



Winter peak
28.4GW, 583.3MWh

In 2008, the peak load and the minimum load were 30517 MW and 10409 MW respectively. For 2009, the peak load was 29870 MW and the minimum load 11123 MW. Yearly consumption in 2010 reached 209.4 TWh, with the peak load at 33,392 MW.

In 2007, 40% of the total electricity in Turkey was consumed by the industrial sector, 25% by residential, and approximately 35% by the commercial and public sectors.

Demand Forecast

Gross electricity consumption (equal to gross generation + import – export) had reached 198.1 TWh with an annual increase of 8.8% for the year 2008, and 194.1 TWh by an annual decrease of 2.0% in 2009. Net consumption (internal consumption, grid losses and power theft included) was 161.9 TWh in 2008 and 156.9 TWh in 2009. Expected average growth rate for peak load and energy consumption is 7.5% per year.

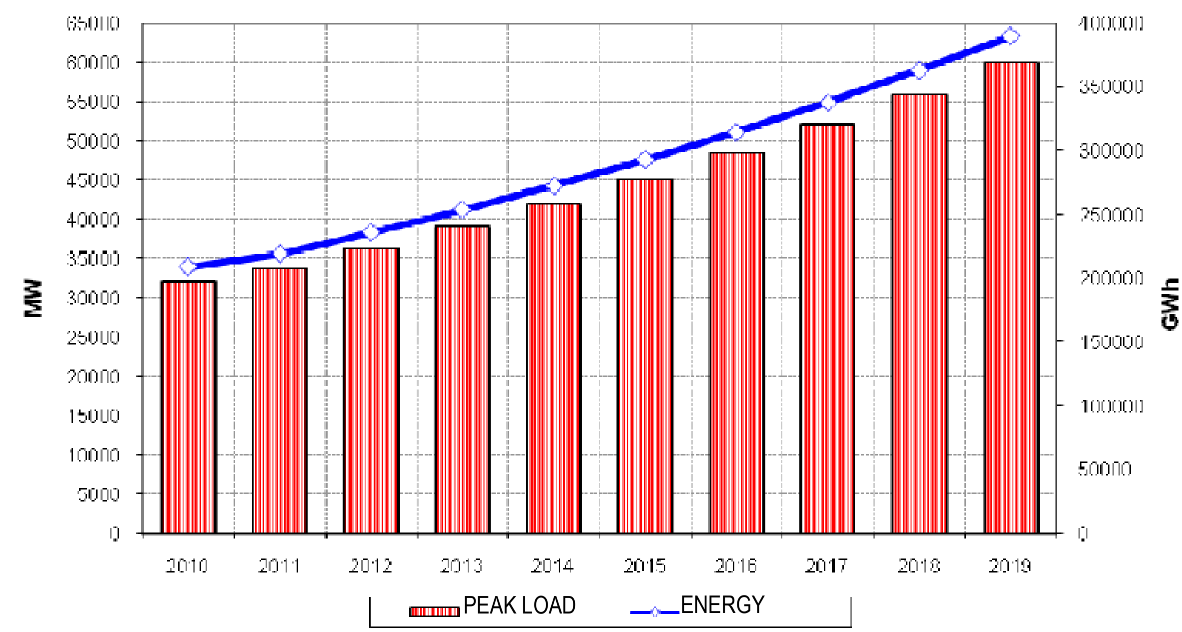


Figure 3.49- Turkey – Demand Forecast

Tariff

Since 1960, Turkey's electricity demand has increased by an average of 8% annually. The growth has been fuelled by a growing population and per capita economic growth. The demand growth has been particularly rapid in recent years partly due to a booming economy but also because of a significant erosion of the real tariff level to end users in Turkey.

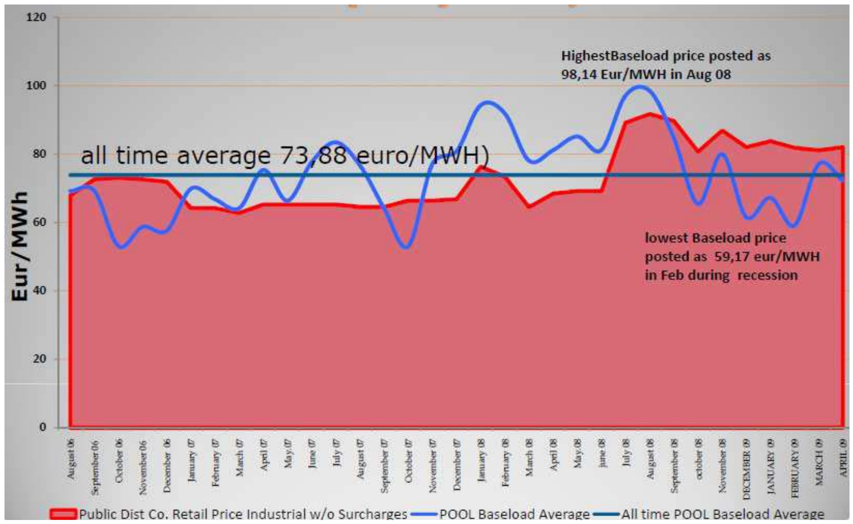


Figure 3.50 – Turkey – Prices of electricity

On December 29, 2010, Turkey's Parliament approved a new law for regulating the renewable energy resources market in Turkey.

Table 3.44 – Turkey – tariffs for RES (before taxes)

kategory		EURc/KWh Base	EURc/KWh Incentive	USDc/KWh Base	USDc/KWh incentive
I	Small hydro	5.1	1.6	7.3	2.3
II	Wind	5.1	2.6	7.3	3.7
III	Geothermal	7.35	-	10.5	-
IV	Solar	9.3	4.7	13.3	6.7
V	Biomass (incl. LFG)	9.3	-	13.3	-

*Incentives apply only if Turkish built equipment is used

The established tariffs are valid for the PPs that come online between May 18, 2005 and December 31, 2015 are valid for 10 years. After December 31, 2015 a new tariff will be established by the Turkish Government but will not exceed the previous one.

Incentive mechanisms for renewable generation include the following:

- 90 % discount in system usage tariff & 99% discount in license fees
- Extra incentives in the case of usage of domestic equipment
- Technical privileges such as ancillary services & market regulations
- Priority in system interconnection
- Land usage incentives
- For further details see Turkish Law #5346

1.11.5 Export Potential for 2015 and 2020

The electricity market in Turkey is well developed. Imports and exports to and from countries are possible if they fulfill the international requirements for interconnection. The exchange is subject to the available capacity and the approval of EMRA. The eligible market participants are:

- Electricity Trading and Contracting Company (TETAŞ)
- Private sector wholesale companies
- Retail sale companies (import only)
- Distribution companies holding retail sale licenses (import only)

Based on the demand forecasts (low/high) and plans for new generation capacities (Scenario 1/2), Turkey will not be self-sufficient in terms of production after 2016 or 2017. The Turkish Government attempts to mitigate the shortage by promoting hydro, lignite, RES and mentioned nuclear projects. Nevertheless, importing electricity in the future will become a strong option for Turkey.

1.11.6 Remarks and comments

Many steps have been taken to promote renewable energy sources and the results are satisfactory. On the other hand, there are two main challenges regarding the integration of renewable power plants to the national grid. Connecting more renewable energy is challenging the system operator because it makes the load management more difficult due to the intermittency of the source. In this context, the amount of intermittent sources being integrated to the system has to be limited in compliance with the capacity projection of the system. Therefore, even though viable potential is much higher, available capacity for licensing (wind and solar) is limited. In parallel with the commissioning of RES plants, the system operator has double its efforts to always keep the system in balance.

Table 3.45 – Turkey – power plants participating in system balancing

Plant Identification	BSTP Code	Type	Existing/ Planned	Installed Capacity (MW)	Available Balancing Capacity (MW)	Service Price
Ataturk	60885	Hydro	Existing	8x300	400	Market Dependent
Karakaya	60894	Hydro	Existing	6x300	300	Market Dependent
Altinkaya	60690	Hydro	Existing	4x175	160	Market Dependent
H. Ugurlu	60693	Hydro	Existing	4x125	60	Market Dependent
Adapazari	60155	CCGT	Existing	770	30	Market Dependent
Gebze A	60177	CCGT	Existing	760	30	Market Dependent
Gebze B	60177	CCGT	Existing	760	30	Market Dependent
Ankara	60516	CCGT	Existing	770	35	Market Dependent
Izmir A	60324	CCGT	Existing	760	35	Market Dependent
Izmir B	60324	CCGT	Existing	760	35	Market Dependent

The total 30 second reserve, also known as the primary reserve, of the ENTSO-E system including Turkey is ~3000 MW. Turkey as a control area provides ~300 MW of this reserve.

Following rules have to be implemented:

- Hourly integral of ACE should not exceed ±60 MWh
- Number of cases with ACE > ±175 MW (measured per 2 seconds, evaluated per 4 seconds) over an hour should not exceed 10% of the cases in normal operation to prevent overloads in the electricity transmission systems of the neighboring Balkan countries.
- The amount of sum of tie line flows due to inter area oscillations should not exceed 30 MW in normal operation to prevent overloads due to inter area power oscillations through the ENTSO-E countries.

Frequency stability of Turkish Electricity Transmission System has been drastically enhanced with the ENTSO-E CESA Interconnection. There is an increased standard deviation of ACE due to intermittent generation in short term (turbulent peaks/dips). Balancing and settlement market problems occur due to an inadequate prediction of wind capacity in long term. To resolve this, possible solution include the following:

- Effective management of tertiary reserve (current market conditions do not encourage generation curtailment)

- Increased amount of secondary reserve under the influence of the AGC system (short term) for the entire day

Special monitoring/control system requirements especially for wind power that consist of two main parts:

- WIND FORECAST SYSTEM
  The wind forecast system has been developed by Turkish State Meteorological Service which provides information regarding wind forecasts for different heights and for 48 hours with 4 km solubility all around Turkey. The trial tests are continuously conducted to improve the system.
- WIND MONITORING SYSTEM
  Specific monitoring system for wind generation is planned and the procedures are underway with a consultant company (Figure 3.51)

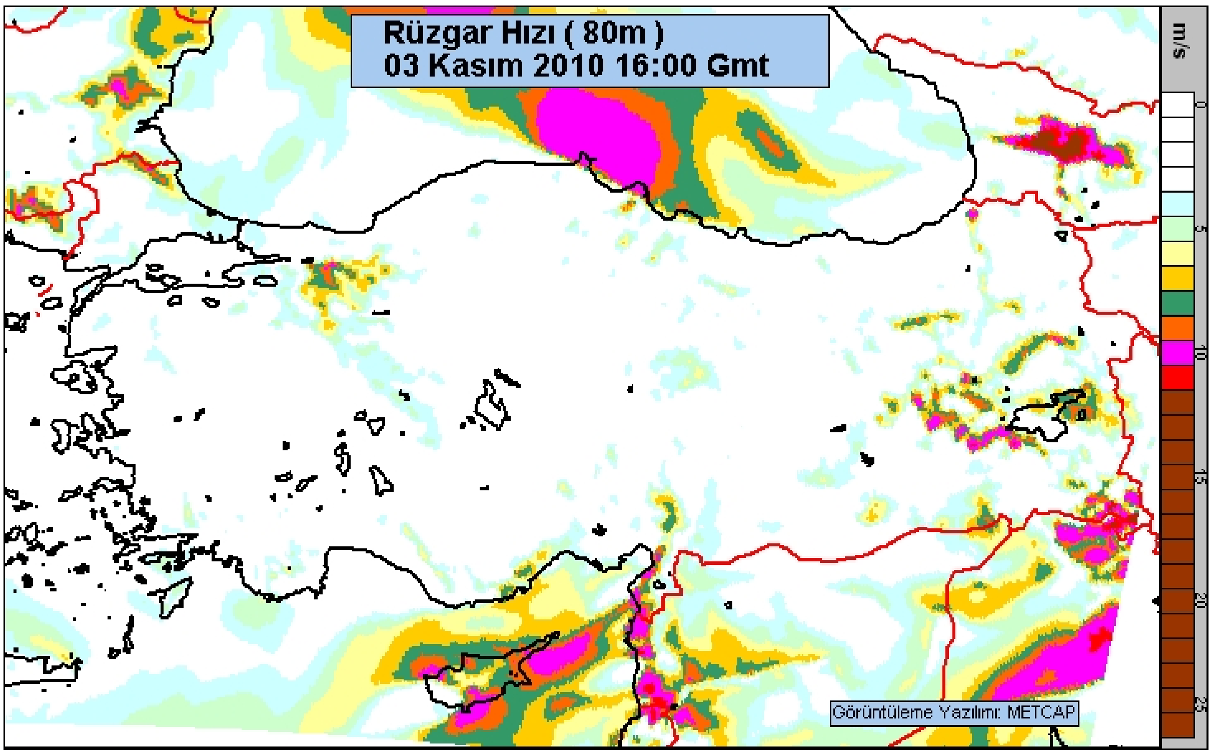


Figure 3.51 – Turkey – WIND MONITORING SYSTEM

1.12 Ukraine

1.12.1 General Information

Ukraine is a country in Eastern Europe. It has an area of 603,628 km², making it the largest contiguous country on the European continent. Ukraine borders the Russian Federation to the east and northeast, Belarus to the northwest, Poland, Slovakia and Hungary to the west, Romania and Moldova to the southwest, and the Black Sea and Sea of Azov to the south and southeast, respectively.

Area: 603628 sq. km
Water: 7%
Arable land: 53.8 %
Permanent crops: 1.5 %
Forest area: 16.5 % (2005)
Population: 45,888,000 (2010 est.)

GDP: purchasing power parity - $302.7 billion (2010 est.)
GDP per capita: purchasing power parity - $6656 (2010 est.)

GDP composition per sector:
- agriculture: 9.3 % (2008)
- industry: 31.7 % (2008)
- services: 58.9 % (2008)

1.12.2 Transmission Network

Ukraine's transmission system consists of a 800 kV DC line, a basic infrastructure of 750 kV, single circuit AC system that overlays an extensive 330 kV (single and double circuit) network, feeding into 220 kV and 110 kV systems, but also 500 kV and 400 kV AC systems in some parts of the country. Figure 3.53 shows the transmission network of Ukraine and Table 3.46 gives an overview of Ukrainian transmission network.

Table 3.46 – Ukraine –network overview

lines		transformers	
Voltage level	Length of the overhead lines and cables	Voltage level	Installed capacities
(kV)	(km)	(kV/kV)	(MVA)
800	100		
750	4120		
400	710	400/x	24240
330	13330		
220	4010	220/x	300
110	540	154/x	46979
35	550	66/x	678
total	23360		76963.6

Currently, the Southwest part of the Ukrainian system called the Burstyn Island is part of the 220 kV network that includes the Burstinskaya TPP, and is connected to the Mukachevo substation, is separated from the main Ukrainian system and operates in a synchronous and parallel mode with the main grid of ENTSO-E. This was done in order to export electricity from Ukraine to Western Europe.

Figure 3.52 – Ukraine – Bustin island

Planned Network Reinforcements

Ukraine has an extensive development plan shown on Table 3.47. Large part of the network is aging and needs to be reconstructed and increase its capacity. One of the major planned projects is a second 750 kV back-bone from the South to the North of the country and the reconstruction of a 750 kV connection to Poland.

Figure 3.53 – Ukraine – network map

Table 3.47 – Ukraine – Network reinforcements till 2015

TYPE		SUBSTATION1		SUBSTATION2	VOLTAGE LEVEL kV/kV	number of circuits /units	CAPACITY A or MVA	limited A or MVA	MATERIAL OR TRANSFORMER TYPE	CROSS mm2	LENGTH BR1 km	BR2 km	TOTAL km	DATE OF COMMISSIONING	STATUS	COMMENT
1	2	3	2	3	4	5	6	7	8	9	10	11	12	13	14	15
OHL	UA	Novoodeska	UA	Artsyz	330	1	1670 A	-	ACSR	400*2	140	0	140	2010	Construction	
OHL	UA	Adgalyk	UA	Usatovo	330	1	1670 A	-	ACSR	400*2	124	0	124	2009	finished	second line
OHL	UA	Zarya	UA	Mirna	330	1	1380 A	-	ACSR	300*2	14	0	14	2008	finished	second line
SS	UA	Simferopol			330	1			SVC					2011	project	SVC
OHL	UA	Simferopol	UA	Sevastopol	330	1	1670 A	-	ACSR	400*2	70	0	70	2007	finished	upgrade from 220kV
OHL	UA	Dgankoj	UA	Melitopol–Simferopol	330	1	1380 A	-	ACSR	400*2	16	0	16	2006	finished	Connectors of Dgankoj SS to OHL Melitopol–Simferopol
OHL	UA	Zapadnokrymskaya	UA	Sevastopol	330	1	1670 A	-	ACSR	400*2				2012	feasibility	upgrade from 220kV
OHL	UA	Zapadnokrymskaya	UA	Kahovska	330	1	1670 A	-	ACSR	400*2				2014	feasibility	upgrade from 220kV
SS	UA	Kyivska			750/330	1	1000 MVA	-	PST	-	-	-	-	2009	finished	
OHL	UA	Pivnichnoukrainska	UA	Kyivska	750	1	4000 A	-	ACSR	400*5	292	0	292	2015	Feasibility study	
OHL	UA	Rivnenska NPP	UA	Kyivska	750	1	4000 A	-	ACSR	400*5	370	0	370	2009	finished	
OHL	UA	Zahidnoukrainska	UA	Bogorodchani	330	1	1670 A	-	ACSR	400*2	111	0	111	2010	Construction	
OHL	UA	Zahidnoukrainska	UA		330	4	1670 A	-	ACSR	400*2				2013	Construction	
OHL	UA	Zahidnoukrainska	UA		110	8		-	ACSR					2013	Construction	
SS	UA	Drogobych			330/110			-		-	-	-	-	2010		
OHL	UA	Zahidnoukrainska	UA	Drogobych	330	1	1670 A	-	ACSR	400*2	111	0	111	2010	Construction	
OHL	UA	NPP Rivne	BY	Mikashevichi	330	1	1670 A	-	ACSR	400*2				2013	feasibility	
SS	UA	Novodonbaska			500/220			-		-	-	-	-	2015	feasibility	Reconstruction 500 кV SS "Novodonbasskaya" with construction 2 OHL 500 кV, AT 500/220 кV and 5 OHL 220 кV
SS	UA	Primorska			750/330	1	1000 MVA	-	PST	-	-	-	-	2015	feasibility	
OHL	UA	Pivdenoukrainskaya	RO	Isaccea	750	1	4000 A	-	ACSR	400*5	406	3	409	2015	Feasibility study	Restoration. Voltage level to be defined
OHL	UA	Dnistrovska PSHPP	UA	Bar	330	1	1670 A	-	ACSR	400*2	95	0	95	2007	finished	
OHL	UA	Dnistrovska PSHPP	UA		750	1	4000 A	-	ACSR	400*5				2015	project	To existing line Zapadnoukrainskaya – Vinnitsa
OHL	UA	K.Podolska	UA	Ternopil	330	1	1670 A	-	ACSR	400*2	150	0	150	2012	Feasibility study	
OHL	UA	Lutsk Pivnichna	UA	Ternopil	330	1	1670 A	-	ACSR	400*2	180	0	180	2010	Feasibility study	
OHL	UA	HPP Dnistrovska	MD	Balti	330	1	1670 A	-	ACSR	400*2	120	0	120	2012	Idea	second line
SS	UA	Kahovska			750/330	2	1000 MVA	-	PST	-	-	-	-	2015	finished	
OHL	UA	Zaporizka NPP	UA	Kahovska	750	1	4000 A	-	ACSR	400*5	190	0	190	2015	Feasibility study	
SS	UA	Zaporizka NPP			750/330	1	1000 MVA	-	PST	-	-	-	-	2015	finished	second transformer
SS	UA	Dnieprovska			750/330	1	1000 MVA	-	PST	-	-	-	-	2012	finished	third transformer

1	Type of project (OHL - overhead line, K - kable, SK - submarin kable, SS - substation, BB - back to back system...)	8	Type of conductor or transformer
2	Country (ISO code)	9	Cross section (number of ropes in bundle x cross section/cross section of reinforcement rope)
3	Substation name	10	Length till border of first state
4	Installed voltage (for lines nominal voltage, for transformers ratio in voltages)	11	Length till border of second state
5	number of circuits/units	12	Total length
6	Conventional transmission capacity of elements for OHL in Amps, for transformers in MVA	13	Date of commissioning (estimate)
7	Conventional transmission capacity limited by transformers or substations	14	Status of project (Idea, Feasibility study, Construction, Damaged, Decommissioned...)

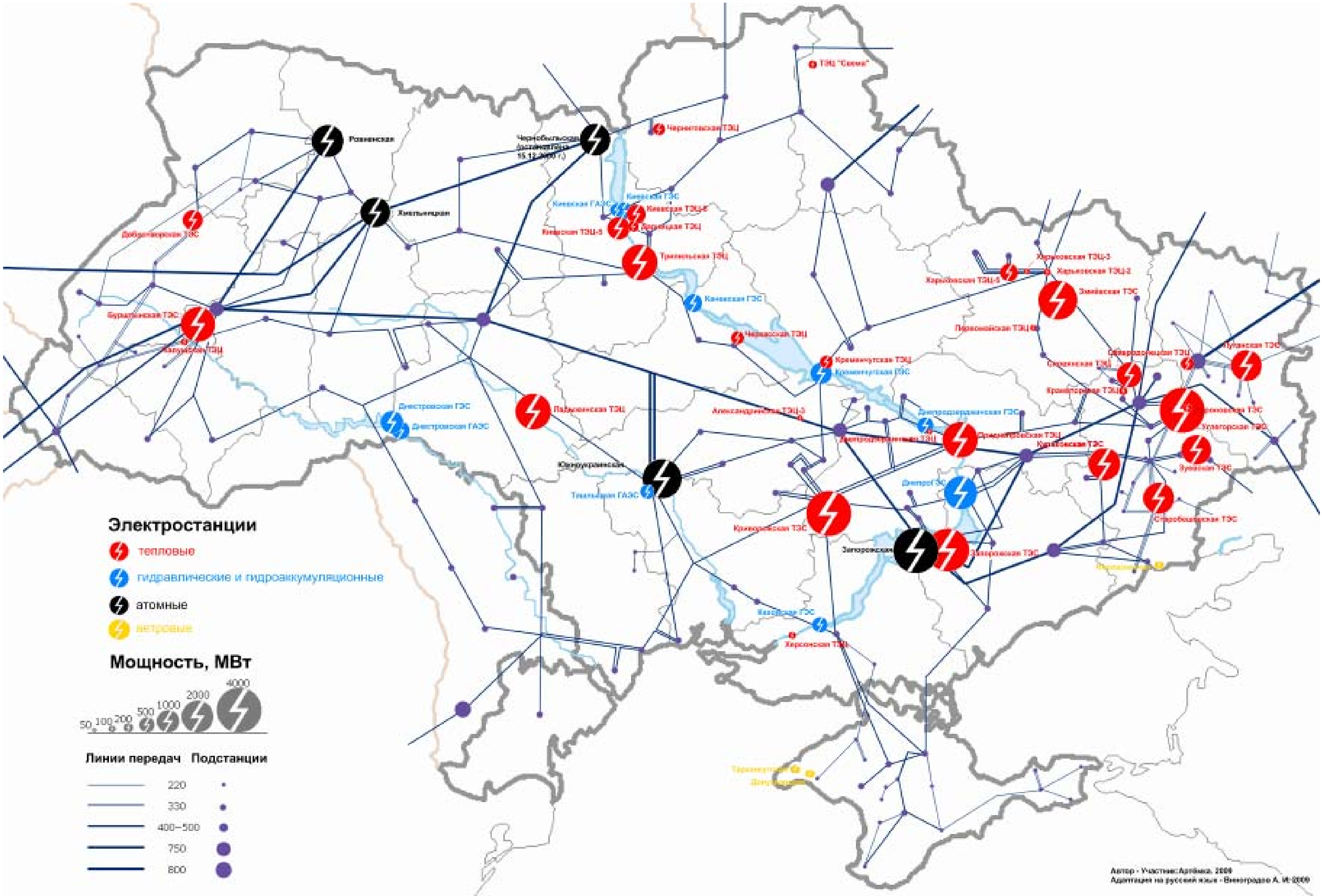


Figure 3.54 – Ukraine – Generation capacities and transmission network

1.12.3 Generation

Most of the Ukrainian generation capacities are aging thermal power plants run on brown coal 27225MW (52%), nuclear power plants 13835MW (26%), CHPP run mainly on imported gas 6360MW (12%), and hydro power plants with 5089MW (10%).

TPP Burstinska
Location: Ukraine
Operator:
Configuration: 12 X 200 MW
Operation: 1965-1969
T/G supplier: Kharkov, Electrosila
EPC:
Quick facts: Power plant is located in western Ukraine, and presently is operated connected to European grid to realize export from Ukraine.

TPP Pridneprovska
Location: Ukraine
Operator:
Configuration: 4X150, 4x 300 MW
Operation: 1959-1966
T/G supplier: Kharkov, Electrosila
EPC:
Quick facts:

TPP Starobeshivska
Location: Ukraine
Operator:
Configuration: 10X200
Operation: 1961-1967
T/G supplier: Kharkov, Electrosila
EPC:
Quick facts:

TPP Trypilska
Location: Ukraine
Operator: Centrenergo
Configuration: 6 X 300 MW
Fuel: natural gas, coal, fuel oil
Operation: 1969-1972
Boiler supplier: Taganrog
T/G supplier: Kharkov

NPP Khmelnitska
Location: Ukraine
Operator: Energoatom
Configuration: 2 X 1,000 MW PWR
Operation: 1988-2004
Reactor supplier: Mintyazhmash
T/G supplier: LMZ, Electrosila
EPC: EnergoProekt Kyiv
Quick facts: This plant is in Slavutsky district near the Goryn River in western Ukraine. In 1981, construction got underway and the first unit was put online in late 1987. Sites for three more units were cleared and construction on Unit-2 began in 1983 with plans to finish it in 1991. In 1990, however, construction was stopped as part of a moratorium on new plant construction adopted by Verkhovna Rada. After the moratorium was lifted, construction proceeded very slowly and was finally completed in Aug 2004. Units 3&4 are planned for completion by 2020.

NPP Pivdenoukrainska
Location: Ukraine
Operator: Energoatom
Configuration: 3 X 1,000 MW PWR
Operation: 1983-1989
Reactor supplier: Mintyazhmash
T/G supplier: Kharkov
EPC: EnergoProekt Kharkov
Quick facts: The South-Ukraine power complex is located on the South Bun river in Mykolaiv region and consists of the NPP, a small conventional hydroelectric plant, and a pumped-storage plant. Construction of the nuclear plant and satellite town of Yuzhno-Ukrainsk started in 1975 and Unit-1 was connected in Dec 1982 after 72 months of construction. The 25-MW Olexandrivska hydro plant was finally completed in 1999 after years of delay and the first 150-MW unit at the Tashlyk pumpedstorage plant in late 2006.

NPP Rivnenska
Location: Ukraine
Operator: Energoatom
Configuration: 2 X 400 MW, 2 X 1,000 PWR
Operation: 1981-2004
Reactor supplier: Mintyazhmash
T/G supplier: Kharkov, LMZ
EPC: EnergoProekt Kyiv
Quick facts: Design of Rivne began in 1971 and this was the first nuclear power plant with the VVER-440, B-213 reactors. Construction started in 1973. The construction of Unit-4 started in 1984 with plans for completion in 1991 but construction was suspended in that year and did not resume until 1993. Engineering assistance was provided by EDF and Fortum and Unit-4 was put online in Oct 2004.

NPP Zaporoshka
Location: Ukraine
Operator: Energoatom
Configuration: 6 X 1,000 MW PWR
Operation: 1983-1989
Reactor supplier: Mintyazhmash
T/G supplier: Kharkov

HPPs Dnieper cascade

The Dnieper Cascade is one of the largest hydro systems in the world. It consist of seven hydro and pumping stations with a total installed capacity over 4000MW. Dnieper is a slow and vast river and all the plants are small with Kaplan turbine run units.

Table 3.48 – Ukraine – New production units

TYPE		SUBSTATION1	VOLTAGE LEVEL kV	kV	CAPACITY MW	MVA	DATE OF COMMISSIONING year	STATUS	COMMENT
1	2	3	4	5	6	7	8	9	10
PSHPP	UA	Dnistrovska	15.75	330	360/390	420	2008	in operation	unit 1
PSHPP	UA	Dnistrovska	15.75	330	360/390	420	2009	Construction	unit 2
PSHPP	UA	Dnistrovska	15.75	330	360/390	420	2010	Construction	unit 3
PSHPP	UA	Dnistrovska	15.75	330	4x360/4x390	420	2010-2012	Construction	units 4-7
CCHP	UA	Kyivska 6	20	330	300	353	2008	Construction	
PSHPP	UA	Tashlykska	15.75	330	2x151/2x233	307	2008	in operation	units 1 and 2
PSHPP	UA	Tashlykska	15.75	330	2x151/2x233	307	2009	Construction	units 3 and 4
NPP	UA	Khmelinskaya	24	750	2x1000		2020	PLANNED	
TPP	UA	Dobrotvirska	15.75	220	3x225		2020	PLANNED	
PSHPP	UA	Kanev	15.75	330	4x250/4x280	4x280	2030	PLANNED	
WPP	UA	Bakhchisarayskaya	35	110	67x3	200	2012	Construction	67x3MW units VESTAS on 0.65kV
WPP	UA	Pervomayskaya	35	330	67x3	400	2015	planned	134x3MW units VESTAS on 0.65kV
WPP	UA	Holmogorskaya	33	110	67x3	200	2015	planned	67x3MW units VESTAS on 0.65kV
WPP	UA	Turgenevskaya	33	110	67x3	200	2015	planned	67x3MW units VESTAS on 0.65kV
WPP	UA	Nova-Eco I (west Crimea)	33	330	67x3	200	2015	planned	67x3MW units VESTAS on 0.65kV
WPP	UA	Nova-Eco II (east Crimea)	33	220	33x3	100	2015	planned	33x3MW units VESTAS on 0.65kV
WPP	UA	Batiskaya	33	330	33x3	200	2015	planned	67x3MW units VESTAS on 0.65kV
WPP	UA	Odesskaya	33	220	33x3	100	2015	planned	33x3MW units VESTAS on 0.65kV
WPP	UA	Ochakovskaya	33	220	33x3	100	2015	planned	33x3MW units VESTAS on 0.65kV
WPP	UA	Trikhatskaya	33	220	100x3	300	2015	planned	100x3MW units VESTAS on 0.65kV
SPV	UA	Crimea		110	70		2012	Construction	
SPV	UA	Crimea		110	100		2013	Construction	
SPV	UA	Crimea		110	230		2015	planned	
SPV	UA	Mainland Ukraine		110	200		2015	planned	

1 Type of plant (HPP - Hydropower plant, TPP - Thermal power plant, PSHPP - Pump Storage Hydro Power Plant, CCHP - Combined Cycle Heating Plant...)
2 Country
3 Substation name
4 Generator voltage level
5 Network voltage level
6 Instaled active power
7 Instaled apparent power
8 Date of commissioning (estimate)
9 Status of the project (Idea, Feasibility study, Construction...)

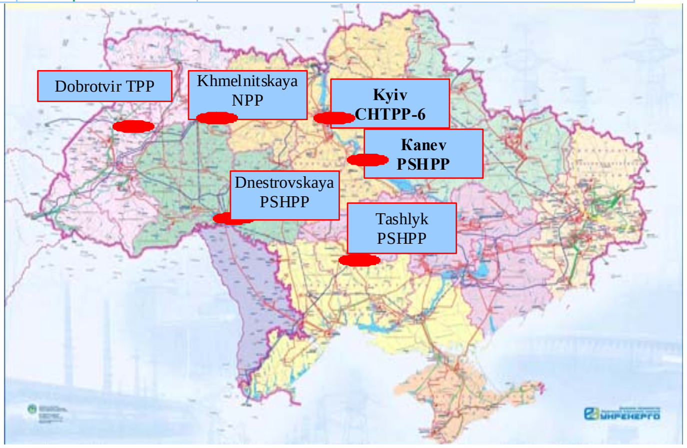


Figure 3.55 – Ukraine – new generation capacities

Generation Capacities Planned

Ukraine had an ambitious development program with an emphasis on nuclear facilities, but because of the economic crisis and other political issues these plans were reduced, and many investments are either canceled or postponed.

Nuclear Power Plants: Ukraine has planned to increase the capacity of the NPP Khmelnitska with 2x1000MW PWR blocks. New blocks are planned to be operational by 2017 (Table 3.48) The construction of the Crimea NPP in Schelkino began in 1976 and was stopped in 1989. Engineering work was essentially complete, but after the Chernobyl accident, seismic concerns of the Crimea site resurfaced and work was stopped. Unit-1 was said to be 80% complete and Unit-2 18% finished. The formal cancellation was announced in June of 2000. Part of the site may be reused for a new 800MW CCGT power station.

Hydro Power Plants: Hydro power is an important energy source in Ukraine from an energy and system control points of view. Currently, Ukraine lacks effective regulation of power and energy. As a result, the main development plans are in direction of constructing reversible hydro capacities or pumping stations Dnistrovska and Tashlinska, and in the long term, the Kanevska PHPP. Additionally, the reconstruction and modernization of large existing HPPs is in the process (Table 3.48)

Thermal Power Plants: The Dobrotvirska, run on domestic coal, is the only new thermal power plant planned in Ukraine (Table 3.48) Potentially existing capacities will be modernized and reconstructed. The district heating power plants (CHPs) that are run on imported gas are included in the development plans. They could be replaced by new Combined Cycle units run on imported natural gas.

Renewables: The Crimean region of Ukraine has a high potential for renewable energy resources such as solar and wind production (Table 3.48). Relatively large scale renewables penetration in the Ukrainian system is expected in the forthcoming period. Construction of a 400MW solar power plant in Crimea has begun, and an additional 200MW are planned on the mainland of Ukraine. Wind power is the main renewable source that will be used, with more than 1300MW planned capacities in Crimean peninsula alone.

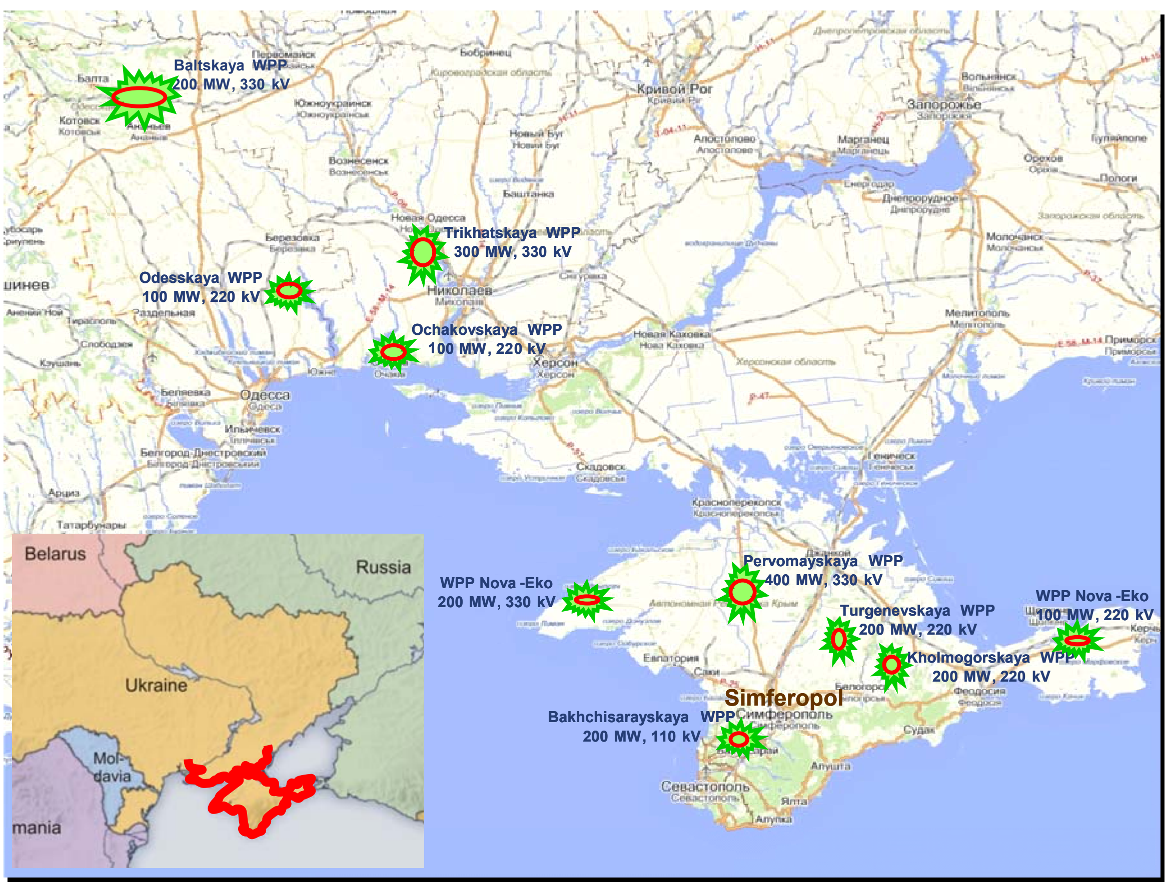


Figure 3.56 *– Ukraine – Planned wind projects in Crimea*

1.12.4 Demand

Demand Behavior

The following two diagrams show the wind demand behavior in the Ukrainian system for two characteristic regimes. They also present how this demand is covered by the production units.

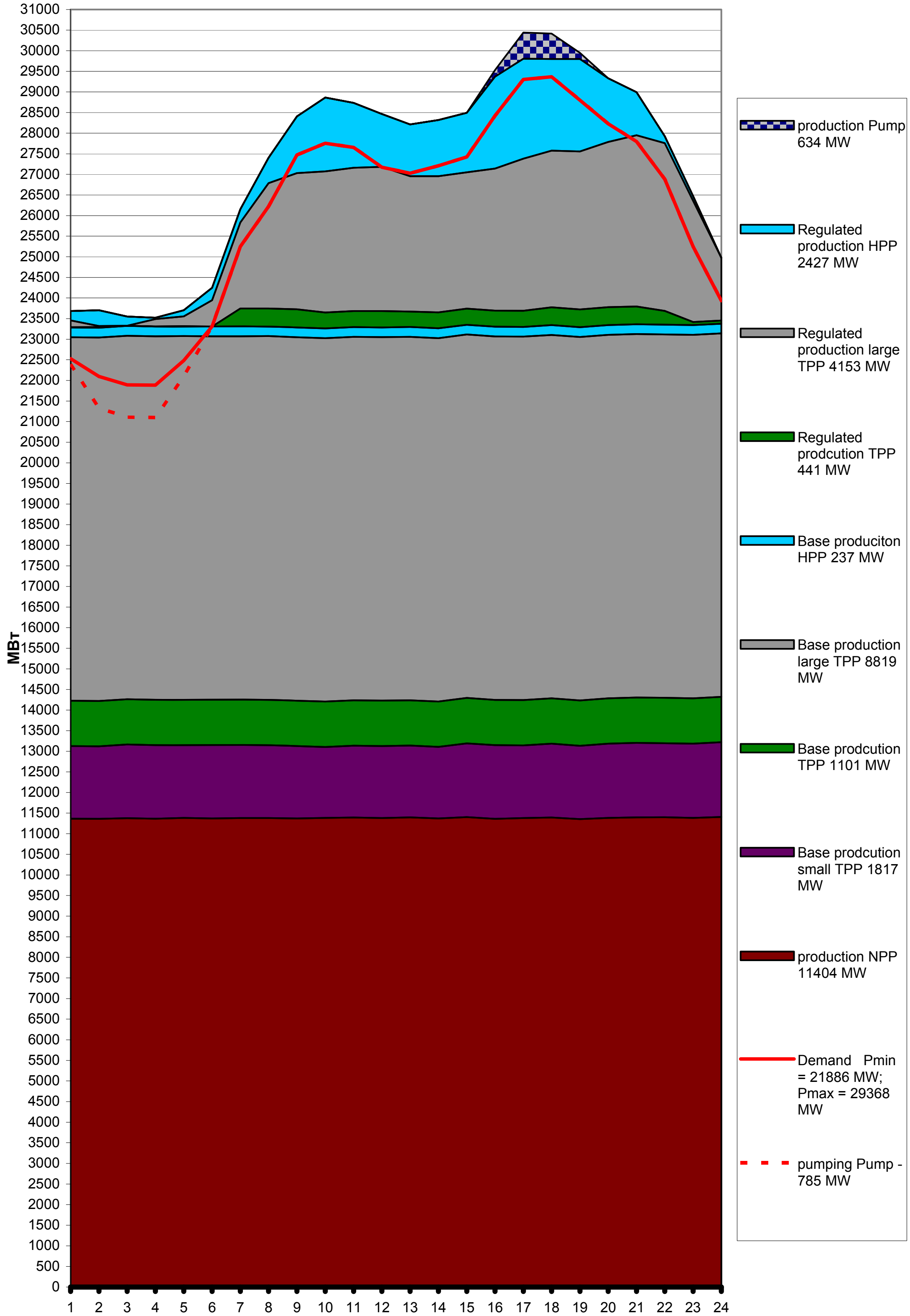


Figure 3.57 – Ukraine – Balance of Ukraine for winter peak day 15.12.2010.

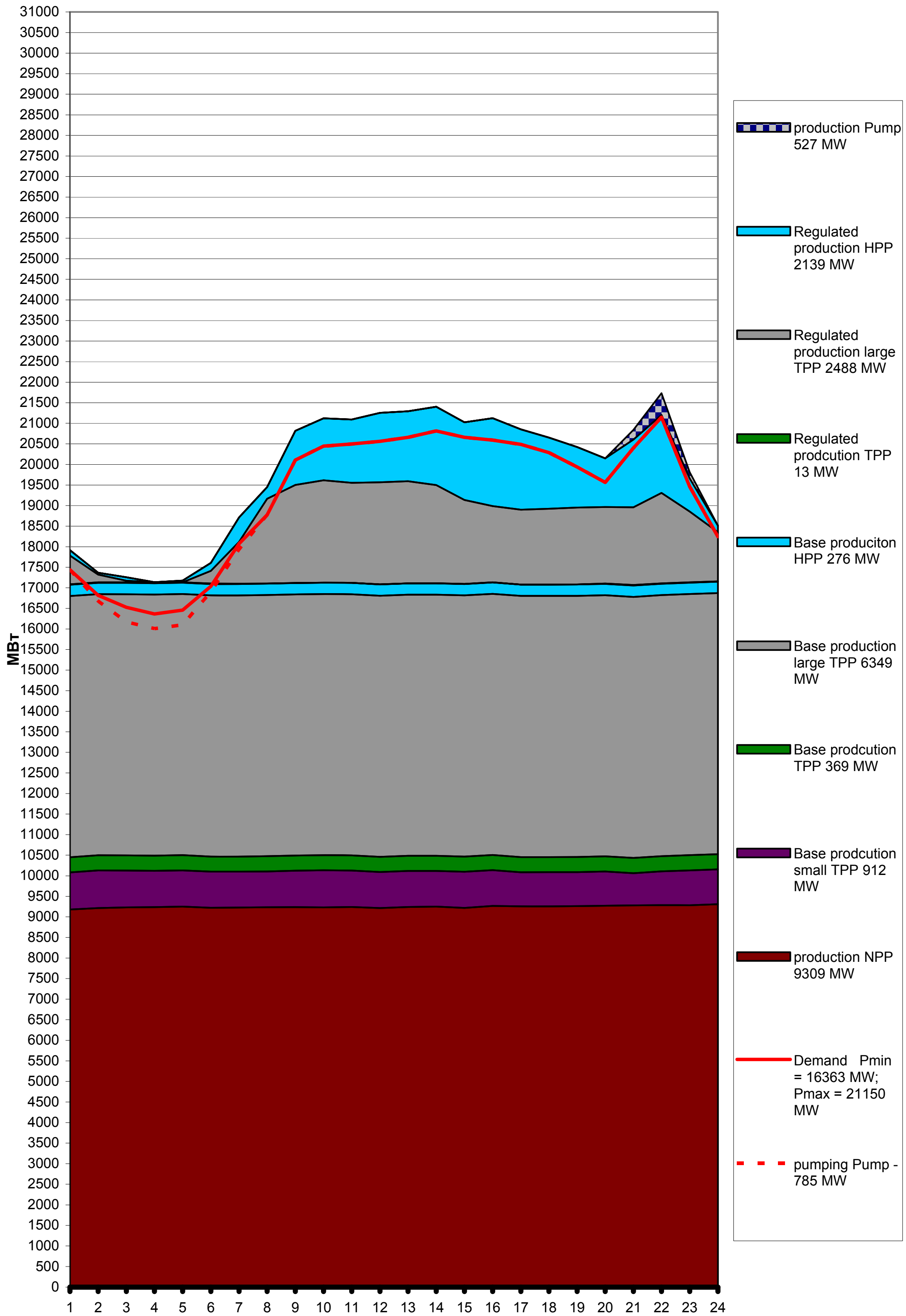


Figure 3.58 – Ukraine – Balance of Ukraine for summer peak day 16.06.2010.

Demand Forecast

Table 3.49 and Figure 3.59 show forecasted demand and distribution of demand by type, the generation level, and distribution of production by type, for an average winter and summer day. Based on the forecast, Ukraine plans to export up to 2.5TWh. The primary fuel for the majority of the production comes from Russia. Due to the nature of the production facilities, Ukraine has a large deficit in the control reserve. Because of this factor, most of the new planned generation units are PHPP stations.

Table 3.49 – Ukraine – Demand and generation Forecast

	2015		2020	
	Winter	Summer	Winter	summer
Demand GWh	**700**	**530**	**775**	**590**
industry	378.0	286.2	348.8	265.5
	54.00%	*54.00%*	*45.00%*	*45.00%*
households	**245.0**	**185.5**	**310.0**	**236.0**
	35.00%	*35.00%*	*40.00%*	*40.00%*
other	**77.0**	**58.3**	**116.3**	**88.5**
	11.00%	*11.00%*	*15.00%*	*15.00%*
export	**24**	**22**	**24**	**22**
Total energy demand GWh	**724**	**552**	**799**	**612**
TPP	**410**	**280**	**443**	**309**
	56.6%	*50.7%*	*55.4%*	*50.5%*
HPP+PHPP	**28**	**33**	**28**	**33**
	3.9%	*6.0%*	*3.5%*	*5.4%*
NPP	**276**	**230**	**312**	**255**
	38.1%	*41.7%*	*39.0%*	*41.7%*
RES (WPP+SHPP)	**10**	**9**	**16**	**15**
	1.38%	*1.63%*	*2.00%*	*2.45%*

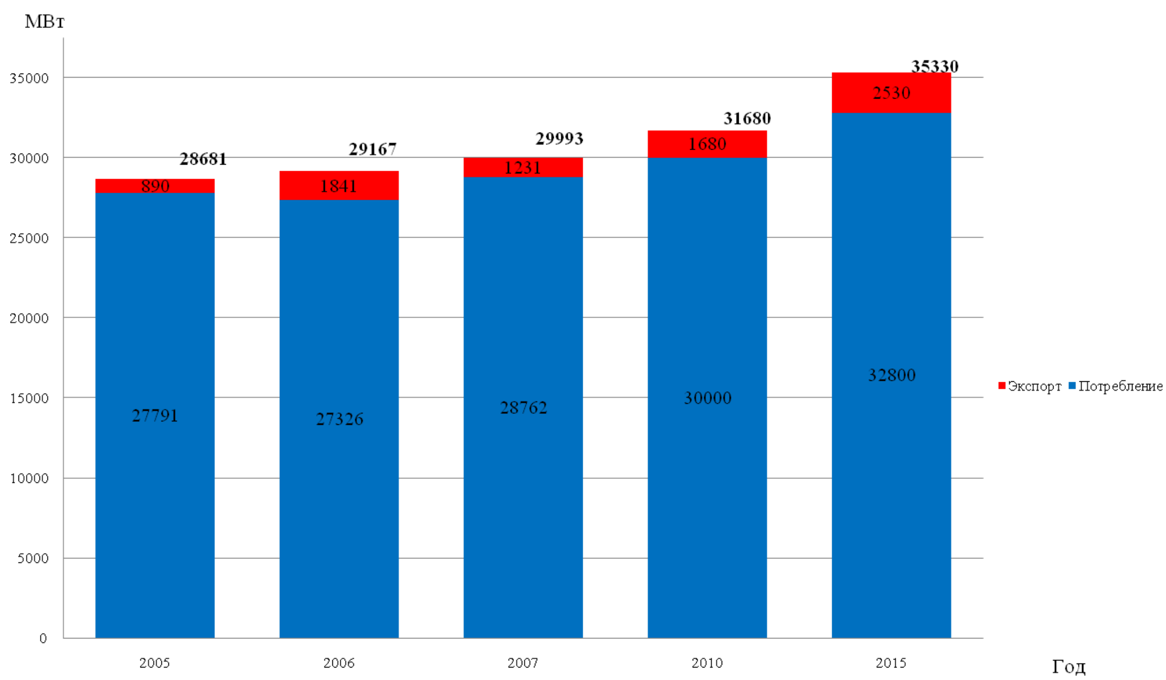


Figure 3.59 – Ukraine – Demand forecast

Tariff

This chapter outlines the tariff system and prices in Ukraine. Table 3.50 shows the wholesale customer prices, and Table 3.51 shows the prices of electricity paid to producers. Table 3.52 presents the tariffs for

RES, which are also used for the construction of the OPF model. All these have been used for generation curves and tables construction.

Table 3.50 – Ukraine – wholesale prices (before taxes)

	kategory	tariffs (without tax)		
		UAHkp/KWh	EURc/KWh	USDc/KWh
	average	42.87	3.74	5.41
I	regulated	41.27	3.60	5.21
II	non-regulated	53.61	4.67	6.77

Table 3.51 – Ukraine – tariffs for Power producers (before taxes)

	kategory	tariffs (without tax)		
		UAHkp/KWh	EURc/KWh	USDc/KWh
I	Nuclear	18.51	1.61	2.34
II	Thermal (coal)	69.00	6.02	8.71
III	Thermal CHP (gas)	83.00	7.24	10.48
IV	Hydro	10.29	0.90	1.30

Table 3.52 – Ukraine – tariffs for RES (before taxes)

	kategory	tariffs (without tax)		
		UAHkp/KWh	EURc/KWh	USDc/KWh
I	Small hydro	88.08	7.68	11.12
II	Wind >2000kW	128.47	11.20	16.22
	Wind >600kW	85.64	7.47	10.81
	Wind <600kW	73.41	6.40	9.27
III	Solar PV >100kW	506.46	44.16	63.95
	Solar PV <100kW	484.44	42.24	61.17
	Solar PV large	528.48	46.07	66.73
IV	Biomass (incl. LFG)	140.70	12.27	17.77

1.12.5 Export Potential for 2015 and 2020

As mentioned in Chapter 3.8.3, Ukraine has a large potential for electricity exports, reaching 2.5TWh a year. Coupled with relatively lower prices that other regions, this plan is feasible.

1.13 Equivalent Countries

Parts of the model have been estimated based on the level of load flow. Realistic parts of the model include power plants modeled in detail. Portions of the model with less detail have been estimated based on a general power plant model.

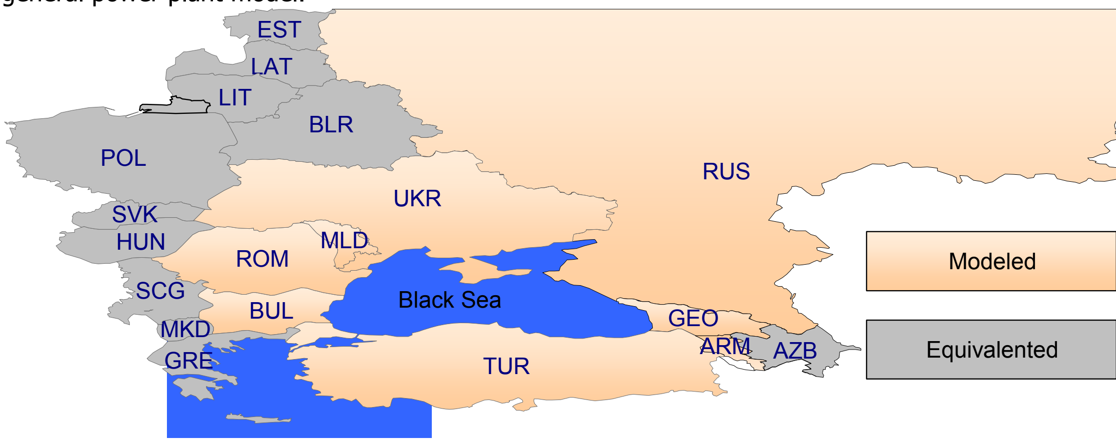


Figure 3.60- Modeled and equivaleted parts of the system

1.14 Black Sea Region

Black Sea regional model has following characteristics:

▪ BSR plants:	1008units	209.3GW
▪ BSR Wind plants:	32units	99.5GW
▪ BSR equivalented plants:	40units	7.1GW
Total:	**1080units**	**315.9GW**
▪ Outside plants:	40units	18.9GW
▪ Outside equivalented plants:	81units	18.7GW
Total:	**103units**	**37.7GW**
MODEL:	**1183units**	**353.6GW**

Table 3.61 – Black Sea –Dynamic model summary

GENS:	GENROU	GENSAL	CGEN1	CIMTR3
	671	443	6	40
STABS:	STAB1	IEEEST	IEE2ST	PSS2A
	18	290	11	61
	PSS2B	PSS3B		
	6	13		
EXSYS:	IEEET1	SEXS	EXST1	ESAC1A
	27	67	87	30
	ESAC4A	ESDC1A	ESST1A	ESST2A
	174	36	298	37
	ESST3A	ESAC6A	ESST4B	BUDCZT
	1	8	80	14
	URST5T	CELIN	ST6B	ST5B
	136	27	8	54
GOVS:	TGOV1	GAST	HYGOV	IEESGO
	301	55	149	30
	IEEEG1	IEEEG3	GASTWD	WSIEG1
	87	195	12	212
	WSHYGP	URCSCT	GGOV1	
	86	3	15	
TLCS:	LCFB1			
	20			
LOADS:	IEELAR	IEELOW		
	1	17		

IV. OPF MODELING (BY COUNTRY)

1.15 Armenia

According to the data provided and generic cost curves described in Chapter 2.1.3 OPF model of Armenia is constructed and below are the characteristics.

1.15.1 PSS/E OPF Transmission System Modeling

The transmission network is presented with buses and connection links-network elements (lines, cables, transformers, etc…) and its OPF model consists of data describing network limitations, according to the respective country grid codes and rules of engagement (voltage limits, line and transformer load ratings). The transmission system model of Armenia is given in Figure 4.1

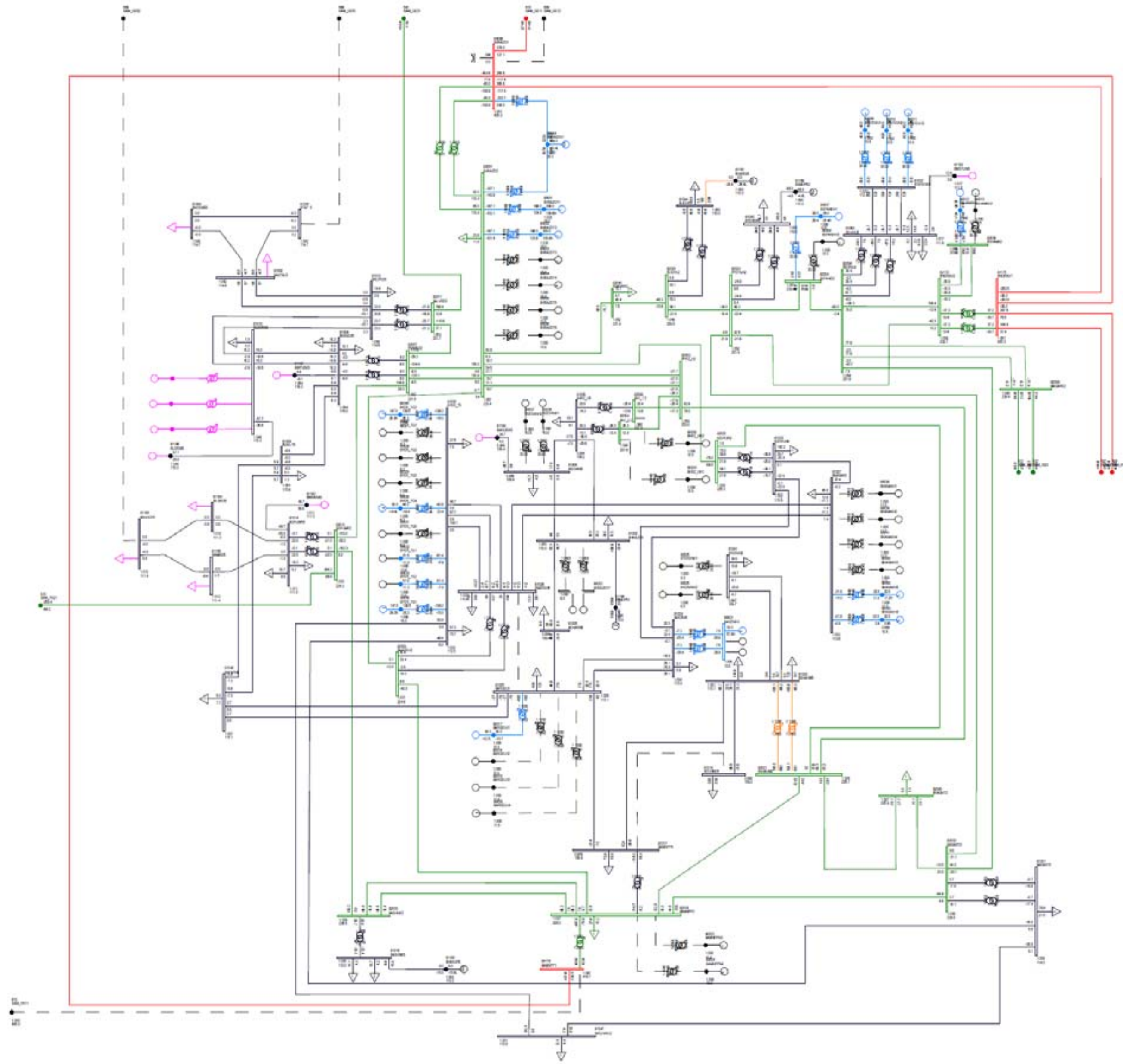


Figure 4.1 Armenia – transmission network model 2020

1.15.2 PSS/E OPF Generation Modeling

The generation OPF model consists of tables and cost curves. Table 4.1 shows the main characteristics of the Armenian generation OPF model.

Table 4.1 – Armenia – Generation units OPF model

Power plant	Plant type	Fuel	Turbine	heat rate (mBTU/MWh)	Bus Num	Bus Name	Id	Mbase (MVA)	Pmax (MW)	Pmin (MW)	cost ($/MWh)	curve
Hrazdan	TPP	Gas	Steam	10.8	80001	8HRAZDT1	1	258.8	220.0	130.0	74.47	806
	TPP	Gas	Steam	10.8	80002	8HRAZDT2	2	235.0	200.0	130.0	74.47	806
	TPP	Gas	Steam	10.8	80003	8HRAZDT3	3	235.0	200.0	130.0	74.47	806
	TPP	Gas	Steam	10.8	80004	8HRAZDT4	4	247.0	210.0	90.0	74.47	806
	CHP	Gas	Steam		80005	8HRAZDT5	7	75.0	60.0	12.0	74.47	803
	CHP	Gas	Steam		80006	8HRAZDT6	8	75.0	60.0	12.0	74.47	803
	CHP	Gas	Steam		80022	8HRAZDT7	5	117.5	100.0	35.0	74.47	803
	CHP	Gas	Steam	10.8	80044	8HRAZDS1	1	376.0	320.0	88.0	70.97	815
	CHP	Gas	GT	7.4	80049	8HRAZDG1	1	195.0	165.0	88.0	70.97	816
Tatev	HPP	Hydro	Pelton		80009	8TATEVH1	1	65.5	52.4	20.0	4.87	801
	HPP	Hydro	Pelton		80010	8TATEVH2	2	65.5	52.4	20.0	4.87	801
	HPP	Hydro	Pelton		80011	8TATEVH3	3	65.5	52.4	20.0	4.87	801
Shamb	HPP	Hydro	Francis		80012	8SHAMBH1	1	107.0	85.5	20.0	4.87	802
	HPP	Hydro	Francis		80013	8SHAMBH2	2	107.0	85.5	20.0	4.87	802
Spandaryan	HPP	Hydro	Francis		80007	8SPANDH1	1	47.5	38.0	10.0	4.87	803
	HPP	Hydro	Francis		80008	8SPANDH2	2	47.5	38.0	10.0	4.87	803
Sevan	HPP	Hydro	Francis		80036	8SEVANH1	1	21.3	17.0	5.0	4.87	802
	HPP	Hydro	Francis		80037	8SEVANH2	2	21.3	17.0	5.0	4.87	802
Hrazdan	HPP	Hydro	Francis		80034	8HRZ_HH1	1	51.0	40.8	10.0	4.87	802
	HPP	Hydro	Francis		80035	8HRZ_HH2	2	51.0	40.8	10.0	4.87	802
Argel	HPP	Hydro	Francis		80017	8ARGELH1	1	66.0	56.0	20.0	4.87	802
	HPP	Hydro	Francis		80018	8ARGELH2	2	66.0	56.0	20.0	4.87	802
	HPP	Hydro	Francis		80019	8ARGELH3	3	66.0	56.0	20.0	4.87	802
	HPP	Hydro	Francis		80020	8ARGELH4	4	66.0	56.0	20.0	4.87	802
Arzni	HPP	Hydro	Francis		80021	8ARZNIH1	1	29.4	23.5	5.0	4.87	802
	HPP	Hydro	Francis		80021	8ARZNIH1	2	29.4	23.5	5.0	4.87	802
	HPP	Hydro	Francis		80021	8ARZNIH1	3	29.4	23.5	5.0	4.87	802
Kanaker	HPP	Hydro	Francis		80038	8KANAKH1	1	16.5	12.5	5.0	4.87	802
	HPP	Hydro	Francis		80039	8KANAKH2	2	16.5	12.5	5.0	4.87	802
	HPP	Hydro	Francis		80040	8KANAKH3	3	16.5	12.5	5.0	4.87	802
	HPP	Hydro	Francis		80041	8KANAKH4	4	16.5	12.5	5.0	4.87	802
	HPP	Hydro	Francis		80042	8KANAKH5	5	33.0	26.0	5.0	4.87	802
	HPP	Hydro	Francis		80043	8KANAKH6	6	33.0	26.0	5.0	4.87	802
Yerevan	HPP	Hydro	Francis		80025	8YERVNH1	1	27.5	22.0	5.0	4.87	802
	HPP	Hydro	Francis		80026	8YERVNH2	2	27.5	22.0	5.0	4.87	802
Dzora	HPP	Hydro	Francis		81039	8DZORA5	EQ	28.2	23.8	0.0	4.87	802
Meghri	HPP	Hydro	Kaplan		80081	8MEGRIH1	1	82.5	70.0	20.0	4.87	804
	HPP	Hydro	Kaplan		80082	8MEGRIH2	2	82.5	70.0	20.0	4.87	804
Medzamor	NPP	Uranium	Steam	10.4	80047	8AMNPPG1	1	259.0	204.0	180.0	18.79	805
	NPP	Uranium	Steam	10.4	80048	8AMNPPG2	2	259.0	204.0	180.0	18.79	805
	NPP	Uranium	Steam	10.4	80023	8AMNPPG3	3	259.0	204.0	185.0	18.79	805
	NPP	Uranium	Steam	10.4	80024	8AMNPPG4	4	259.0	204.0	185.0	18.79	805
Medzamor	NPP	Uranium	Steam	10.4	80047	8AMNPPG1	1	1111.0	1000.0	600.0	65.09	805
Yerevan	CHP	Gas	CCGT	7.4	80045	8YER_TG1	1	258.0	218.5	72.0	70.97	802
	CHP	Gas	CCGT	7.4	80046	8YER_TG2	2	258.0	218.5	72.0	70.97	802
Small hydro	SHPP	Hydro			80110	8AMNPPSH	Y	30.0	24.0	0.0	5.07	820
	SHPP	Hydro			80111	8DALARSH	Y	23.5	20.0	0.0	5.07	820
	SHPP	Hydro			80112	8SHINUSH	Y	61.6	52.4	0.0	5.07	820
	SHPP	Hydro			80113	8HRAZDSH	Y	23.5	20.0	0.0	5.07	820
	SHPP	Hydro			80114	8LICHKSH	Y	37.5	30.0	0.0	5.07	820
	SHPP	Hydro			80207	8ARARTSH	Y	5.0	4.0	0.0	5.07	820
	SHPP	Hydro			80307	8EXEGNSH	Y	61.6	52.4	0.0	5.07	820
	SHPP	Hydro			80402	8VANDZSH	Y	71.2	57.0	0.0	5.07	820
	SHPP	Hydro			80502	8ABOVYSH	Y	15.0	12.0	0.0	5.07	820
	SHPP	Hydro			80602	8GYUMRSH	Y	23.5	20.0	0.0	5.07	820
Wind power	WPP	Wind			80117	8GYUMRW	W	20.0	20.0	0.0	8.88	819
	WPP	Wind			80118	8HRAZDW	W	10.0	10.0	0.0	8.88	819
	WPP	Wind			80209	8LICHKW	W	20.0	20.0	0.0	8.88	819

Hydro Power Plants

Hydro power plants in Armenia are an important source of energy. In Chapter 3.1.3, two main cascades can are described. The Vorotan cascade has three power plants. The HPP Tatev has pelton turbines (High head, long penstock) and its cost curve is presented in Figure 4.2 This curve is presented in Chapter 2.1.3 and adjusted according to the tariff policy explained in chapter 3.1.4. The same approach was used for the other two power plants, HPPs Shamb and Spandaryan, with difference in the turbine type (Francis).

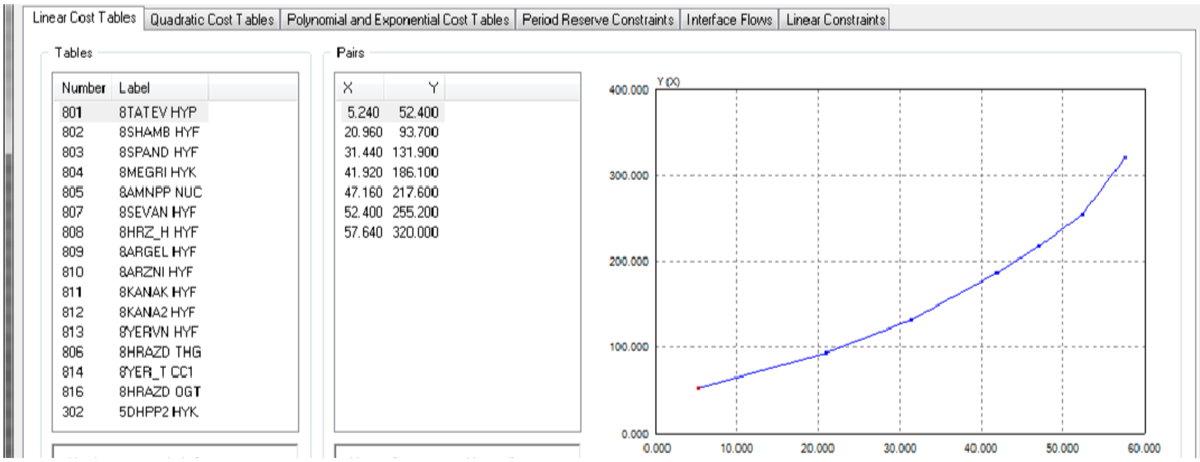


Figure 4.2 – Armenia – Cost curve and table for HPP Tatev (curve 801)

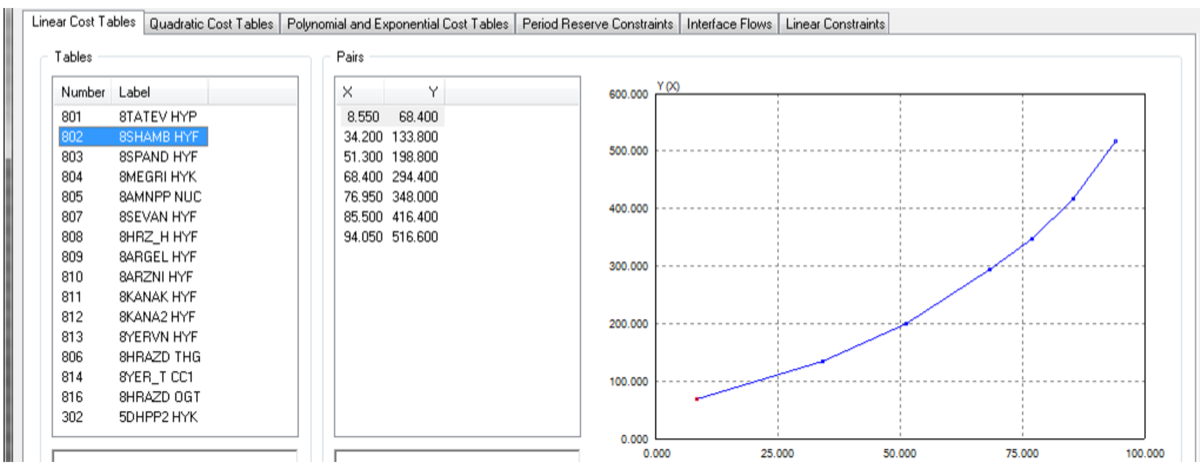


Figure 4.3 – Armenia – Cost curve and table for HPP Shamb (curve 802)

All units on the Sevan-Hrazdan cascade are equipped with Francis turbines and have the same tariffs, that are higher than for the Vorotan cascade, so the cost curves are adjusted based on the costs (Figure).

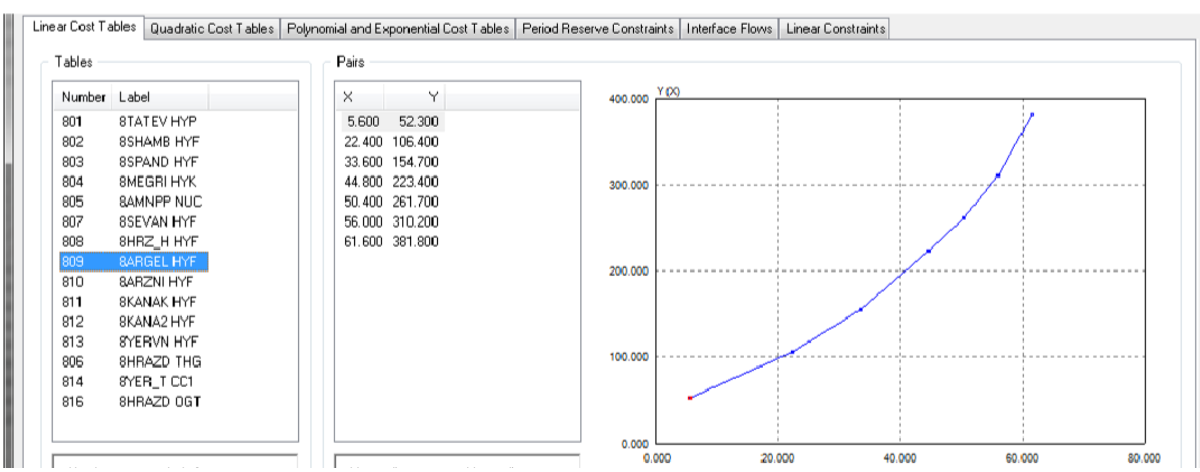


Figure 4.4– Armenia – Cost curve and table for HPPs on Sevan-Hrazdan cascade (curve 809)

Figure 4.5 shows the cost curve of the newly built HPP Meghri on Aras river.

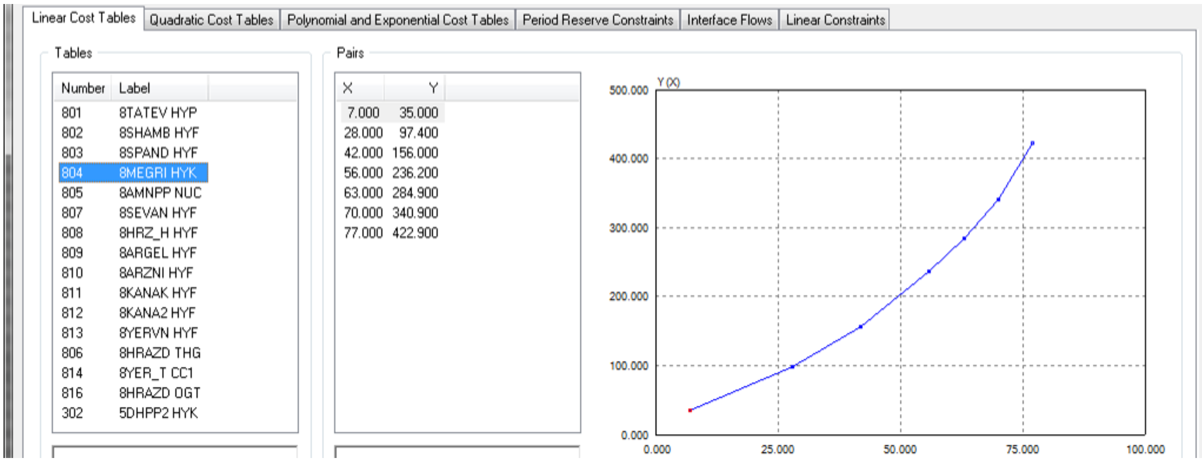


Figure 4.5– Armenia – Cost curve and table for HPP Meghri (curve 804)

Thermal Power Plants

All thermal power plants in Armenia are run on imported natural gas, and price for this gas is \$210/tcm, or \$5.34/mBTU, which is lower than prices on some market hubs (Figure 2.12). This price is implemented in generic curves. The tariffs of these power plants are known and included, generating the curves presented in Figure 4.6 and Figure 4.7

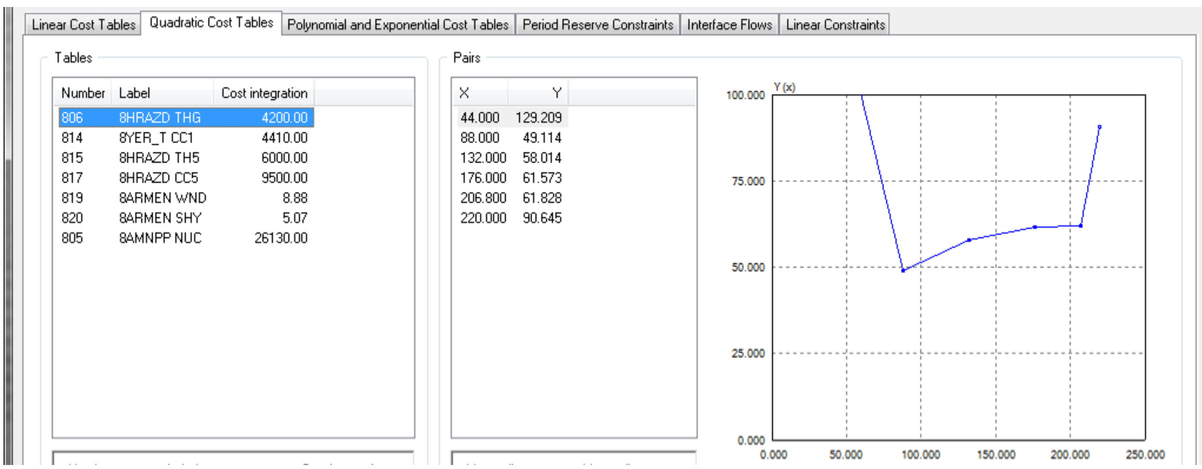


Figure 4.6 – Armenia – Cost curve and table for TPP Hrazdan units 1-4 (curve 806)

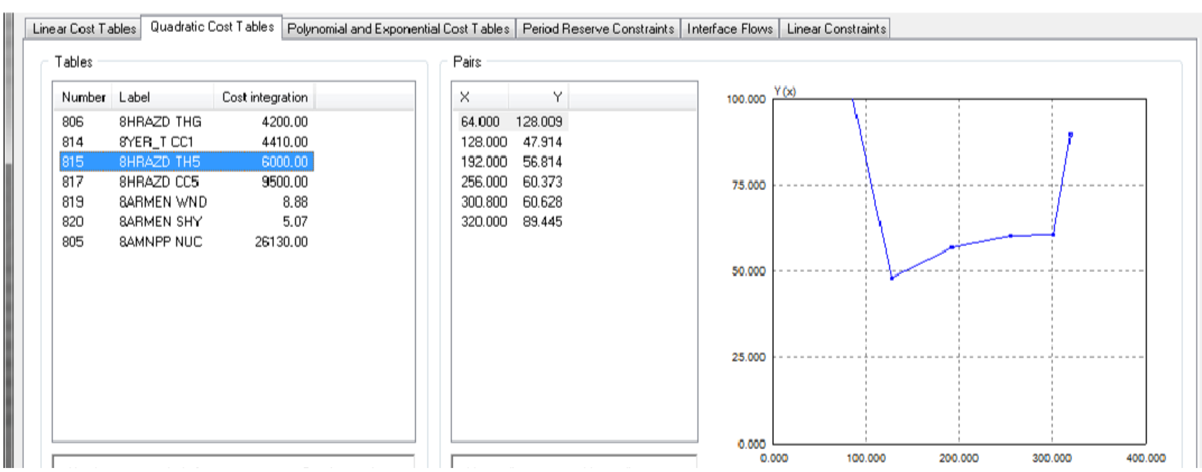


Figure 4.7 – Armenia – Cost curve and table for TPP Hrazdan unit 5 in independent mode (curve 815)

The TPP Hrazdan unit 5 has a standard steam unit run on natural gas. Part of the steam comes from the new GT unit in the power plant allowing it to operate as an independent unit or in a combined cycle mode.

As a result, two curves are presented, one for an independent mode (Figure 4.7) and one when both units are operational (equivalented as one and curve on (Figure 4.8).

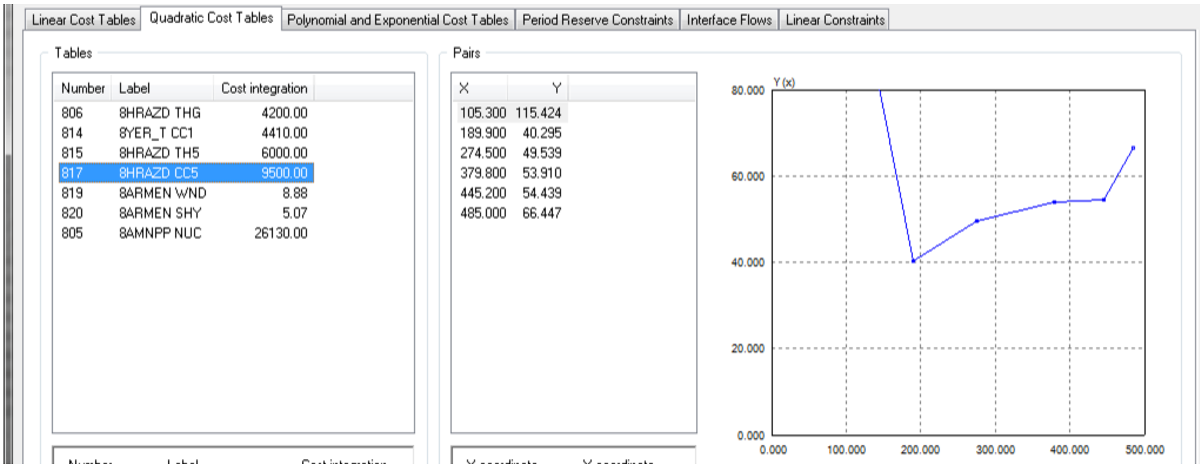


Figure 4.8 Armenia – Cost curve and table for TPP Hrazdan unit 5 in combined cycle mode (curve 817)

Gas Turbine Power Plants

Armenia has one gas turbine unit installed and its cost curve, when operated independently from unit 5, is shown on Figure 4.9 Price of engagement is based on the price of imported gas and basic characteristics of similar units.

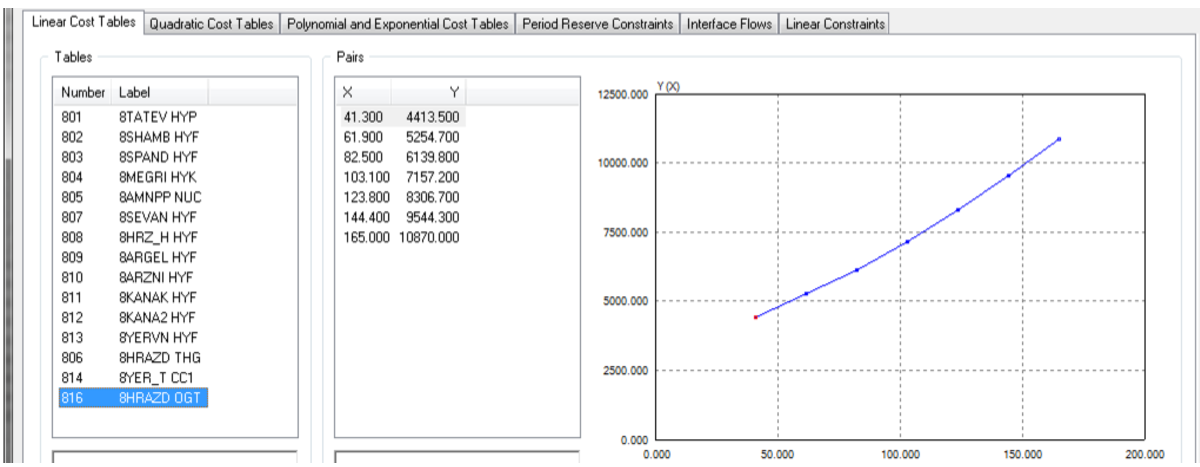


Figure 4.9 – Armenia – Cost curve and table for new OGT Hrazdan unit in independent mode (curve 816)

There are plans to replace the existing CHP Yerevan units with more modern CCGT units, like in the regional model. Figure 4.10 shows the cost curves for these type of units, adjusted according to the price of imported gas for Armenia, and taking investment and capital costs into consideration.

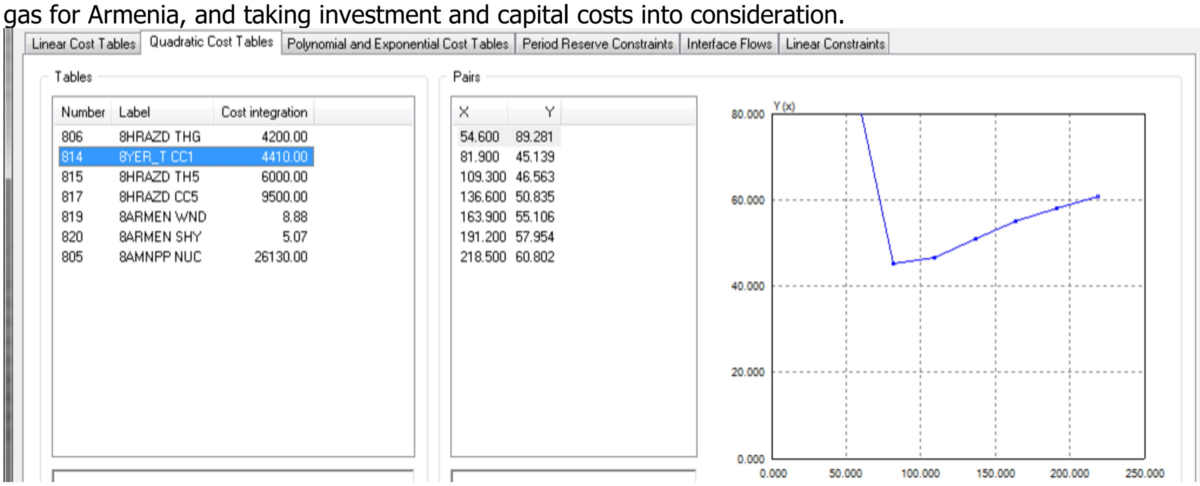


Figure 4.10 – Armenia – Cost curve and table for new CCGT Yerevan units 1-2 (curve 814)

Nuclear Power Plants

The Armenian system consists of one nuclear power plant, NPP Metsamor, with two out of four 204MW operational units. Figure 4.11 represents the cost curves for these units, adjusted according to real tariffs.

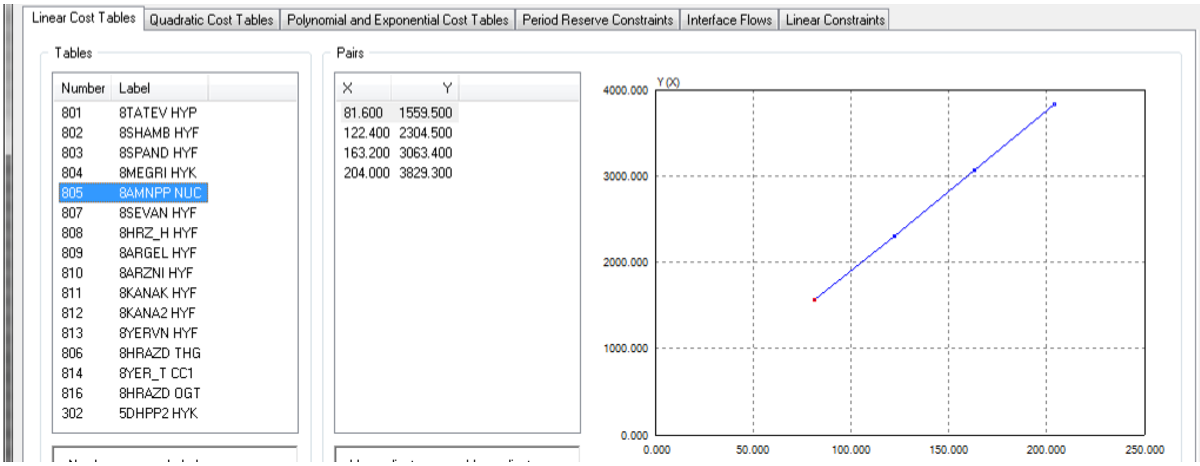


Figure 4.11 – Armenia – Cost curve and table for NPP Metsamor 200MW units (curve 805)

There are plans to replace the old Metsamor units with a 1000MW one. A typical cost curve for this unit is presented in Figure 4.12, including capital costs as well.

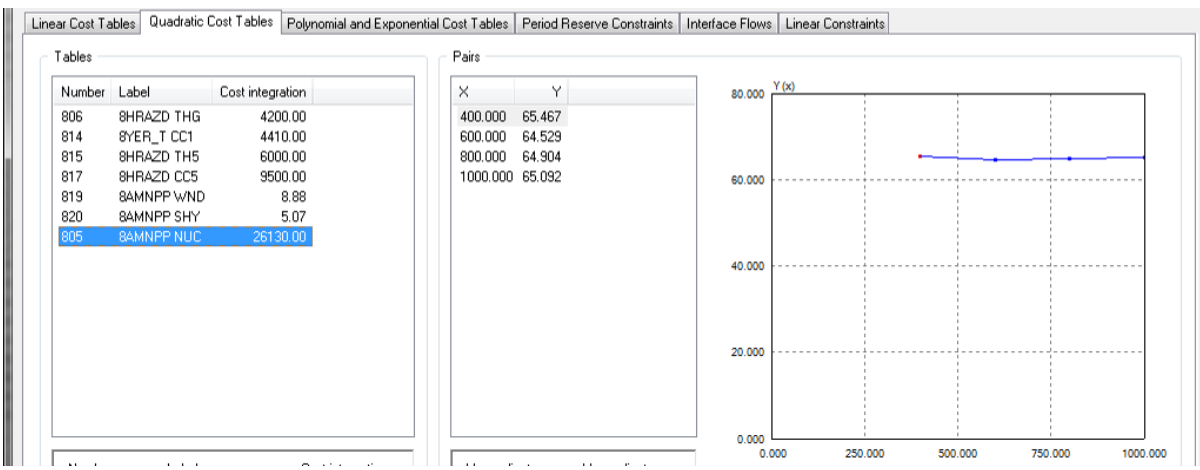


Figure 4.12 – Armenia – Cost curve and table for new NPP Metsamor 1000MW unit (curve 805)

Renewables

Renewable power plants are modeled as shown in Figure 4.13 for WPP and Figure 4.14 for SHPP, adjusted to represent the feed in tariff system in Armenia.

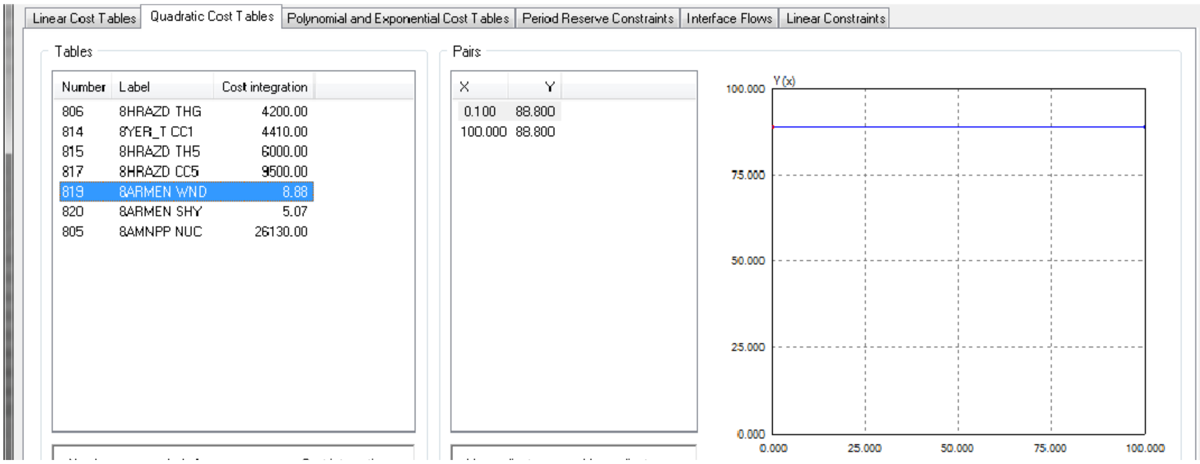


Figure 4.13 – Armenia – Cost curve and table for Wind power plants (curve 819)

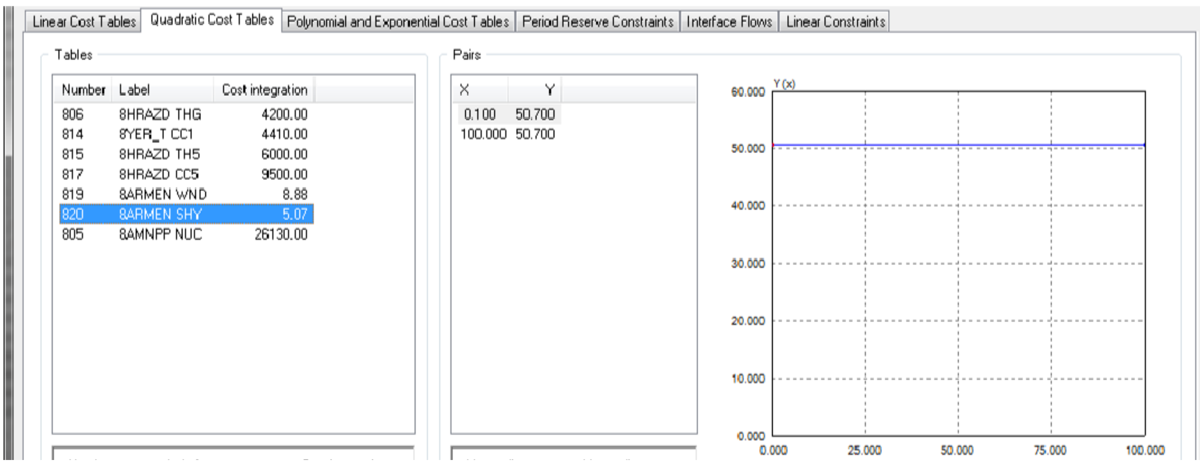


Figure 4.14– Armenia – Cost curve and table for Small Hydro units (curve 820)

The cost curves should be used to calculate production costs, and not for generation engagement optimization, since these units are engaged based on energy availability and not on economics. Therefore, for optimization calculations they should be disabled by setting the dispatch value to zero.

1.16 Bulgaria

According to the data provided and generic cost curves described in Chapter 2.1.3 OPF model of Bulgaria is constructed and below are the characteristics

1.16.1 PSS/E OPF Transmission System Modeling

The transmission network is presented with buses and connection links-network elements (lines, cables, transformers, etc…) and its OPF model consists of data describing network limitations, according to respective country grid codes and rules of engagement (voltage limits, line and transformer load ratings). Transmission system model of Bulgaria is given in Figure 4.15

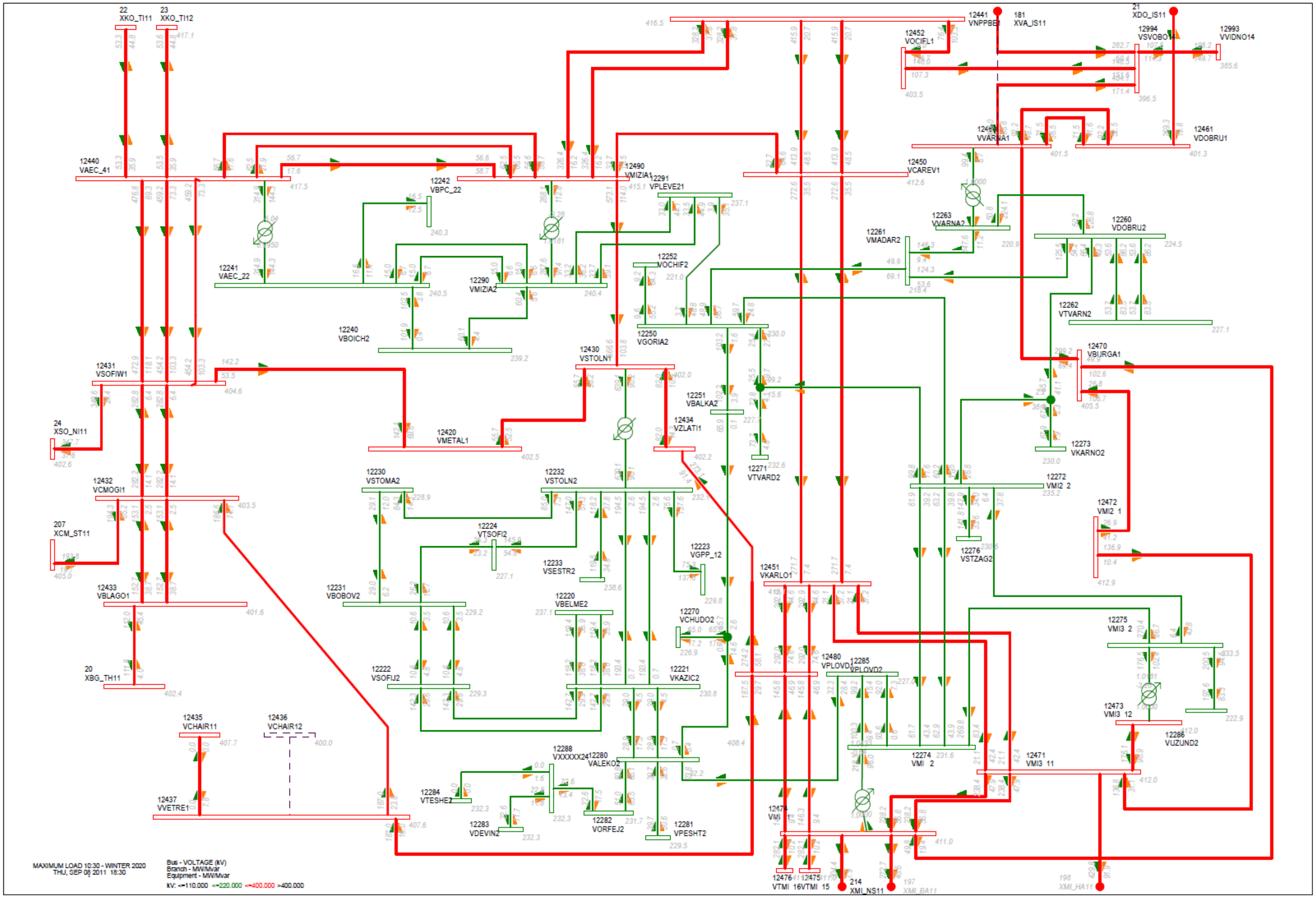


Figure 4.15 Bulgaria – transmission network model

1.16.2 PSS/E OPF Generation Modeling

The generation OPF model consists of tables and cost curves. Table 4.2 shows the main characteristics of the Bulgarian generation OPF model.

Table 4.2 – Bulgaria – Generation units OPF model

Power plant	Plant type	Fuel	Turbine	heat rate (mBTU/MWh)	Bus Num	Bus Name	Id	Mbase (MVA)	Pmax (MW)	Pmin (MW)	cost ($/MWh)	curve
Belene	NPP	Uranium	Steam	10.4	13401	VNBEL_N1	N1	1111.0	1015.8	600.0	39.87	102
	NPP	Uranium	Steam	10.4	13402	VNBEL_N2	N2	1111.0	1015.8	600.0	39.87	102
Kozloduy	NPP	Uranium	Steam	10.4	13404	VNKOZ_N9	N9	1111.0	1015.8	600.0	68.15	101
	NPP	Uranium	Steam	10.4	13405	VNKOZ_N0	N0	1111.0	1015.8	600.0	68.15	101
Chaira	HPP	Hydro	Francis	Maritza	13305	VHCH12H	H1	235.0	214.0	0.0	4.87	105
	HPP	Hydro	Francis	Maritza	13305	VHCH12H	H2	235.0	214.0	0.0	4.87	105
	HPP	Hydro	Francis	Maritza	13310	VHCH34H	H3	235.0	214.0	0.0	4.87	105
	HPP	Hydro	Francis	Maritza	13310	VHCH34H	H4	235.0	214.0	0.0	4.87	105
Belmeken	HPP	Hydro	Francis	Maritza	13200	VBELM_H5	H5	83.0	74.7	0.0	4.87	107
	HPP	Hydro	Pelton	Maritza	13201	VBEL12H	H1	83.0	74.7	0.0	4.87	106
	HPP	Hydro	Pelton	Maritza	13201	VBEL12H	H2	83.0	74.7	0.0	4.87	106
	HPP	Hydro	Pelton	Maritza	13202	VBEL34H	H3	83.0	74.7	0.0	4.87	106
	HPP	Hydro	Pelton	Maritza	13202	VBEL34H	H4	83.0	74.7	0.0	4.87	106
Sestrimo	HPP	Hydro	Pelton	Maritza	13303	VHSES.H1	H1	145.0	130.6	0.0	4.87	108
	HPP	Hydro	Pelton	Maritza	13304	VHSES.H2	H2	145.0	130.6	0.0	4.87	108
M.Klisura	HPP	Hydro	Francis	Maritza	13308	VHMKL.H1	H1	67.0	60.0	0.0	4.87	109
	HPP	Hydro	Francis	Maritza	13309	VHMKL.H2	H2	67.0	60.0	0.0	4.87	109
Batak	HPP	Hydro	Pelton	Batak	13805	VHB123H	H	50.0	40.0	0.0	4.87	110
Peshtera	HPP	Hydro	Pelton	Batak	13800	VHPE12H	H	180.0	300.0	0.0	4.87	111
Aleko	HPP	Hydro	Francis	Batak	13813	VHALEKH3	H	93.0	64.8	0.0	4.87	112
Teshel	HPP	Hydro	Francis	Vasha	13811	VHTESHH	H	70.6	60.0	0.0	4.87	113
Devin	HPP	Hydro	Francis	Vasha	13809	VDEVINH1	H	98.0	80.0	0.0	4.87	114
Orphey	HPP	Hydro	Francis	Vasha	13803	VHO123H	H	150.0	120.0	0.0	4.87	115
Kricim	HPP	Hydro	Francis	Vasha	13807	VHKRI.H1	H	96.0	81.6	0.0	4.87	116
Kardzali	HPP	Hydro	Francis	Arda	13819	VHKA12H	H	125.0	106.4	0.0	24.98	117
Studen Klanec	HPP	Hydro	Francis	Arda	13821	VHSK12H	H	84.0	60.0	0.0	24.98	118
Ivajlovgrad	HPP	Hydro	Francis	Arda	13823	VHIW.GH	H	127.1	108.0	0.0	24.98	119
Varna	TPP	Coal	Steam	10.8	13600	VTVARNT1	T1	247.0	210.0	140.0	66.14	120
	TPP	Coal	Steam	10.8	13601	VTVARNT2	T2	247.0	210.0	140.0	66.14	120
	TPP	Coal	Steam	10.8	13602	VTVARNT3	T3	247.0	210.0	140.0	66.14	120
	TPP	Coal	Steam	10.8	13603	VTVARNT4	T4	247.0	210.0	140.0	66.14	120
	TPP	Coal	Steam	10.8	13604	VTVARNT5	T5	247.0	210.0	140.0	66.14	120
	TPP	Coal	Steam	10.8	13605	VTVARNT6	T6	247.0	210.0	140.0	66.14	120
Maritza East 2	TPP	Coal	Steam	10.8	13703	VTMI2_T1	T1	176.5	157.3	100.0	58.86	123
	TPP	Coal	Steam	10.8	13704	VTMI2_T2	T2	176.5	157.3	100.0	58.86	123
	TPP	Coal	Steam	10.8	13705	VTMI2_T3	T3	176.5	157.3	100.0	58.86	123
	TPP	Coal	Steam	10.8	13706	VTMI2_T4	T4	176.5	157.3	100.0	58.86	123
	TPP	Coal	Steam	10.8	13707	VTMI2_T5	T5	247.0	210.0	140.0	58.86	124
	TPP	Coal	Steam	10.8	13708	VTMI2_T6	T6	247.0	210.0	140.0	58.86	124
	TPP	Coal	Steam	10.8	13709	VTMI2_T7	T7	253.0	215.0	140.0	58.86	124
	TPP	Coal	Steam	10.8	13710	VTMI2_T8	T8	253.0	215.0	140.0	58.86	124
Maritza East 3	TPP	Coal	Steam	10.8	13711	VTMI3_T1	T1	247.0	215.0	140.0	58.86	121
	TPP	Coal	Steam	10.8	13712	VTMI3_T2	T2	247.0	215.0	140.0	58.86	121
	TPP	Coal	Steam	10.8	13713	VTMI3_T3	T3	247.0	215.0	140.0	58.86	121
	TPP	Coal	Steam	10.8	13714	VTMI3_T4	T4	247.0	215.0	140.0	58.86	121
	TPP	Coal	Steam	10.8	13719	VTMI3_T5	T5	440.0	400.0	200.0	85.26	122
	TPP	Coal	Steam	10.8	13720	VTMI3_T6	T6	440.0	400.0	200.0	85.26	122
Maritza3	TPP	Coal	Steam	10.8	13812	VTMAR3T3	T3	150.0	120.0	70.0	74.47	806
Galabovo	TPP	Coal	Steam	10.8	13906	VTMI1 T5	T5	400.0	340.0	190.0	83.89	125
	TPP	Coal	Steam	10.8	13907	VTMI1 T6	T6	400.0	340.0	190.0	83.89	125
	TPP	Coal	Steam	10.8	13908	VTMI1 T7	T7	400.0	340.0	190.0	83.89	125
Devin	TPP	Coal	Steam	10.8	13606	VTDEV.G3	I1	138.0	110.0	60.0	70.97	126
Ruse	TPP	Coal	Steam	10.8	13501	VTRUSEG3	T3	138.0	110.0	60.0	70.97	126
	TPP	Coal	Steam	10.8	13502	VTRUSEG4	T4	138.0	110.0	0.0	70.97	126
	TPP	Coal	Steam	10.8	13503	VTRUSEG5	T5	78.8	63.0	0.0	70.97	126
	TPP	Coal	Steam	10.8	13504	VTRUSEG6	T6	78.8	63.0	0.0	70.97	126
Republika	TPP	Coal	Steam	10.8	13306	VTREP.G5	D5	68.0	54.4	0.0	70.97	126
Sofia	CHP	Gas	Steam	10.8	13205	VTSF_GG6	D6	75.0	60.0	0.0	70.97	128

Sofia Istok	CHP	Gas	Steam	10.8	13206	VTSF.IG5	D5	82.5	66.0	0.0	70.97	128
	CHP	Gas	Steam	10.8	13208	VTSF.IG3	D3	40.0	30.4	0.0	70.97	128
Industrial	CHP	Gas	Steam	10.8	13210	VTKREMG4	I4	75.0	60.0	0.0	70.97	128
	CHP	Gas	Steam	10.8	13505	VTSV12G	I1	75.0	60.0	0.0	70.97	128
	CHP	Gas	Steam	10.8	13505	VTSV12G	I2	75.0	60.0	0.0	70.97	128
	CHP	Gas	Steam	10.8	13715	VTBR34G	I3	75.0	65.8	0.0	70.97	128
	CHP	Gas	Steam	10.8	13715	VTBR34G	I4	75.0	65.8	0.0	70.97	128
	CHP	Gas	Steam	10.8	13716	VTBR.GG5	I5	75.0	65.8	0.0	70.97	128
	CHP	Gas	Steam	10.8	13717	VTBR.GG6	I6	75.0	65.8	0.0	70.97	128
	CHP	Gas	Steam	10.8	13900	VT_PLEG	I1	75.0	60.0	0.0	70.97	128
Berkovica	WPP	Wind			12639	VBERKO5	W	52.6	50.0	0.0	125.00	103
Borovo	WPP	Wind			12675	VBOROV5	W	73.7	70.0	0.0	125.00	103
Valci dol	WPP	Wind			12714	V_VDOL5	W	573.6	545.0	0.0	125.00	103
Dobrich	WPP	Wind			12716	VDOBRI5	W	52.6	50.0	0.0	125.00	103
Gen.Toshevo	WPP	Wind			12717	VG_TOS5	W	52.6	50.0	0.0	125.00	103
Shabla	WPP	Wind			12718	VSHABL5	W	73.7	70.0	0.0	125.00	103
Kavarna	WPP	Wind			12719	VKAVAR5	W	157.8	150.0	0.0	125.00	103
Baltchik	WPP	Wind			12720	VBALTC5	W	47.3	45.0	0.0	125.00	103
Velitchokovo	WPP	Wind			12749	VVELIC5	W	52.6	50.0	0.0	125.00	103
Binkos	WPP	Wind			12796	VBINKO5	W	63.1	60.0	0.0	125.00	103
Rechica	WPP	Wind			12797	VRECHI5	W	52.6	50.0	0.0	125.00	103
Burgas	WPP	Wind			12834	VBURGA52	W	63.1	60.0	0.0	125.00	103
Trastenik	WPP	Wind			12964	VTRAST51	W	52.6	50.0	0.0	125.00	103
Guljanci	WPP	Wind			12965	VGULJA5	W	42.1	40.0	0.0	125.00	103
Vidno	WPP	Wind			12983	VVIDNO5	W	558.1	530.0	0.0	125.00	103
Svoboda	WPP	Wind			12984	VSVOBO5	W	631.5	600.0	0.0	125.00	103
Majakovo	WPP	Wind			12985	VMAJAK5	W	378.6	360.0	0.0	125.00	103
Jeravica	WPP	Wind			13903	VJERAV5	W	105.2	100.0	0.0	125.00	103
Martinovo	WPP	Wind			13904	VMARTI5	W	42.1	40.0	0.0	125.00	103
Carevec	SPP	Solar			12653	VCAREV5	W	21.0	20.0	0.0	474.30	104

Hydro Power Plants

The first power plant modeled is the pumping station in Chaira. The same diagram shape is used for other pumping stations in the Bulgarian system. Since the power plant is relatively new (operational from 1999) full capital costs were taken into consideration. Unlike other hydro power plants, this one does not have fuel costs since the water is pumped. The costs are estimated at half price of HV level (low tariff since pumping is usually done during the night) multiplied with the conversion factor (usually for pumping of 1MWh consumed it is 0.7MWh produced). The cost curve is given in Figure 4.16 The same approach is taken for other pumping stations, but with adjusted capital costs based on their age.

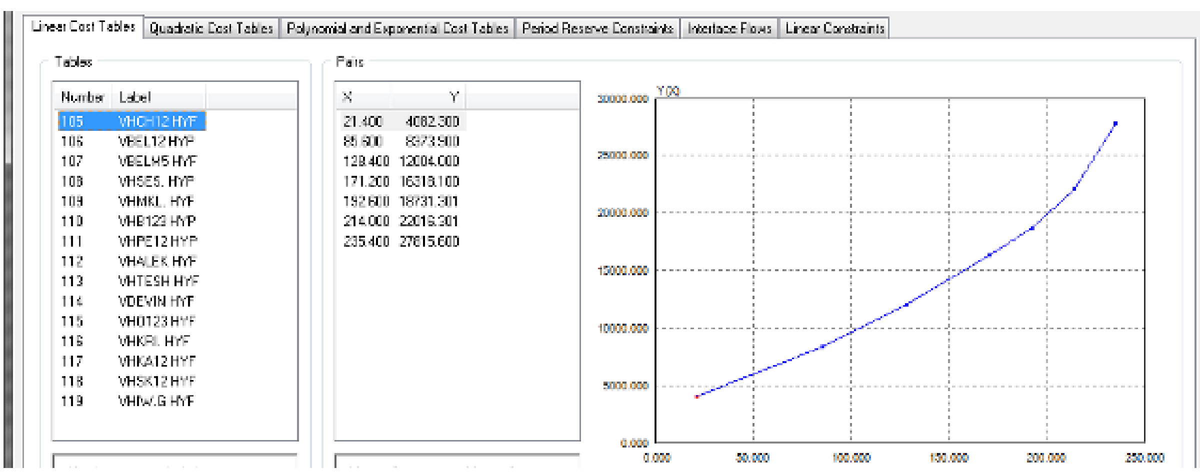


Figure 4.16– Bulgaria – Cost curve and table for PHPP Chaira (curve 105)

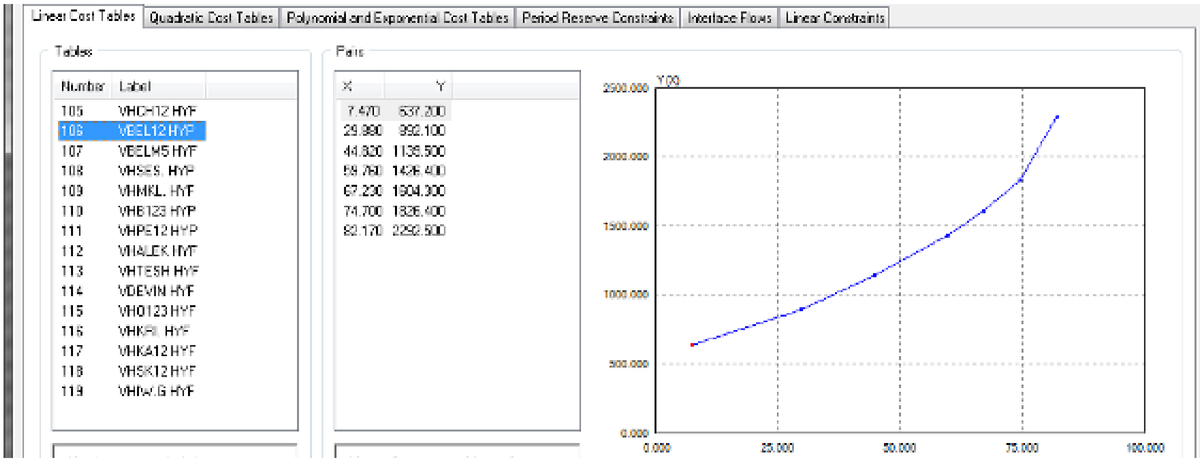


Figure 4.17 – Bulgaria – Cost curve and table for PHPP Belmeken (curve 106)

For standard hydro power plant units, the cost curve is based on the turbine type. For power plants on the same cascade, the same price of output power is used. Eventual capital costs for one power plant are divided equally on all power plants in a cascade, making the output price relatively the same, leaving the turbine type the only difference. There are four cascades in the Bulgaria: Maritza, Batak, Arda and Vasha.

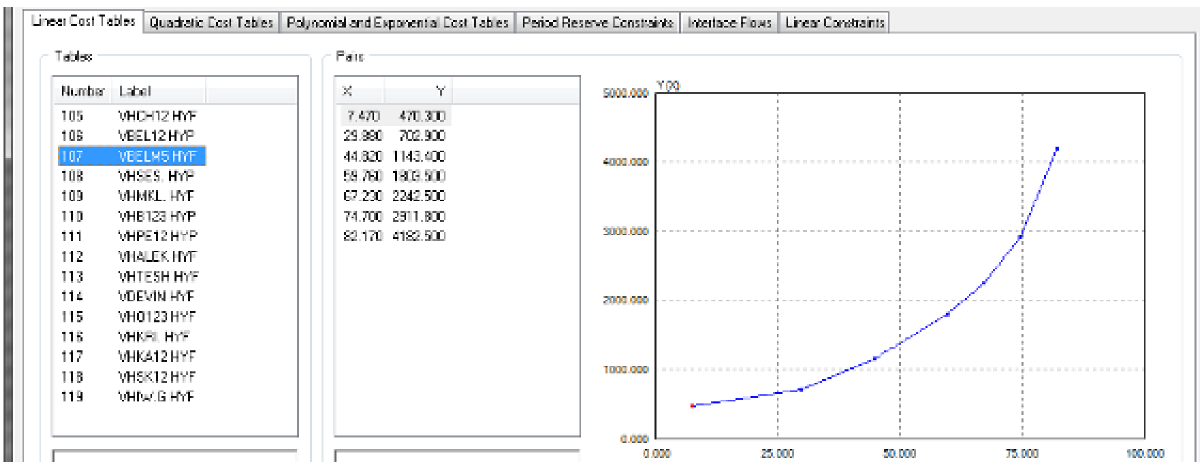


Figure 4.18– Bulgaria – Cost curve and table for HPPs on Maritza cascade Francis (curve 107)

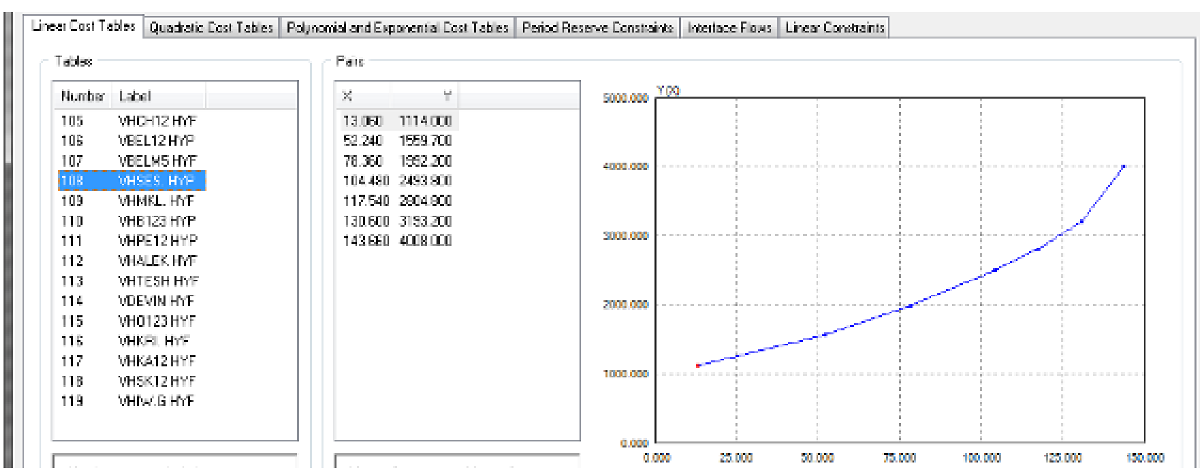


Figure 4.19 – Bulgaria – Cost curve and table for HPPs on Maritza cascade pelton (curve 108)

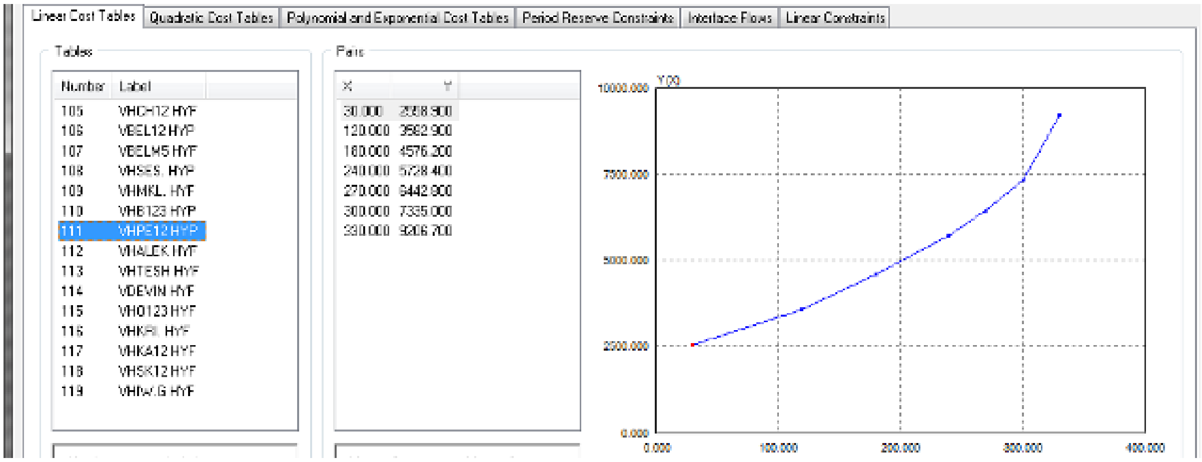


Figure 4.20– Bulgaria – Cost curve and table for HPPs on Batak cascade (curve 111)

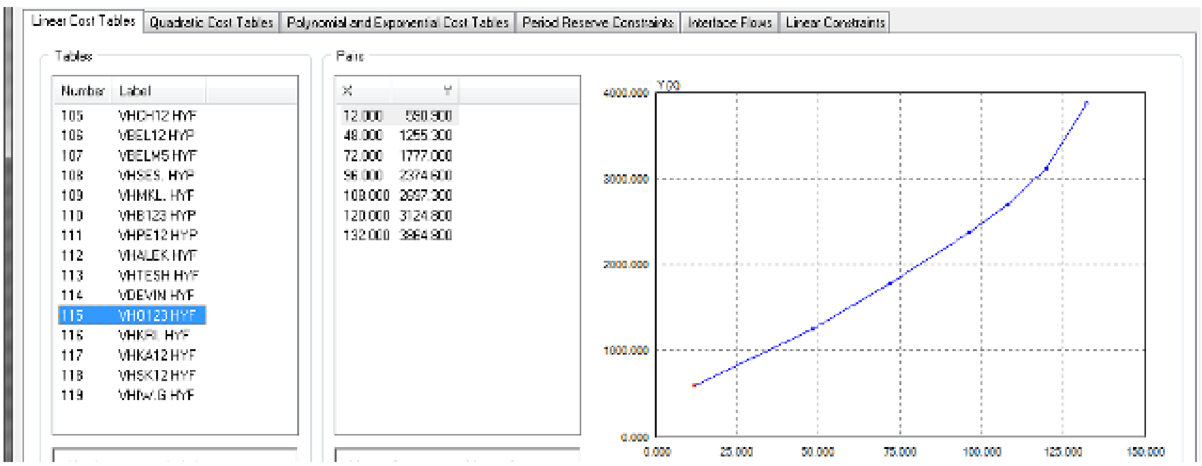


Figure 4.21 – Bulgaria – Cost curve and table for HPPs on Vasha cascade (curve 115)

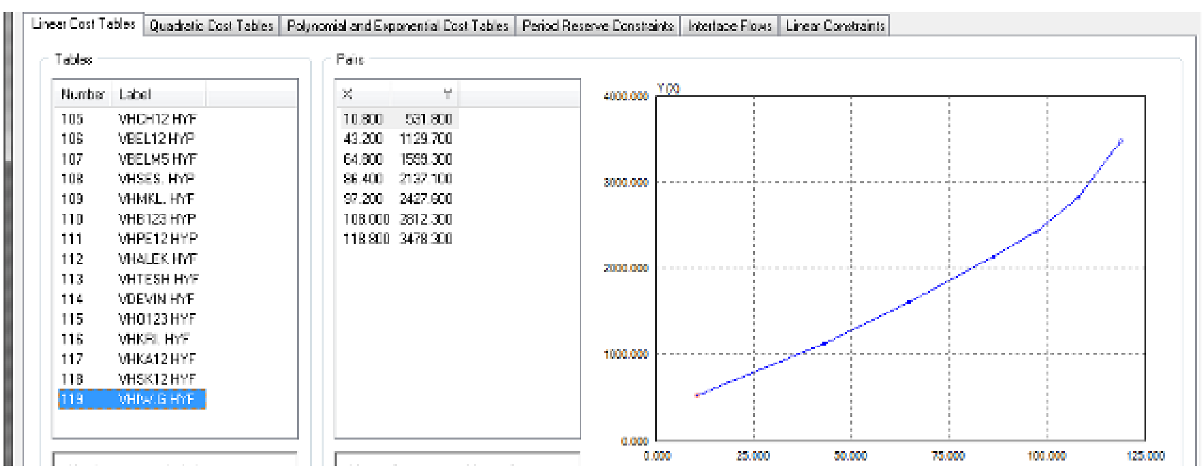


Figure 4.22– Bulgaria – Cost curve and table for HPPs on Arda cascade (curve 119)

Thermal Power Plants

Most of the thermal power plants in Bulgaria are run on domestic open pit coal, but TPP Varna is operated on imported coal from Ukraine. This plant price of coal is equal to that of Ukraine $95/ton or $4.5/mBTU, and for the remaining power plants it is 20% lower at $75/ton or $3.6/mBTU, due to lower transportation costs. The prices are implemented in generic curves presented below.

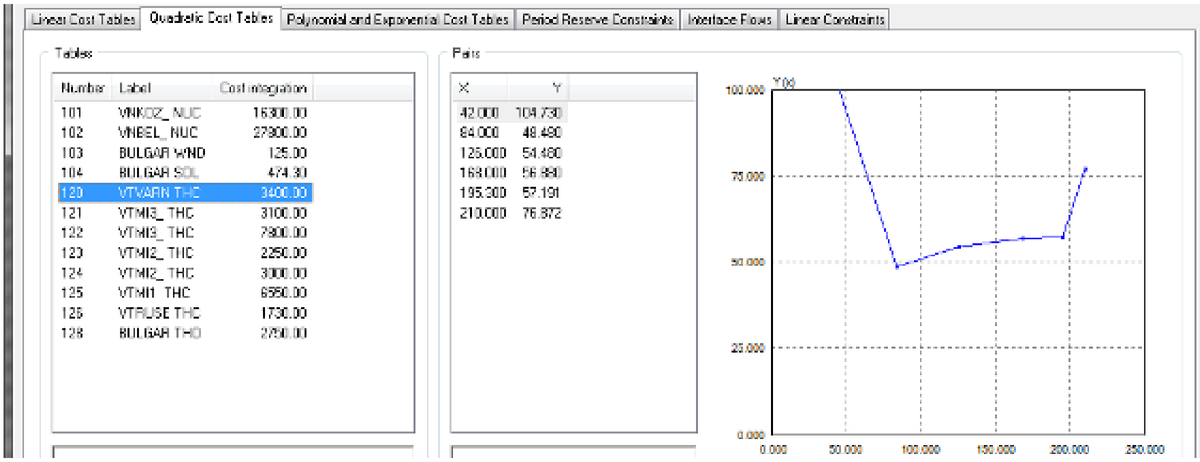


Figure 4.23 – Bulgaria – Cost curve and table for TPP Varna (curve 120)

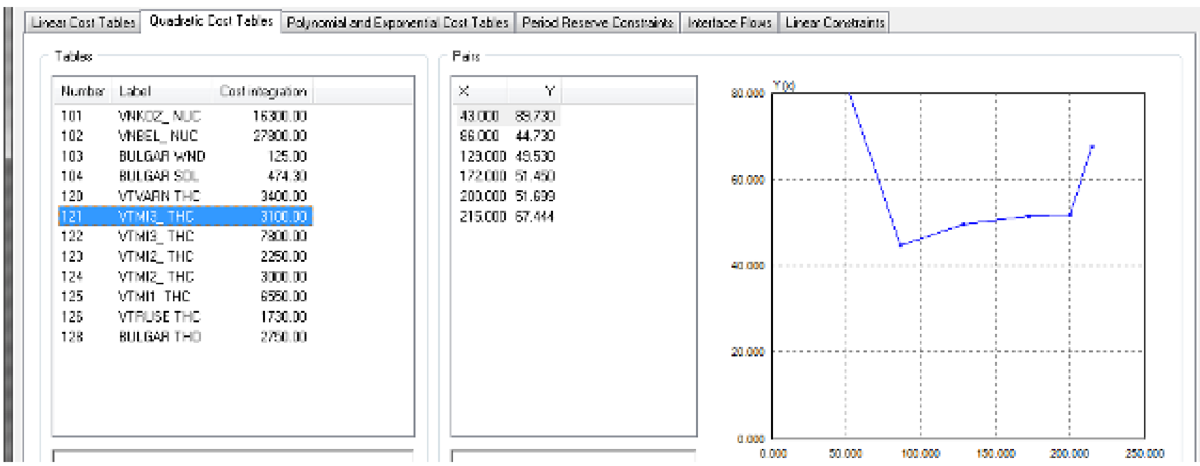


Figure 4.24 – Bulgaria – Cost curve and table for TPP Maritza East 3 (curve 121)

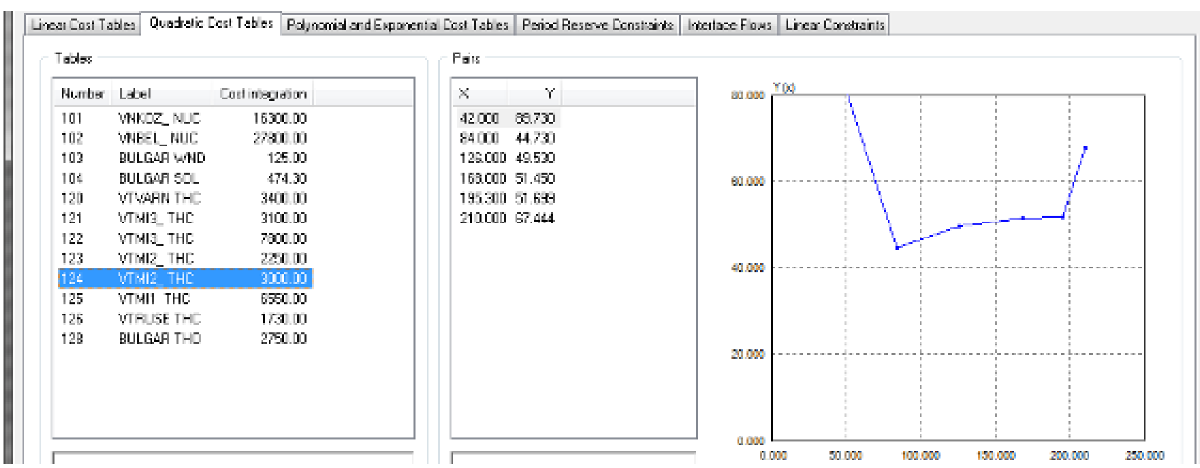


Figure 4.25 – Bulgaria – Cost curve and table for TPP Maritza East 2 (curve 124)

For the newly built blocks and units in the TPP Maritsa East 1-Galabovo, and the TPP Maritza East 3, capital costs were taken into consideration.

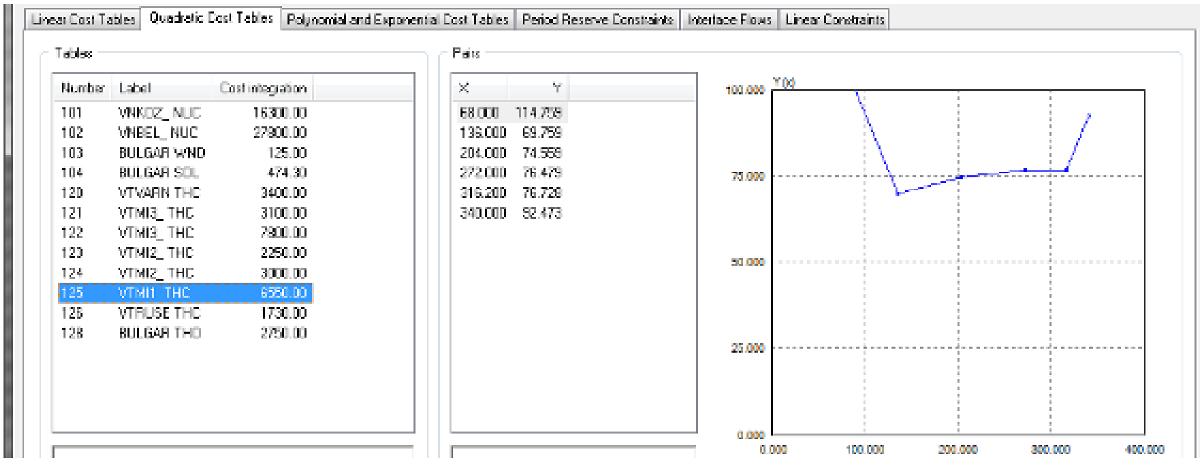


Figure 4.26-Bulgaria – Cost curve and table for TPP Galabovo (curve 806)

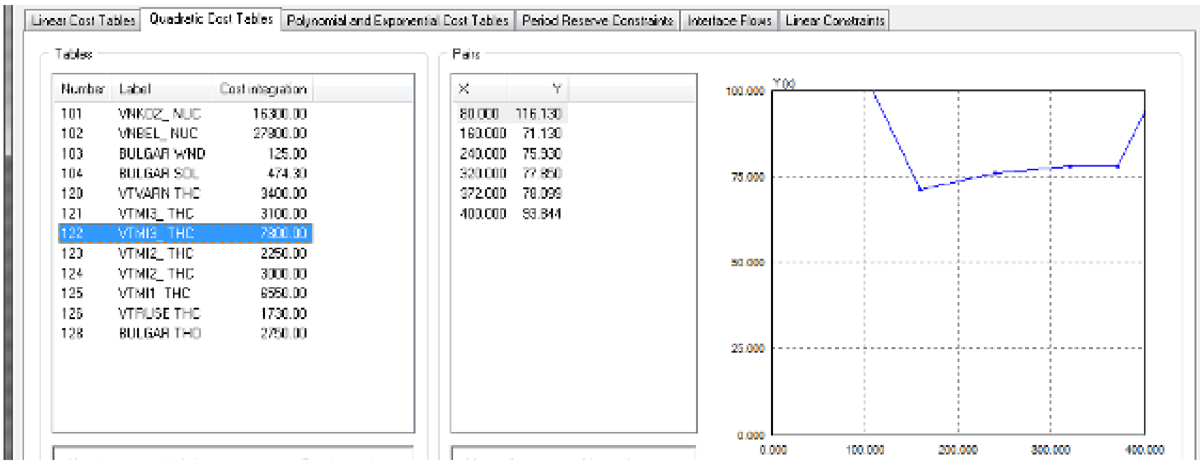


Figure 4.27 – Bulgaria – Cost curve and table for TPP Maritza East 3 400MW units (curve 122)

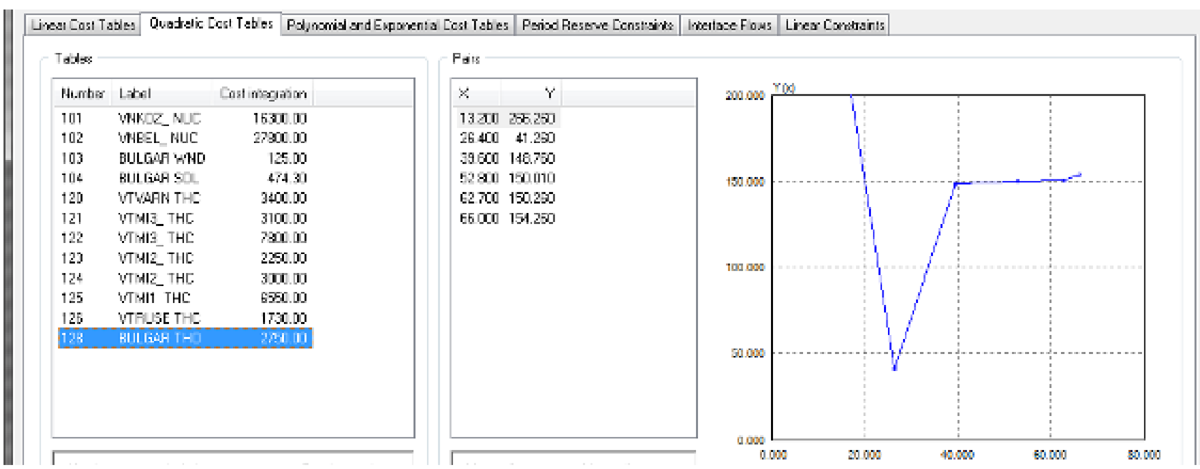


Figure 4.28 – Bulgaria – Cost curve and table for CHP units run on fuel oil and industrial plants (curve 128)

Industrial TPPs and CHP units run on fuel oil or gas are represented with the same cost curve.

Nuclear Power Plants

Currently, Bulgaria has a nuclear power station, NPP Kozloduy, with plans to refurbish it and increase its capacity. This is taken into consideration by implementing 30% of the capital costs for new units. The second power plant is the NPP Belene that has yet to be built. In this case, full capital costs were taken into consideration.

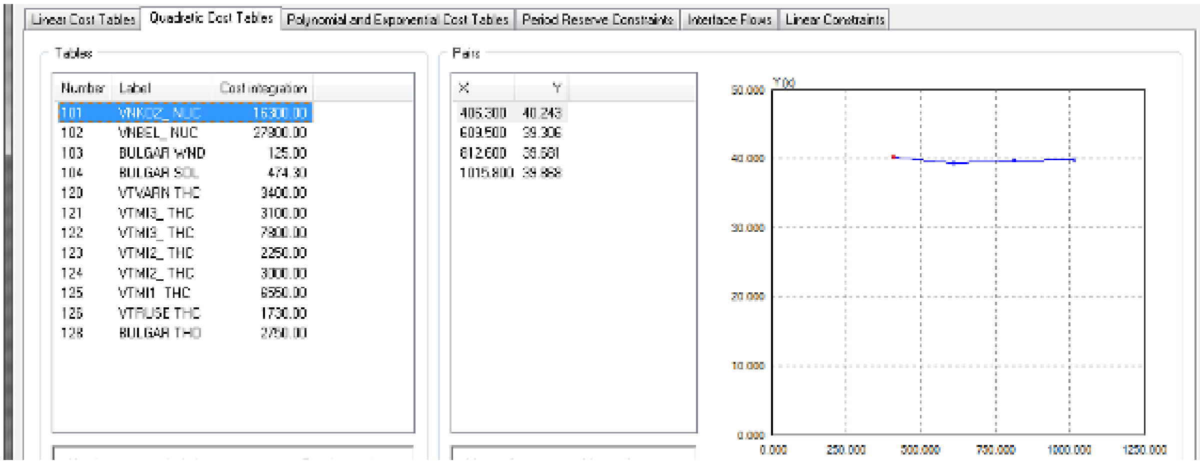


Figure 4.29 – Bulgaria – Cost curve and table for NPP Kozloduy 1000MW units (curve 101)

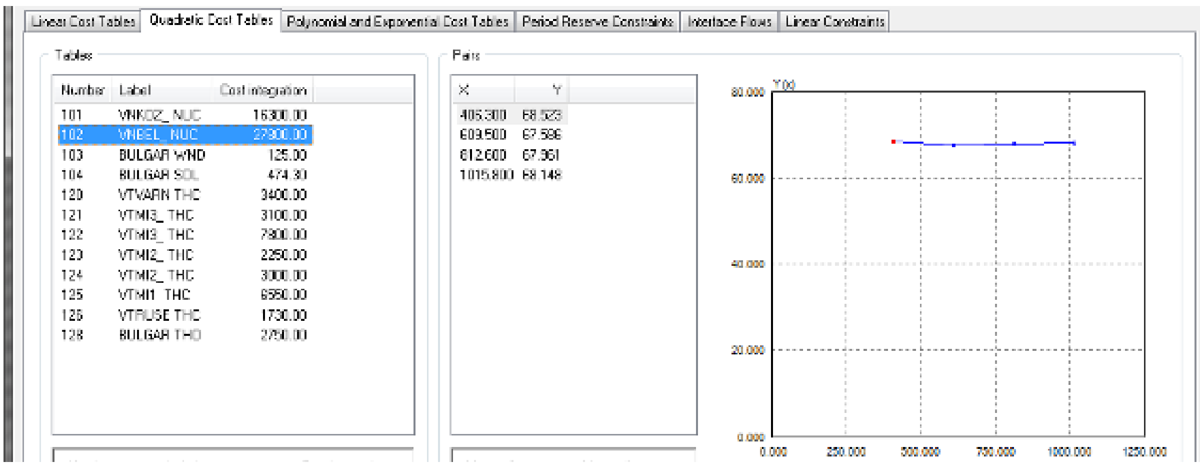


Figure 4.30 – Bulgaria – Cost curve and table for new NPP Belene 1000MW unit (curve 102)

Renewables

Renewable power plants are modeled and shown in Figure 4.31 WPP takes into account the wind tariff of $125/MWh. Figure 4.32 shows the Solar PP with a tariff of $474.3/MWh.

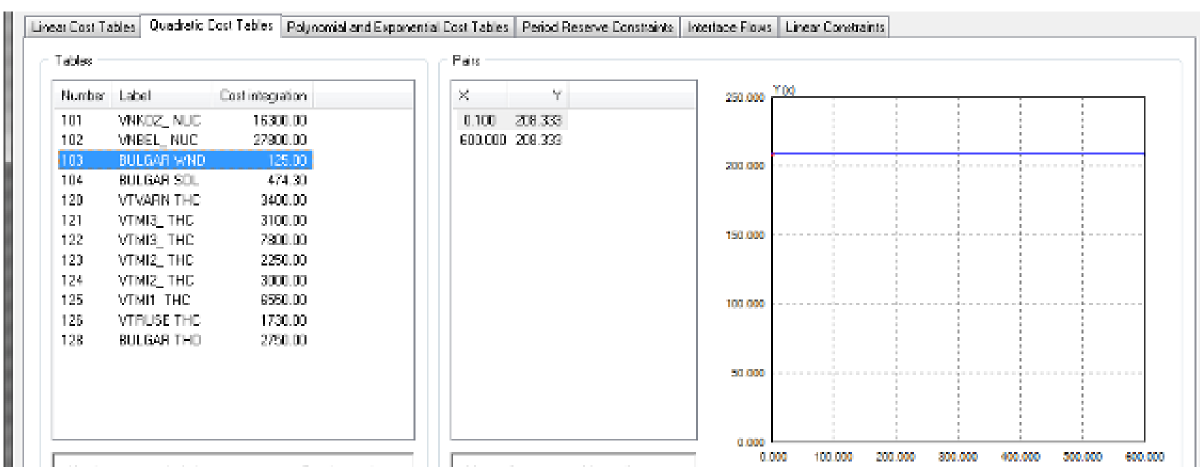


Figure 4.31 – Bulgaria – Cost curve and table for Wind power plants (curve 103)

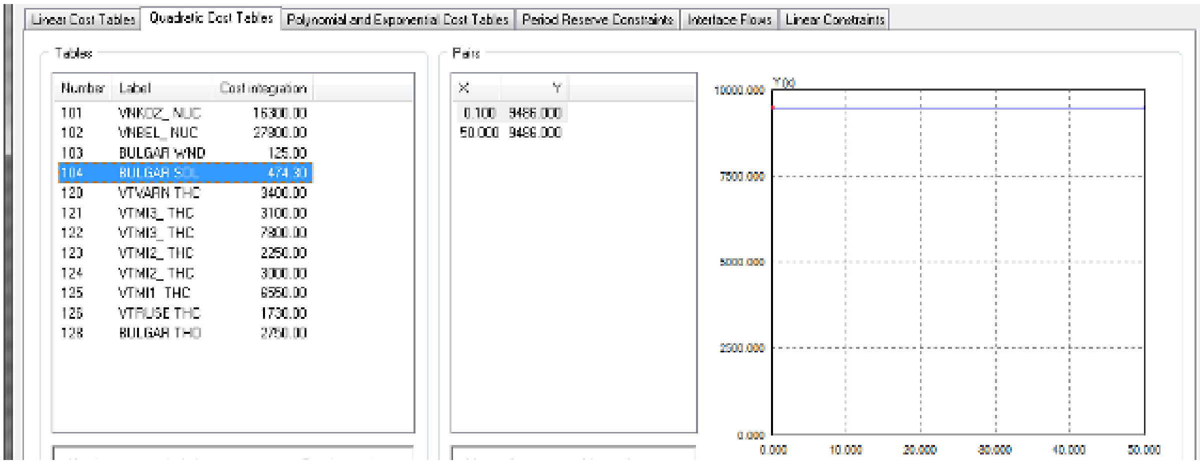


Figure 4.32 – Bulgaria – Cost curve and table for Solar units (curve 104)

The cost curves should be used to calculate production costs, and not for generation engagement optimization, since these units are engaged based on energy availability and not on economics. Therefore, for optimization calculations they should be disabled by setting the dispatch value to zero.

1.17 Georgia

According to the data provided and generic cost curves described in Chapter 2.1.3 , the OPF model of Georgia is constructed and presented with the following characteristics.

1.17.1 PSS/E OPF Transmission System Modeling

The transmission network is presented with buses and connection links-network elements (lines, cables, transformers, etc…) and its OPF model consists of data describing network limitations, according to respective country grid codes and rules of engagement (voltage limits, line and transformer load rating). The transmission system model of Georgia is shown in Figure 4.33

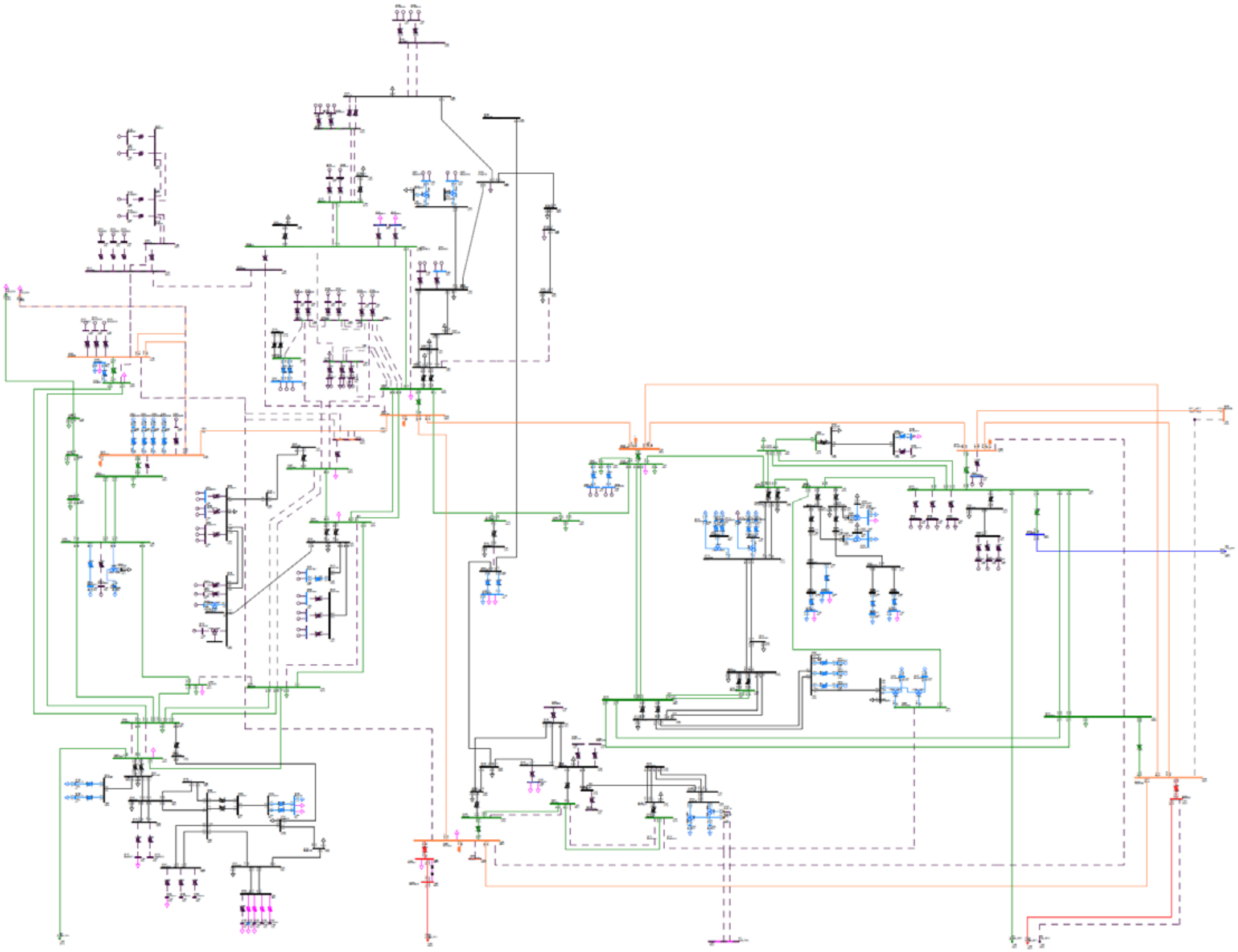


Figure 4.33- Georgia – transmission network model

1.17.2 PSS/E OPF Generation Modeling

Generation OPF model consists of tables and cost curves. Table 4.3 shows the main characteristics of Georgian Generation OPF model.

Table 4.3 – Georgia – Generation units OPF model

Power plant	Plant type	Fuel	Turbine	heat rate (mBTU/MWh)	Bus Num	Bus Name	Id	Mbase (MVA)	Pmax (MW)	Pmin (MW)	cost ($/MWh)	curve
Enguri	HPP	Hydro	Francis		20001	6HENHUH1	1	306.0	260.0	100.0	25.51	201
	HPP	Hydro	Francis		20002	6HENHUH2	2	306.0	260.0	100.0	25.51	201
	HPP	Hydro	Francis		20003	6HENHUH3	3	306.0	260.0	100.0	25.51	201
	HPP	Hydro	Francis		20004	6HENHUH4	4	306.0	260.0	100.0	25.51	201
	HPP	Hydro	Francis		20005	6HENHUH5	5	306.0	260.0	100.0	25.51	201
Vardinli	HPP	Hydro	Kaplan		20011	6VARDNH1	1	86.3	73.3	30.0	23.83	202
	HPP	Hydro	Kaplan		20012	6VARDNH2	2	86.3	73.3	30.0	23.83	202
	HPP	Hydro	Kaplan		20013	6VARDNH3	3	86.3	73.3	30.0	23.83	202
Mtkvari	TPP	Gas	Steam	10.8	20023	6GARDAT9	9	376.5	320.0	200.0	56.33	202
	TPP	Gas	Steam	10.8	20024	6GARDATA	10	376.5	320.0	200.0	56.33	202
Tbilresi	TPP	Gas	Steam	10.8	20025	6GARDAT8	8	176.5	150.0	90.0	62.25	203
	TPP	Gas	Steam	10.8	20027	6GARDAT3	3	176.5	150.0	90.0	62.25	203
	TPP	Gas	Steam	10.8	20028	6GARDAT4	4	176.5	150.0	90.0	62.25	203
Gardabani	TPP	Gas	CCGT	6.8	20181	6AIR GG1	GS	194.1	159.6	46.0	61.30	201
Dzevurla	HPP	Hydro	Francis		20031	6DZEVRH1	E	100.0	80.0	5.0	22.00	215
Lajanuri	HPP	Hydro	Kaplan		20041	6HLAJAH1	E	138.0	111.6	10.0	21.50	206
Shaori	HPP	Hydro	Francis		20051	6SHAORH1	E	48.0	38.4	5.0	23.00	214
Vartsikhe	HPP	Hydro	Kaplan		20061	6VARTSH1	E	57.0	46.0	10.0	17.50	209
	HPP	Hydro	Kaplan		20062	6VARTSH3	E	171.0	138.0	10.0	17.50	209
Khrami1	HPP	Hydro	Pelton		20071	6KHRM1H1	E	141.0	112.8	15.0	13.40	204
Khrami2	HPP	Hydro	Francis		20074	6KHRM2H1	E	137.0	120.0	33.0	21.40	205
Khrami3	HPP	Hydro	Francis		20188	6KHRAMY	E	100.0	90.0	33.0	21.40	205
Jhinvali	HPP	Hydro	Kaplan		20081	6JHINVH1	E	162.4	130.0	12.0	12.54	213
Gumati1	HPP	Hydro	Kaplan		20091	6GUMATH1	E	83.5	66.8	4.0	20.50	207
Gumati2	HPP	Hydro	Kaplan		20095	6GUMATH5	E	28.5	22.8	4.0	20.50	207
Rioni	HPP	Hydro	Kaplan		20103	6RIONIH3	E	60.0	48.0	8.0	20.50	208
Khudoni	HPP	Hydro	Francis		20121	6KHUDOH1	1	250.0	215.0	60.0	52.50	203
	HPP	Hydro	Francis		20122	6KHUDOH2	2	250.0	215.0	60.0	52.50	203
	HPP	Hydro	Francis		20123	6KHUDOH3	3	250.0	215.0	60.0	52.50	203
Khaisi	HPP	Hydro	Francis		20131	6KHAISG1	1	270.0	260.0	100.0		
Tobari	HPP	Hydro	Francis		20134	6TOBARG2	1	270.0	200.0	50.0		
Fari	HPP	Hydro	Francis		20136	6FARI-G1	1	270.0	200.0	50.0		
Sadmeli	HPP	Hydro	Kaplan		20141	6SADMEH1	E	112.0	90.0	0.0	44.20	210
Sori	HPP	Hydro	Kaplan		20146	6SORI-H1	E	60.0	134.0	20.0	44.20	210
Oni	HPP	Hydro	Kaplan		20150	6ONI-GH2	E	93.0	79.2	10.0	44.20	210
Utsera	HPP	Hydro	Kaplan		20153	6UTSERH2	E	200.0	170.0	5.0	44.20	211
Tkibuli	TPP	Coal	Steam	10.8	20191	6TKIBUT1	1	253.0	215.0	130.0	73.73	204
	TPP	Coal	Steam	10.8	20192	6TKIBUT2	2	253.0	215.0	130.0	73.73	204
	TPP	Coal	Steam	10.8	20193	6TKIBUT3	3	253.0	215.0	130.0	73.73	204
Tvishi	HPP	Hydro	Francis		20194	6TVISHH1	E	125.0	100.0	10.0	41.64	207
Namakhvani	HPP	Hydro	Francis		20196	6NAMAKH1	1	147.0	125.0	25.0	41.64	212
	HPP	Hydro	Francis		20197	6NAMAKH2	2	147.0	125.0	25.0	41.64	212
Joneti	HPP	Hydro	Francis		20198	6JONETH1	E	125.0	100.0	10.0	41.64	207
Alpana	HPP	Hydro	Francis		20201	6ALPANH1	E	100.0	80.0	10.0	41.64	207
Neskra	HPP	Hydro	Francis		20204	6NESKRH	H	290.0	260.0	0.0	25.51	201
Tskhenikali	HPP	Hydro	Francis		20205	6TSKHEH	H	145.0	130.0	0.0	44.20	210

Hydro Power Plants

Hydro power plants in Georgia are an important source of energy. The largest HPP is Enguri, with a high head and Francis turbines. Its cost curve is presented in Figure 4.34 The curve is presented in Chapter 2.1.3 and adjusted by including the capital costs, since the plant was recently reconstructed with a $20 million loan from EBRD. HPP Vardinli is shown on Figure 4.34 with Kaplan turbines no capital costs since it is more than 40 years old.

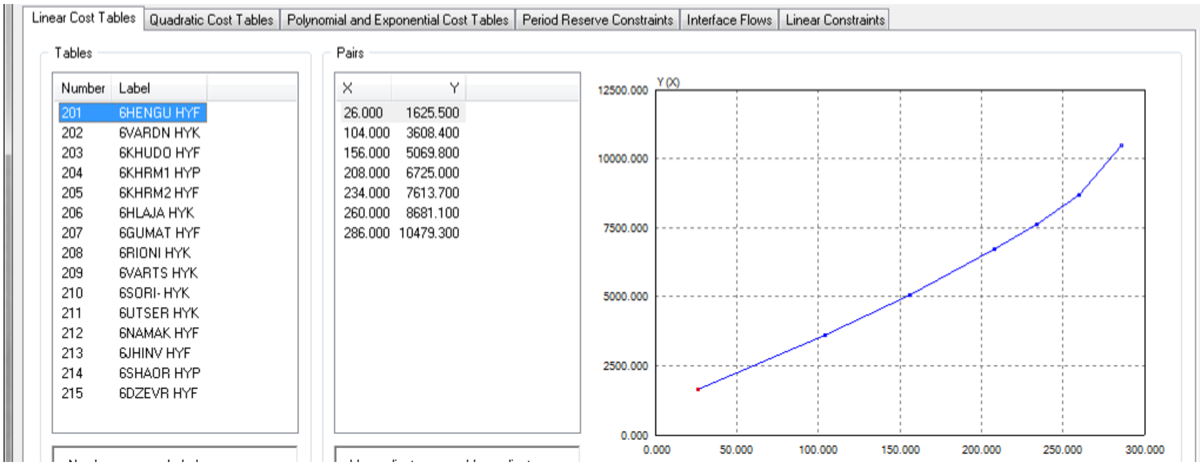


Figure 4.34 – Georgia – Cost curve and table for HPP Enguri (curve 201)

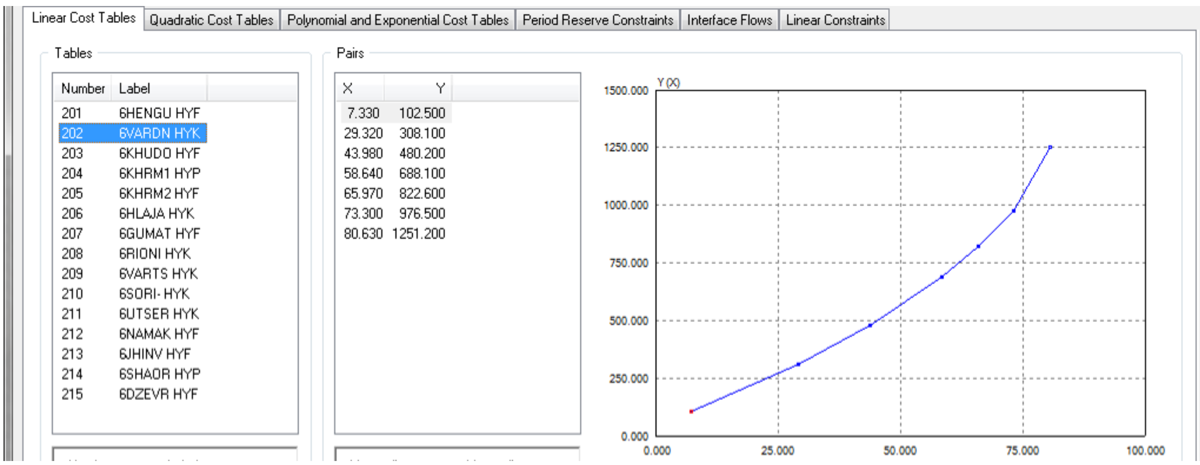


Figure 4.35 – Georgia – Cost curve and table for HPP Vardinli (curve 202)

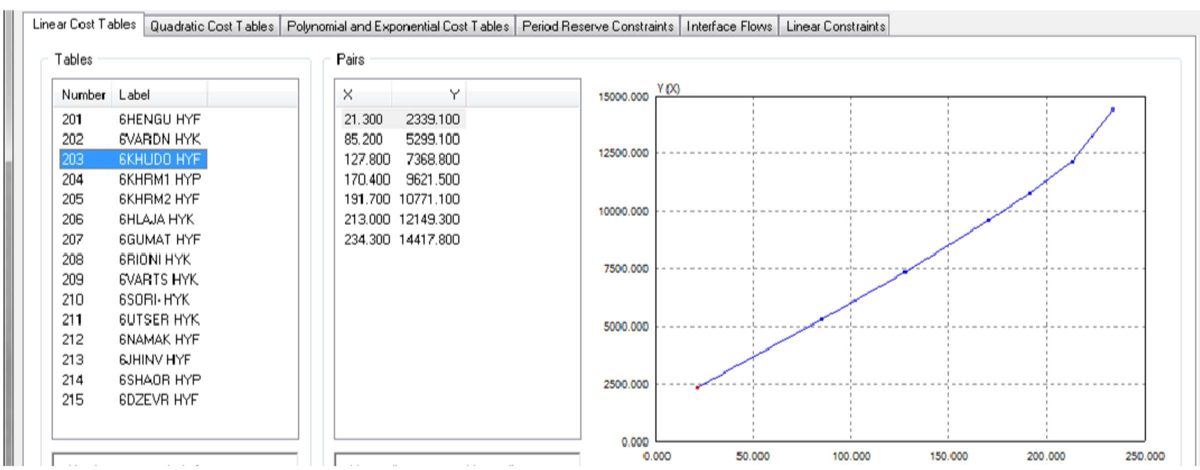


Figure 4.36 – Georgia – Cost curve and table for HPP Khudoni (curve 203)

The cost curve for the new HPP Khudoni (Figure 4.36) is modeled with full estimated capital costs. The Nescra cascade has the same curve as HPP Enguri.

The power plants on the Rioni cascade are similar by type, and cost per MWh. Therefore, all power plants: Utsera, Oni, Sori, Sadmeli, Tskheniskali, Lajanuri, Tvishi, Namakhvani, Joneti, Alpana, Gumati, Rioni and Vartsike are presented in a similar way. Newly planned power plants on the Kura river cascade have the same curve shape without taking capital costs into consideration. If these plans are realized, all Khrami power plants should divide the capital costs to have the same price per MWh.

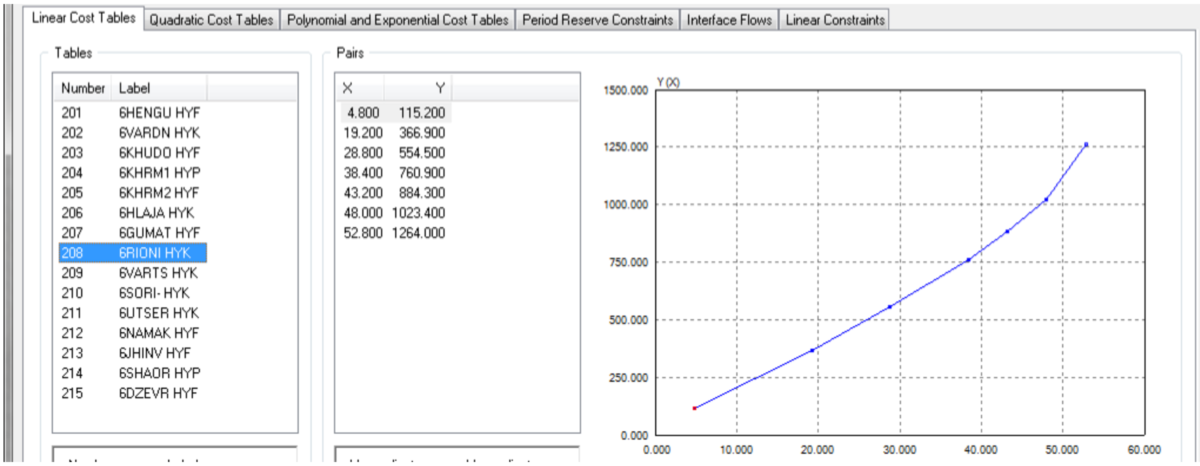


Figure 4.37– Georgia – Cost curve and table for HPPs Rioni cascade (curve 208)

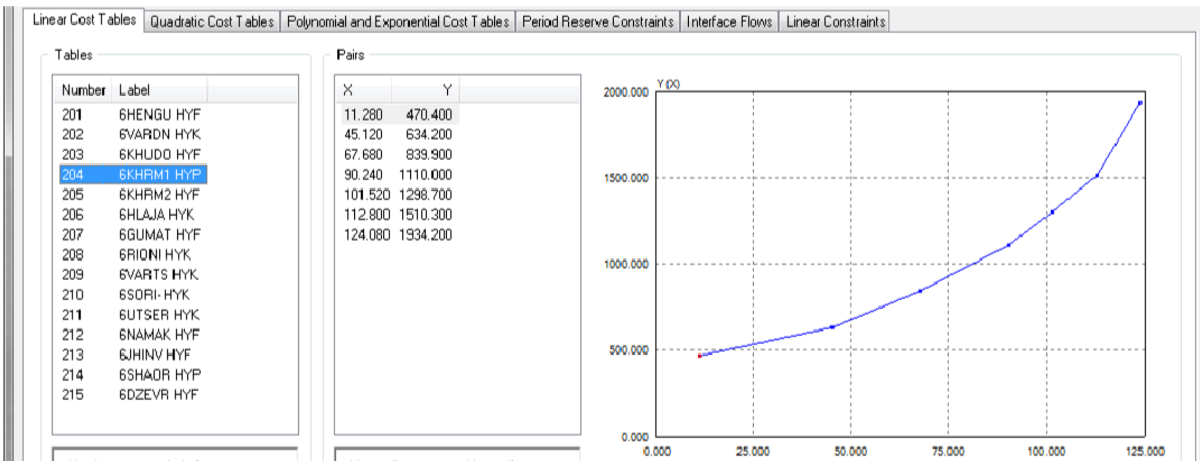


Figure 4.38– Georgia – Cost curve and table for HPPs Kura cascade (curve 204)

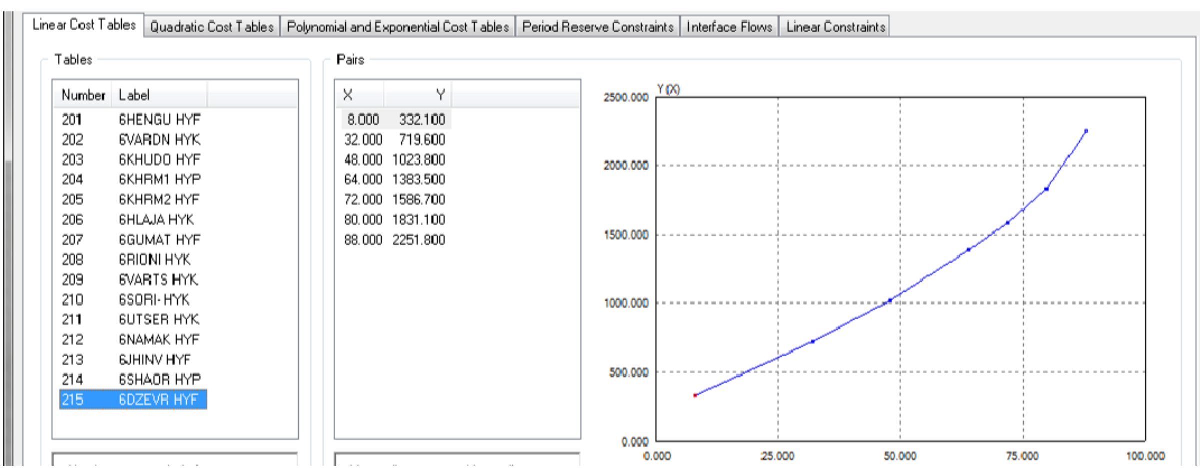


Figure 4.39 – Georgia – Cost curve and table for HPPs SH-TKI cascade (curve 214)

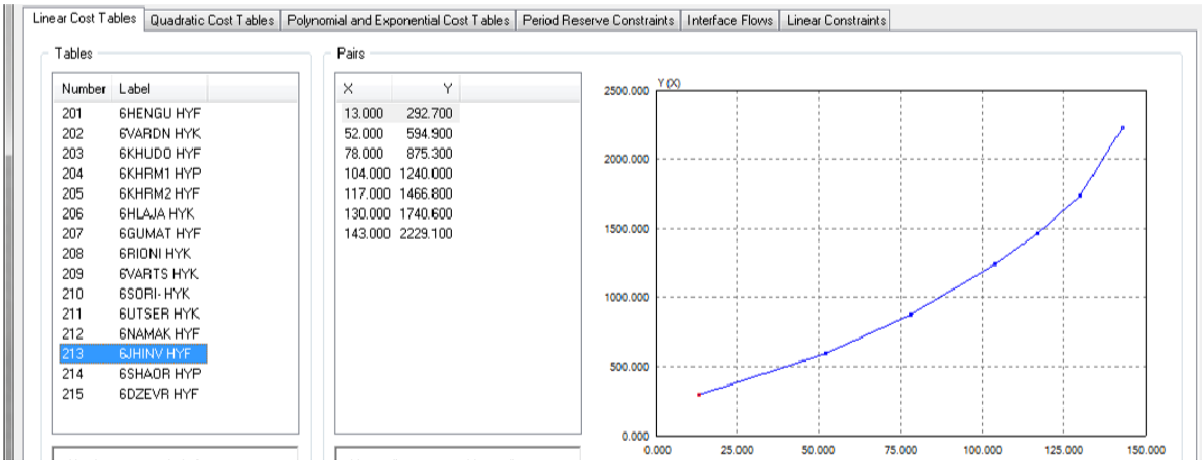


Figure 4.40 – Georgia – Cost curve and table for HPP Jhinvali (curve 213)

All curves are adjusted according to the tariffs presented in Table , and for power plants that are reconstructed or are new, capital costs are taken into consideration according to the investment information.

Thermal Power Plants

All thermal power plants in Georgia are run on imported natural gas, and the price of gas is $220/tcm, or $5.6/mBTU, which is lower than prices on some market hubs (Figure 2.12). This price is implemented in generic curves, and since tariffs for these power plants are known, remaining costs adjusted accordingly, generating the following curves.

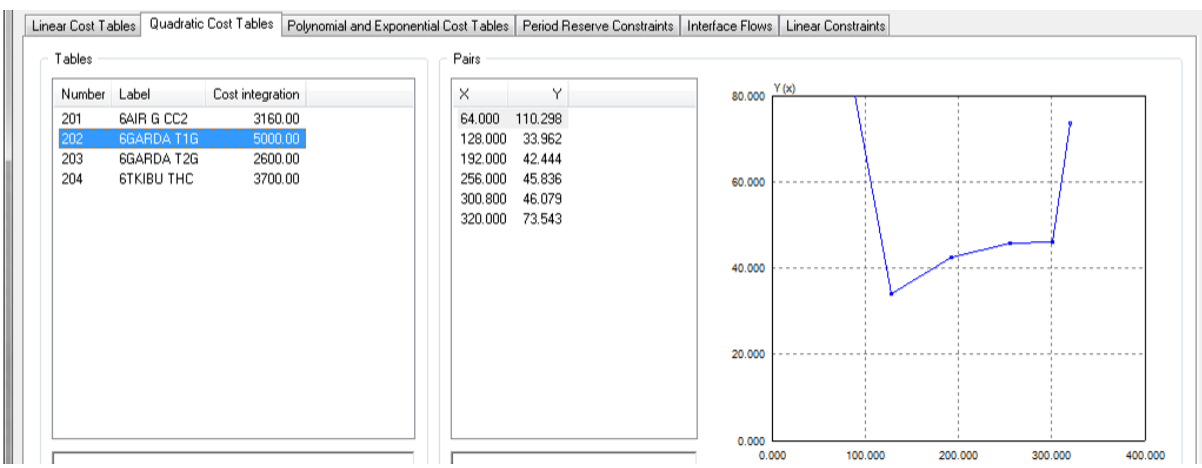


Figure 4.41– Georgia – Cost curve and table for TPP Mtkvari (curve 202)

The TPP Tkibuli is a planned power plant run on domestic coal. Since this plant is new full capital costs are taken into consideration.

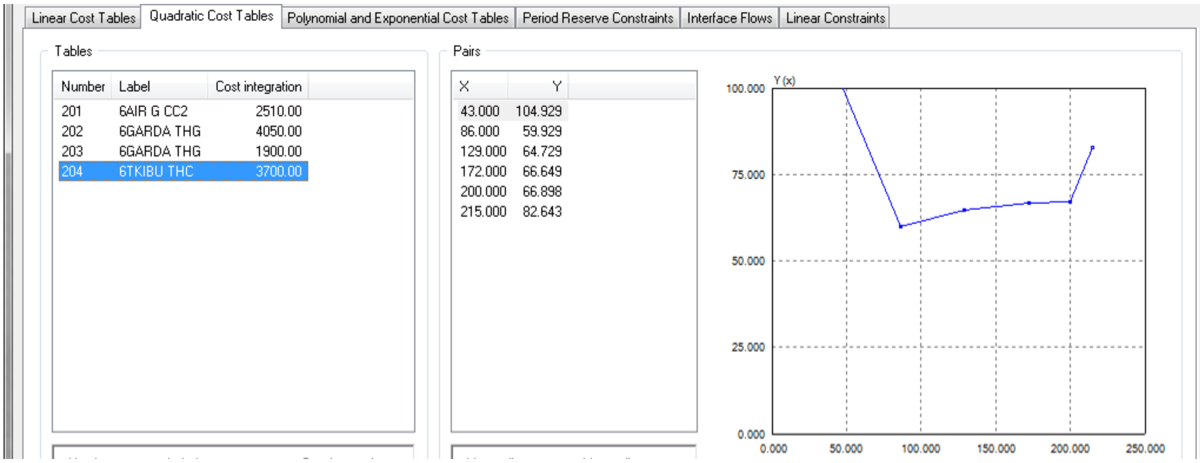


Figure 4.42 – Georgia – Cost curve and table for TPP Tkibuli (curve 204)

Gas Turbine Power Plants

Georgia has one gas turbine block installed comprising of two GT units that will be converted into a combined cycle power plant. Its cost curve is shown in Figure 4.43. Price of engagement is set according to the price of imported gas and general characteristics of similar units.

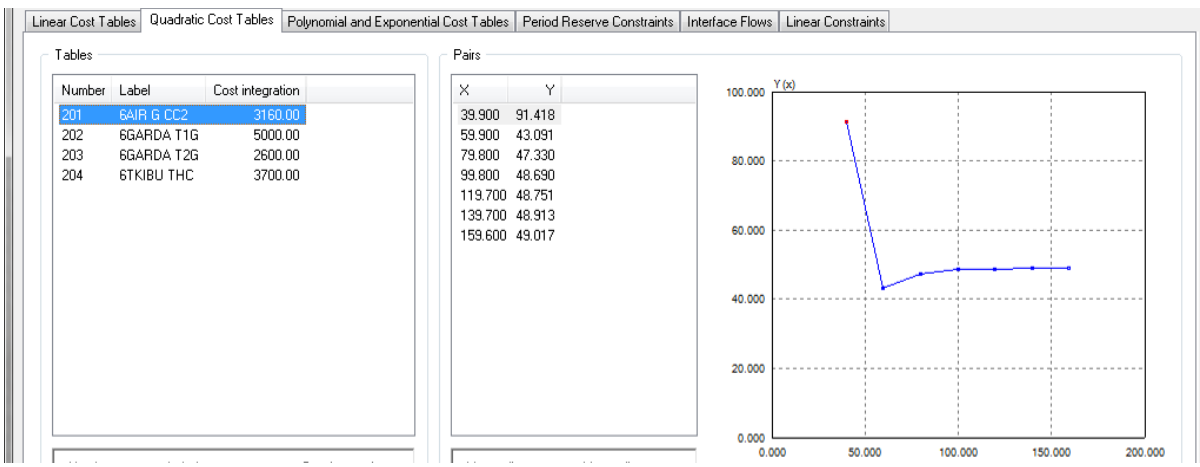


Figure 4.43 – Georgia – Cost curve and table for new CCGT Gardabani (curve 201)

Renewables

Most of renewable power plants in Georgia are small hydro, which are usually modeled as negative load. Therefore, they do not have a cost curve. Another renewable source is a 50 MW wind power plant Paravani, which is also modeled as negative load. No information on feed in tariffs was available, as a result, these plants could not be included in the OPF model with cost curves.

1.18 Moldova

According to the data provided and generic cost curves described in Chapter 2.1.3 OPF model of Moldova is constructed its main characteristics are described below.

1.18.1 PSS/E OPF Transmission System Modeling

The transmission network is usually presented with buses and connection links-network elements (lines, cables, transformers, etc…) and its OPF model consists of data describing network limitations, according to respective country grid codes and rules of engagement (voltage limits, line and transformer load rating). The transmission system model of Moldova is given in Figure 2.39..

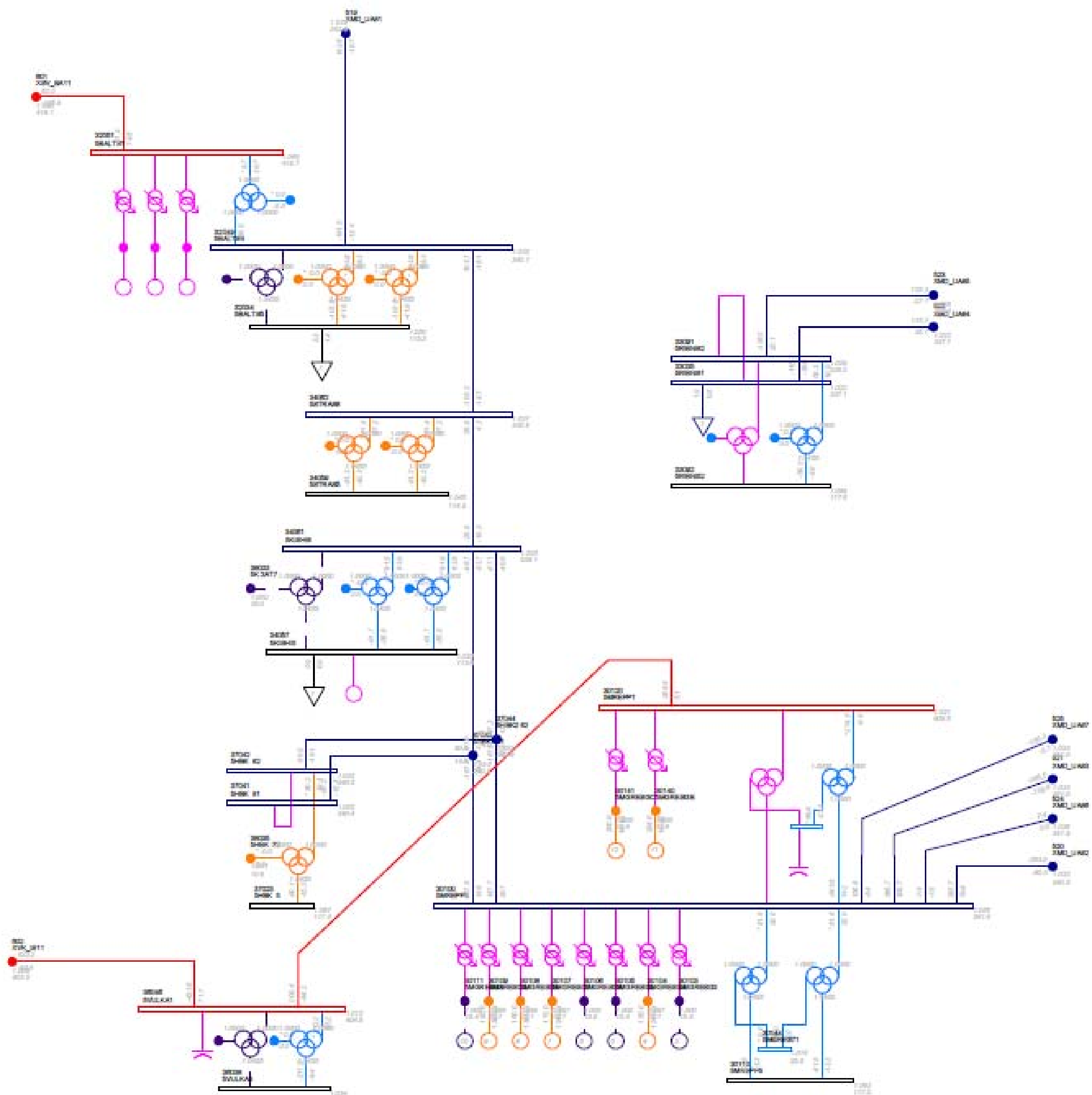


Figure 4.44- Moldova – transmission network model

1.18.2 PSS/E OPF Generation Modeling

Generation OPF model consists of tables and cost curves. Table 4.4 shows the main characteristics of Moldova's Generation OPF model.

Table 4.4 – Moldova– Generation units OPF model

Power plant	Plant type	Fuel	Turbine	heat rate (mBTU/MWh)	Bus Num	Bus Name	Id	Mbase (MVA)	Pmax (MW)	Pmin (MW)	cost ($/MWh)	curve
Moldovska GRES	TPP	Coal	Steam	10.8	30150	5MGRESG1	1	235.3	200.0	100.0	49.20	301
	TPP	Coal	Steam	10.8	30102	5MGRESG2	2	235.3	200.0	100.0	49.20	301
	TPP	Coal	Steam	10.8	30103	5MGRESG3	3	235.3	200.0	100.0	49.20	301
	TPP	Coal	Steam	10.8	30104	5MGRESG4	4	235.3	200.0	100.0	49.20	301
	TPP	Coal	Steam	10.8	30105	5MGRESG5	5	235.3	200.0	100.0	49.20	301
	TPP	Coal	Steam	10.8	30106	5MGRESG6	6	235.3	200.0	100.0	49.20	301
	TPP	Coal	Steam	10.8	30107	5MGRESG7	7	235.3	200.0	100.0	49.20	301
	TPP	Gas	Steam	10.8	30108	5MGRESG8	8	247.0	210.0	100.0	75.42	301
	TPP	Gas	Steam	10.8	30109	5MGRESG9	9	247.0	210.0	100.0	75.42	301
	TPP	Gas	Steam	10.8	30111	5MGRESGA	10	247.0	210.0	100.0	75.42	301
	TPP	Gas	Steam	10.8	30140	5MGRESGB	11	247.0	210.0	100.0	75.42	301
	TPP	Gas	Steam	10.8	30141	5MGRESGC	12	247.0	210.0	100.0	75.42	301
	CHP	Gas	Steam	10.8	30197	5MGRE3G2	G2	75.0	60.0	12.0	75.42	304
	CHP	Gas	Steam	10.8	30198	5MGRE3G1	G1	75.0	60.0	12.0	75.42	304
Kishinev CHP	CHP	Gas	Steam	10.8	38001	5KSPP2G1	1	125.0	100.0	25.0	75.42	303
	CHP	Gas	Steam	10.8	38002	5KSPP2G2	2	125.0	100.0	25.0	75.42	303
	CHP	Gas	Steam	10.8	38003	5KSPP2G3	3	125.0	100.0	25.0	75.42	303
Kishinev	CHP	Gas	CCGT	7.5	38333	5KSPP2G4	4	235.3	200.0	50.0	60.12	305
Dubosari	HPP	Hydro	Kaplan		38010	5DHPP1G	3	15.0	12.0	5.0	4.87	302
	HPP	Hydro	Kaplan		38010	5DHPP1G	4	15.0	12.0	5.0	4.87	302
	HPP	Hydro	Kaplan		38011	5DHPP2G	1	15.0	12.0	5.0	4.87	302
	HPP	Hydro	Kaplan		38011	5DHPP2G	2	15.0	12.0	5.0	4.87	302

Hydro Power Plants

The Dubosary HPP is the only plant modeled in the generation of the Moldovan model. The other plant is modeled as negative load.

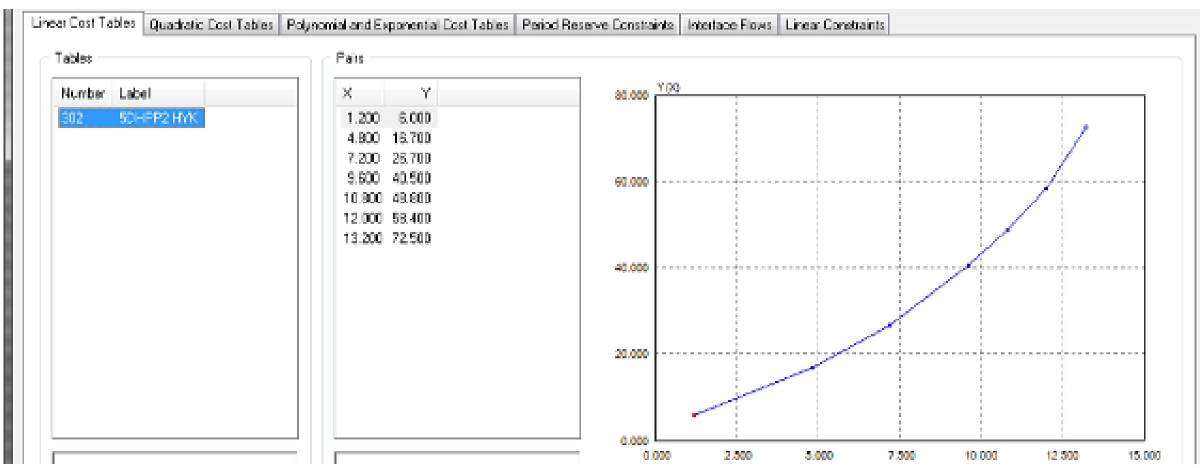


Figure 4.45– Moldova – Cost curve and table for HPP Dubosari (curve 302)

Thermal Power Plants

Thermal power plant Moldovska GRES is the only large production facility in Moldova. Since it is owned by a Russian company, and run on imported fuel, mainly natural gas imported from Russia, it is modeled according to the lower gas prices (prices that can be implied for Russian customers). The other important production facilities are the CHP plants in Moldovska GRES and CHP Kishinev.

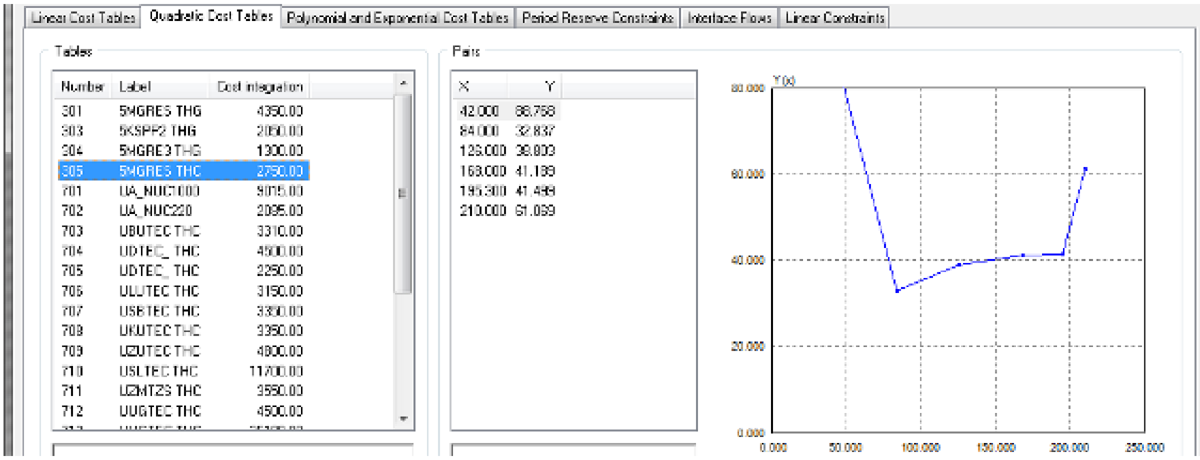


Figure 4.46 – Moldova – Cost curve and table for TPP Moldovskaya GRES units 1-7 (curve 305)

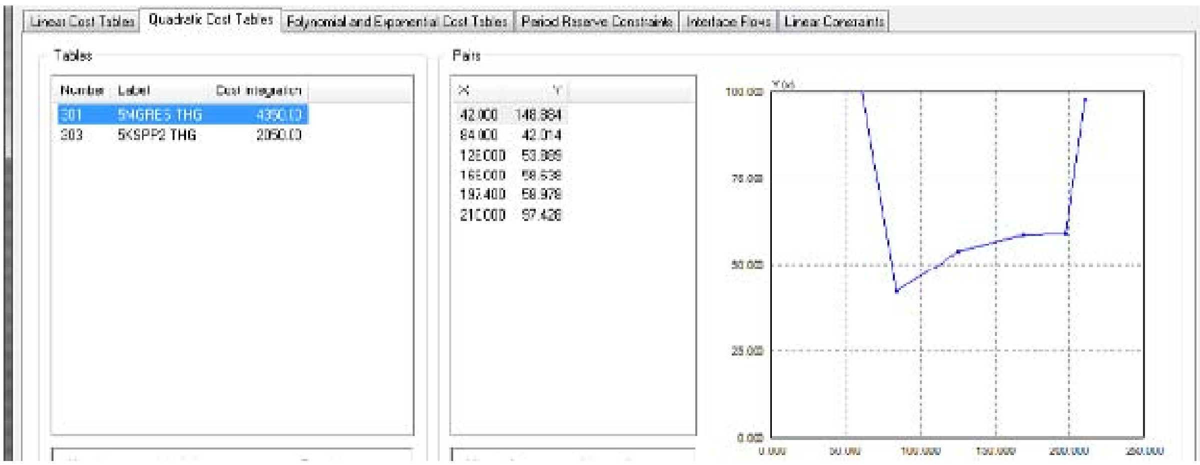


Figure 4.47 – Moldova – Cost curve and table for TPP Moldovskaya GRES units 8-12 (curve 301)

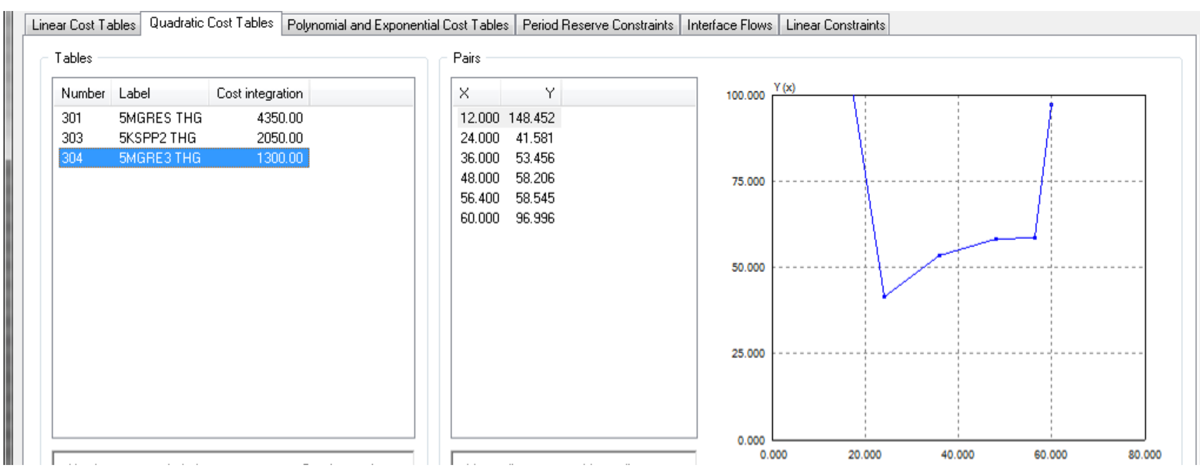


Figure 4.48 – Moldova – Cost curve and table for CHP Moldovskaya GRES G1-2 (curve 304)

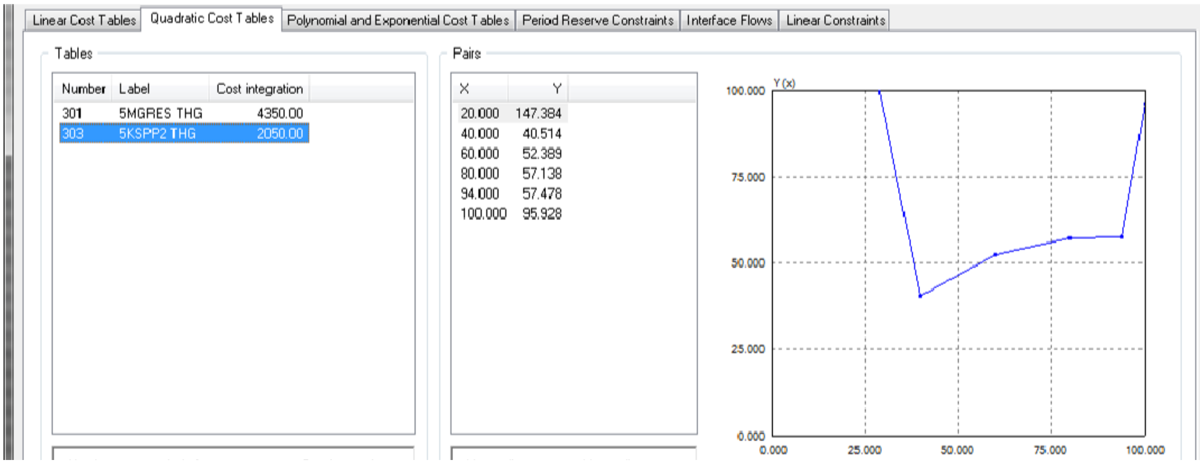


Figure 4.49 – Moldova – Cost curve and table for CHP Kishinev G1-3 (curve 303)

Gas Turbine Power Plants

There are plans to replace aging CHP Kishinev with a modern CCGT units run on imported natural gas. These units will produce electricity for export.

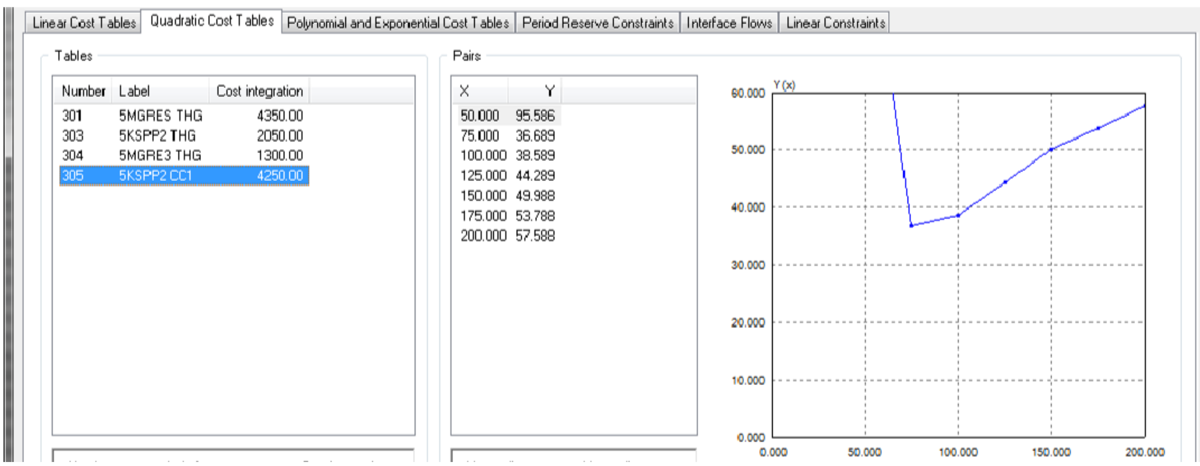


Figure 4.50 – Moldova – Cost curve and table for new CCGT Kishinev (curve 305)

Renewables

The only renewables modeled in Moldova, are planned WPPs. A similar model to the Armenian one is used, since the countries have similar policies and price ranges. These models are used only for an estimate of production costs, and not for optimal engagement of production units.

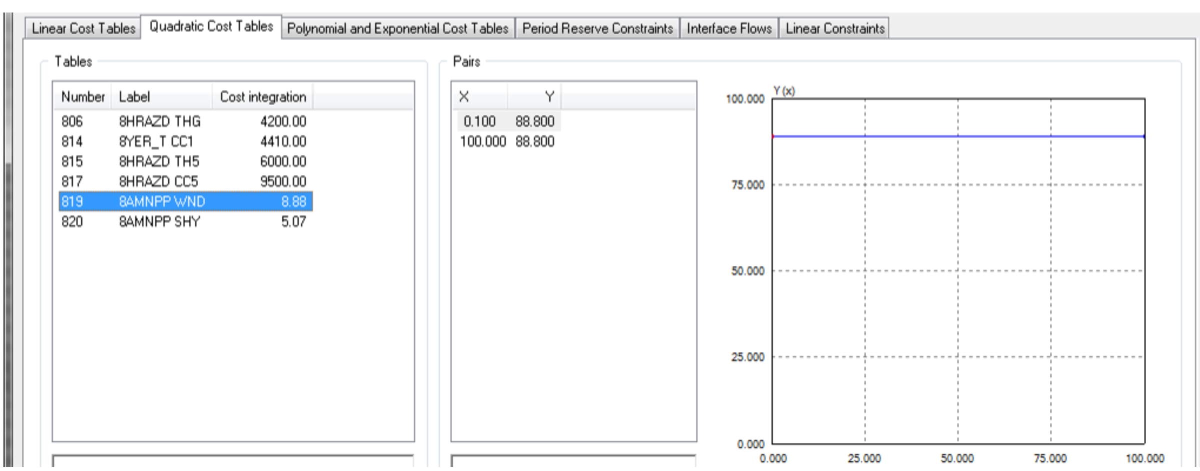


Figure 4.51– Moldova – Cost curve and table for Wind power plants

1.19 Romania

According to the data provided and generic cost curves described in Chapter 2.1.3 OPF model of Romania is constructed and its main characteristics are outlined below.

1.19.1 PSS/E OPF Transmission System Modeling

The transmission network is usually presented with buses and connection links-network elements (lines, cables, transformers, etc…) and its OPF model consists of data describing network limitations, according to respective country grid codes and rules of engagement (voltage limits, line and transformer load ratings). The transmission system model of Romania is given in Figure 4.52.

1.19.2 PSS/E OPF Generation Modeling

Generation OPF model consists of tables and cost curves. Table 4.5 shows the main characteristics of Romanian Generation OPF model.

Table 4.5 – Romania – Generation units OPF model

Power plant	Plant type	Fuel	Turbine	heat rate (mBTU/MWh)	Bus Num	Bus Name	Id	Mbase (MVA)	Pmax (MW)	Pmin (MW)	cost ($/MWh)	curve
Portile de Fier	HPP	Hydro	Kaplan	Danube	49189	RP.D.FH1	1	216.0	194.4	80.0	22.73	401
	HPP	Hydro	Kaplan	Danube	49190	RP.D.FH2	1	216.0	194.4	80.0	22.73	401
	HPP	Hydro	Kaplan	Danube	49191	RP.D.FH3	1	216.0	194.4	80.0	22.73	401
	HPP	Hydro	Kaplan	Danube	49192	RP.D.FH4	1	216.0	194.4	80.0	22.73	401
	HPP	Hydro	Kaplan	Danube	49193	RP.D.FH5	1	216.0	194.4	80.0	22.73	401
	HPP	Hydro	Kaplan	Danube	49250	RP.D.FH6	1	216.0	194.4	80.0	22.73	401
PDF2	HPP	Hydro	Kaplan	Danube	49199	RGRUIAH6	1	318.5	314	27.5	22.73	402
Lotru	HPP	Hydro	Pelton	Lotru	49232	RLOTRUH1	1	185.0	170.0	20.0	23.56	404
	HPP	Hydro	Pelton	Lotru	49233	RLOTRUH2	1	185.0	170.0	20.0	23.56	404
	HPP	Hydro	Pelton	Lotru	49234	RLOTRUH3	1	185.0	170.0	20.0	23.56	404
Arefu	HPP	Hydro	Francis	Arges	49125	RAREFUH1	1	244.0	220.0	35.0	22.82	403
Sugag	HPP	Hydro	Francis	Sebes	49172	RSUGAGH1	1	85.0	76.5	50.0	22.82	405
	HPP	Hydro	Francis	Sebes	49173	RSUGAGH2	1	85.0	76.5	50.0	22.82	405
Galcegag	HPP	Hydro	Francis	Sebes	49170	RGALCEH1	1	90.0	81.0	50.0	22.82	405
	HPP	Hydro	Francis	Sebes	49171	RGALCEH2	1	90.0	81.0	50.0	22.82	405
Tarnita	HPP	Hydro	Francis	S.Cald	49471	RTARNIH1	1	284.0	256.0	180.0	69.29	406
	HPP	Hydro	Francis	S.Cald	49472	RTARNIH2	1	284.0	256.0	180.0	69.29	406
	HPP	Hydro	Francis	S.Cald	49473	RTARNIH3	1	284.0	256.0	180.0	69.29	406
	HPP	Hydro	Francis	S.Cald	49474	RTARNIH4	1	284.0	256.0	180.0	69.29	406
Mariselu	HPP	Hydro	Francis	S.Cald	49164	RMARISH1	1	246.0	220.5	60.0	7.34	407
Retezat	HPP	Hydro	Francis	Riul Mare	49162	RRETEZH1	1	185.0	167.5	65.0	7.34	408
	HPP	Hydro	Francis	Riul Mare	49163	RRETEZH2	1	185.0	167.5	65.0	7.34	408
Ruieni	HPP	Hydro	Francis	Bistra	49183	RRUIENH1	H	154.0	140.0	35.0	44.79	409
Stejaru	HPP	Hydro	Francis	Bistrica	49209	RSTEJAH	1	120.0	96.0	40.0	7.24	411
	HPP	Hydro	Francis	Bistrica	49207	RSTEJAH5	H	108.0	97.0	28.0	7.24	411
hydro <50MW	HPP	Hydro	Francis				H	165.0	150.0	0.0	22.74	410
Cerna Voda	NPP	Uranium	Steam	10.4	49218	RCERNAN1	1	800.0	705.6	500.0	71.00	401
	NPP	Uranium	Steam	10.4	49332	RCERNAN2	2	800.0	705.6	500.0	71.00	401
	NPP	Uranium	Steam	10.4	49470	RCERNAN3	3	800.0	705.6	500.0	71.00	401
	NPP	Uranium	Steam	10.4	49475	RCERNAN4	4	800.0	705.6	500.0	71.00	401
Turceni	TPP	Coal	Steam	8.9	49110	RTURCEG1	1	388.0	330.0	174.0	74.31	402
	TPP	Coal	Steam	8.9	49112	RTURCEG3	3	388.0	330.0	174.0	74.31	402
	TPP	Coal	Steam	8.9	49113	RTURCEG4	4	388.0	330.0	174.0	74.31	402
	TPP	Coal	Steam	8.9	49114	RTURCEG5	5	388.0	330.0	174.0	74.31	402
	TPP	Coal	Steam	8.9	49116	RTURCEG6	6	388.0	330.0	174.0	74.31	402
	TPP	Coal	Steam	8.9	49117	RTURCEG7	7	388.0	330.0	174.0	74.31	402
Rovinari	TPP	Coal	Steam	8.9	49121	RROVING3	3	388.0	330.0	174.0	74.31	402
	TPP	Coal	Steam	8.9	49238	RROVING4	4	388.0	330.0	174.0	74.31	402
	TPP	Coal	Steam	8.9	49119	RROVING5	5	388.0	330.0	174.0	74.31	402
	TPP	Coal	Steam	8.9	49120	RROVING6	6	388.0	330.0	174.0	74.31	402
	TPP	Coal	Steam	8.9	49455	RROVING7	7	388.0	330.0	174.0	74.31	402
Isalnita	TPP	Coal	Steam	8.9	49184	RISALNG7	7	370.0	315.0	135.0	74.31	402
	TPP	Coal	Steam	8.9	49185	RISALNG8	8	370.0	315.0	135.0	74.31	402
Mintia-Deva	TPP	Coal	Steam	8.9	49167	RMINTIT1	1	247.0	210.0	80.0	62.10	403
	TPP	Coal	Steam	8.9	49168	RMINTIT2	2	247.0	210.0	80.0	62.10	403
	TPP	Coal	Steam	8.9	49259	RMINTIT4	4	247.0	210.0	80.0	62.10	403
	TPP	Coal	Steam	8.9	49169	RMINTIT5	5	247.0	210.0	80.0	62.10	403
	TPP	Coal	Steam	8.9	49260	RMINTIT3	3	247.0	210.0	80.0	62.10	403
	TPP	Coal	Steam	8.9	49262	RMINTIT6	6	247.0	210.0	80.0	62.10	403
Stuparei	TPP	Coal	Steam	10.4	49140	RSTUPAT1	1	225.0	180.0	40.0	62.10	404
Oradea I	TPP	Coal	Steam	10.4	49174	RORAD T4	1	225.0	180.0	40.0	62.10	404
Oradea II	TPP	Coal	Steam	10.4	49175	RORAD2T1	1	225.0	180.0	40.0	62.10	404

Brasov	TPP	Coal	Steam	10.4	49235	RBRASOT1	1	150.0	120.0	40.0	62.10	404
Drobeta	TPP	Coal	Steam	10.4	49251	RDROBEG4	1	225.0	180.0	40.0	62.10	404
	TPP	Coal	Steam	10.4	49253	RDROBEG1	1	225.0	180.0	40.0	62.10	404
Arad	CHP	Coal	Steam	10.4	49181	RARAD G1	1	75.0	60.0	30.0	52.77	405
Bacau	CHP	Coal	Steam	10.4	49212	RBACAUG1	1	75.0	60.0	36.0	52.77	405
Ghizdaru	CHP	Coal	Steam	10.4	49156	RGHIZDG1	1	75.0	51.0	30.0	52.77	405
FAI2	TPP	Coal	Steam	10.4	49214	RFAI 2G1	1	150.0	120.0	40.0	62.10	404
Petrom	CCGT	Gas	CCGT	6.7	49478	ROMVBZG1	1	1084.0	925.0	310.0	83.40	406
Grozavesti	CHP	Gas	CCGT	6.7	49147	RGROZAG2	1	107.0	79.0	40.0	86.04	407
Progresu	CHP	Gas	CCGT	6.7	49149	RPROGRG1	1	263.0	219.8	40.0	86.04	407
Palas	CHP	Gas	Steam	10.8	49226	RPALASG1	1	75.0	58.0	30.0	92.23	405
	CHP	Gas	Steam	10.8	49226	RPALASG1	1	32.0	21.0	10.0	92.23	405
	CHP	Gas	Steam	10.8	49227	RPALASG2	1	75.0	60.0	40.0	92.23	405
	CHP	Gas	CCGT	6.7	49226	RPALASG1	1	107.0	79.0	40.0	86.04	407
Barbosi	CHP	Gas	Steam	10.8	49224	RBARBOG3	1	141.5	120.0	37.0	92.23	405
	CHP	Gas	Steam	10.8	49221	RBARBOG5	1	141.5	120.0	37.0	92.23	405
FAI1	CHP	Gas	Steam	10.8	49217	RFAI 1G3	1	75.0	60.0	40.0	92.23	405
	CHP	Gas	Steam	10.8	49216	RFAI 1G4	1	75.0	60.0	40.0	92.23	405
Bucharesti Sud	CHP	Gas	Steam	10.8	49139	RBUC.SG1	1	75.0	60.0	33.0	92.23	405
	CHP	Gas	Steam	10.8	49317	RBUC.SG2	1	75.0	60.0	33.0	92.23	405
	CHP	Gas	Steam	10.8	49138	RBUC.SG3	1	117.5	100.0	50.0	92.23	405
	CHP	Gas	Steam	10.8	49318	RBUC.SG4	1	117.5	100.0	50.0	92.23	405
	CHP	Gas	Steam	10.8	49136	RBUC.SG5	1	170.0	136.0	58.0	92.23	405
	CHP	Gas	Steam	10.8	49137	RBUC.SG6	1	170.0	136.0	58.0	92.23	405
	CHP	Gas	CCGT	6.7	49461	RBUC.STG	1	181.0	162.0	80.0	86.04	407
Buchasresti Vest	CHP	Gas	Steam	10.8	49155	RBUC.VG1	1	170.0	136.0	65.0	92.23	405
	CHP	Gas	Steam	10.8	49154	RBUC.VG2	1	170.0	136.0	65.0	92.23	405
	CHP	Gas	CCGT	6.7	49431	RBUC.VG3	1	258.4	215.8	40.0	86.04	407
Smardan	CHP	Gas	Steam	10.8	49310	RSMARDG4	1	75.0	60.0	25.0	92.23	405
	CHP	Gas	Steam	10.8	49225	RSMARDG6	1	141.5	120.0	37.0	92.23	405
Braila-Lacu sarat	CHP	Gas	Steam	10.8	49219	RBRAILG1	1	247.0	210.0	130.0	95.98	409
	CHP	Gas	Steam	10.8	49220	RBRAILG2	1	247.0	210.0	130.0	95.98	409
	CHP	Gas	Steam	10.8	49299	RBRAILG3	1	247.0	210.0	130.0	95.98	409
Valea Nucarilor	WPP	Wind	Type4	Dobrogea	48019	RTULCE1A	W	66.3	63.0	0.0	86.17	410
	WPP	Wind	Type4	Dobrogea	48254	RTULCE5A	W	26.3	25.0	0.0	86.17	410
	WPP	Wind	Type4	Dobrogea	48254	RTULCE5A	W1	26.3	25.0	0.0	86.17	410
	WPP	Wind	Type4	Dobrogea	48254	RTULCE5A	W2	42.1	40.0	0.0	86.17	410
	WPP	Wind	Type4	Dobrogea	48255	RTULCE5B	W	26.3	25.0	0.0	86.17	410
	WPP	Wind	Type4	Dobrogea	48255	RTULCE5B	W1	26.3	25.0	0.0	86.17	410
	WPP	Wind	Type4	Dobrogea	48255	RTULCE5B	W2	42.1	40.0	0.0	86.17	410
Basarabi	WPP	Wind	Type4	Dobrogea	48275	RBASAR5B	W	80.0	75.0	0.0	86.17	410
	WPP	Wind	Type4	Dobrogea	48276	RBASAR5C	W	80.0	75.0	0.0	86.17	410
Medgida Nord	WPP	Wind	Type4	Dobrogea	48278	RMEDGI51	W	42.1	40.0	0.0	86.17	410
Medgida Sud	WPP	Wind	Type4	Dobrogea	48279	RMEDGI52	W	42.1	40.0	0.0	86.17	410
	WPP	Wind	Type4	Dobrogea	48854	RMEDGI54	W	42.1	40.0	0.0	86.17	410
Rahmanu	WPP	Wind	Type4	Dobrogea	49567	RRAHMA5	W	631.6	600.0	0.0	86.17	410
Tariverde	WPP	Wind	Type4	Dobrogea	49568	RTARIV5	W	631.6	600.0	0.0	86.17	410
Tataru	WPP	Wind	Type4	Dobrogea	48120	RTATAR51	W	26.3	25.0	0.0	86.17	410
	WPP	Wind	Type4	Dobrogea	48274	RTATAR53	W	26.3	25.0	0.0	86.17	410
Falci	WPP	Wind	Type4	Dobrogea	48209	RFALCI5	W	31.6	30.0	0.0	86.17	410
Smirdan	WPP	Wind	Type4	Dobrogea	48228	RSMIRD5B	W	61.0	58.0	0.0	86.17	410
Neptun	WPP	Wind	Type4	Dobrogea	48272	RNEPTU5	W	26.3	25.0	0.0	86.17	410
Mihailov	WPP	Wind	Type4	Dobrogea	48870	RMIHAI53	W	49.5	47.0	0.0	86.17	410
Stupi	WPP	Wind	Type4	Dobrogea	49569	RSTUPI5	W	286.3	272.0	0.0	86.17	410
Vacaru	WPP	Wind	Type4	Dobrogea	49570	RVACAR5	W	210.5	200.0	0.0	86.17	410
Miron	WPP	Wind	Type4	Dobrogea	49572	RMIRON5	W	131.6	125.0	0.0	86.17	410
Insur	WPP	Wind	Type4	Moldova	48286	RINSUR5	W	26.3	25.0	0.0	86.17	410
Liesti	WPP	Wind	Type4	Moldova	48220	RLIEST5	W	94.7	90.0	0.0	86.17	410
Bacau	WPP	Wind	Type4	Moldova	48147	RBACAU5	W	55.8	53.0	0.0	86.17	410
Adjurdi	WPP	Wind	Type4	Moldova	48151	RADJUD5	W	80.0	76.0	0.0	86.17	410

Muntenu	WPP	Wind	Type4	Moldova	48132	RMUNTE51	W	80.0	76.0	0.0	86.17	410
Negresti	WPP	Wind	Type4	Moldova	48133	RNEGRE51	W	18.9	18.0	0.0	86.17	410
Urlea	WPP	Wind	Type4	Moldova	48308	RURLEA5	W	26.3	25.0	0.0	86.17	410
Moldova	WPP	Wind	Type4	Banat	48722	RMOLDO5A	W	25.2	24.0	0.0	86.17	410
Socol	WPP	Wind	Type4	Banat	49571	RSOCOL5	W	315.8	300.0	0.0	86.17	410

Hydro Power Plants

Romania has a large number of hydro power plants which have an important role for energy generation and system regulation and control. The largest HPP in Romania is the Portile de Fier on Danube river. Together with PDF2, they use Kaplan turbines (vertical ones in first case and horizontal bulb ones in PDF2). Since both power plants were recently modernized and refurbished, 50% of the capital costs were taken into consideration for the cost curves. The HPP Lotru has an important role in terms of control. It has pelton turbines, that have been refurbished recently, and these capital costs were taken into consideration.

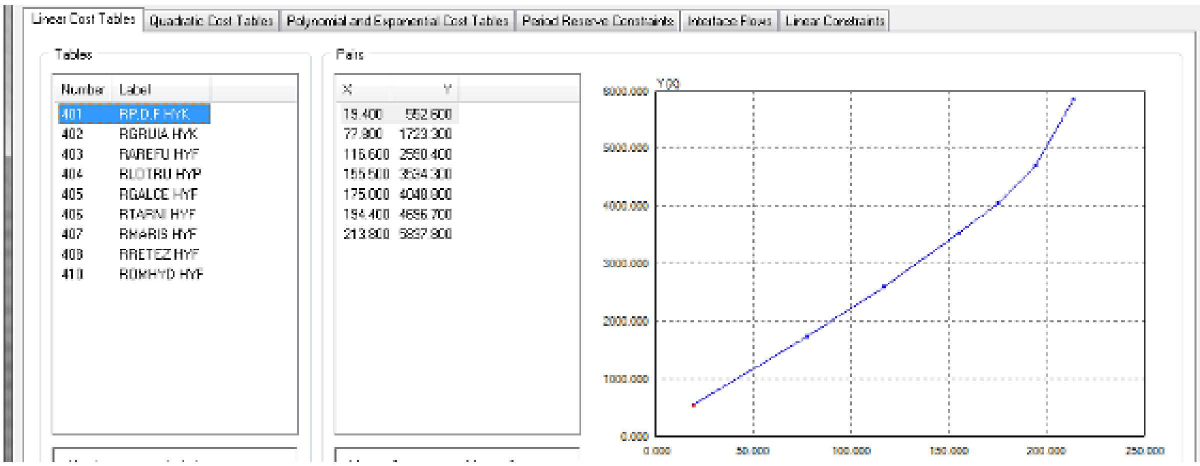


Figure 4.53 Romania – Cost curve and table for HPP Portile de Fier (curve 401)

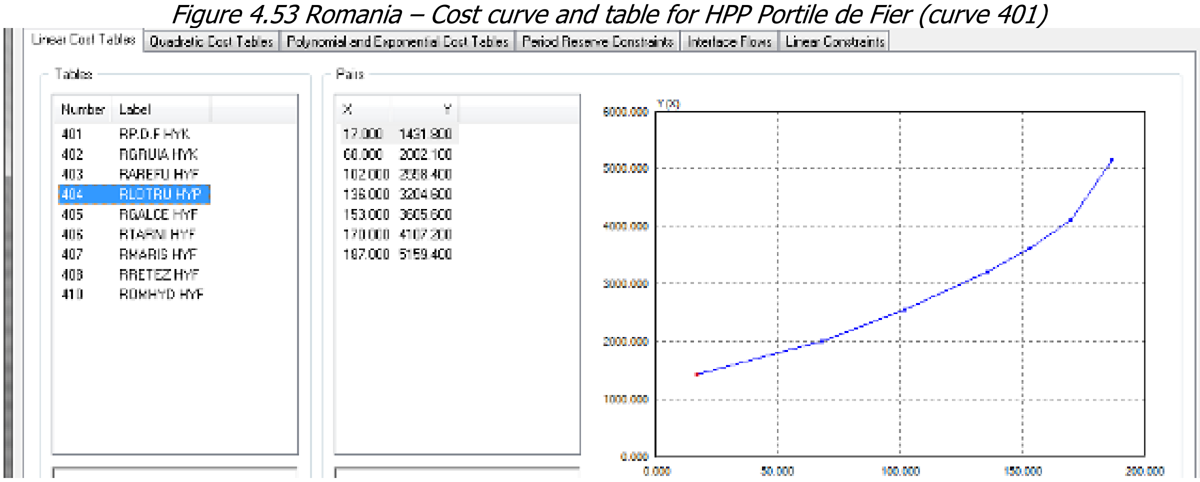


Figure 4.54 – Romania – Cost curve and table for HPP Lotru (curve 402)

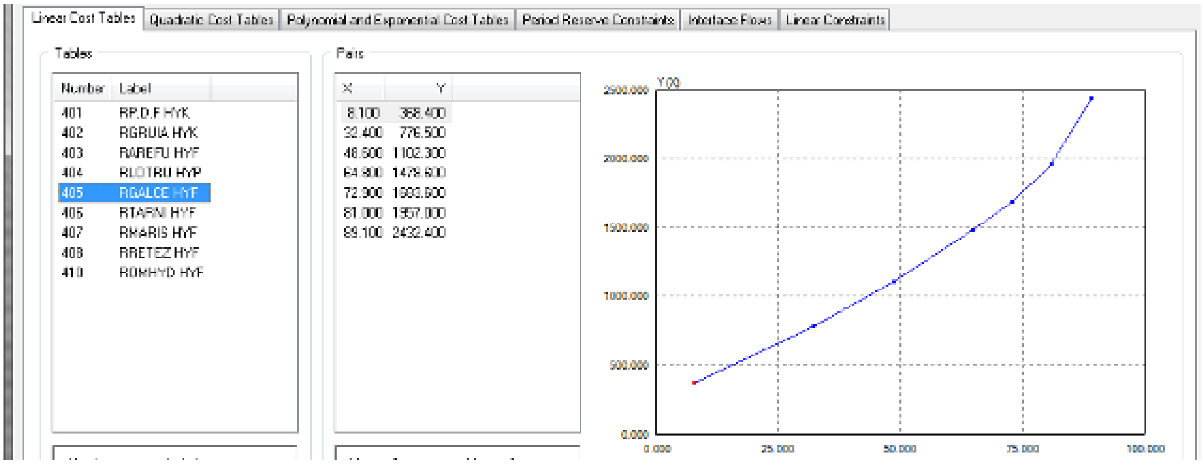


Figure 4.55 – Romania – Cost curve and table for HPP Sugag and Galcegag (curve 405)

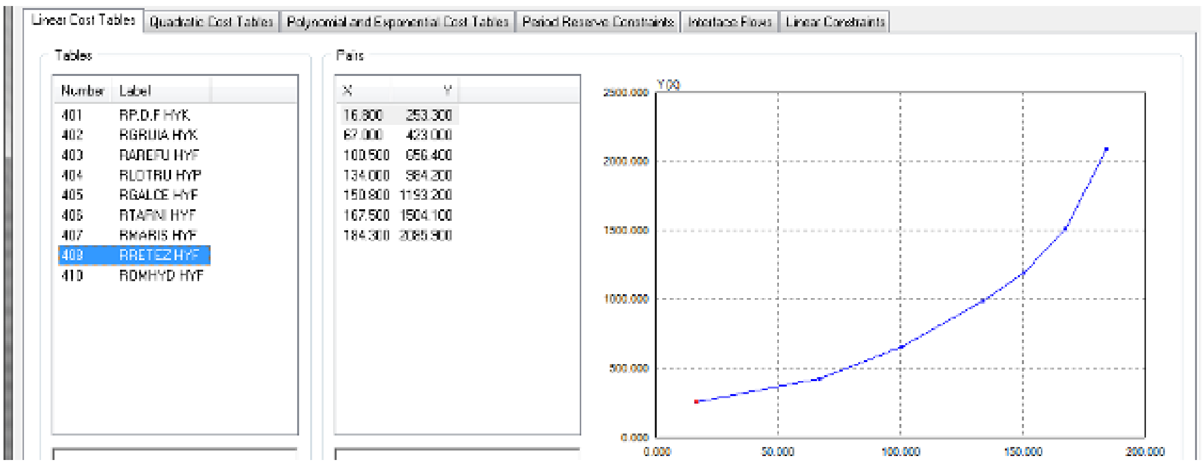


Figure 4.56 – Romania – Cost curve and table for HPP Retezat (curve 408)

The curve for HPPs Sugag and Galcegag, on the Sebes river, are shown on *Figure 4.55.* These power plants use Francis turbines. The same curve applies to the HPP Retezat with largest units installed. PHPP Tarnita is an important development project, especially for its future role in control of a large wind power in feed as well as the nuclear power plants' operation during the off-peak period. Unlike other hydro power plants, these have fuel costs, since water is pumped. Here costs are estimated at half price on the HV level (low tariff since pumping is usually done during night) multiplied with conversion factor (for pumping for 1MWh consumed it is 0.76MWh produced). The cost curve is made according to the price of energy for pumping $39.15/MWh. Also, since power plant is new, full capital costs are assumed.

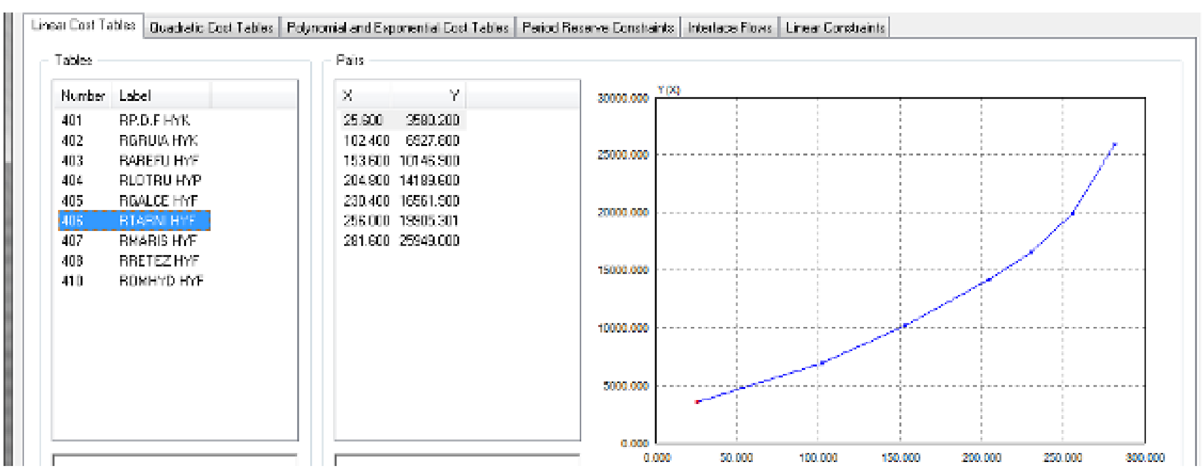


Figure 4.57 – Romania – Cost curve and table for PHPP Tarnita (curve 406)

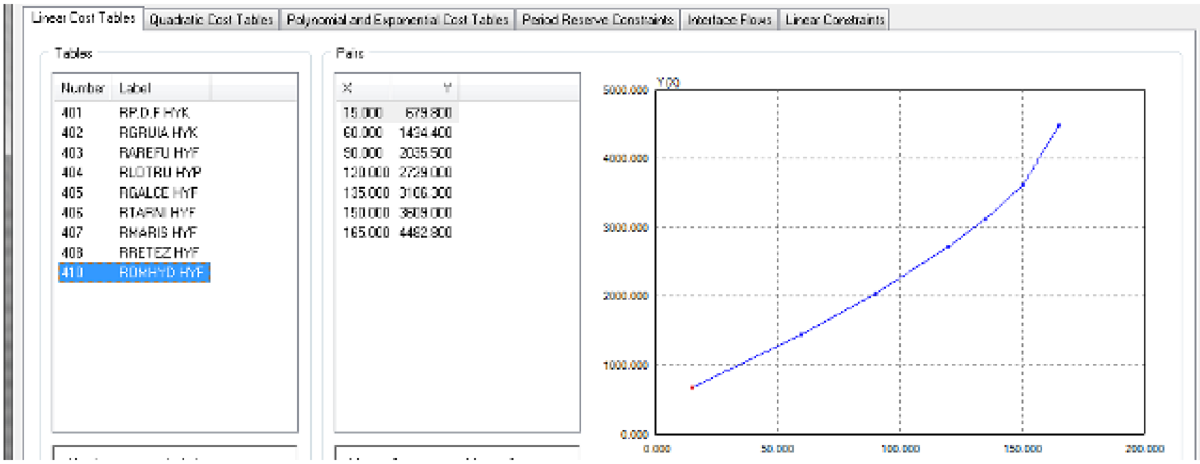


Figure 4.58 – Romania – Cost curve and table for Small HPPs (curve 410)

Smaller HPPs with a capacity less than 50MW, are modeled by using the cost curve on Figure 4.58 Most of these plants are modeled as a negative load in feed.

Thermal Power Plants

Romanian thermal power plants can be divided into two major groups: ones run on domestic coal (lignite, and subbituminous) and ones run on domestic fuel oil or natural gas. The first group consists of larger power plants in Romania like Turceni, Rovinari, Isalnita, and Mintia-Deva.

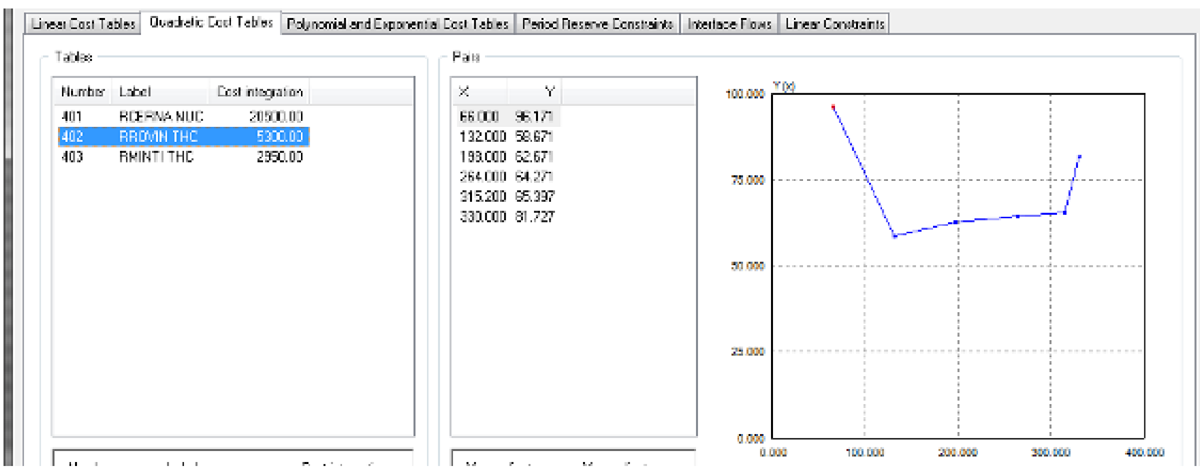


Figure 4.59 – Romania – Cost curve and table for TPP Turceni, Rovinari, Isalnita (curve 402)

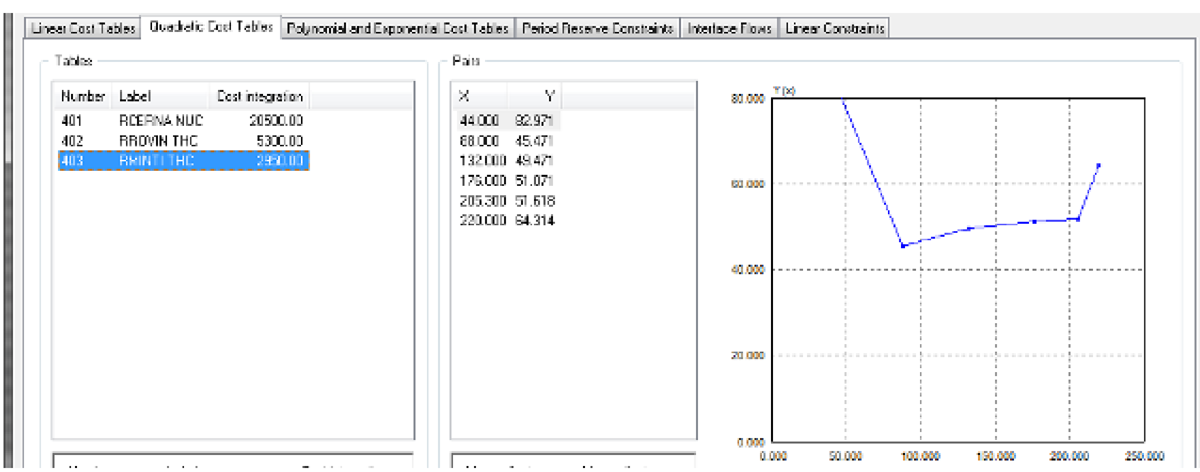


Figure 4.60 – Romania – Cost curve and table for TPP Mintia (curve 403)

Also included in the first group are the smaller CHP units run on coal. Other CHP units are run on natural gas or fuel oil. Most of this equipment is old, and will be shut down or replaced with gas fired CCGT units.

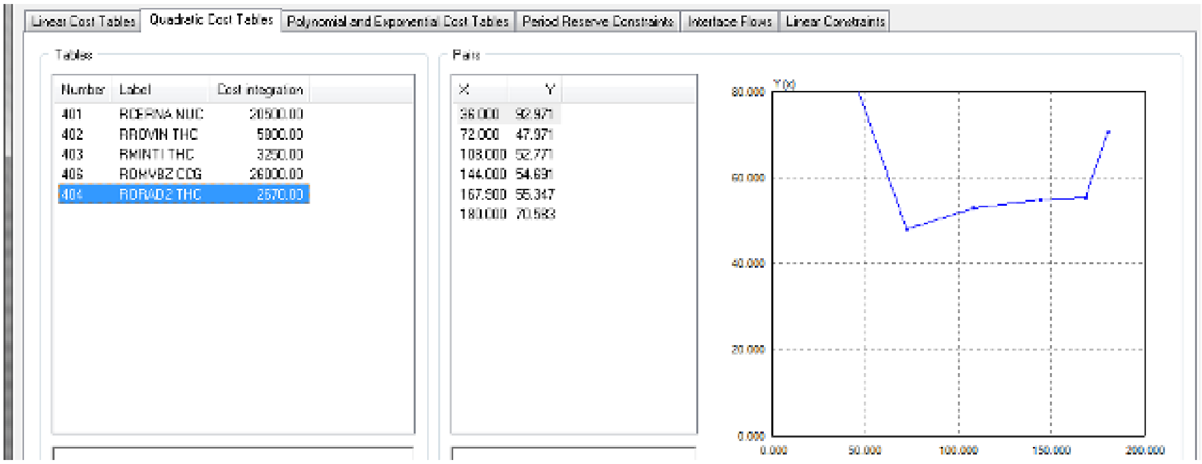


Figure 4.61 – Romania – Cost curve and table for CHPs run on coal (curve 404)

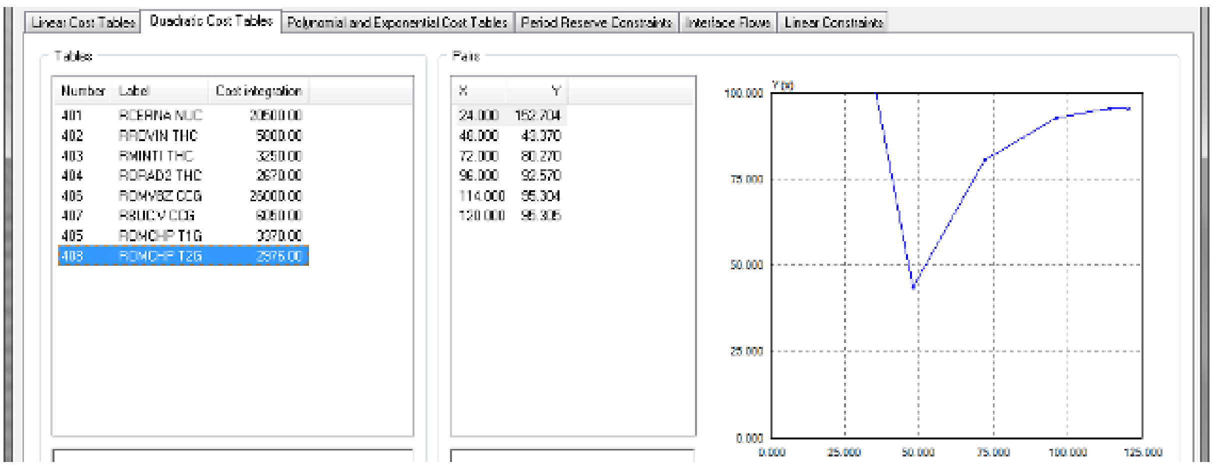


Figure 4.62 – Romania – Cost curve and table for CHPs run on gas (curve 408)

Gas Turbine Power Plants

Petrom in an oil refinery near Brazi, is the only gas turbine power plant installed in Romania. The country has ambitious plans to replace most its existing CHP units run on gas or oil with CCGT systems.

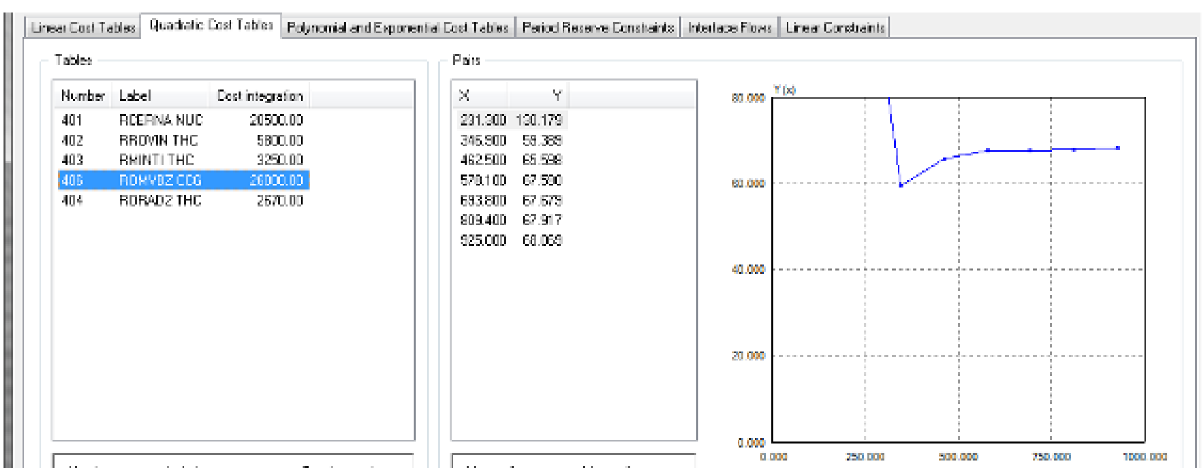


Figure 4.63 – Romania – Cost curve and table for new CCGT Petrom in Brazi (curve 406)

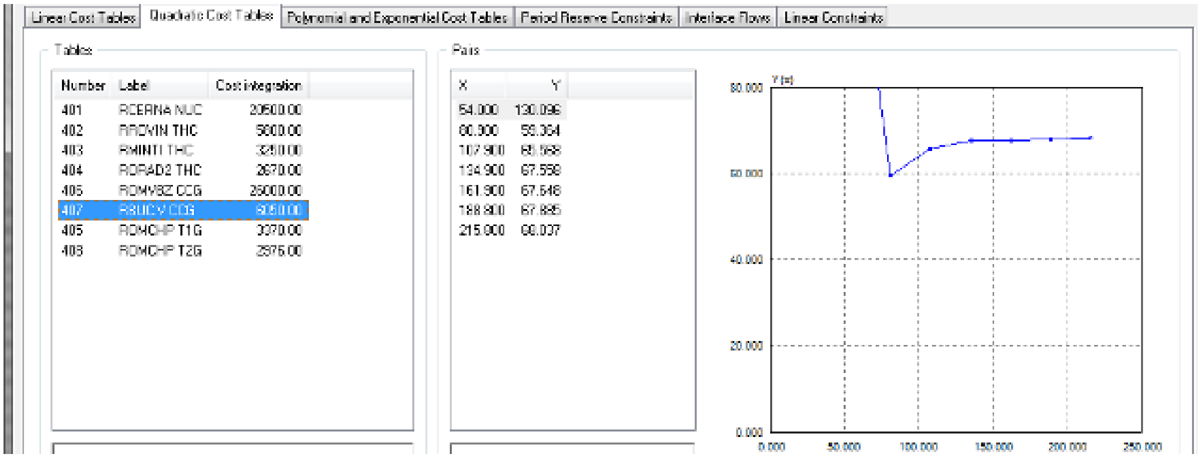


Figure 4.64 – Romania – Cost curve and table for new CCGT CHP (curve 407)

Nuclear Power Plants

Romania has a nuclear power station Cerna Voda with two operational units and two more in construction. All units assume the same cost curve that takes into consideration capital costs, since these units are relatively new (less than 20 years old).

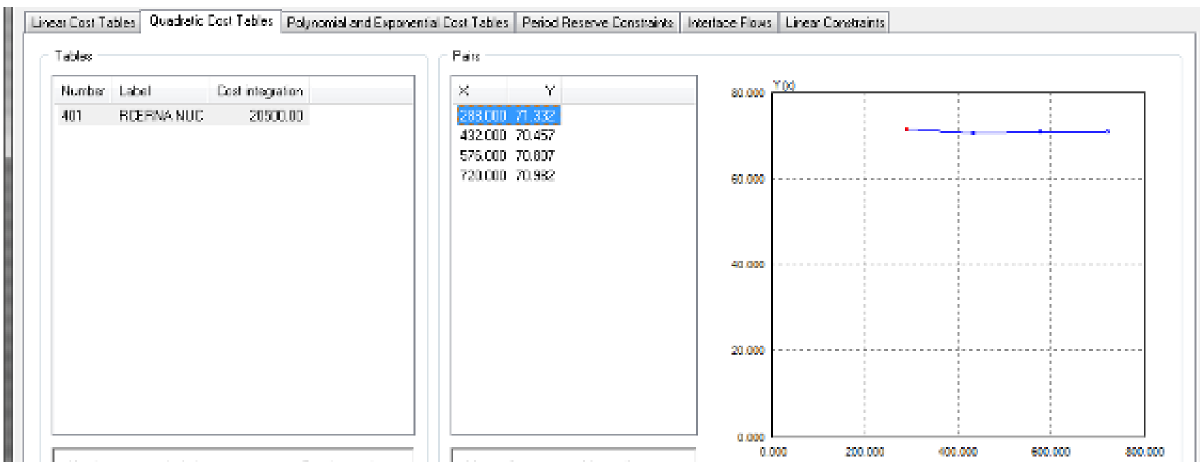


Figure 4.65 – Romania – Cost curve and table for NPP Cerna Voda (curve 401)

Renewables

Renewable power plants are modeled in Figure 4.66 for WPP and adjusted to represent the tariff system in Romania. Since Romania has a Green Certificate system in place, it is difficult to represent market behavior, therefore, the price is calculated according to the costs (capital costs included).

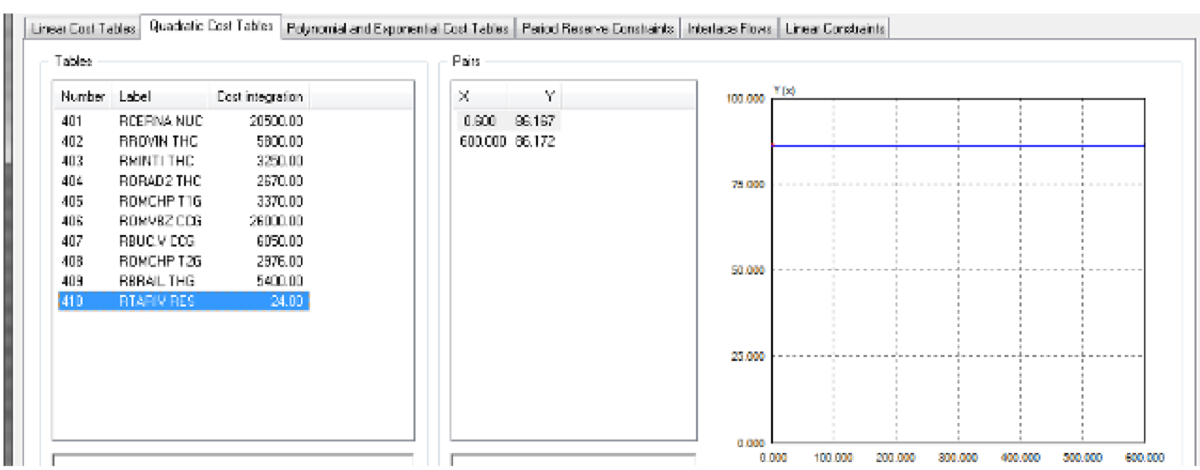


Figure 4.66 – Romania – Cost curve and table for Wind power plants (curve 410)

The cost curves should be used to calculate production costs, and not for generation engagement optimization, since these units are engaged based on energy availability and not on economics. Therefore, for optimization calculations they should be disabled by setting the dispatch value to zero.

1.20 Russia

According to the data provided and generic cost curves described in Chapter 2.1.3 OPF model of Russia is constructed and here are main characteristics.

1.20.1 PSS/E OPF Transmission System Modeling

The transmission network is usually presented with buses and connection links-network elements (lines, cables, transformers, etc…) and its OPF model consists of data describing network limitations, according to respective country grid codes and rules of engagement (voltage limits, line and transformer load ratings). The transmission system model of Russia is given in Figure 4.67 and Figure 4.68.

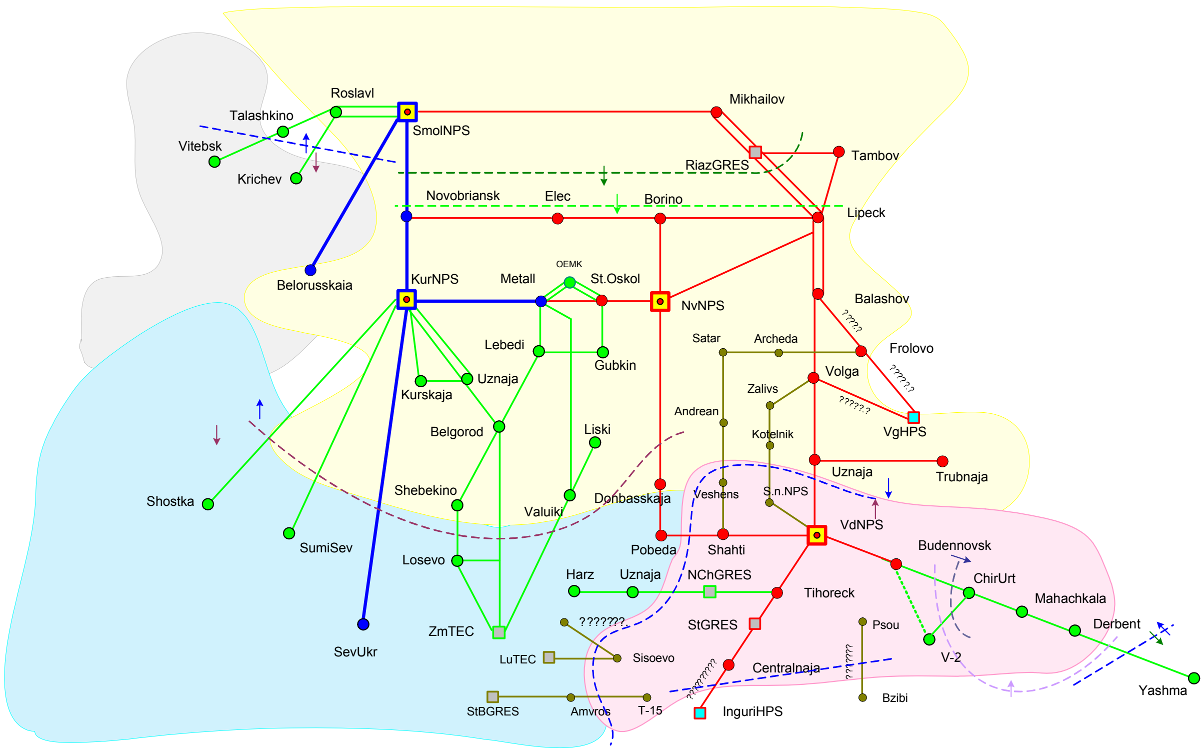


Figure 4.67– Russia – network map (modeled part in Black Sea regional model)

1.20.2 PSS/E OPF Generation Modeling

Generation OPF model consists of tables and cost curves. Table 4.6 shows the main characteristics of Russian Generation OPF model.

Table 4.6 – Russia – Generation units OPF model

Power plant	Plant type	Fuel	Turbine	heat rate (mBTU/MWh)	Bus Num	Bus Name	Id	Mbase (MVA)	Pmax (MW)	Pmin (MW)	cost ($/MWh)	curve
North Caucasus												
Volgodonska	NPP	Uranium	Steam	10.4	59001	4VDAESN1	1	1111.0	1000.0	300.0	69.33	5901
	NPP	Uranium	Steam	10.4	59002	4VDAESN2	2	1111.0	1000.0	300.0	69.33	5901
	NPP	Uranium	Steam	10.4	59003	4VDAESN3	3	1333.0	1200.0	600.0	69.33	5902
	NPP	Uranium	Steam	10.4	59004	4VDAESN4	4	1333.0	1200.0	600.0	69.33	5902
Stavropol	CHP	Gas	Steam	10.8	59021	4STGRSG1	1	353.0	300.0	150.0	60.22	5903
	CHP	Gas	Steam	10.8	59022	4STGRSG2	2	353.0	300.0	150.0	60.22	5903
	CHP	Gas	Steam	10.8	59023	4STGRSG3	3	353.0	300.0	150.0	60.22	5903
	CHP	Gas	Steam	10.8	59024	4STGRSG4	4	353.0	300.0	150.0	60.22	5903
	CHP	Gas	Steam	10.8	59025	4STGRSG5	5	353.0	300.0	150.0	60.22	5903
	CHP	Gas	Steam	10.8	59026	4STGRSG6	6	353.0	300.0	150.0	60.22	5903
	CHP	Gas	Steam	10.8	59027	4STGRSG7	7	353.0	300.0	150.0	60.22	5903
	CHP	Gas	Steam	10.8	59028	4STGRSG8	8	353.0	300.0	150.0	60.22	5903
Novocherkask	CHP	Gas	Steam	10.8	59031	4NCHGRG1	1	353.0	264.0	200.0	60.22	5903
	CHP	Gas	Steam	10.8	59032	4NCHGRG2	2	353.0	264.0	225.0	60.22	5903
	CHP	Gas	Steam	10.8	59033	4NCHGRG3	3	353.0	264.0	200.0	60.22	5903
	CHP	Gas	Steam	10.8	59034	4NCHGRG4	4	353.0	264.0	225.0	60.22	5903
	CHP	Gas	Steam	10.8	59035	4NCHGRG5	5	353.0	264.0	225.0	60.22	5903
	CHP	Gas	Steam	10.8	59036	4NCHGRG6	6	353.0	264.0	225.0	60.22	5903
	CHP	Gas	Steam	10.8	59037	4NCHGRG7	7	353.0	264.0	225.0	60.22	5903
	CHP	Gas	Steam	10.8	59038	4NCHGRG8	8	353.0	264.0	225.0	60.22	5903
Nevinomiis	CHP	Gas	Steam	10.8	59041	4NEVGRG1	1	176.5	150.0	80.0	60.23	5904
	CHP	Gas	Steam	10.8	59042	4NEVGRG2	2	176.5	150.0	80.0	60.23	5904
	CHP	Gas	Steam	10.8	59043	4NEVGRG3	3	176.5	150.0	80.0	60.23	5904
	CHP	Gas	Steam	10.8	59044	4NEVGRG4	4	176.5	150.0	80.0	60.23	5904
	CHP	Gas	Steam	10.8	59048	4NEVGRG8	8	176.5	150.0	130.0	60.23	5904
	CHP	Gas	Steam	10.8	59046	4NEVGRG6	6	176.5	150.0	80.0	60.23	5904
	CHP	Gas	Steam	10.8	59047	4NEVGRG7	7	176.5	150.0	80.0	60.23	5904
Kropotkin	TPP	Coal	Steam	10.2	59051	4KTEC G1	1	176.5	150.0	100.0	69.51	5905
	TPP	Coal	Steam	10.2	59052	4KTEC G2	2	176.5	150.0	100.0	69.51	5905
	TPP	Coal	Steam	10.2	59053	4KTEC G3	3	176.5	150.0	100.0	69.51	5905
	TPP	Coal	Steam	10.2	59054	4KTEC G4	4	176.5	150.0	100.0	69.51	5905
Centralna												
Novovoronezh	NPP	Uranium	Steam	10.4	51451	4NVAESN9	9	259.0	220.0	66.0	30.59	5001
	NPP	Uranium	Steam	10.4	51452	4NVAESN0	10	259.0	220.0	66.0	30.59	5001
	NPP	Uranium	Steam	10.4	51453	4NVAESNA	11	259.0	220.0	66.0	30.59	5001
	NPP	Uranium	Steam	10.4	51454	4NVAESNB	12	259.0	220.0	66.0	30.59	5001
	NPP	Uranium	Steam	10.4	51455	4NVAESNC	13	588.0	500.0	150.0	30.59	5001
	NPP	Uranium	Steam	10.4	51456	4NVAESND	14	588.0	500.0	150.0	30.59	5001
Smolensk	NPP	Uranium	Steam	10.4	51561	4S AESN1	1	588.0	500.0	150.0	30.53	5001
	NPP	Uranium	Steam	10.4	51562	4S AESN2	2	588.0	500.0	150.0	30.53	5001
	NPP	Uranium	Steam	10.4	51563	4S AESN3	3	588.0	500.0	150.0	30.53	5001
	NPP	Uranium	Steam	10.4	51564	4S AESN4	4	588.0	500.0	150.0	30.53	5001
	NPP	Uranium	Steam	10.4	51565	4S AESN5	5	588.0	500.0	250.0	30.53	5001
	NPP	Uranium	Steam	10.4	51566	4S AESN6	6	588.0	500.0	250.0	30.53	5001
Kursk	NPP	Uranium	Steam	10.4	51461	4K AESN1	1	588.0	500.0	250.0	30.53	5001
	NPP	Uranium	Steam	10.4	51462	4K AESN2	2	588.0	500.0	250.0	30.53	5001
	NPP	Uranium	Steam	10.4	51463	4K AESN3	3	588.0	500.0	250.0	30.53	5001
	NPP	Uranium	Steam	10.4	51464	4K AESN4	4	588.0	500.0	250.0	30.53	5001
	NPP	Uranium	Steam	10.4	51465	4KAES2N1	5	588.0	500.0	300.0	30.53	5001
	NPP	Uranium	Steam	10.4	51466	4KAES2N2	6	588.0	500.0	300.0	30.53	5001
	NPP	Uranium	Steam	10.4	51467	4KAES2N3	7	588.0	500.0	300.0	30.53	5001
	NPP	Uranium	Steam	10.4	51468	4KAES2N4	8	588.0	500.0	300.0	30.53	5001
Ryazan	CHP	Gas	Steam	10.8	51400	4RGRESG4	4	353.0	300.0	150.0	60.22	5002
	CHP	Gas	Steam	10.8	51403	4RGRESG7	7	353.0	300.0	150.0	60.22	5002
	CHP	Gas	Steam	10.8	51404	4RGRESG1	1	353.0	300.0	150.0	60.22	5002
	CHP	Gas	Steam	10.8	51405	4RGRESG2	2	353.0	300.0	150.0	60.22	5002
	CHP	Gas	Steam	10.8	51406	4RGRESG3	3	353.0	300.0	150.0	60.22	5002
	CHP	Gas	Steam	10.8	51401	4RGRESG5	5	889.0	800.0	400.0	67.20	5003

	CHP	Gas	Steam	10.8	51402	4RGRESG6	6	889.0	800.0	400.0	67.20	5003
Smolensk	CHP	Gas	Steam	10.8	51440	4SMGREG1	1	235.3	200.0	100.0	60.22	5002
	CHP	Gas	Steam	10.8	51441	4SMGREG2	2	235.3	200.0	100.0	60.22	5002
	CHP	Gas	Steam	10.8	51442	4SMGREG3	3	247.0	210.0	100.0	60.22	5002
Volga 3	CHP	Gas	Steam	10.8	51410	4TEC-3G1	G	375.0	300.0	30.0	60.22	5002
Volga 1	CHP	Gas	Steam	10.8	51414	4VTEC-G6	G	726.5	588.8	318.8	63.50	5003

Hydro Power Plants

There is large number of hydro power plants in Russia, but in this model they are not modeled for OPF analyses. The power plants are mainly used for domestic consumption, and since the model is made for export analysis, only thermal and nuclear units were taken into consideration.

Thermal Power Plants

Russian thermal power plants are mostly run on natural gas, and are usually providers of heat and electricity (CHP). Production of electricity on natural gas is cheaper than coal. As a result, there is no incentive in building new coal fired power plants, as long as prices of natural gas in Russia remain low. Price of gas taken into consideration for these cost curves is $160/tcm.

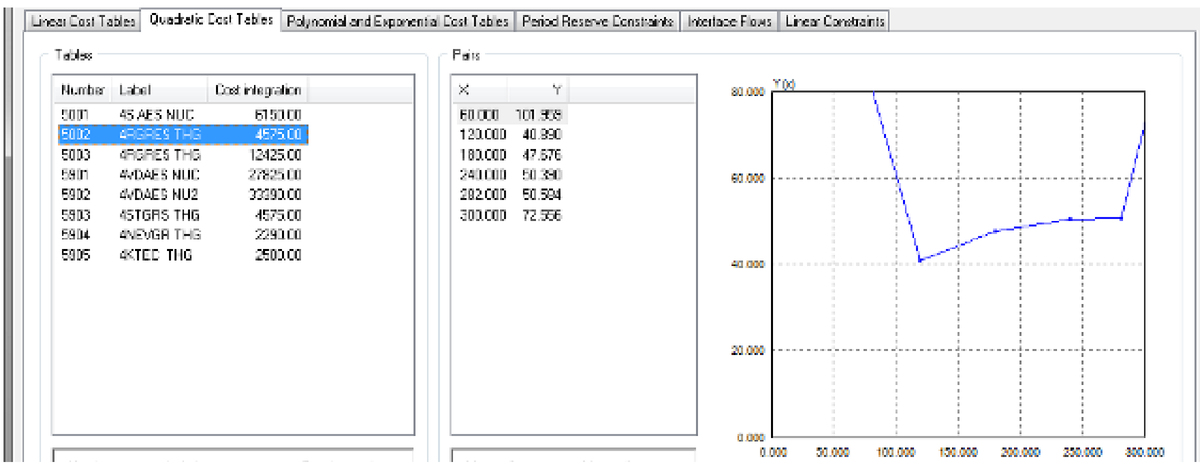


Figure 4.69 – Russia – Cost curve and table for TPP 300MW gas fired unit (curve 5002)

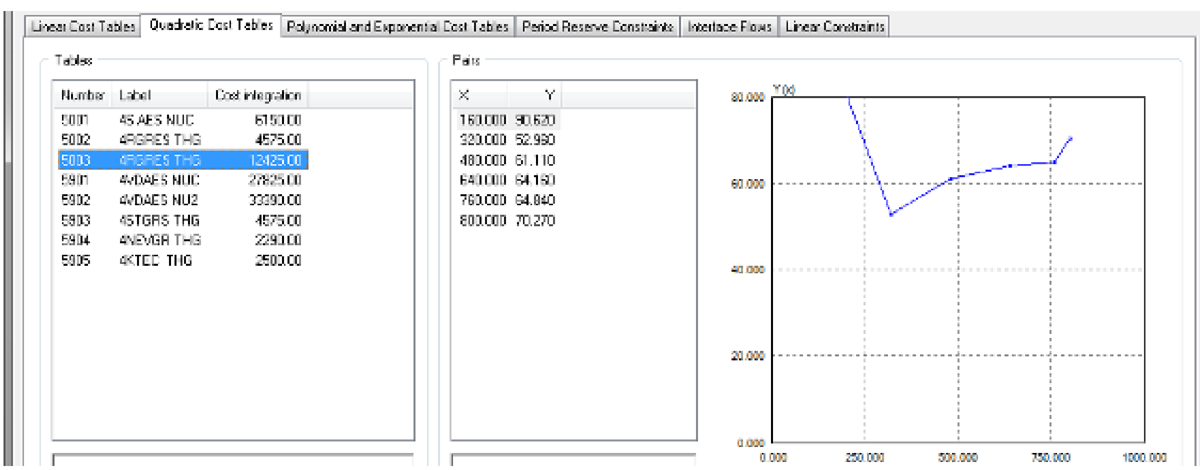


Figure 4.70 – Russia – Cost curve and table for TPP 800MW gas fired unit (curve 5003)

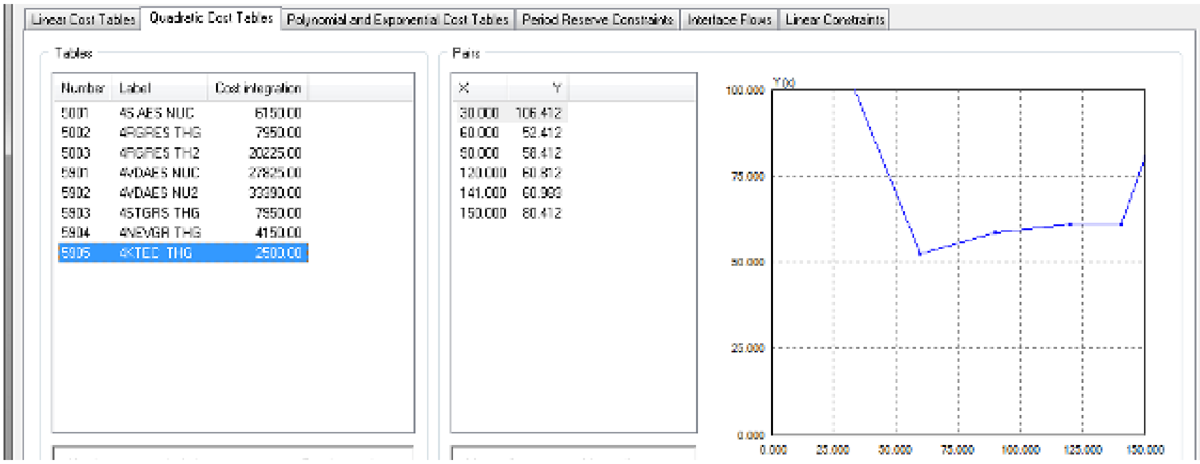


Figure 4.71 – Russia – Cost curve and table for CHPs run on coal (curve 404)

Gas Turbine Power Plants

So far there is only few power plants with gas turbine unit installed in Russian system, but it is expected that in future all obsolete gas fired units will be replaced with these more efficient ones. So far only units installed are near Sankt Petersburg and Kaliningrad.

Nuclear Power Plants

Russia has 31 operational nuclear reactors. For all the 500 MW units, a similar cost curve is used without implementing capital costs, since these units are more than 20 years old. For 1000 MW units, capital costs were taken into consideration, since these units are relatively new (less than 20 years old).

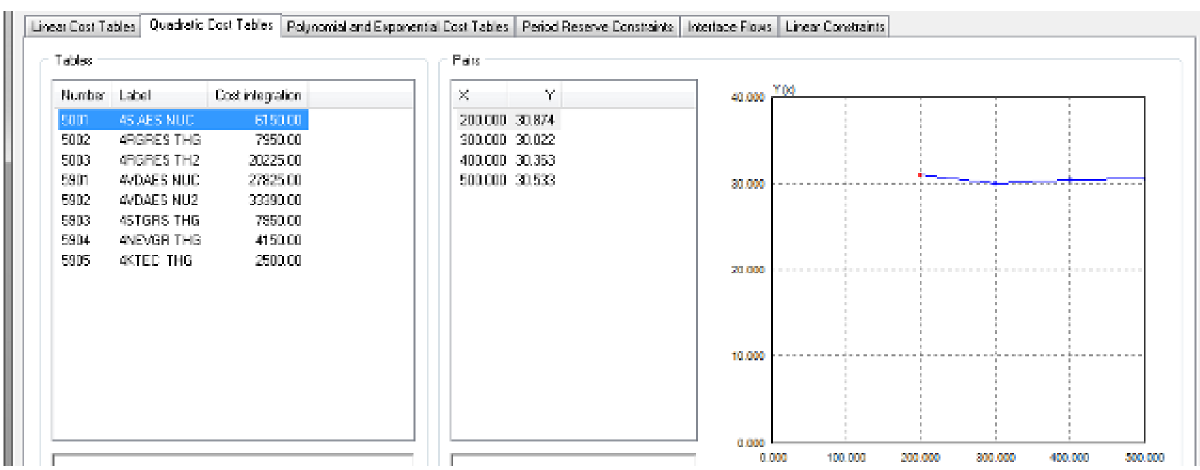


Figure 4.73– Russia – Cost curve and table for NPP Smolensk 500MW (curve 5001)

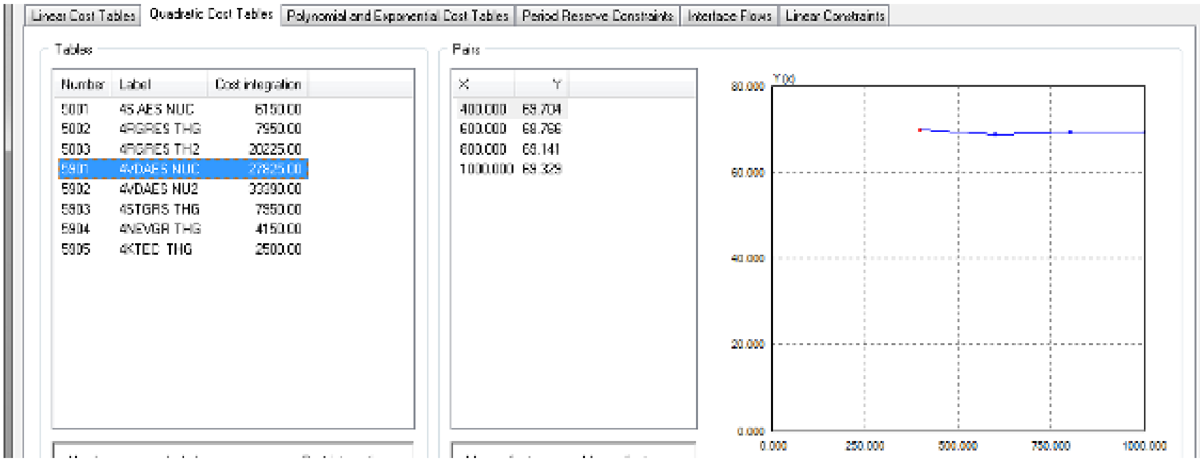


Figure 4.74 – Russia – Cost curve and table for NPP Volgodonsk 1000MW (curve 5901)

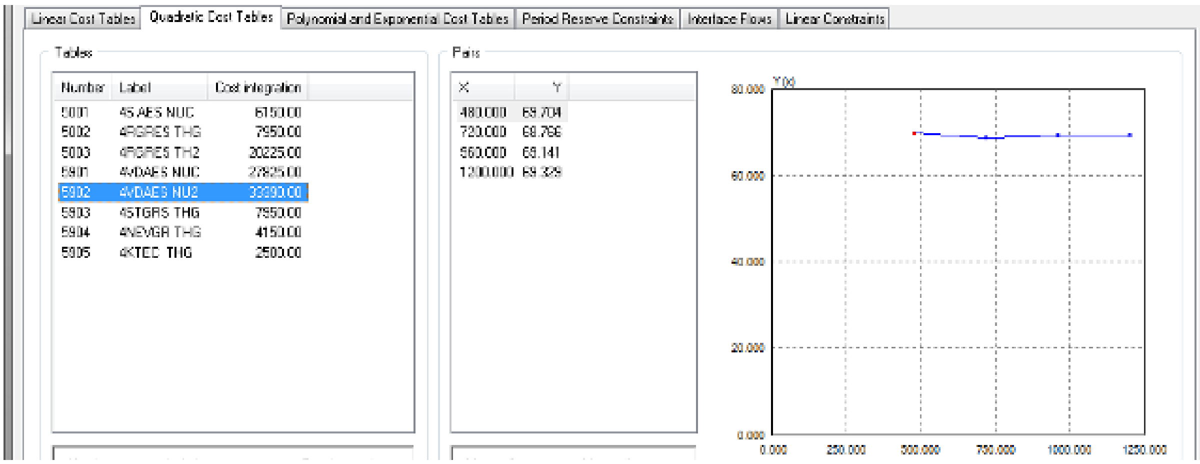


Figure 4.75– Russia – Cost curve and table for NPP Volgodonsk 1200MW (curve 5902)

Renewables

Since renewable power plants are modeled as negative load and not as generation units, no generation cost curves are used.

1.21 Turkey

According to the data provided and generic cost curves described in Chapter 2.1.3 OPF model of Turkey is constructed and its main characteristics are described below.

1.21.1 PSS/E OPF Transmission System Modeling

The transmission network is usually presented with buses and connection links-network elements (lines, cables, transformers, etc…) and its OPF model consists of data describing network limitations, according to respective country grid codes and rules of engagement (voltage limits, line and transformer load ratings). The transmission system model of Turkey is given in Figure 4.76.

1.21.2 PSS/E OPF Generation Modeling

Generation OPF model consists of tables and cost curves. Table 4.7 shows the main characteristics of Turkey Generation OPF model.

Table 4.7 – Turkey – Generation units OPF model

Power plant	Plant type	Fuel	Turbine	heat rate (mBTU/MWh)	Bus Num	Bus Name	Id	Mbase (MVA)	Pmax (MW)	Pmin (MW)	cost ($/MWh)	curve
Elbistan	TPP	Coal	Steam	10.8	69131	TELBS1T1	1	382.5	344.3	156.0	79.48	601
	TPP	Coal	Steam	10.8	69132	TELBS1T2	2	382.5	344.3	156.0	79.48	601
	TPP	Coal	Steam	10.8	69133	TELBS1T3	3	382.5	344.3	156.0	79.48	601
	TPP	Coal	Steam	10.8	69134	TELBS1T4	4	382.5	344.3	156.0	79.48	601
	TPP	Coal	Steam	10.8	69127	TELBS2T1	1	403.0	362.7	140.0	79.48	601
	TPP	Coal	Steam	10.8	69128	TELBS2T2	2	403.0	362.7	140.0	79.48	601
	TPP	Coal	Steam	10.8	69129	TELBS2T3	3	403.0	362.7	140.0	79.48	601
	TPP	Coal	Steam	10.8	69130	TELBS2T4	4	403.0	362.7	140.0	79.48	601
	TPP	Coal	Steam	10.8	69241	TELBSCT1	1	403.0	342.5	156.0	84.35	602
	TPP	Coal	Steam	10.8	69242	TELBSCT2	2	403.0	342.5	156.0	84.35	602
	TPP	Coal	Steam	10.8	69243	TELBSCT3	3	403.0	342.5	156.0	84.35	602
	TPP	Coal	Steam	10.8	69244	TELBSCT4	4	403.0	342.5	156.0	84.35	602
	TPP	Coal	Steam	10.8	69245	TELBSDT1	1	403.0	342.5	156.0	84.35	602
	TPP	Coal	Steam	10.8	69246	TELBSDT2	2	403.0	342.5	156.0	84.35	602
	TPP	Coal	Steam	10.8	69247	TELBSDT3	3	403.0	342.5	156.0	84.35	602
	TPP	Coal	Steam	10.8	69248	TELBSDT4	4	403.0	342.5	156.0	84.35	602
Sugozu	TPP	Coal	Steam	10.8	69121	TSUGOZT1	1	733.5	660.0	185.0	90.70	603
	TPP	Coal	Steam	10.8	69122	TSUGOZT2	2	733.5	660.0	185.0	90.70	603
Seyitomer	TPP	Coal	Steam	10.8	69112	TSEYITT1	1	180.0	153.0	34.0	64.77	604
	TPP	Coal	Steam	10.8	69113	TSEYITT2	2	180.0	153.0	34.0	64.77	604
	TPP	Coal	Steam	10.8	69114	TSEYITT3	3	188.0	159.8	48.0	64.77	604
	TPP	Coal	Steam	10.8	69115	TSEYITT4	4	188.0	159.8	48.0	64.77	604
Orhaneli	TPP	Coal	Steam	10.8	69138	TORHANT	1	247.0	210.0	14.0	55.53	605
Yatagan	TPP	Coal	Steam	10.8	69142	TYATAGT1	1	247.0	210.0	20.0	55.53	605
	TPP	Coal	Steam	10.8	69143	TYATAGT2	2	247.0	210.0	20.0	55.53	605
	TPP	Coal	Steam	10.8	69144	TYATAGT3	3	247.0	210.0	20.0	55.53	605
Yenikoy	TPP	Coal	Steam	10.8	69145	TYENIKT1	1	247.0	210.0	51.0	55.53	605
	TPP	Coal	Steam	10.8	69146	TYENIKT2	2	247.0	210.0	51.0	55.53	605
Cayirhan	TPP	Coal	Steam	10.8	69123	TCAYIRT1	1	188.0	159.8	37.0	91.18	606
	TPP	Coal	Steam	10.8	69124	TCAYIRT2	2	188.0	159.8	37.0	91.18	606
	TPP	Coal	Steam	10.8	69125	TCAYIRT3	3	189.0	160.0	37.0	91.18	606
	TPP	Coal	Steam	10.8	69126	TCAYIRT4	4	189.0	160.0	37.0	91.18	606
Kangali	TPP	Coal	Steam	10.8	69135	TKANGAT1	1	188.0	159.8	37.0	91.18	606
	TPP	Coal	Steam	10.8	69136	TKANGAT2	2	188.0	159.8	37.0	91.18	606
	TPP	Coal	Steam	10.8	69137	TKANGAT3	3	188.0	159.8	37.0	91.18	606
Catalgezi	TPP	Coal	Steam	10.8	69226	TCATALT1	1	189.0	159.8	37.0	95.6	609
	TPP	Coal	Steam	10.8	69227	TCATALT2	2	189.0	159.8	37.0	95.6	609
Can	TPP	Coal	Steam	10.8	69116	TCANTST1	1	177.8	160.0	81.0	91.18	606
	TPP	Coal	Steam	10.8	69117	TCANTST2	2	177.8	160.0	81.0	91.18	606
Soma	TPP	Coal	Steam	10.8	69147	TSOMABT1	1	194.1	165.0	12.0	64.77	607
	TPP	Coal	Steam	10.8	69148	TSOMABT2	2	194.1	165.0	12.0	64.77	607
	TPP	Coal	Steam	10.8	69149	TSOMABT3	3	194.1	165.0	12.0	64.77	607
	TPP	Coal	Steam	10.8	69150	TSOMABT4	4	194.1	165.0	12.0	64.77	607
	TPP	Coal	Steam	10.8	69151	TSOMABT5	5	194.1	165.0	12.0	64.77	607
	TPP	Coal	Steam	10.8	69152	TSOMABT6	6	194.1	165.0	12.0	64.77	607
Kemerkoy	TPP	Coal	Steam	10.8	69139	TKEMERT1	1	247.0	210.0	51.0	64.77	607
	TPP	Coal	Steam	10.8	69141	TKEMERT3	3	247.0	210.0	51.0	64.77	607
	TPP	Coal	Steam	10.8	69140	TKEMERT2	2	270.6	230.0	43.0	64.77	607
Tuncilbek	TPP	Coal	Steam	10.8	69119	TTUNCBT4	4	188.0	159.8	43.0	64.77	607
	TPP	Coal	Steam	10.8	69118	TTUNCBT5	5	188.0	159.8	43.0	64.77	607
	TPP	Coal	Steam	10.8	69120	TTUNCBT3	3	82.0	65.6	21.0	64.77	607
Eren	TPP	Coal	Steam	10.8	69278	TEREN T1	1	189.0	159.8	120.0	95.60	609
	TPP	Coal	Steam	10.8	69279	TEREN T2	2	706.0	600.0	300.0	90.70	603
	TPP	Coal	Steam	10.8	69280	TEREN T3	3	706.0	600.0	300.0	90.70	603
Akkuyu	NPP	Uranium	Steam	10.4	69251	TNAKKYN1	1	1333.0	1200.0	600.0	88.60	608
	NPP	Uranium	Steam	10.4	69252	TNAKKYN2	2	1333.0	1200.0	600.0	88.60	608
	NPP	Uranium	Steam	10.4	69253	TNAKKYN3	3	1333.0	1200.0	600.0	88.60	608
	NPP	Uranium	Steam	10.4	69254	TNAKKYN4	4	1333.0	1200.0	600.0	88.60	608

Power plant	Plant type	Fuel	Turbine	heat rate (mBTU/MWh)	Bus Num	Bus Name	Id	Mbase (MVA)	Pmax (MW)	Pmin (MW)	cost ($/MWh)	curve
Sinop	NPP	Uranium	Steam	10.4	69288	TSINOPN1	1	889.0	800.0	50.0	88.60	608
	NPP	Uranium	Steam	10.4	69289	TSINOPN2	2	889.0	800.0	50.0	88.60	608
Dicle	HPP	Hydro	Francis	Tigris	69160	TDICLEH1	H	130.0	110.5	46.0	30.75	634
Batman	HPP	Hydro	Francis	Tigris	69157	TBATMAH1	H	226.5	192.5	105.0	71.49	635
Ilisu	HPP	Hydro	Francis	Tigris	69257	TILISUH1	1	222.0	200.0	30.0	71.49	636
	HPP	Hydro	Francis	Tigris	69257	TILISUH1	2	222.0	200.0	30.0	71.49	636
	HPP	Hydro	Francis	Tigris	69258	TILISUH2	3	222.0	200.0	30.0	71.49	636
	HPP	Hydro	Francis	Tigris	69258	TILISUH2	4	222.0	200.0	30.0	71.49	636
	HPP	Hydro	Francis	Tigris	69259	TILISUH3	5	222.0	200.0	30.0	71.49	636
	HPP	Hydro	Francis	Tigris	69259	TILISUH3	6	222.0	200.0	30.0	71.49	636
Ozluce	HPP	Hydro	Francis	Eufrat	69202	TOZLUCH1	H	200.0	170.0	106.0	30.75	627
Uzuncere	HPP	Hydro	Francis	Eufrat	69218	TUZUNCH1	H	93.6	70.7	36.0	30.75	601
Keban	HPP	Hydro	Francis	Eufrat	69095	TKEBANH1	1	175.0	157.5	78.0	30.75	602
	HPP	Hydro	Francis	Eufrat	69096	TKEBANH2	2	175.0	157.5	78.0	30.75	602
	HPP	Hydro	Francis	Eufrat	69097	TKEBANH3	3	175.0	157.5	78.0	30.75	602
	HPP	Hydro	Francis	Eufrat	69098	TKEBANH4	4	175.0	157.5	78.0	30.75	602
	HPP	Hydro	Francis	Eufrat	69099	TKEBANH5	5	201.3	181.0	88.0	30.75	603
	HPP	Hydro	Francis	Eufrat	69100	TKEBANH6	6	201.3	181.0	88.0	30.75	603
	HPP	Hydro	Francis	Eufrat	69101	TKEBANH7	7	201.3	181.0	88.0	30.75	603
	HPP	Hydro	Francis	Eufrat	69102	TKEBANH8	8	201.3	181.0	88.0	30.75	603
Karakaya	HPP	Hydro	Francis	Eufrat	69089	TKARAKH1	1	315.0	300.0	98.0	30.75	604
	HPP	Hydro	Francis	Eufrat	69090	TKARAKH2	2	315.0	300.0	98.0	30.75	604
	HPP	Hydro	Francis	Eufrat	69091	TKARAKH3	3	315.0	300.0	98.0	30.75	604
	HPP	Hydro	Francis	Eufrat	69092	TKARAKH4	4	315.0	300.0	98.0	30.75	604
	HPP	Hydro	Francis	Eufrat	69093	TKARAKH5	5	315.0	300.0	98.0	30.75	604
	HPP	Hydro	Francis	Eufrat	69094	TKARAKH6	6	315.0	300.0	98.0	30.75	604
Ataturk	HPP	Hydro	Francis	Eufrat	69081	TATATUH1	1	315.0	300.0	97.0	30.75	605
	HPP	Hydro	Francis	Eufrat	69082	TATATUH2	2	315.0	300.0	97.0	30.75	605
	HPP	Hydro	Francis	Eufrat	69083	TATATUH3	3	315.0	300.0	97.0	30.75	605
	HPP	Hydro	Francis	Eufrat	69084	TATATUH4	4	315.0	300.0	97.0	30.75	605
	HPP	Hydro	Francis	Eufrat	69085	TATATUH5	5	315.0	300.0	97.0	30.75	605
	HPP	Hydro	Francis	Eufrat	69086	TATATUH6	6	315.0	300.0	97.0	30.75	605
	HPP	Hydro	Francis	Eufrat	69087	TATATUH7	7	315.0	300.0	97.0	30.75	605
	HPP	Hydro	Francis	Eufrat	69088	TATATUH8	8	315.0	300.0	97.0	30.75	605
Birecik	HPP	Hydro	Francis	Eufrat	69077	TBIRECH1	1	140.0	115.0	80.0	30.75	606
	HPP	Hydro	Francis	Eufrat	69077	TBIRECH1	2	140.0	115.0	80.0	30.75	606
	HPP	Hydro	Francis	Eufrat	69078	TBIRECH3	3	140.0	115.0	80.0	30.75	606
	HPP	Hydro	Francis	Eufrat	69078	TBIRECH3	4	140.0	115.0	80.0	30.75	606
	HPP	Hydro	Francis	Eufrat	69079	TBIRECH5	5	140.0	115.0	80.0	30.75	606
	HPP	Hydro	Francis	Eufrat	69079	TBIRECH5	6	140.0	115.0	80.0	30.75	606
Karkamas	HPP	Hydro	Francis	Eufrat	69103	TKARKMH1	H	208.8	187.8	72.0	30.75	607
Oymapinar	HPP	Hydro	Francis	Mangavati	69065	TOYMAPH1	1	150.0	135.0	20.0	30.81	608
	HPP	Hydro	Francis	Mangavati	69066	TOYMAPH2	2	150.0	135.0	20.0	30.81	608
	HPP	Hydro	Francis	Mangavati	69067	TOYMAPH3	3	150.0	135.0	20.0	30.81	608
	HPP	Hydro	Francis	Mangavati	69068	TOYMAPH4	4	150.0	135.0	20.0	30.81	608
Kilickaya	HPP	Hydro	Francis	Yeslirmak	69155	TKILICH1	H	134.0	120.6	56.0	30.75	609
Kokluce	HPP	Hydro	Francis	Yeslirmak	69110	TKOKLUH1	H	100.0	90.0	44.0	30.75	610
Hasan Ugurlu	HPP	Hydro	Francis	Yeslirmak	69106	TH.UGUH1	1	145.0	130.5	43.0	30.75	611
	HPP	Hydro	Francis	Yeslirmak	69106	TH.UGUH1	2	145.0	130.5	43.0	30.75	611
	HPP	Hydro	Francis	Yeslirmak	69107	TH.UGUH3	3	145.0	130.5	43.0	30.75	611
	HPP	Hydro	Francis	Yeslirmak	69107	TH.UGUH3	4	145.0	130.5	43.0	30.75	611
Suat Ugurlu	HPP	Hydro	Francis	Yeslirmak	69108	TS.UGUH1	H	76.5	69.0	38.0	30.81	612
Alpaslan	HPP	Hydro	Francis	Kizilirmak	69206	TALPS1H1	H	180.0	160.0	76.0	30.75	618
Yamula	HPP	Hydro	Francis	Kizilirmak	69217	TYAMULH1	H	125.0	100.0	40.0	30.75	613
Hirfanli	HPP	Hydro	Francis	Kizilirmak	69198	THIRFAH1	H	184.0	147.2	112.0	30.75	614
Kesikopru	HPP	Hydro	Francis	Kizilirmak	69239	TKESKOH1	H	109.0	87.2	26.6	30.75	615
Obruk	HPP	Hydro	Francis	Kizilirmak	69194	TOBRUKH1	H	250.0	200.0	80.0	30.75	616
Altinkaya	HPP	Hydro	Francis	Kizilirmak	69061	TALTINH1	1	195.0	175.0	83.0	30.75	617
	HPP	Hydro	Francis	Kizilirmak	69062	TALTINH2	2	195.0	175.0	83.0	30.75	617
	HPP	Hydro	Francis	Kizilirmak	69063	TALTINH3	3	195.0	175.0	83.0	30.75	617
	HPP	Hydro	Francis	Kizilirmak	69064	TALTINH4	4	195.0	175.0	83.0	30.75	617
Sariyar	HPP	Hydro	Francis	Sakaryar	69210	TSARIYH1	H	177.8	160.0	76.0	30.75	619
Gokcekaya	HPP	Hydro	Francis	Sakaryar	69214	TGOKCEH1	1	103.1	92.8	46.0	30.75	620
	HPP	Hydro	Francis	Sakaryar	69215	TGOKCEH2	2	103.1	92.8	46.0	30.75	620
	HPP	Hydro	Francis	Sakaryar	69216	TGOKCEH3	3	103.1	92.8	46.0	30.75	620

Power plant	Plant type	Fuel	Turbine	heat rate (mBTU/MWh)	Bus Num	Bus Name	Id	Mbase (MVA)	Pmax (MW)	Pmin (MW)	cost ($/MWh)	curve
Menzelet	HPP	Hydro	Francis	Ceyhan	69176	TMENZEH1	H	132.0	118.8	56.0	30.75	621
Sir	HPP	Hydro	Francis	Ceyhan	69173	TSIR H1	1	105.0	94.5	36.0	30.75	622
	HPP	Hydro	Francis	Ceyhan	69174	TSIR H2	2	105.0	94.5	36.0	30.75	622
	HPP	Hydro	Francis	Ceyhan	69175	TSIR H3	3	105.0	94.5	36.0	30.75	622
Berke	HPP	Hydro	Francis	Ceyhan	69170	TBERKEH1	1	187.5	168.8	127.5	30.75	623
	HPP	Hydro	Francis	Ceyhan	69171	TBERKEH2	2	187.5	168.8	127.5	30.75	623
	HPP	Hydro	Francis	Ceyhan	69172	TBERKEH3	3	187.5	168.8	127.5	30.75	623
Aslantas	HPP	Hydro	Francis	Ceyhan	69167	TASLANH1	H	168.0	134.4	48.0	30.75	624
Ermenek	HPP	Hydro	Francis	Goksu	69162	TERMENH1	1	168.0	151.2	70.0	42.39	625
	HPP	Hydro	Francis	Goksu	69163	TERMENH2	2	168.0	151.2	70.0	42.39	625
Gezende	HPP	Hydro	Francis	Goksu	69164	TGEZENH1	H	187.5	159.4	114.0	42.39	626
Torul	HPP	Hydro	Francis	Harsit	69204	TTORULH1	H	121.5	103.2	50.0	71.49	627
Kartun	HPP	Hydro	Francis	Harsit	69221	TKARTUH1	H	92.0	78.2	32.0	71.49	628
Catalan	HPP	Hydro	Francis	Seyhan	69223	TCATALH1	H	195.0	165.8	99.0	71.49	629
Yusufelly	HPP	Hydro	Francis	Coruh	69261	TYUSUFH1	1	150.0	135.0	43.0	71.49	630
	HPP	Hydro	Francis	Coruh	69262	TYUSUFH2	2	150.0	135.0	43.0	71.49	630
	HPP	Hydro	Francis	Coruh	69263	TYUSUFH3	3	150.0	135.0	43.0	71.49	630
	HPP	Hydro	Francis	Coruh	69264	TYUSUFH4	4	150.0	135.0	43.0	71.49	630
Deriner	HPP	Hydro	Francis	Coruh	69073	TDERINH1	1	186.0	167.5	70.0	71.49	631
	HPP	Hydro	Francis	Coruh	69074	TDERINH2	2	186.0	167.5	70.0	71.49	631
	HPP	Hydro	Francis	Coruh	69075	TDERINH3	3	186.0	167.5	70.0	71.49	631
	HPP	Hydro	Francis	Coruh	69076	TDERINH4	4	186.0	167.5	70.0	71.49	631
Borcka	HPP	Hydro	Francis	Coruh	69071	TBORCKH1	1	167.0	150.0	60.0	71.49	632
	HPP	Hydro	Francis	Coruh	69072	TBORCKH2	2	167.0	150.0	60.0	71.49	632
Muratli	HPP	Hydro	Francis	Coruh	69069	TMURATH1	H	147.0	117.6	50.0	71.49	633
Unimar	CCGT	Gas	CCGT	6.7	69001	TUNIMRG1	CC	632.0	505.6	18.0	91.31	611
Hamidabat	CCGT	Gas	CCGT	6.7	69004	THAMIG1	CC	1168.1	934.5	435.0	91.31	612
	CCGT	Gas	CCGT	6.7	69014	THAMIGB	CC	389.4	311.5	145.0	91.31	613
Gebze	CCGT	Gas	CCGT	6.7	69016	TGEBZAG1	CC	944.5	802.8	90.0	91.31	614
	CCGT	Gas	CCGT	6.7	69019	TGEBZBG1	CC	944.5	802.8	90.0	91.31	614
Trakiya	CCGT	Gas	CCGT	6.7	69022	TTRAKYG1	CC	588.0	499.7	199.0	91.31	615
Ambarli	CCGT	Gas	CCGT	6.7	69025	TAMBARG1	CC	563.0	450.4	135.0	91.31	616
	CCGT	Gas	CCGT	6.7	69028	TAMBA2G1	CC	563.0	450.4	135.0	91.31	616
	CCGT	Gas	CCGT	6.7	69031	TAMBA2G3	CC	563.0	450.4	135.0	91.31	616
Bursa	CCGT	Gas	CCGT	6.7	69043	TBURSAG2	CC	841.8	715.5	182.5	91.31	617
	CCGT	Gas	CCGT	6.7	69045	TBURSAG3	CC	841.8	715.5	182.5	91.31	617
Adapazari	CCGT	Gas	CCGT	6.7	69048	TADAPAG1	CC	944.5	802.8	90.0	91.31	614
Aliaga	CCGT	Gas	CCGT	6.7	69051	TALIAGG1	CC	944.5	802.8	90.0	91.31	614
	CCGT	Gas	CCGT	6.7	69054	TALIAGG3	CC	944.5	802.8	90.0	91.31	614
Temel	CCGT	Gas	CCGT	6.7	69188	TTEMELG2	CC	998.0	817.4	299.0	91.31	618
Bandirma	CCGT	Gas	CCGT	6.7	69265	TBANDRG1	CC	1110.0	1000.0	321.3	91.31	619
Denizli	CCGT	Gas	CCGT	6.7	69178	TDENIZG1	CC	998.0	847.0	90.0	91.31	619
AEI	CCGT	Gas	CCGT	6.7	69292	TAEI__G1	CC	1030.0	875.0	362.7	91.31	619
Aksa	CCGT	Gas	CCGT	6.7	69295	TAKSA_G1	CC	1086.0	900.0	351.9	91.31	619
Tufanbey	CCGT	Gas	CCGT	6.7	69228	TTUFANG1	CC	567.0	480.0	111.0	91.31	615
Sugozu2	TPP	Coal	Steam	10.8	69290	TAYAS2G	1	941.0	850.0	300.0	90.70	620
Gerze	TPP	Coal	Steam	10.8	69282	TGERZET1	1	647.0	550.0	270.0	90.70	603
	TPP	Coal	Steam	10.8	69283	TGERZET2	2	647.0	550.0	270.0	90.70	603

Hydro Power Plants

Hydro power plants in Turkey are an important source of energy. The largest HPPs are located on the Euphrates river and use Francis turbines. Recently, most of these machines have been refurbished and reconstructed in scope of a project that connects Turkey to ENTSO-E, because they represent main plants used for system control. Other power plants used for control are HPP Hasan Ugurlu and HPP Altinkaya.

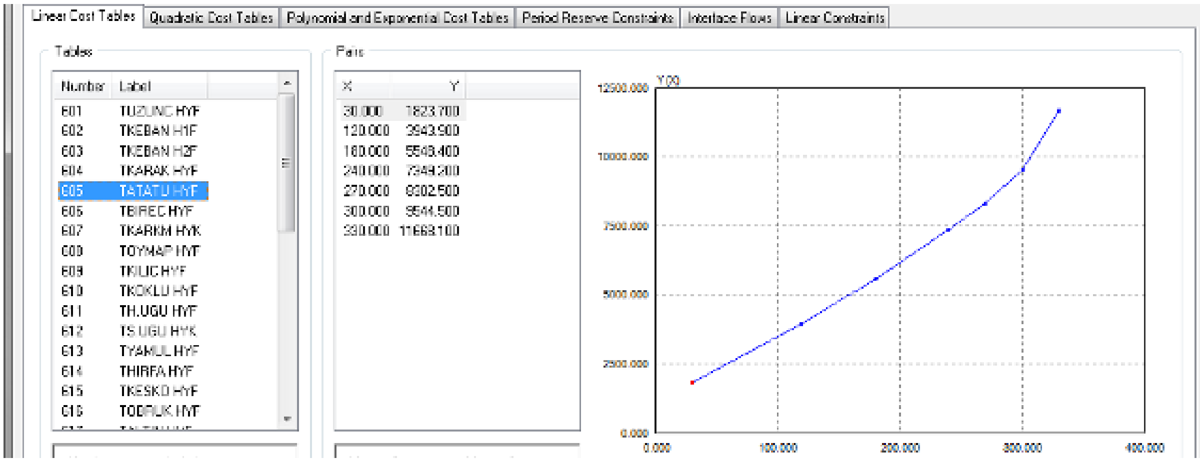


Figure 4.77 – Turkey – Cost curve and table for HPP Ataturk Euphrat cascade (curve 605)

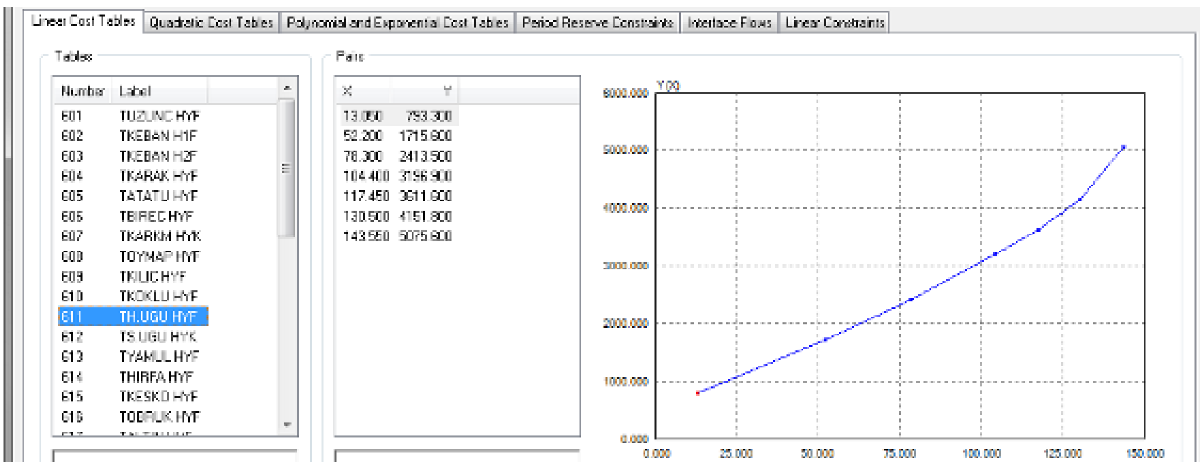


Figure 4.78 – Turkey – Cost curve and table for HPP Hasan Ugurlu (curve 611)

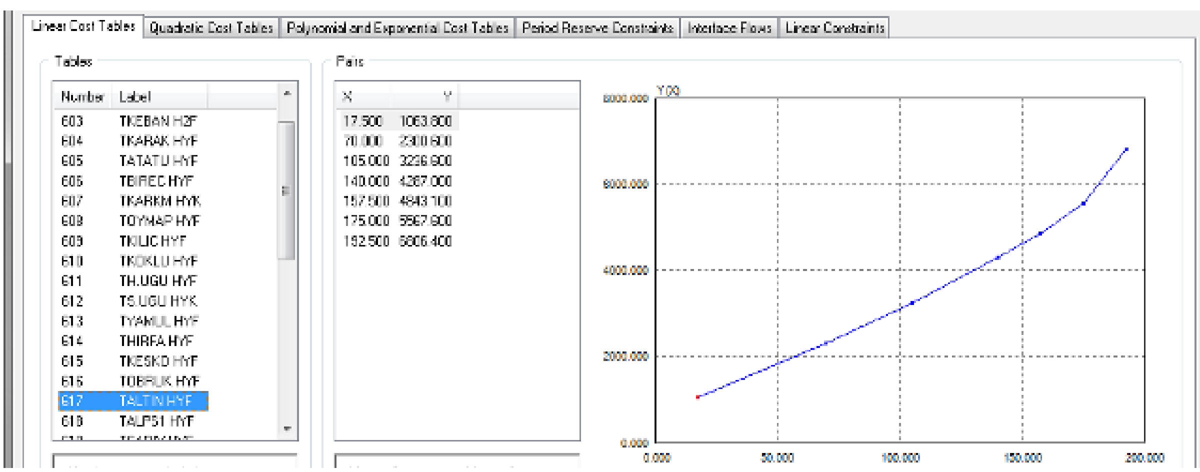


Figure 4.79 – Turkey – Cost curve and table for HPP Altinkaya (curve 617)

Currently there are many new HPP in the construction phase, and for these, full capital costs were taken into consideration when deriving cost curves.

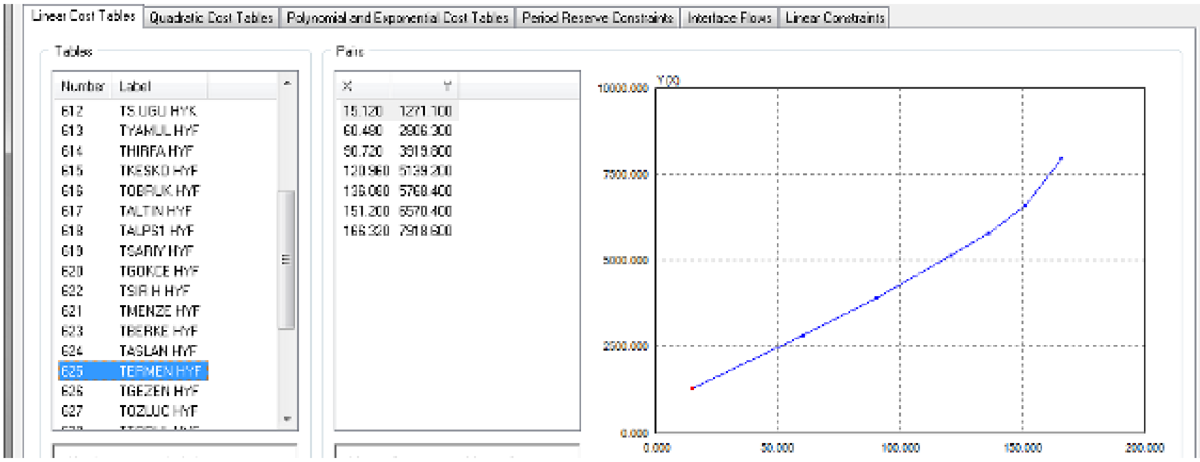


Figure 4.80 – Turkey – Cost curve and table for HPP Ermenek (curve 625)

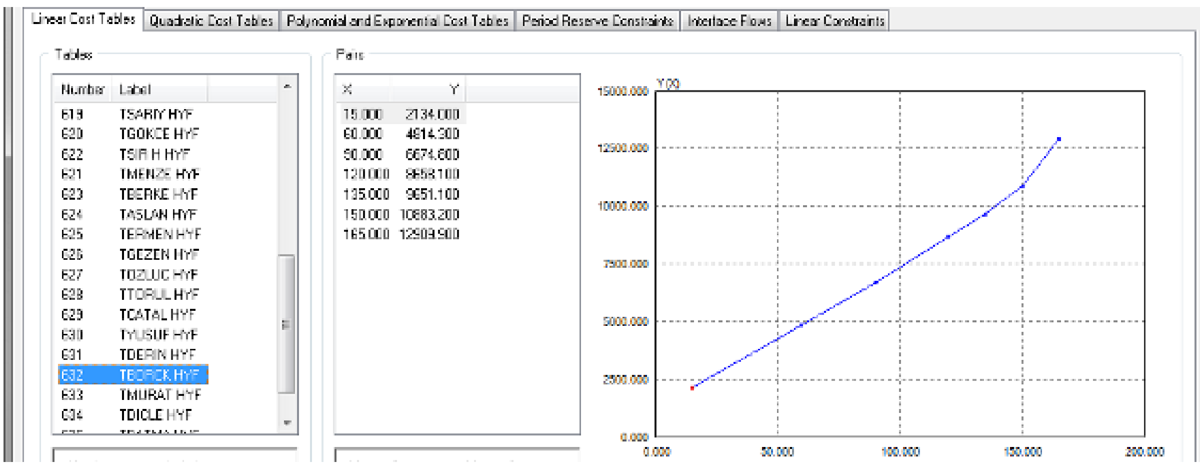


Figure 4.81 – Turkey – Cost curve and table for HPP Borcka (curve 632)

Thermal Power Plants

Thermal power plants in Turkey can be divided into three groups based on the fuel intake: TPPs run on domestic coal, imported coal and fuel oil. The domestic coal price of $75/ton or $3.6/mBTU is calculated, and imported coal (which is higher grade) 20% higher price $90/ton or $4/mBTU is calculated to cover transportation costs. Most of the power plants are new (less than 20 years old) and therefore include capital costs. TPP Sugozu is one of the newest coal fired power plants in Turkey, and it is used as reference for all new coal fired power plants in Turkey.

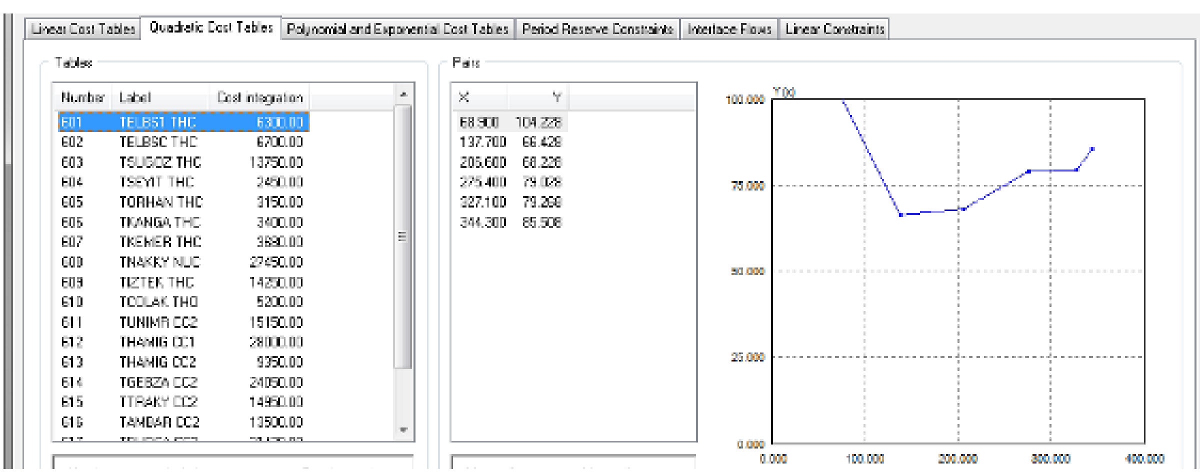


Figure 4.82 – Turkey – Cost curve and table for TPP Elbistan (curve 601)

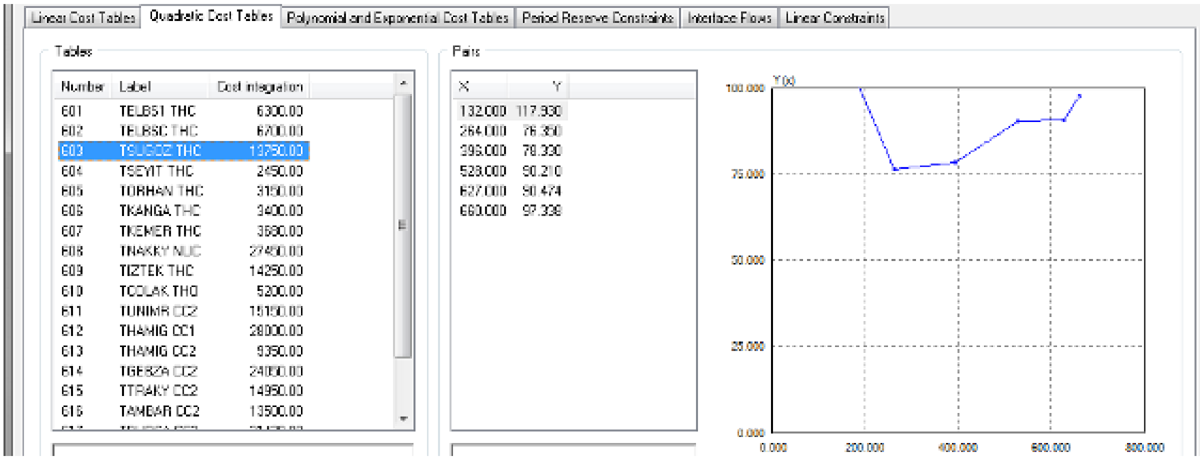


Figure 4.83– Turkey – Cost curve and table for TPP Sugozu (curve 603)

Some of older constructed power plants like TPP Ambarli in Istanbul and TPP Colak are run on fuel oil (or natural gas). In the TPP Colak case there is second set run on imported coal.

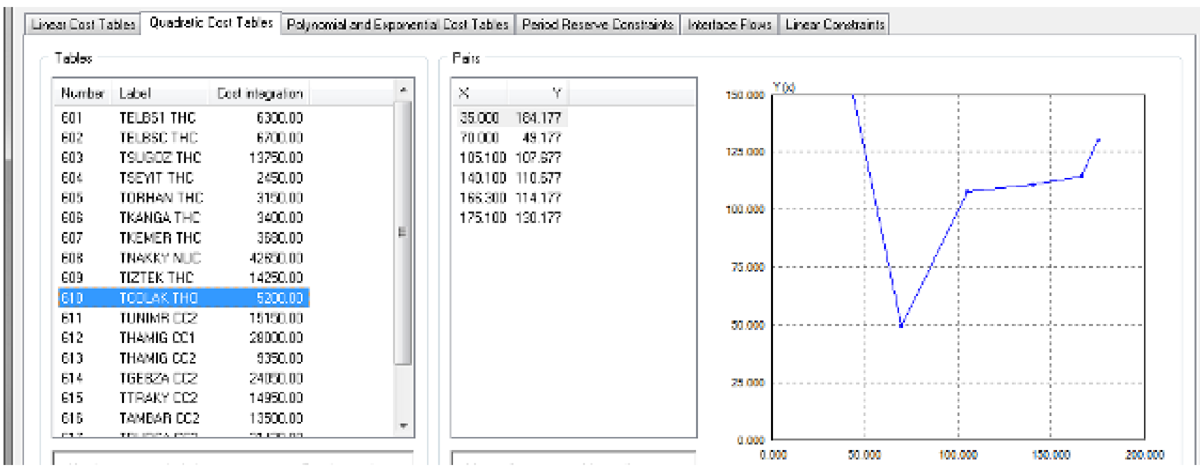


Figure 4.84 – Turkey – Cost curve and table for oil fired TPP Colak (curve 610)

Gas Turbine Power Plants

Almost all new thermal power plants built are CCGT and are built on the principal of BOT, build-operate-transfer, so after a certain period, 15-20 years, all these units will be transferred to the Turkish state. These power plants are useful as base power units, and some are used for system control. Usually, these are units are owned by EUAS, but IPPs participate as well. Since they are all fairly new, all curves include capital costs with the price of gas set as $350/tcm or $8.9/mBTU.

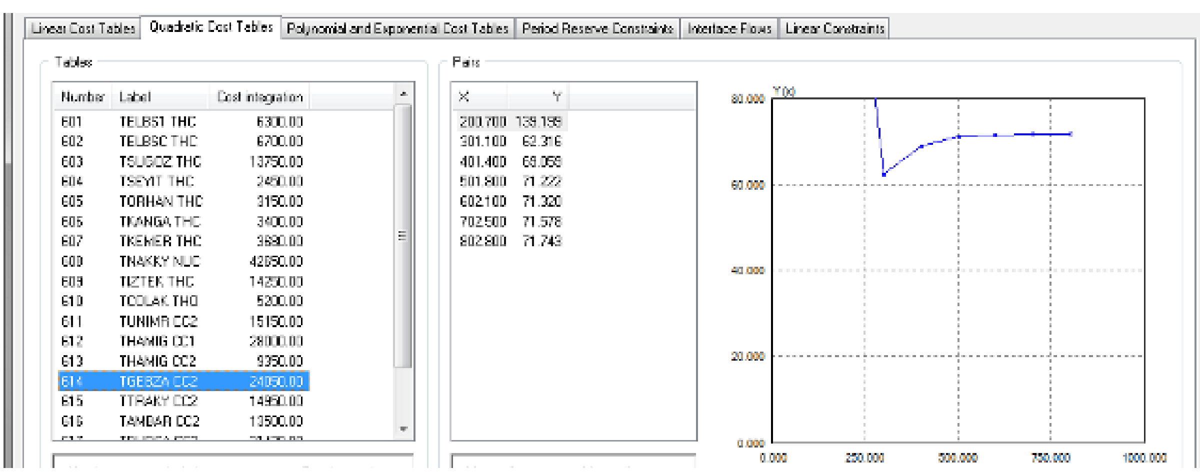


Figure 4.85 – Turkey – Cost curve and table for new CCGT Ada Pazari-Gebze (curve 614)

Nuclear Power Plants

There are no nuclear power stations in Turkey at the moment, but two major projects are planned: NPP Akkuyu 4800MW and NPP Sinop 1600MW. NPP Akkuyu is based on Russian technology, and second on South Korean. The same cost curve is used for both, and it includes capital costs at \$4.15mil per MW of installed power.

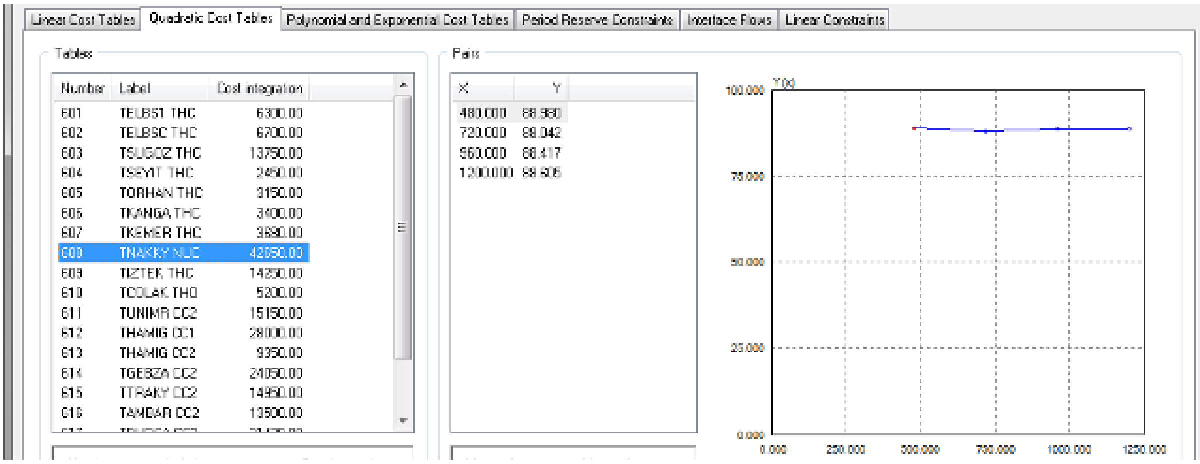


Figure 4.86 – Turkey – Cost curve and table for NPP Akkuyu 1200MW units (curve 608)

Renewables

Renewable power plants are modeled as shown in Figure 4.87 for WPP and Figure for SHPP, adjusted to represent the feed in tariff system in Turkey.

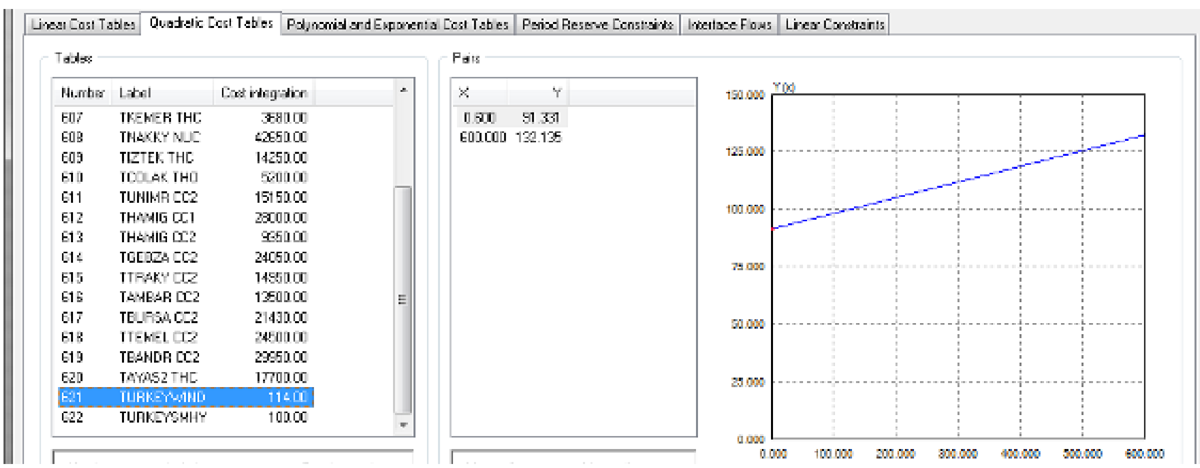


Figure 4.87 – Turkey – Cost curve and table for Wind power plants (curve 621)

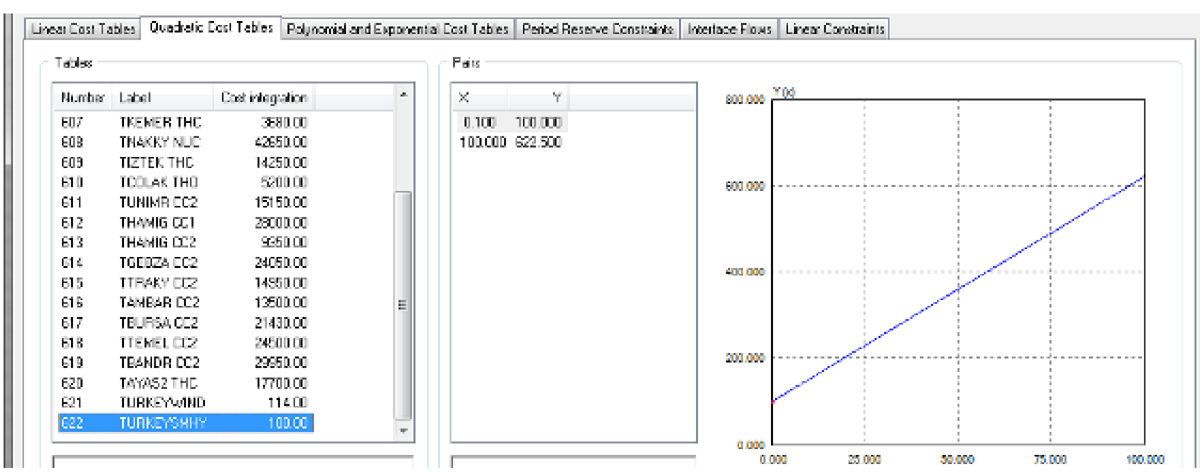


Figure 4.88 Turkey – Cost curve and table for Small Hydro units (curve 622)

The cost curves should be used to calculate production costs, and not for generation engagement optimization, since these units are engaged based on energy availability and not on economics. Therefore, for optimization calculations they should be disabled by setting the dispatch value to zero.

1.22 Ukraine

According to the data provided and generic cost curves described in Chapter 2.1.3 OPF model of Ukraine is constructed and its main characteristics are outlined below.

1.22.1 PSS/E OPF Transmission System Modeling

The transmission network is usually presented with buses and connection links-network elements (lines, cables, transformers, etc…) and its OPF model consists of data describing network limitations, according to respective country grid codes and rules of engagement (voltage limits, line and transformer load ratings). The transmission system model of Ukraine is given in Figure 4.89.

1.22.2 PSS/E OPF Generation Modeling

Generation OPF model consists of tables and cost curves. Table 4.8 shows the main characteristics of Ukrainian Generation OPF model.

Table 4.8 Ukraine – Generation units OPF model

Power plant	Plant type	Fuel	Turbine	heat rate (mBTU/MWh)	Bus Num	Bus Name	Id	Mbase (MVA)	Pmax (MW)	Pmin (MW)	cost ($/MWh)	curve
Juzna	NPP	Uranium	Steam	10.4	79521	UJUAZSN1	1	1111	1000.0	600.0	22.30	701
	NPP	Uranium	Steam	10.4	79522	UJUAZSN2	2	1111	1000.0	600.0	22.30	701
	NPP	Uranium	Steam	10.4	79523	UJUAZSN3	3	1111	1000.0	600.0	22.30	701
Zaporozhje	NPP	Uranium	Steam	10.4	79311	UZAEC_N1	1	1111	1000.0	600.0	22.30	701
	NPP	Uranium	Steam	10.4	79312	UZAEC_N2	2	1111	1000.0	600.0	22.30	701
	NPP	Uranium	Steam	10.4	79313	UZAEC_N3	3	1111	1000.0	600.0	22.30	701
	NPP	Uranium	Steam	10.4	79314	UZAEC_N4	4	1111	1000.0	600.0	22.30	701
	NPP	Uranium	Steam	10.4	79315	UZAEC_N5	5	1111	1000.0	600.0	22.30	701
	NPP	Uranium	Steam	10.4	79316	UZAEC_N6	6	1111	1000.0	600.0	22.30	701
Rivne	NPP	Uranium	Steam	10.4	79901	URAEC_N1	1	259	220.0	150.0	23.50	702
	NPP	Uranium	Steam	10.4	79902	URAEC_N2	2	259	220.0	150.0	23.50	702
	NPP	Uranium	Steam	10.4	79903	URAEC_N3	3	259	220.0	150.0	23.50	702
	NPP	Uranium	Steam	10.4	79904	URAEC_N4	4	259	220.0	150.0	23.50	702
	NPP	Uranium	Steam	10.4	79905	URAEC_N5	5	1111	1000.0	600.0	22.30	701
	NPP	Uranium	Steam	10.4	79906	URAEC_N6	6	1111	1000.0	600.0	22.30	701
Khmelnick	NPP	Uranium	Steam	10.4	79808	UHAEC_N2	2	1111	1000.0	600.0	22.30	701
	NPP	Uranium	Steam	10.4	79809	UHAEC_N1	1	1111	1000.0	600.0	22.30	701
Kiev 5	CHP	Gas	Steam	10.8	79701	UKTEC5G1	1	141.2	120.0	25.0	103.80	723
	CHP	Gas	Steam	10.8	79702	UKTEC5G2	2	141.2	120.0	25.0	103.80	723
	CHP	Gas	Steam	10.8	79703	UKTEC5G3	3	376.5	320.0	100.0	102.40	722
	CHP	Gas	Steam	10.8	79704	UKTEC5G4	4	376.5	320.0	100.0	102.40	722
Kiev 6	CHP	Gas	Steam	10.8	79711	UKTEC6G1	1	376.5	320.0	100.0	102.40	722
	CHP	Gas	Steam	10.8	79712	UKTEC6G2	2	376.5	320.0	100.0	102.40	722
	CHP	Gas	Steam	10.8	79713	UKTEC6G3	3	376.5	320.0	100.0	102.40	722
Zaporozhje	CHP	Gas	Steam	10.8	79231	UZALJUG1	1	125	110.0	25.0	112.6	716
	CHP	Gas	Steam	10.8	79232	UZALJUG2	2	125	110.0	25.0	112.6	716
	CHP	Gas	Steam	10.8	79233	UZALJUG3	3	376.5	320.0	100.0	102.40	722
Burstin	TPP	Coal	Steam	10.8	79911	UBUTECT1	1	235.3	200.0	100.0	62.74	703
	TPP	Coal	Steam	10.8	79912	UBUTECT2	2	235.3	200.0	100.0	62.74	703
	TPP	Coal	Steam	10.8	79913	UBUTECT3	3	235.3	200.0	100.0	62.74	703
	TPP	Coal	Steam	10.8	79914	UBUTECT4	4	235.3	200.0	100.0	62.74	703
	TPP	Coal	Steam	10.8	79915	UBUTECT5	5	235.3	200.0	100.0	62.74	703
	TPP	Coal	Steam	10.8	79916	UBUTECT6	6	235.3	200.0	100.0	62.74	703
	TPP	Coal	Steam	10.8	79917	UBUTECT7	7	235.3	200.0	100.0	62.74	703
	TPP	Coal	Steam	10.8	79918	UBUTECT8	8	235.3	200.0	100.0	62.74	703
	TPP	Coal	Steam	10.8	79919	UBUTECT9	9	247	210.0	100.0	62.74	703
	TPP	Coal	Steam	10.8	79920	UBUTECTA	10	247	210.0	100.0	62.74	703
	TPP	Coal	Steam	10.8	79921	UBUTECTB	11	235.3	200.0	100.0	62.74	703
	TPP	Coal	Steam	10.8	79922	UBUTECTC	12	235.3	200.0	100.0	62.74	703
Dobrotvir	TPP	Coal	Steam	10.8	79925	UDTEC_T5	E	352.5	300.0	50.0	60.10	704
	TPP	Coal	Steam	10.8	79927	UDTEC_T7	7	167.5	150.0	0.0	60.10	705
	TPP	Coal	Steam	10.8	79928	UDTEC_T8	8	167.5	150.0	0.0	60.10	705
Luganska	TPP	Coal	Steam	10.8	79108	ULUTECT8	8	235.3	200.0	100.0	60.20	706
	TPP	Coal	Steam	10.8	79109	ULUTECT9	9	235.3	200.0	100.0	60.20	706
	TPP	Coal	Steam	10.8	79110	ULUTECTA	10	235.3	200.0	100.0	60.20	706
	TPP	Coal	Steam	10.8	79111	ULUTECTB	11	235.3	200.0	100.0	60.20	706
	TPP	Coal	Steam	10.8	79112	ULUTECTC	12	235.3	200.0	100.0	60.20	706
	TPP	Coal	Steam	10.8	79113	ULUTECTD	13	235.3	200.0	100.0	60.20	706
	TPP	Coal	Steam	10.8	79114	ULUTECTE	14	253.3	200.0	100.0	60.20	706
	TPP	Coal	Steam	10.8	79115	ULUTECTF	15	253.3	200.0	100.0	60.20	706
Kurakovska	TPP	Coal	Steam	10.8	79143	UKUTECT3	3	235.3	200.0	100.0	63.10	708
	TPP	Coal	Steam	10.8	79144	UKUTECT4	4	235.3	200.0	100.0	63.10	708
	TPP	Coal	Steam	10.8	79145	UKUTECT5	5	235.3	210.0	100.0	63.10	708
	TPP	Coal	Steam	10.8	79146	UKUTECT6	6	235.3	210.0	100.0	63.10	708
	TPP	Coal	Steam	10.8	79147	UKUTECT7	7	235.3	210.0	100.0	63.10	708
	TPP	Coal	Steam	10.8	79148	UKUTECT8	8	235.3	210.0	100.0	63.10	708
	TPP	Coal	Steam	10.8	79149	UKUTECT9	9	235.3	210.0	100.0	63.10	708

Power plant	Plant type	Fuel	Turbine	heat rate (mBTU/MWh)	Bus Num	Bus Name	Id	Mbase (MVA)	Pmax (MW)	Pmin (MW)	cost ($/MWh)	curve
Starobeshevo	TPP	Coal	Steam	10.8	79125	USBTEC45	4	235.3	200.0	100.0	63.10	707
	TPP	Coal	Steam	10.8	79125	USBTEC45	5	247	210.0	130.0	63.10	707
	TPP	Coal	Steam	10.8	79126	USBTECT6	6	235.3	200.0	100.0	63.10	707
	TPP	Coal	Steam	10.8	79127	USBTECT7	7	235.3	200.0	100.0	63.10	707
	TPP	Coal	Steam	10.8	79128	USBTECT8	8	235.3	200.0	100.0	63.10	707
	TPP	Coal	Steam	10.8	79129	USBTECT9	9	235.3	200.0	100.0	63.10	707
	TPP	Coal	Steam	10.8	79130	USBTECTA	10	235.3	200.0	100.0	63.10	707
	TPP	Coal	Steam	10.8	79131	USBTECTB	11	235.3	200.0	100.0	63.10	707
	TPP	Coal	Steam	10.8	79132	USBTECTC	12	235.3	200.0	100.0	63.10	707
	TPP	Coal	Steam	10.8	79133	USBTECTD	13	235.3	200.0	100.0	63.10	707
Zmiievo	TPP	Coal	Steam	10.8	79200	UZMTZSGA	10	353	300.0	180.0	65.16	711
	TPP	Coal	Steam	10.8	79201	UZMTZSG1	1	235.3	200.0	130.0	65.16	711
	TPP	Coal	Steam	10.8	79202	UZMTZSG2	2	235.3	200.0	130.0	65.16	711
	TPP	Coal	Steam	10.8	79203	UZMTZSG3	3	235.3	200.0	100.0	65.16	711
	TPP	Coal	Steam	10.8	79204	UZMTZSG4	4	258.8	220.0	100.0	65.16	711
	TPP	Coal	Steam	10.8	79205	UZMTZSG5	5	235.3	200.0	100.0	65.16	711
	TPP	Coal	Steam	10.8	79206	UZMTZSG6	6	258.8	220.0	100.0	65.16	711
Uglegirska	TPP	Coal	Steam	10.8	79181	UUGTECT1	1	353	300.0	180.0	61.20	712
	TPP	Coal	Steam	10.8	79182	UUGTECT2	2	353	300.0	180.0	61.20	712
	TPP	Coal	Steam	10.8	79183	UUGTECT3	3	353	300.0	180.0	61.20	712
	TPP	Coal	Steam	10.8	79184	UUGTECT4	4	353	300.0	180.0	61.20	712
	TPP	Coal	Steam	10.8	79207	UZMTZSG7	7	353	300.0	180.0	65.16	712
	TPP	Coal	Steam	10.8	79208	UZMTZSG8	8	353	300.0	180.0	65.16	712
	TPP	Coal	Steam	10.8	79209	UZMTZSG9	9	353	300.0	180.0	65.16	712
	TPP	Gas	Steam	10.8	79185	UUGTECT5	5	889	800.0	500.0	112.60	713
	TPP	Gas	Steam	10.8	79186	UUGTECT6	6	889	800.0	500.0	112.60	713
	TPP	Gas	Steam	10.8	79187	UUGTECT7	7	889	800.0	500.0	112.60	713
Zaporozhje	TPP	Coal	Steam	10.8	79301	UZATECT1	1	353	300.0	180.0	61.30	715
	TPP	Coal	Steam	10.8	79302	UZATECT2	2	353	300.0	180.0	61.30	715
	TPP	Coal	Steam	10.8	79303	UZATECT3	3	353	300.0	180.0	61.30	715
	TPP	Coal	Steam	10.8	79304	UZATECT4	4	353	300.0	180.0	61.30	715
	TPP	Coal	Steam	10.8	79305	UZATECT5	5	889	800.0	500.0	61.30	715
	TPP	Coal	Steam	10.8	79306	UZATECT6	6	889	800.0	500.0	61.30	715
	TPP	Coal	Steam	10.8	79307	UZATECT7	7	889	800.0	500.0	61.30	715
Krivorozhje	TPP	Coal	Steam	10.8	79321	UKRTECT1	1	353	300.0	180.0	61.35	717
	TPP	Coal	Steam	10.8	79322	UKRTECT2	2	353	300.0	180.0	61.35	717
	TPP	Coal	Steam	10.8	79323	UKRTECT3	3	353	300.0	180.0	61.35	717
	TPP	Coal	Steam	10.8	79324	UKRTECT4	4	353	300.0	180.0	61.35	717
	TPP	Coal	Steam	10.8	79325	UKRTECT5	5	353	300.0	180.0	61.35	717
	TPP	Coal	Steam	10.8	79326	UKRTECT6	6	353	300.0	180.0	61.35	717
	TPP	Coal	Steam	10.8	79327	UKRTECT7	7	353	300.0	180.0	61.35	717
	TPP	Coal	Steam	10.8	79328	UKRTECT8	8	353	300.0	180.0	61.35	717
	TPP	Coal	Steam	10.8	79329	UKRTECT9	9	353	300.0	180.0	61.35	717
	TPP	Coal	Steam	10.8	79330	UKRTECTA	10	353	300.0	180.0	61.35	717
Pridnieprovska	TPP	Coal	Steam	10.8	79337	UPDTECT7	7	187.5	150.0	75.0	63.70	718
	TPP	Coal	Steam	10.8	79338	UPDTECT8	8	235.3	200.0	100.0	63.70	718
	TPP	Coal	Steam	10.8	79339	UPDTECT9	9	235.3	200.0	100.0	63.70	718
	TPP	Coal	Steam	10.8	79340	UPDTECTA	10	235.3	200.0	100.0	63.70	718
	TPP	Coal	Steam	10.8	79341	UPDTECTB	11	353	300.0	180.0	63.70	719
	TPP	Coal	Steam	10.8	79342	UPDTECTC	12	353	300.0	180.0	63.70	719
	TPP	Coal	Steam	10.8	79343	UPDTECTD	13	353	300.0	180.0	63.70	719
	TPP	Coal	Steam	10.8	79344	UPDTECTE	14	353	300.0	180.0	63.70	719
Trupilsk	TPP	Coal	Steam	10.8	79721	UTPTECT1	1	353	300.0	180.0	64.40	720
	TPP	Coal	Steam	10.8	79722	UTPTECT2	2	353	300.0	180.0	64.40	720
	TPP	Coal	Steam	10.8	79723	UTPTECT3	3	353	300.0	180.0	64.40	720
	TPP	Coal	Steam	10.8	79724	UTPTECT4	4	353	300.0	180.0	64.40	720
	TPP	Coal	Steam	10.8	79725	UTPTECT5	5	353	300.0	180.0	64.40	720
	TPP	Coal	Steam	10.8	79726	UTPTECT6	6	353	300.0	180.0	64.40	720
Ladigin	TPP	Coal	Steam	10.8	79821	ULDTECT1	1	353	300.0	180.0	61.15	721
	TPP	Coal	Steam	10.8	79822	ULDTECT2	2	353	300.0	180.0	61.15	721
	TPP	Coal	Steam	10.8	79823	ULDTECT3	3	353	300.0	180.0	61.15	721
	TPP	Coal	Steam	10.8	79824	ULDTECT4	4	353	300.0	180.0	61.15	721
	TPP	Coal	Steam	10.8	79825	ULDTECT5	5	353	300.0	180.0	61.15	721
	TPP	Coal	Steam	10.8	79826	ULDTECT6	6	353	300.0	180.0	61.15	721
Slovyanska	TPP	Coal	Steam	10.8	79159	USLTECT7	7	889	800.0	500.0	61.80	710

Power plant	Plant type	Fuel	Turbine	heat rate (mBTU/MWh)	Bus Num	Bus Name	Id	Mbase (MVA)	Pmax (MW)	Pmin (MW)	cost ($/MWh)	curve
Zuevska	TPP	Coal	Steam	10.8	79171	UZUTECT1	1	353	300.0	180.0	63.10	709
	TPP	Coal	Steam	10.8	79172	UZUTECT2	2	353	300.0	180.0	63.10	709
	TPP	Coal	Steam	10.8	79173	UZUTECT3	3	353	300.0	180.0	63.10	709
	TPP	Coal	Steam	10.8	79174	UZUTECT4	4	353	300.0	180.0	63.10	709

Hydro Power Plants

Hydro power plants in Ukraine are divided into the Dnieper and the Dniestr cascades. The Dnieper cascade has small head run-of-river power plants with similar cost curves, adjusted to reflect their capacity. For hydro power plants that are pumping stations, price of electricity is calculated based on a low electricity tariff wholesale price, and 0.7 conversion factor (from 1MWh of power consumed in pumping mode, 0.7MWh is gained in generation mode).

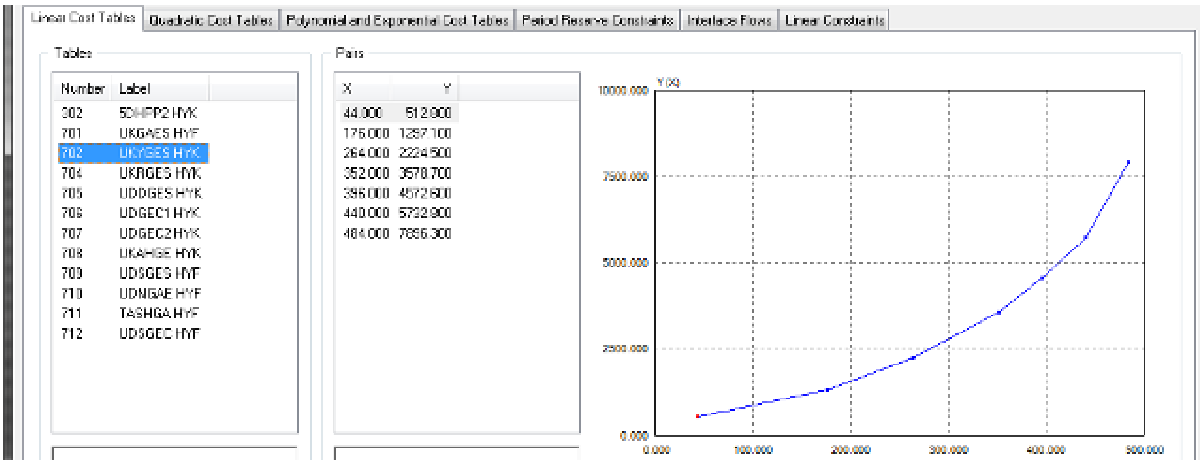


Figure 4.90 – Ukraine – Cost curve and table for HPP Kiev (curve 702)

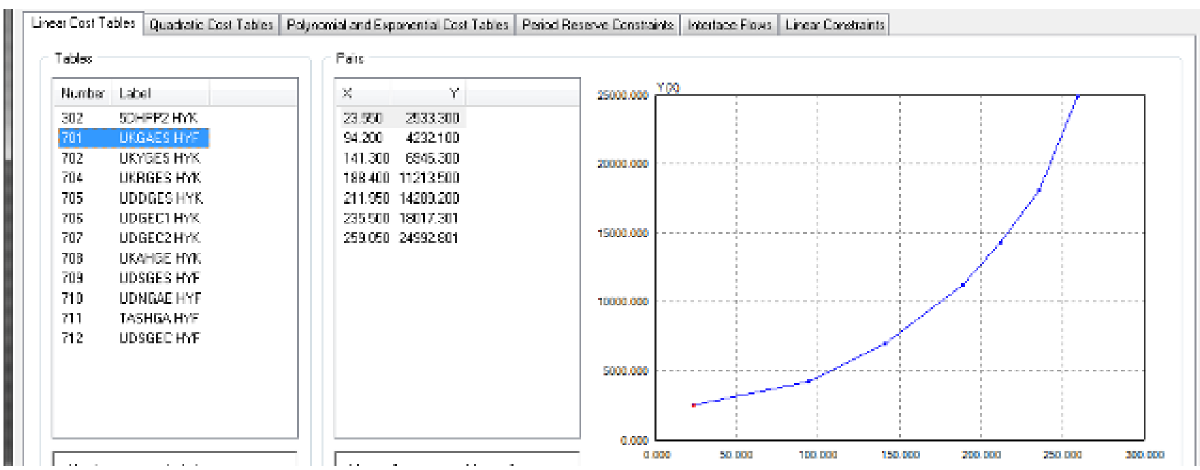


Figure 4.91 – Ukraine – Cost curve and table for PHPP Kiev (curve 701)

The Diestr cascade HPPs utilize Francis turbines, and two, the Tashlyk and Dniestr, are pumping stations. When construction is complete, it will be the largest pumping station in the world. Cost curves for the two include capital costs since they are new.

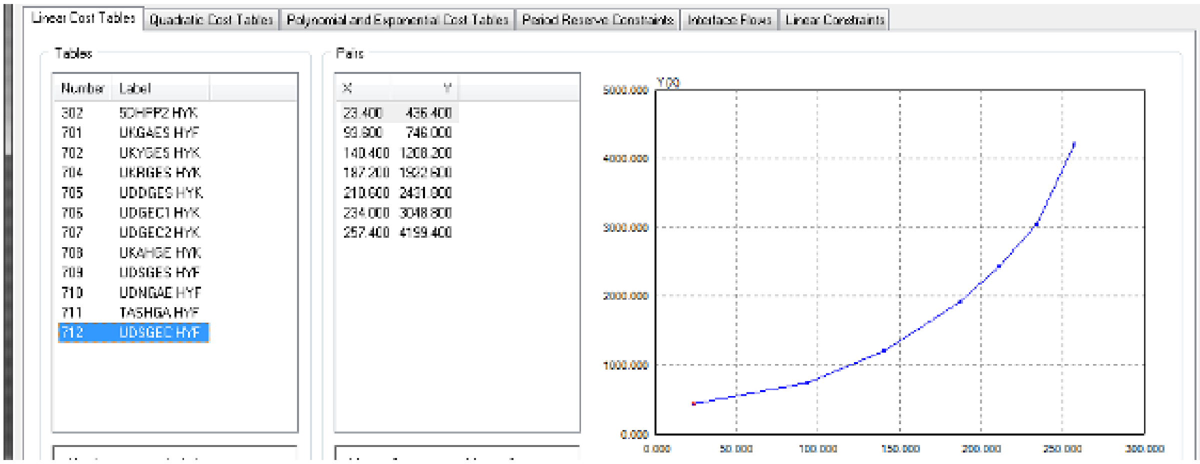


Figure 4.92 – Ukraine – Cost curve and table for HPPs on Sevan-Hrazdan cascade (curve 809)

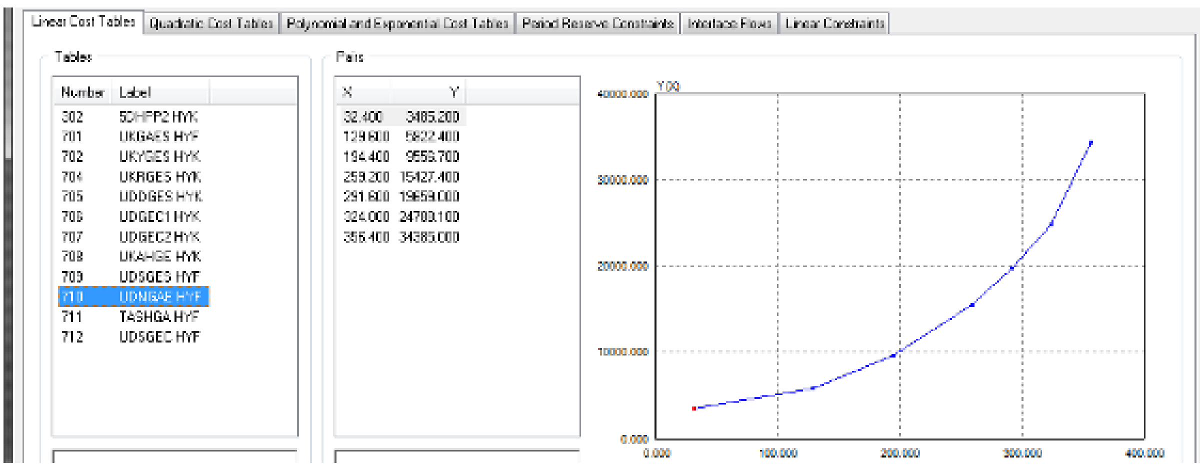


Figure 4.93 – Ukraine – Cost curve and table for PHPP Dniestr (curve 804)

Thermal Power Plants

Most of the power plants in Ukraine are thermal power plants that use domestic coal with different grades and quality. In some units natural gas is used. The gas prices are not reflected in the models since the gas price for these units is not usually used (only in case of power shortages, as reserve). For each power plant a different cost curve is made, based on the available data of coal quality, usage of natural gas in power production, and unit size. The units are old, and some of them are in a reconstruction phase, therefore, the capital costs were not included. Price of coal for power plants in Ukraine is around \$93.2/ton, or \$4.5/mBTU, which is high but lower than prices on some market hubs. Ukraine also is exports coal. This price is implemented in generic curves, and since tariffs for these power plants are known, remaining costs are adjusted accordingly generating the following curves:

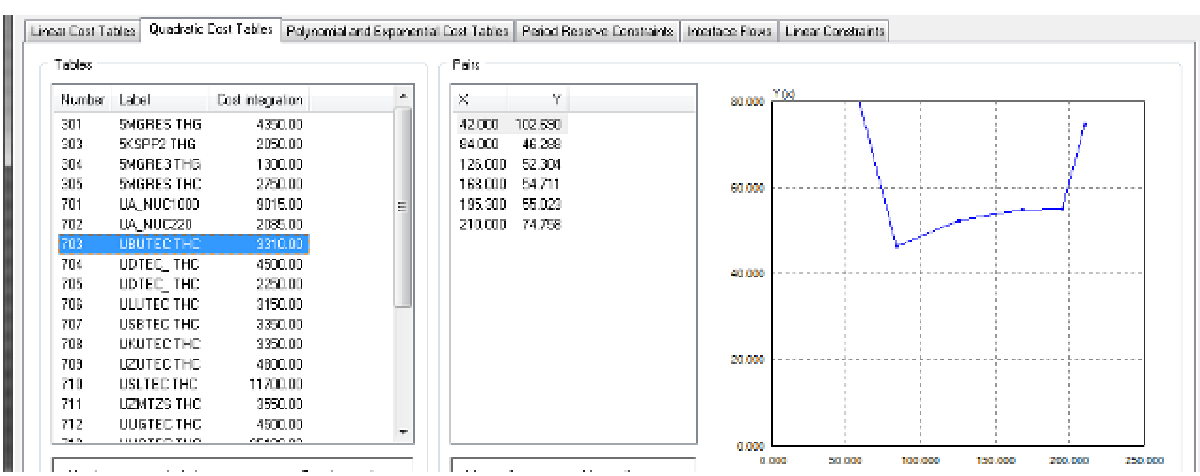


Figure 4.94 – Ukraine – Cost curve and table for TPP 200MW units (curve 703)

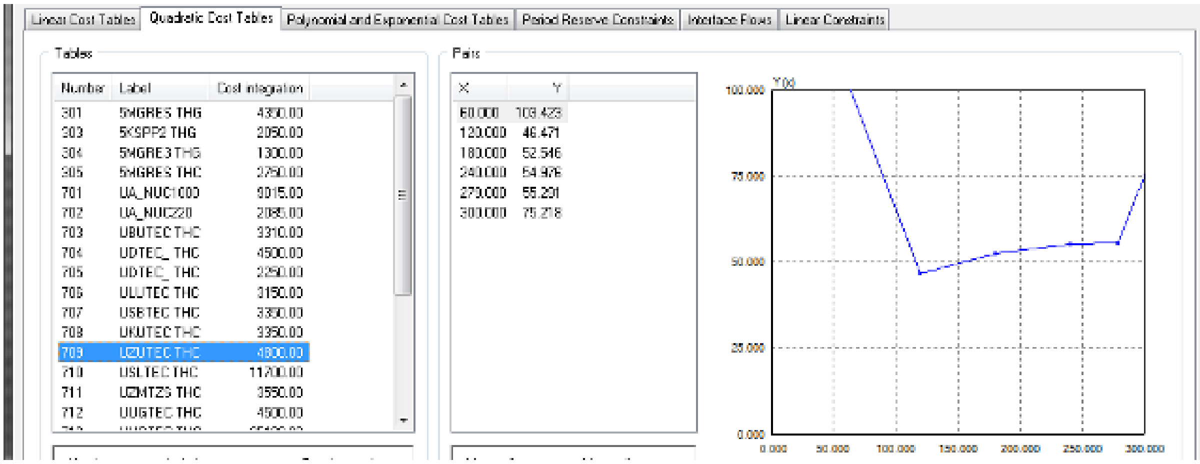


Figure 4.95 – Ukraine – Cost curve and table for TPP 300MW unit (curve 709)

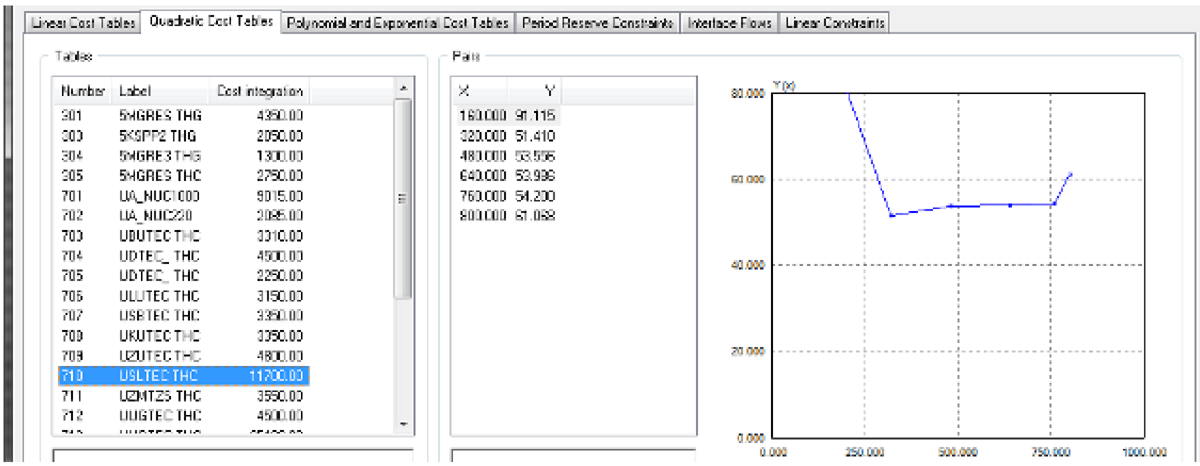


Figure 4.96 – Ukraine – Cost curve and table for TPP 800MW unit (curve 710)

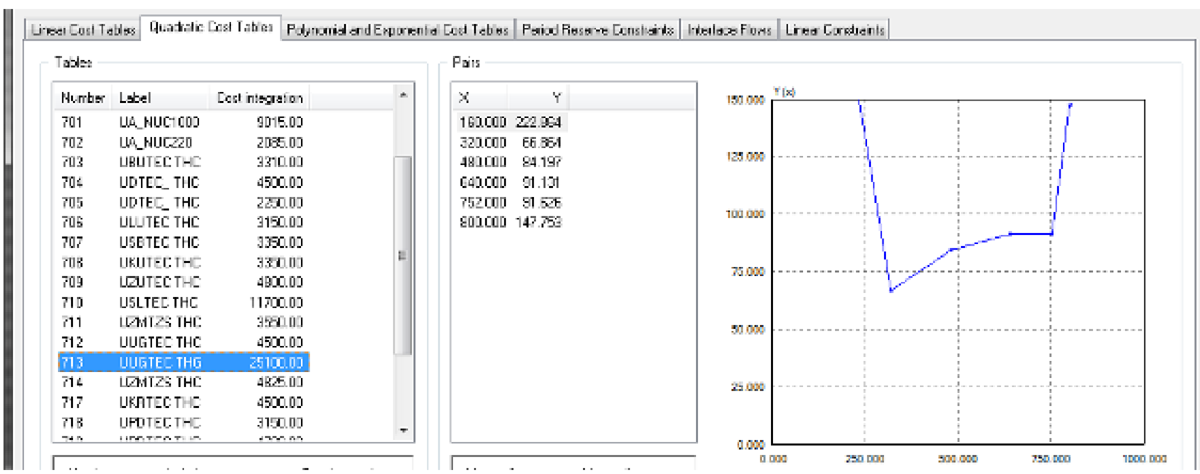


Figure 4.97 – Ukraine – Cost curve and table for TPP 800MW gas fired units (curve 713)

CHP or combined heat and power plants in Ukraine are run on imported gas from Russia, and price of this gas is $384.3/tcm.

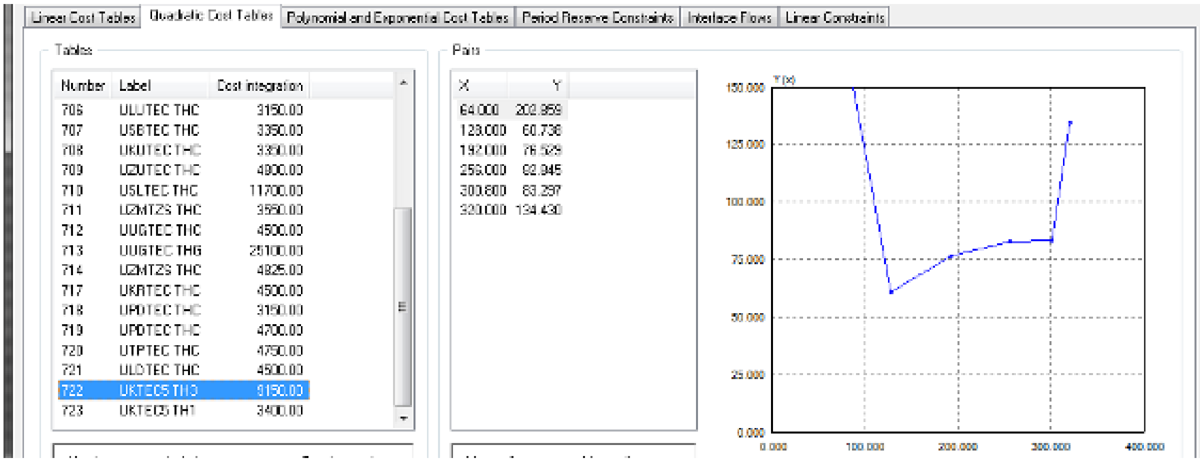


Figure 4.98 – Ukraine – Cost curve and table for CHP 300MW units (curve 722)

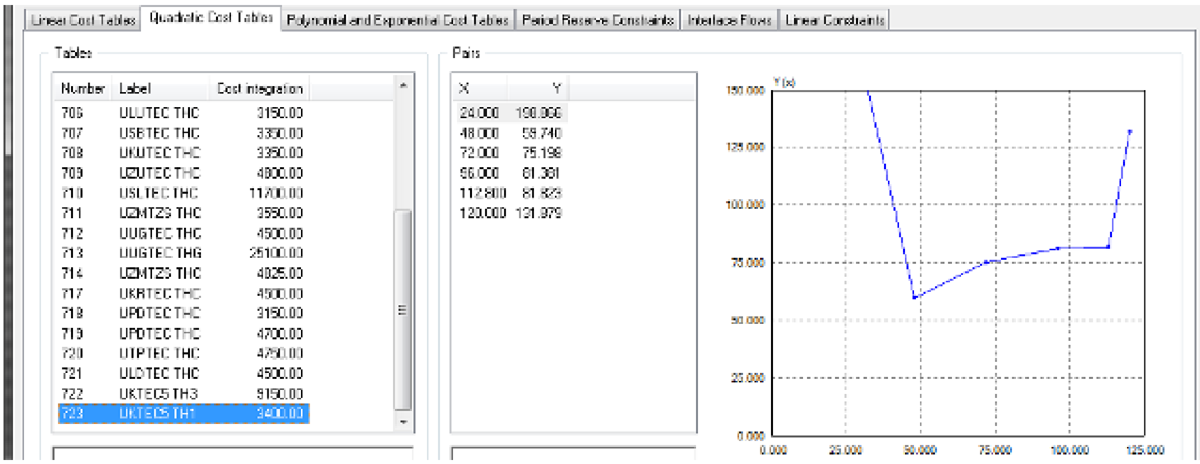


Figure 4.99 – Ukraine – Cost curve and table for CHP 120MW units (curve 723)

Nuclear Power Plants

Ukraine has many nuclear power plants. Most are 1000MW PWR units, and the NPP Rivne has 220MW units, which are also the oldest. Figure 4.100 and Figure 4.101 represents the cost curves for these types of units, adjusted according to real tariffs. Since all these power plants are more than 20 years old, no capital costs have been implemented into the curves.

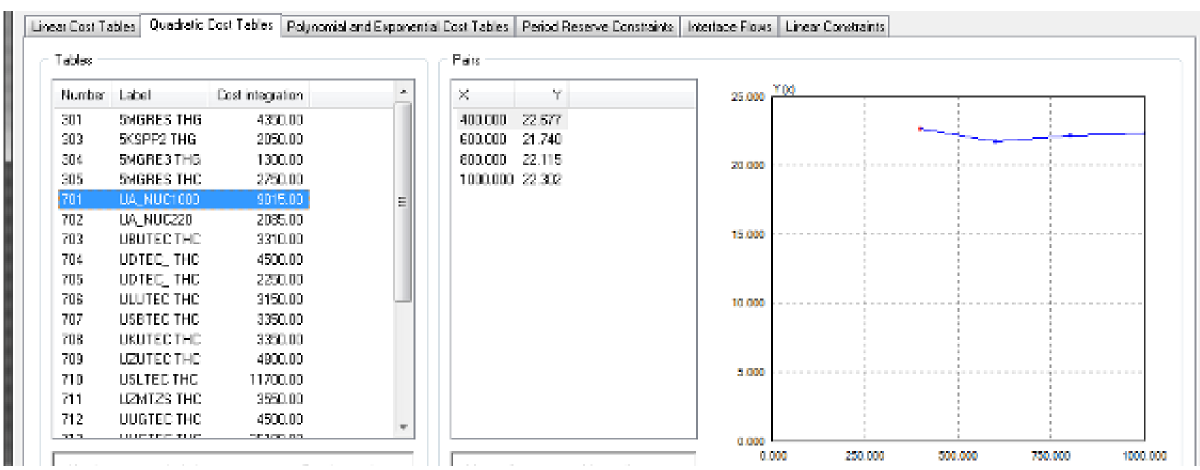


Figure 4.100 – Ukraine – Cost curve and table for 1000MW units (curve 701)

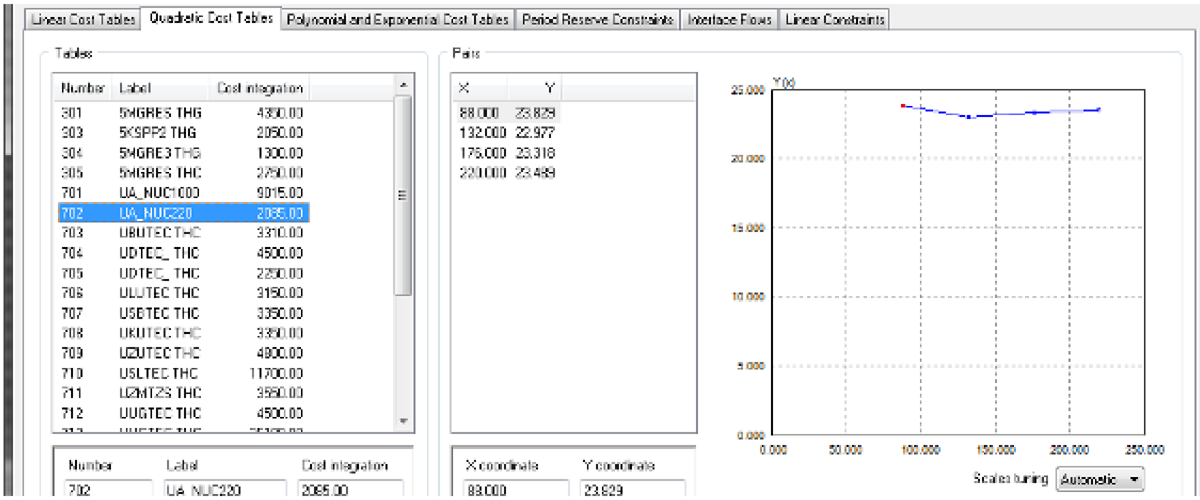


Figure 4.101 – Ukraine – Cost curve and table for 220MW units (curve 702)

Renewables

Renewable power plants are modeled as shown in Figure . WPP power plants are adjusted to represent the feed in tariff system in Ukraine.

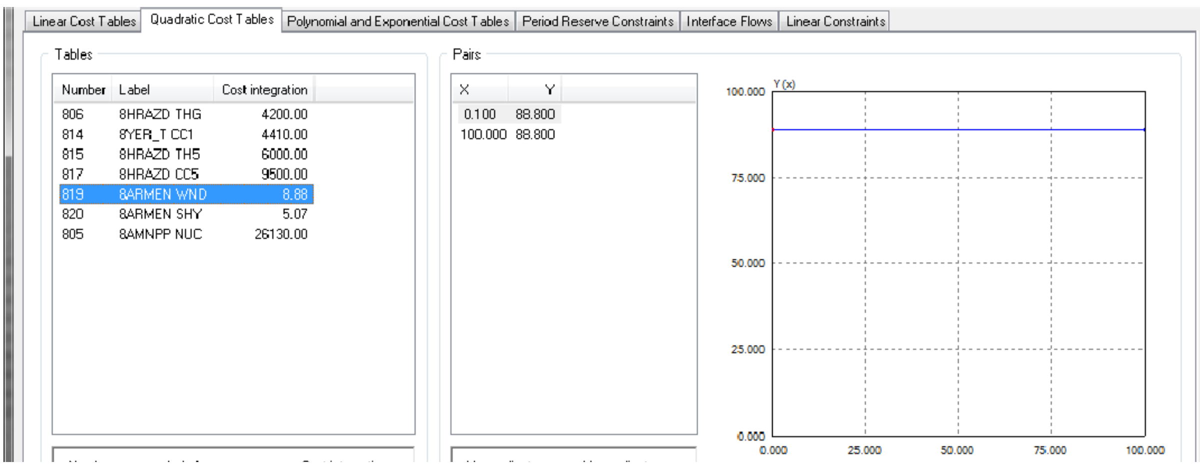


Figure 4.102 – Ukraine – Cost curve and table for Wind power plants (curve 819)

The cost curves should be used to calculate production costs, and not for generation engagement optimization, since these units are engaged based on energy availability and not on economics. Therefore, for optimization calculations they should be disabled by setting the dispatch value to zero.

V. FINDINGS

1.23 2015 and 2020 Model Status

The national and regional models, using 2015 and 2020 data, were built and tested under static load flow and dynamic stability conditions. The Project team has a high degree of confidence in the 2015 model data. There is a high level of certainty that lines, generation and loads included in this model are a good estimate of conditions that will exist in 2015. However, this level of certainty does not extend to the 2020 model for two important reasons:

- In the current world economic situation, it is difficult to accept the very optimistic forecast of new system expansions and load growth presented in the 2020 models. Many of the 2020 assumptions were developed before the world economic crises occurred and for many of the participants, this was a first look at the 2020 planning horizon.
- The impact of renewable energy supplies in the Black Sea Region by 2020 has not been adequately quantified in the 2020 models. The growth of renewable forms of generation in one location, that could supplement new conventional generation in another, is an important issue to be addressed in the process of finalizing the 2020 regional models.

As has been stated in the Conclusions section of this report, the project team has a high degree of confidence in the 2015 model data due to a high level of certainty that lines, generation and loads included in this model are a good estimate of conditions that will exist in 2015. However, this level of certainty does not extend to the 2020 model because renewable energy sources are not adequately modeled (see "Integrating Renewable Energy into National and Regional Network Models" discussed above) and because estimates of growth in lines, conventional generation and loads are thought to be inconsistent with current world economic forecasts.

The next step for the BSTP should be to revisit national modeling data estimates for 2020, taking into account current economic forecasts for the region and the estimates of renewable generation with an emphasis on wind, including the amount of such generation and its location. It is probable that the amount and location of wind generation will significantly alter the need for other sources of generation and will change the required system network configuration.

1.24 Synchronous Operation

The Black Sea region currently operates in three synchronous parts (Figure 1.2) By 2015 it is expected that Turkey will be officially accepted as full member of ENTSO-E and will be in parallel and synchronous operation. By 2015, Black Sea region will operate in two synchronous groups.

- West (Romania, Bulgaria, Turkey)
- East (Ukraine, Russia, Moldova, Georgia, Georgia, Azerbaijan)

The final BSTP report data and results have been determined using the 2015 model and assume that two synchronous zones will exist in 2015 and will consist of ENTSO-E (Romania, Bulgaria and Turkey) and the IPS/UPS (Russia, Ukraine, Moldova, Georgia, Georgia and Azerbaijan). Two additional scenarios should be investigated for 2015:

- 3 synchronous zones consisting of ENTSO-E (including Turkey), Ukraine and Moldova (in an ENTSO-E testing mode) and IPS/UPS.
- 2 synchronous zones consisting of ENTSO-E that includes Turkey, Ukraine and Moldova and the IPS/UPS.

Once the 2020 model is updated as described above, the 2020 regional model should be used to examine two possible scenarios:

- 2 synchronous zones consisting of ENTSO-E that includes Turkey, Ukraine and Moldova and the IPS/UPS.
- 2 synchronous zones consisting of ENTSO-E (including Turkey) and IPS/UPS (including Ukraine & Moldova).

1.25 Georgia

1.25.1 Renewables development plan

Table 7.1– Georgia – Generation units renewables according to priorities

Small hydro

Figure 7.1 – Georgia - network ma