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Research Report

A lower carbon strategy for the electricity sector of Kazakhstan to 2030/50: Scenarios for generation and network development. Technical report

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Politikberatung kompakt

Deutsches Institut für Wirtschaftsforschung

2014

A Lower Carbon Strategy for the Electricity Sector of Kazakhstan to 2030/50

Scenarios for Generation and Network Development

Jonas Egerer, Roman Mendelevitch and Christian von Hirschhausen

IMPRESSUM

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DIW Berlin: Politikberatung kompakt 85

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A Lower Carbon Strategy for the Electricity Sector of Kazakhstan to 2030/50

Scenarios for Generation and Network Development

Technical Report

Berlin, August 2014

Study developed within the frame of the project “Integrated Approach for the Development of Climate-Friendly Economies in Central Asia”, carried out by a consortium coordinated by DIW econ and supported by the International Climate Change Initiative of the Federal Ministry of Environment, Nature Conservation and Nuclear Safety of Germany

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Abbreviations

AC	Alternating current
bcm/a	Billion cubic meter per year
bn	Billion (1,000,000,000)
CC	Combined cycle
CCGT	Combined cycle gas turbine
CHP	Combined heat and power
DC	Direct current
EU-ETS	European emissions trading system
GT	Gas turbine
GTPP	Gas turbine power plant
WEP	Wind energy plant
HVDC	High voltage direct current
M	Million
Mbbl/d	Million barrel per day
RoR	Run of River
ST	Steam turbine
WTO	World Trade Organization

1 Introduction

Kazakhstan has taken commitments for a long-term climate policy including an emission trading system (ETS) that was introduced in 2013. A further linking with the European EU-ETS is discussed. However, the instrument set to reach the climate policy targets of lower greenhouse gas (GHG) emissions is yet somewhat unclear. Undoubtedly, a major share of the GHG reduction effort must come from the electricity sector, just as in the European Union where model forecasts and EC plans call for a full decarbonization of the electricity sector until 2050. This report thus sets out elements of a lower carbon strategy for the electricity sector of Kazakhstan at the horizon 2030/2050. As part of the Kazakh „green growth“ strategy, the report identifies pathways to lower the greenhouse gas emissions, mainly CO₂, from the electricity sector.

The report takes KEGOC's estimates for 2030 as the basis to develop a "Conventional" scenario, and, since this base scenario is clearly not "low-carbon", then develops two lower-carbon alternatives: i) a „Renewables“ and, ii) an „Efficiency“ scenario. It compares the system costs, the generation mix, CO₂-intensities, as well as the institutional conditions that favor such lower-carbon pathways. The assumptions of the Conventional Scenario for 2030 are largely based on the KEGOC "Masterplan" (KEGOC, 2011). We have complemented the generation data base to arrive at a regional representation of the Kazakh electricity system on the unit level. Generally, the "Masterplan" envisages a continuation of reliance on coal as the primary fuel for electricity generation. By contrast, the Renewables scenario constitutes a major change in the electricity system with 30% of the electricity generated in 2030 coming from wind and solar (PV). A third, more stringent, "Efficiency" scenario with stricter efficiency efforts (including demand-side management for peak shaving), may be a compromise between the two first scenarios.

The report is based on extensive analytical work on the Kazakh electricity sector, and also relies on previous experience of lower-carbon strategies in Europe and in Germany. It discusses the potential contribution of the electricity sector to the reduction of GHG emissions in Kazakhstan and sketches out pathways towards different kinds of electricity systems for 2030. The considerations explicitly take into account the national resource base and long-term commitments. It is structured in the following way: Section 2 provides a description

and analytical insights on lower-carbon strategies at the European level („EU Energy Roadmap“) as well as at national level in Germany („Energiewende“). The subsequent Section 3 gives a general to the Kazakh energy sector and Section 4 sets out the point of inception of the Kazakh electricity sector including generation and transmission infrastructure. Additionally, it surveys the potential for renewable energy sources (i.e. solar and wind). Section 5 proposes two alternatives to the high-carbon „Conventional“ scenario that is derived from KEGOC’s 2030 “Masterplan”. These alternatives are a „Renewables“ and an „Efficiency“ scenario. Section 6 then calculates, based on an electricity sector model, the implications of the different strategies, in terms of electricity system costs, CO₂-emissions, and network extension. The last section concludes with an interpretation of the model results and provides policy implications and a 2050 perspective.

2 Lessons from Low-Carbon Transformations: Europe and Germany

Both Europe and Germany have embarked on pathways towards a largely decarbonized electricity sector by 2050. Europe has defined policy targets in the „Energy Roadmap 2050“, including the reduction of greenhouse gases by 80-95 % (compared to 2005), and a full decarbonization of the electricity sector (to allow other sectors, such as transport and industry, a higher GHG-budget) (see Figure 1). In addition to a „Reference“ scenario which under current policy misses the GHG reduction target, the „High Renewables“ scenario sketches out a pathway of 85 % renewable electricity supply, whereas the „High Efficiency“ scenario indicates ways towards lower electricity consumption.

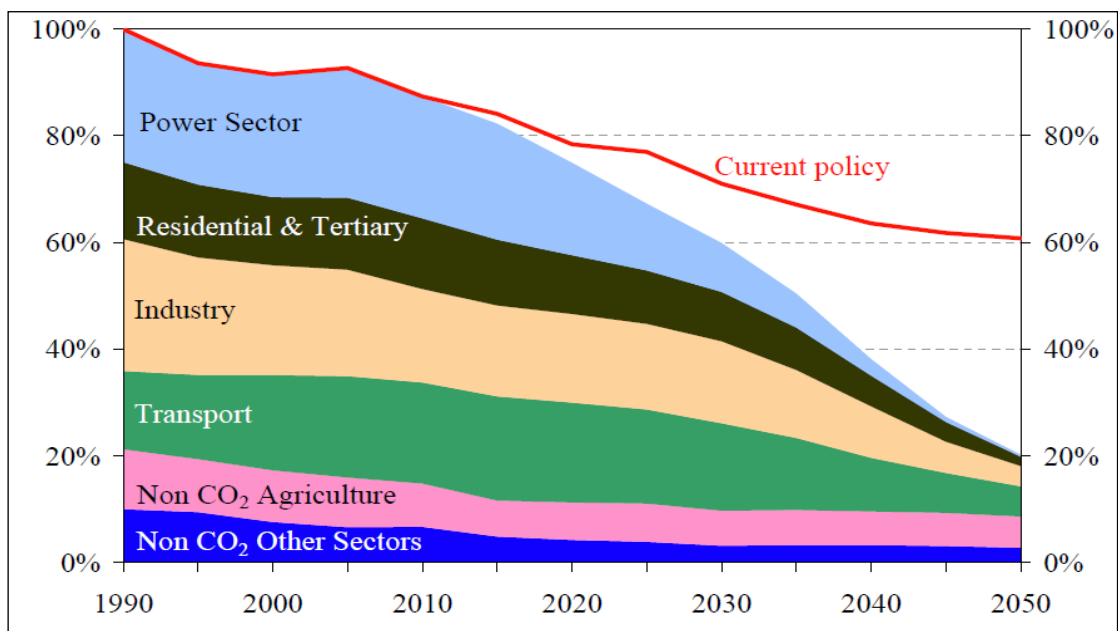


Figure 1: The Decarbonization in the European Energy and Power Sector

Source: European Commission (2011).

Germany has likewise embarked on an ambitious path to decarbonize its energy sector, and push the use of renewable source in the electricity sector beyond 50 % in 2030, and beyond 80 % in 2050 (with a share of renewables in primary energy of 60 % by 2050). This is accompanied by an integrated approach to develop generation, transmission, and demand-side resources into a comprehensive market design. Just like Europe, the German government has set out a „Reference“ scenario (Scenario B) until 2033, with upper and lower scenarios („A“, and „C“) defined at the horizon 2023 (Table 1).

The use of natural gas is the most critical issue both with respect to a lower-carbon energy mix, and to spur the flexibility of the electricity system with a high share of intermittent renewables. Given that new nuclear plants are too expensive, and that there is no hope for a low-carbon use of coal in the foreseeable future, natural gas is the „natural“ partner for a lower-carbon energy transformation. Natural gas will help to bridge the lower-carbon electricity sector in the next decades, but will then cede market shares to the renewables and, thus, decline in importance in a 2050 perspective. To fulfill this purpose new gas-fired power plants have to substitute the remaining coal-fired capacity as base technology. In the scenarios by the German government this is enforced with an emission price of 45 €/t CO₂ in 2033 (see Figure 2). In addition to the nuclear phase-out by 2022, the fuel with the highest carbon intensity, lignite, starts to phase out, too. No new projects are realized and almost half of the existing capacity is shut down by 2033.

Scenarios	Reference 2011	Scenario A 2023	Scenario B 2023	Scenario B 2033	Scenario C 2023
Technology	Installed Generation [GW]				
Nuclear	12.1	0.0	0.0	0.0	0.0
Lignite	20.2	18.0	17.6	11.8	18.5
Hard Coal	26.3	31.9	25.7	20.2	25.7
Natural Gas	26.5	23.2	33.0	41.0	33.0
Pump Storage	6.4	11.0	11.0	11.0	11.0
Oil	3.8	2.7	2.7	1.0	2.7
Other	4.1	3.3	3.3	2.3	3.3
Sum Conventional	99.4	90.1	93.3	87.3	93.3
Hydro	4.4	4.5	4.8	5.0	4.8
Wind (onshore)	28.9	45.7	49.3	66.3	86.0
Wind (offshore)	0.2	10.3	14.1	25.3	17.8
Photovoltaic	25.3	55.3	61.3	65.3	55.6
Biomass	5.5	8,1	8.5	9.0	7.3
Other Renewable	0.9	1.0	1.5	2.3	1.4
Sum RES	65.2	124.9	139.5	173.2	172.9
Sum Capacity	164.6	215.0	232.8	260.5	266.2

Table 1: Scenario Framework for the “Energiewende” in Germany

Source: Bundesnetzagentur (2012).

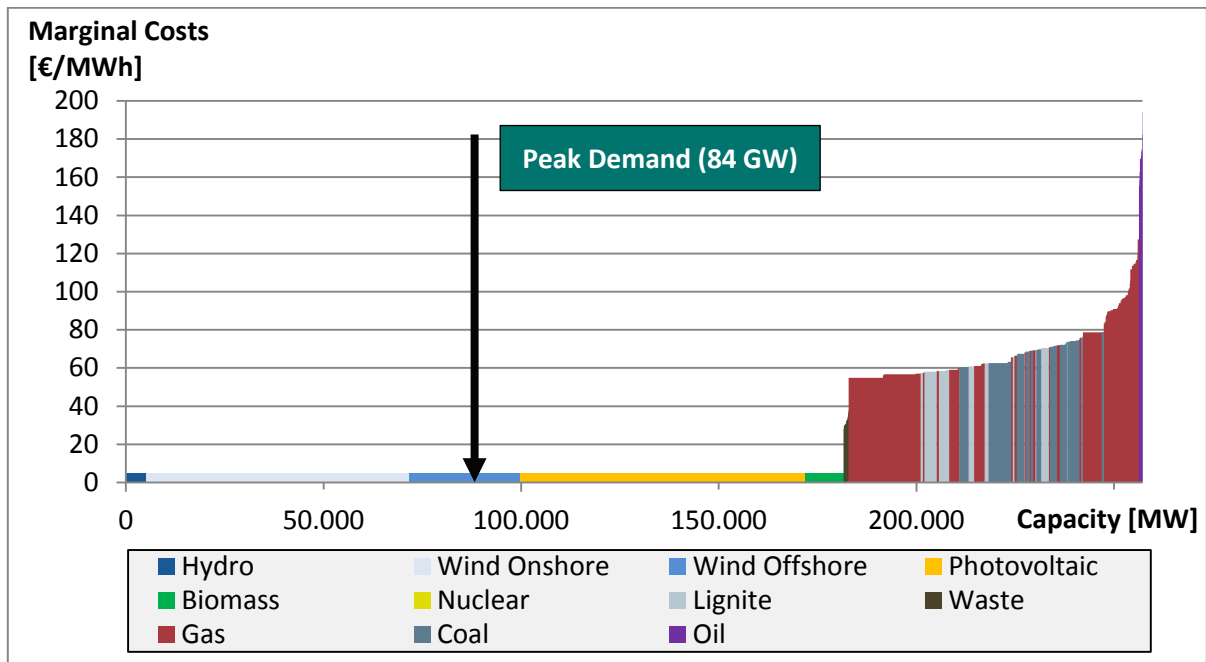


Figure 2: The Scenario Outlook for Germany in 2033 and the Role of Renewables and Natural Gas

Source: Bundesnetzagentur (2012).

Realizing the impact of high shares of renewables (e.g. in Figure 2 they exceed peak demand twice for Germany in 2033) there is a broad consensus that the traditional market design is not suited to accompany the lower-carbon transformation. This regards both the market segments, which do not include sufficient flexibility resources, as well as financing aspects of new generation (conventional or renewable). Issues like flexibility markets, capacity instruments, renewable feed-in tariffs, and the like may also become relevant for the lower-carbon transformation in Kazakhstan.

3 The Kazakh Energy Sector

Kazakhstan is the largest of the former Soviet Union republics after Russia. It has 15.7 million inhabitants and a size five times as big as Germany. Administratively, it is divided in 14 regions (see Figure 3). It has a continental climate with cold winters in the north and hot summers in the south.

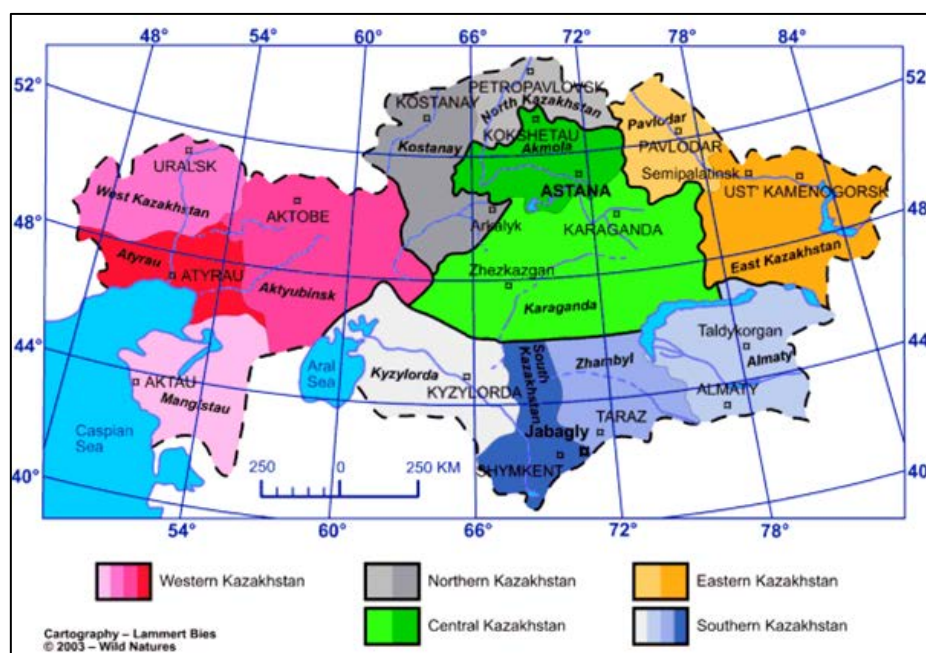


Figure 3: Economical and Political Regions of Kazakhstan

Source: Wild Natures (2003).

The breakdown of the Soviet Union caused a severe economic downturn to the closely linked Kazakh economy. During this period the contribution of industry to the GDP fell from 31 to 21 percent (Library of Congress, 2006). International investments, mainly in the oil sector, restored the country's economy. While Kazakhstan has accomplished a privatization of formerly state owned companies and has promoted unbundling in the energy and other sectors in the 1990s (there has been some re-nationalization since), the economy still suffers from a low diversification. The government wants to address this issue with goals to establish domestic renewable energy, pharmaceutical and other innovative industries. Kazakhstan has joined a trade union with Russia and Belarus to facilitate commodity flows and to incentivize foreign investments into this region (CIA Factbook, 2012). Moreover, the country is expected to become a WTO member in 2013.

Most regions are characterized by mostly agricultural activity (Akmola, Almaty, Zhambyl, Kostanai, North Kazakhstan, South Kazakhstan) and (non-oil) industrial activity is concentrated in East Kazakhstan, Karagandy, and Pavlodar. Kazakhstan has three main industrial regions: The western regions with their oil and gas resources and associated industries, the northern regions that are strongly bound to Russia and comprise the main non-oil industry, and South Kazakhstan (Almaty region).

Kazakhstan is rich of natural resources, in particular oil, natural gas and coal. Atyrau, Mangystau and West Kazakhstan are the main oil and gas producing regions of the country. With an oil production of 1.6 (1.4 for export) mbbbl/d in 2012 and a gas production of 36 bcm/a (currently 75 percent of the produced volumes are being re-injected to enhance oil recovery) Kazakhstan is a major oil exporting country and is expected to become a significant gas exporter in the future (EIA, 2012). The energy intensive oil processing is currently accomplished at three sites: close to production centers in city of Atyrau, in the Pavlodar region, which is supplied with crude oil from Siberia and in Shymkent, in the South Kazakhstan region, which is served from smaller oil fields in central Kazakhstan. Gas processing plants are located in Mangystau, Akotbe, and Pavlodar region (Yenikeyeff, 2008).



Figure 4: Existing and Proposed Gas Pipelines in Kazakhstan

Source: EIA (2008).

While Kazakhstan used to be a net importer of natural gas, the produced volumes are nowadays sufficient to satisfy domestic demand. However, due to its two separate natural gas

transportation systems in the west and in the south of the country, inherited from the Soviet era, the gas produced in the Atyrau and Mangystau regions cannot supply demand in the economic centers in the north and the south of the country. Therefore, at the moment, the country still needs to import natural gas from Uzbekistan which supplies the southern industrial belt (see Figure 4). The construction of the Beineu-Bozoi-Akbulak pipeline which is scheduled to deliver 5 bcm per year by 2015 will decrease the dependency on Uzbek natural gas supply (EIA, 2012).

4 The Kazakh Electricity Sector

The Kazakh electricity sector will face some major challenges in the next years. It will have to supply increasing electricity demand, while relying on an aging power plant fleet. Figure 5 shows the age structure of the electricity generation capacity. It reveals that a substantial share of the current capacity consists of old coal-power plants from the Soviet era. About 10 GW of coal power plants and 1 GW of natural gas power plants have been built before 1990 whereof 6 GW of the coal power plants even before 1980. A generation that is largely based on coal will also be a challenge with respect to greenhouse gas emissions.

There is also a spatial challenge of transmission infrastructure for having one single internal electricity market in Kazakhstan. The electricity transmission system today is still largely based on the integration in former Soviet Union system. Among other particularities, it includes a 1,150 kV transit line which connects hydropower from Siberia to industrial centers in central and western Russia.

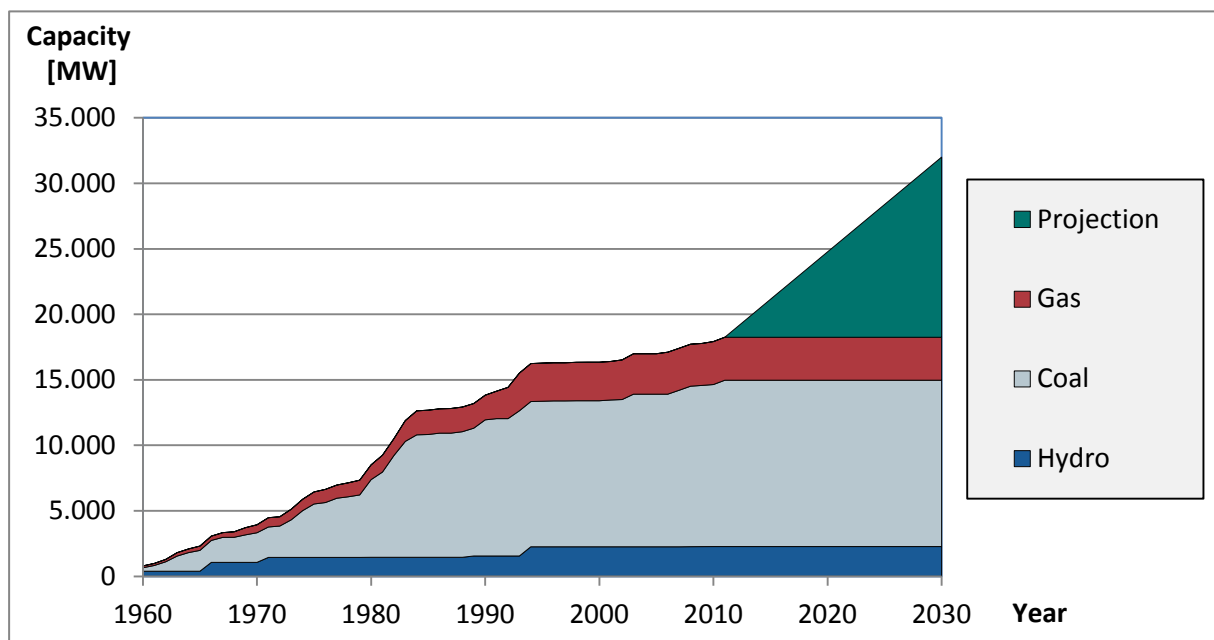


Figure 5: Age Structure of the Power Plant Fleet and Projected Investments

Source: Own illustration based on data from KazNIEK (2012b) and KEGOC (2011).

4.1 Electricity Demand

The spatial character of an electricity market is determined by local demand for electricity and district heat. On the generation side the main constraints are the local availability of fossil fuels at a competitive price and the renewable energy potential, respectively. The high-voltage transmission system has to bridge the distance between generation and demand centers. This section analyses current electricity demand, generation and transmission data for Kazakhstan which are required for developing a consistent electricity market model.

The annual electricity demand in Kazakhstan amounts to 83.8 TWh/year in 2010 and is expected to increase by 73 % to 144.7 TWh/year in 2030 (Table 1). The data reveals a strong concentration of demand in the central and eastern economic region. Yet there, only the Akmola region with 85 % is expected to have demand growth rates above the national average of 73 % until 2030. The western regions of Atyrau (133 %), West Kazakhstan (127 %), and Mangystau (105 %) and the southern regions of Zhambyl (117 %) and Almaty (108 %) are expected to see the highest growth rates. Until 2030, these five regions increase their joint contribution to Kazakhstan's total electricity demand from 25 % to 31 %.

Region		2010	2030	Increase
Political	Economic	[TWh/year]	[TWh/year]	[%]
Aktobe	West	3.7	6.2	67
Almaty	South	8.8	18.3	108
Akmola	Central	6.6	12.2	85
Atyrau	West	3.6	8.4	133
East Kazakhstan	East	8.3	14.1	70
Karagandy	Central	15.3	26.3	72
Kostanay	North	5.5	8.6	56
Kyzylorda	South	1.2	1.8	50
Mangystau	West	4.1	8.4	105
North Kazakhstan	North	1.6	2.4	50
Pavlodar	East	17.4	22.8	31
South Kazakhstan	South	3.3	5.5	67
West Kazakhstan	West	1.5	3.4	127
Zhambyl	South	2.9	6.3	117
All of Kazakhstan		83.8	144.7	73

Table 1: Regional Electricity Demand today and 2030

Source: KEGOC (2011).

The distribution of demand is very heterogeneous within the 14 regions of Kazakhstan. Therefore, the regional demand is further disaggregated to district level based on population data. Here we assume that demand for electricity is correlated with population. Figure 6 shows the population distribution on the district level. This data enables a more precise allocation of regional demand to the respective network nodes (substations) of the transmission system. For the development of scenarios, demand allocation on the districts and network nodes is kept constant from 2010 to 2030, for each region.

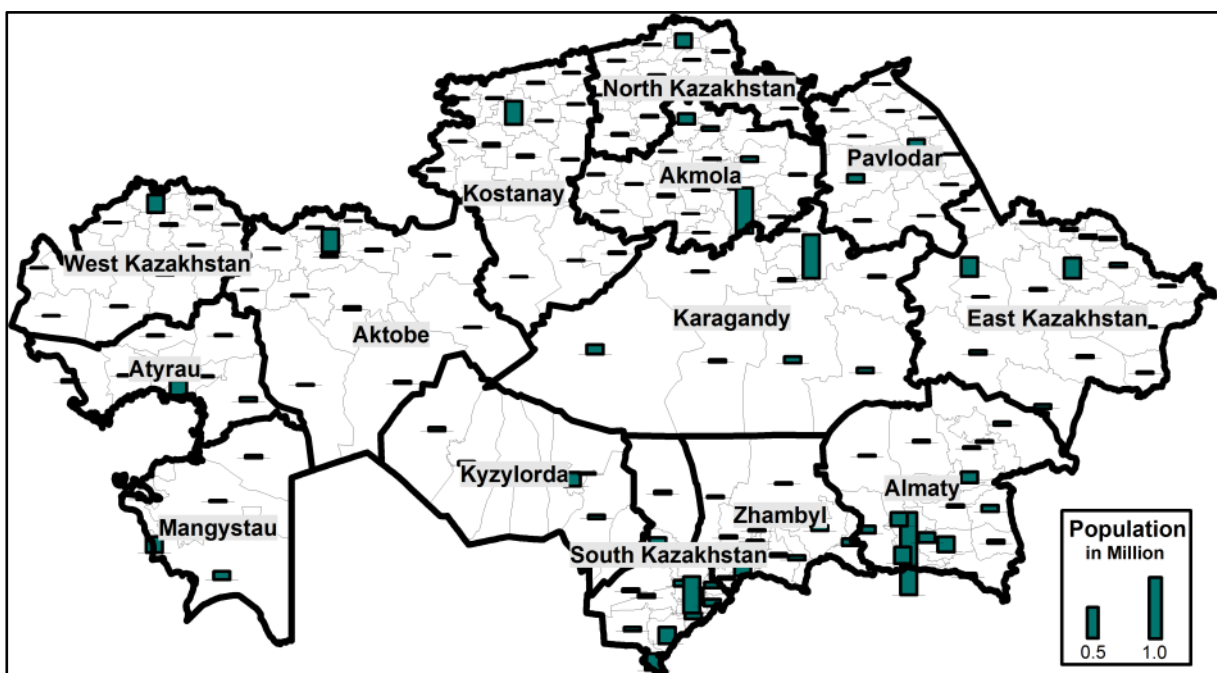


Figure 6: Population Distribution on District Level in 2011

Source: Own illustration based on Agency of Statistics of the Republic of Kazakhstan (2012).

Since electricity demand strongly differs between seasons as well as between hours of day, we do not use yearly data but further refine it. The time resolution is abstracted from 8,760 hours per year to three representative days for the winter and summer season, respectively. We derive a reference value on the distribution of demand between summer and winter (KazNIIIEK, 2012a) and employ it to arrive at consumption values for the respective representative day. The load curve of each day is split into 24 different time slices (hours) representing hourly load variation (Figure 7). The data on demand variation is derived from the day with the highest demand in 2011 and employed accordingly. The average winter and summer day is weighted with 0.8 compared to 0.1 for the respective low and high demand

days. If scaled up to one year the load curves of the representative days cover the annual demand of the respective year.

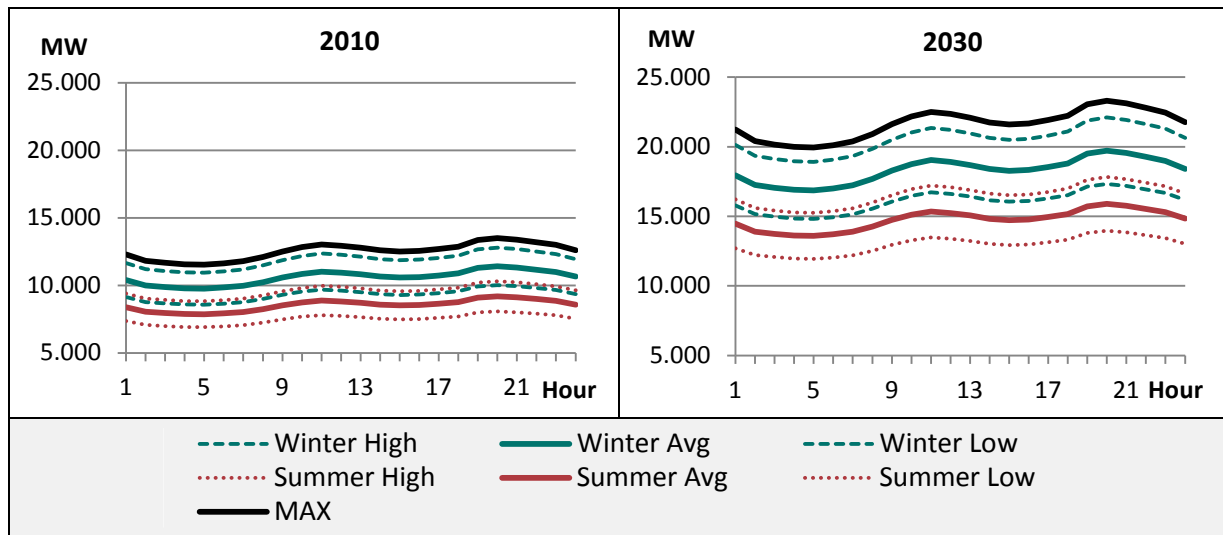


Figure 7: Hourly Demand of Peak Demand Day and Modeled Summer and Winter Days

Source: Own illustration based on data provided by KazNIIIEK (2012a).

4.2 Electricity Supply

4.2.1 Conventional power generation capacities

Data on conventional coal and gas-fired power stations is disaggregated to the individual blocks of each power plant. The database contains information on location, fuel in use, generation technology, installed and available generation capacity, efficiency, combined heat and power (CHP) capabilities, and year of installation of the respective power plant block. The detailed list of power plants is attached in the Appendix. The aggregate (Table 2) illustrates the importance of coal for the electricity system in Kazakhstan. A significant share of the installed capacity is equipped with CHP indicating the strong linkage between electricity generation and district heat supply. The low share of currently available generation capacity originates from an old and technologically outdated power plant fleet (KazNIIPIITES, 2010).

In 2011 electricity generation from conventional fossil power plants sum up to 78.7 TWh. At the same time power plants equipped with CHP produced 44.7 TWh of district heat as a by-product. 7.9 TWh of electricity was produced from hydro power. There is hardly any renewable electricity generation other than hydro, i.e. solar and wind.

Fuel Type	Technology	CHP	Total Capacity [MW]	Available Capacity [MW]
Coal-fired plant	Steam Turbine	No	7,430	5,045
	Steam Turbine	Yes	4,602	3,749
Gas-fired plant	Gas Turbine	No	1,448	1,180
	Steam Turbine	Yes	2,498	1,840
Hydro power plant	Renewable	No	2,272	1,953
Solar and Wind			-	-
Sum of Capacity:			18,250	13,767

Table 2: Aggregate of the Generation Data for 2011

Sources: KazNIPITES (2010) and data provided by KazNIEK (2012b).

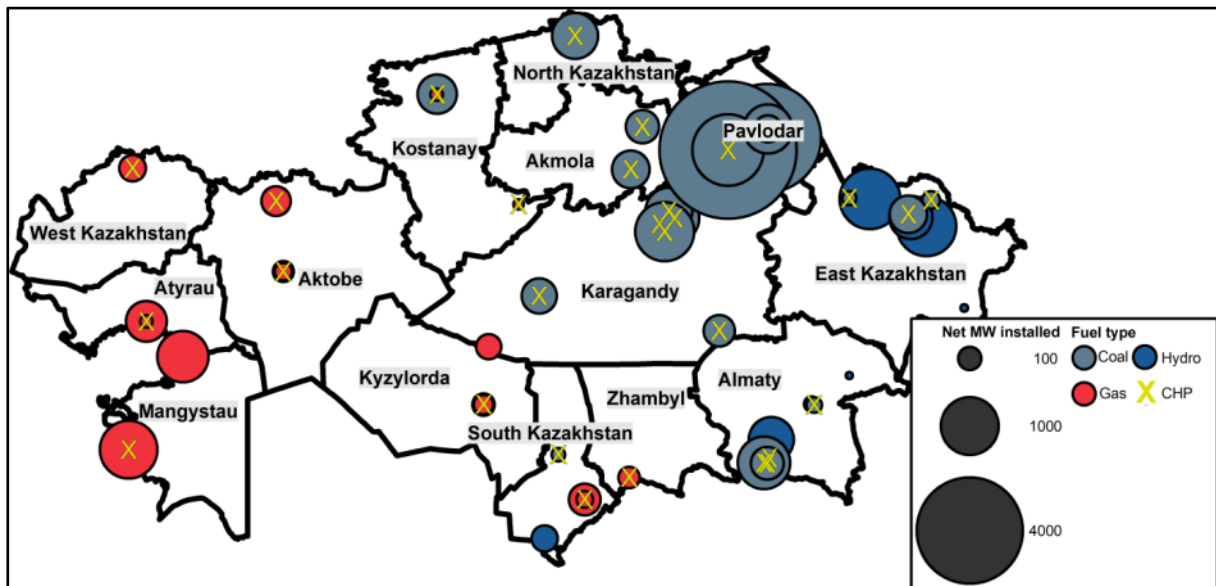


Figure 8: Spatial Distribution of Installed Generation Capacity for Kazakhstan in 2011

Source: Own illustration based on data provided by KazNIEK (2012b).

Figure 8 illustrates the spatial distribution of power plants by capacity and fuel type in Kazakhstan. The main characteristic is the concentration of coal generation capacity on the north-east. In total, 72 % of the generation capacity is located in the central and east economic region but the regional demand share is only about 57 %. With the exceptions of the city of Almaty and Taldykorgan, the southern and western regions of Kazakhstan are supplied from gas-fired generation. All major cities have local CHP plants ensuring the district heat supply during the winters. The clear separation between coal and gas capacity results

from the local access to either coal resources or gas production and pipelines.¹ Hydro power is available in East Kazakhstan, Almaty, and South Kazakhstan and amounts to 12 % of the total installed capacity.

The variable generation costs for the individual power plants are derived from the input fuel price, the CO₂ content per MWh_{thermal} of the respective fuel in use, the respective efficiency factor and the assumed CO₂ emission price.

Table 3 shows the assumed fuel prices for coal and gas. A common estimate of the CO₂ price in Europe in 2030 is about 40 €/t CO₂ (50Hertz et al., 2012). Kazakhstan has currently set up an EU-ETS-style carbon trading system including emissions from power generation and other sources. For 2030 we assume a CO₂ price of 20 €/t and perform a sensitivity analysis on market coupling with the EU-ETS by using a CO₂ price of 40€/t.

Efficiency values for the existing power plant fleet are not available on plant or block level. They are estimated based on the respective year of installation. For existing conventional plants efficiency values range between 25 and 43 %. Refurbishments improve the efficiency to 38 %. New steam and gas turbine plants are assumed to have an efficiency of 45 % and new CCGT plants 60 %, respectively.

Fuel type	Unit	2010	2030
Coal	€/MWh	5	6
Gas	€/MWh	13	19

Table 3: Price Assumptions on Resources for 2010 and 2030

Source: DIW Econ (2011).

As outlined by KazNIPITES (2010), existing generation capacity includes a high share of aging power plants which have to undergo refurbishments if they want to re-enter or remain in the market. In this study, we assume a technical lifetime of 40 years for gas-fired and 50 years for coal-fired power plants. In addition, the increasing demand for electricity also re-

¹ Coal resources: Ekibastuz (Pavlodar region), Karagandy (Karagandy region) and Kushmurun (Kostanay region).

Gas resources: among others, Tengiz (Atyrau region), Tolkyn (Mangystau region), Karachaganak (West Kazakhstan region), Kukmol (Karagandy and Kyzylorda region). Supplied by gas pipeline: Aktobe, Kostanay, South Kazakhstan and Almaty regions. Supplied by coal trains: Almaty and East Kazakhstan regions.

quires new investments in generation capacity. The cost of maintaining and expanding the power plant fleet depends on the choice of technology. The investment costs (Table 4) are used to give an indication of the fixed cost related to the scenarios. Refurbishments are assumed to be associated with 50 % of the fixed cost for new installations.

Fuel Type	Technology	New / Re-furbished	Investment Costs 2010 [€/kW]	Investment Costs 2030 [€/kW]
Coal Power Plant	Steam Turbine	New	1,300	1,153
	Steam Turbine	Refurb.	650	576
Gas Power Plant	Gas Turbine	New	400	400
	Gas Turbine	Refurb.	200	200
	Steam Turbine	New	400	400
	Steam Turbine	Refurb.	200	200
	Combined Cycle	New	800	729
Hydro Power Plant		New	3,000	3,000
		Refurb.	1,500	1,500
Nuclear Power Plant		New	6,000	5,671
Onshore Wind		New	1,300	1,182
Photovoltaics		New	1,800	1,207

Table 4: Assumption on Investment Costs for Generation Capacity

Source: Schröder et al. (2012).

4.2.2 Renewables Potential: Wind and Solar

4.2.2.1 Wind Power

The Government of Kazakhstan has adopted “The Program of Wind Power Development till 2030” which defined non-conventional power development as one of the priority profiles (Maximov, 2010). Kazakhstan possesses enormous potential of wind energy, especially at the Dzungarian Gate and the Shelek Corridor in the Almaty region. It should be noted that almost the entire territory of Kazakhstan shows favorable conditions for installation of wind power plants (Figure 9). Despite the great potential, the current installed wind capacity in Kazakhstan is limited to a 0.5 MW plant in Dostyk at the Dzungarian Gate and 1.5 MW in the Zhambyl region.

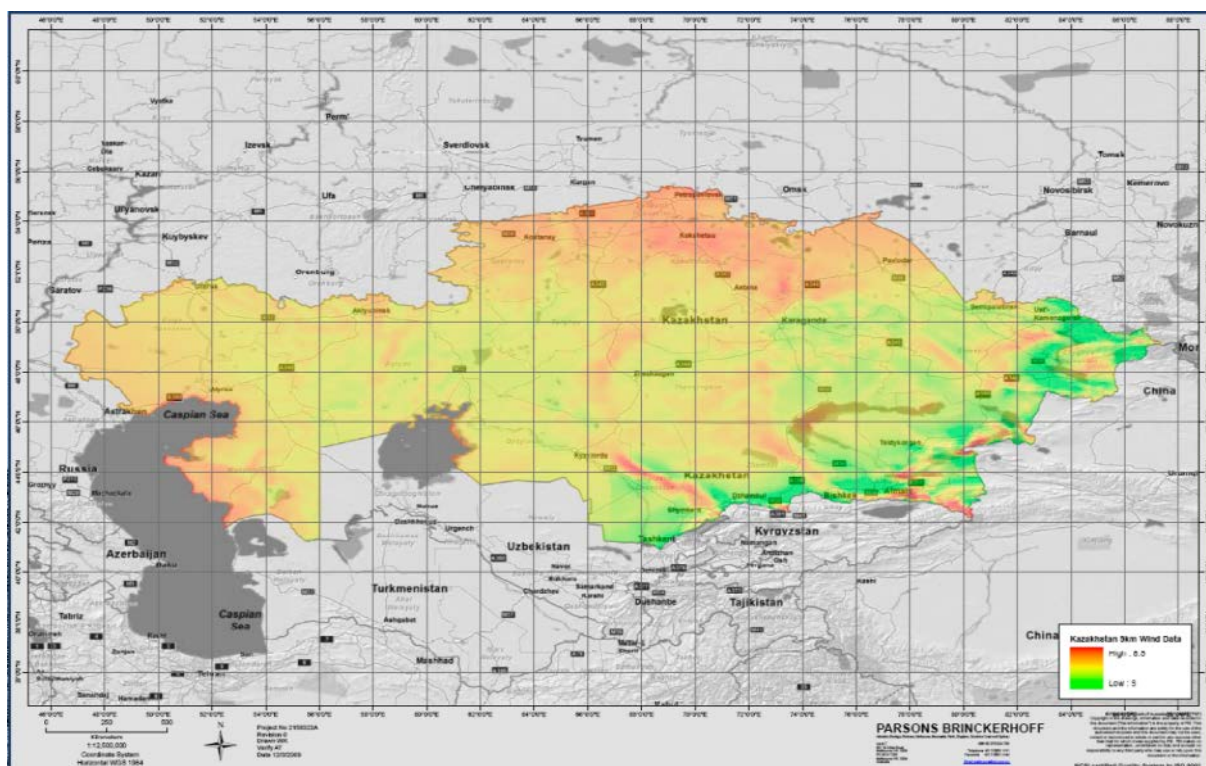


Figure 9: Kazakhstan Wind Resource Map

Source: Parsons Brinckerhoff (2011).

Company	Region	Planned Start of Operation	Installed Capacity [MW]
The first wind farm	Akmola (Ereimentau)	2013	45
Green Energy Almaty	Almaty	2013	51
NAR	Zhambyl	2015	75
South Wind Power	Mangystau	2015	42
TOO «Synergy Astana»	Kostanay (Arkalyk)	2014	48
Central Asia Green Power	Zhambyl	2013 - 2016	100
Spain Consulting	East Kazakhstan	2013	24

Table 5: Planned Wind Installations until 2016

Source: KazNIIK (2012c)

The most promising sites for wind power development are (i) in the South-eastern part of the country; the Dzungarian Gate (wide-gap south from the Alakol lake to the border with China), the Chu-Iliysky mountains in the area of the town of Tien-Shan and off spurs (Karatau ridge) in the area of Zhambyl; (ii) in the western part of the country the Urals southern off spurs (Mugojar mountains) and the Caspian zone with the Mangyshlak peninsula; and (iii) in

the northern part of the country. Currently, envisaged projects account for a total of 400 MW installed by 2016 (Table 5).

4.2.2.2 Solar Power

No notable development has taken place for solar electricity generation, so far. In the next two decades, the technology could be a relevant factor in increasing the renewable share of the electricity system for several reasons.

Firstly, the solar energy resource potential is no binding constraint given the vast territory of Kazakhstan that is subject to considerable sunlight exposure due to its geographic location. The best conditions for photovoltaic are in the southern part of the country (Figure 10) with a high number of sunlight hours (2,200-3,000 per year) and solar irradiation of 1,300-1,800 kW/m² per year.

While investment cost in photovoltaic has been at 3,000 €/kW and higher five years ago, enormous price reduction could be observed in the last years. Today installation cost per kW for multi-megawatt plants are well below 1,500 € which is the same range as onshore wind power plants. Photovoltaic has a lower annual load factor than wind but possesses good correlation in its availability with the demand levels during the day.

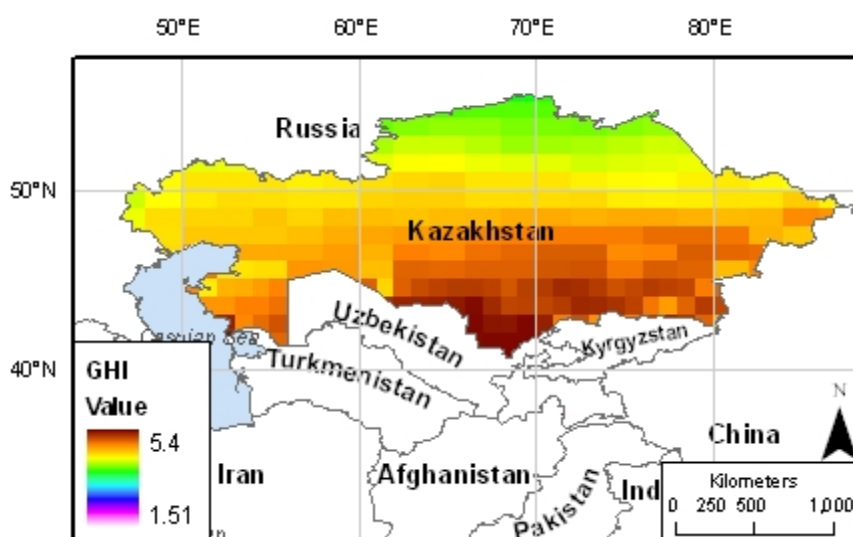


Figure 10: Kazakhstan Solar Global Horizontal Irradiation

Source: EBR Renewables (2012).

4.2.2.3 Fluctuating Renewable Generation in Type-Hours

The fluctuating character of the availability of wind and PV can be modeled employing a limited number of type-hours. We assume an average availability of 0.36 or about 3,150 load hours per year for the wind power plants in Kazakhstan. The wind generation is differentiated in three type-hours both for the winter and the summer days (Figure 11). The medium hour is weighted with 0.6 and assumes availability factors of 0.3 for summer days and 0.42 for winter days. The low and high wind hours are weighted with 0.2 each and have significantly lower/higher availability factors. For PV installations in southern Kazakhstan we assume an average availability of 0.18 or about 1,580 load hours per year. Two separate curves for the hourly availability of PV are used to differentiate between winter and summer days (Figure 11).

Weight		Low Wind 0.2	Medium Wind 0.6	High Wind 0.2
Season	Winter Days	0.08	0.42	0.76
	Summer Days	0.06	0.30	0.54

Table 6: Type-Hours for Wind

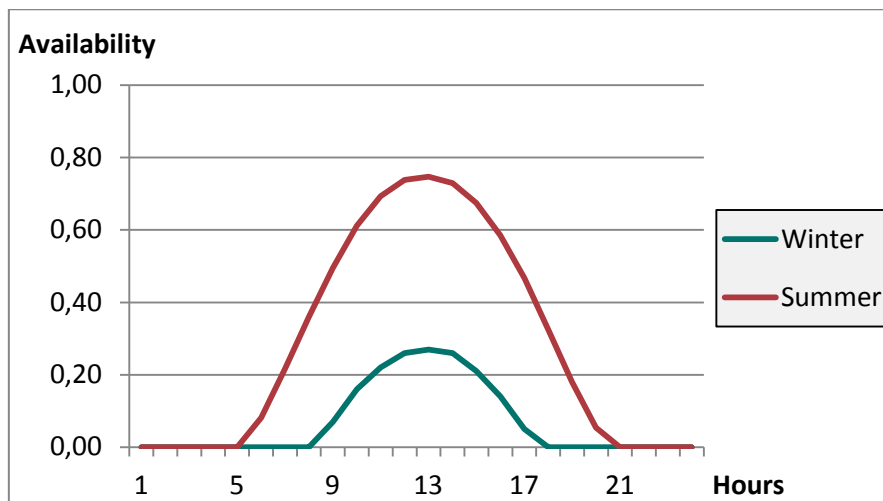


Figure 11: Type-Hours for Photovoltaic

4.3 High-voltage Transmission Network

Building on network data from KEGOC (2012) a comprehensive representation of the Kazakh high-voltage transmission system is developed. We digitalized the network map (Figure 12) which consists of 224 network nodes and a total of 277 power lines on three different voltage levels (1150 kV in green, 500 kV in red and 220 kV in black color). The data contains information on the location of the network node and combines the network topology with regional generation and demand. For power lines it includes the number of circuits and the length of each network link in kilometers to approximate the resistance and reactance as well as investment costs of the respective connection.

Today's electricity system consists of two separated transmission networks for Kazakhstan. The western part of the country is still isolated from the rest of Kazakhstan. The integration of both markets within the next years is discussed in the scenario section. In the Eastern part of the country the north-east is well connected into the Russian system while the connection to the population centers in the south, has been enforced with a second 500 kV link in 2010. The cross-border connections to its neighbors (Russia, Uzbekistan, and Kirgizstan) are included in the network topology but no foreign generation and demand is implemented. Therefore, self-sufficiency in electricity supply is assumed.

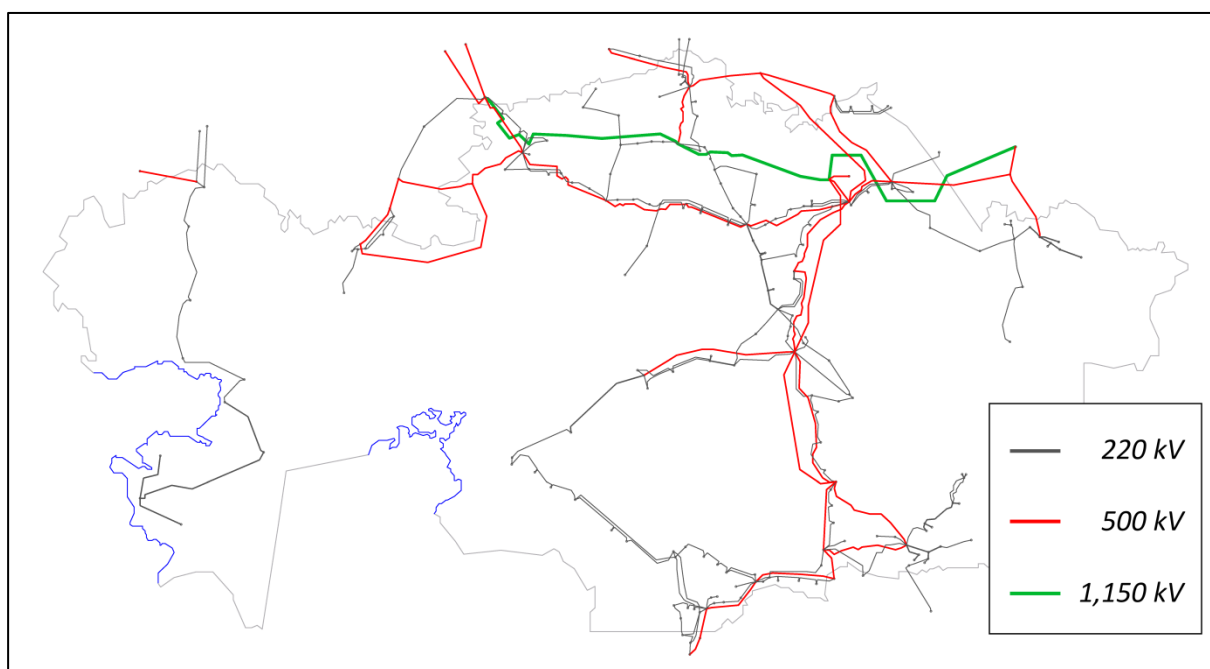


Figure 12: Digitalized Map of the High-Voltage Transmission Network of Kazakhstan

Source: Own illustration based on illustration from KEGOC (2012).

5 Scenarios for Kazakhstan in the Year 2030

This section outlines three scenarios of the future electric system in Kazakhstan. The underlying paradigms are highlighted and both economic and technical implications are discussed on national and regional level. The consecutive sections evaluate the interdependencies with transmission infrastructure and energy policies. In addition to the analyses for 2030 the scenarios are discussed in their role as milestones for the long-term 2050 perspective and beyond.

5.1 Overview on Scenarios

The scenarios “Conventional” (close to the “Base Case” by KEGOC), “Renewables” (with 30 % of demand supplied by solar and wind generation), and “Efficiency” (reduced demand growth) reflect on three different pathways to an electricity system for Kazakhstan in 2030. While cross-border exchange can be beneficial, all scenarios provide sufficient capacity for domestic supply of electricity.

5.1.1 KEGOC Masterplan

The starting point for the development of the three scenarios is the “Master Plan for the development of the power sector in the Republic of Kazakhstan until 2030” published by KEGOC the Kazakh network operator in November 2011 (KEGOC, 2011). The document includes demand projections (see section 4.1) and suggests an increase of generation capacity from today 19.4 GW to 32 GW in 2030. The electricity system remains dominated by conventional generation capacity (25.6 GW) covering 87.2 % of total supply. Hydro, solar and wind generation are represented with a joint capacity of 6.6 GW and a respective 12.8 % share of the electricity supply (see Table 7).

	Capacity installed [MW]	Share of Total [%]
Fossil Power Plants (ST / CC)	22,600	75.9
Fossil Power Plants (GT)	2,000	7.1
Nuclear Power Plant	1,000	4.2
Large Hydro Power Plants	2,900	6.8
Wind, Solar and Small Hydro	3,500	6.0

Table 7: Installed Generation Capacities and Shares in KEGOC Masterplan

Source: KEGOC (2011).

While the KEGOC Masterplan includes national figures and a list of projects for new and refurbished power plants, it does not provide detailed information on all individual power plants required for its 2030 projection. Thus, especially on regional level additional sources and assumptions are required.

5.1.2 Scenario Data of Generation Capacity on National Level

The Conventional scenario closely follows the generation fleet envisaged in the projections of the KEGOC Masterplan on national level. To develop a comprehensive scenario we add assumptions on the split between coal and gas-fired generation capacity according to planned projects and the regional availability of coal and gas resources. In the Conventional scenario the energy system remains dominated by coal-fired electricity generation (+4,700 MW of non-CHP capacity and +1,400 MW of CHP capacity) which covers most of the national demand increase until 2030. Gas-fired power plants continue to play a minor role in the electricity system with some installation of new gas turbine plants to address for peak demand (+1,900 MW). The investment in one nuclear power plant provides additional non-fossil base load generation (+1,000 MW). The few planned renewable capacities consists of wind power (+2,000 MW), additional hydro power plants (+1,750 MW), and minor investments in PV.

In contrast to the Conventional scenario the Renewables scenario constitutes a major change in the electricity system of Kazakhstan. It assumes substantial investments in wind power (+10,000 MW) and PV (+8,000 MW) which ultimately cover 30 % of the electricity demand in 2030. Hydro power is expanded to the same level as in the Conventional scenario but no nuclear power plant is realized. To meet the future demand for district heat and in the absence of locally available gas resources coal-fired CHP capacity expansion is almost at the same level as in the Conventional scenario (+1,300 MW). In contrast, no new projects for electricity-only coal-based capacity are initiated in the Renewables scenario. Compared to 2011 levels non-CHP coal-fired power plants start to decline (-600 MW). The higher share of renewable capacity is backed-up by substantial expansions of gas turbine capacity (+4,500 MW). New CCGT plants serve the increasing demand for electricity-only capacity (+2,300 MW) and CHP capacity (+1,500 MW). At the same time they replace some of the older gas-fired steam turbine CHP plants (-600 MW).

In both scenarios the increase in installed capacity (see Figure 13) reflects the rising electricity demand in Kazakhstan (83.8 TWh/year up to 144.8 TWh/year). In the Conventional scenario generation capacity of about 31,000 MW is required. The capacity is adjusted to cover the annual peak demand (see Figure 7 in section 4.1) and therefore includes 1,000 MW less in conventional generation than the KEGOC Masterplan. In the Renewables scenario wind and PV are assumed to have a low capacity credit requiring additional back-up. Under conservative assumptions the amount of conventional power plants in the Renewables scenario almost equals the level of the Conventional scenario. At the same time CO₂ emissions to meet the anticipated demand are significantly lower in the Renewables scenario (see section 6.3.2) due to a higher share of low-emission gas-fired generation.

The third scenario highlights the high potential for an increase in energy efficiency in Kazakhstan. For 2030 it assumes an annual demand of 114.3 TWh compared to the 144.8 TWh/year in the Conventional and Renewables scenario which is equal to a 50% reduction in demand increase from 2010 to 2030.

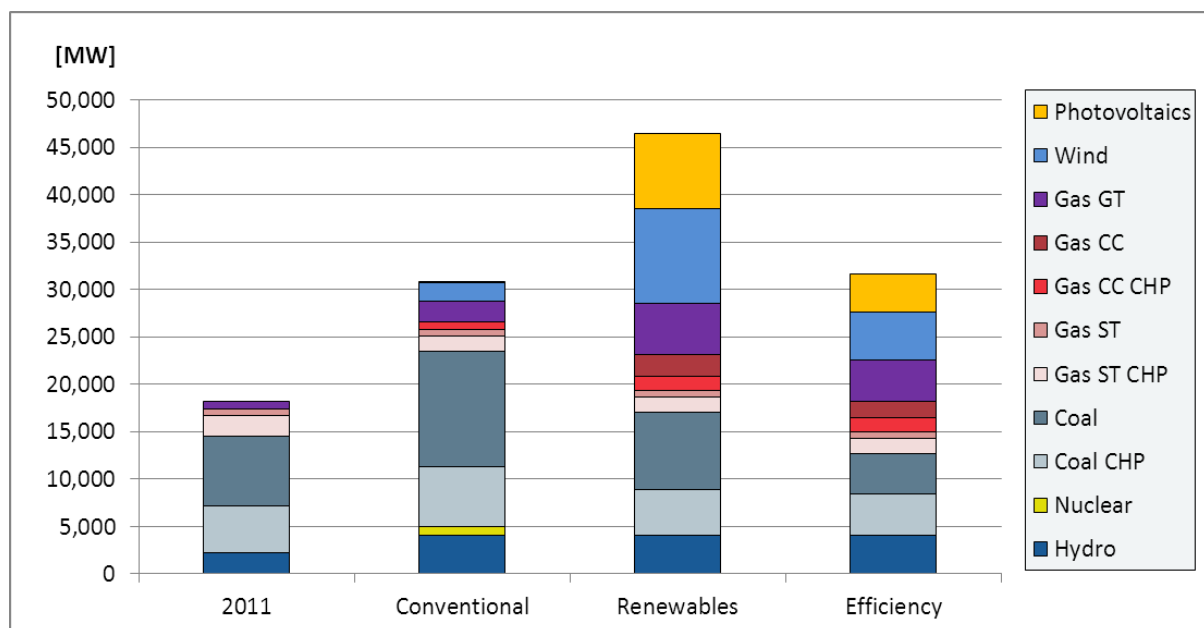


Figure 13: Installed Generation Capacities in 2011 and for the three Scenarios in 2030

5.2 Costs for Decommissioning, Refurbishment and New Investment

Based on cost assumption from Table 4 (see section 4.2.1) and assumptions on the respective power plant fleet (see Figure 14) we estimate the costs associated with refurbishment and installation of new capacity for the two scenarios (see Table 8). In the Renewables sce-

nario investment intensive coal-fired and nuclear generation capacity dedicated to serve the increasing electricity demand is substituted by cheaper gas-fired generation. Consequently, the required investments in new fossil-fueled capacity and in refurbishing the old coal-fired fleet are € 1.3 bn lower compared to the Conventional scenario. Moreover, the scenario spares the introduction of a nuclear facility in Aktau which induces additional savings of € 5.7 bn. While required investments in hydro power are the same in both scenarios, investments in new wind power plants and photovoltaic facilities are significantly higher in the Renewables scenario (€ 2.5 bn compared to € 21.5 bn). In total investments for refurbishments and new capacity sum up to € 40.8 bn in the Renewables scenario and total investment costs for the Conventional scenario are estimated as € 28.7 bn. While the Renewables scenario results in higher investment costs the reduced fuel consumption and lower CO₂ emissions significantly lower operational costs. A discussion on the timing of investment decisions for new generation capacity is included in section 7.1 and a more detailed analysis of variable costs induced in the respective scenarios is performed in section 6.3.

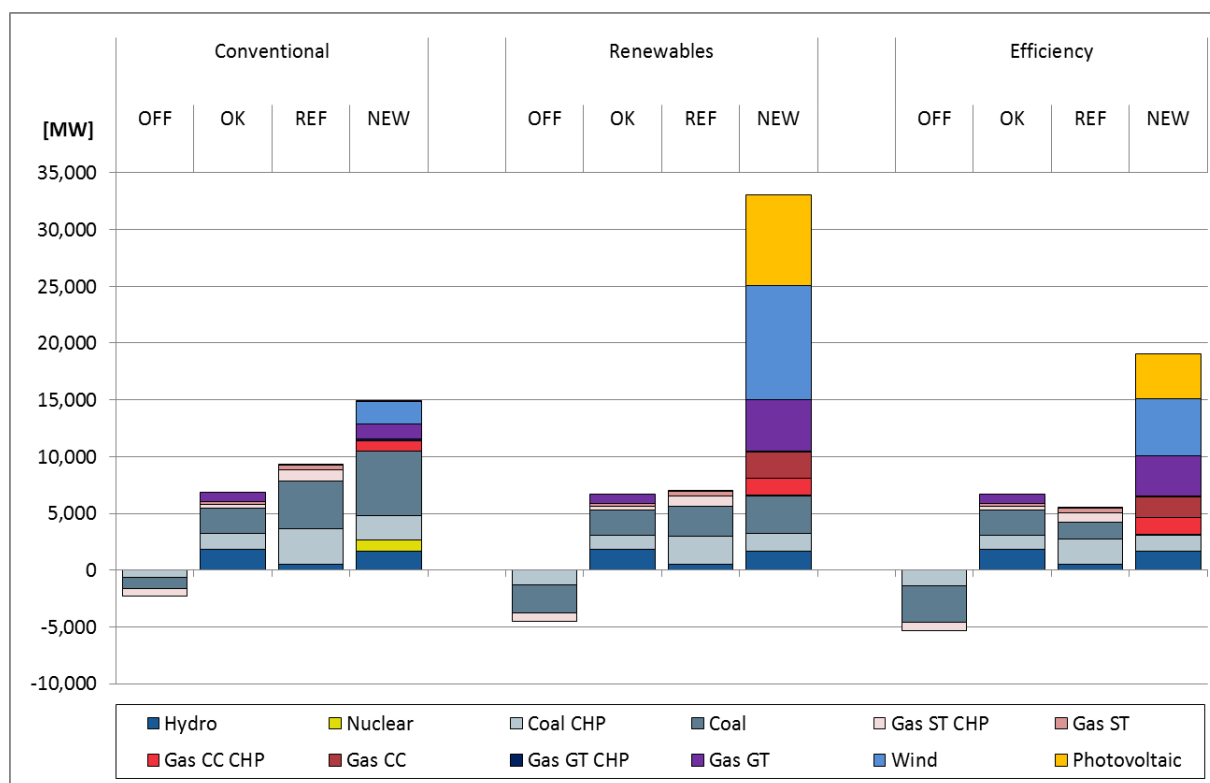


Figure 14: Decommissioned (OFF), Unaffected (OK), Refurbished (REF), and New Capacity (NEW)

Source: Own illustration based on data from KazNIIIEK (2012b), KazNIPITES (2010), KEGOC (2011) and own assumptions.

Fuel Type	Technology	Conventional Scenario [m €]			Renewables Scenario [m €]		
		Refurb	New	Total	Refurb	New	Total
Nuclear	ST	0	5,665	5,665	0	0	0
Coal	ST	1,803	2,421	4,224	1,389	1,822	3,211
Coal	ST	2,421	6,589	9,011	1,557	3,770	5,327
Gas	ST	185	12	197	168	20	188
Gas	ST	84	0	84	84	0	84
Gas	CCGT	0	638	638	0	1,090	1,090
Gas	CCGT	0	0	0	0	1,677	1,677
Gas	GT	7	51	58	7	51	58
Gas	GT	0	538	538	0	1,818	1,818
Subtotal of Fossil Generation		4,500	10,249	14,748	3,204	10,426	13,451
Hydro	RES	825	5,009	5,834	825	5,009	5,834
Wind	RES	0	2,364	2,364	0	11,820	11,820
Photovoltaic	RES	0	97	97	0	9,656	9,656
Total		5,325	23,384	28,708	4,029	36,911	40,761

Table 8: Investment Costs for Generation Capacity in the Conventional and Renewables Scenario

Source: Own calculations based on costs data from Schröder et. al (2012) and own assumptions.

Box 1: Excursus on Economic Considerations in Electricity System Planning

The economic rationale for a generation mix consisting of several technologies originates from their cost structure. A schematic example is presented in Figure 15. Generation technologies with high initial investment costs and low variable costs provide electricity at a lower average price per unit if the number of full load hours are sufficiently high (e.g. coal and nuclear power plants). The supply of peak load generation requires capacity generating only in several hundred hours per year. For this purpose technologies with low investment costs are more competitive despite the higher variable costs (e.g. gas turbines). The cost characteristics of different generation technologies and the varying level of demand results in the differentiation in base, mid, and peak load.

Combining information on available technologies with the load duration curve of the region of interests, the least cost power plant fleet can be determined. With the generalized assumptions in Figure 15, the optimal technology mix is a combination of coal power plants for base load, combined cycle gas turbines for mid load, and gas turbines for peak load. This optimization is often used in electricity sector models to determine the optimal

investment mix. The results are static and highly dependent on the cost and price assumptions. They should be related to the various uncertainties and additional constraints in the system:

- For nuclear power plants the assumption on investment costs is of key importance. While their construction costs are often estimated in the range of 2,000 to 3,000 €/kWh, figures from the latest projects in France and Finland have skyrocketed to well above 5,000 €/kWh. In addition, the cost of decommissioning and waste management has to be evaluated carefully. The uncertainty is mainly on the fixed cost;
- The choice between coal and gas has three main aspects: (i) CCGT plants are cheaper in investment and have a higher efficiency; (ii) domestic coal and gas resources have political and economic implications; (iii) the carbon emission price is the major price risk to coal due to higher specific emissions and lower efficiency than CCGT plants;
- Policies aiming to increase renewable capacities in the market negatively affect the economics of conventional power plants by a reduced and more volatile residual load;
- The market design (e.g. price zones, etc.) can affect the economics of power plants increasing the need for regional studies of the electricity market.

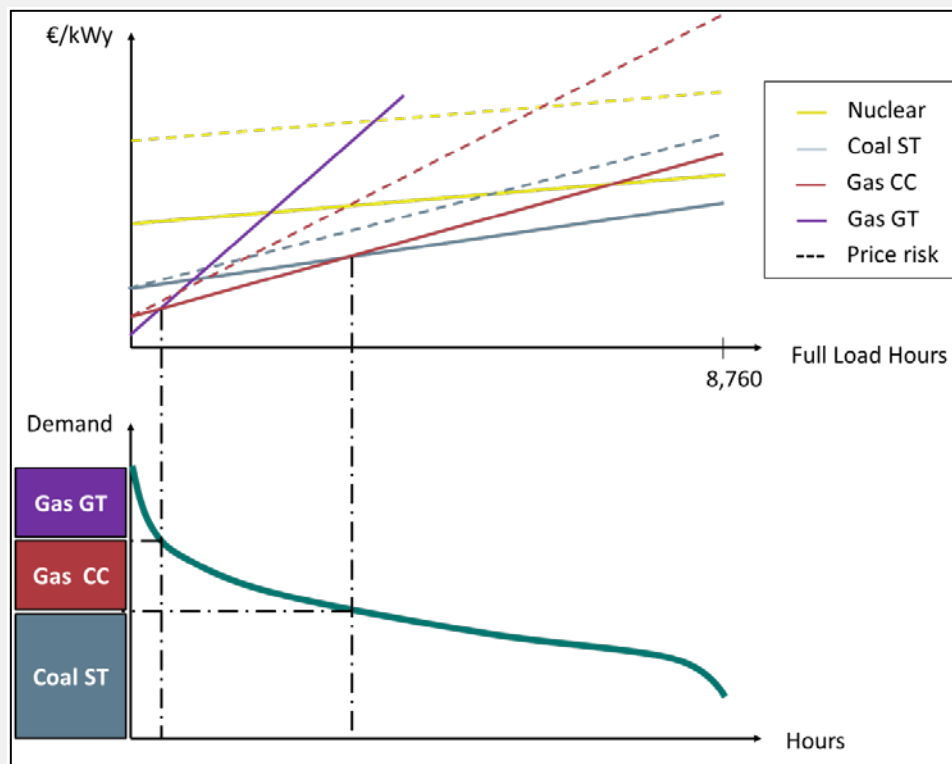


Figure 15: Technology Costs and Price Duration Curve

5.3 Changes in Regional Generation Capacity

5.3.1 The Conventional Scenario

Regionally disaggregated generation data builds on the figures for national generation of KEGOC Masterplan (see section 5.1.2) which do not include major changes in the coal dominated generation fleet in Kazakhstan. Additionally, we use data on planned cumulative generation capacity by technology and region provided by KazNIPPIITES (2010) to benchmark data on the residual power generation fleet and to adjust for discrepancies. With some own assumptions on the fuel type and the local distribution within one region we conclude on the capacities for every power plant on block level. The scenario data is illustrated on power plant level for new investments and refurbishments (see Figure 16) and aggregated to changes in the generation capacity for conventional technologies on regional level for 2011 and 2030 (see Table 9). The regional analysis indicates that coal-fired generation which has a high share of the planned additional capacity (68 %) is mainly to be installed in the northern and north-eastern regions (47 % of planned capacity). The remaining 21 % are added from electricity-only generation in the Almaty region which will be supplied by coal trains from the north. The additional demand in the western regions is met by 1,000 MW of nuclear generation capacity. Gas-fired capacity provides supply for peak load hours in the western regions (additional gas turbines) and some additional CHP capacity (additional CCGT capacity) but does not substitute electricity-only coal-fired generation in any region.

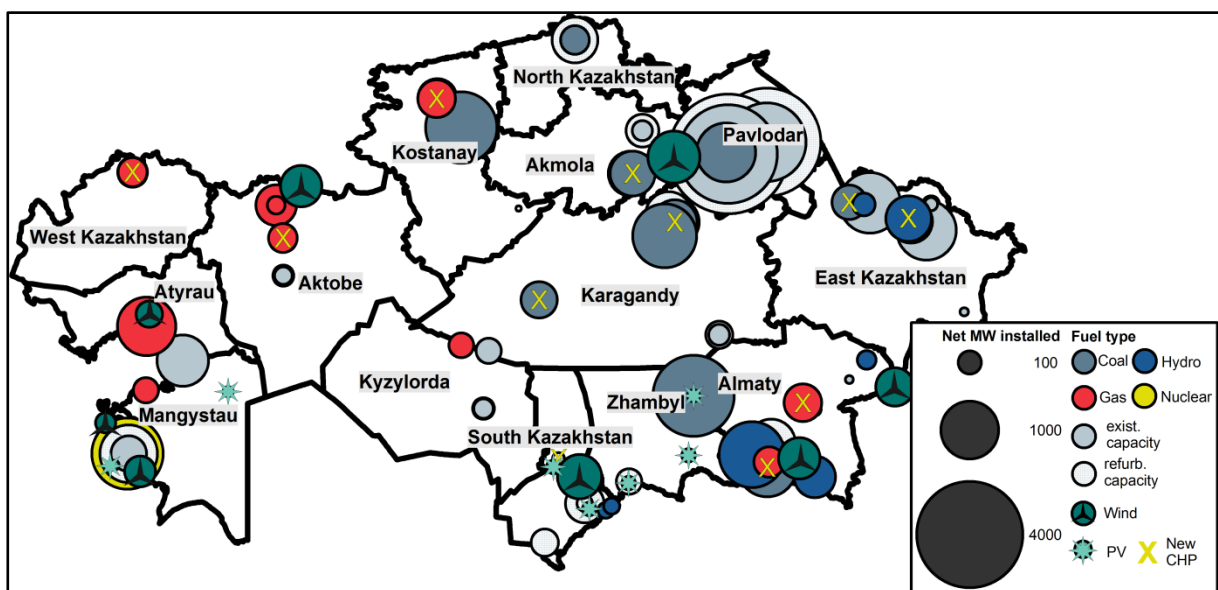


Figure 16: Local Investment in New Generation Capacity in the Conventional Scenario

[MW]	Nuclear	Coal CHP	Coal	Gas ST CHP	Gas ST	Gas CC CHP	Gas CC	Gas GT CHP	Gas GT	Delta
AKM		698								698
AKT				30				127	323	480
ALM		-78	1,980			385				2,287
ATY								650		650
KAR		258	785							1,043
KUS			1,000	-12		240				1,228
KZY								87		87
MAN	999			-630				90		459
PAV			950							950
SEV		125								125
VOS		385								385
YUZ				100						100
ZAP						250		194		444
ZHA				40						40
SUM	999	1,388	4,715	-472	0	875	0	127	1,344	8,976

Table 9: Regional Change in Conventional Capacity until 2030 in the Conventional Scenario

5.3.2 The Renewables Scenario

In contrast to the Conventional scenario, the Renewables scenario envisages a major reformation of the electricity system in Kazakhstan with 30 % of electricity generated from solar and wind. Despite the expected demand increase, existing coal-fired generation capacity is refurbished but no new projects are initiated. This scenario assumes a reduction of the supply surplus in the coal regions in the north-east. CCGT electricity-only plants with a total capacity of 2,300 MW are built in the southern and western regions. In the coal regions CHPs remain coal-fired while in all other regions they are substituted with gas-fired CHP plants. Renewable generation is mainly located in the western and southern regions. Capacity needed to back-up their intermittent supply is provided by additional gas turbines installed in these regions. The transformation from extensive coal to more renewable and gas generation results in a strong shift of generation capacity on regional level (see Table 10). Compared to the Conventional scenario the major share of new investment takes place in the south and west of Kazakhstan. In the coal regions the scenario assumes the conservation of the status quo (see Figure 17).

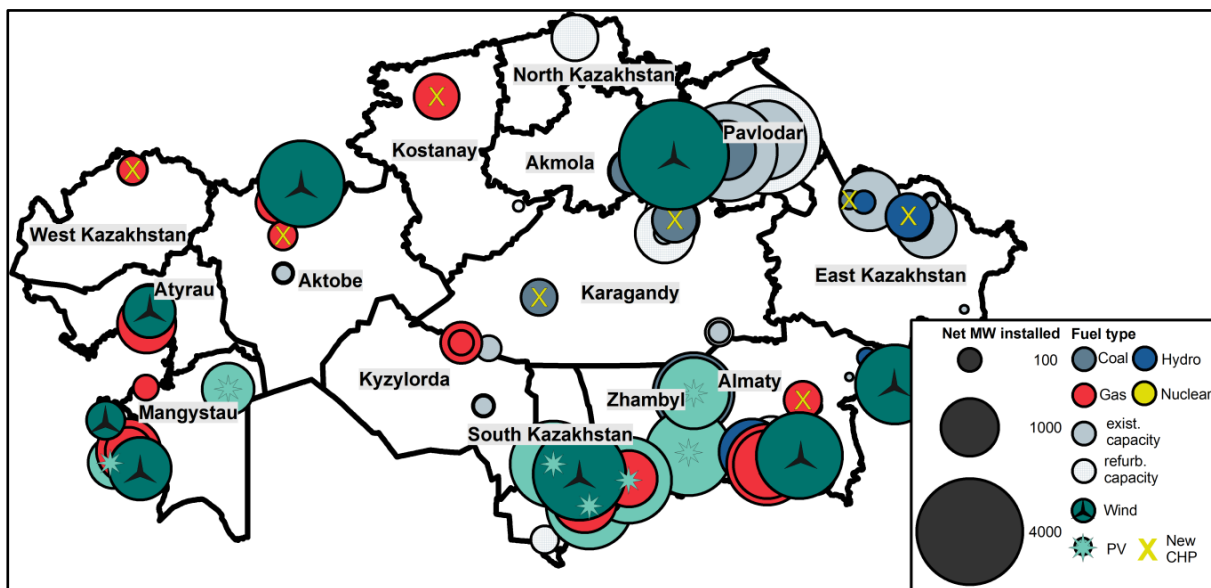


Figure 17: Local Investment in New Generation Capacity in the Renewables Scenario

[MW]	Nuclear	Coal CHP	Coal	Gas ST CHP	Gas ST	Gas CC CHP	Gas CC	Gas GT CHP	Gas GT	Delta
AKM		628								628
AKT				30				127	323	480
ALM		-558	1,320			885	1,200		1,200	4,047
ATY				-85					1,050	965
KAR		234								234
KUS		-112		-12		360				236
KZY							300		87	387
MAN				-630			400		890	660
PAV		-160	-550							-710
SEV										0
VOS		-26								-26
YUZ		-16		120			400			504
ZAP						250			194	444
ZHA				40					800	840
SUM	0	-10	770	-537	0	1,495	2,300	127	4,544	8,689

Table 10: Regional Change in Conventional Capacity until 2030 in the Renewables Scenario

5.3.3 The Efficiency Scenario

While the Conventional and the Renewables scenario only differs in the respective generation fleet aiming at the satisfying a predefined demand, the efficiency scenario assumes a less rigid growth in electricity demand due to the realization of efficiency potentials in various energy-intensive sectors. Consequently the required generation capacity is smaller

which opens an even wider scope for a transition towards a low-emission, renewable energy based electricity system (see Table 11). The generation fleet assumed here deviates from the assumptions of the renewable scenario by enforcing an even more consequent reduction of no-CHP coal-fired generation. Compared to the renewable scenario 700 MW of coal-based generation is decommissioned instead of being refurbished in Pavlodar region. Additionally, planned projects with a volume of 1,950 MW are not realized in this area. The same is true for the Almaty region where a 1,320 MW project for coal-fired generation is not realized. The substitution for reduced availability of coal-fired generation and the balancing of an increased share of intermittent electricity supply is again performed with additional capacity of gas turbines in this scenario. Due to the reduced demand the dimensioning of both the renewable system and the supplement gas-fired back-up capacity has been downsized. Again aiming at achieving a 30 % share of combined wind and solar supply the scenario assumes 6,400 MW of photovoltaic and 8,000 MW of wind powered generation. The sites of renewable generation remain unchanged. Compared to the Renewables scenario less installations for gas-fired capacity is required in the western regions (-580 MW) and in the southern part of the country (-900 MW) (see Figure 18).

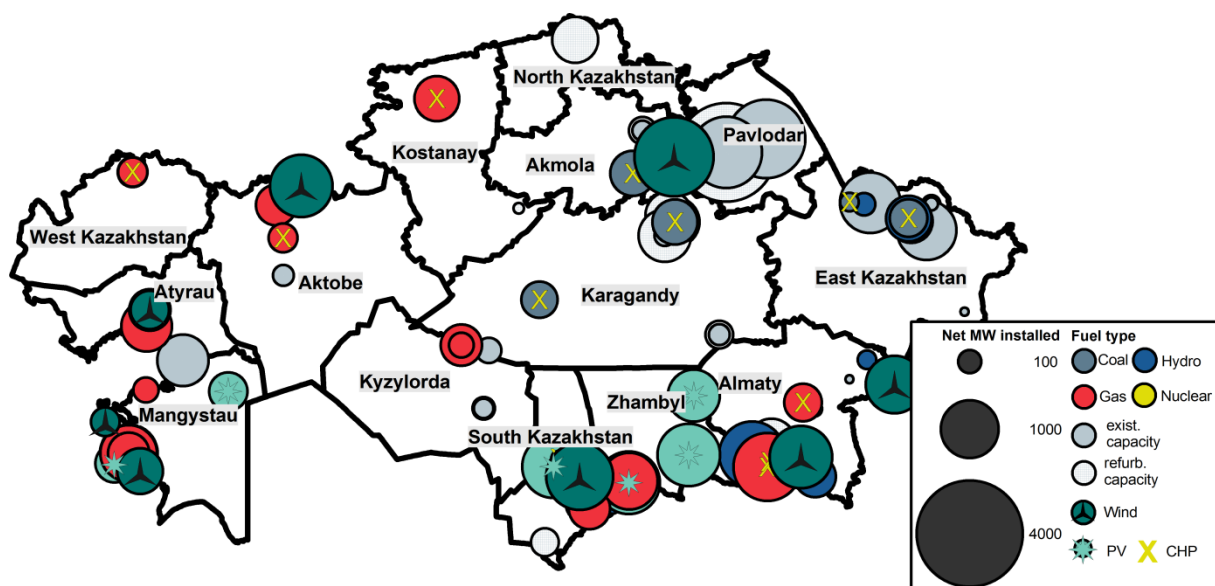


Figure 18: Local Investment in New Generation Capacity in the Efficiency Scenario

[MW]	Nuclear	Coal CHP	Coal	Gas ST CHP	Gas ST	Gas CC CHP	Gas CC	Gas GT CHP	Gas GT	Delta
AKM	0	468	0	0	0	0	0	0	0	468
AKT	0	0	0	30	0	0	0	127	288	445
ALM	0	-558	0	0	0	885	900	0	900	2,127
ATY	0	0	0	-85	0	0	0	0	770	685
KAR	0	84.3	0	0	0	0	0	0	0	84.3
KUS	0	-112	0	-12	0	360	0	0	0	236
KZY	0	0	0	0	0	0	300	0	87	387
MAN	0	0	0	-630	0	0	300	0	690	360
PAV	0	-270	-3,200	0	0	0	0	0	0	-3,470
SEV	0	0	0	0	0	0	0	0	0	0
VOS	0	-26	0	0	0	0	0	0	0	-26
YUZ	0	-16	0	120	0	0	300	0	0	404
ZAP	0	0	0	0	0	250	0	0	194	444
ZHA	0	0	0	40	0	0	0	0	600	640
	0	-430	-3,200	-537	0	1,495	1,800	127	3,529	2,784

Table 11: Regional Change in Conventional Capacity until 2030 in the Efficiency Scenario

6 Scenario Results

The applied methodology provides a techno-economic assessment of the Conventional, Renewables, and Efficiency scenario. It builds on the spatial electricity data for Kazakhstan in 2030 described in section 3 and evaluates network investments and utilization of generation capacity, quantifying usage of the respective technology in electricity generation and associated CO₂ emissions. The model is a mixed integer linear optimization problem developed in the open access modeling software GAMS (General Algebraic Modeling System). The objective function includes the sum of variable generation costs and annualized network investment costs. The model is solved using the commercial solver CPLEX. The mathematical formulation is shown in Box 3.

6.1 Network Topology and Options for Investment

The network topology of the high voltage transmission grid of Kazakhstan for 2030 includes only minor updates compared to the 2010 data (Figure 19).

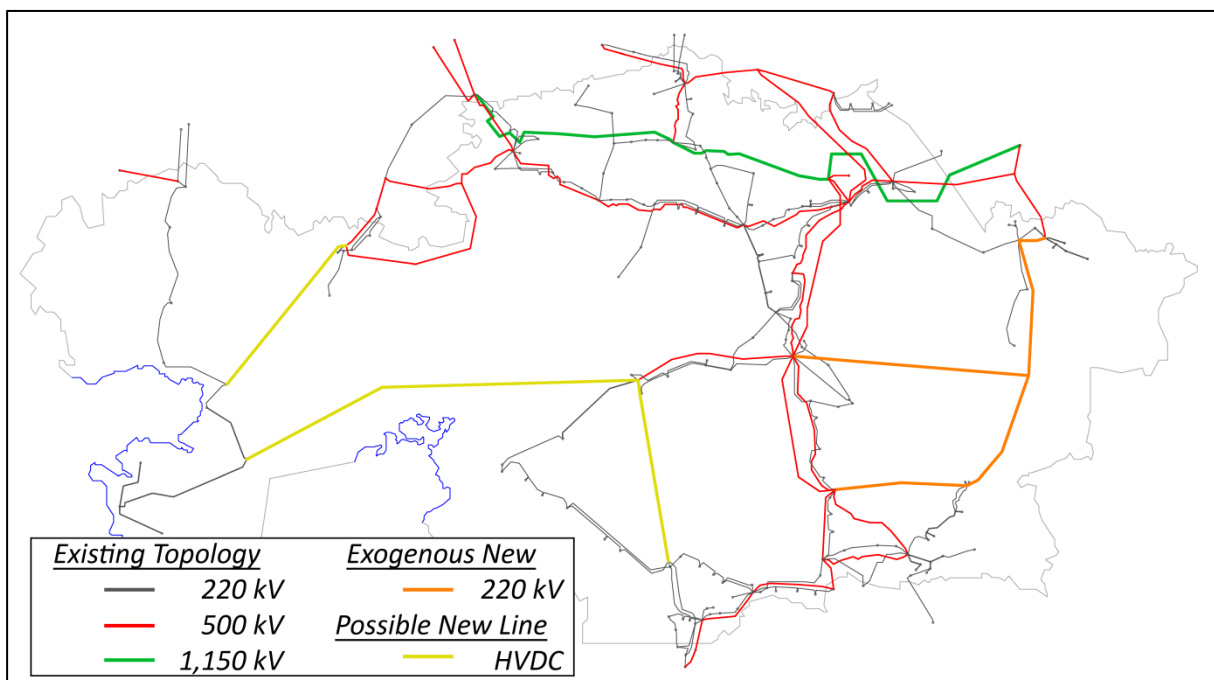


Figure 19: Topology for Transmission Investment Model in 2030

The model can decide endogenously on the expansion of individual transmission lines as long as they already exist in the topology. Therefore the network for 2030 includes the new 220 kV lines in the eastern part of the country proposed in the KEGOC “Masterplan”. The

separated networks of western and eastern Kazakhstan can be connected by optional investments in HVDC connectors.

In the model the possibility of endogenous line expansion increases the system costs. For expansions of 500 kV lines with one additional circuit we assume 4 m € for transformer stations and 1.4 m €/km of transmission line. In the 220 kV network the cost of additional circuits is calculated for every line with half the cost factors as for 500 kV. HVDC lines can be built in 1,000 MW steps and impose 130 m € in cost for the transformer station and 0.8 M €/km of transmission line. The costs are annualized assuming a lifetime of 40 years and an interest rate of 10 %.

6.2 Model Description

The model includes two decision levels; (i) the investment decision in transmission infrastructure and (ii) the decision on the generation. The two stages are reduced to one objective function assuming perfect competition between the generation companies and optimal infrastructure planning by the TSO. Given the generation mix of the respective scenario, the objective of the model is to compute the cost minimizing dispatch of generation capacity that satisfies demand. The costs consist of variable expenditures for operation (fuel and CO₂ emission costs) and capital cost for investments in transmission infrastructure.

The market dispatch balances varying nodal demand and available generation capacity. Generation is constrained by the availability of conventional generation capacity and varying levels of renewable generation output for each hour. Network restrictions include the transmission capacity of each link and we apply the DC load flow (DCLF) approach (Schweppe et al., 1988) for the meshed AC network. The DCLF constraint is a simplified model approach to enforce physical flows according to line characteristics in meshed electricity networks.

The main driver of infrastructure investments is the regional level of demand in relation to the spatial availability and cost of generation. In case of network congestion, it is not possible to operate the electricity system with the least cost generation capacities. Additional infrastructure could relieve this congestion as it provides exchange capacity and alters the flow pattern in the AC network. The options for expansions include the investment in additional circuits for the existing topology of the 220 kV and the 500 kV voltage level. Further-

more, we include three investment options on HVDC lines connecting the two separated networks in the west and east of Kazakhstan. An overall reduction in system costs is achieved, if costs savings from congestion relieve are higher than expenditures for new transmission infrastructure. All results are scaled to and reported on annual basis.

Box 3: Excursus on the Mathematical Formulation of Model Equations

Objective function: Minimization of electricity system cost

$$\begin{aligned} \text{Min cost}_{g_{p,d,t}, \Delta_{n,d,t}, \text{exp}AC_l, \text{exp}DC_{dc}} = & \sum_{p,d,t} (\text{Weight}(d) * MC_p * g_{p,d,t}) \\ & + \sum_l (\text{exp}AC_l * \text{Cost}EXP_l) \\ & + \sum_{dc} (\text{exp}DC_{dc} * \text{Cost}DC_{dc}) \end{aligned}$$

Energy balance: Generation minus demand and network in-/outflows have to be zero at each node according to Kirchhoff's current law

$$\sum_p g_{p,d,t} - Q_{n,d,t} + \sum_{nn} (\Delta_{nn,d,t} * B_{n,nn}) + dcInput_{dc} = 0 \quad \forall n, t$$

Generation constraints: Generation constraint for each block of conventional and renewable power stations (see Appendix)

$$g_{p,d,t} \leq G_{\max_{p,d,t}} \quad \forall p, d, t$$

AC line flow constraint: Power flow limit for every AC transmission line determined by voltage level and number of circuits. Additional capacity from upgrades and expansions.

$$\begin{aligned} |lfAC_{l,d,t}| = |\sum_n (\Delta_{n,d,t} * H_{l,n})| \leq & \text{Powerflowlimit}_l \\ & + \text{exp}AC_l * \text{CapacityExp}_l \quad \forall l, d, t \end{aligned}$$

DCLF constraint: Voltage angle for one slack node of every AC network equals zero

$$\text{Slack}_n * \Delta_{n,d,t} = 0 \quad \forall n, d, t$$

DC line flow constraint: Power flow limit link determined by investments in respective new DC connector

$$|lfDC_{l,d,t}| \leq \text{exp}DC_{dc} * \text{CapacityDC} \quad \forall l, d, t$$

6.3 Results of the Network Expansion Model

The results are discussed for the scenarios and include a sensitivity analysis of the emission prices with 20 €/t CO₂ and 40 €/t CO₂. We provide quantitative results on system costs, on the annual output for each generation technology, on annual CO₂ emissions, and insights in usage and investments in transmission infrastructure.

6.3.1 Electricity System Costs

All scenarios address the age structure of today's generation park and the projections of rising demand with refurbishments of existing and investments in new power plants. The resulting system costs which include investments in generation and transmission and operational cost are discussed from the 2030 perspective.

Table 12 depicts the scenario specific investment costs. Investment costs are determined exogenously for generation by the scenario specifications and endogenously for the transmission costs by the investments decisions in the infrastructure model. The Conventional Scenario has the highest investments in conventional generation capacity (16.7 bn €). Due to 5 bn € for new hydro power and only 2.5 bn € for wind power the overall costs for generation capacity is moderate compared to the Renewables scenario and almost in range of the Efficiency scenario. The Renewables scenario has the highest capital requirements though the major share of almost 30 bn € is directed towards renewable generation. The network investments include 0.5 bn € for one west-east HVDC connector in all scenarios. The extensions in the AC network are only punctual in the Conventional and in the Efficiency scenario. In the Renewables scenario some more line extensions are built (1.3 bn €). The higher CO₂ emission price influences only the Renewables scenario (+0.5 bn €). The cost figures do not include required refurbishments in the high voltage transmission network until 2030.

[bn €]	CO ₂ Price	"Conventional"		"Renewables"		"Efficiency"	
		20 €/t	40 €/t	20 €/t	40 €/t	20 €/t	40 €/t
New Conventional		16.69		10.74		5.74	
New Renewables		7.61		29.45		17.23	
Refurbishment		5.59		4.22		3.32	
Transmission		0.71	0.60	1.83	2.30	0.81	0.89
Sum		30.60	30.49	46.24	46.71	27.10	27.18

Table 12: Investment Costs of the Scenarios in the Electricity System until 2030

The scenario specific investments in generation and transmission infrastructure provide the market setting for the cost minimal generation dispatch. Table 13 states the variable system costs for fuel and CO₂ emissions for the two analyzed CO₂ prices. The Renewables and the Efficiency scenario save about 0.4 bn € per year in fuel costs at 20 €/t CO₂ and about 0.2 bn € per year at 40 €/t CO₂ compared to the Conventional scenario. Thereby, with the higher CO₂ emission price the Renewables and Efficiency scenario include significantly higher expenses for gas and lower ones for coal. The fuel costs of the Conventional scenario are more robust with increasing CO₂ emission prices indicating missing alternatives in the generation park. The expenses for CO₂ emissions are about 1.5 bn € higher.

[bn €/year]	Conventional Scenario		Renewables Scenario		Efficiency Scenario	
	20 €/t	40 €/t	20 €/t	40 €/t	20 €/t	40 €/t
CO ₂ price						
Fuel Costs Coal	1.55	1.49	1.06	0.78	0.94	0.71
Fuel Costs Gas	0.39	0.51	0.55	1.13	0.65	1.09
Fuel Costs Nuclear	0.07	0.07	-	-	-	-
Sum Fuel Costs	2.01	2.07	1.61	1.91	1.59	1.80
CO₂ Emission Costs	1.94	3.78	1.39	2.31	1.26	2.15

Table 13: Annual Variable Costs of the Scenarios in the Electricity System 2030

6.3.2 Results on Annual Generation in the year 2030

Table 14, Table 15, and Table 16 provide scenario results for generation, CO₂ emissions and the full load hours for each technology at 20 €/t CO₂ :

- In the Conventional scenario, RES only supply 20.5 TWh (14%) of the 144.8 TWh of annual demand. Except for the gas-fired CHP generation (9.1 TWh) the remaining generation is coal-based (107.5 TWh);
- In the Renewables scenario, RES generate 57.6 TWh (40%), gas-fired generation accounts for 14.5 TWh and coal-fired power plants for 72.8 TWh. Full load hours of coal-fired generation are significantly reduced due to the high share of fluctuating renewable generation. As total available coal-fired capacity is lower in this scenario more generation from CCGT plants is included into the dispatch;
- In the Efficiency scenario 36.1 TWh are supplied from RES which corresponds to a 32% share of total generation given lower demand predictions (114.3 TWh). The remainders are 60.7 TWh from coal and 17.5 TWh from gas-fired generation.

At a CO₂ price of 20 €/t CCGT plants only complement coal-fired generation in hours of high demand. Electricity generation from coal is not substituted by gas.

In the scenarios the generation capacities are an exogenous assumption. Thus, a policy instrument which implements CO₂ prices can only evaluate the impact on the short term generation dispatch assuming a market design with marginal pricing. In this sensitivity analysis the changes of model results for an increased CO₂ emission price of 40 €/t CO₂ are discussed.

With higher emission prices variable costs of CCGT plants become lower than those for coal-fired generation. The impact is rather low for the Conventional scenario (fuel switch for 3.5 TWh) as CCGT capacities are low. For the two alternative scenarios where additional CCGT capacity is available the fuel switch from coal to gas is significantly higher (about 18 TWh in the Renewables scenario and about 14 TWh in the Efficiency scenario). It is important to note that the CO₂ price required to make CCGT plants competitive highly depends on the assumptions on coal and natural gas prices.

	Conventional Scenario					
	20 €/t CO ₂			40 €/t CO ₂		
	Utilization [hours]	Output [TWh]	Emission [Mt CO ₂]	Utilization [hours]	Output [TWh]	Emission [Mt CO ₂]
Coal CHP	6,484	43.17	39.05	6,218	41.39	37.37
Coal	5,294	64.29	54.00	5,137	62.40	52.19
Sum of Coal		107.46	93.05		103.79	89.56
Gas CC CHP	3,860	3.38	1.05	7,709	6.75	2.11
Gas CC	-	-	-	-	-	-
Gas ST CHP	3,854	4.89	2.39	3,854	4.89	2.39
Gas ST	0	0	0	0	0	0
Gas GT CHP	3,854	0.84	0.37	3,854	0.84	0.37
Gas GT	0	0.01	0	146	0.31	0.13
Sum of Gas		9.12	3.82		12.79	5.00
Nuclear	7,709	7.70	-	7,709	7.70	-
Water	3,504	14.11	-	3,504	14.11	-
Wind	3,154	6.31	-	3,154	6.31	-
PV	1,569	0.13	-	1,569	0.13	-
Sum RES		20.54	-		20.54	-
Total Supply		144.82	96.87		144.82	94.56

Table 14: Annual Utilization, Generation and CO₂ Emissions for the Conventional Scenario

	Renewables Scenario					
	20 €/t CO ₂			40 €/t CO ₂		
	Utilization [hours]	Output [TWh]	Emission [Mt CO ₂]	Utilization [hours]	Output [TWh]	Emission [Mt CO ₂]
Coal CHP	4,874	32.07	29.04	4,288	28.21	25.43
Coal	5,916	40.70	34.85	3,754	25.83	21.54
Sum of Coal		72.77	63.89		54.04	46.97
Gas CC CHP	4,362	6.52	2.04	7,241	10.82	3.38
Gas CC	1,042	2.40	0.75	7,059	16.24	5.07
Gas ST CHP	3,857	4.64	2.26	3,856	4.64	2.26
Gas ST	0	0.00	0.00	0	0	0
Gas GT CHP	3,854	0.84	0.37	3,856	0.84	0.37
Gas GT	20	0.10	0.04	44	0.24	0.10
Sum of Gas		14.50	5.46		32.78	11.18
Nuclear	-	-	-	-	-	-
Water	3,462	13.97	-	3,496	14.08	-
Wind	3,120	31.20	-	3,138	31.37	-
PV	1,551	12.40	-	1,569	12.55	-
Sum RES		57.57	-		58.00	-
Total Supply		144.82	69.35		144.82	58.15

Table 15: Annual Utilization, Generation and CO₂ Emissions for the Renewables Scenario

	Efficiency Scenario					
	20 €/t CO ₂			40 €/t CO ₂		
	Utilization [hours]	Output [TWh]	Emission [Mt CO ₂]	Utilization [hours]	Output [TWh]	Emission [Mt CO ₂]
Coal CHP	7,043	34.08	31.16	6,047	29.26	26.54
Coal	6,293	26.62	25.17	4,154	17.57	16.30
Sum of Coal		60.70	56.33		46.83	42.84
Gas CC CHP	4,951	7.40	2.31	7,709	11.52	3.60
Gas CC	2,307	4.15	1.30	7,606	13.69	4.27
Gas ST CHP	3,855	4.64	2.26	3,861	4.65	2.26
Gas ST	0	0	0	0	0	0
Gas GT CHP	3,854	0.84	0.37	3,874	0.84	0.38
Gas GT	109	0.47	0.20	153	0.66	0.28
Sum of Gas		17.50	6.44		31.37	10.79
Nuclear	-	-	-	-	-	-
Water	3,504	14.11	-	3,502	14.10	-
Wind	3,150	15.75	-	3,153	15.77	-
PV	1,569	6.28	-	1,568	6.27	-
Sum RES		36.14	-		36.14	-
Total Supply		114.34	62.77		114.34	53.62

Table 16: Annual Utilization, Generation and CO₂ Emissions for the Efficiency Scenario

6.3.3 Annual CO₂ Emissions

The CO₂ emission levels for all scenarios and both CO₂ prices are illustrated in Figure 20. At a price of 20 €/t, the Conventional scenario results in annual emissions of 97 Mt CO₂ in 2030 which represents a 50% increase compared to 2010. Only 69 Mt are emitted in the Renewables scenario. In both scenarios more than 90 % of the emissions originate from coal-fired power plants. Due to its lower variable costs, coal remains the base load technology in all scenarios. A higher CO₂ price of 40 €/t results in a shift from coal to natural gas as the least cost fuel. While the impact on the Conventional scenario is limited with its persistence in coal fired generation infrastructure, the emissions in the Renewables scenario decrease significantly. The annual level decreases by 11 Mt to 58 Mt CO₂ in 2030 which is slightly lower than the emission level in 2010.

The Efficiency scenario realizes only slightly lower emissions than the Renewables scenario for both emission prices. The higher efforts in conservation measures allow the scenario to reach this levels at almost half the costs compared to the Renewables scenario (19 bn € less in investments until 2030).

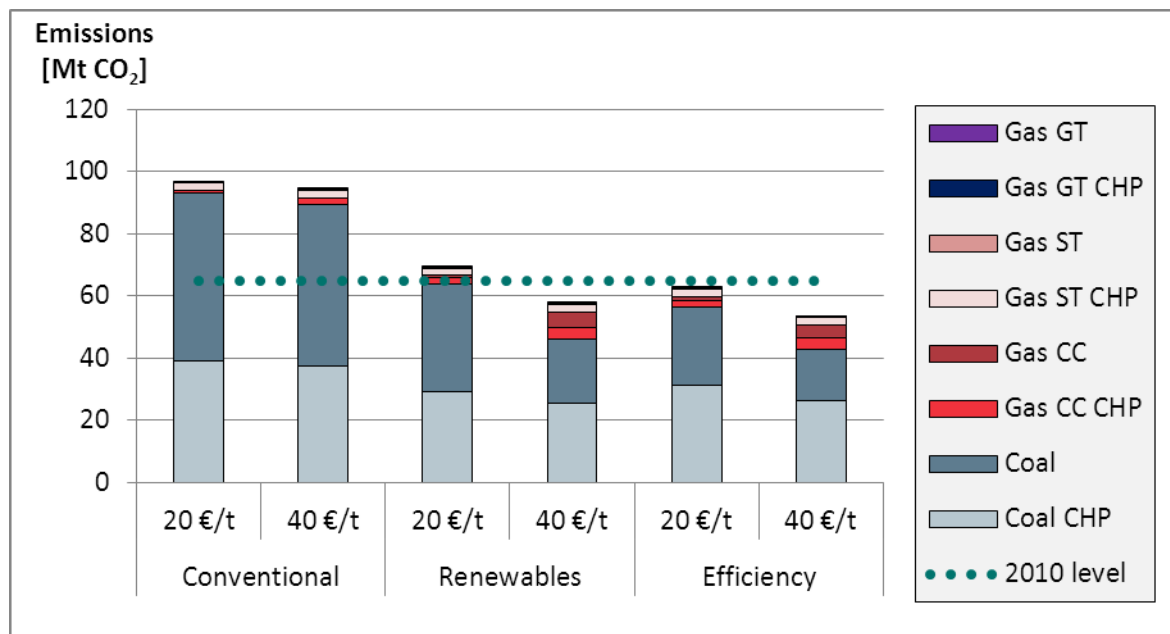


Figure 20: CO₂ Emission for Scenarios and Technologies

6.3.4 Expansion of the AC and DC Network

The new transmission lines connecting the region East Kazakhstan with the high-voltage transmission network in Karagandy and Almaty are exogenously implemented (exogenous lines in Figure 19). In both scenarios model results indicate only one HVDC transmission line upgrade of 1,000 MW connecting the cities of Aktobe (in Aktobe region) and Kulsary (in Atyrau region) (Figure 21 and Figure 22. In the Conventional scenario (Figure 21) two AC lines are extended on the 220 kV level with one additional circuit. In the region Atyrau one line starts at the station of the DC connector and ends in the city of Atyrau. In Karagandy the second line is located between north of Akadyr and Topar.

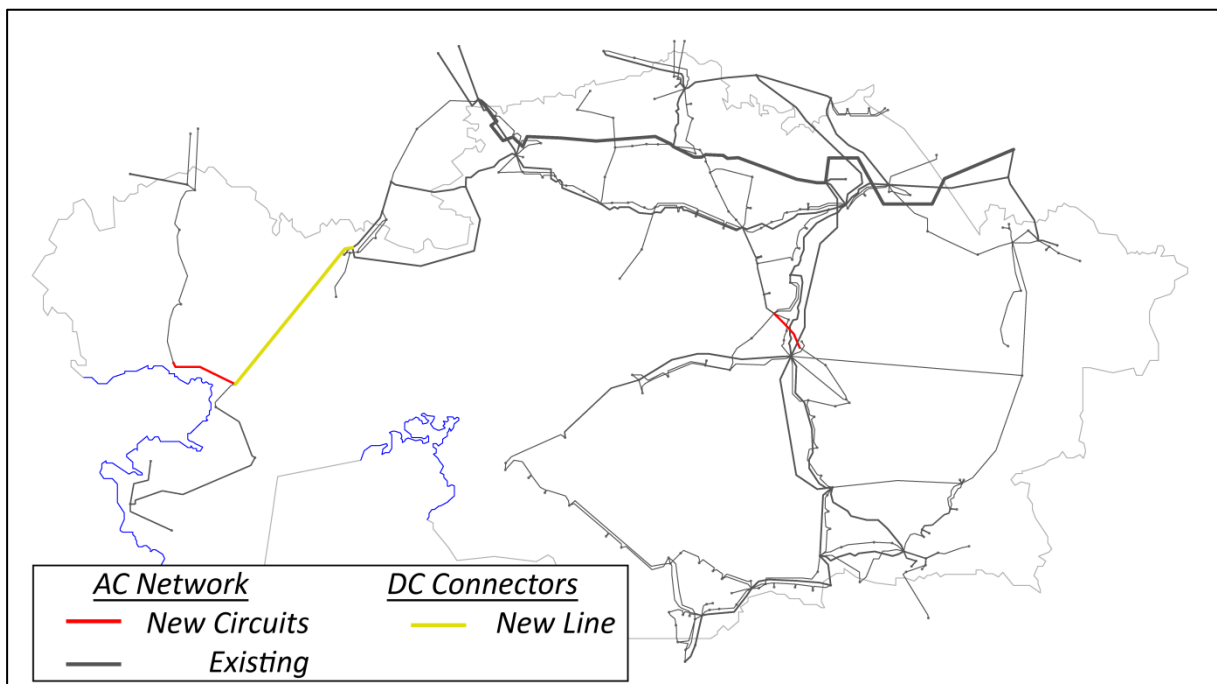


Figure 21: Expansion Decisions in the Conventional Scenario in 2030

Like in the Conventional scenario a transmission line from Akadyr to Topar is expended in the Renewables scenario. The regional integration of the increased renewable capacities required some extensions of lines on the 220 kV level. For combined wind and PV integration lines in South Kazakhstan, Zhambyl, and Almaty have to be extended. The wind capacity in eastern Akmola requires additional lines to enforce the connection to Astana. In Zhambyl, the model builds an additional circuit on the 500 kV connections between Shu and Taras which passes through Kirghizstan.

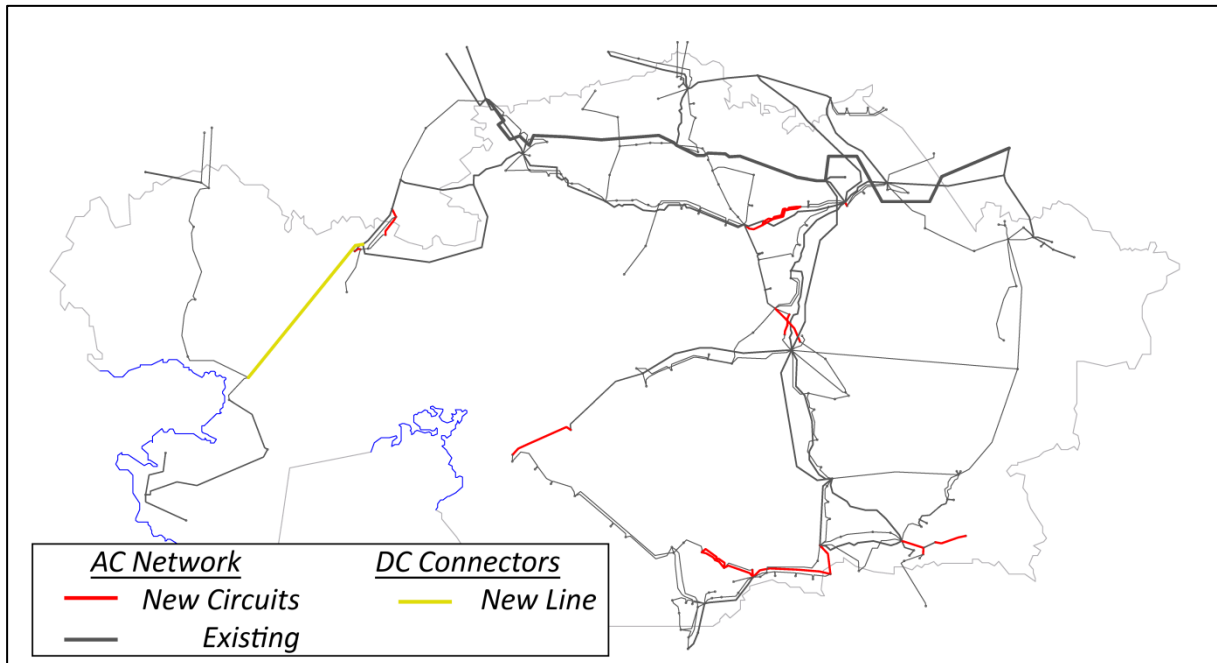


Figure 22: Expansion Decisions in the Renewables Scenario in 2030

6.3.5 Flows between the Western and Eastern Network

The motivation of the model to invest in the DC connector between the western and eastern electricity network in Kazakhstan is important to understand the spatial results of the scenarios. From an economic perspective flows (indicating trade) provide insights in the relation of the regional electricity balance and prices. The aggregated load flow on the HVDC connector (Figure 23) illustrates for one year the exports from west to east with negative values and imports to west from east with positive values.

In most hours western Kazakhstan imports cheap electricity from the coal-fired power plants in the east to substitute more expensive generation from gas-fired power plants. The annual net exchange is 5.2 TWh in the Renewables Scenario and 5.1 TWh in the Conventional scenario. These insights suggest that from an economic perspective the DC connector reduces system costs but in all scenarios it increases emission volumes by substituting about 5 TWh of generation from yet to be built modern gas-fired power plants in the west with coal-fired generation from the large coal producing regions.

Further considering the surplus of natural gas and possible developments of new oil and gas resources in western Kazakhstan the local gas-price in the western part of the country could be significantly lower.

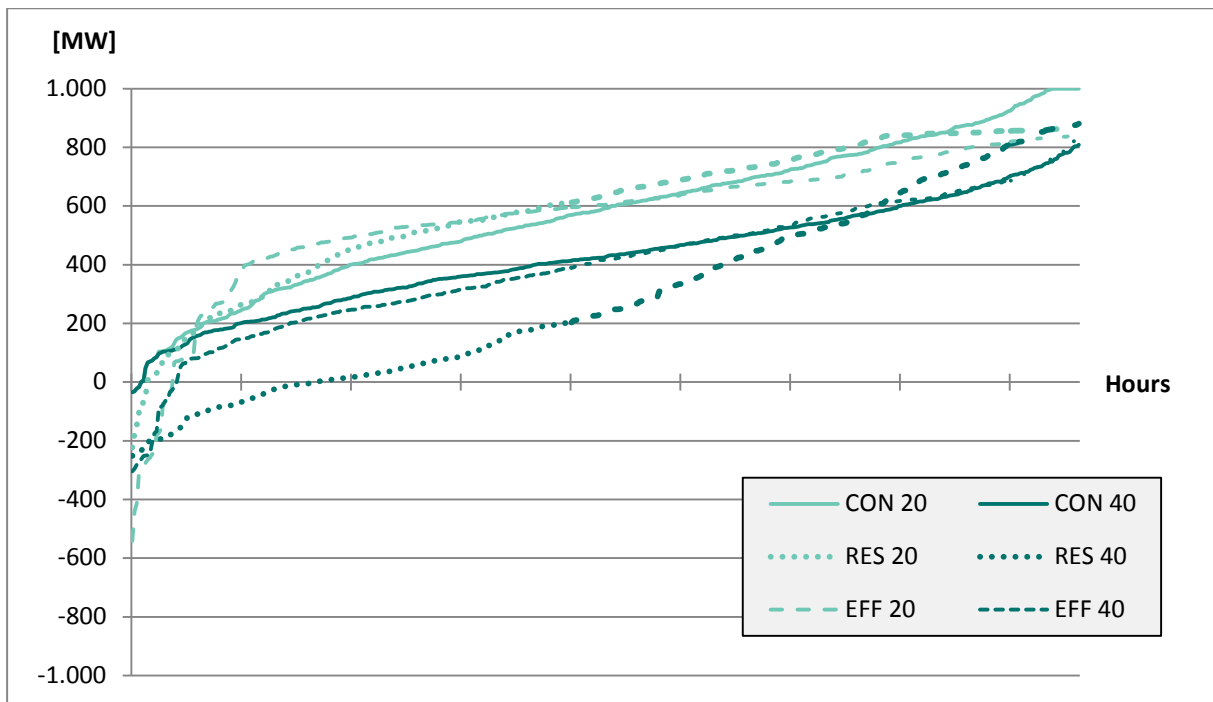


Figure 23: Exchange Flows on DC Connector between the Western and Eastern Electricity Network

7 Conclusion and Outlook to 2050

7.1 Discussion of the Scenarios in the 2050 Perspective

The fundamental questions regarding the transformation of the Kazakh electricity system are:

- Does Kazakhstan want to move away from using its large domestic coal deposits as main resource for electricity generation? The alternatives are increasing shares of electricity from renewable sources and natural gas as bridge towards a renewable electricity system as well as more efforts in energy conservation.
- What is the time line to shift from coal to less carbon intense electricity generation? Will the investments required to satisfy increasing electricity demand be coal power station in the next ten years or will the green transformation be initiated in the next decade?

In 2010 the available capacity was dominated by coal with a share of 64%. Facing a carbon constrained world, a reduction of the “share” of coal generation capacity does not automatically result in a reduction of carbon emissions. Growing demand has to be balanced with investments in new generation capacity. If the demand is to increase by 73% as predicted in the KEGOC Masterplan, halving the share of capacity from coal-fired power plants would still require refurbishments and even investments in new coal-fired power plants. Moreover, the carbon intensive coal-fired power plants will be around for at least 50 years. In a 2050 perspective postponing the efforts beyond 2030 while preceding a faster decarbonization after 2030 results in a conflict between increasing fluctuating renewable generation and coal power plants built in the 2020th. Advancing technology for wind and PV could let the coal power plants become obsolete long before their technical life time expires (see Figure 17).

The exemplary Renewables scenario is not a radical turnaround. It rather elaborates on a sooner turning point in the electricity system. It still relies on coal and gas generation but reduces the dependency on fossil fuels before 2030. Still, the assumed pathway of this scenario introduces renewables on a more conservative path than the frontrunners (e.g. Germany). Kazakhstan can still observe and benefit from their experiences. In the Conventional scenario possible future corrections towards sustainability will be very costly and face even stronger opposition due to the risk of stranded assets. The paradigm of the Renewables

scenario is to keep doors open. It suggests a gradual but timely change of the system. The Efficiency scenario follows a similar pathway. Higher efforts on energy conservation buy time in the transformation as they lower electricity demand and the need for new investments. Raising the question if changing the capacity mix is sufficient to make the first step towards a low carbon electricity system, we also test the sensitivities of the scenario with respect to higher CO₂ prices.

Year	Conventional Scenario	Renewable Scenario
2030	KEGOC "Masterplan"	30 % Solar and Wind
2050	Stranded Assets	Decarbonization

Table 17: Scenario Matrix for the Kazakh Electricity System

7.2 Conclusion on Policy Implications

The spatial techno-economic electricity market model (section 6.2) has been applied to the regional electricity data (section 4) to compare three scenarios for the electricity system of Kazakhstan in 2030. Closely following the generation fleet envisaged in the projections of the KEGOC Masterplan the Conventional scenario heavily relies on coal. By contrast, the Renewables scenario constitutes a major change in the electricity system of Kazakhstan. It assumes substantial investments in wind and solar power which together cover 30 % of the electricity demand in 2030. All scenarios are specified and analyzed on a regionally disaggregated level. For a CO₂ price of 20 €/t in 2030 the Conventional scenario results in annual emissions of almost 100 Mt CO₂ while emissions in the Renewables scenario sum up to about 70 Mt CO₂. This means that neither the replacement of high-emission coal-fired generation with low-emission gas-fired generation (5,300 MW), nor large new renewable capacities of 10,000 MW in wind power and 8,000 MW in photovoltaics were capable of reducing the carbon emissions in 2030 compared to current levels. The largest share (96% in the Conventional versus 93% in the Renewables scenario) is emitted by coal-fired power plants. Compare to gas-fired power plants, coal has lower variable generation costs. In the market dispatch it is therefore not substituted by gas. A sensitivity analysis with a CO₂ emission price of 40 €/t indicates a partial shift from coal-fired to gas-fired generation (CCGT) in the Renewables scenario. Assuming the same power plant capacities the annual emissions decrease to 58 Mt CO₂ which represent a reduction of almost 20% compared to 2011.

While it requires 12.0 bn € of additional investments for generation capacity, the annual variable fuel costs are even slightly lower (0.01 bn €) than in the Conventional scenario. Higher annual emission costs (0.4 bn €) are in fact rather a redistribution of income than a cost term. The additional upgrades of the transmission network add 1.4 bn € for AC lines and an additional 0.5 bn € resulting from a new HVDC connector which is constructed in all scenarios.

A detailed examination of the electricity flows on the HVDC line connecting the western and eastern network illustrates that it is not a priority project for the development of a sustainable electricity system. To prevent the export of coal based electricity into the demand centers in the western parts of Kazakhstan the connection should be realized in a mid-term 2030 and beyond perspective.

The underlying economics of the electricity data and the model results for the three scenarios as well as the sensitivity analysis provide an indication on the required policy measures:

- (i) It is not sufficient to implement a single policy which either addresses investments or the market dispatch. In the long-run renewable generation is the most sustainable option for a low carbon electricity system. In the medium-term additional emission reduction is possible by investments in gas-fired generation. To successfully manage the transformation of the electricity system both technologies are needed. Thus, policies have to support investment in these technologies but also guarantee their competitiveness in the market dispatch;
- (ii) The transformation towards a low carbon electricity system requires a renewable support schemes (e.g. feed-in tariffs, a quota system, etc.) to incentivize investments in renewable generation technologies. Once built, wind and solar power plants are very competitive in the market dispatch substituting conventional generation;
- (iii) Gas-fired power generation is important for a reduction in GHG emissions in the transformation process. Due to its operational flexibility, CCGT plants and GT plants better suit a system with high shares of fluctuating renewable generation. Though less expensive in investment costs, a sufficiently high price for CO₂ emissions is required for the competitiveness of gas-fired generation over coal in the market dispatch;

- (iv) To redirect investments from coal towards gas a strong commitment to an increasing price path for CO₂ is necessary. Yet a predetermined price path might not be sufficient. If introduced, a trading scheme similar to the EU-ETS could be favorable to limit the amount of CO₂ emitted in the power sector. The emission price would add variable costs to the extent where variable costs of coal-fired generation are above those of gas-fired power plants;
- (v) Each investment in carbon intensive base load generation capacity today, represents sunk costs in the future. Therefore, it increases the relative cost of the transformation process by altering the starting position. With increasing shares of renewable generation capacity available at almost no variable costs, the full load hours of the conventional base load plants will decline. Thus, opposition against the transformation process will arise from owners of conventional base load capacity as it devalues their assets.

To set course for decarbonization of the electricity sector we propose a combination of two policy measures; (a) a flexible technology specific feed-in tariff for solar and wind power to provide a predefined amount of capacity combined with (b) a CO₂ trading scheme which freezes the CO₂ budget of the power sector to today's level and starts to decrease emissions in the medium-term depending on the development of electricity demand. This objective might sound challenging and will be considered elusive when facing the vast amount of "cheap" coal in Pavlador, Karagandy, and Kostany and the related economic interests. The overall costs and benefits indicate that directing investments towards the Renewables scenario increase initial costs but provide benefits in the medium-term. Postponing the projects is in fact making the transformation more expensive and more difficult as it increases the risk of path dependence and stronger opposition due to the risk of stranded assets.

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Appendix: Power Plants

Plant Name (RUS)	Plant Name	City	region	fuel	type	purpose	capacity	year
ТЭЦ-1 АО "Астана-Энергия"	Akmola CHP 1 - 2	Astana	KZ-AKM	Coal	ST	CHP	3	1962
ТЭЦ-1 АО "Астана-Энергия"	Akmola CHP 1 - 3	Astana	KZ-AKM	Coal	ST	CHP	5	1962
ТЭЦ-1 АО "Астана-Энергия"	Akmola CHP 1 - 4	Astana	KZ-AKM	Coal	ST	CHP	10	1972
ТЭЦ-2 АО "Астана-Энергия"	Akmola CHP 2 - 1	Astana	KZ-AKM	Coal	ST	CHP	80	1979
ТЭЦ-2 АО "Астана-Энергия"	Akmola CHP 2 - 4	Astana	KZ-AKM	Coal	ST	CHP	80	1979
ТЭЦ-2 АО "Астана-Энергия"	Akmola CHP 2 - 2	Astana	KZ-AKM	Coal	ST	CHP	80	1980
	Astana NEW CHP 3	Astana	KZ-AKM	Gas	ST	CHP	0.1	1983
ТЭЦ-2 АО "Астана-Энергия"	Akmola CHP 2 - 3	Astana	KZ-AKM	Coal	ST	CHP	80	1983
ТЭЦ ТОО "Джет-7"	Jet-7 CHP - 1	Stepnogorsk	KZ-AKM	Coal	ST	CHP	35	1966
ТЭЦ ТОО "Джет-7"	Jet-7 CHP - 2	Stepnogorsk	KZ-AKM	Coal	ST	CHP	35	1967
ТЭЦ ТОО "Джет-7"	Jet-7 CHP - 5	Stepnogorsk	KZ-AKM	Coal	ST	CHP	60	1975
ТЭЦ ТОО "Джет-7"	Jet-7 CHP - 4	Stepnogorsk	KZ-AKM	Coal	ST	CHP	25	1986
ТЭЦ ТОО "Джет-7"	Jet-7 CHP - 3	Stepnogorsk	KZ-AKM	Coal	ST	CHP	25	1990
АО "Актобе ТЭЦ"	Aktobe CHP - 3	Aktobe	KZ-AKT	Gas	ST	CHP	14	1954
АО "Актобе ТЭЦ"	Aktobe CHP - 6	Aktobe	KZ-AKT	Gas	ST	CHP	25	1987
АО "Актобе ТЭЦ"	Aktobe CHP - 1	Aktobe	KZ-AKT	Gas	ST	CHP	6	1991
АО "Актобе ТЭЦ"	Aktobe CHP - 2	Aktobe	KZ-AKT	Gas	ST	CHP	6	1992
АО "Актобе ТЭЦ"	Aktobe CHP - 5	Aktobe	KZ-AKT	Gas	ST	CHP	22	1994
ЭС АЗФ ТНК "Казхром" ПСУ-37	ES AFP TNK Kazchrome	Aktobe	KZ-AKT	Gas	GT	CHP_I	98	1996
ЭС АЗФ ТНК "Казхром" ПСУ-37	ES AFP TNK Kazchrome	Aktobe	KZ-AKT	Gas	GT	CHP_I	37	2002
АО "Актобе ТЭЦ"	Aktobe CHP - 4	Aktobe	KZ-AKT	Gas	ST	CHP	29	2003
Жанажолская ГТЭС-56	ZHGTS 56 JSC CNPC-Aktobe	Zhanazhol	KZ-AKT	Gas	GT	CHP_I	12	1999
Жанажолская ГТЭС-56	ZHGTS 56 JSC CNPC-Aktobe	Zhanazhol	KZ-AKT	Gas	GT	CHP_I	12	1999
Жанажолская ГТЭС-56	ZHGTS 56 JSC CNPC-Aktobe	Zhanazhol	KZ-AKT	Gas	GT	CHP_I	16	2004
Жанажолская ГТЭС-56	ZHGTS 56 JSC CNPC-Aktobe	Zhanazhol	KZ-AKT	Gas	GT	CHP_I	16	2005
Жанажолская ГТЭС-45	ZHGTS 45 JSC CNPC-Aktobe	Zhanazhol	KZ-AKT	Gas	GT	CHP_I	34	2009
Жанажолская ГТЭС-56	ZHGTS 56 JSC CNPC-Aktobe	Zhanazhol	KZ-AKT	Gas	GT	CHP_I	16	2010
Жанажолская ГТЭС-56	ZHGTS 56 JSC CNPC-Aktobe	Zhanazhol	KZ-AKT	Gas	GT	CHP_I	16	2010
Жанажолская ГТЭС-56	ZHGTS 56 JSC CNPC-Aktobe	Zhanazhol	KZ-AKT	Gas	GT	CHP_I	16	2010
АО "АлЭС" Алматинский каскад ГЭС	Almatinskaya 11	Almaty	KZ-ALM	Hydro	RES	N	2.5	1944
АО "АлЭС" Алматинский каскад ГЭС	Almatinskaya 5	Almaty	KZ-ALM	Hydro	RES	N	2.5	1944
АО "АлЭС" Алматинский каскад ГЭС	Almatinskaya 9	Almaty	KZ-ALM	Hydro	RES	N	2.5	1944
АО "АлЭС" Алматинский каскад ГЭС	Almatinskaya 6	Almaty	KZ-ALM	Hydro	RES	N	2.5	1946
АО "АлЭС" Алматинский каскад ГЭС	Almatinskaya 7	Almaty	KZ-ALM	Hydro	RES	N	2.5	1948
АО "АлЭС" Алматинский каскад ГЭС	Almatinskaya 8	Almaty	KZ-ALM	Hydro	RES	N	2.5	1948
АО "АлЭС" Алматинский каскад ГЭС	Almatinskaya 10	Almaty	KZ-ALM	Hydro	RES	N	2.5	1950
АО "АлЭС" Алматинский каскад ГЭС	Almatinskaya HPS 8a	Almaty	KZ-ALM	Hydro	RES	N	1	1954
АО "АлЭС" Алматинский каскад ГЭС	Almatinskaya HPS № 2	Almaty	KZ-ALM	Hydro	RES	N	14.3	1959
АО "АлЭС" Алматинская ТЭЦ-3	Almaty CHP 3 - 1	Almaty	KZ-ALM	Coal	ST	CHP	41	1962
АО "АлЭС" Алматинская ТЭЦ-3	Almaty CHP 3 - 2	Almaty	KZ-ALM	Coal	ST	CHP	41	1962

Appendix: Power Plants

Plant Name (RUS)	Plant Name	City	region	fuel	type	purpose	capacity	year
АО "АлЭС" Алматинская ТЭЦ-3	Almaty CHP 3 - 3	Almaty	KZ-ALM	Coal	ST	CHP	41	1964
АО "АлЭС" Алматинская ТЭЦ-3	Almaty CHP 3 - 4	Almaty	KZ-ALM	Coal	ST	CHP	50	1965
АО "АлЭС" Алматинская ТЭЦ-1	Almaty CHP 1 - 9	Almaty	KZ-ALM	Coal	ST	CHP	60	1970
	Almaty NEW CHP 5	Almaty	KZ-ALM	Gas	ST	CHP	0.1	1970
АО "АлЭС" Алматинская ТЭЦ-1	Almaty CHP 1 - 10	Almaty	KZ-ALM	Coal	ST	CHP	60	1971
	Almaty NEW CHP 5	Almaty	KZ-ALM	Gas	ST	CHP	0.1	1971
АО "АлЭС" Алматинский каскад ГЭС	Verkhne-Almatinskaya HPS	Almaty	KZ-ALM	Hydro	RES	N	16	1971
АО "АлЭС" Алматинская ТЭЦ-2	Almaty CHP 2 - 1	Almaty	KZ-ALM	Coal	ST	CHP	80	1980
	Almaty NEW CHP 5	Almaty	KZ-ALM	Gas	ST	CHP	0.1	1980
АО "АлЭС" Алматинская ТЭЦ-2	Almaty CHP 2 - 2	Almaty	KZ-ALM	Coal	ST	CHP	80	1981
АО "АлЭС" Алматинская ТЭЦ-2	Almaty CHP 2 - 3	Almaty	KZ-ALM	Coal	ST	CHP	80	1982
АО "АлЭС" Алматинская ТЭЦ-2	Almaty CHP 2 - 4	Almaty	KZ-ALM	Coal	ST	CHP	50	1986
	Almaty NEW CHP 5	Almaty	KZ-ALM	Gas	ST	CHP	0.1	1986
АО "АлЭС" Алматинская ТЭЦ-2	Almaty CHP 2 - 5	Almaty	KZ-ALM	Coal	ST	CHP	110	1988
АО "АлЭС" Алматинская ТЭЦ-2	Almaty CHP 2 - 6	Almaty	KZ-ALM	Coal	ST	CHP	110	1989
АО "АлЭС" Алматинская ТЭЦ-1	Almaty CHP 1 - 8	Almaty	KZ-ALM	Gas	ST	CHP	25	1996
	Antonovskaya HPP	Antonovka	KZ-ALM	Hydro	RES	N	1.6	1980
Исыкская ГЭС-2 ТОО "ЭнергоАлем"	Issykskaya HPP-2	Issyk	KZ-ALM	Hydro	RES	N	5.1	2008
АО "АлЭС" Капшагайская ГЭС	Kapshagayskaya HPP	Kapshagaj	KZ-ALM	Hydro	RES	N	364	1971
Каратальские ГЭС	Karatalskaya HPS-1	Karatalsk	KZ-ALM	Hydro	RES	N	10.71	1954
Каратальские ГЭС	Karatalskaya HPS-2	Karatalsk	KZ-ALM	Hydro	RES	N	4	2008
Каратальские ГЭС	Karatalskaya HPS-3	Karatalsk	KZ-ALM	Hydro	RES	N	4.4	2009
Каратальские ГЭС	Karatalskaya HPS-4	Karatalsk	KZ-ALM	Hydro	RES	N	3.5	2010
	Merek HPP	Merek	KZ-ALM	Hydro	RES	N	1.5	1980
	Moynakskaya HPP	Moinak	KZ-ALM	Hydro	RES	N	300	2012
Талдыкорганские ГЭС	Talgarskaya HPS	Talghar	KZ-ALM	Hydro	RES	N	7.1	2008
Текелийская ТЭЦ-2 ТЭК АО "Казцинк"	Tekeli CHP 2	Tekeli	KZ-ALM	Coal	ST	CHP	12	1959
Текелийская ТЭЦ-2 ТЭК АО "Казцинк"	Tekeli CHP 2	Tekeli	KZ-ALM	Coal	ST	CHP	12	1959
ТЭЦ ТОО "АНПЗ"	ANPS CHP	Atyrau	KZ-ATY	Gas	ST	CHP	6	1945
ТЭЦ ТОО "АНПЗ"	ANPS CHP	Atyrau	KZ-ATY	Gas	ST	CHP	6	1946
ТЭЦ ТОО "АНПЗ"	ANPS CHP	Atyrau	KZ-ATY	Gas	ST	CHP	6	1947
АО "Атырауская ТЭЦ"	Atyrau CHP - 3	Atyrau	KZ-ATY	Gas	ST	CHP	25	1963
АО "Атырауская ТЭЦ"	Atyrau CHP - 4	Atyrau	KZ-ATY	Gas	ST	CHP	25	1963
АО "Атырауская ТЭЦ"	Atyrau CHP - 5	Atyrau	KZ-ATY	Gas	ST	CHP	60	1969
АО "Атырауская ТЭЦ"	Atyrau CHP - 6	Atyrau	KZ-ATY	Gas	ST	CHP	60	1974
АО "Атырауская ТЭЦ"	Atyrau CHP - 7	Atyrau	KZ-ATY	Gas	ST	CHP	45	1976
АО "Атырауская ТЭЦ"	Atyrau CHP - 4	Atyrau	KZ-ATY	Gas	ST	CHP	25	1985
АО "Атырауская ТЭЦ"	Atyrau CHP - 8	Atyrau	KZ-ATY	Gas	ST	CHP	25	2010
АО "Атырауская ТЭЦ"	Atyrau CHP - 9	Atyrau	KZ-ATY	Gas	ST	CHP	25	2010
АО "Атырауская ТЭЦ"	Atyrau CHP - 10	Atyrau	KZ-ATY	Gas	ST	CHP	25	2010

Appendix: Power Plants

Plant Name (RUS)	Plant Name	City	region	fuel	type	purpose	capacity	year
ЭС "Кашаган" AGIP KCO	ES Kashagan AGIP KCO	Bolashak	KZ-ATY	Gas	GT	N	40.7	2010
ЭС "Кашаган" AGIP KCO	ES Kashagan AGIP KCO	Bolashak	KZ-ATY	Gas	GT	N	40.7	2010
ЭС "Кашаган" AGIP KCO	ES Kashagan AGIP KCO	Bolashak	KZ-ATY	Gas	GT	N	40.7	2010
ЭС "Кашаган" AGIP KCO	ES Kashagan AGIP KCO	Bolashak	KZ-ATY	Gas	GT	N	40.7	2010
ТГТЭС-1 ТОО "Тенгизшевройл" (ГТЭС-144)	TGTES-1 LLP TCO (GTPS-144)	Tengiz	KZ-ATY	Gas	GT	N	34	1999
ТГТЭС-1 ТОО "Тенгизшевройл" (ГТЭС-144)	TGTES-1 LLP TCO (GTPS-144)	Tengiz	KZ-ATY	Gas	GT	N	34	1999
ТГТЭС-1 ТОО "Тенгизшевройл" (ГТЭС-144)	TGTES-1 LLP TCO (GTPS-144)	Tengiz	KZ-ATY	Gas	GT	N	34	2000
ТГТЭС-1 ТОО "Тенгизшевройл" (ГТЭС-144)	TGTES-1 LLP TCO (GTPS-144)	Tengiz	KZ-ATY	Gas	GT	N	34	2000
ТГТЭС-2 ТОО "Тенгизшевройл" (ГТЭС-480)	TGTES-2 Tengizchevroil LLP GTPS-480	Tengiz	KZ-ATY	Gas	GT	N	34	2000
ТГТЭС-2 ТОО "Тенгизшевройл" (ГТЭС-480)	TGTES-2 Tengizchevroil LLP GTPS-481	Tengiz	KZ-ATY	Gas	GT	N	34	2000
ТГТЭС-2 ТОО "Тенгизшевройл" (ГТЭС-480)	TGTES-2 Tengizchevroil LLP GTPS-482	Tengiz	KZ-ATY	Gas	GT	N	43	2006
ТГТЭС-ЗВП ТОО "Тенгизшевройл" (ГТЭС-242)	TGTES-3 Company TCO GTPS-242	Tengiz	KZ-ATY	Gas	GT	N	121	2008
ТГТЭС-ЗВП ТОО "Тенгизшевройл" (ГТЭС-242)	TGTES-3 Company TCO GTPS-243	Tengiz	KZ-ATY	Gas	GT	N	121	2008
Балхашская ТЭЦ ТОО "Корпорация Казахмыс"	Kazakhmys Corporation Balkhash CHP - 1	Balkhash	KZ-KAR	Coal	ST	CHP	28	1937
Балхашская ТЭЦ ТОО "Корпорация Казахмыс"	Kazakhmys Corporation Balkhash CHP - 2	Balkhash	KZ-KAR	Coal	ST	CHP	20	1940
Балхашская ТЭЦ ТОО "Корпорация Казахмыс"	Kazakhmys Corporation Balkhash CHP - 3	Balkhash	KZ-KAR	Coal	ST	CHP	30	1940
Балхашская ТЭЦ ТОО "Корпорация Казахмыс"	Kazakhmys Corporation Balkhash CHP - 6	Balkhash	KZ-KAR	Coal	ST	CHP	25	1940
Балхашская ТЭЦ ТОО "Корпорация Казахмыс"	Kazakhmys Corporation Balkhash CHP - 7	Balkhash	KZ-KAR	Coal	ST	CHP	60	1963
ТЭЦ-1 ТОО "Караганда-Энергоцентр"	Karaganda energy center CHP 1 - 1	Karaganda	KZ-KAR	Coal	ST	CHP	8	1958
ТЭЦ-1 ТОО "Караганда-Энергоцентр"	Karaganda energy center CHP 1 - 2	Karaganda	KZ-KAR	Coal	ST	CHP	6	1961
ТЭЦ-1 ТОО "Караганда-Энергоцентр"	Karaganda energy center CHP 1 - 3	Karaganda	KZ-KAR	Coal	ST	CHP	6	1961
	Karaganda NEW CHP 4	Karaganda	KZ-KAR	Gas	ST	CHP	0.1	1965
ТЭЦ-1 ТОО "Караганда-Энергоцентр"	Karaganda energy center CHP 1 - 4	Karaganda	KZ-KAR	Coal	ST	CHP	6	1965
ТЭЦ-1 ТОО "Караганда-Энергоцентр"	Karaganda energy center CHP 1 - 5	Karaganda	KZ-KAR	Coal	ST	CHP	6	1965
	Karaganda NEW CHP 4	Karaganda	KZ-KAR	Gas	ST	CHP	0.1	1977
ТЭЦ-3 ТОО "Караганда-Энергоцентр"	Karaganda energy center CHP 2 - 1	Karaganda	KZ-KAR	Coal	ST	CHP	110	1977
ТЭЦ-3 ТОО "Караганда-Энергоцентр"	Karaganda energy center CHP 2 - 2	Karaganda	KZ-KAR	Coal	ST	CHP	110	1977

Appendix: Power Plants

Plant Name (RUS)	Plant Name	City	region	fuel	type	purpose	capacity	year
ТЭЦ-3 ТОО "Караганда-Энергоцентр"	Karaganda energy center CHP 2 - 3	Karaganda	KZ-KAR	Coal	ST	CHP	110	1978
ТЭЦ-3 ТОО "Караганда-Энергоцентр"	Karaganda energy center CHP 2 - 4	Karaganda	KZ-KAR	Coal	ST	CHP	110	1990
Карагандинская ГРЭС-1	Bassel Group LLS Karaganda TTP 1	Karaganda	KZ-KAR	Coal	ST	N	50	1991
Карагандинская ГРЭС-1	Bassel Group LLS Karaganda TTP 1 - 9	Karaganda	KZ-KAR	Coal	ST	N	50	1993
АО "ПКР" (Кумкольская ГТЭС)	GTPS Kumkol	Kumkol	KZ-KAR	Gas	GT	N	18	2004
АО "ПКР" (Кумкольская ГТЭС)	GTPS Kumkol	Kumkol	KZ-KAR	Gas	GT	N	18	2004
АО "ПКР" (Кумкольская ГТЭС)	GTPS Kumkol	Kumkol	KZ-KAR	Gas	GT	N	18	2004
АО "ПКР" (Кумкольская ГТЭС)	GTPS Kumkol	Kumkol	KZ-KAR	Gas	GT	N	18.3	2011
АО "ПКР" (Кумкольская ГТЭС)	GTPS Kumkol	Kumkol	KZ-KAR	Gas	GT	N	18.3	2011
АО "Шахтинская ТЭЦ"	JSC Shakhtinskaya CHP	Shachtinsk	KZ-KAR	Coal	ST	CHP	6	1964
АО "Шахтинская ТЭЦ"	JSC Shakhtinskaya CHP	Shachtinsk	KZ-KAR	Coal	ST	CHP	6	1964
АО "Шахтинская ТЭЦ"	JSC Shakhtinskaya CHP	Shachtinsk	KZ-KAR	Coal	ST	CHP	6	1965
ТЭЦ-ПВС ТОО "Арселор Миттал Темиртау"	Arcelor Mittal TPP - 3	Temir Tau	KZ-KAR	Coal	ST	CHP	12	1959
ТЭЦ-ПВС ТОО "Арселор Миттал Темиртау"	Arcelor Mittal TPP - 5	Temir Tau	KZ-KAR	Coal	ST	CHP	60	1960
ТЭЦ-ПВС ТОО "Арселор Миттал Темиртау"	Arcelor Mittal TPP - 4	Temir Tau	KZ-KAR	Coal	ST	CHP	60	1960
ТЭЦ-2 АО "Арселор Миттал Темиртау"	Arcelor Mittal Temir Tau CHP 2 - 1	Temir Tau	KZ-KAR	Coal	ST	CHP	100	1973
ТЭЦ-2 АО "Арселор Миттал Темиртау"	Arcelor Mittal Temir Tau CHP 2 - 2	Temir Tau	KZ-KAR	Coal	ST	CHP	100	1974
ТЭЦ-2 АО "Арселор Миттал Темиртау"	Arcelor Mittal Temir Tau CHP 2 - 3	Temir Tau	KZ-KAR	Coal	ST	CHP	100	1975
ТЭЦ-2 АО "Арселор Миттал Темиртау"	Arcelor Mittal Temir Tau CHP 2 - 4	Temir Tau	KZ-KAR	Coal	ST	CHP	135	1982
ГРЭС ТОО "Корпорация Казахмыс"	Kazakhmys Corporation TTP 1 - 1	Topar	KZ-KAR	Coal	ST	N	55	1960
ГРЭС ТОО "Корпорация Казахмыс"	Kazakhmys Corporation TTP 1 - 2	Topar	KZ-KAR	Coal	ST	N	60	1962
ГРЭС ТОО "Корпорация Казахмыс"	Kazakhmys Corporation TTP 1 - 3	Topar	KZ-KAR	Coal	ST	N	100	1963
ГРЭС ТОО "Корпорация Казахмыс"	Kazakhmys Corporation TTP 1 - 4	Topar	KZ-KAR	Coal	ST	N	100	1963
ГРЭС ТОО "Корпорация Казахмыс"	Kazakhmys Corporation TTP 1 - 5	Topar	KZ-KAR	Coal	ST	N	100	1964
ГРЭС ТОО "Корпорация Казахмыс"	Kazakhmys Corporation TTP 1 - 7	Topar	KZ-KAR	Coal	ST	N	86	1980
ГРЭС ТОО "Корпорация Казахмыс"	Kazakhmys Corporation TTP 1 - 8	Topar	KZ-KAR	Coal	ST	N	86	1980
ГРЭС ТОО "Корпорация Казахмыс"	Kazakhmys Corporation TTP 1 - 6	Topar	KZ-KAR	Coal	ST	N	86	1985
Жезкаганская ТЭЦ ТОО "Корпорация Казахмыс"	Zhezkazgan CHP - 4	Zhezkazgan	KZ-KAR	Coal	ST	CHP	25	1959
Жезкаганская ТЭЦ ТОО "Корпорация Казахмыс"	Zhezkazgan CHP - 3	Zhezkazgan	KZ-KAR	Coal	ST	CHP	30	1959
Жезкаганская ТЭЦ ТОО "Корпорация Казахмыс"	Zhezkazgan CHP - 5	Zhezkazgan	KZ-KAR	Coal	ST	CHP	42	1960
Жезкаганская ТЭЦ ТОО "Корпорация Казахмыс"	Zhezkazgan CHP - 6	Zhezkazgan	KZ-KAR	Coal	ST	CHP	50	1963
Жезкаганская ТЭЦ ТОО "Корпорация Казахмыс"	Zhezkazgan CHP - 7	Zhezkazgan	KZ-KAR	Coal	ST	CHP	60	1969
Аркалыкская ТЭЦ ГПП АТЭК	Arkalyk CHP - 1	Arkalyk	KZ-KUS	Gas	ST	CHP	4	1963

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Plant Name (RUS)	Plant Name	City	region	fuel	type	purpose	capacity	year
Аркалыкская ТЭЦ ГПП АТЭК	Arkalyk CHP - 2	Arkalyk	KZ-KUS	Gas	ST	CHP	2.5	1963
Костанайская ТЭЦ ГПП КТЭК	Kostanai CHP 1 - 2	Kostanai	KZ-KUS	Gas	ST	CHP	6	1957
Костанайская ТЭЦ ГПП КТЭК	Kostanai CHP 1 - 1	Kostanai	KZ-KUS	Gas	ST	CHP	6	1961
ТЭЦ АО "ССГПО" (Рудненская ТЭЦ)	SSGPO Rudny CHP - 1	Rudny	KZ-KUS	Coal	ST	CHP	58	1961
ТЭЦ АО "ССГПО" (Рудненская ТЭЦ)	SSGPO Rudny CHP - 2	Rudny	KZ-KUS	Coal	ST	CHP	54	1962
ТЭЦ АО "ССГПО" (Рудненская ТЭЦ)	SSGPO Rudny CHP - 3	Rudny	KZ-KUS	Coal	ST	CHP	58	2001
ТЭЦ АО "ССГПО" (Рудненская ТЭЦ)	SSGPO Rudny CHP - 4	Rudny	KZ-KUS	Coal	ST	CHP	17	2002
ТЭЦ АО "ССГПО" (Рудненская ТЭЦ)	SSGPO Rudny CHP - 5	Rudny	KZ-KUS	Coal	ST	CHP	17	2002
ТЭЦ АО "ССГПО" (Рудненская ТЭЦ)	SSGPO Rudny CHP - 6	Rudny	KZ-KUS	Coal	ST	CHP	63	2010
	GTPP Akshabulak	Akshabulak	KZ-KZY	Gas	GT	N	87	2012
ГКП "Кызылордатеблоэлектростанция" (КТЭЦ-6)	Kyzylorda CHP - 6	Kyzylorda	KZ-KZY	Gas	ST	CHP	42	1977
ГКП "Кызылордатеблоэлектростанция" (КТЭЦ-6)	Kyzylorda CHP - 3	Kyzylorda	KZ-KZY	Gas	ST	CHP	73	1994
КОГТЭС ГКП "Кызылордатеблоэлектростанция"	KOGTES	Kyzylorda	KZ-KZY	Gas	ST	N	15	2005
КОГТЭС ГКП "Кызылордатеблоэлектростанция"	KOGTES	Kyzylorda	KZ-KZY	Gas	ST	N	15	2005
КОГТЭС ГКП "Кызылордатеблоэлектростанция"	KOGTES	Kyzylorda	KZ-KZY	Gas	ST	N	15	2005
ТЭЦ-1 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 1 - 1	Aktau	KZ-MAN	Gas	ST	CHP	6	1962
ТЭЦ-1 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 1 - 2	Aktau	KZ-MAN	Gas	ST	CHP	6	1962
ТЭЦ-1 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 1 - 3	Aktau	KZ-MAN	Gas	ST	CHP	25	1963
ТЭЦ-1 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 1 - 4	Aktau	KZ-MAN	Gas	ST	CHP	25	1965
ТЭЦ-1 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 1 - 5	Aktau	KZ-MAN	Gas	ST	CHP	25	1965
ТЭЦ-2 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 2 - 1	Aktau	KZ-MAN	Gas	ST	CHP_I	60	1968
ТЭЦ-2 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 2 - 2	Aktau	KZ-MAN	Gas	ST	CHP_I	60	1969
ТЭЦ-2 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 2 - 3	Aktau	KZ-MAN	Gas	ST	CHP_I	60	1970
ТЭЦ-2 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 2 - 4	Aktau	KZ-MAN	Gas	ST	CHP_I	100	1973
ТЭЦ-2 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 2 - 5	Aktau	KZ-MAN	Gas	ST	CHP_I	50	1973
ТЭЦ-2 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 2 - 6	Aktau	KZ-MAN	Gas	ST	CHP_I	50	1973
ТЭЦ-2 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 2 - 7	Aktau	KZ-MAN	Gas	ST	CHP_I	50	1975
ТЭЦ-2 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 2 - 8	Aktau	KZ-MAN	Gas	ST	CHP_I	60	1978
ТЭЦ-2 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 2 - 9	Aktau	KZ-MAN	Gas	ST	CHP_I	60	1979
ТЭЦ-2 МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC CHP 2 - 10	Aktau	KZ-MAN	Gas	ST	CHP_I	80	1981
ТЭС МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC TPP 3	Aktau	KZ-MAN	Gas	ST	N	200	1983
ТЭС МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC TPP 3	Aktau	KZ-MAN	Gas	ST	N	210	1984
ТЭС МАЭК АО "МАЭК-Казатомпром"	Kazatomprom MAEC TPP 3	Aktau	KZ-MAN	Gas	ST	N	215	1991
ГРЭС г. Аксу АО "ЕЭК"	EKE - 1A	Aksu	KZ-PAV	Coal	ST	N	300	1972
ГРЭС г. Аксу АО "ЕЭК"	EKE - 2A	Aksu	KZ-PAV	Coal	ST	N	330	1972
ГРЭС г. Аксу АО "ЕЭК"	EKE - 3A	Aksu	KZ-PAV	Coal	ST	N	300	1972

Appendix: Power Plants

Plant Name (RUS)	Plant Name	City	region	fuel	type	purpose	capacity	year
ГРЭС г.Аксу АО "ЕЭК"	EKE - 5A	Aksu	KZ-PAV	Coal	ST	N	300	1973
ГРЭС г.Аксу АО "ЕЭК"	EKE - 4A	Aksu	KZ-PAV	Coal	ST	N	300	1973
ГРЭС г.Аксу АО "ЕЭК"	EKE - 6A	Aksu	KZ-PAV	Coal	ST	N	300	1974
ГРЭС г.Аксу АО "ЕЭК"	EKE - 7A	Aksu	KZ-PAV	Coal	ST	N	300	1974
ГРЭС г.Аксу АО "ЕЭК"	EKE - 8A	Aksu	KZ-PAV	Coal	ST	N	300	1975
	Aksuskaya HPS	Aksu	KZ-PAV	Hydro	RES	N	2	1980
Экибастузская ТЭЦ АО "Павлодарэнерго"	Ekibastuz CHP - 1	Ekibastuz	KZ-PAV	Coal	ST	CHP	6	1964
Экибастузская ТЭЦ АО "Павлодарэнерго"	Ekibastuz CHP - 2	Ekibastuz	KZ-PAV	Coal	ST	CHP	6	1964
ТОО "Экибастузская ГРЭС-1"	Ekibastuz TTP 1 - 1	Ekibastuz	KZ-PAV	Coal	ST	N	0	1980
ТОО "Экибастузская ГРЭС-1"	Ekibastuz TTP 1 - 2	Ekibastuz	KZ-PAV	Coal	ST	N	0	1980
ТОО "Экибастузская ГРЭС-1"	Ekibastuz TTP 1 - 3	Ekibastuz	KZ-PAV	Coal	ST	N	500	1981
ТОО "Экибастузская ГРЭС-1"	Ekibastuz TTP 1 - 4	Ekibastuz	KZ-PAV	Coal	ST	N	500	1982
ТОО "Экибастузская ГРЭС-1"	Ekibastuz TTP 1 - 5	Ekibastuz	KZ-PAV	Coal	ST	N	500	1982
ТОО "Экибастузская ГРЭС-1"	Ekibastuz TTP 1 - 6	Ekibastuz	KZ-PAV	Coal	ST	N	500	1983
ТОО "Экибастузская ГРЭС-1"	Ekibastuz TTP 1 - 7	Ekibastuz	KZ-PAV	Coal	ST	N	500	1983
ТОО "Экибастузская ГРЭС-1"	Ekibastuz TTP 1 - 8	Ekibastuz	KZ-PAV	Coal	ST	N	500	1984
АО "Станция Экибастузская ГРЭС-2"	Ekibastuz TTP 2 - 1	Ekibastuz	KZ-PAV	Coal	ST	N	500	1990
АО "Станция Экибастузская ГРЭС-2"	Ekibastuz TTP 2 - 2	Ekibastuz	KZ-PAV	Coal	ST	N	500	1993
ТЭЦ-2 АО "Павлодарэнерго"	Pavlodarenergo Pavlodar CHP 2 - 1	Pavlodar	KZ-PAV	Coal	ST	CHP	25	1961
ТЭЦ-2 АО "Павлодарэнерго"	Pavlodarenergo Pavlodar CHP 2 - 2	Pavlodar	KZ-PAV	Coal	ST	CHP	25	1961
ТЭЦ-1 АО "Алюминий Казахстана"	Aluminium of Kazakhstan Pavlodar CHP 1 - 4	Pavlodar	KZ-PAV	Coal	ST	CHP_I	50	1963
ТЭЦ-1 АО "Алюминий Казахстана"	Aluminium of Kazakhstan Pavlodar CHP 1 - 5	Pavlodar	KZ-PAV	Coal	ST	CHP_I	50	1963
ТЭЦ-2 АО "Павлодарэнерго"	Pavlodarenergo Pavlodar CHP 2 - 3	Pavlodar	KZ-PAV	Coal	ST	CHP	60	1963
ТЭЦ-1 АО "Алюминий Казахстана"	Aluminium of Kazakhstan Pavlodar CHP 1 - 1	Pavlodar	KZ-PAV	Coal	ST	CHP_I	60	1964
ТЭЦ-1 АО "Алюминий Казахстана"	Aluminium of Kazakhstan Pavlodar CHP 1 - 2	Pavlodar	KZ-PAV	Coal	ST	CHP_I	50	1964
ТЭЦ-1 АО "Алюминий Казахстана"	Aluminium of Kazakhstan Pavlodar CHP 1 - 3	Pavlodar	KZ-PAV	Coal	ST	CHP_I	50	1965
ТЭЦ-3 АО "Павлодарэнерго"	Pavlodar CHP 3 - 2	Pavlodar	KZ-PAV	Coal	ST	CHP	60	1972
ТЭЦ-3 АО "Павлодарэнерго"	Pavlodar CHP 3 - 3	Pavlodar	KZ-PAV	Coal	ST	CHP	50	1973
ТЭЦ-3 АО "Павлодарэнерго"	Pavlodar CHP 3 - 4	Pavlodar	KZ-PAV	Coal	ST	CHP	110	1975
ТЭЦ-3 АО "Павлодарэнерго"	Pavlodar CHP 3 - 5	Pavlodar	KZ-PAV	Coal	ST	CHP	110	1976
ТЭЦ-3 АО "Павлодарэнерго"	Pavlodar CHP 3 - 6	Pavlodar	KZ-PAV	Coal	ST	CHP	110	1977
ТЭЦ-1 АО "Алюминий Казахстана"	Aluminium of Kazakhstan Pavlodar CHP 1 - 6	Pavlodar	KZ-PAV	Coal	ST	CHP_I	80	1983
ТОО "СевКазЭнерго Петропавловск"	SevKazEnergo Petropavlovsk CHP - 1	Petropawl	KZ-SEV	Coal	ST	CHP	42	1961

Appendix: Power Plants

Plant Name (RUS)	Plant Name	City	region	fuel	type	purpose	capacity	year
ППТЭЦ-2								
ТОО "СевКазЭнерго Петрпавловск" ППТЭЦ-2	SevKazEnergo Petropavlovsk CHP - 2	Petropawl	KZ-SEV	Coal	ST	CHP	60	1962
ТОО "СевКазЭнерго Петрпавловск" ППТЭЦ-2	SevKazEnergo Petropavlovsk CHP - 3	Petropawl	KZ-SEV	Coal	ST	CHP	60	1963
ТОО "СевКазЭнерго Петрпавловск" ППТЭЦ-2	SevKazEnergo Petropavlovsk CHP - 5	Petropawl	KZ-SEV	Coal	ST	CHP	33	1965
ТОО "СевКазЭнерго Петрпавловск" ППТЭЦ-2	SevKazEnergo Petropavlovsk CHP - 6	Petropawl	KZ-SEV	Coal	ST	CHP	76	1967
ТОО "СевКазЭнерго Петрпавловск" ППТЭЦ-2	SevKazEnergo Petropavlovsk CHP - 7	Petropawl	KZ-SEV	Coal	ST	CHP	76	1969
ТОО "АЕС Усть-Каменогорская ГЭС"	Ust-Kamenogorskaya HPP	Ablakетка	KZ-VOS	Hydro	RES	N	331.2	1959
Бухтарминский ГЭК АО "Казцинк"	Bukhtarminskaya HPS	Bukhtarma	KZ-VOS	Hydro	RES	N	77	1960
Бухтарминский ГЭК АО "Казцинк"	Bukhtarminskaya HPS	Bukhtarma	KZ-VOS	Hydro	RES	N	77	1960
Бухтарминский ГЭК АО "Казцинк"	Bukhtarminskaya HPS	Bukhtarma	KZ-VOS	Hydro	RES	N	77	1960
Бухтарминский ГЭК АО "Казцинк"	Bukhtarminskaya HPS	Bukhtarma	KZ-VOS	Hydro	RES	N	77	1961
Бухтарминский ГЭК АО "Казцинк"	Bukhtarminskaya HPS	Bukhtarma	KZ-VOS	Hydro	RES	N	77	1961
Бухтарминский ГЭК АО "Казцинк"	Bukhtarminskaya HPS	Bukhtarma	KZ-VOS	Hydro	RES	N	77	1961
Бухтарминский ГЭК АО "Казцинк"	Bukhtarminskaya HPS	Bukhtarma	KZ-VOS	Hydro	RES	N	77	1963
Бухтарминский ГЭК АО "Казцинк"	Bukhtarminskaya HPS	Bukhtarma	KZ-VOS	Hydro	RES	N	77	1966
Бухтарминский ГЭК АО "Казцинк"	Bukhtarminskaya HPS	Bukhtarma	KZ-VOS	Hydro	RES	N	60	2011
	Bulaksk HPP	Bulaksk	KZ-VOS	Hydro	RES	N	2	1980
АО "АЕС Усть-Каменогорская ТЭЦ"	Ust-Kamenogorsk CHP - 12	Öskemen	KZ-VOS	Coal	ST	CHP	80	1950
АО "АЕС Усть-Каменогорская ТЭЦ"	Ust-Kamenogorsk CHP - 5	Öskemen	KZ-VOS	Coal	ST	CHP	9	1951
АО "АЕС Усть-Каменогорская ТЭЦ"	Ust-Kamenogorsk CHP - 6	Öskemen	KZ-VOS	Coal	ST	CHP	8	1951
АО "АЕС Усть-Каменогорская ТЭЦ"	Ust-Kamenogorsk CHP - 7	Öskemen	KZ-VOS	Coal	ST	CHP	8	1952
АО "АЕС Усть-Каменогорская ТЭЦ"	Ust-Kamenogorsk CHP - 8	Öskemen	KZ-VOS	Coal	ST	CHP	25	1954
АО "АЕС Усть-Каменогорская ТЭЦ"	Ust-Kamenogorsk CHP - 4	Öskemen	KZ-VOS	Coal	ST	CHP	4	1959
ТОО "АЕС Согринская ТЭЦ"	Sogra CHP	Öskemen	KZ-VOS	Coal	ST	CHP	25	1962
АО "АЕС Усть-Каменогорская ТЭЦ"	Ust-Kamenogorsk CHP - 10	Öskemen	KZ-VOS	Coal	ST	CHP	50	1966
АО "АЕС Усть-Каменогорская ТЭЦ"	Ust-Kamenogorsk CHP - 9	Öskemen	KZ-VOS	Coal	ST	CHP	38	1967
АО "АЕС Усть-Каменогорская ТЭЦ"	Ust-Kamenogorsk CHP - 11	Öskemen	KZ-VOS	Coal	ST	CHP	100	1970
АО "Риддер ТЭЦ"	Ridder Leninogorsk CHP - 5	Ridder	KZ-VOS	Coal	ST	CHP	12	1955
АО "Риддер ТЭЦ"	Ridder Leninogorsk CHP - 5	Ridder	KZ-VOS	Coal	ST	CHP	12	1955
АО "Риддер ТЭЦ"	Ridder Leninogorsk CHP - 4	Ridder	KZ-VOS	Coal	ST	CHP	5	1958
АО "Риддер ТЭЦ"	Ridder Leninogorsk CHP - 5	Ridder	KZ-VOS	Coal	ST	CHP	30	1958
ТОО "Компания ЛК ГЭС "	Ridder HPP	Ridder	KZ-VOS	Hydro	RES	N	14	1965
Зайсанская ГЭС	Zaysanskaya HPP	Saissan	KZ-VOS	Hydro	RES	N	2	1980
ГКП "Теплокоммунэнерго" (ТЭЦ-1) Семипалатинск	Semipalatinsk CHP 1 - 2	Semey	KZ-VOS	Coal	ST	CHP	12	1958
ГКП "Теплокоммунэнерго" (ТЭЦ-1)	Semipalatinsk CHP 1 - 1	Semey	KZ-VOS	Coal	ST	CHP	6	1959

Appendix: Power Plants

Plant Name (RUS)	Plant Name	City	region	fuel	type	purpose	capacity	year
Семипалатинск								
ТОО "АЕС Шульбинская ГЭС"	Shulbinskaya HPS	Shulbinsk	KZ-VOS	Hydro	RES	N	702	1996
ГКП "Кентаусервис" (КТЭЦ-5)	Kentau CHP 5 - 4	Kentau	KZ-YUZ	Coal	ST	CHP	4.5	1952
ГКП "Кентаусервис" (КТЭЦ-5)	Kentau CHP 5 - 5	Kentau	KZ-YUZ	Coal	ST	CHP	7	1955
ГКП "Кентаусервис" (КТЭЦ-5)	Kentau CHP 5	Kentau	KZ-YUZ	Coal	ST	CHP	5.5	1958
АО "Шардаринская ГЭС"	Shardarinskaya HPS	Shardara	KZ-YUZ	Hydro	RES	N	100	1967
ТЭЦ-1 ТОО "Казспецэлектрод"	Shymkent CHP-1	Shymkent	KZ-YUZ	Gas	ST	CHP	18	1964
АО "3-Энергоорталык" (ШТЭЦ-3)	Shymkent CHP 3 - 1	Shymkent	KZ-YUZ	Gas	ST	CHP	80	1981
ТЭЦ-2 ТОО "Казспецэлектрод"	Shymkent CHP-2	Shymkent	KZ-YUZ	Gas	ST	CHP	12	1983
АО "3-Энергоорталык" (ШТЭЦ-3)	Shymkent CHP 3 - 2	Shymkent	KZ-YUZ	Gas	ST	CHP	80	1983
ГТЭС-КПО б.в.	Karachaganak GES	Aksay	KZ-ZAP	Gas	GT	CHP_I	40	2000
ГТЭС-КПО б.в.	Karachaganak GES	Aksay	KZ-ZAP	Gas	GT	CHP_I	40	2001
ГТЭС-КПО б.в.	Karachaganak GES	Aksay	KZ-ZAP	Gas	GT	CHP_I	40	2002
ГТЭС-КПО б.в.	Karachaganak GES	Aksay	KZ-ZAP	Gas	GT	CHP_I	41	2005
ГПЭС "Ю.Каратобе"	Karatobe	Karatobe	KZ-ZAP	Gas	GT	N	6.2	2008
Уральская ТЭЦ	Ural CHP	Uralsk	KZ-ZAP	Gas	ST	CHP	12	1960
Уральская ТЭЦ	Ural CHP	Uralsk	KZ-ZAP	Gas	ST	CHP	8	1969
Уральская ТЭЦ	Ural CHP	Uralsk	KZ-ZAP	Gas	ST	CHP	12	1994
ПГУ Уральской ТЭЦ АО "Жайыктепозэнерго"	Ural CHP	Uralsk	KZ-ZAP	Gas	CC	CHP	29	2006
Уральская ГТЭС	Ural GTPS	Uralsk	KZ-ZAP	Gas	GT	N	54	2011
ТОО "РемКоммСтрой" (Меркенская ГЭС-3)	Merke Hydro	Merke	KZ-ZHA	Hydro	RES	N	1.5	2011
АО "Таразэнергоцентр" (ЖТЭЦ-4)	Taraz CHP 4	Taraz	KZ-ZHA	Gas	GT	CHP	30	1963
АО "Таразэнергоцентр" (ЖТЭЦ-4)	Taraz CHP 4	Taraz	KZ-ZHA	Gas	GT	CHP	30	1963
Жамбылская ГРЭС им.Батурова	Zhambyl GES	Taraz	KZ-ZHA	Gas	GT	N	200	1967
Жамбылская ГРЭС им.Батурова	Zhambyl GES	Taraz	KZ-ZHA	Gas	GT	N	200	1968
Жамбылская ГРЭС им.Батурова	Zhambyl GES	Taraz	KZ-ZHA	Gas	GT	N	200	1969
Жамбылская ГРЭС им.Батурова	Zhambyl GES	Taraz	KZ-ZHA	Gas	GT	N	200	1975
Жамбылская ГРЭС им.Батурова	Zhambyl GES	Taraz	KZ-ZHA	Gas	GT	N	200	1976
Жамбылская ГРЭС им.Батурова	Zhambyl GES	Taraz	KZ-ZHA	Gas	GT	N	200	1976