1. POWER MARKET ANALYSIS

An analysis of the Polish power system was used to investigate the potential role that small-scale Combined Heat and Power (CHP) plants may play during a peak load situation. The economic value of CHP plants and the short-term financial gains that CHP owners may gain was also estimated. A candidate gas-fired CHP plant was located in the region with the highest economic cost of energy. A second object of the power systems analysis is to estimate the potential for east-to-west power transfers across Poland. The Polish Power Grid could potentially reap financial by purchasing energy from an adjoining power system to its east at relatively low price and resell this energy to its west at a higher price. The Polish Power Grid Company could also wheel energy for a third party for a service fee.

1.1 MODELING METHODOLOGY

The Generation and Transmission Maximization (GTMax) model simulates the dispatch of electric generating units and the economic trade of energy among utility companies using a network representation of the power grid. Generation and energy transactions serve electricity loads that are located at various locations throughout the simulated region. Links and transformers connect generation and energy delivery points to load centers. Electricity loads are satisfied, curtailed via contractual agreements, or not served due to a generator supply shortage or because of transmission limitations.

The objective of GTMax is to maximize the net revenues of power systems by finding a solution that increases income while keeping expenses at a minimum. When multiple systems are simulated, GTMax identifies utilities and projects that can successfully compete on the open market. The model computes and tracks hourly energy transactions, market prices, and production costs. Using a mixed integer Linear Programming (LP) approach GTMax simultaneously solves the maximization objective for all hourly time steps in a weekly simulation period. The model can be run for all 52-weeks in a year or selected weeks that are representative of a month or a season.

Simulated activities are driven by energy market forces and are performed within the physical and institutional constraints of the interconnected systems. Some limitations that are modeled include power plant seasonal and hourly maximum and minimum generation levels, limited energy constraints, contractual transmission capabilities, and terms specified in firm and IPP contracts. GTMax also considers detailed operational limitations such as power plant ramp rates and hydropower reservoir constraints. Firm transmission contracts, along with Transmission Reliability Margins (TRM) and Capacity Benefit Margins (CBM) are also factored into model simulations. GTMax computes Available Transmission Capabilities (ATC) for each transmission link, over Composite Transfer Capability (CTC) link groups and over user-specified pathways.

The model is designed to be user-friendly. It operates under a Microsoft Windows environment and employs a Geographical Information System (GIS) interface. The user builds power system components and interconnections using mouse point and click actions. By clicking on a map of utility power plants and transmission lines input data can be viewed and modified. Model results for hourly energy flows from supply resources such as generators and IPP firm contract purchases to load centers and spot market delivery points are graphically displayed on a map. The user can also simultaneously view two or more scenarios at once. GTMax also produces financial reports.

1.2 GTMAX NETWORK COMPONENTS

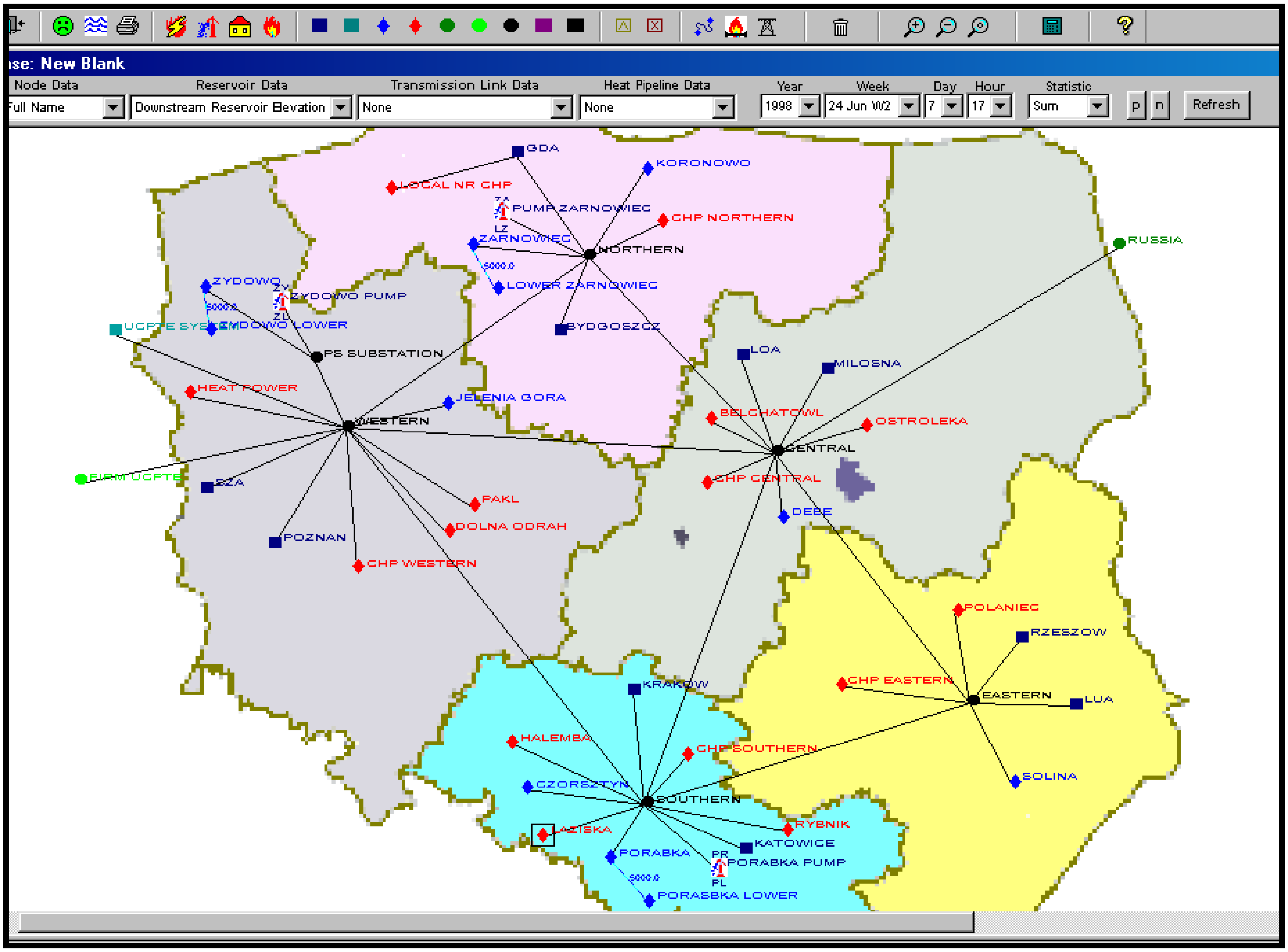
The GTMax model utilizes a node and link network representation of a power system. Nodes in the system represent various generation supply options, substations, market hubs, electricity loads, firm purchase and sales contracts, power exchange points, and points of energy interchange. The model also contains nodes that represent the market for energy at interconnection points with systems that border the simulated region. Links represent transmission and distribution systems and waterway systems that connect cascaded hydropower systems. The GTMax model is very versatile in that the user starts with an empty workspace and builds a power system topology of nodes and links via the GIS interface. Each node and link in the network contains information for many variables that is contained in a database. Inputs are separated into three categories that include weekly, daily, and hourly variables. As the category name imply weekly variables remain constant throughout a simulated week, while daily variables are specified for each day of the week and hourly variables are specified for each hour of a simulated week (i.e., 168 input values).

1.3 GTMax Model Topology

The Polish power grid was modeled as a set of interconnected power regions or power pools. As shown in Figure 1.0, there are a total of five regions that consist of the following: (1) Central, (2) Eastern, (3) Southern, (4) Western, and (5) Northern. The characteristics of these regions in terms of loads are provided in Figures 5.2 through 5.6 for a peak load day (Thursday) and an off-peak load day (Sunday). The loads shown in figures are for the 48th week of the year; that is, an early December week which is typically the peak load week in the year. Hourly loads are not publicly available at the regional level. Therefore, the loads shown in the Figures are estimates based on actual regional loads for the peak hour in 1998 and hourly load profiles for the entire Polish power grid. These total system-wide loads are available for all hours of the year. Regional load fractions for the peak hour were derived and applied to country-wide loads profiles to estimate regional loads in all other hours in the year.

Tables 1.1 through 1.5 show the characteristics of generation resources in the five regions. It should be noted that there is an imbalance of supply resources and electricity demand in some regions. For example, in the northern region the peak hourly load including losses is more than 2,700 MW while generation resource are about 1,585 MW. On the other hand, the central region has an excess supply with a peak load of about 4,600 MW and generation resource of more than 6,600 MW.

Regional energy imbalances are rectified through the transfer of power and energy via the Polish transmission network. Table 1.6 shows the transfer capacity of major lines that connect the regions. The total transfer capabilities (TTC) that were input into the links shown in Figure 1.0 were based on load flow modeling analyses that estimates transfer capabilities between regions for equivalent or aggregate lines that both directly and indirectly link regions. These transfer capabilities typically exceed those shown in Table 1.6 since other smaller lines not shown in the table also add to the transfer capability.



Node Data: Full Name
Reservoir Data: Downstream Reservoir Elevation
Transmission Link Data: None
Heat Pipeline Data: None
Year: 1998
Week: 24 Jun W2
Day: 7
Hour: 17
Statistic: Sum

Figure 1.0 Topology of the Polish power grid that is used in the GTMax model.

1.4 CHP Technology Description

The small combined heat and power (CHP) plants investigated in this study are local natural gas fired plants. The technology assumed is the natural gas reciprocating (internal combustion) engines. Reciprocating engines are available in a broad size range of 50kW to 10 MW suitable for a wide variety of residential, commercial and industrial applications, typically where there is a substantial hot water demand. The assumed size of a local CHP plant is 24 MW_e. The other main assumptions are:

- The plant operates only during the heating season (approximately 5100 h/year), i.e. outside that season the thermal balance is achieved through supplemental heat sources such as gas boilers.
- Furthermore, the plant operates only during the periods of high loads (peak and shoulder hours), approximately 3000 hours/year, and is switched off during the periods of low demand,
- The assumed operation of the small CHP plant is regulated for heat on a seasonal basis. However, since the CHP plant has heat storage capabilities, the hourly operation of the plant takes advantage of the daily price profile of the electric energy market. Therefore, the CHP plant is operated mainly during the daytime when the associated electricity production reaps the most money. Excess heat production during the daytime is used during the night when the plant does not operate. For this analysis it was assumed the power plant would operate 14 hours per day (from 9 a.m. to 10 p.m.) for 7-days per week during the heating season.
- The assumed incremental electricity generation cost is 10 USD/MWh
- A candidate CHP power plant was located in the northern region since this region has a negative reserve margin and has the highest hourly value of energy.
- Transmission and distribution losses are assumed to be negligible since the CHP plant is assumed to be located very near to the load.

1.4.1 Central Region

The basic characteristics of the Central region are shown in Fig 1.1 and Table 1.1. The available capacity amounts to around 6600MW; that is, 22% of the total Polish power system capacity. The biggest plant in Poland is the lignite-fired Bełchatów facility. This one power plant accounts for 65% of the generation capacity in the Central region. The rest of capacity is mostly coal-fired CHP plants. For that reason, among all regions the Central one has the lowest average generation costs. Net generation in 1998 was about 35 TWh, that is approximately 29% of the total power generation in Poland. The peak demand was around 4600 MW, i.e. 20% of the national peak demand. Central region is a net power exporter.

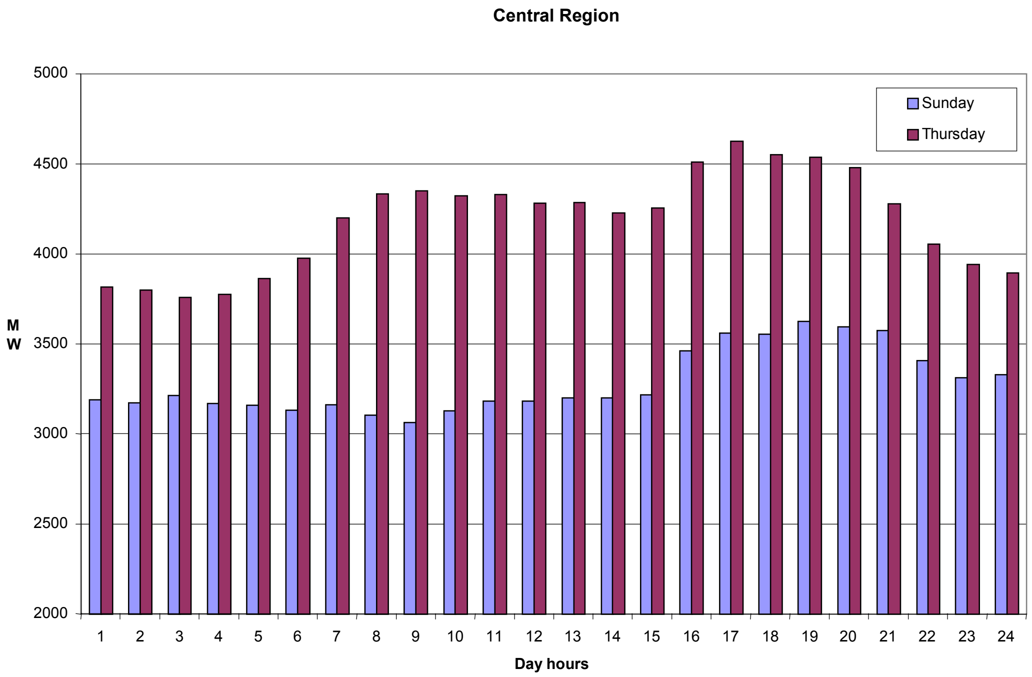


Figure 1.1 Central region load profile (48th week, year 1998)

Table 1.1 Central region available capacities, net electric energy production and average generation costs in 1998, aggregated by plant type

CENTRAL REGION	Available capacity	Net generation	Generation cost		
			Fixed	Variable	Total
	MW	GWh	USD/MWh		
Hard Coal Power Plants	600,0	2494,0	9,61	22,83	32,44
Lignite Power Plants	4320,0	26932,4	8,28	11,11	19,39
Combined Heat and Power Plants	1678,60	5805,66	12,87	14,32	27,19
Hydro Power Plants	16,70	120,80	8,61	0,00	8,61
ALL PLANTS	**6615,3**	**35352,9**	**9,13**	**12,43**	**21,55**

1.4.2 Eastern Region

The load profile and basic generation data of the Eastern region are shown in Fig 1.2 and Table 1.2. The available capacity, covered almost exclusively by two largest Polish coal-fired power plants (Kozienice and Połaniec), represents about 17% of the total country's available power. Net generation in 1998 amounted to about 15TWh, i.e. 12% of the total generation. The total generating capability of the region is over 5000 MW while the peak demand was a little bit over 3000 MW, i.e. 13% of the total peak demand in the country. This high reserve margin allows the region to export power to other regions.

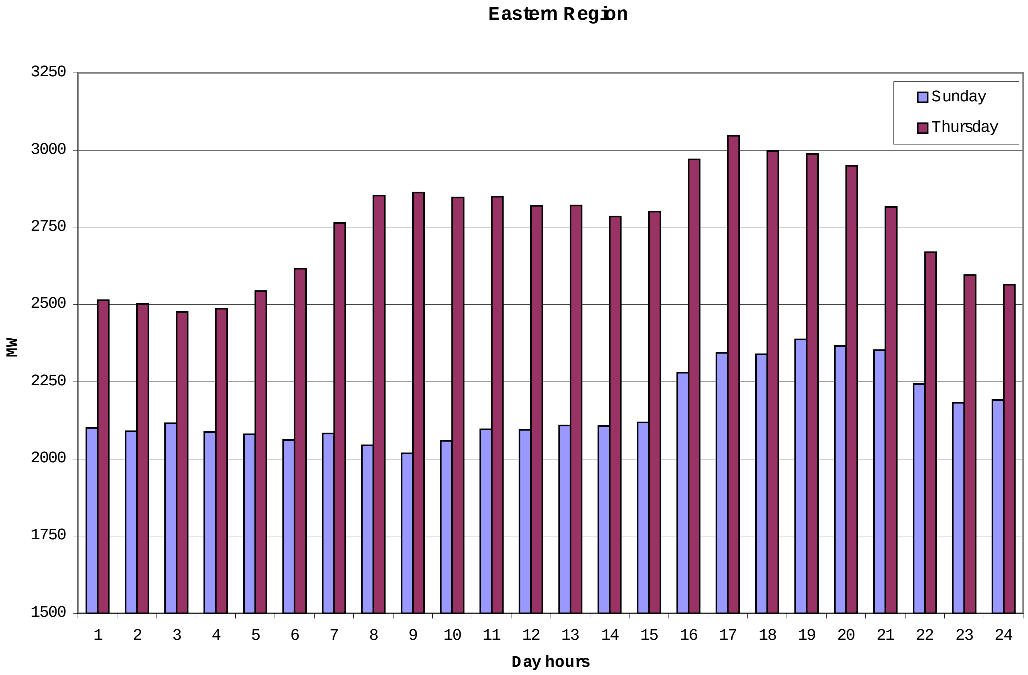


Figure 1.2 Eastern region load profile (48th week, year 1998)

Table 1.2 Eastern region available capacities, net electric energy production and average generation costs in 1998, aggregated by plant type

EASTERN REGION	Available capacity	Net generation	Generation cost Fixed	Variable	Total
	MW	GWh	USD/MWh		
Hard Coal Power Plants	4785,6	14721,3	12,76	18,98	31,73
Combined Heat and Power Plants	95,7	207,9	17,00	14,54	31,54
Pumped Storage Hydro Plants	140,0	203,4	36,15	0,00	36,15
ALL PLANTS	**5021,3**	**15132,6**	**13,13**	**18,66**	**31,79**

1.4.3 Southern Region

The Southern region encompasses one third of the national electric power capacity and has approximately the same share of the electricity generation (Table 1.3). The peak demand (Fig 1.3) in 1998 was around 7000 MW, i.e. 30% of the national peak demand. There are no lignite-fired facilities in this region. Above 80% of available capacity comes from hard-coal power plants, about 10% are coal-fired CHP plants and the rest are hydro facilities which are mostly pumped storage. Coal prices and hence variable production costs in this region are fairly low. This region has the most of hard coal and transport costs are relative low. However, due to high fixed costs the Southern region has the highest total generation costs in Poland. For example, total generation costs are more than 50% higher than in the Central and Northern regions.

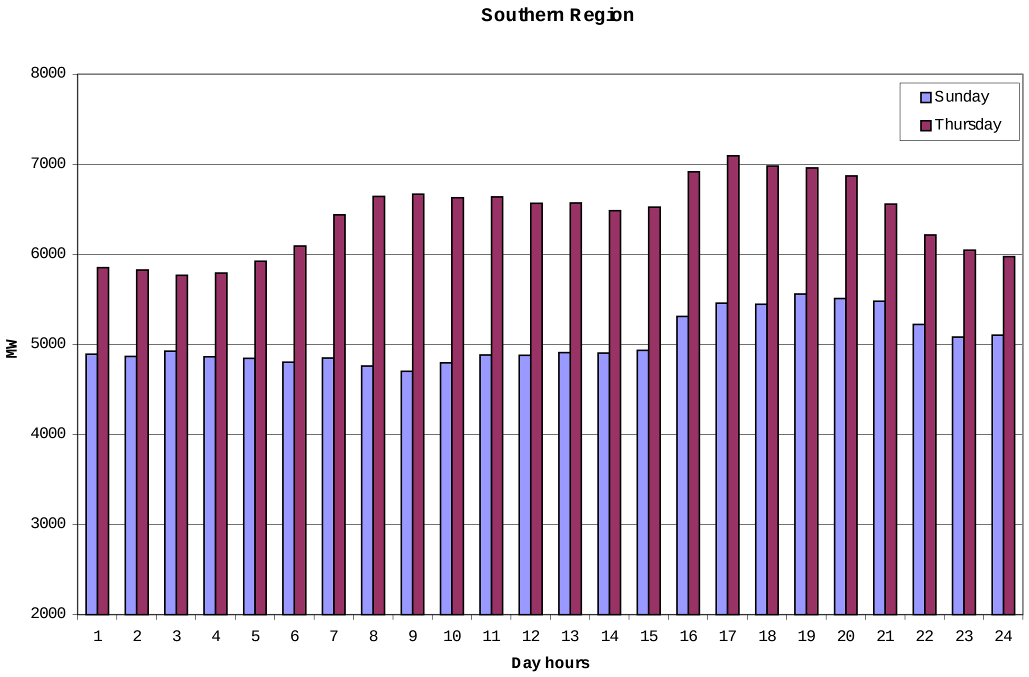


Figure 1.3 Southern region load profile (48th week, year 1998)

Table 1.3 Southern region available capacities, net electric energy production and average generation costs in 1998, aggregated by plant type

SOUTHERN REGION	Available capacity	Net Generation	Generation cost Fixed	Generation cost Variable	Generation cost Total
	MW	GWh	USD/MWh		
Hard Coal Power Plants	8151,0	32738,9	17,22	17,88	35,10
Combined Heat and Power Plants	1068,4	3558,1	14,55	16,58	31,13
Hydro Power Plants	58,1	252,8	19,50	0,00	19,50
Pumped Storage Hydro Plants	534,0	689,7	20,01	0,00	20,01
ALL PLANTS	**9811,5**	**37239,6**	**16,66**	**17,30**	**33,96**

1.4.4 Western Region

The basic data depicting the Western region are shown in Fig 1.4 and Table 1.4. The available capacity is about 6750MW (i.e. 23% of the total system capacity), providing approximately one quarter of the country’s electric power supply. Similarly, the peak demand is about one quarter of the national peak demand. Above 60% of the available power is provided by the lignite-fired power plants.

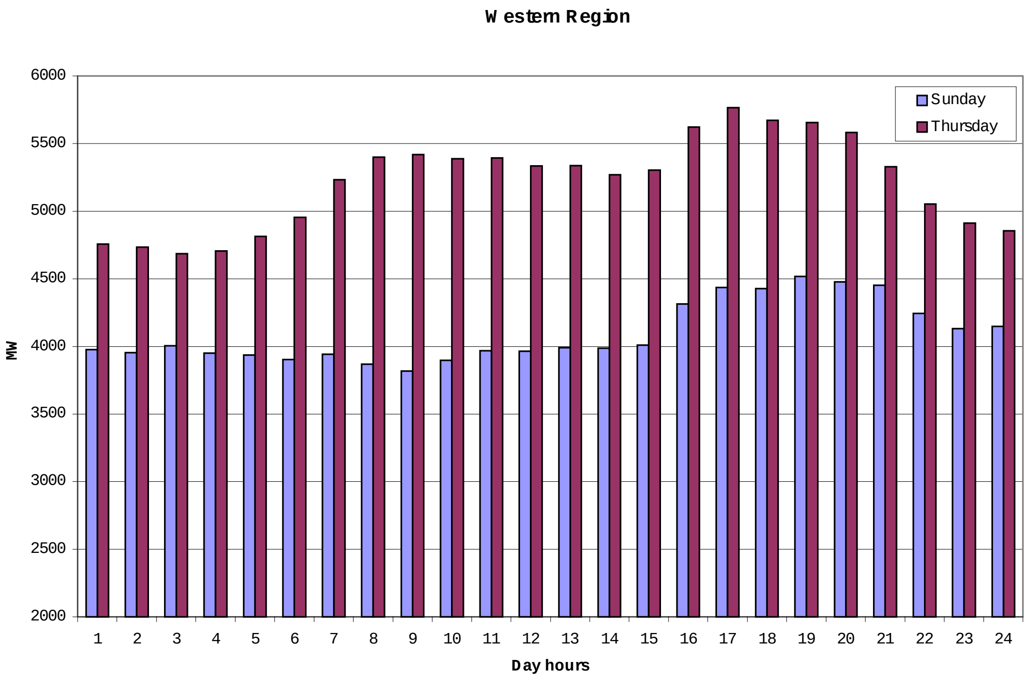


Figure 1.4 Western region load profile (48th week, year 1998)

Table 1.4 Western region available capacities, net electric energy production and average generation costs in 1998, aggregated by plant type

WESTERN REGION	Available capacity	Net generation	Generation cost Fixed	Generation cost Variable	Generation cost Total
	MW	GWh	USD/MWh		
Hard Coal Power Plants	1708,0	6305,8	12,32	21,63	33,95
Lignite Power Plants	4131,1	20795,7	9,11	17,82	26,93
Combined Heat and Power Plants	782,5	2735,2	14,65	16,56	31,20
Hydro Power Plants	29,4	203,6	29,54	0,00	29,54
Pumped Storage Hydro Plants	96,0	141,4	64,31	0,00	64,31
ALL PLANTS	**6747,0**	**30181,6**	**10,68**	**18,30**	**28,98**

1.4.5 Northern Region

The Northern region is characterised by the smallest generation capacity, representing only about 5% of the national total. Its share in the total net generation is even smaller, only about 3.5%. On the other hand its peak demand is about two and a half times greater than the available capacity, hence the need for import of energy.

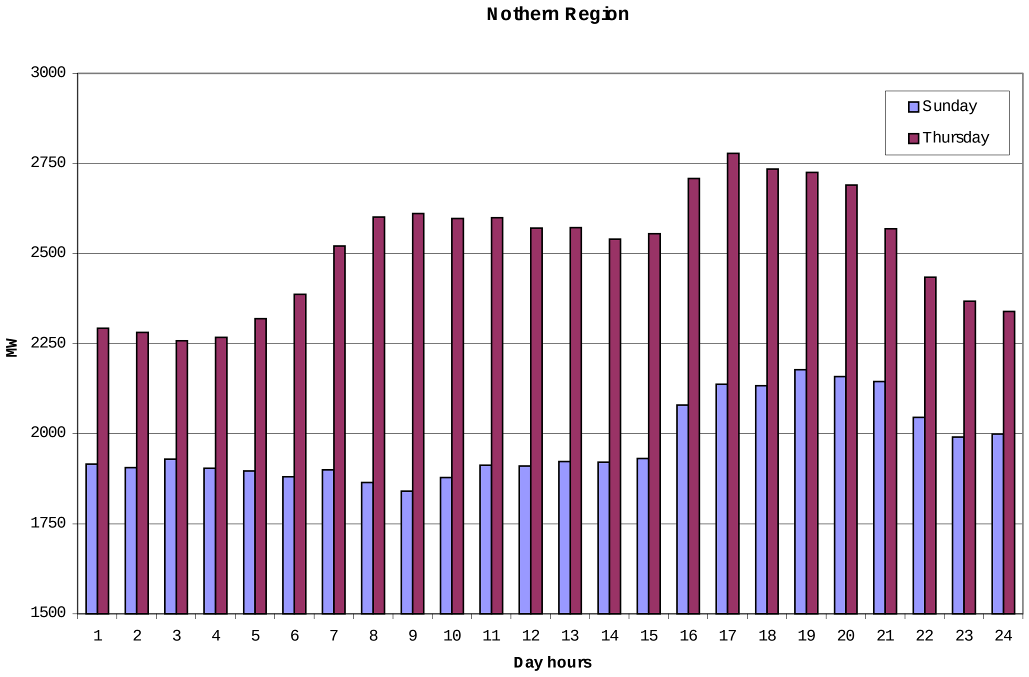


Figure 1.5 Northern region load profile (48th week, year 1998)

Table 1.5 Northern region available capacities, net electric energy production and average generation costs in 1998, aggregated by plant type

NORTHERN REGION	Available capacity	Net generation	Generation cost		
			Fixed	Variable	Total
	MW	GWh	USD/MWh		
Combined Heat and Power Plants	521,6	1999,7	15,67	15,46	31,13
Hydro Power Plants	347,0	1295,3	9,08	0,00	9,08
Pumped Storage Hydro Plants	716,0	1062,1	23,00	0,00	23,00
ALL PLANTS	**1584,6**	**4357,1**	**15,50**	**7,10**	**22,59**

1.4.6 Transmission System

Transmission system includes all 400kV and 220kV power lines between the five regions as well as between Poland and UCPTE. Power flow limits of the transmission system are shown in Table 1.6. Presently there are no bottlenecks in the transmission system, however, some transmission paths are at times heavily loaded with economic bulk power transfers. In normal situations the transmission capability is adequate for transferring all economic transfers. In extreme situations, for example, outages of large plants or labour problems, the transmission lines may be used more heavily utilised and insufficient transfer capabilities result in unserved energy in the transmission constrained regions.

Table 1.6 Inter-Regional Transmission Capacities of 400 kV and 220 kV lines

Transmission Lines		**Total capacity**
From	**To**	**MW**
Central Region	Eastern Region	2027
Central Region	Southern Region	6513
Central Region	Western Region	1684
Central Region	Northern Region	1295
Eastern Region	Southern Region	3766
Southern Region	Western Region	1329
Western Region	Northern Region	2254
Poland	UCTE	10404

Table 1.7 Total Transfer Capabilities Asssumed in the GTMax Model

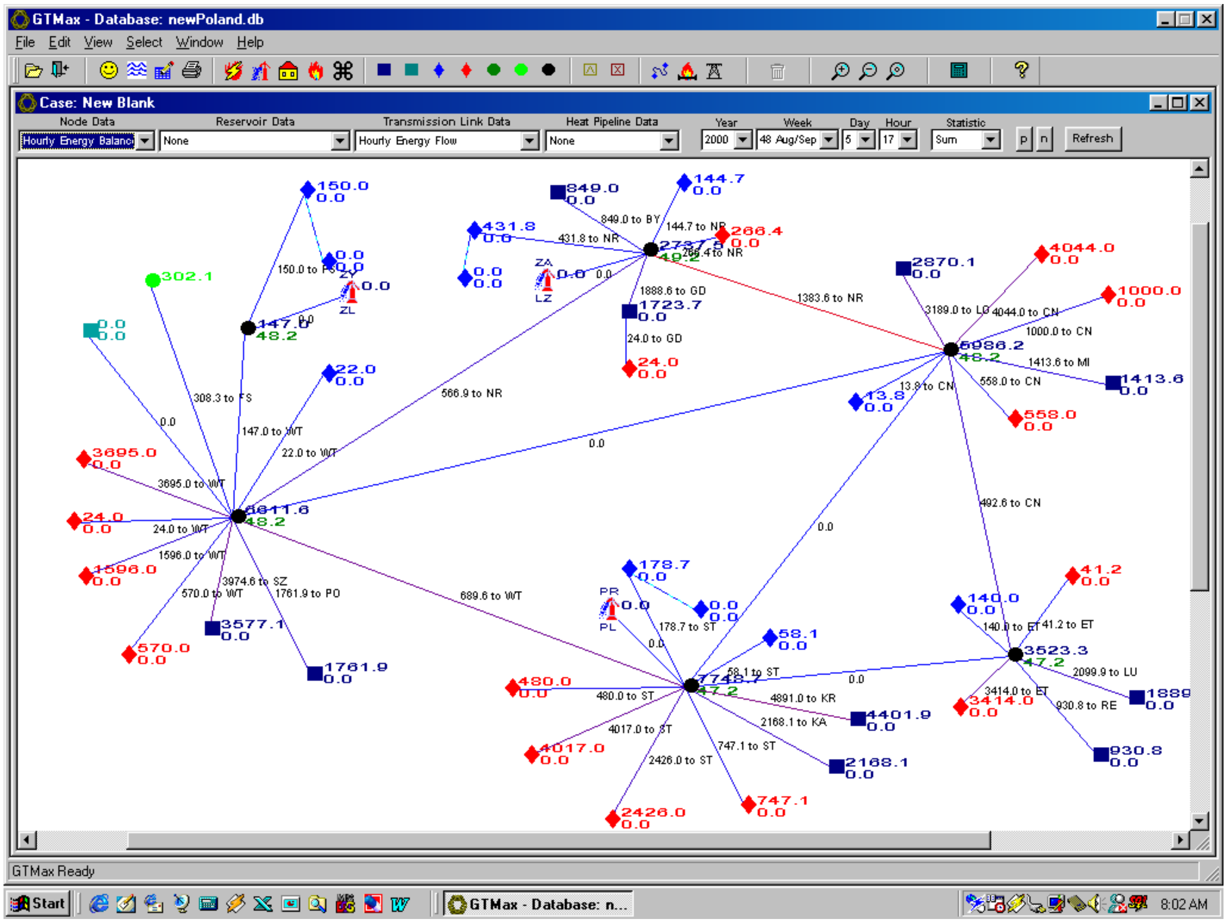
Transmission Lines		**Total capacity**
From	**To**	**MW**
Central Region	Eastern Region	2432
Central Region	Southern Region	7816
Central Region	Western Region	2021
Central Region	Northern Region	1554
Eastern Region	Southern Region	4519
Southern Region	Western Region	1595
Western Region	Northern Region	2705
Poland	UCTE	10404

1.5 Modelling Results

The GTMax model was run for the week that has the highest hourly load. This run was compared to a load flow analysis for the peak load hour. Model results were also generated for all other hours in that week. Based on these results the costs and expenses for a candidate CHP power are computed. Also, the net transfers of power from east to west through Poland were investigated in terms of the costs of power transfers. Power transfer costs are mainly attributed to the additional losses in the grid. Power transfers may also distort the economic dispatch of power plants.

1.5.1 Modelling the Peak Hourly Load

The dispatch of the power system to meet loads in the peak hour of the year was simulated by both the ROZPLYW load flow model and GTMax. A comparison of the two model results was then performed. Figure 1.6 shows GTMax model results for this peak hour that was assumed to occur at 5 PM on Thursday of the 48th week (early December) of the year.



GTMax - Database: newPoland.db

Case: New Blank

Node Data: Hourly Energy Balance
Reservoir Data: None
Transmission Link Data: Hourly Energy Flow
Heat Pipeline Data: None
Year: 2000
Week: 48 Aug/Sep
Day: 5
Hour: 17
Statistic: Sum

GTMax Ready

Figure 1.6 GTMAx Model Results for the Annual Peak Load

The figure shows the dispatch of thermal power plants (numbers associated with the red diamonds) and hydropower plants (numbers associated with the blue diamonds. Generation is used to serve regional loads (numbers associated with the dark blue squares) and firm energy sales (numbers associated with green circles). Estimates of the marginal value of energy are shown at market hubs (green numbers associated with black circles) and the loads for pumping water are also displayed (numbers associated with pumping symbols). The contractual flow of power is displayed adjacent to links that connect the regions. Lines colored red have estimated transfers that are near the assumed maximum transfer capability while those colored blue are utilized well below the maximum transfer capability.

A comparison of GTMax model results with those projected by the ROZPLYW load flow model are shown in Figure 1.7. Whereas, the GTMax model estimates the dispatch of power plants the ROZPLYW model, these power plant generation levels are provided by the user as energy injections at various specified locations in the grid. These energy injection points and levels were based on pre-schedules or planning dispatch studies. The figure shows that for all regional loads, generation, and net energy imports are very similar. In general loads are slightly higher in the ROZPLYW model than in GTMax. Also, GTMax projects somewhat lower generation levels for the Northern region. This mainly attributed to the lower utilization rate of the pumped storage power plant in GTMax versus the utilization rate assumed in the ROZPLYW. A more detailed explanation of pumped storage is provided later in this section.

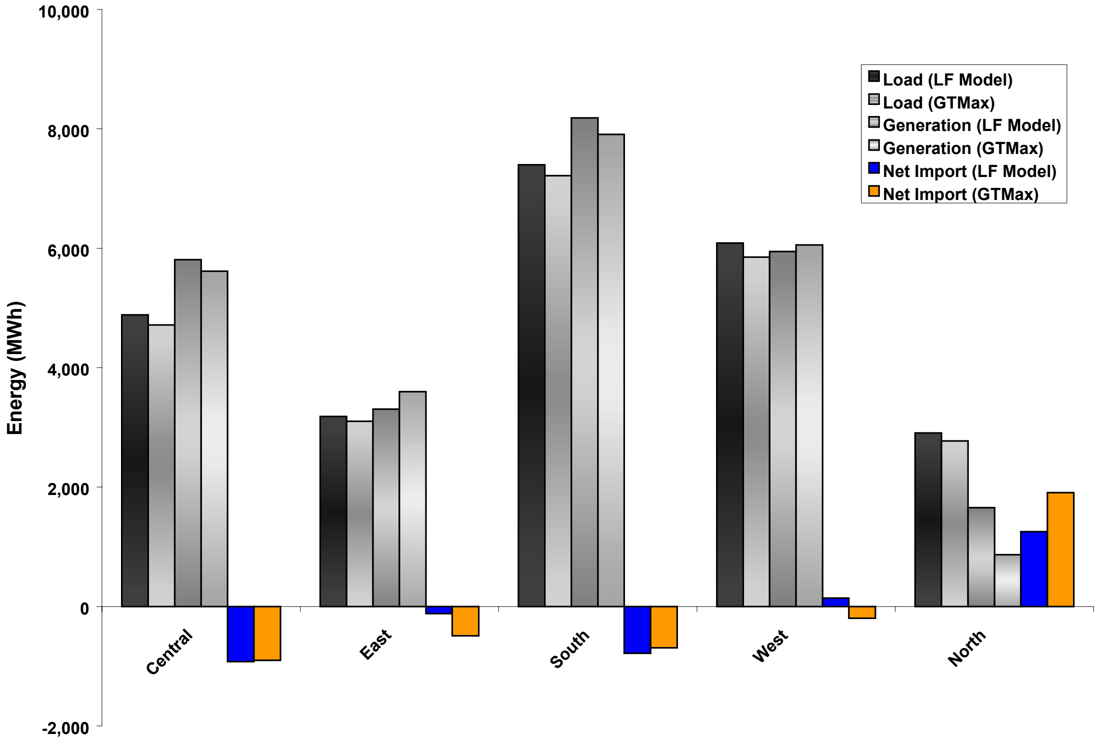


Figure 1.7 Regional Comparison of ROZPLYW and GTMax Model Results

1.5.2 Estimates of the Marginal Energy Production Costs

The GTMax model was used to estimate the delivered price of energy to regional market hubs in the Polish power grid. These delivered prices are based on marginal production costs and both transmission losses and costs. Regional costs projected by GTMax may be significantly different among regions. However, in the simulations performed in this analysis regional price difference were small (typically within 5%) because there were no significant congestion in the transmission network.

The average price of delivered energy to the five market hubs (one for each region) along with loads for the simulated week is provided in Figure 1.8. Prices are mainly a function of load, whereby energy is the cheapest during off-peak hours and are the most expensive during the highest demand periods. Market prices range from less than 29.4 $/MWh on Sunday morning to almost 50 $/MWh during late afternoon of three weekdays (Tuesday, Wednesday, and Thursday); that is, a price difference over 65%. The off-peak price is set by the marginal production cost of electricity for CHP plants in the Central region and the on-peak price is set by marginal production costs for the pumped storage power plants. This includes the cost to purchase off-peak power and pumping losses.

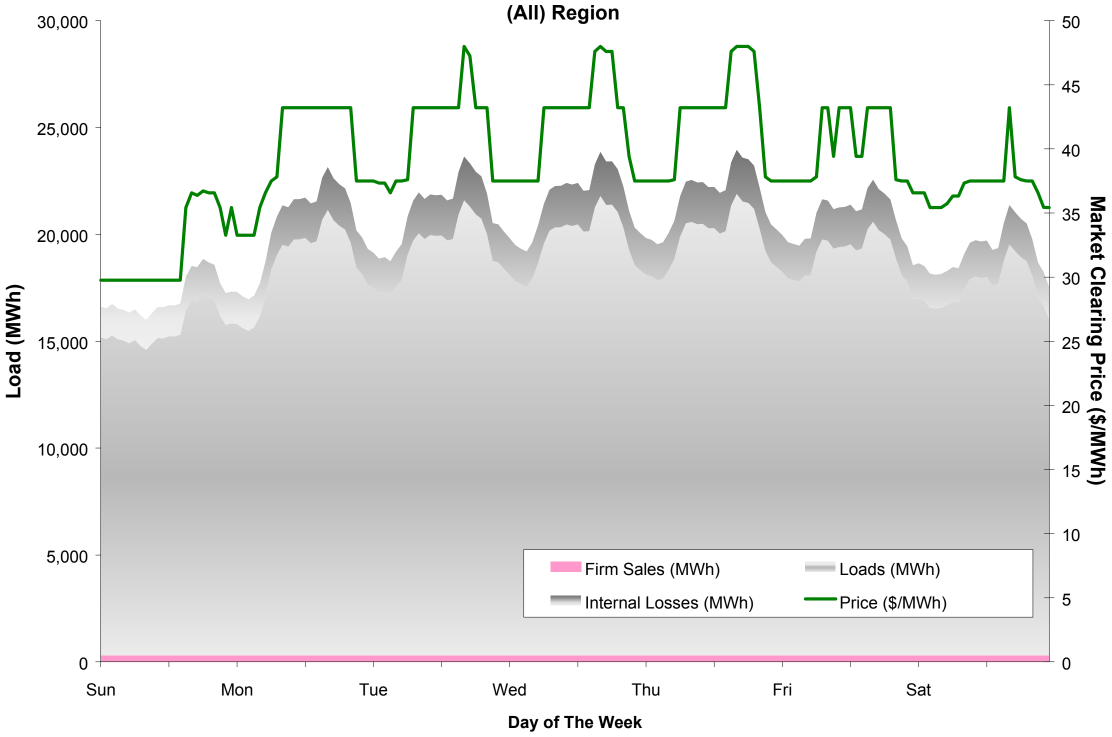


Figure 1.8 Projections of Market Clearing Price During the Peak Load Week

1.5.3 Weekly Operations

The GTMax model solves the dispatch of the power system on an hourly basis for a week time period. Some variables in the dispatch problem are independent of time; that is, the solution for one hour does not affect a future potential position or operation level. For example, a gas turbine can change operation from no production in one hour to maximum output levels in the next hour. Other variables are time dependent such that the operation in one hour of the week has an impact on it operation in other hours of the week. For example, energy drawn from the grid to pump water from a lower reservoir to an upper reservoir at a pumped storage power plant will be used to generate electricity in a future hour. Also, some technologies such as large coal-fired and nuclear plants have relatively slow ramp rates.

Figure 1.9 shows the operation of power plants during the peak load week. Thermal power plants serve a large majority of the load. However, although a small portion of the total energy market is served by pumped storage and storage hydro power plants, these technologies play an important role in moderating hourly price volatility. During Sunday and on some weekday nights pumped storage power plants consume relatively inexpensive energy thus helping to prop up prices. On the other hand, during the highest on-peak periods this stored energy is used to serve load that helps to moderate high on-peak prices. As shown on Figure 1.9 the operation of the pumped storage power plant fills load valleys and shaves peak loads. It should also be noted that storage hydro power plants with reservoirs are also used to reduce on-peak loads put on the thermal system.

The reservoirs associated with the pumped storage plants have about 2 to 3 hours of storage capacity. Due to this limited capacity the relatively low energy price during Saturday is not taken advantage of since in GTMax, filling takes place mainly on Sunday when prices are the lowest. There is sufficient pumping capacity to fill upper reservoirs during Sunday and pumping on Saturday would result in a higher overall cost of operation. Even though the price is lower on Saturday compared to weeknights there are small amounts of additional pumping on weeknights to refill reservoirs for release during the next day.

It should be noted that the actual operations of the pumped storage power plants in Poland differ somewhat from these model results. Actual daily operations fill and release the entire upper reservoir on a daily basis. Actual operations are not driven by costs but by dispatching center rules. This mode of operation may be partly the result of historical operations when there was a capacity shortage in the system. Also consumption during the night is at times used for voltage control in the Northern region. Transmission voltages are not taken into account in GTMax. However, by placing additional operational rules in GTMax (i.e., setting minimum daytime water releases) GTMax can reproduce actual operations and the need for voltage control.

GTMax pumped storage operations are driven by market price signals. Figure 1.10 shows that pumping occurs when energy prices are low and for generation when prices are the highest.

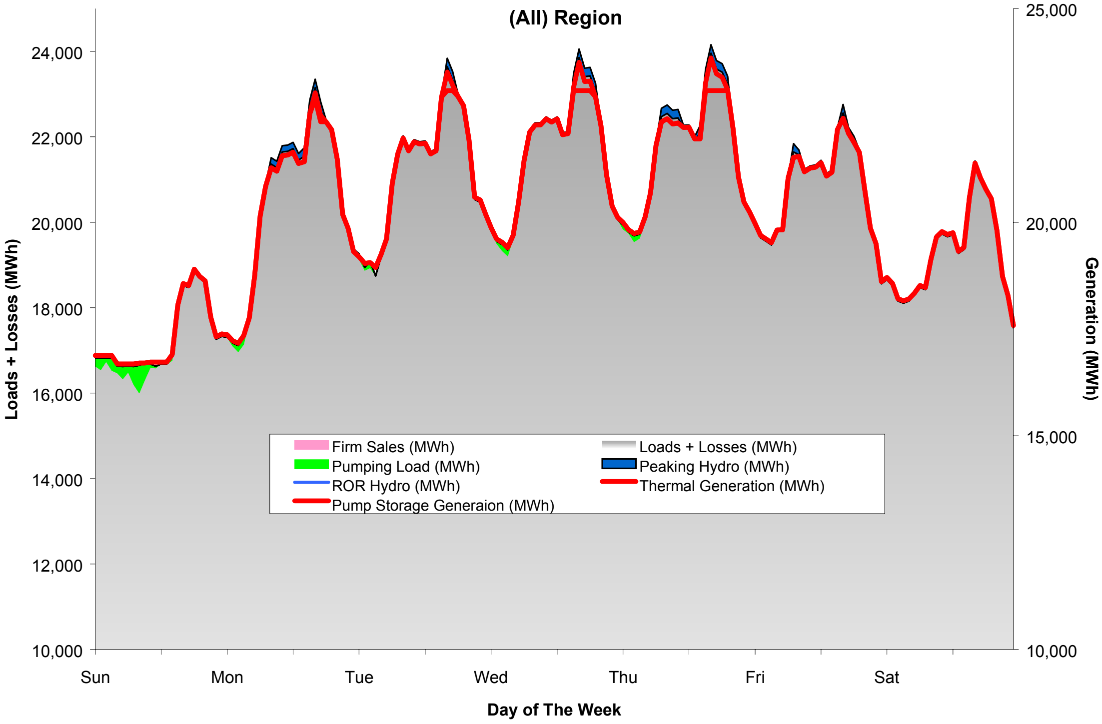


Figure 1.9 Weekly Operations of the Polish Power Suppy Resources to Meet Loads During the Peak Demand Week of the Year

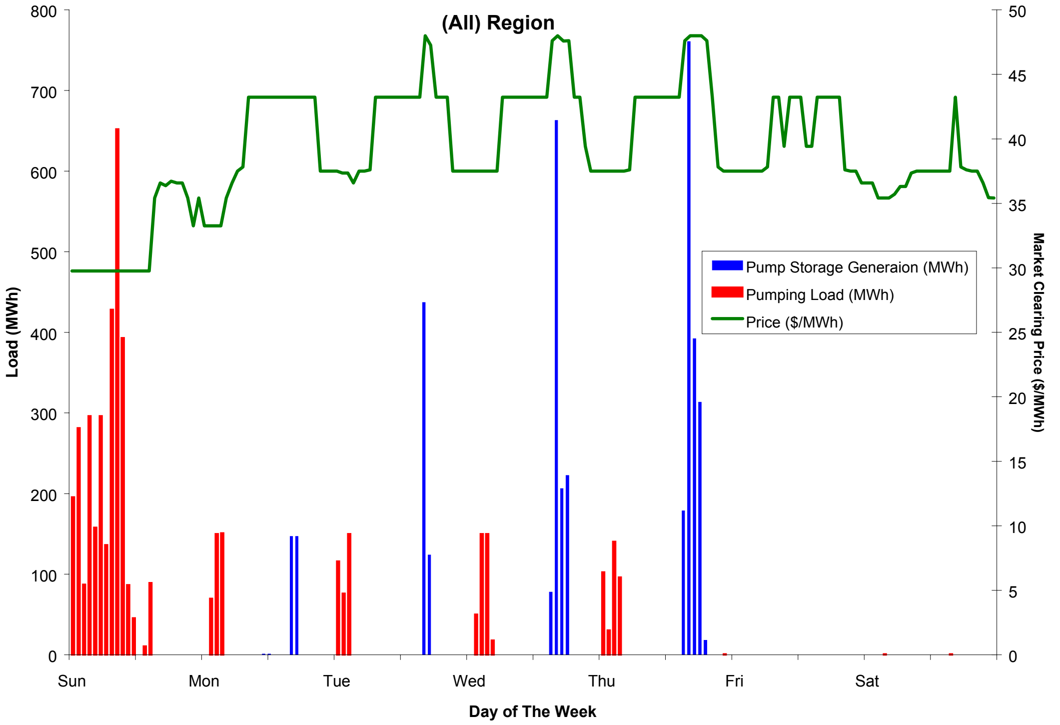


Figure 1.10 Pumped Storage Operations in GTMax as Driven by Market Prices – Actual Operations May Differ Due to the Need for Northern Region Voltage Control at Night

1.5.4 Regional Operations

As described previously in more detail each dispatch region in Poland has its own unique characteristics in terms of load levels and generation supply resources. While some regions have high load factors others have a supply deficit. Also, production costs vary significantly among regions. The regional supply and demand balance along with the regional marginal cost production differences leads to unique operational characteristics in each region.

1.5.4.1 Central Region

Figure 1.11 shows loads and generation levels in the Central region for the peak week of the year. This region is characterised by high reserve margins and low variable costs. Fuel is relatively inexpensive in this region. As shown in the figure hourly generation is significantly higher than loads. The vast majority of the energy production is from thermal power and CHP plants. Run-of-river hydro production is very small. In addition, total regional generation levels are almost constant during the week with only slightly lower production levels during Sunday. The excess generation is exported to other regions that have supply deficits or higher costs.

Figure 1.12 shows export levels from the Central region for the peak load day (Thursday). Export of power range from about 900 MWh during the peak load hour to over 1760 MWh at 3 AM in the morning. Note that exports follow a pattern that is directly opposite that of Central regional loads. At night when loads are low the region exports relatively higher levels since less energy is needed to meet its own demands. The reverse occurs during the daytime.

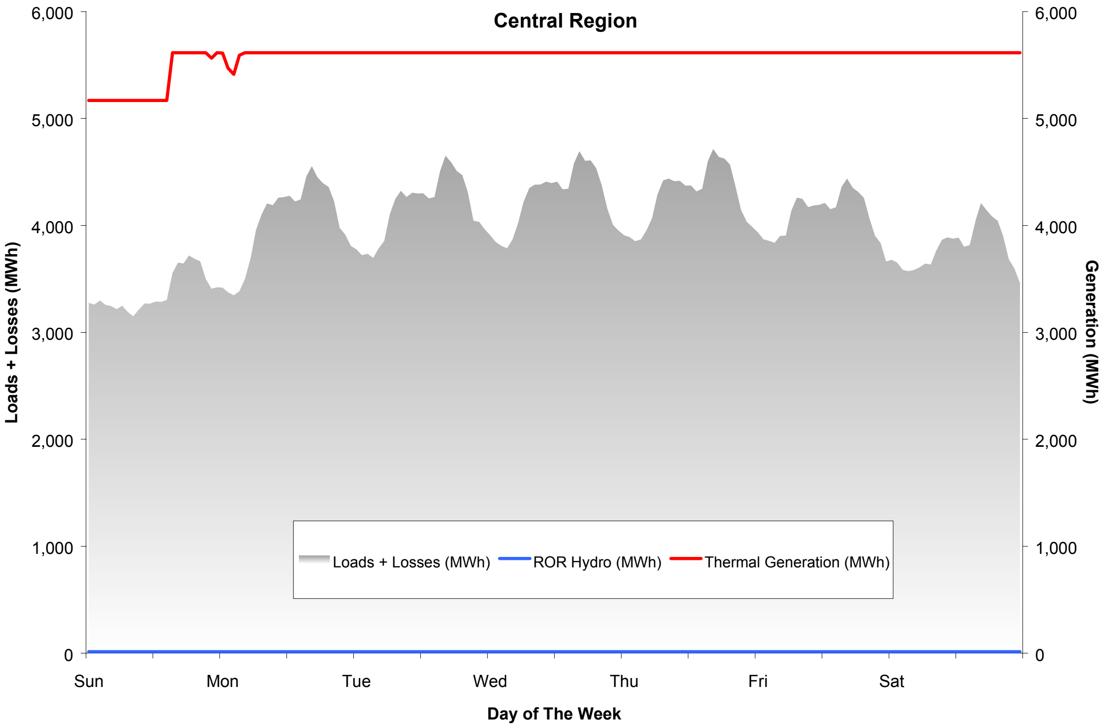


Figure 1.11 Generation and Loads in the Cenrtal Region During the Peak Load Week

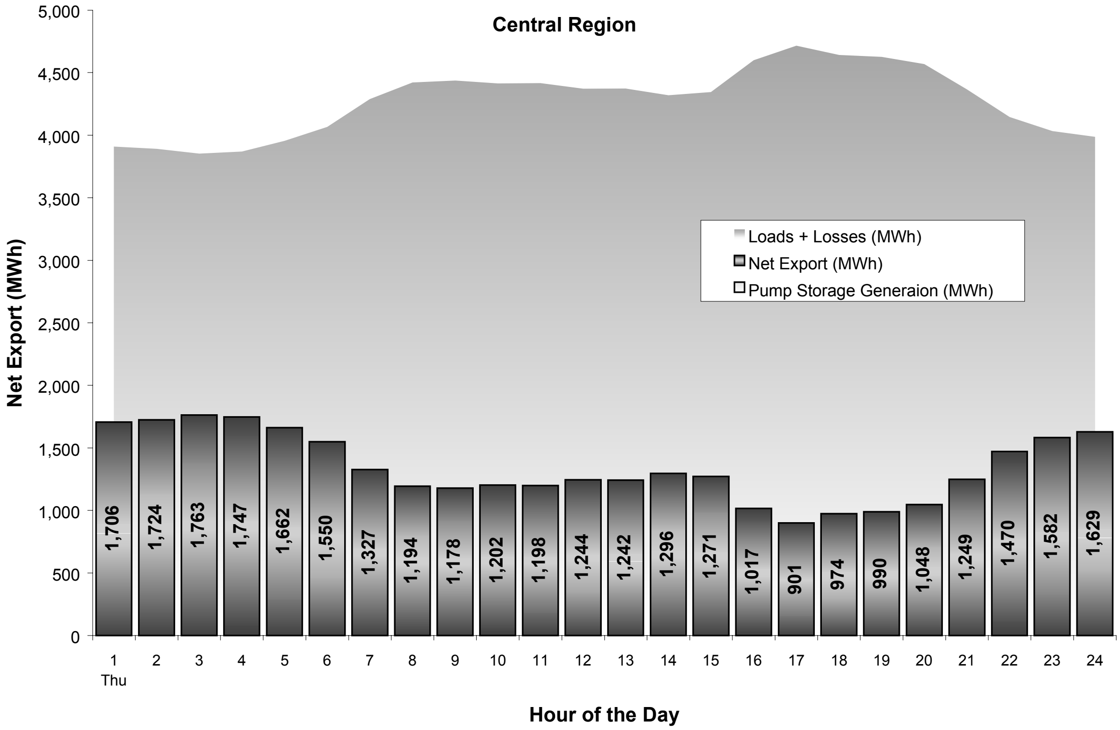


Figure 1.12 Power Exports/Sales from the Central Region During the Peak Load Day

1.5.4.2 Northern Region

Much of the excess energy production from the Central regions is transfer and sold to the Northern region that is characterised by negative reserve margins and higher variable production costs. Figure 1.13 shows that electricity demand in the North are much higher than the combined generation from run-of-river hydropower, thermal, CHP and pumped storage power plants. Operations of the CHP and thermal power plants are nearly constant during the week with slightly higher production levels during the daytime.

Energy import levels by the Northern region are shown in Figure 1.12 for the peak load day. Import of power range from slightly less than 1850 MWh during an earl morning hour to 2268 MWh. The import pattern closely follows the loads most of the time. However, when generation from the pumped storage power plants occurs import level decline.

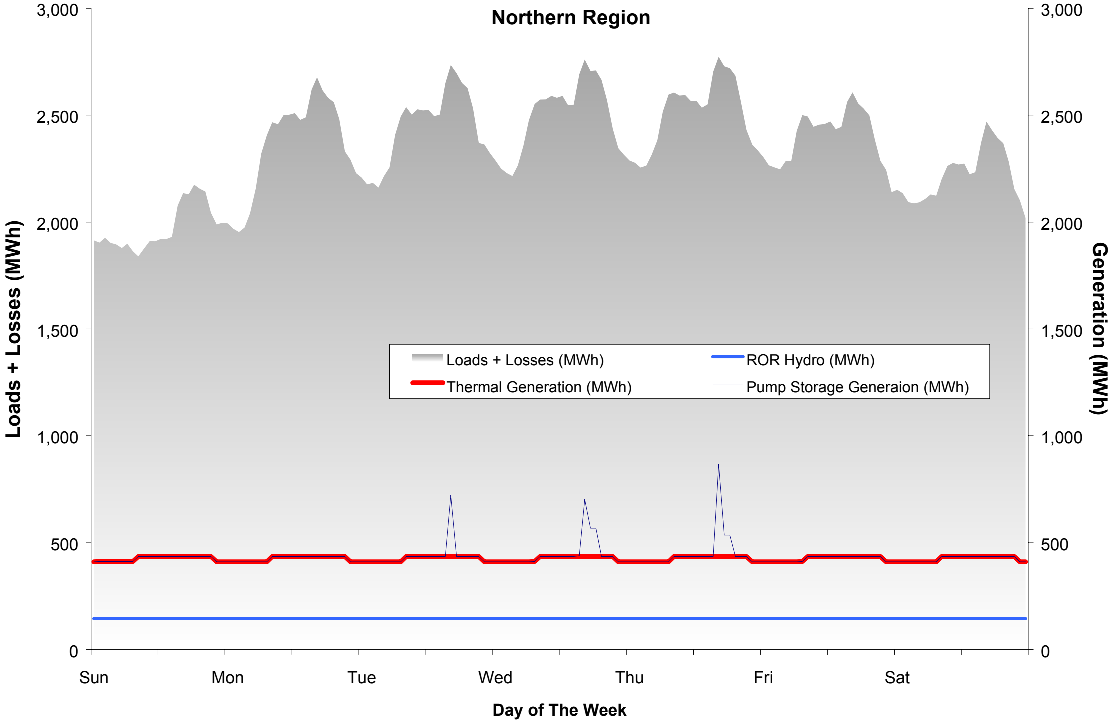


Figure 1.13 Generation and Loads in the Nothern Region (Peak Load Week)

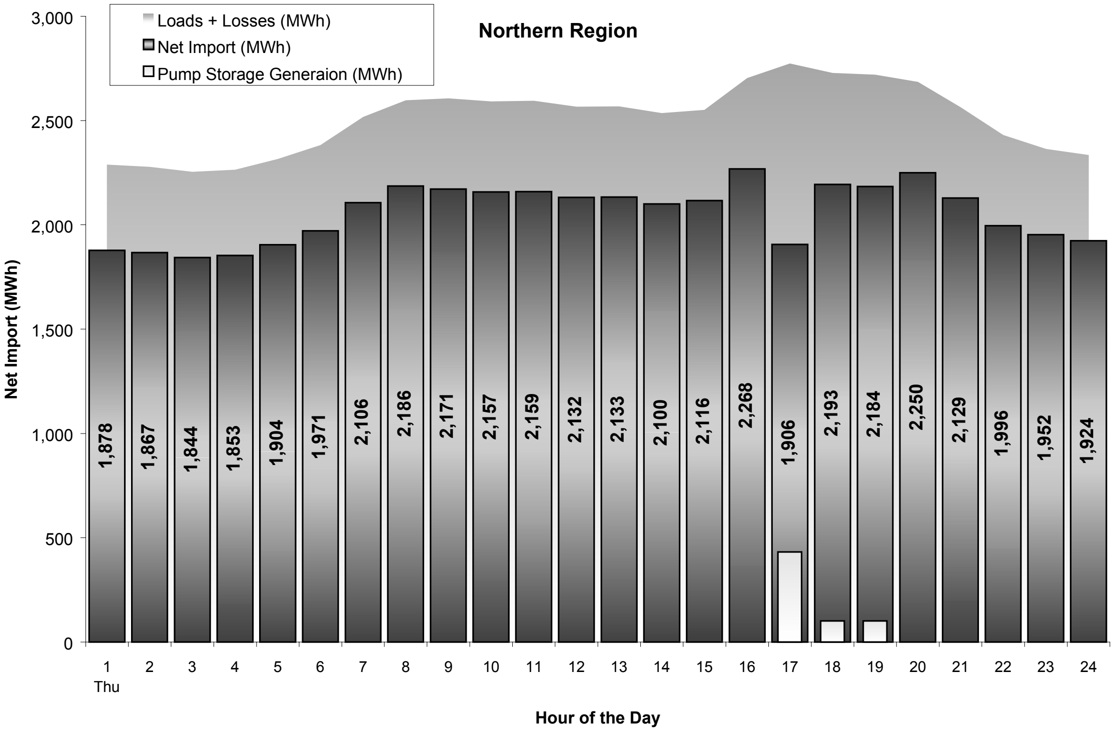


Figure 1.14 Power Imports/Purchases by the Northern Region (Peak Load Day)

1.5.4.3 Southern Region

The Southern region differs from both the Northern and Central regions in that generation patterns follow loads much more closely. As shown on Figure 1.15, thermal power plant generation in the region tends to follow loads with generation levels that exceed regional loads during some peak load hours. During the night and some shoulder hours, thermal generation is slightly lower than loads. Note that generation of storage hydro power plants occurs during the highest load hours and is exported to serve loads elsewhere in the grid.

There are relatively small amounts of power that are at times exported from the region and during other times energy is imported into the region. As shown in Figure 1.16 for the peak load day, energy is imported into the region during low load hours and exported during on-peak hours. Generation from pumped storage power plants aids in the region's capacity to export power during peak hours. Selling energy at high prices during the day and buying energy during the night adds to the net revenues of the region. Both imports and exports are below 1000 MWh and are relatively small compared to total loads and generation resources.

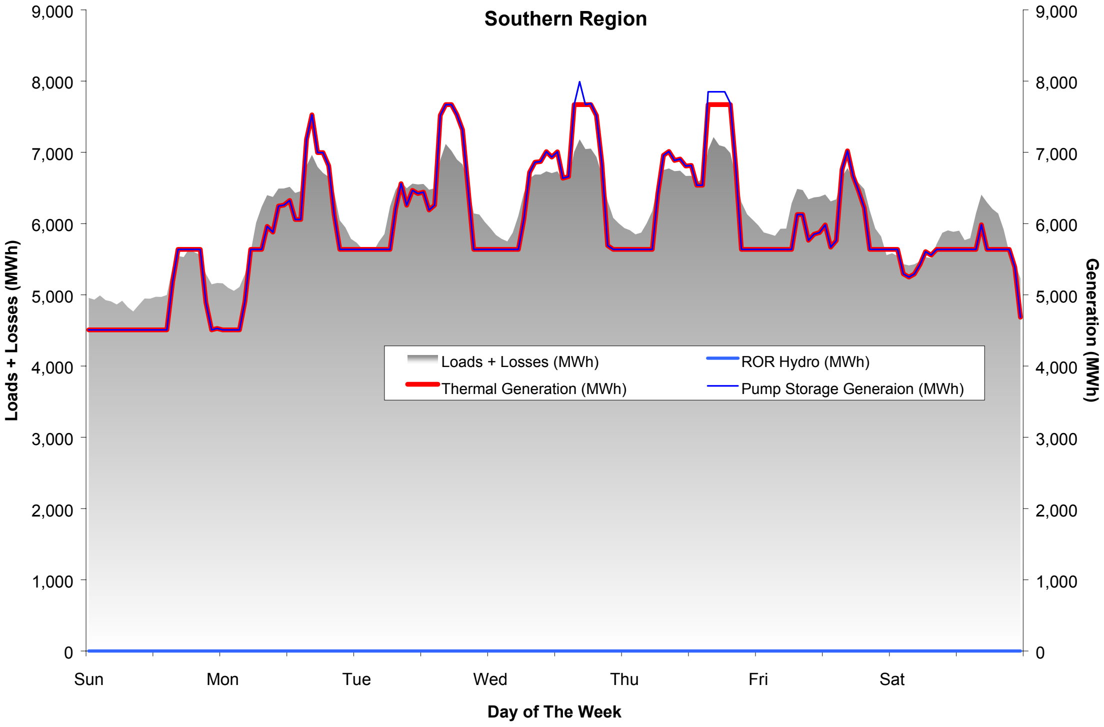


Figure 1.15 Generation and Loads in the Southern Region (Peak Load Week)

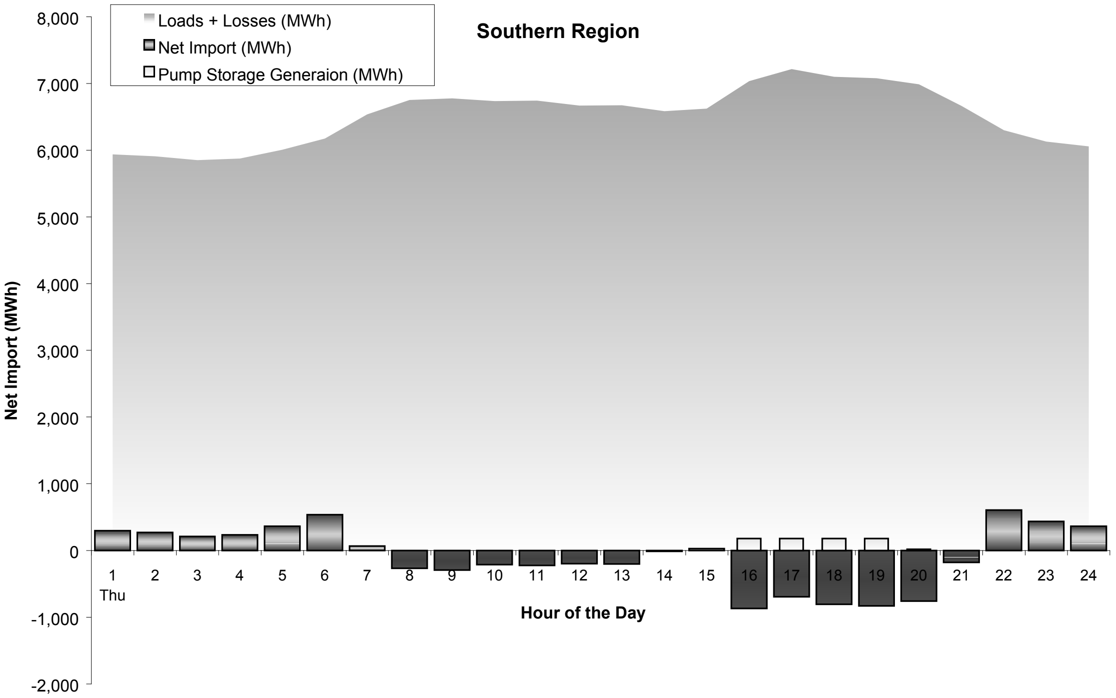


Figure 1.16 Power Imports and Exports in the Southern Region (Peak Load Day)

1.5.4.4 Eastern Region

Similar to the Southern region, the generation pattern tends to follow lows in the Eastern region. However, as shown on Figure 1.17 the region has generation levels that are higher than loads in the region during all weekday hours and during peak hours on Saturday. Generation from storage hydro power plants occurs during the highest load hours and is exported to serve electricity demands elsewhere in the grid. Generation levels dip below loads during Sunday and off-peak hours on Saturday. As shown in Figure 1.18 Power exports occur during all hours of the highest load day and from about 215 MWh to 730 MWh.

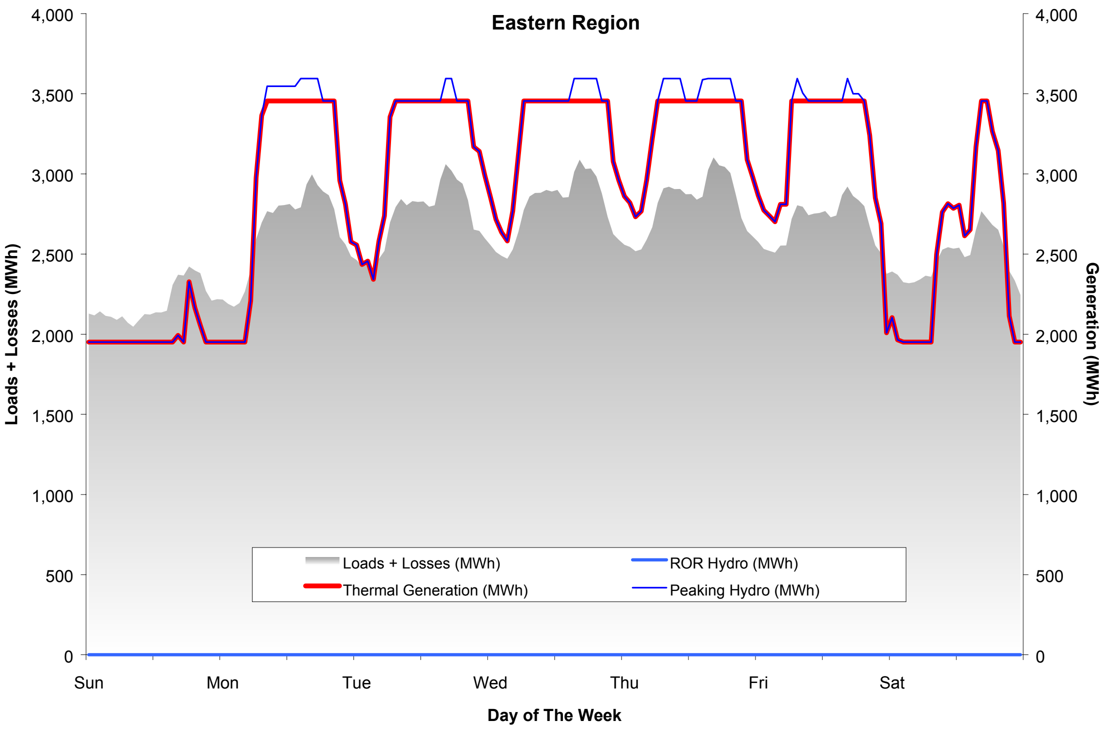


Figure 1.17 Generation and Loads in the Eastern Region (Peak Load Week)

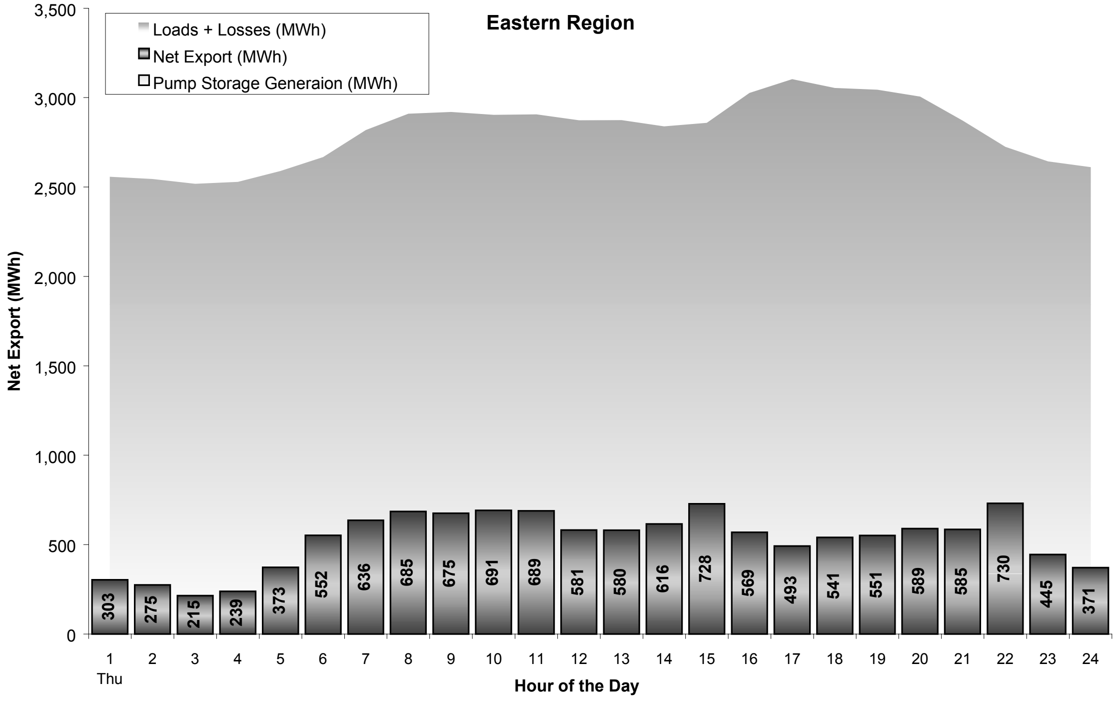


Figure 1.18 Power Exports/Sales for in the Eastern Region (Peak Load Day)

1.5.4.5 Western Region

Generation in the Western region, also tends to follow loads plus sales but the range of generation is less than the range in loads. As shown in Figure 1.19, generation levels during the night are higher than the loads/sales while loads/sales and generation levels are nearly identical during the weekday peak. Net exports shown in Figure 1.20 show that exports and imports for the peak load day are small compared to the loads and resources.

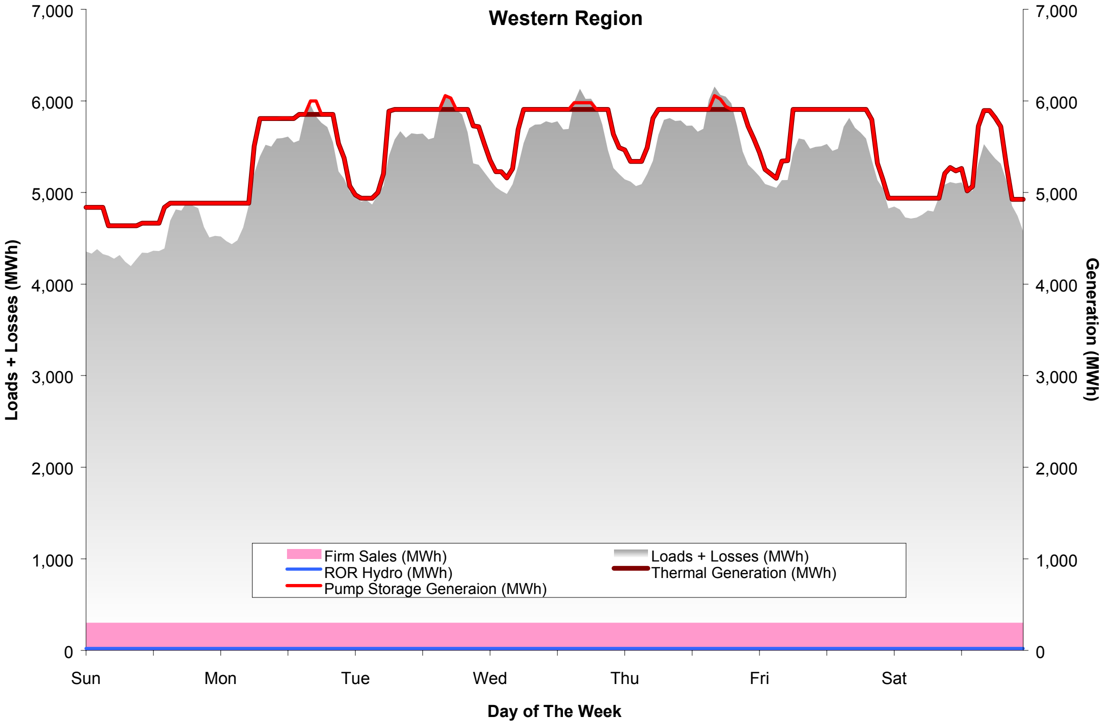


Figure 1.19 Generation and Loads in the Western Region (Peak Load Week)

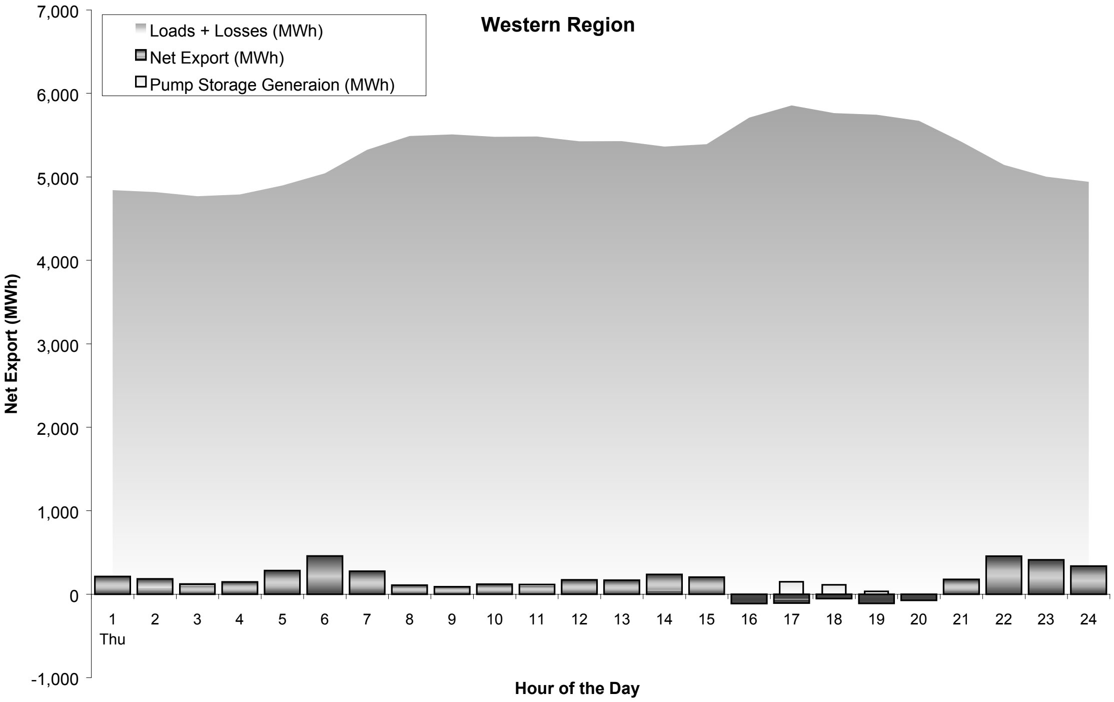


Figure 1.20 Power Exports/Sales for in the Western Region (Peak Load Day)

1.6 Small-Scale Gas-Fired CHP Analysis

Revenues for a candidate CHP power plant were estimated by the peak load week. This plant is a small local CHP facility with a generation capability of 24 MW. The candidate plant was assumed to be located in the Northern region since this part of Poland is estimated by GTMax to have the highest marginal value of energy. Since the CHP was assumed to be located very near a load centre losses would be negligible.

The generation pattern projected by GTMax along with estimate prices for energy are shown in Figure 1.21. Prices delivered to the 15 kV system are higher than prices at the market hub which are on the high voltage transmission system. Therefore the price of energy shown on Figure 1.21 are higher than the average market hub price displayed in previous figures.

The CHP power plant generates electricity at full capacity for 14 hours per day from 9 AM to 10 PM. This generation pattern is projected for all 7 days during the simulated week. The amount of money that owners of the CHP plant would receive is assumed to be the hourly market price of energy multiplied by the amount of energy sold in the hour. However, a payment tariff structure was established for energy sales. Based on an earlier study conducted by ARE the average payment that would be received by CHP owners is about 43.25 $/MWh. This is somewhat lower than the average price that is estimated by the GTMax model.

Table 1.8 shows the estimated revenues and incremental production costs for owners of a CHP facility. Incremental production costs are estimated to be between 6 to 10 $/MWh. This is the cost difference between operating the plant for only heat production and for generating both heat and electricity. The CHP operational expenses of $23530 shown in the table is based on a 10 $/MWh incremental production cost. Revenues or the amount owner would receive during the peak load week is about $109.340. The difference or short-term net revenue is about $86000. When an incremental cost of 6 $/MWh is assumed the net revenue increases to more than $95000. Over the lifetime of the project, these net short-term revenues must be large enough to pay for all fixed expenses plus capital expenses. Although a company may have positive short-term net revenues, in the long-term the company may become bankrupt.

This is an average payment for energy of about 27.11 $/MWh. This is somewhat higher than the 43.25 $/MWh estimated by ARE in its previous study. However, GTMax prices for other weeks of the year would most likely be lower for non-peak weeks in the year.

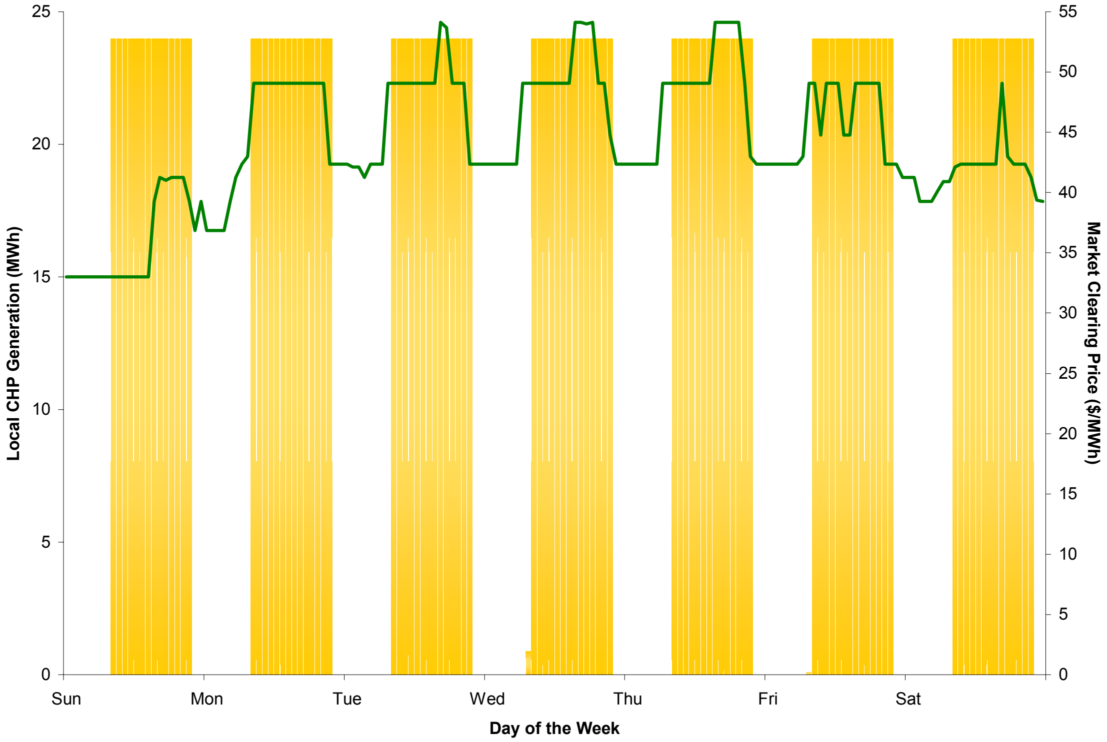


Figure 1.21 CHP Power plant generation and delivered energy prices

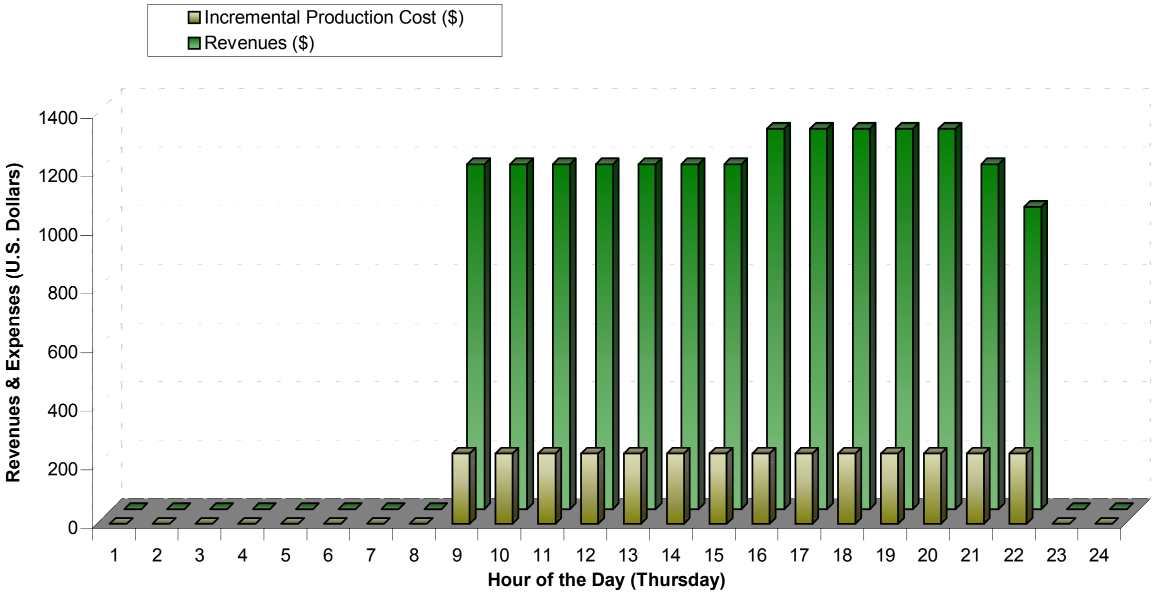


Figure 1.22 Revenues and Expenses for Owners of CHP Power Plants.

Table 1.8 GTMax Estimates of Net Revenues From CHP Electricity Sales

Day	Revenues ($)	Incremental Cost ($)	Net Revenues ($)
Sun	12,374	3,360	9,014
Mon	16,323	3,360	12,963
Tue	16,555	3,360	13,195
Wed	16,908	3,369	13,539
Thu	16,946	3,360	13,586
Fri	15,858	3,361	12,497
Sat	14,375	3,360	11,015
Grand Total	109,340	23,530	85,810

1.7 Transactions East-West Analysis

In order to represent East – West international power transmission two additional nodes, shown in Fig. 1.0, were created: one injection node of firm purchase RU (Russia) and a sink node of firm sale GE (Germany).

The objective was to determine:

- maximum power to be transferred in the framework of the “East-West Bridge” by the existing Polish Transmission Grid;
- wheeling cost of the power transmission.

To that goal a number of simulations were performed for the 24th week (June) and 48th week (December).

Wheeling costs curve was determined by setting increasing transmission power. These costs include two factors: additional transmission costs caused by the transactions and costs due distortions in optimal power dispatch. Wheeling costs are presented in Fig. 1.23.

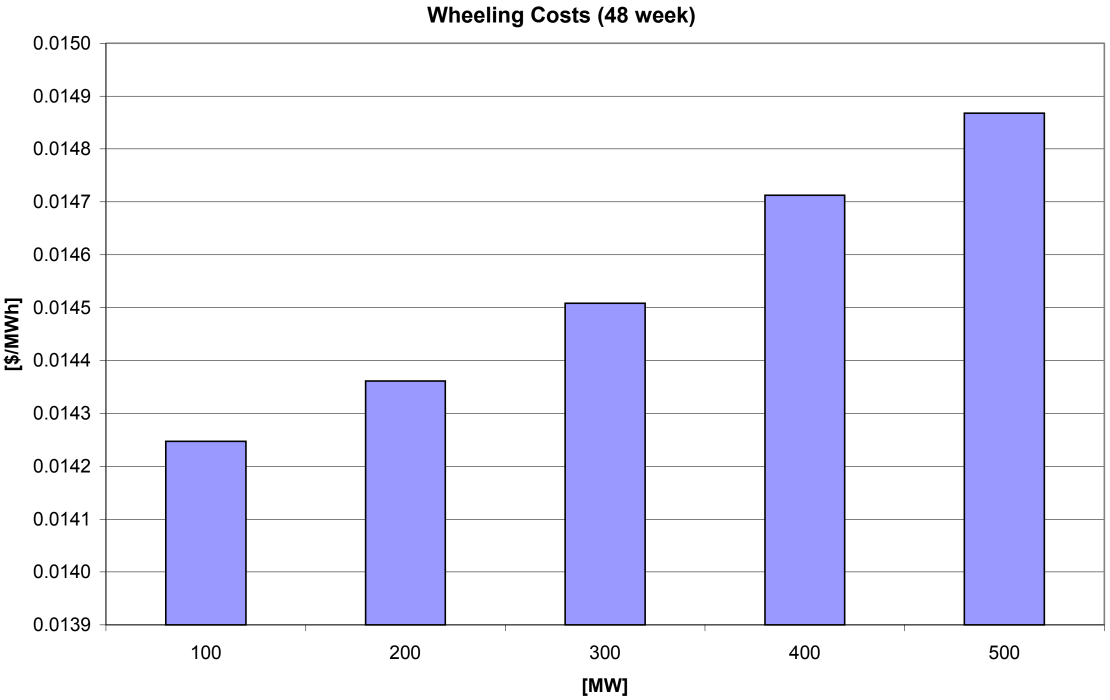


Fig. 1.23. Wheeling Costs of the East-West Transmission through existing grid

In order to obtain a rough estimate of contractual power transfers across Poland Available Transmission Capabilities (ATC) were calculated. The GTMax model bases these computations on the Total Transfer Capability (TTC) that is input into the model minus contractual energy flows computed by GTMAx. Results for ATC over user-defined paths are provided in Figure 1.24. Estimated values are relatively small for the Northern path while the central path has the highest values that at times exceed over 2,000 MW. The northern path is often at or near its defined transmission transfer capability since the Northern region has a supply shortage that is satisfied via less expensive production for the Western and Eastern regions.

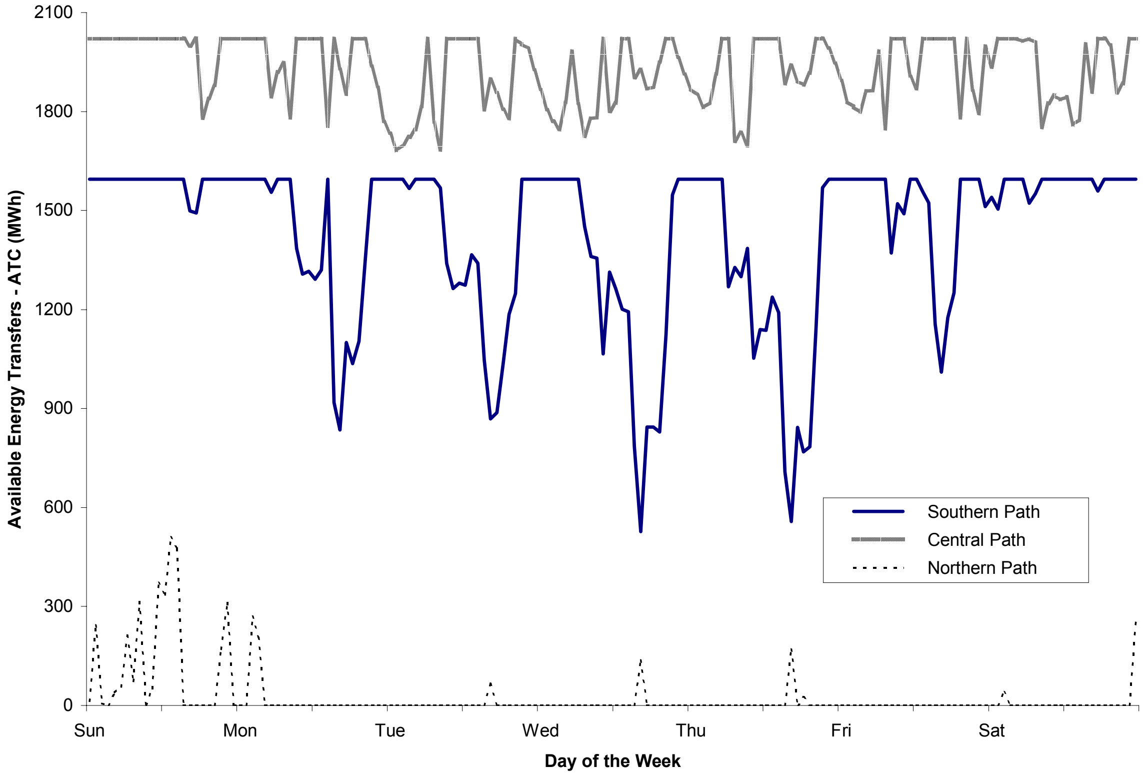


Fig. 1.24. Computed ATC Values for Three Paths Across the Polish Power System