KAZENERGY

THE NATIONAL ENERGY REPORT 2017

KAZENERGY

EXPO 2017 ASTANA
FUTURE ENERGY

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DEAR LADIES AND GENTLEMEN!

Over the past two years since publication of the KAZENERGY National Energy Report 2015, Kazakhstan's economy has adjusted to the new reality. The end of the era of high energy prices has significantly changed the pace of the country's economic development, as well as state policy priorities.

Despite the fact that the stabilization of oil prices has halted the decline of investment in oil production, the main challenge facing Kazakhstan's economy in the foreseeable future will be the creation of new sectors with a competitive advantage for attracting investments into the country.

To that end, the government is working on the preparation of a new Subsoil Code, as well as amending the Tax Code, taking into account some of the recommendations provided in the NER 2015. These actions inspire confidence in the importance of the work on national reports performed by KAZENERGY Association, and reaffirm the role of such reports as reliable tools for promoting a constructive dialogue between the business community and government.

The new conditions of the global oil market opened up new opportunities. In a low oil price environment, some producers managed to significantly improve cost efficiency while maintaining and even increasing previous production levels. Utilizing this experience is extremely important for Kazakhstan's oil and gas sector, which could benefit from the application of cost-optimization measures. Application of such cost optimization mechanisms, combined with the reliable transportation infrastructure that has developed since independence, will allow Kazakhstan to not only maintain, but also to enhance its role and position in global energy markets, and ultimately ensure stable revenue flows for the national budget.

In electric power sectors around the world, a new paradigm defined by the development of renewable energy sources has gained importance in recent years, and is expected to continue to grow over the near term. However, there are a number of limitations to the development of renewables in Kazakhstan: fully embracing such a renewables-centric paradigm requires state support. At the same time, introducing renewable resources into electric power generation represents only one of several tools that can be used to transition to "green" energy. Renewables should therefore be carefully introduced in combination with other policy measures, so as to ensure the reliable and affordable delivery of electric power to end consumers at a minimum social cost.

The unfettered development of renewables in Kazakhstan under current conditions, without necessary market mechanisms, will result in a significant increase in the cost of electricity and ultimately reduce the cost competitiveness of domestic producers. It is therefore extremely important for the state to establish a cogent vision for the country's transition to "green" economy, select the best mechanisms through which to realize this vision, and determine the maximum limit of new renewable power capacity installations taking into account the current capacities of Kazakhstan's power infrastructure.

This systemic approach, integrating renewables into the power sector, should also take into account the commitment to reduce greenhouse gas emissions by 15% undertaken by Kazakhstan in 2016 within the framework of the Paris Agreement, as well as feedback on greenhouse gas emissions regulation and legislation from the business community and independent experts.

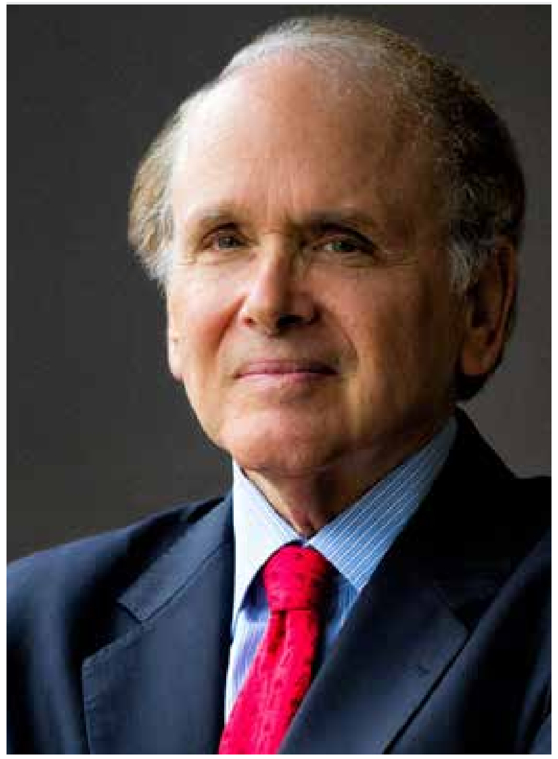
Given such developments, KAZENERGY Association decided to prepare a third edition of the National Energy Report as part of the International Specialized Exhibition EXPO-2017 and the XI KAZENERGY Eurasian Forum. The 2017 Report was developed by world-renowned energy experts and the international consultancy, IHS Markit, who worked closely with the supportive members of the Association, while researching and writing the report.

I am grateful to the many experts from Kazakhstan who participated in preparing this Report. I am convinced that such a format of cooperation represents another significant contribution by the Association to improving the skills of domestic specialists, as interacting with foreign consultants allows them to develop their analytical skills in line with global standards.

This document, the 2017 Report, presents current and forecasted indicators on the fuel and energy sector, analysis of predominant trends for all main types of energy resources, as well as specific proposals by the Association to improve the current legislation in order to attract investment and implement advanced energy technologies in the country with the purpose of sustainable development.

I am confident that the rigor and independence with which the research for the Report was conducted ensures a balanced outcome that reflects the interests of the energy sector and economy as a whole. I hope that the Report will be a meaningful contribution to the future development of state energy policy.

Timur Kulibayev
Chairman
KAZENERGY Association



DEAR READERS!

On behalf of IHS Markit, we greatly appreciate the opportunity to be invited back to collaborate on the updated National Energy Report 2017 for Kazakhstan and to present an integrated outlook for its energy future. Hydrocarbons and other energy resources remain critical growth drivers in Kazakhstan's economy and will be for some time to come, despite some diversification since independence and the traditional importance of the mining sector. The development of the oil and gas industry has served Kazakhstan very well, generating revenues that have been crucial since 1991 in solidifying its independence as a nation and delivering increasingly higher incomes and standards of living for its people. This development has also strengthened Kazakhstan's relations with its neighbors and, together with rapidly increasing uranium production, established the country as a burgeoning force in the global energy industry and an important player in world markets and global affairs.

But the world has changed and the global energy situation continues to evolve. Kazakhstan faces strikingly different challenges than it did when the previous report was completed in 2015. For much of the period since independence, global commodity markets were dominated by the "commodity supercycle" of strong demand and high prices, driven by the emerging market nations and especially China. Kazakhstan, as a major natural resource producer, greatly benefited from the supercycle, although that period of rapidly growing demand for nearly all types of mineral resources has now ended. The oil market, too, has been turned upside down: it is now characterized by oversupply. Prices in international markets are now hovering at levels less than half of what they were three years ago and have been reluctant to show much buoyancy. In late 2016, Kazakhstan joined a historic agreement with OPEC and several key non-OPEC producers to reduce production and allow the market to re-balance, an agreement that was extended into 2018. Despite unprecedented compliance among the participants, the pact is challenged by the resurgence of US supply as a result of the emergence of shale oil.

These changes in the oil market are putting great fiscal pressure on the budgets of producer countries, like Kazakhstan. They are also changing the orientation of the international industry. Among international companies there is no longer the urgency to obtain access to resources as there was previously: now the goal is to remain profitable and cost-efficient in the new low-price environment through such strategies as reducing the length of investment cycles, focusing exploration in familiar basins and near existing infrastructure, and increasing use of automation and digitization technologies. Companies will continue to actively search for new opportunities, but they will be more selective, increasing the competition among resource-holding countries for available investment. As a result, we expect host countries will offer more flexible fiscal terms and local content requirements. There will also be increasing emphasis on timeliness and predictability in decision-making by countries in attracting international investment.

A second key change is that we are now in a post-Paris Climate Agreement world. The broad international support and general policy direction to reduce greenhouse gas emissions from the energy sector set in the Paris Climate Agreement of 2015 naturally has important implications for Kazakhstan not only as an energy producer and exporter, but also as an energy consumer. Kazakhstan's unconditional commitment as part of the Agreement is to reduce its greenhouse gas emissions by 15% in 2030 compared to 1990, and by 25% contingent on availability of international funding. The Report provides projections for how much of this reduction is possible by following policies and measures already in place, and outlines further strategies that could be employed to achieve full compliance.

Thirdly, the emergence of new technologies has the potential to dramatically alter the nature of energy production and use globally. One example is the accelerating build-out and falling costs of renewable energy, which registered record capacity additions in 2016. In transportation, electric vehicles appear to be poised to gain market, and this, coupled with new forms of mobility detailed in the Report, could have major implications both for greenhouse gas emissions and fuel demand.

These and other major changes provide the context for the work featured in this new Report. It presents a baseline outlook for Kazakhstan's long-term energy future that is based on a careful analysis of both above-ground and below-ground factors. And although that future will be shaped by a vast array of drivers, developments, and conditions that we identify and explore in this update, it will likely be determined to an equal, if not greater, degree by Kazakhstan's own policy responses and decisions.

Our hope is that this Report will contribute to an ongoing process of decision-making and policy formation in Kazakhstan that must respond to the changes outlined above. As before, the goal of the Report is to advance Kazakhstan's economic progress and well-being in this dynamic new context, continuously building on the gains the country has achieved since 1991.

Dr. Daniel Yergin
Vice Chairman
IHS Markit

The National Energy Report 2017 (NER 2017) is developed as an integral part of the international exposition Expo 2017, hosted by Kazakhstan in Astana. The theme of Expo 2017 is "Future Energy," with the goal of finding innovative and practical energy solutions to pressing global social, economic, and environmental challenges.

From the same perspective, NER 2017 sets a course toward Kazakhstan's energy future that is based both on emerging new technologies, with the potential to revolutionize the ways energy is produced and consumed, and on careful stewardship of the country's abundant energy resources. Yet the energy future must also be sustainable.

The path to future energy outlined in NER 2017 is sustainable because it relies on domestic resources, will become increasingly "green" and efficient, allowing the country to fulfill its international environmental commitments, and it supports and enhances Kazakhstan's economic growth and the well-being of its people.

TABLE OF CONTENTS

APPRECIATION

The National Energy Report 2017 was prepared for KAZENERGY by IHS Markit, but incorporates the work of many experts, both within Kazakhstan and abroad. These specialists represent a wide variety of organizations, including KAZENERGY members, state authorities of the Republic of Kazakhstan, research, development, design and engineering entities, as well as companies operating in the sector. The contributions of all these experts are gratefully acknowledged.

We especially thank the Avangarde Group represented by its General Director, Ruslan Mukhamedov, as well as Oleg Arkhipkin, who was actively involved in preparation of the Report. Their collaboration was invaluable in setting the overall direction and focus of the Report. Numerous specialists within and outside Kazakhstan also reviewed individual chapters of the Report corresponding to their individual areas of expertise. We are sincerely grateful for their suggestions and revisions.

We especially thank Uzakbay Kazabalin, Deputy Chairman of the KAZENERGY Association, Bolat Akchulakov, General Director of the KAZENERGY Association, Ramazan Zhampiisov, Executive Director of the KAZENERGY Association, and Rustam Zhursunov, Deputy Chairman of the Board of the National Chamber of Entrepreneurs of Kazakhstan "Atameken". This Report would not have been possible without their assistance and support.

Of key importance to production of the Report on schedule and in two languages was the work of the highly proficient translator, Maria Gavrilova. We also express gratitude to Ekaterina de Vere Walker for the translation of the chapter on electric power as well as to Nikolay Mirenkov and Andrew R. Bond for their keen editorial assistance.

In addition to the individuals and organizations mentioned above, we extend our special thanks to a large number of organizations (industrial enterprises, energy producers, power plants, etc.) and their employees who contributed to preparation of the Report:

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In closing, during the preparation of this report we have been truly fortunate to have met and worked with many wonderful and talented colleagues in Kazakhstan. We are particularly honored to present this report as part of the proceedings of the major international exposition EXPO 2017, hosted in Astana and devoted to issues of future energy.

It has been a great honor for us to participate in the important work of charting the future development of Kazakhstan's energy sector. Energy will remain a central element of the country's economy for many years to come, helping to provide a solid foundation for the welfare of its people. On behalf of IHS Markit, the authors of this Report wish Kazakhstan the very brightest and most successful future.

In Appreciation,

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1. INTRODUCTION

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On the global stage, Kazakhstan is particularly prominent as an energy producer. Its proven reserves of oil, coal, and uranium all rank among the top dozen or so countries in the world, and natural gas in the top 20. Further, Kazakhstan leads the world in production of uranium, and annually ranks among the top 10 producing countries for coal and top 20 for oil. Over the past two decades, it has nearly quadrupled its oil output and is emerging as a new global oil-producing "heavyweight"; most of the incremental oil production growth within the Commonwealth of Independent States (CIS) over the next two decades is expected to come from Kazakhstan.

The passage above, from The National Energy Report 2015 (NER 2015)[1], provides clear evidence of Kazakhstan's international stature as an energy producer. That report also highlights the importance of energy to Kazakhstan's national economy, when it notes (based on 2014 data):

The energy sector, especially oil, is of paramount importance for the country's economy, accounting for about 22% of the country's GDP, two-thirds of total export earnings, and 50% of state budget revenues. It has also been the primary destination of foreign direct investment (FDI) within Kazakhstan.[2]

The numbers cited above have declined slightly since 2014, reflecting the downturn in world oil prices, but the energy sector still accounts for about 20.4% of total GDP (2016) and about 60% of total export earnings.[3] Thus the imperative for wise and careful stewardship over the country's diverse and abundant energy resources is as compelling today as at any time in the country's history.

[1] KazEnergy, The National Energy Report 2015, p. 16.

[2] KazEnergy, The National Energy Report 2015, p. 30.

[3] Kazakhstan's oil and gas industry contribution to GDP in 2016 was 18.2%

1.1. NATIONAL ENERGY REPORT 2017

The National Energy Report 2017 (NER 2017) builds on the comprehensive analysis in NER 2015 (which covered all sectors of Kazakhstan's energy industry), but through a more selective focus on four key dimensions, which feature prominently in the organization of this report.

First, the chapters on oil, refined products, gas, coal, uranium, electric power, and greenhouse gas (GHG) emissions each provide a concise *update* of the main statistical indicators and developments in these areas since the publication of NER 2015. Wherever possible, analysis of data for 2015 and 2016 are accompanied by coverage of trends and developments up through mid-2017.

Second, NER 2017 provides an updated assessment of the *Outlook* for each energy sector, evaluating the most recent energy industry targets and forecasts contained in official state documents (e.g., Concepts, Strategies) and Energy Ministry plans in light of current conditions. In many cases this evaluation includes comparison with proprietary IHS Markit forecasts and scenarios. When IHS Markit forecasts differ from state and industry projections—such as in the case of crude oil production—NER 2017 provides general explanations for the divergence in expected outcomes.

A key section in most chapters—*Infrastructure and Technologies*—represents a third major focus of NER 2017. Here the goal is to review the state of development of promising new sector-relevant technologies globally and their potential impact on energy markets. This also assesses their suitability for implementation in Kazakhstan, taking into account the development goals and targets for the country's fuel and energy complex.

A fourth and final focus in each sector-themed chapter—*Regulation*—is on the legislative and regulatory environment surrounding energy production and consumption in Kazakhstan. Here NER 2017 reviews current legislation in each major energy industry, identifies key problems and major themes, and suggests changes in legislation and regulation that could potentially improve market function, energy security, and investment attractiveness.

1.2. A CHANGING INTERNATIONAL ENVIRONMENT

In addition to its specific focus on the four dimensions described above, NER 2017 stands out by virtue of a new perspective that reflects major developments in the international energy environment since the publication of NER 2015. These include:

• **The agreement reached at the 21st Conference of the United Nations Framework Convention on Climate Change (so-called "Paris Agreement")** in November 2015, whereby nearly all of the world's nations agreed to reduce (GHG) emissions according to self-defined goals, known as intended nationally determined contributions (INDCs). The agreement went into force a year later with the status of international law (having achieved a record number of ratifications in so short a time), and now commits countries (including Kazakhstan) to make concerted efforts to reduce emissions through such measures as energy efficiency improvements, modification of the energy mix in their economies (away from coal and toward natural gas and renewable energy), and carbon pricing (either through carbon taxation or emissions trading).

• **A resetting of the world crude oil balance (reflecting oversupply in the medium term coupled with moderate demand growth) at a new price level only roughly half (~$50/bbl) that of early 2014.** A combination of lower services costs, efficiency improvements, and voluntary production cuts (among OPEC and selected other major producers such as Russia and Kazakhstan) have allowed major oil producers to remain profitable despite the lower price environment. However, their adjustments-in the form of reducing cycle length, focusing exploration in familiar basins and near existing infrastructure, and relying on automation and digitization technologies to enhance productivity and reduce cost-have shifted the terms of trade in their favor vis-à-vis national governments in negotiations involving new energy investments. In this highly competitive environment, Kazakhstan and other countries must redouble efforts to enhance their investment attractiveness.

• **Accelerating build-out of renewable energy capacity.** There were record additions of renewable energy capacity globally in 2016 (150 GW), reflecting strong policy support for solar photovoltaics and onshore wind, design improvements, scale economies, and falling capital costs, especially for solar. Renewable energy accounted for more than half of total global generation capacity added, and will be the fastest-growing source of new energy supply for global power generation to 2040. If the necessary policy support is maintained, solar and wind power could capture 50% or more of total net power capacity added in 2016–40. **Their share of total energy supply will still remain small, however, because of the initial base, but growing over time**. Climate change mitigation is a powerful driver for renewables, but in many countries, reducing air pollution and diversifying energy supplies to improve energy security play an equally strong role.

• **Role of natural gas as a "bridge" fuel in question.** Renewables' rapid growth has come in part at the expense of new thermal–fired capacity. Although gas has definite advantages in terms of flexibility, reliability, and—in certain markets—cost over other types of thermal generation, new gas investments are now lagging behind investments in renewables.[4] This calls into question the role gas will play in bridging the transition to renewable energy by displacing coal in power generation. One factor that could conceivably disrupt or attenuate this role is more rapid than expected development of grid battery storage technology. Will the economics of renewables improve so rapidly that it could dramatically transform the global energy transition away from gas? If this transition happens quickly, the current global oversupply situation and low price environment for gas could be exacerbated.

• **The "next big thing" in low-carbon energy?** The accelerated build-out of wind and solar power has benefitted from a largely unexpected convergence of favorable policy, economic conditions, and technological advances. Could some other low-carbon energy technology be poised for a similar "breakthrough"—i.e., much more rapidly than anticipated—as governments and industry position themselves to exploit the opportunities arising from the Paris agreement targets, and the venture capital and financial markets leverage more capital for transition technologies? A number of such technologies—including electric and autonomous vehicles, new forms of nuclear power, battery storage, and carbon capture technologies—will be closely watched and are discussed in this report. This being said, it is important to bear in mind that although new technologies ultimately may prove disruptive, their commercial development and widespread adoption will still require time: despite projected compound annual rates of growth in capacity for renewable energy of 6% (2021–30) and 4% (2031–40), by 2040 renewables will still count for only 5% of total global primary energy consumption, with the aggregate share of coal, oil, and gas still accounting for over three-fourths.

1.3. CHALLENGES FOR KAZAKHSTAN

These changes in the international energy environment have brought into sharper focus a number of challenges requiring policy responses in Kazakhstan since publication of NER 2015.

• **"Lower for longer" oil price means slower GDP growth.** Mainly due to a lower future global crude oil price estimate (~$80 per barrel post-2024 as opposed to ~$100) resulting from significant cost reductions within a large segment of the industry, IHS Markit projections of average annual GDP growth for Kazakhstan over the forecast period out to 2040 have been lowered a full percentage point, from 3.4% to 2.4% (the lower oil price also reflects the overall market situation for global commodities in general). This will reduce the domestic financial resources available for investment in energy exploration and development, and in some cases has resulted in modifications to the domestic energy demand growth forecasts made in NER 2015. For instance, projected annual demand growth for electric power—a measure closely linked to economic activity—to 2040 has now fallen to 1.1%, from 1.2% in NER 2015. On the positive side, slower energy demand growth should result in slightly lower GHG emissions (as reflected in the new NER 2017 forecasts), facilitating Kazakhstan's effort to meet its Paris commitment (see below).

• **"Lower for longer" also means foreign direct investment is increasingly important.** The limited availability of domestic capital for financing energy sector expansion—due to slower GDP growth, lack of tenge liquidity, and the overall weak capitalization levels in Kazakhstan's banking sector—make attraction of foreign capital an important strategy for Kazakhstan's energy companies in their efforts to finance planned expansion projects. Kazakhstan has taken important steps in this direction, although NER 2017 identifies areas where continued progress is desirable, both with respect to oil and gas industry–specific investment (upstream success, as measured by reserves added per new field wildcat well) as well as overall investment attractiveness (primary fiscal balance, labor skills of the workforce, predictability of monetary policy, and access to financing).

• **Differential external demand for Kazakhstan's energy commodities is reflected in different policies for their marketing and utilization in the economy.** Two of Kazakhstan's major energy products—oil and uranium—are in relatively healthy demand globally and can withstand the requisite transportation costs to reach international markets. As such, these are primarily destined for export, although about a fifth of crude oil production is directed to domestic refineries. Two others—natural gas and coal—are abundant but face constraints in foreign markets either due to quality (coal), high transportation costs, or stiff competition from alternative suppliers or alternative fuels. As such, these could be "stranded" resources beyond what can be utilized in the domestic economy. Energy export trade tends to be developed primarily according to a commercial logic, whereas use of energy such as gas, coal, and to an extent refined products in the domestic economy tends to be guided by a quasi-commercial logic in which social interests also play a role. For instance, substantial quantities of coal used to generate heat energy at combined heat-and-power plants are consumed at a net economic loss (subsidized by revenues from electric power generation). Somewhat similarly, the build-out of natural gas–fired power generation capacity in southern Kazakhstan, which would support the country's efforts to reduce its carbon footprint as well as assist in the disposal of associated gas from oil production, has been limited in part by high import prices, high transportation and processing costs of domestic associated gas as well as concerns that electricity rate hikes to consumers needed to finance the build-out and the costs of gas processing would violate a social commitment to low-cost power. NER 2017 observes that a less than fully commercial approach by the state towards any energy sector generates opportunity costs in the form of diminished companies' revenues that would otherwise be devoted to capital investments in upgrading existing capacities and installing new ones. Mechanisms have proven to be efficient in allocating costs of such investment through the process of price formation.

• **Integrated approach to power sector development calls for a new concept for the sector's development to 2035 with a view to 2050.** Kazakhstan faces a familiar global trilemma in its electric power sector: security of supply, affordability versus value to consumers, and environmental sustainability. Although Kazakhstan's power sector regulation is extensive with a plethora of sound initiatives covering most of these aspects, they tend to exist in isolation from current policy, market mechanisms and international commitments. An integrated approach needs to be applied to overall power sector planning, market mechanisms (inclusive of the capacity market), tariff regulation, and use of technology (inclusive of the demand side and grid). As part of this change, Kazakhstan should accelerate heat energy market reform and introduce performance-based tariff methodologies for electricity and heat energy transmission and distribution. Considering all of the above, a new concept for power sector development to 2035 with a view to 2050 needs to be developed.

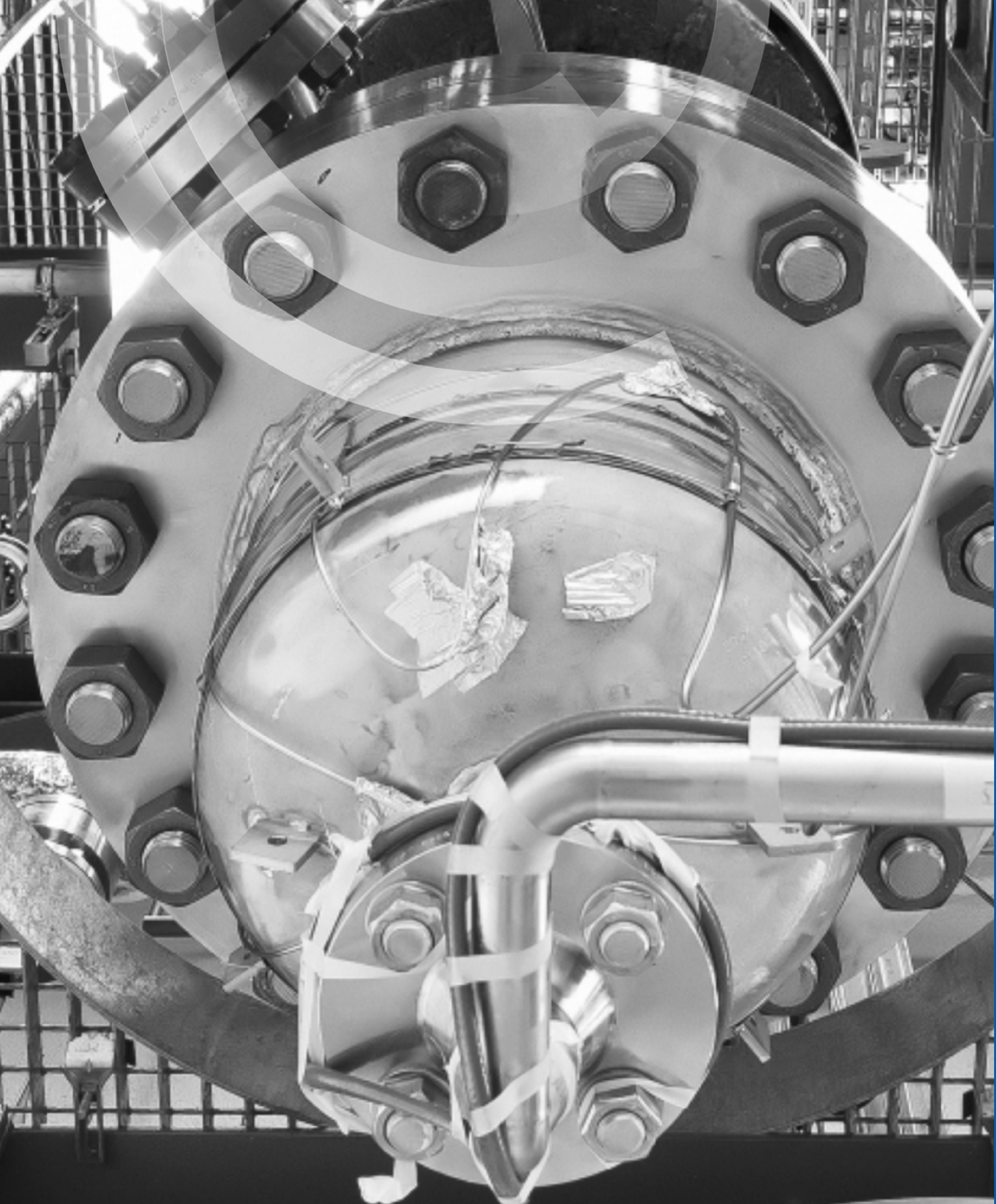
• **Kazakhstan is on track to reduce GHG emissions, but additional work is needed to meet its Paris commitment.** Kazakhstan's INDC under the Paris climate agreement includes an unconditional target of reducing GHG emissions economy-wide by 15% below 1990 levels by 2030. To fulfill its unconditional INDC, Kazakhstan needs to reduce its GHG emissions by 53.4 MMt to 302.8 MMt of CO_2 equivalent by 2030. Analysis in NER 2017 shows that Kazakhstan can attain about half (an almost 8% reduction) of this emissions target by following a "business-as-usual" approach—i.e., pursuing policies already in place or planned for implementation.[5] In addition, the report presents an alternative scenario whereby Kazakhstan not only can attain its full 15% emissions reduction under the Paris agreement but even get almost halfway to its conditional target of 25% through a much greater improvement in aggregate energy efficiency, a more pronounced reduction in coal consumption, and a more rapid build-out of wind and solar energy.

• **"Use it or lose it": Kazakhstan's comparative advantage as an energy producer.** One of the themes highlighted in NER 2015 is Kazakhstan's continuing comparative advantage as an energy producer. Although economic diversification remains a primary goal for many commodity-exporting states, including Kazakhstan, husbanding hydrocarbon resources by delaying their development is a strategy that yields an uncertain result. This is because possible advances in energy use and production technologies ultimately make the future value of hydrocarbon resources difficult to predict (e.g., see the discussion of natural gas above). For this reason, NER 2017 continues to advocate investments in exploration, production, and export capacity of hydrocarbon energy resources whenever such investments make good sense economically *in the current environment and given the foreseeable future outlook*.[6] In the upstream sector, this reasoning applies equally to major planned expansions in the country's "mega" projects and to enhanced recovery operations at smaller, more mature fields. Changes in the proposed new Subsoil Code discussed in this report should facilitate future investments by further increasing Kazakhstan's competitiveness as an attractive investment destination.

[4]In the United States in 2016, for example, solar and wind made up 63% of new capacity additions while gas additions were 29% of the total.

[5]The emissions are calculated by IHS Markit for energy consumption only (about 80–85% of total GHG emissions economy-wide in recent years), thus allowing for consistent historical comparison.

[6]It should be noted, however, that Kazakhstan's planning outlook in many key areas extends only scarcely more than a decade (to 2030), so there is a growing need for a longer term perspective for many sectors of the fuel and energy complex, especially for electric power.



2. GENERAL INVESTMENT CLIMATE IN KAZAKHSTAN

2. GENERAL INVESTMENT CLIMATE IN KAZAKHSTAN

2.1. KEY POINTS

• The stabilization of world oil prices around $50 per barrel since the second half of 2016 has launched a new upstream investment cycle globally. This new cycle, a response to supply growth deceleration resulting from dramatic cuts in capital investment since 2014, has been strengthened by commitments of OPEC and key non-OPEC oil producers to collectively slash output by almost 1.8 million barrels per day (MMb/d) during the first half of 2017 (now extended to March 2018). Annual exploration and production (E&P) spending will rise for the first time since 2014.

• Companies participating in the new investment cycle perceive the opportunity to remain profitable at a much lower price than that prevailing over much of the previous decade. Reflecting an emphasis on reducing oil and gas E&P costs, the focus of new investment thus far has been on projects in which production can respond quickly to price signals (i.e., shorter cycles) and in areas where geology, operating conditions, and host-country environment are known to be favorable, and where infrastructure either already exists or is close at hand.

• IHS Markit forecasts that the growth in demand for hydrocarbons in the world market will reach 115 million barrels per day by 2040, but at the same time a lower level of price equilibrium for crude oil is expected (about $80 per barrel, instead of about $100 per barrel according to the National Energy Report 2015) due to a significant cost reduction of a large oil production segment. Due to the decline in the price equilibrium to $80 per barrel in the long term, the forecast of Kazakhstan's average annual GDP growth rate over the forecast period to 2040 was reduced by 1 percentage point (from 3.4% to 2.4%).

• Another key investment trend globally involved record additions of renewable energy capacity in electric power in 2016 (150 GW), more than for any other form of energy. This is more than half of the total generating capacity added, and reflects falling capital costs and strong policy support for solar photovoltaics and onshore wind. The trend is expected to continue into 2017 and beyond. Although new renewable capacity in electric power is projected to be added more rapidly than other sources on an average annual percentage basis, by 2040 renewable sources of energy will still account for only 5% of total global primary energy consumption, with the aggregate share of coal, oil, and gas still accounting for over three-fourths. In Kazakhstan, as much as 2 GW of renewable energy capacity (wind, solar) could be installed by 2020 (amounting to 3% of total capacity), a ten-fold increase from the 2016 level.

• In Kazakhstan, in response to negative developments in the global oil and gas industry after Q2-2014 (the low oil price environment as well as the stasis in the investment cycle for big upstream projects), gross inflows of foreign direct investment (FDI) contracted by nearly half, falling to $14.8 billion in 2015. The stabilization of oil prices in 2016, however, helped reverse the trend: gross FDI inflows in 2016 increased by 39% to $20.6 billion.

• Kazakhstan's overall score according to IHS Markit's proprietary Petroleum Economics and Policy Solutions Country Ratings and Rankings Module (PEPS)—which measures the country's attractiveness as a destination for FDI in upstream oil and gas development—decreased slightly from 4.6 in Q4-2014 to 4.4 in Q1-2017. The decline was mainly driven by a modest decrease in upstream success (negligible addition of reserves per new field wildcat well) as well as a deterioration of macroeconomic factors (the country's primary fiscal balance deteriorated while real per capita GDP growth fell significantly).

• In contrast, Kazakhstan recently has ascended rapidly in the annual country rankings on the World Bank Group's "Ease of Doing Business Index" (EDB), a widely used ranking of countries according to the degree to which a country's regulatory environment is conducive to the operation of a business. Kazakhstan ranked 35th of 190 countries for 2017; of special relevance to its attractiveness to outside investors, Kazakhstan scores particularly high on the "protecting minority investors" component, ranking third among all countries for 2017. However, it continues to be hindered on general measures of overall investment attractiveness by the relatively low labor skills of the workforce, unpredictability of monetary policy (reflecting pressure on the tenge in the low oil price environment, clarity and predictability of currency control laws), and limited access to financing.

2.2. GLOBAL INVESTMENT TRENDS

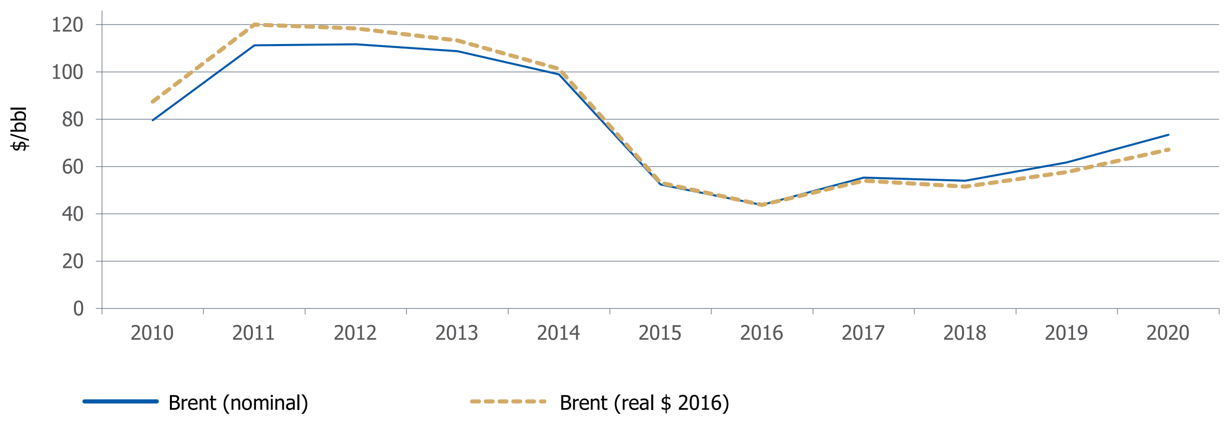
This section briefly reviews major changes in the energy investment environment over the past three years, which have been especially prominent in the oil/gas and electric power sectors. In other sectors, such as coal and uranium, changes in the character of investment have been less dynamic, reflecting a depressed price environment or, in the case of uranium, a rough balancing between new nuclear capacity additions (Asia) and decommissioning (Europe, North America). The overall investment environment for these sectors is discussed in the relevant individual chapters.

2.2.1. Crude oil and liquids production

Global investment in nonrenewable energy in 2017 is only now beginning to recover after more than two years of retrenchment in response to depressed prices for oil, natural gas, coal, and uranium. Investment cutbacks beginning in 2014 were particularly pronounced in oil, where robust supply growth and weakening demand growth had created a surplus of ~1.5 MMb/d on the world market. The ensuing global oil price decline that began in mid-2014 (when prices were above $100 per barrel) reached a bottom in February 2016, with Brent prices rebounding off lows (below $28 per barrel) to levels of above $50 per barrel by early June 2016—a level that has held more or less stable since that time as supply and demand appear to be moving slowly toward a new equilibrium (see Figure 2.1; Figure 2.2; and Figure 2.3).[1]

One factor leading toward that new equilibrium has been the supply growth deceleration resulting from dramatic cuts in capital investment in the industry. Spending in exploration and production in the global oil and gas industry (upstream E&P capex) is estimated to have declined from $706 billion in 2014 to $495 billion in 2015 and $355 billion in 2016 (see Figure 2.4)[2]; according to the International Energy Agency (IEA), upstream E&P capex of ~$600 billion annually is necessary to keep global supply stable over the long term. Cutbacks were especially pronounced in parts of the world where the industry is highly sensitive to price signals, such as North American shale production and offshore North Sea. North American E&P capex plummeted from $328 billion in 2014 to $98 billion in 2016. US production, reflecting a declining rig count among shale producers,[3] fell from 9.6 MMb/d in June 2015 to 8.5 MMb/d by mid-August 2016. Other major producers registering output declines in 2016 included Kazakhstan, China, Mexico, Colombia, Venezuela, Nigeria, and Canada.

Figure 2.1. Dated Brent (FOB North Sea) price outlook to 2020 (base case)



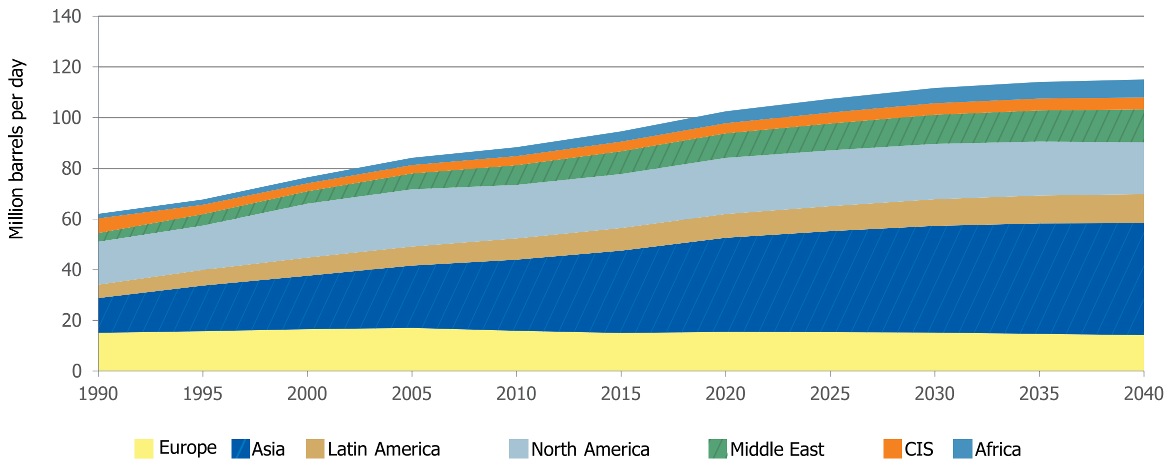
Source: IHS Markit

[1]The US Energy Information Administration (EIA) projects global demand growth of 1.6 MMb/d in each of 2017 and 2018; the production growth forecast for these two years is 1.4 MMb/d and 1.9 MMb/d, respectively. IHS Markit projects demand growth at 1.6 MMb/d in 2017 and 1.7 MMb/d in 2018. This reflects, among other factors, a recovery in refined product demand growth in commodity-exporting countries in the Middle East, Eurasia, and Latin America, due to improved economic conditions prompted by higher oil prices. Rising US and Brazilian production in 2017 in the face of supply cuts elsewhere implies that global oil inventory levels will remain relatively steady on an annual basis.

[2] See IHS Markit, Global Upstream Spending: Market Analysis, 15 February 2017

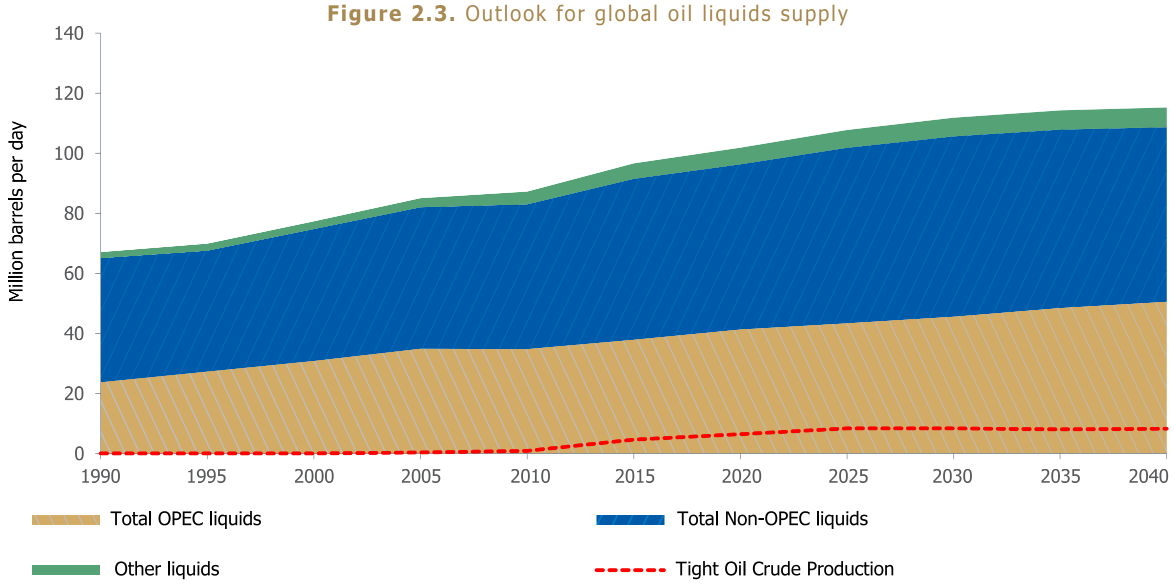
[3]According to Baker Hughes, the US rotary oil and gas rig count fell precipitously, from 1,811 on 2 January 2015 to 885 on 22 May 2015 and 404 on 20 May 2016.

Figure 2.2. Outlook for global oil liquids demand



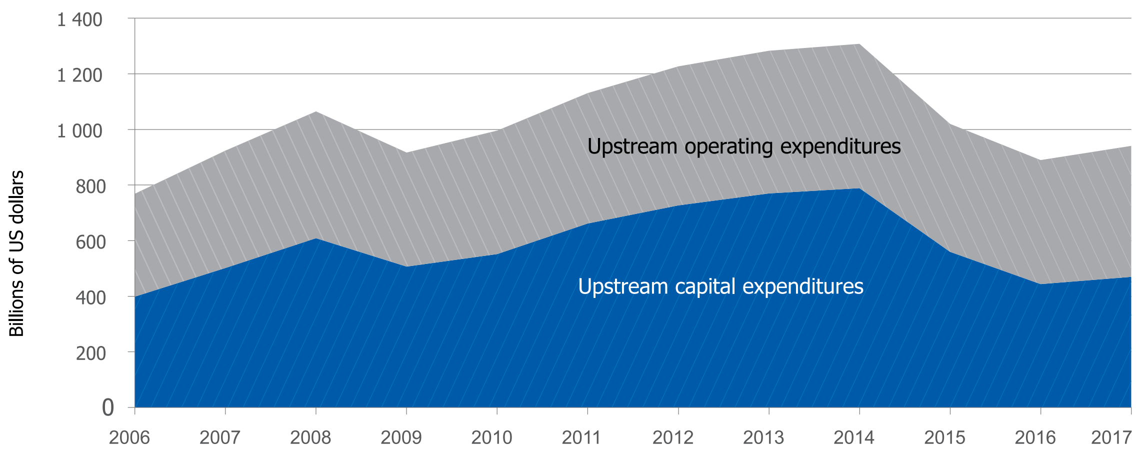
Notes: Liquids include crude, condensate, and NGL. Other liquids include GTL, CTL, biofuels, and other liquids.
Source: IHS Markit

Figure 2.3. Outlook for global oil liquids supply



Notes: Liquids include crude, condensate, and NGL.. Other liquids include GTL, CTL, biofuels, and other liquids.
Source: IHS Markit

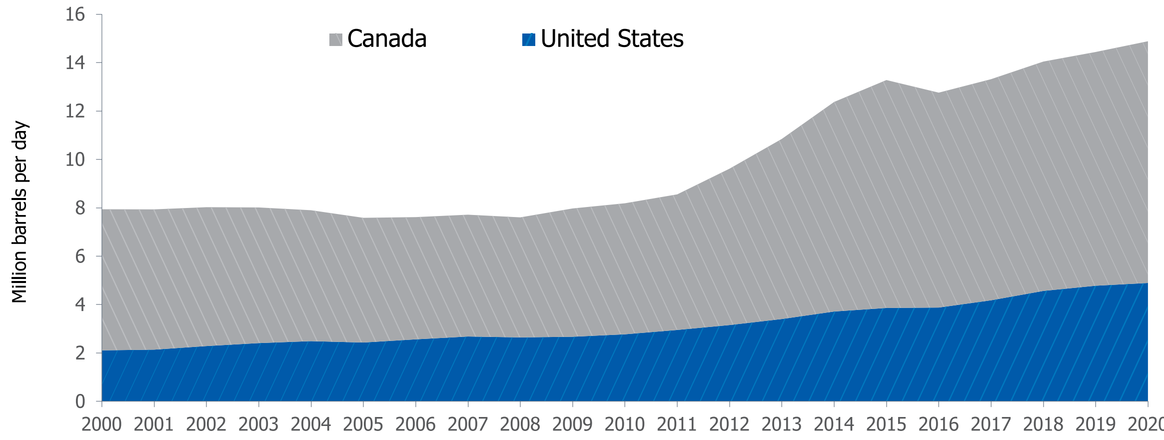
Figure 2.4. Trends in global upstream spending



Notes: Capital expenditures include exploration, development, LNG, and pipelines. Operating costs do not include LNG and pipelines. Figures for 2016 and 2017 are IHS estimates.
Source: IHS Markit

Efforts to preserve capital varied across the industry, but included such strategies as selling assets, cutting dividends, and reducing exploration budgets and staff.[4] Producers also postponed or abandoned exploration and field development in higher marginal cost environments, shut down less productive rigs, became takeover targets, or filed for bankruptcy protection (as have over 120 North American oil and gas producers since the start of 2015) (see Figure 2.5).

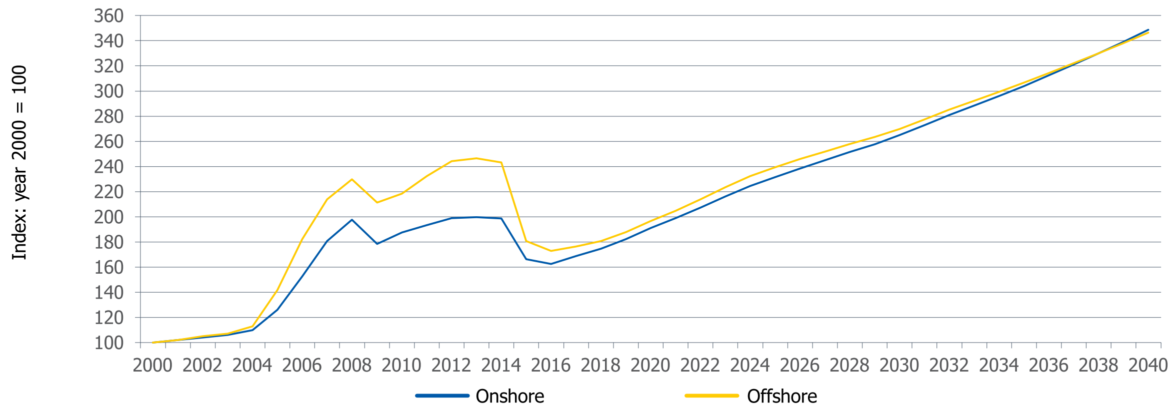
Figure 2.5. North American total liquids production and short-term forecast, 2000-2020



Notes: Liquids includes: Crude, Segregated Condensate, NGL
Source: IHS Markit

It should be noted, however, that not all of the E&P spending reductions reflected negative conditions for the producers. Their payments to oil and gas services providers also declined markedly during the downturn. The IHS Energy Upstream Operating Costs Index recorded a 5% decline in 2016. The index is currently 18% below its peak of second quarter 2014 (see Figure 2.6).

Figure 2.6. Upstream Capital Cost Index (UCCI) based on nominal dollars



Source: IHS Markit

However, the stabilization of oil prices around $50 per barrel since the second half of 2016 appears to have launched a new global upstream investment cycle, strengthened by the commitments of OPEC and key non-OPEC oil producers (in November and December 2016, respectively) to collectively slash output by almost 1.8 MMbd during the first half of 2017 to support prices.[5] On 25 May 2017 the agreement was extended nine months, to March 2018.

The new wave of upstream spending is evident in the

[4]Over 250,000 jobs in the industry worldwide were estimated to have been lost between mid-2014 and 2016.

[5]Although skepticism remains regarding whether the cartel's members will honor these commitments going forward, in April 2017 the IEA issued data indicating 99% compliance with the OPEC reduction target for Q1 2017.

rapid revival of North American shale drilling activity[6] as well as in deals recently concluded by multinational oil companies to develop new fields in Iran and in the Gulf of Mexico. Further evidence of resumption in investment activity is the rising trend in the monthly global oil and gas rig count since December 2014, the month that marked the beginning of the drilling nosedive that lasted into mid-2016. The resumption in upstream spending also is reflected in decisions to proceed with significant expansions at two of Kazakhstan's three major "mega" projects described in Chapter 3. The CC01 plan at Kashagan appears to be a promising way of boosting phase 1 production by an additional 80,000 b/d, to 450,000 b/d, in advance of a decision on phase 2. The FID on TCO's Future Growth Project at Tengiz sets the stage for the addition of 12 MMt/y (260,000 b/d) of field production, with first oil from the expansion expected in 2022.

The number of final investment decisions (FIDs) world wide on major projects is expected to rise in 2017, and IHS Markit specialists foresee E&P capex rising modestly (by 2.9%) to $365 billion. That anticipated 2017 expenditures are only slightly more than half those in 2014 suggests not only a more cautious approach over the near term but likely also a fundamentally different strategy in an environment of $50 oil. It will take some time for activity to recover to 2014 levels, with upstream E&P capex in 2021 expected to remain 19% below 2014 levels in nominal terms.

Companies participating in the new investment cycle expect to achieve profitability at a much lower price than that prevailing over much of the previous decade, with consequences for projects based on higher-cost reserves.[7] In part this reflects long-term calculations of increasing competition from renewable sources of energy, the prospect of reaching "peak demand" at some point in the future, or even the necessity of leaving some reserves "in the ground" should the political impetus toward reducing carbon emissions be strengthened. These long-term concerns, as well as the uncertainty of price movements over the near term, place a greater emphasis on economies and cost reductions in current operations than on reserve replenishment. Although only general trends in the new investment cycle are emerging, at least three can be identified that deserve greater scrutiny: cycle length (time between FID and first output); geography; and technological approaches to boosting operating efficiency.

First, the focus thus far in the new investment environment seems to be on projects in which production can respond quickly to price signals (i.e., shorter cycles). An example would be the North American shale producers, who can ramp production up or down rapidly by adding or shutting down wells at existing fields, as opposed to greenfield mega-projects with long-term payouts and a degree of notoriety for logistical problems and cost overruns.[8] Chevron, which will cut its capital spending for the fourth consecutive year in 2017, plans to focus on projects that will produce first oil within two years. Similarly, ExxonMobil's acquisition of a 275,000 acre tract in the Permian Basin in west Texas/eastern New Mexico mid-January 2017 is designed to increase the share of oil and gas in its portfolio that can be brought on stream rapidly in the current price environment. In Kazakhstan, by contrast, much of "new" production involves long cycles, together with challenging geological and field (offshore) conditions.

Second, the geography of recent investment thus far favors areas near or adjacent to productive fields, where some combination of geology, operating conditions, and host-country environment are known to be generally favorable, and where infrastructure either already exists or is close at hand. A good example is BP's plan to invest $9 billion to install a second platform at its Mad Dog field in American waters in the Gulf of Mexico, and the company's bid (along with many other majors) for exploration and production licenses in nearby Mexican waters. The Gulf is familiar territory to these companies and affords ready access to large markets. Similarly, the most important recent investment decision in Kazakhstan—the FID on the Future Growth Project at Tengiz in July 2016—involves expansion of production at an existing field. Conversely, greenfield projects more remote from major markets, or where operating conditions present challenges or uncertainties, have recently been cancelled (e.g., Shell's departure from the Arctic offshore Alaska in 2015; BP's decision to leave a joint venture with Statoil to explore the Great Australian Bight off Australia's southern coast in 2016) or postponed.

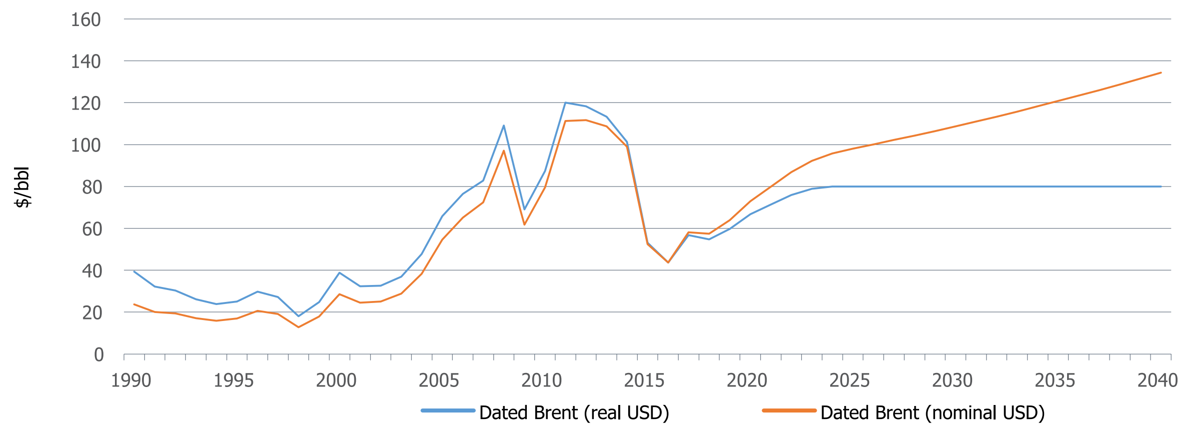
Finally, there is an effort among oil and gas industry executives to see whether experience in other industries (ranging from information technology to aviation and automobile manufacturing) can be employed to increase production efficiencies by economizing on labor and streamlining equipment inventories. Among these initiatives are efforts to utilize advanced technologies of supply chain management to optimize inventories of parts and equipment, to expand wireless data collection in seismic exploration, and to increase the role of automation in well and tank monitoring. Examples of specific applications might include, for example, the use of drones and robots for simple tasks in dangerous environments; the collection of real-time data from well sensors (examined remotely at field headquarters offices) for use in adjusting the speed and pressure of drilling; and the development by Baker Hughes, a US services company, of an automated drill bit capable of self-adjustment, depending on the characteristics of the rock strata it is penetrating. Producers are also finding various ways to reduce the number of days it takes to drill a well, or increasing its efficiency by increasing the lateral length of wells or higher proppant intensity.

Although there has been a rapid rebound in unconventional production in North America in response to rising prices (with US output rising to 9 MMb/d in March 2017), signs also are emerging of a nascent recovery in deepwater, largely as a result of cost reductions in rig rates, high-grading, improved well performance, and scalebacks in project design. Deepwater project costs have fallen by more than 20% since 2014, with 5 billion barrels of oil and gas equivalent globally now developable at breakeven prices of $50 per barrel of oil equivalent (boe), assuming a 15% internal rate of return (IRR).[9] Offshore E&P capex had reacted more slowly to the market downturn, as spending was maintained by ongoing projects that were initiated prior to the collapse in oil prices (owing to generally longer offshore project lead times). Nonetheless, some smaller independent producers exited the offshore space during the period of below-$50 oil, leaving the most cost-competitive offshore projects in the hands of a select group of majors (Petrobas, Chevron, ExxonMobil, Shell, BP, Total, and Statoil), who are now in a good position to launch new production in the near future. Three offshore projects (Mad Dog [noted above] and Kaikias in the US Gulf of Mexico and Leviathan offshore Israel) have been sanctioned thus far in 2017.

Revised IHS Markit Projections for Global Oil Prices and Demand

Of major relevance for future investment decisions in Kazakhstan's oil sector and for GDP growth more broadly are downward revisions in IHS Markit forecasts for global oil prices and demand. Instead of averaging ~$80/bbl over the near term (2017–20) and in the $100–$105 range over 2021–40 as envisaged in NER 2015 (p. 60), our revised projection shows average Brent crude prices reaching the $80/bbl level only in the mid-2020s, after which the price remains relatively stable in constant 2016 dollar terms out to the end of the forecast period (see Figure2.7).

Figure 2.7. Long-term crude oil price outlook



Source: IHS Markit; Historical Prices: Argus Media Limited

The key assumptions underlying the revised price forecast are lower E&P cost inflation, as well as reduced marginal costs of E&P through efficiency gains derived from technological advances. More specifically, global liquids demand is now projected to reach roughly 108 MMb/d by 2025, and grow to 115 MMb/d by 2040. In combination with this slower demand growth, the E&P cost curve has now been recalibrated at a lower level. The marginal demand barrel is now expected to require a Brent price of only ~$80 to cover full-cycle costs (falling from ~$90–100/bbl in the previous forecast) (see Figure 2.8). In this more competitive environment, only a few of non-OPEC countries (US, Canada, Russia, Kazakhstan, and Brazil) are expected to contribute material output growth.

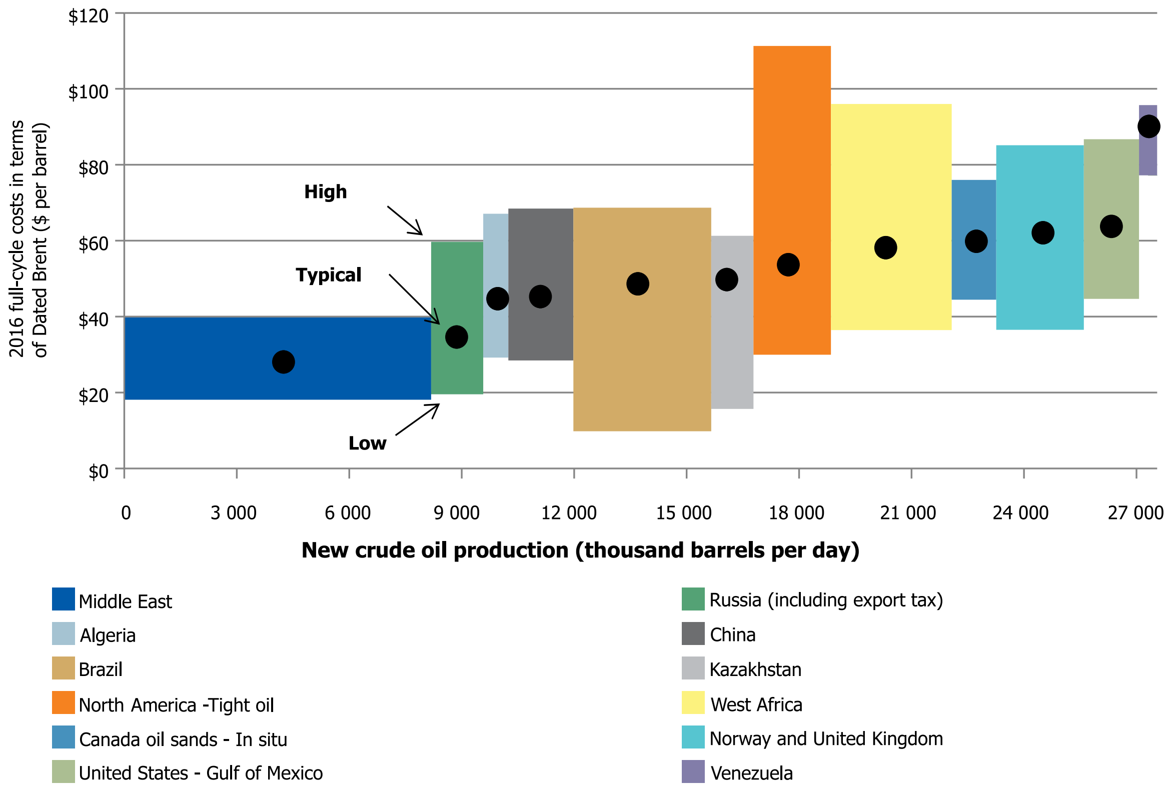
[6]For the week ending 3 June 2016, the US rotary oil and gas rig count rose for the first time in 41 weeks, to 408 units, after which it has increased more or less steadily through the spring of 2017. For the week ending 16 June 2017, the count stood at 933.

[7] ExxonMobil, for example, removed more than 4 billion barrels of North American crude (Canadian oil sands) from its proved reservesbecause they are too expensive to develop profitably in the new price environment.

[8] See "Megaprojects: The Problem Big Oil Can't Solve," Petroleum Intelligence Weekly, 6 October 2014.

[9]This compares with 15 billion bbloe of land-based tight oil resources in undrilled wells.

Figure 2.8. Cost curve of global crude oil supply from new projects in select areas to 2030

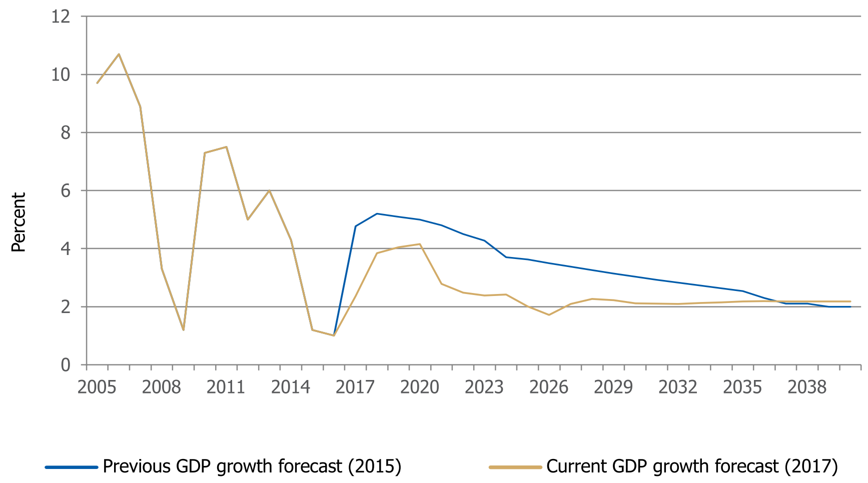


Note: This cost of oil is expressed by the Dated Brent price necessary for projects to "break even," assuming a 10% IRR. The break-even cost estimates are for greenfield projects. The low- and high-cost projects are chosen from among the more than 600 that IHS has modeled or our cost of oil analysis. For North American tight oil, the cost estimates are for subplays. The supply outlook is consistent with the IHS 2016 Global Crude Oil Markets Annual Strategic Workbook, released in April 2016. For each region, the supply additions are gross additions in 2016–30 from new projects, which are calculated by summing the maximum annual production of sanctioned projects, of unsanctioned projects, and of yet-to-find (YTF) categories for the areas. Exceptions are North American tight oil, the tight oil components of other producing areas, and Canadian oil sands, all of which are simple net additions. The global supply shown represents more than 70% of all global supply from new projects , as calculated by the method explained above. New global supply from new projects in all producing areas is not shown, in part so as not to reduce clarity of the figure. The break-even cost estimate for in-situ Canadian oil sands is based on a steam-assisted gravity drainage (SAGD) project. The Middle East includes Saudi Arabia, Kuwait, United Arab Emirates, Iraq, Iran, Oman, Qatar, and Bahrain. West Africa includes Nigeria and Angola. Break-even costs for groups of countries are weighted by volume.

Source: IHS Markit

A major consequence for Kazakhstan of an outlook for a mean Brent price that is "lower for longer" is that our forecast for the country's GDP growth has been moderated. More specifically, the lower long-term oil price expectation (and lower global prices for other key export commodities) knocks a full percentage point off Kazakhstan's projected annual GDP growth over the forecast period: 2.4% versus 3.4% (see Figure 2.9).

Figure 2.9. Kazakhstan's GDP growth rate has been reduced

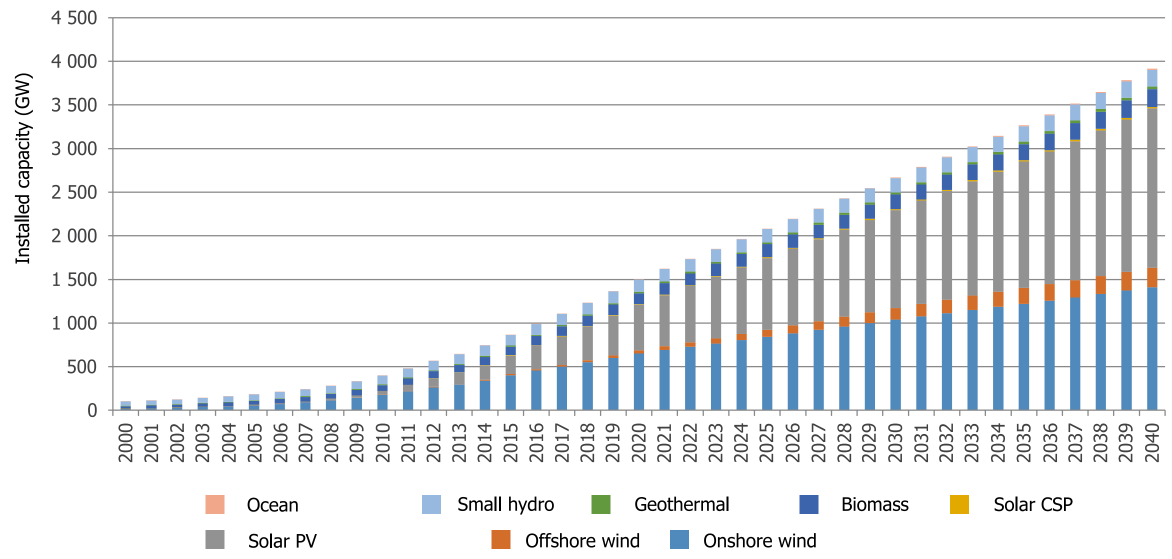


Source: IHS Markit

2.2.2. Electric power and the role of renewable energy

Another key development in overall global energy investment trends is the dramatic growth in renewable energy capacity. There were record additions of renewable energy capacity globally in 2016 (150 GW, 87% of which were wind and solar), more than for any other form of energy, reflecting strong policy support for solar photovoltaics and onshore wind and falling capital costs, especially for solar (see Figure 2.10)[10]. Renewable capacity accounted for more than half of total generation capacity added, and the trend is expected to continue in 2017. While climate change mitigation is a powerful driver for renewables, it is not the only one. In many countries, cutting deadly air pollution in urban areas and diversifying energy supplies to improve energy security play an equally strong role in growing low-carbon energy sources, especially in emerging Asia. This growth has come in part at the cost of new natural gas–fired capacity. Although gas has considerable advantages in terms of flexibility, reliability, and—in certain markets—cost, new gas investments are lagging behind investments in renewables. In the United States in 2016, for example, solar and wind made up 63% of new capacity additions while gas additions were 29% of the total. [11]

Figure 2.10. Global cumulative installed renewable capacity by technology, 2000 -2040



Source: IHS Markit

In many countries of the world, the accelerated development of renewable energy has been accompanied by a shift in financing mechanisms, away from more costly (fixed) feed-in tariffs (FITs) and in the direction of capacity auctions/tenders, which are believed to afford a more cost-effective way of supporting renewable energy development (as detailed in NER 2015). This trend is particularly noticeable in Asia.[12] For instance, India issued tenders of more than 7 GW of solar and wind capacity in 2016 under national- and state-level schemes. Meanwhile, the Chinese central government lowered onshore wind and utility-scale solar FITs (by 5–15% starting in 2018 for wind and by 13–19% starting in 2017 for utility-scale photovoltaics [PV]) and has begun trials of competitive auctions for utility-scale solar PV. In late 2016 Japan announced plans to cut FITs annually over a three-year period and plans to switch to an auction-based procurement system in 2017, and in Australia the launch of several large-scale tenders (focusing on PV and storage) was part of a program to restore confidence in overall market potential. In the Middle East, Jordan and Dubai increased their solar targets, while tenders proceeded. And Saudi Arabia confirmed its commitment to a revised 2030 renewable target by announcing new tenders.

In Latin America, progress is more challenged, as Brazil canceled both wind and solar tenders in 2016, creating uncertainty for developers and financiers. The first reserve energy auction (LER) was delayed repeatedly but was finally canceled at the end of 2016. The second LER has also been delayed, and will seek offers from solar and wind projects starting in 2019. Mexico's second renewable energy tender showed fierce competition for renewable contracts. Twenty-three winners were selected by Centro Nacional de Control Energía (CENACE) for long-term energy contracts and clean energy certificates (CELs) in the October 2016 tender. The average price for both wind and solar dropped by 30%, to US$33.47/MWh, from the previous tender. Mexico is still expected

[10] The previous years, 2015 and 2014, also set records for new capacity additions—147 and 120 GW, respectively. The falling costs primarily reflect economies of scale, increased supply of raw materials, and technological improvements.

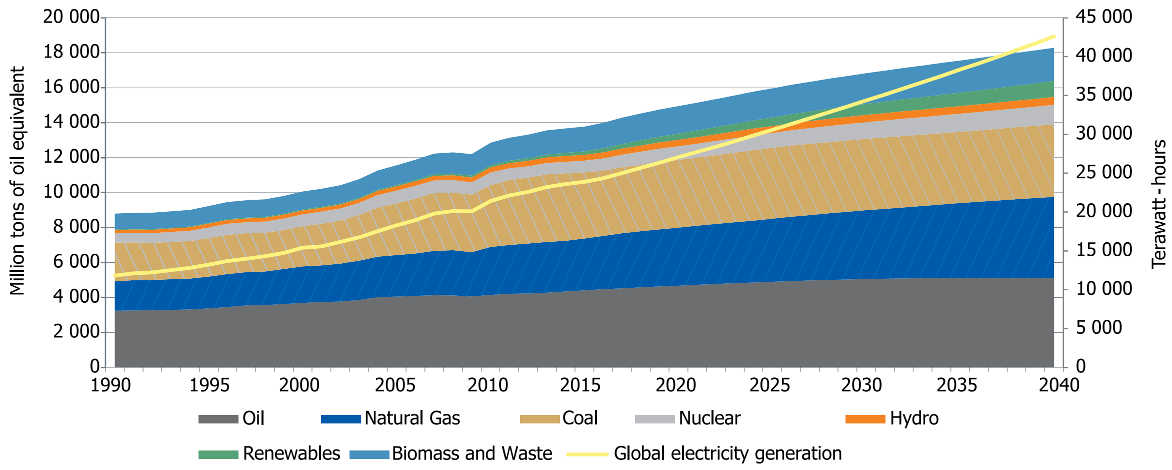
[11] In terms of new capacity additions, solar and wind capacity additions dominate the medium-term outlook, thanks to US tax credit extensions for renewables. Gas capacity additions will likely peak in 2017-18, as the bulk of gas projects replacing coal assets were already completed and commissioned.

[12] See IHS Markit, Power and Renewables, Renewable Policy Trends in Emerging Markets, Market Update, April 2017.

to announce a third auction in 2017 for power, capacity, and CELs.

Despite the rapid pace of the renewable energy build-out, it is important to keep in mind that traditional hydrocarbon sources will continue to support the bulk of global energy consumption for many years to come, at least out to the end of our projection period. By 2040, renewable sources of energy will account for only 5% of total global primary energy consumption, with the aggregate share of coal, oil, and gas still accounting for over three-fourths (see Figure 2.11). However, the picture will vary widely in different parts of the world, with some regions (e.g., Europe) relying on renewable energy to play a much greater role, whereas in others natural gas (US, Kazakhstan) or natural gas and nuclear power (China) are expected to account for most incremental energy consumption (see Figure 2.12, Figure 2.13, 2.14., 2.15). Focusing more narrowly on future global electricity generation, the expanding role of renewables is more evident. By 2040 wind and solar generation are expected to account for 8% and 6%, respectively, of total generation, as their costs become increasingly competitive with traditional sources of electric power (see Figure 2.16 and Figure 2.17). Even here, however, it is important to note that: (a) the economics of renewables is much more complicated than simple comparisons of the levelized cost of electricity (LCOE) would suggest; (b) renewable capacity additions still require policy support; and (c) intermittent renewable power technologies alone will not reliably provide all the capacity and energy demanded by consumers.

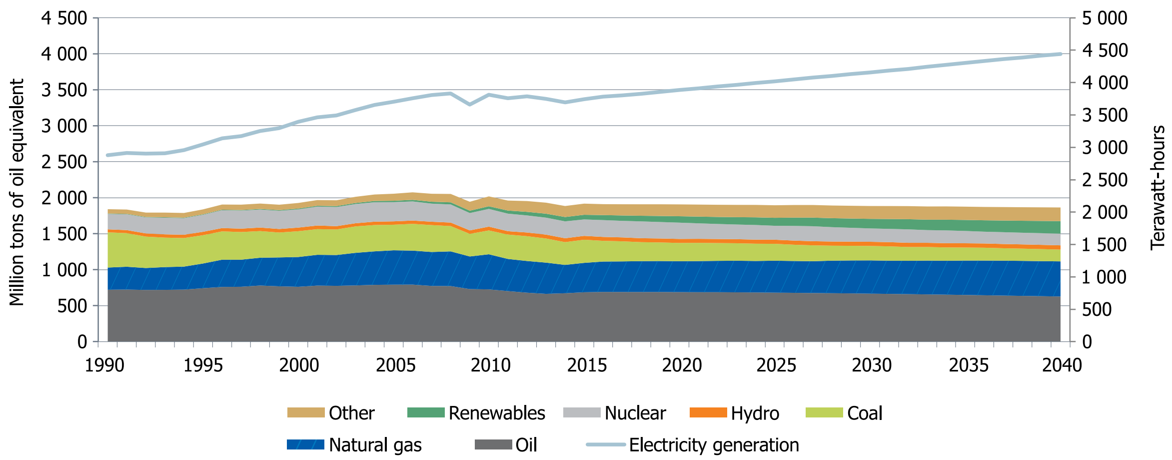
Figure 2.11. World's primary energy consumption by fuel



Notes: Renewables include solar, wind, geothermal, and tide/wave/ocean energy. Other includes biofuels, solid waste, biomass, and net trade of electricity and heat.

Source: IHS Markit

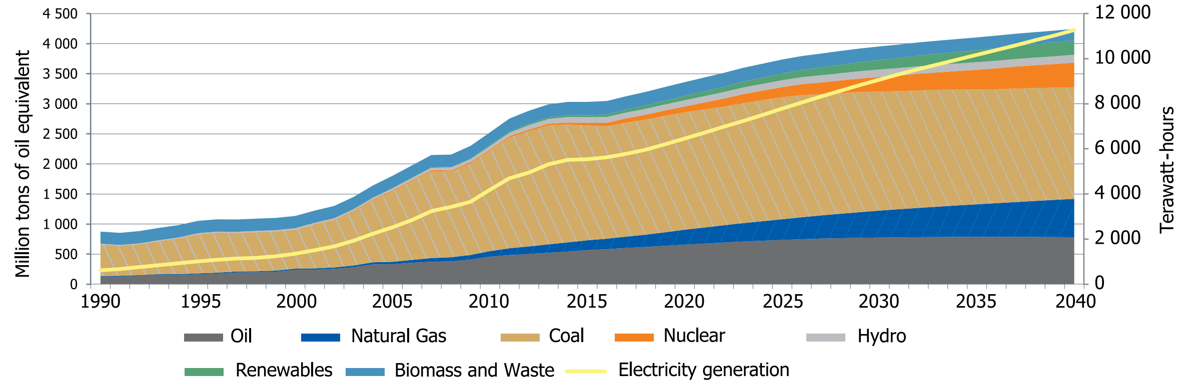
Figure 2.12. Europe's primary energy consumption by fuel



Notes: Renewables include solar, wind, geothermal, and tide/wave/ocean energy. Other includes biofuels, solid waste, biomass, and net trade of electricity and heat.

Source: IHS Markit

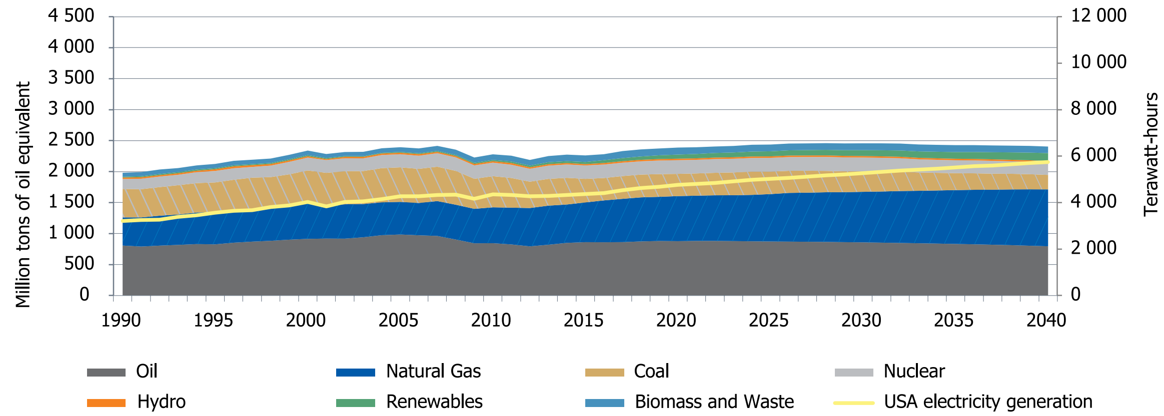
Figure 2.13. China's primary energy consumption by fuel



Notes: Renewables include solar, wind, geothermal, and tide/wave/ocean energy. Other includes biofuels, solid waste, biomass, and net trade of electricity and heat.

Source: IHS Markit

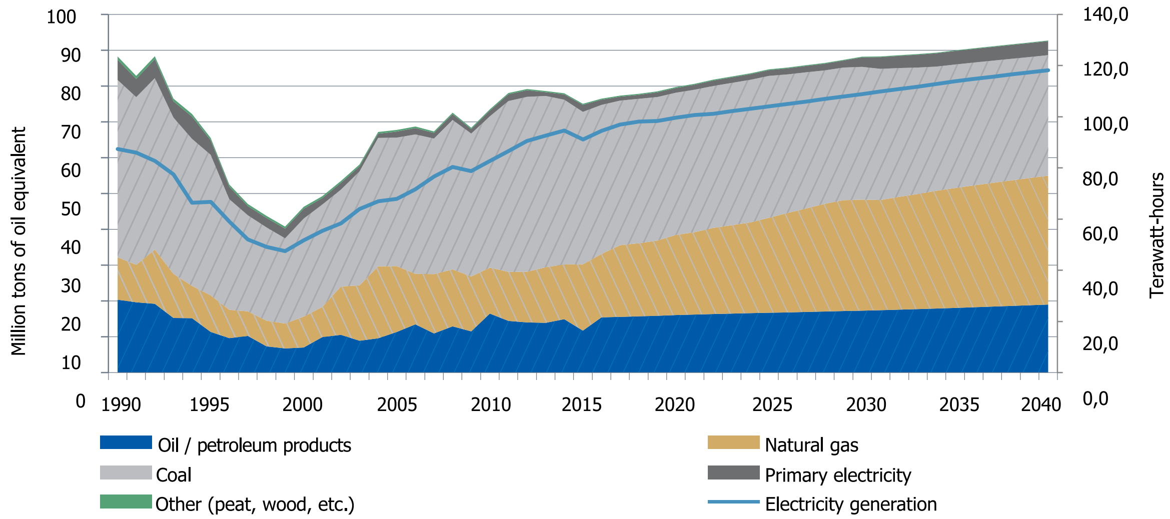
Figure 2.14. United States' primary energy consumption by fuel



Notes: Renewables include solar, wind, geothermal, and tide/wave/ocean energy. Other includes biofuels, solid waste, biomass, and net trade of electricity and heat.

Source: IHS Markit

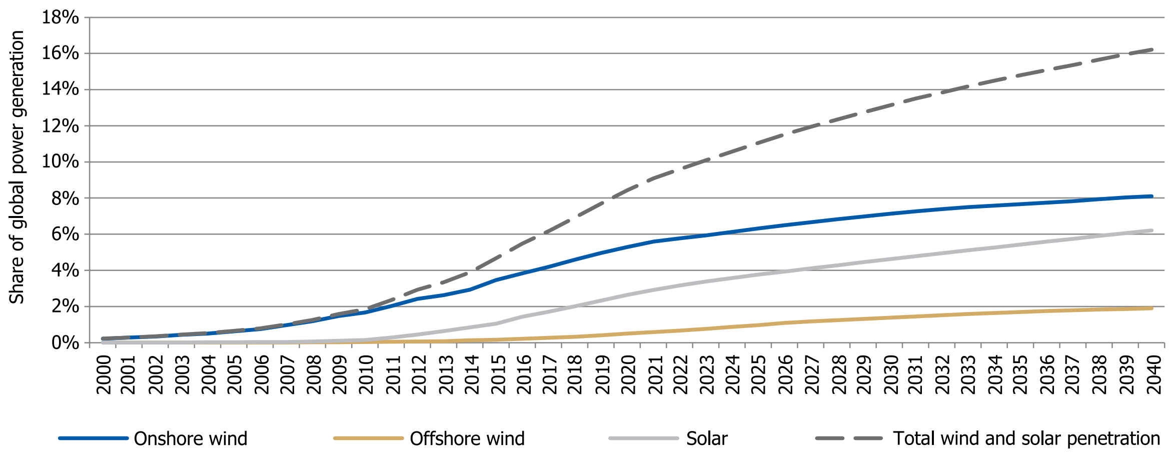
Figure 2.15. Kazakhstan's primary energy consumption by fuel



Notes: Renewables include solar, wind, geothermal, and tide/wave/ocean energy. Other includes biofuels, solid waste, biomass, and net trade of electricity and heat.

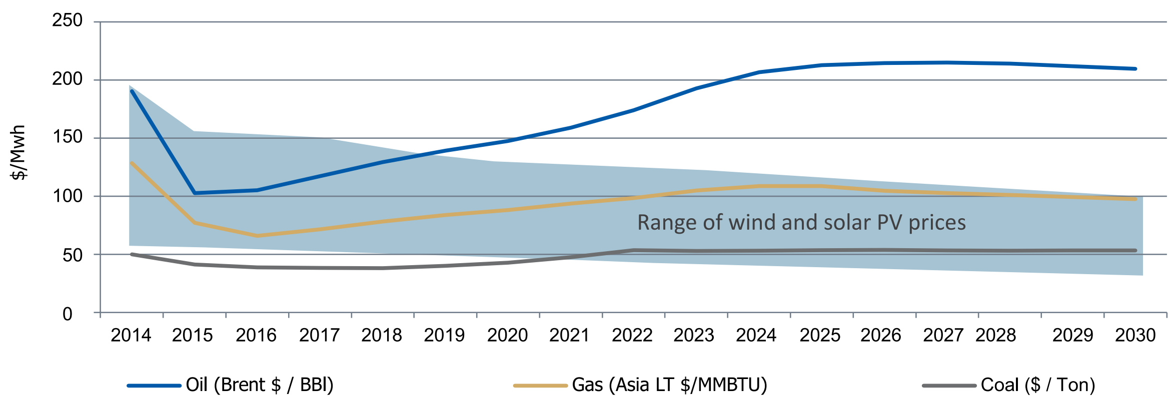
Source: IHS Markit

Figure 2.16. Share of total power generation from wind and solar, 2000-2040



Source: IHS Markit

Figure 2.17. Marginal price of coal-, LNG-, and oil-fired generation relative to wind and solar prices



Source: IHS Markit

2.3. OVERVIEW OF KEY INVESTMENT TRENDS IN THE FUEL AND ENERGY COMPLEX OF KAZAKHSTAN

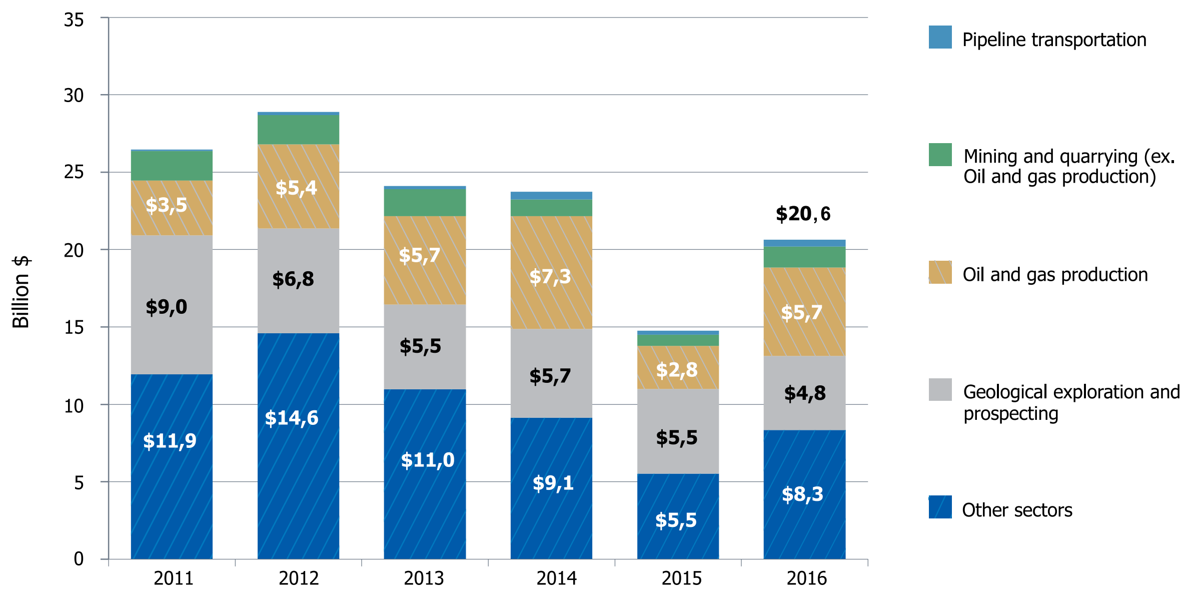
Foreign investment contributes greatly to economic development in emerging economies such as Kazakhstan's. Even though it generally accounts for a relatively small share of gross investments, it is a key means of obtaining technologies, capital, management skills, and access to export markets. Kazakhstan's success in attracting substantial inflows of foreign investment in the years since independence has accelerated the country's national development and the overall transition to a market economy, especially in the energy sector. Initially, during the Soviet period, the only available form for investment by foreign nationals were joint ventures, but Kazakhstan has established a variety of other vehicles, including wholly owned foreign subsidiaries and equity investment in domestic firms.

For Kazakhstan's energy sector, the importance of foreign direct investment (FDI) is that it allows the country to utilize its enormous resource potential by carrying out projects that otherwise simply could not have been realized, either because of their scale or their technical challenges. Specifically, such operationally and technologically challenging projects as Kashagan, Karachaganak, or Tengiz all required engineering and managerial capabilities available only outside of Kazakhstan, found largely in the leading international oil companies (IOCs). In turn, the expenditures on these projects in-country have driven expansion and change in many other supporting sectors across the economy.

Total gross inflows of foreign direct investment (FDI) in Kazakhstan's economy has increased from $1.3 billion in 1993 to a peak of $29 billion in 2012 before decreasing slightly to $24 billion in 2013-14. The total stock (cumulative amount) of direct foreign investment for the entire economy since 1993 had reached $241.9 billion by the end of 2014. However, in response to negative developments in the global oil and gas industry after Q2-2014, gross FDI inflows into Kazakhstan's economy contracted by nearly half, falling to $14.8 billion in 2015 (see Figure 2.18). The low oil price environment and the downturn in the investment cycle hit foreign investment flows into two sectors particularly hard in 2015: investments into oil and gas production declined by $4.5 billion to $2.8 billion, while investments into exploration fell by $0.2 billion. This decrease explains half of the overall gross FDI decline. Other sectors of the economy that experienced lower FDI inflows include manufacturing (primarily the metallurgical sector with a $1.2 billion decline) and trade (a decline of $1.3 billion). The stabilization of oil prices in 2016 reversed the trend: gross FDI inflows increased by $5.8 billion to $20.6 billion, driven by FDI into oil and gas production (a $2.9 billion increase) and other sectors (manufacturing and trade; a $2.8 billion increase).

[13]FDI is a widely used indicator for assessing the inflow of foreign investment into the national economy. According to the generally accepted methodology of the International Monetary Fund, FDI refers to the investment of a resident of one country into a company that is a resident of another country with the aim of acquiring a stake (and earning a profit) for a long period. For the threshold value that separates direct investments from portfolio investments, a share of 10% is accepted. The statistical data used in the preparation of this chapter of the Report collected and published by the National Bank of the Republic of Kazakhstan reflect the acquisition by foreign investors of more than 10% of voting shares, their share in reinvested (undistributed) profits, and the gross increase in the debt burden of such enterprises.

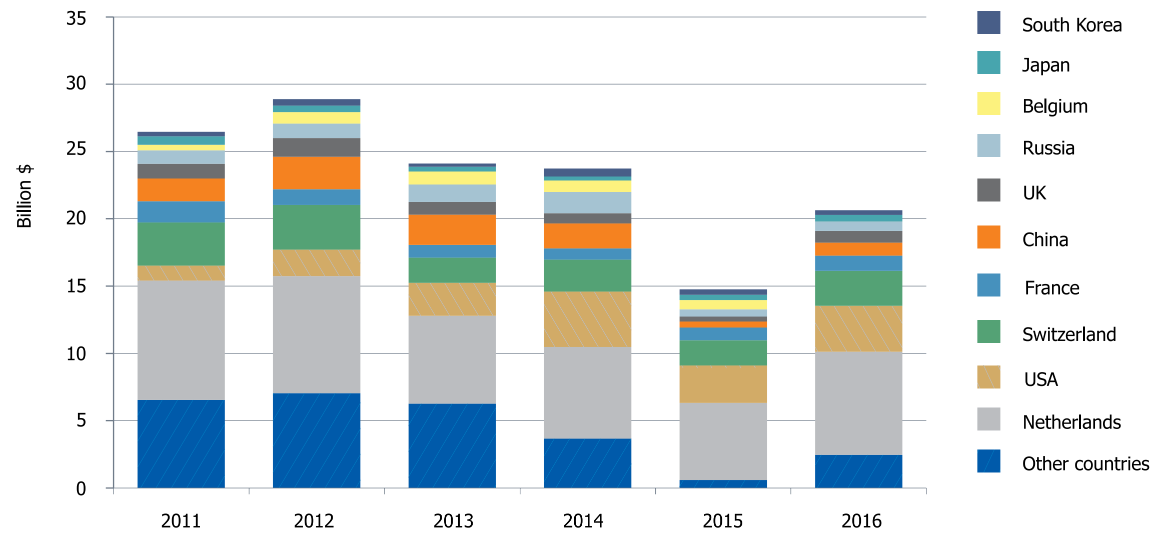
Figure 2.18. Gross FDI flows to Kazakhstan's oil and gas production and exploration



Source: National Bank of Kazakhstan, IHS Markit

In terms of individual investor countries, the Netherlands retained its lead-investor position. It was responsible for roughly two-thirds ($7.7 billion) of overall FDI inflows in 2016, compared to 29% ($6.8 billion) in 2014 (see Figure 2.19). This is explained by the fact that operators of major projects like Kashagan and Karachaganak are companies registered in the Netherlands.

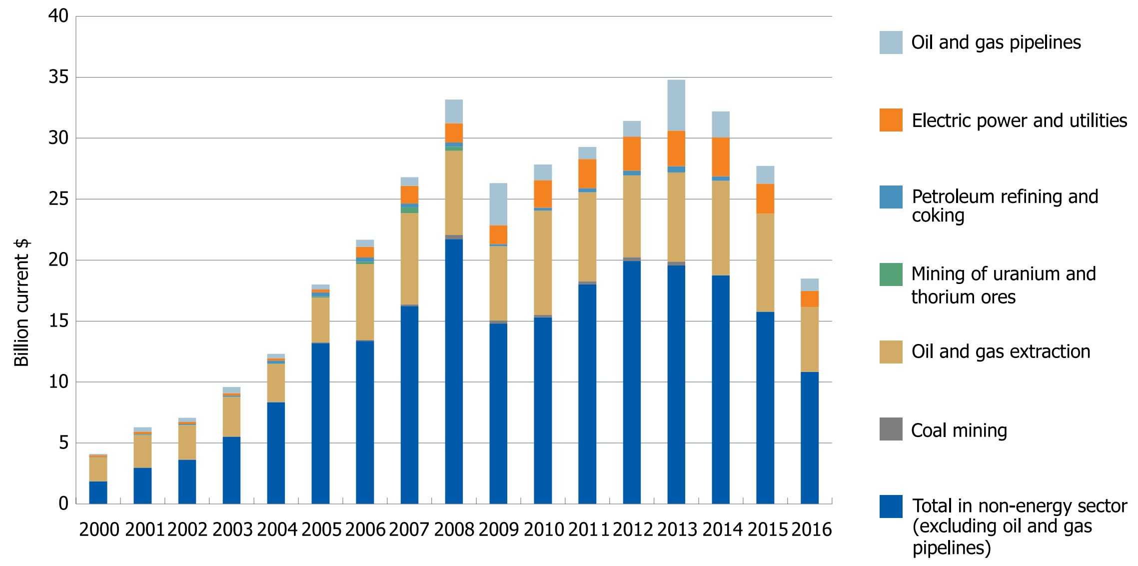
Figure 2.19. Gross FDI flows to Kazakhstan by investor country



Source: National Bank of Kazakhstan, IHS Markit

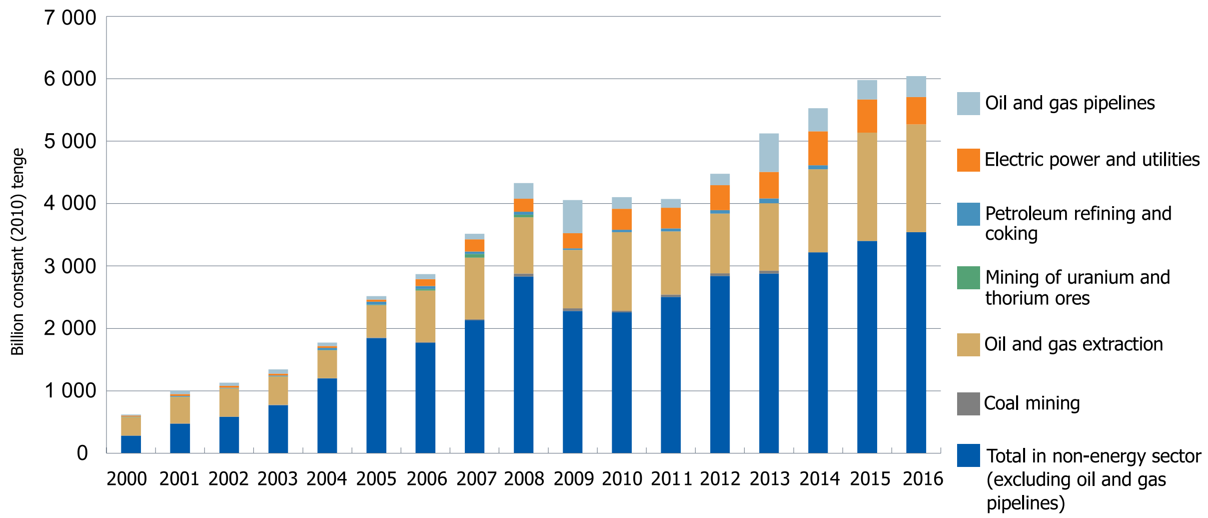
Investments in fixed capital—i.e., investment in durable (fixed) assets such as buildings, machinery and equipment, or other infrastructure or structures that a firm holds for at least one year—fell sharply in current dollar terms (by roughly 43%) during 2014–16, a decline enhanced by the depreciation of the tenge against the dollar in 2015 and 2016 (see Figure 2.20). However, fixed capital investment in (constant) local currency terms rose by 25% relative to 2014, to 6 trillion tenge in 2015 and 2016 (see Figure 2.21). About two-thirds of this increase was driven by three sectors within the broader "industry" category: oil and gas extraction, mining and exploration services, and petroleum refining. The share of fixed investment in the oil and gas sector rose from 18.4% of the total economy in 2013 to 23.4% in 2016.

Figure 2.20. Total investment in fixed assets in Kazakhstan's economy - current US dollars



Source: IHS Markit, Statistical Committee of RK

Figure 2.21. Total investment in fixed assets in Kazakhstan's economy - constant (2010) tenge



Source: IHS Markit, Statistical Committee of RK

The ratio of net FDI inflows to GDP (a variable used by the World Bank to compare world economies) for Kazakhstan increased from 3.2% in 2014 to 3.6% in 2015, after averaging 5.7% during the period between 2010 and 2013 (prior to the world oil price collapse in 2014). For other hydrocarbon producing

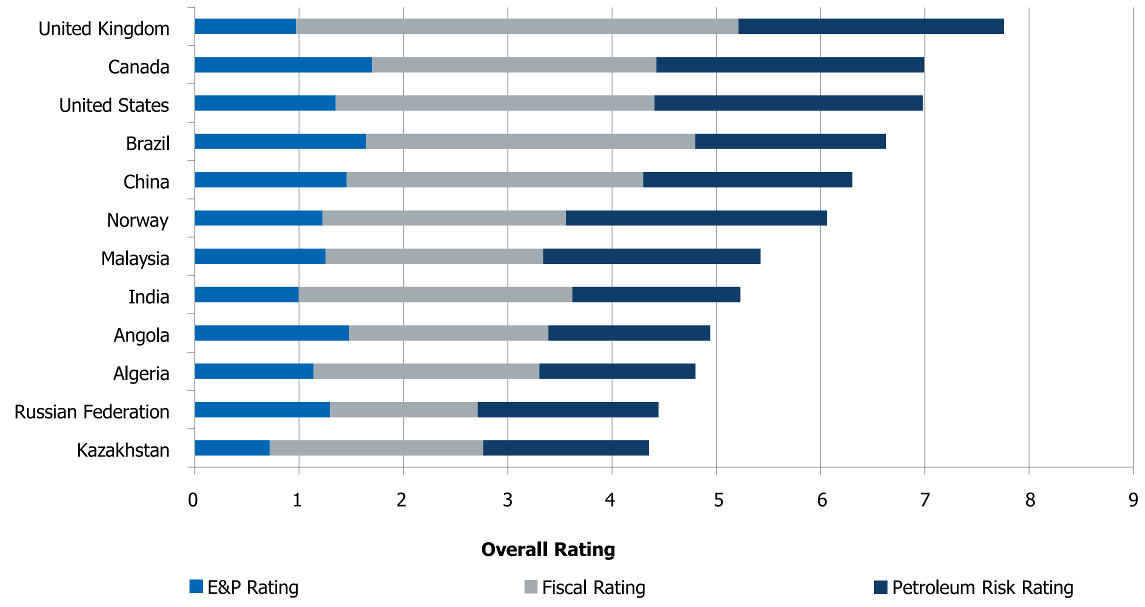
countries of the region, Azerbaijan's FDI inflows as a share of GDP picked up as well, increasing from 5.9% to 7.6% during the same period, which reflects the continuing implementation of key upstream projects, including Shah Deniz Stage 2. The FDI to GDP ratio in Turkmenistan and Uzbekistan increased by 2.3 and 0.6 percentage points, respectively, to 11.9% and 1.6%, driven by multiple upstream and refining projects involving foreign investors. At the same time, the ratio in Russia decreased from 1.1% in 2014 to 0.5% in 2015 largely due to imposed international sanctions. These FDI dynamics demonstrate that investor interest in the region continues, albeit at a moderated pace, especially with regard to specific major projects. Such dynamics also speak to the existing competition for FDI between countries.

2.4. KAZAKHSTAN'S FUEL AND ENERGY COMPLEX INVESTMENT ATTRACTIVENESS UPDATE

2.4.1. IHS Markit PEPS country ratings and rankings module

The assessment of Kazakhstan's investment attractiveness dynamics in 2015 and 2016 is based on the IHS Markit PEPS (Petroleum Economics and Policy Solutions) Country Ratings and Rankings Module (CRRM) that ranks various countries by overall exploration and production attractiveness. The module uses over 50 variables under three key categories—Recent E&P Activity, Fiscal Attractiveness, and Petroleum Sector Risk—weighted at 20%, 50%, and 30% (respectively)—to produce overall country scores. The scores are updated on a quarterly basis (see Figure 2.22).

Figure 2.22. IHS Markit PEPS Country Ratings and Rankings, Q1 2017



Notes: To produce the overall rating for each country, ratings of each type are weighted as follows: E&P 20%, Fiscal 50%, Petroleum Risk 30%

Source: IHS Markit

The Fiscal Attractiveness category considers eight fiscal factors, each modeled under a country's fiscal regime for three groups of hypothetical oil fields—marginal, economic, or upside. These groups are formed by considering economics (on a gross project basis—i.e., before government involvement) for six hypothetical fields with a preselected size of reserves first under three development cost scenarios, and then under three market price scenarios.

The Recent E&P Activity category provides an assessment of the country's upstream potential. It includes four groups of factors: country's production of oil and gas, remaining reserves of oil and gas, upstream activity, and upstream success (the two latter factors are assessed over the last five years). The upstream activity group includes such factors as the number of new field wildcats (NFW) drilled, new licenses awarded, and the number of active companies. Upstream success is evaluated using four factors: reserves added for oil and for gas, success rate of NFW, as well as reserves added per NFW.[14]

The Petroleum Sector Risk category's objective is to help assess whether the expected rewards from oil and gas projects will be commensurate with the associated above-ground risks. Five groups—Politics, Economics, Hydrocarbon Sector Entry, Hydrocarbon Sector Operations, and Hydrocarbon Sector Shocks—contain 21 risk factors, most of which are based on qualitative judgements.

Kazakhstan's overall PEPS score decreased from 4.6 in Q4-2014 to 4.4 in Q1-2017. Kazakhstan's overall ranking is generally low, in the bottom quartile, and its relative standing is declining over time. Among other peer countries, a decrease in the overall score during the same period is observed for the United States (by 0.4 to 7.0), Norway (by 0.3 to 6.1), Canada (by 0.2 to 7.0), and Angola (by 0.2 to 4.9), while countries that increased their overall score include the UK (by 1.0 to 7.8), Russia (by 0.2 to 4.4), and China (by 0.1 to 6.3).

• Among the three key categories utilized to compile the PEPS, Recent E&P Activity declined most steeply for Kazakhstan, falling from 4.2 in Q4-2014 to 3.6 in Q1-2017. The decline was mainly driven by a decrease in the Upstream Success group of factors, as the addition of reserves per NFW during this period was negligible.

• Fiscal Attractiveness category's score remained at 4.1 during the same period, as the higher export duty (as the result of replacing a flat rate with a new formula tying the duty to the oil price on the global market in 2016) lowered the tax base, thus softening the overall financial impact

• Kazakhstan's Petroleum Sector Risk score decreased from 5.6 to 5.3. This decrease was driven by macroeconomic factors, as the country's primary fiscal balance deteriorated while real per capita GDP growth fell significantly. In contrast, improvements were registered in scores for Sanctity of Contract, (lack of) Political Violence, International Openness, and (reduction in) Civil Society and Export Risk.

• Although the Fiscal Attractiveness category did not contribute to Kazakhstan's falling PEPS score, foreign operators in Kazakhstan's oil and gas industry remain concerned over a tax system that continues to allow a relatively high government take and in which frequent changes (some retroactive) erode confidence in tax stability (these were among the main challenges to investor attractiveness identified in the IHS proprietary Index for Oil and Gas Industry Investment presented in Chapter 5.3 in The National Energy Report 2015). There also are concerns about specific regulations, including the volume of permitted TUGF (technically unavoidable gas flaring) on steady state operations, which foreign operators argue should be increased from the current 0.5% to at least the international industry benchmark of 1-2%. They also are wary of certain provisions within the proposed-Law "On Currency Regulations and Currency Control." The draft law proposes that branches/representative offices of foreign companies be treated as residents from a currency control perspective, meaning that all transactions between these offices and domestic entities would take place only in tenge. The idea behind the proposal is to move towards de-dollarization of the economy. Although a solid goal for the national economy, foreign operators argue that the branches then would fall under the repatriation requirements currently applicable to Kazakh legal entities, making it difficult for them to repatriate earnings outside the country.

2.4.2. General indicators of investment attractiveness

In addition to the insights provided by IHS Markit's E&P rankings Fiscal Attractiveness and Petroleum Sector Risk modules, it is instructive to briefly review how Kazakhstan's overall business environment has been evaluated according to two widely used comparative international indicators.

The World Bank Group's "Ease of Doing Business Index" is the best-known such comparative indicator, compiled annually since 2001. The Index ranks countries according to the degree to which a country's environment is conducive to the operation of a business.[15] The rankings are adjusted each year to reflect, among other things, reforms or changes initiated that have made it either easier or more difficult to conduct business.[16]

As the figures in Table 2.1 indicate, in recent years Kazakhstan has ascended rapidly in the EDB rankings as the scope and number of business regulatory reforms has broadened, ranking 35th of 190 countries for 2017, and 75th for the component "getting electricity." In fact, Kazakhstan was one of 10 countries registering the greatest improvement in the 2017 ranking, having initiated reforms in 7 of the 10 component areas, and was only one of two countries (Georgia being the other) listed among the "top improvers" four times in the past 12 years.[17] A second table compares Kazakhstan's EDB rankings with those of its peer group of oil and gas producing countries (see Table 2.1).

[14]The NFW Success rate is the ratio of total NFW Discoveries to total NFWs. A NFW discovery is defined as one that tested oil and/or gas, and is a technical success, not necessarily a commercial success.

[15]The Index averages a country's percentile rankings on 10 component indicators to derive a composite score, which is then used to assign a final "Ease of Doing Business" (EDB) ranking. The 10 indicators measure the ease of: starting a business; dealing with construction permits; getting electricity; registering property; obtaining credit; protecting minority investors; paying taxes; trading across borders; enforcing contracts; and resolving insolvency (see http://www.doingbusiness.rog/rankings).

[16]Rankings are annual and the coverage period ends on 1 June of the preceding year; for example, the 2017 index covers the period beginning 2 June 2015 and ending on 1 June 2016.

Table 2.1. Impacts of Reforms Undertaken by Kazakhstan as Assessed by World Bank on the Country's Ease of Doing Business (EDB) Ranking

Reform area	EDB index year				
	2013	2014	2015	2016	2017
Starting a business	•	•		•	•
Dealing with construction permits				•	•
Getting electricity					•
Registering property		•	•	•	
Getting credit	•			•	
Protecting minority investors				•	•
Paying taxes			–		
Trading across borders			•		•
Enforcing contracts			•	•	•
Resolving insolvency	•		•	•	•
Kazakhstan overall ranking	49	50	77	41	35
No. of countries	185	189	189	189	190

[a] • reform initiated making it easier to do business; – reform initiated making it more difficult to do business.

Source: World Bank

Table 2.2. Ease of Doing Business (EDB) and Global Competitiveness Index (GCI) Rankings for Kazakhstan and Peer-Group Countries

Country	EDB index year					GCI year	
	2013	2014	2015	2016	2017	2015 – 2016	2016 – 2017
Leaders							
United States	4	4	7	7	8	3	3
United Kingdom	7	10	8	6	7	10	7
Norway	6	9	6	9	6	11	11
Malaysia	12	6	18	18	23	18	25
Canada	17	19	16	14	22	13	15
Reformers							
Kazakhstan	49	50	77	41	35	42	53
Russia	112	92	62	51	40	45	43
China	91	96	90	84	78	28	28
Others							
Algeria	152	153	154	163	156	87	87
Angola	172	179	181	181	182	–	–
Brazil	130	116	120	116	123	75	81
India	163	132	134	142	130	55	39

Source: World Bank

[17] World Bank Group, Doing Business 2017: Equal Opportunity for All. Washington, DC: International Bank for Reconstruction and Development/The World Bank, pp. 29–30. The anomalous 2015 ranking reflects several factors, including increases in vehicle and environmental taxes, making it more complicated for companies to pay taxes (World Bank Group, Doing Business 2017: Equal Opportunity for All. Economy Profile 2017—Kazakhstan. Washington, DC: International Bank for Reconstruction and Development/The World Bank, p. 77).

A second indicator briefly mentioned here is the World Economic Forum's Global Competitiveness Report.[18] Although it is not explicitly a measure of investment attractiveness, it can be viewed as a proxy of sorts, inasmuch as the components it uses to define competitiveness—the set of institutions, policies, and factors that determine the level of productivity of an economy—should also manifest more or less directly in returns on investment.[19]

As evident from Table 2.2, the World Bank hierarchy is similar to that for EDB rankings. The United States, United Kingdom, Norway, Canada, and Malaysia all fall within the top 25 slots in the ranking, whereas Kazakhstan, Russia, and China occupy intermediate positions (Kazakhstan ranks 53rd for 2016–2017).

The Global Competitiveness Report also provides the results of a 2016 executive opinion survey indicating the five most problematic factors for doing business in Kazakhstan: inflation (not unexpected given the pressure on the tenge in the low oil price environment), tax rates, corruption, access to financing, and tax regulations. Insight into two of these factors (corruption and the regulatory environment) is provided by a separate Rule of Law Index (ROLI), compiled by the World Justice Project. On the 2016 ROLI rankings, Kazakhstan ranked 73rd of 113 countries, up from 75th in 2015. The index is designed to measure a nation's adherence to the rule of law from the perspective of how ordinary people experience it.[20] Of particular relevance to investment attractiveness, Kazakhstan ranked noticeably higher on order and security (40th) and regulatory enforcement (57th), and near its overall ranking on absence of corruption (71st) and open government (73rd).

2.5. OVERVIEW OF KEY LEGISLATION AND REGULATORY CHANGES IN KAZAKHSTAN RELATED TO INVESTMENT POLICY

As reflected in its rise in the EDB ranking, Kazakhstan has continued to take steps toward improving the investment climate and promoting investments, both domestically and from abroad. In a major administrative change, in August 2014 the Ministry of Industry and New Technologies, and the Ministry of Transport and Communications were combined into a new Ministry for Investments and Development. One of the key goals of the new ministry is to improve the investment climate, as well as stimulate investments into new manufacturing and production projects that use modern technologies. Specifically, the Investment Ministry's strategic plan of actions to 2021 sets goals to improve the investment climate that are tied to Kazakhstan's position in the World Economic Forum's Global Competitiveness Report rankings discussed above. Specifically, the Ministry aims at improving in several areas the GCR identified where Kazakhstan appears to be lagging, including local supplier quality and quantity, state of cluster development, production process sophistication, and value chain breadth (all under the Business Sophistication pillar), FDI and technology transfer (under the Technological Readiness pillar), prevalence of foreign ownership and business impact of rules on FDI (from the Goods Market Efficiency pillar), and others. This is commendable, as it demonstrates a concerted effort in policymaking to address shortcomings identified in surveys of business competitiveness.

Furthermore, Kazakhstan has been partnering with the OECD as part of the organization's Eurasia Competitiveness Program, which helps countries in the region to improve the competitiveness of their economies. In April 2012, the OECD carried out a detailed assessment of Kazakhstan's ability to bring its investment policy closer to recognized international standards such as the OECD's Declaration on International Investment and Multinational Enterprises. This was followed by the launch of an OECD dedicated country program with Kazakhstan. Under the framework of the country program, the second investment policy assessment commenced in late 2015 with the goal of providing actionable recommendations on further improvement of the investment climate. The country program is organized around seven key areas: (1) public governance; (2) fiscal affairs; (3) education; (4) competitiveness and business climate; (5) health, employment, and social inclusion; (6) statistics; and (7) the environment.

In recognition of Kazakhstan's progress, in April 2017 the country became the first one in Central Asia to join OECD's Investment Committee (as an associate member). The Committee's mandate is to interpret and implement the Declaration and Decisions on International Investment and Multinational Enterprises from 1976, and to comply with the Codes of Liberalization of Capital Movements and Current Invisible Operations.

To implement the OECD's recommendations, in June 2013 the government developed a plan of initiatives, which in February 2016 was turned into a concrete plan on improving the investment climate for 2016 and 2017. The plan requires various ministries and state companies to develop specific measures in 12 strategic directions:

- Applying corporate administration principles to companies with state participation
- Improving investment attractiveness
- Broadening investors' access to international arbitrage
- Improving local content requirements
- Developing state-private business partnership
- Defending intellectual property rights
- Developing responsible business practices
- Broadening investors' access to land
- Liberalization of trade policy
- Creating conditions for lowering of administrative burden on investors
- Improving tax and customs legislation
- Reducing the role of the state in the economy.

While the plan's priorities seem to point in the right direction, it remains to be seen whether specific proposals will be implemented successfully. Such commitments must be backed up with funding and systematic efforts to train government functionaries.

Since 1995, Kazakhstan has participated in the Energy Charter Conference, an organization that implements the provisions of the 1994 Energy Charter Treaty between member countries aimed at strengthening legal norms, promoting and protecting investments, reducing trade barriers, improving energy efficiency, and resolving energy disputes. In 2015, a revised version of the earlier Agreement, the International Energy Charter, was signed by 80 countries, including Kazakhstan. In terms of investment, the Treaty commits to reducing investment barriers, promoting transparent legislation, signing international agreements on investment protection, and ensuring access to dispute settlement mechanisms.

In addition, Kazakhstan is continuing its participation in the Extractive Industries Transparency Initiative (EITI), which the country joined in 2013. Gaining EITI accreditation was a significant step, as it demonstrated Kazakhstan's commitment to ensuring responsible, transparent management of oil, gas, and mineral resources. Between 2005 and 2015, the EITI secretariat worked with various ministries and private sector entities within Kazakhstan to identify inconsistencies between company-reported data on social expenditures, data collected by the local government, and the actual financing of programs. Subsoil users are now required by law (Law on Subsoil and Subsoil use) to submit information in support of the EITI implementation, and these reports are made publically available online, on the integrated information system "Unified system of subsoil use management of the Republic of Kazakhstan."[21]

The Law on Introduction of Changes to Certain Legislative Acts of the Republic of Kazakhstan on Improvement of the Investment Climate (Law on Investments) from June 2014 introduced significant changes. A major change was that the Law introduced the concept of "an investment priority project," defined as a newly created project related to an activity or business considered by the government to be of high priority; in the energy sector, the list of priority activities includes oil refining and the production, transmission, and distribution of electric power. Although this type of project is not allowed to receive budget funding (except for an investment subsidy covering up to 30% of the cost of the project's equipment and services), it is exempt from paying duties on imports of equipment and from paying corporate income, land use, and property taxes. Finally, the Law guarantees stability of taxation and of labor regulations.

To help investors obtain services from the state effectively, the Law introduced a "one window" principle for investors. This consolidated government services under a single dedicated channel (Investors Services Center), aimed at minimizing bureaucracy.

Finally, the Law introduced the position of Investment Ombudsman—a government authority (the Minister of Investment and Development) responsible for defending the rights of investors. The Ombudsman receives specific complaints or proposals from investors and either makes specific recommendations on how to resolve them, or provides support to investors, or recommends changes in legislation if needed.

However, this is yet another authority aimed at supporting foreign investors. The first such body is the Foreign Investors Council formed in June 1998 under Kazakhstan's President. Another is a Council on Improving the Investment Climate under Kazakhstan's Prime Minister, which was created in March 2012. Finally, at the end of 2015, another council (known as the Investment Command Center and designed to attract investors) was created under Kazakhstan's Prime Minister; similar councils were created under the heads of all Kazakhstan's regions. This multitude of authorities, in addition to the Ombudsman, responsible for investments might be confusing for foreign investors. Therefore, effort must be made to simplify and consolidate administrative responsibilities. For example, when a business registers with the Ministry of Justice, the business should automatically be registered with the Customs Administration without having to go through a separate registration process.

A major legal change occurred in October 2015, when a new Entrepreneurial Code replaced six

[18] Klaus Schwab, ed., Global Competitiveness Report 2016–2017. Geneva: World Economic Forum.

[19] The report analyzes competitiveness along 12 "pillars": Institutions, Infrastructure, Macroeconomic Environment, Health and Primary Education, Higher Education and Training, Goods Market Efficiency, Labor Market Efficiency, Financial Market Development, Technological Readiness, Market Size, Business Sophistication, and Innovation.

[20] The ROLI ranking is compiled from nine factors (and 47 specific sub-factors) that represent constraints on government power, absence of corruption, open government, fundamental rights, order and security, regulatory enforcement, civil justice, criminal justice, and informal justice.

[21] For EITI reports see www.egsu.energo.gov.kz

separate pieces of legislation, including the Law on Investments. Compared to the Law on Investments, the Code: (a) granted the Investment Ministry the authority to solicit the Foreign Ministry to issue a special Investor type of visa for foreign personnel; (b) increased the period an investor could apply for investment preferences from one year to two years; and (c) expanded tax preferences to include exemption from paying VAT on imports. While these laws are positive developments, authorities must work to ensure universal, uniform understanding, interpretation and application of laws.

Currently, the government is developing a national investments attraction and sustainability strategy until 2022 an initiative designed to promote economic diversification by attracting investments to sectors beyond natural resources based on the recommendations of the World Bank. Specifically, the strategy's goals are to attract foreign investments that will improve operational efficiency, to promote reinvestment in already existing investment projects, to carry out privatization, and to promote public-private partnerships. The implementation of this strategy is the responsibility of the Kazakh Invest Company—an arm of the Investment and Development Ministry, which is mandated to attract investments to Kazakhstan. Kazakh Invest is authorized to provide support to investment projects on the "single window" base, representing Kazakhstan's government.

2.6. RECOMMENDATIONS ON DEVELOPMENT GOALS AND REGULATORY SYSTEM

Kazakhstan has made substantial progress in increasing its attractiveness as a destination for investment. As in all other countries, there is room for further progress. The analyses summarized in this chapter support the following recommendations.

• First, pertaining directly to the oil and gas industry, a decline in investment attractiveness between Q4-2014 and Q1-2017 recorded by the IHS Markit PEPS Country Ratings and Rankings Module (in the category of Recent E&P Activity) suggests continuing challenges within a group of factors defined as "Upstream Success": reserves added for oil and for gas, success rate of NFW, as well as reserves added per NFW. The addition to reserves per NFW during this period, for example, was negligible. These upstream challenges are included among those highlighted by the Kazakhstan Upstream Oil and Gas Technology Roadmap prepared in 2013 (Shell Roadmap), summarized in the following chapter (see Section 3.3.3). The Shell Roadmap identifies the reduction of drilling and well costs in challenging geological environments through new well-drilling technologies and equipment as one of the three main directions that would yield the greatest immediate benefits to the industry and its investors.

• The overall PEPS investment attractiveness score also fell as Petroleum Sector Risk increased due to macroeconomic factors, as the country's primary fiscal balance deteriorated while real per capita GDP growth fell significantly. Consequently there is a need for measures to strengthen the financial system and to increase predictability of monetary policy (boosting confidence for both domestic and foreign investors). This is echoed by the finding in the Global Competitiveness Report that inflation (pressure on the tenge in the low oil price environment) and access to financing are among the more urgent challenges facing investors in Kazakhstan. Along these lines, Kazakhstan's Central Bank announced that a program for the recapitalization of Kazakhstan's banks (including the country's largest bank, Kazkommertsbank) would be launched in mid-2017. The National Bank of Kazakhstan's Problem Loan Fund will take over approximately US$7.6 billion of loans from Kazkommertsbank in order for its merger with Halyk Bank to proceed. The new bank will control over 35% of the entire banking sector. The hope is that clearing out the bad loans will allow normal banking to resume so as to help the economy revive. Nonperforming loans are reported to have fallen from a peak of 34% (May 2014) to 6.7% at end Q1-2017.

• Also within the realm of general measures that can benefit both the oil and gas industry specifically, and the broader economy more generally, is increased spending on domestic workforce training. A relatively low level of labor skills is a weakness identified in firm-level business indicators of economic performance, and is especially relevant in situations in which foreign investments must comply with local content regulations.[22] The goal should be to increase the number of workers available with minimum requisite levels of training, and also to gradually increase the overall level of training. Cooperative training programs involving foreign investors and Kazakhstan's educational institutions should be explored as a means of developing highly specialized and technical skills.

• Kazakhstan's focus on establishing a legislative foundation and creation of a regulatory environment supporting investment is commendable and appears to be achieving tangible results (e.g., the country's recent performance as measured by the World Bank's Ease of Doing Business indicators). However, the build-out appears to have been accompanied by an expansion of the bureaucracy overseeing investments. The consolidation of government services offered to investors under "one window," or a single dedicated channel (Investors Services Center), and the creation of the position of Investment Ombudsman, appear to be positive steps aimed at minimizing the red tape encountered by investors. However, the existence of numerous other offices supporting investment (Foreign Investors Council, Council on Improving the Investment Climate, Investment Command Center, investment councils administered by the heads of Kazakhstan's regions, and the Kazakh Invest company operating in the "single window") introduces a multitude of authorities that could be confusing for foreign investors. Often different bureaucracies have conflicting mandates and overlapping authorities, multiple government approvals for operations adds to the time and administrative efforts required to conduct business. Attention should be focused on a careful delineation of authority among these bodies, the elimination of duplicative responsibilities, and perhaps a certain degree of consolidation.

• Kazakhstan is currently drafting a new Tax Code. Recommendation for the new tax code would be to reduce high levels of multiple forms of government share, as well as to provide for more durable guarantees of stability. It is important to reiterate that the tax framework is one key component of the overall attractiveness of a country to international investors. With global capital expenditure limited, investment will be directed, at the margin, to those countries with more attractive fiscal and regulatory regimes.

• In reforming the Subsoil Code, Kazakhstan should refer to the proposed recommendations in the 2015 NER.

• Kazakhstan should continue to realize its plan to improve the efficiency of the VAT administration process by instituting an E-invoicing initiative. Reducing banking fees and promoting the use of cash registers and electronic payment methods would help to promote transparency and improve efficiency of the financial administration of doing business in Kazakhstan.

• The application of a local content policy has been an extremely important best practice that can, and should, be applied to all future foreign investment projects in Kazakhstan. But a local content policy should be designed to cultivate the long-term growth of domestic capacities, rather than to generate immediate activity. In January 2016, the government introduced new rules for calculating the "local content percentage" of companies contracted by oil companies developing a project. The new definition stipulates that any company with less than 95% of Kazakhstan employees by headcount as zero local content, regardless of other criteria. Whereas previous rules recognized various approaches to defining local content, such as percentage of payroll, hours worked, and value of product produced, the current rule focuses exclusively on short-term job creation. Therefore, Kazakhstan should reform its local content laws to provide additional flexibility and recognize the indirect benefits, such as skills training and technology and know-how transfer, that foreign investment and personnel bring to the country.

• Similarly, greater restrictions on work permits for foreign workers only complicate the ability, and sometimes willingness, of foreign companies to do business in Kazakhstan.

[22] In this context, it is relevant to note that the East Asian "economic miracle" is largely attributed, among other things, to that region's sustained levels of investment in human capital over a long period. In other words, there is "an education miracle behind the economic miracle;" see Jandhyala B.G. Tilak, Building Human Capital in East Asia: What Others Can Learn, Washington, DC: International Bank for Reconstruction and Development, 2002.

3. CRUDE OIL AND GAS CONDENSATE PRODUCTION

3. CRUDE OIL AND GAS CONDENSATE PRODUCTION

3.1. KEY POINTS

• In 2016, oil output from Kazakhstan declined for third year in a row: -1.2% in 2014, -1.6% in 2015, and -1.9% in 2016, to 78 MMt (1.66 MMb/d); these declines were concentrated at mature fields, mainly in Aktobe and Kyzylorda oblasts. But since late 2016, these declines are being counterbalanced by increasing production from the re-start at Kashagan, so national production is now on a general upward trajectory.
• Although Kazakhstan's 2017 output may be deliberately constrained somewhat by its pledge to support oil prices by reducing oil output (see below), ongoing developments at two of its three "mega" projects provide a foundation for solid future output growth: the CC01 debottlenecking at Kashagan will provide an additional 80,000 b/d to the existing designed plateau of about 17 MMt/y (~370,000 b/d) for phase 1, and the decision to proceed with the Future Growth Project at Tengiz sets the stage for the addition of 12 MMt/y (260,000 b/d) of field production in the early 2020s.
• Kazakhstan agreed in late 2016 to participate in the plan by OPEC and other major oil producers to hold back output to support oil prices during the first half of 2017, pledging a symbolic output reduction of 20,000 b/d. This plan was later extended by additional nine months, to March 2018.
• Due to lower expected investment in the current lower global oil price environment, IHS Markit has adjusted (to the downside) its base case scenarios for Kazakhstan's oil production and exports out to 2040. Nonetheless, Kazakhstan is expected to increase production longer term, and will remain the second largest oil producer and exporter within the CIS region.
• Growth in Kazakhstan's crude exports via the CPC pipeline over the past two years occurred as exporters redirected significant volumes from other (more expensive) routes to fill expanded CPC capacity. CPC handled 68% of total Kazakh crude exports in 2016, up from 63% in 2015. Like many other Kazakh producers, Kashagan oil is now also reaching export markets via the Russian pipeline system as well as CPC.
• The reversal of the Atyrau-Kenkiyak oil pipeline section, which has been planned but delayed for several years, is expected to occur in 2017–18. Once the Kenkiyak-Atyrau pipeline section is reversed, increased Kazakhstan-China export flows can be achieved, but this oil will have to be attracted from western Kazakhstan. To flow east, the netback for crude from western Kazakhstan (realized sales price after transportation) needs to be the same or higher as from westward exports. Also, questions remain about the availability of the reserve base to increase oil flows in this direction.
• A key challenge is the lack of growth in the reserve base: recent years have seen a significant decline in the exploration activity and success rates, in the Precaspian Basin and across Kazakhstan in general, by KazMunayGaz (KMG) and international oil companies. Key factors contributing to the decline in exploration activity and success rates have been cutbacks in exploration spending generally in the low oil price environment as well as the declining relative attractiveness of Kazakhstan internationally for upstream investors.

3.2. UPSTREAM OIL AND GAS CONDENSATE EXTRACTION UPDATE

3.2.1. Liquids reserve base

As of 1 January 2016, the State Commission on Reserves (GKS) listed Kazakhstan's petroleum liquids (oil and gas condensate) reserve base (state balance) at 5.3 billion metric tons.[1] Of this, 4.85 billion tons are crude oil reserves, while the rest (445 million metric tons [MMt]) is gas condensate (see Table 3.1). The official state balance lists oil and gas condensate reserves for 332 fields, including 271 oil fields and 61 gas condensate fields. The state reserves balance has increased slightly (by 2.1%) since 1 January 2014, with reserves in the A+B+C1 category increasing by about 1.9%, while those in category C2 increased by 2.6%. A significant part of the increase in reserves is likely the result of recalculation of reserves at existing fields; there have been few new discoveries and those that were made tended to be small fields.

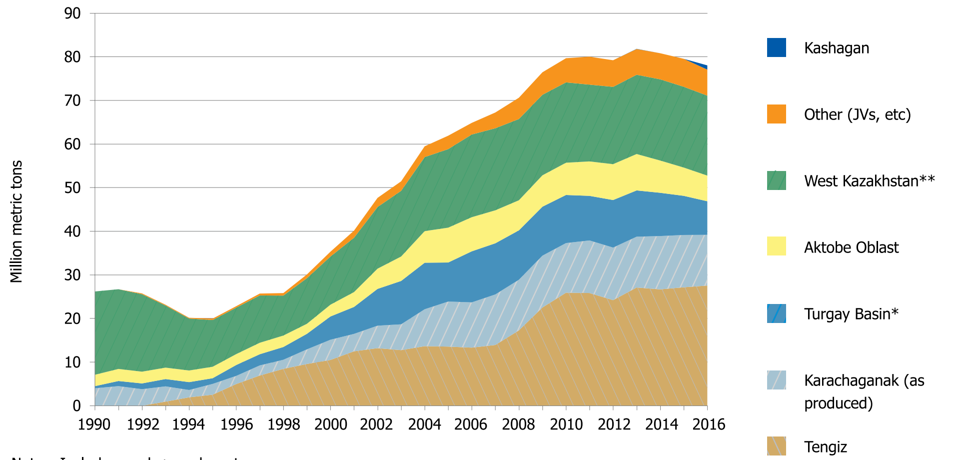
Table 3.1. Kazakhstan's proven oil and condensate reserves in 2016 (MMt)

	A+B+C1	C2	A+B+C1+C2
Crude Oil	3 158 812	1 688 728	4 847 540
Condensate	359 153	86 396	445 549
Total	3 517 965	1 775 124	5 293 089

Source: State Commission on Reserves (GKS)

3.2.2. Key recent oil and gas condensate production trends

Over the past three years, Kazakhstan's oil production has exhibited a declining trend, although the re-start of production at Kashagan is reversing this in 2017 (see Figure 3.1). National crude and condensate output has declined each year since 2014: it fell 1.2% to 80.8 MMt (1.7 MMb/d) in 2014; a further 1.6% to 79.5 MMt (1.67 MMb/d) in 2015; and in 2016 output fell to 78 MMt (1.66 MMb/d), down another 1.9% year-on-year (see Table 3.2). The declines were concentrated in Kyzylorda Oblast (Turgay Basin) and Aktobe Oblast, owing to an ongoing secular decline at mature fields in these two areas. Over the period 2014–16, aggregate oil and condensate output fell by an average annual rate of 8.3% in Kyzylorda Oblast and by 12% in Aktobe Oblast.



Notes: Includes crude+condensate;
* Includes Amangeldy in Zhambyl Oblast
** West Kazakhstan production (not to be confused with the Kazakh oblast of the same name) covers the output of five legacy producers: UzenMunayGaz, MangistauMunayGaz, EmbaMunayGaz, CNPC International/Buzachi Operating, and KarazhanbasMunay. These producers are grouped together because of their location, similar crude quality, and general production dynamics as mature operations.

Source: IHS Markit; Statistics Committee RK; Ministry of Energy

[1] This is reported according to the domestic definition (in categories A+B+C1+C2). Kazakhstan's remaining proven + probable "2P" reserves (roughly the international equivalent of the domestic definition of A+B+C1) is 3.16 billion tons (or about 23 billion barrels); IHS Markit estimates a slightly larger amount of 2P reserves for the country in 2016, at 43 billion barrels. BP estimates Kazakhstan's 2P reserves at about 30 billion barrels.

Table 3.2. Crude Oil Balance for Kazakhstan (million metric tons)

	2010	2011	2012	2013	2014	2015	2016	percent change 2015-2016
Crude oil production	79,7	80,0	79,2	81,8	80,8	79,5	78,0	(1,78)
Apparent domestic crude consumption	19,7	17,5	17,2	16,7	18,3	14,7	15,8	7,14
Refinery throughput	13,7	13,7	15,1	15,3	16,4	15,0	14,9	(0,40)
Direct use of crude/unidentified*	6,0	3,8	2,1	1,4	2,0	(0,3)	0,8	(409,54)
Crude oil exports	67,5	69,6	68,1	72,2	63,0	64,8	62,3	(3,87)
Outside the Former Soviet Union	65,8	67,9	67,4	71,4	61,6	62,0	61,5	(0,72)
via Russian pipeline system (non-Makhachkala)	15,5	15,4	15,4	15,4	14,6	13,5	15,0	11,08
via Caspian Pipeline Consortium	28,5	28,3	25,3	28,7	35,2	39,0	42,4	8,82
via Atasu-Alashankou pipeline	10,1	10,8	10,4	11,8	4,8	4,4	2,8	(37,51)
via railroad	5,7	7,3	6,1	8,7	1,8	0,3	0,5	58,28
via Russian railroad (to Finland, etc.)	5,7	7,3	6,1	8,7	1,8	0,3	0,5	58,28
via Kazakh railroad to China	-	-	-	-	-	-	-	
via Caspian	9,3	5,8	7,6	6,0	5,2	3,2	2,2	(30,75)
through Azerbaijan/Georgia	5,2	2,3	3,8	3,2	3,5	1,6	0,6	(62,70)
to BTC	-	-	-	0,6	2,4	1,1	-	(100,00)
to Iran (including direct shipments by rail)	0,5	0,0	-	-	-	-	-	
to Novorossiysk (via Makhachkala)	3,6	3,4	3,8	2,8	1,7	1,6	1,6	0,63
Former Soviet republics	1,7	1,7	0,7	0,9	1,4	2,8	0,8	(73,22)
Russia	1,2	1,2	0,7	0,9	1,4	2,8	0,8	(72,86)
via Karachaganak-Orenburg pipeline	1,2	1,2	0,7	0,9	0,7	0,7	0,8	12,10
Crude oil imports	7,4	7,1	6,1	7,2	0,5	0,1	0,0	(59,66)
Outside the Former Soviet Union	--	--	--	--	--	--	--	
Former Soviet republics	7,4	7,1	6,1	7,2	7,0	7,0	7,0	(0,28)
Russia	7,4	7,1	6,1	7,2	7,0	7,0	7,0	(0,28)
to Kazakhstan-China pipeline (swap)	2,6	0,2	-	-	7,0	7,0	7,0	(0,28)

* Balancing item. (includes field losses, changes in stock and direct use of crude)

Source: IHS Markit, Statistics Committee RK; Ministry of Energy

Among the three mega-projects, the Karachaganak Petroleum Operating[2] (KPO) consortium in West Kazakhstan Oblast recorded a stable production rate of around 11.6 MMt (256MMb/d) during 2016, during which a planned major shut down maintenance was carried out resulting in a lower production compared to 2015 of about 3.1%. In contrast, the TengizChevroil (TCO) consortium in creased production in 2015 by 1.8% and another 1.5% in 2016, to reach 27.6 MMt. TCO accounted for about 36% of total Kazakh oil output in 2016. The re-start of Kashagan production was a major achievement in 2016. Total output for the field was about 1 MMt in the final three months of the year (an average of 81,000 b/d), but production is continuing to gradually ramp up in 2017.

Taking a closer look at the top oil producers in Kazakhstan, the following dynamics emerge:

TCO (Tengiz)

Output in 2016 reached an all-time high of 27.6 MMt (600,000 b/d), up 1.5% year-on-year. Field production dynamics will remain largely tied in the near term to the specifics of TCO maintenance schedules and turnarounds. For example, over a month was set aside for maintenance of sour gas plant and sour gas injection (SGP/SGI) facilities, beginning in August 2016 (45 days for SGP and 35 days for SGI).

IHS Markit expects Tengiz output to remain relatively flat during the next few years. But the July 2016 final investment decision (FID) for the Future Growth Project (FGP)– wellhead pressure management project (WPMP)– sets the stage for the addition of 12 MMt/y (260,000 b/d) of field production, with first oil from the expansion expected by the consortium in 2022. The $36.8 billion expansion program includes $27.1 billion expenditure on facilities and $3.5 billion on wells. It is noteworthy that over 50% of the detailed engineering work related to the expansion had already been completed before the FID—far beyond the usual amount undertaken before project sanction. Key elements of the FGP-WPMP project, which is expected to generate around 20,000 jobs at the peak of construction, include the following planned new facilities:

- 106 production and 15 gas injection wells
- A hydrocarbon gathering system and plant to reinject sour natural gas
- Five gas turbine generators (GE Frame 9 units, each with capacity of 130 MW).

[2] KPO shareholders are Eni (29.25%), Shell (29.25%), Chevron (18%), LUKOIL (13.5%), and KazMunayGaz (KMG; 10%).

[3] On 7 April 2016 the Kazakh Energy Ministry stated that the Kazakh government disagreed with KPO's calculation of the state's share of profits from PSA activity (according to LUKOIL, the state's claim amounts to $1.6 billion).

[4] KMG has a 20% share in the Tengiz project, a 16.9% share in the Kashagan project, and a 10% share in the Karachaganak project. The company also operates a number of legacy fields via its subsidiary KMG EP, with the most significant assets being the Emba, Zhetybay, and Uzen fields, within its 100%-owned upstream subsidiaries, UzenMunayGaz and EmbaMunayGaz. KMG EP also holds shares in JV KazGerMunay LLP (KGM) [50%], JSC KarazhanbasMunay (CCEL) [50%], and PetroKazakhstan Inc. (PKI) [33%].

[5] This includes equity production from KMG EP's shares in upstream joint ventures KGM, CCEL, and PKI. Production from these partially owned subsidiaries amounted to 3.8 MMt of crude oil (75,360 b/d), 6% less than in 2015, mainly due to a natural decline in production by PKI.

KPO (Karachaganak)

KPO production is expected be maintained at plateau in the near to medium term. Plateau extension projects in concepts definition phase are progressing well towards FID. Further, the major expansion plan that focuses on reinjection of raw gas and stabilization of the associated liquids recovery is in concept selection phase and the JV is actively working to progress into concept definition. Most recently, in June 2017, it was announced that project expansion expenditures are being staged with a phased approach and that overall project costs estimates are being optimized.

Even with the cost-cutting measures, a third phase could be further delayed as the consortium is embattled in a dispute with the Government of Kazakhstan over the methodology for calculating and distributing project profits.[3] In December 2016, the Government of Kazakhstan and the Karachaganak consortium signed a memorandum whereby in 2017, the KPO consortium will propose concrete steps for resolving the dispute. The government of Kazakhstan has filed claims through international arbitration, in case negotiations fail, though both parties have expressed intention to resolve the dispute out of court.

KazMunayGaz (KMG)

National company (NC) KMG owns stakes in almost all significant oil and gas assets in Kazakhstan. The company also acts in the interests of the state, which has pre-emption rights to acquire strategic assets sold (divested) by existing contract holders. Legally, it must hold a 50% stake in all new offshore contractsin the country.[4] The total share of NC KMG (based upon equity ownership) in the country's oil production amounted to about 29% in 2016.

Total output by KMG EP, the exploration and production arm of NC KMG, remained flat in 2015 at 12.3 MMt, but declined by 2% in 2016 to 12.2 MMt.[5] Its 100% owned subsidiaries, UzenMunayGaz and EmbaMunayGaz, registered a 2.2% combined uptick in production in 2015, to 8.3 MMt (167,000 b/d) and another 0.6% increase in 2016 to 8.4MMt (168,000 b/d). All of the growth was concentrated at the fields of UzenMunayGaz, which produced 5.6 MMt (112,000 b/d) in 2016, a 1% year on year increase, while EmbaMunayGaz maintained the same level of output as in 2015 (2.8 MMt [57,000 b/d]).

KMG EP managed to increased output at its core assets in 2015 despite a 38% drop in capital expenditure (capex) in dollar terms, to about $443 million (amounting to a less severe 23% drop in tenge terms, to 98 billion tenge, given the devaluation dividend). The drop in capex reflected a reduction of spending on maintenance and less drilling activity, as well as a reduction of drilling costs (the company reportedly obtained a 15% discount from its drilling contractor). KMG EP increased total capital expenditures in 2016 by 17%, to 115 billion tenge ($337million). For 2017, capital expenditures were set higher at 133 billion tenge ($369 million).

KMG EP is undergoing internal transformation so as to optimize operations and expenditures at its core assets by introducing a "Smartfield" concept.[6] As part of this concept, installed equipment takes data readings and delivers them in real time to a control center and a visualization center for timely decision-making. Currently this concept is implemented at the EmbaMunayGaz-operated Uaz field, and is being tested at UzenMunayGaz. According to KMG, realization of the concept could boost production at the Uaz field by about 3% and reduce the time required to repair wells by 15-20%.

Although KMG EP has remained profitable in the current lower oil price environment, the parent company's (NC KMG's) finances have been very distressed since 2014. Therefore, KMG has turned to piecemeal, external financing arrangements to generate extra funds to meet its capital expenditure targets and service its existing debt obligations. Such measures included the issuance of three tranches of Eurobonds for a total of $10.5 billion completed in April 2017. Also, in late 2015 KMG finalized a deal to sell an 8.4% share in the Kashagan consortium (i.e., half of KMG's 16.8% stake) to its own majority shareholder, Kazakhstan's Samruk-Kazyna sovereign wealth fund, for $4.7 billion. The deal, as initially reported, gives KMG the option to buy back the shares during 2018–20. KMG also struck a prepayment agreement with the global energy and commodities trader Vitol, which involves a commitment by KMG to deliver 7.5 MMt/y (about 163,000 b/d) of crude from KMG's share of oil production from the TCO project over a period of four years, in exchange for a $3 billion prepayment made in tranches by Vitol with financing from commercial banks (six international banks are parties to the deal). In another similar arrangement, the volume of Kashagan oil that KMG will supply to Vitol under terms of an August 2016 prepayment contract will reportedly depend on the actual price, with the total amount capped at $1 billion worth of exports.

Kashagan (NCOC)

The restart of Kashagan in late September 2016 marked a historic moment for Kazakhstan's oil industry.[7] Production restarted almost exactly three years after the October 2013 gas pipeline leaks that forced a shutdown of the field just weeks after its initial startup, following the completion of a pipeline replacement program. The field reached commercial levels of production (75,000 b/d) in early November 2016. Production amounted to 0.966 MMt in the final three months of the year (an average of 81,000 b/d).In the first half of 2017, production amounted to 3.54 MMt (an average of 151,000 b/d, with output in June reaching 192,000 b/d. Production will grow further after reinjection begins—scheduled for the latter part of 2017, and is scheduled to reach the designed plateau level of 365-370,000 b/d perhaps by the end of the year. Kashagan's production ramp-up is not being affected by Kazakhstan's symbolic commitment with OPEC to cut 20,000 b/d of production.

[6] "Smart field," also known as "digital field," technology involves equipping critical field infrastructure, such as valves and pumps, with sensors that measure and transmit important data on temperature, pressure, and other parameters, allowing for quick optimization of well operation.

[7] Kashagan is the world's largest oil field discovery in almost 50 years, since Prudhoe Bay, Alaska, in 1968; IHS Markit estimates that Kashagan contains 11 billion bbl of recoverable oil and 52 Tcf (1.58 Tcm) of recoverable gas. It is also one of the most expensive upstream energy projects ever undertaken, with capital expenditure that has now reached $55 billion.

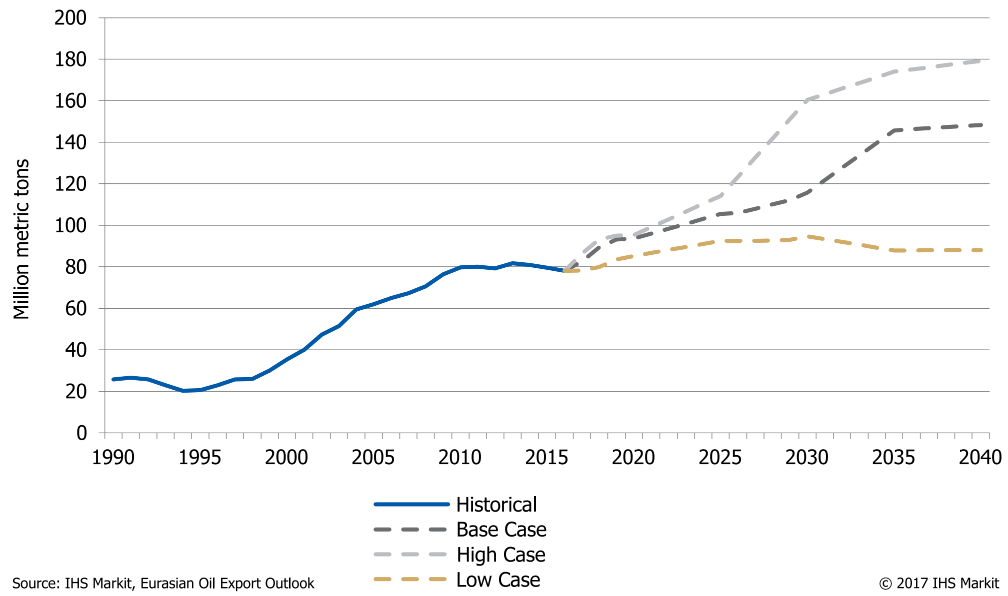
3.2.3. National oil and gas condensateproduction outlook

Despite the considerable distress that the Kazakhstan's upstream sector has been under due to the global oil price decline, overall prospects for the industry are far from gloomy. Kazakhstan still has significant existing reserves and upstream potential, but policy needs to be recalibrated to more effectively encourage exploration and to incentivize producers to invest and expand their operations in Kazakhstan, especially smaller and medium-sized ones. Nonetheless, Kashagan is expected to be the primary driver of production growth in the medium term.

In IHS Markit's base case scenario, Kazakhstan's crude oil production is projected to increase from 78 MMt (1.66 MMb/d) in 2016 to 93.7 MMt (1.97 MMb/d) in 2020 and then 148.3 MMt (3.13 MMb/d) in 2040; this represents an average annual rate of growth of 2.7% over the 2016–40 outlook period (see Figure 3.2). In the high case, national output reaches 179.2 MMt (3.79 MMb/d) in 2040. In the low case, however, output decreases in the later years of the outlook. Output reaches a maximum of 94.7 MMt (2.0 MMb/d) in 2030 and then declines slowly, falling to 88 MMt (1.86 MMb/d) in 2040. IHS Markit's outlook for Kazakhstan's crude oil production in the low case does not include development of Kashagan phase 2, but phase 2 is assumed in the base and high cases.

The rationale for assuming the eventual realization of Kashagan phase 2 has been in line with previously estimated capex, where expected additions in output from phase 2 (raising aggregate output to ~1 MMb/d) would require much lower capex per barrel compared to phase 1's original target of 450,000 b/d, later reduced to 350,000-370,000b/d. Given Kashagan's importance to both the government and the consortium, an accommodation of future development (such as an extension of the project's contract) and implementation of phase 2 seems reasonably likely. The CC01 expansion project approved in November 2016 will bring productive capacity to the original 450,000 b/d of output. This project appears to reflect an evolving perspective on future development at Kashagan, even within phase 1, that seeks incremental productivity improvements at existing operations, similar in philosophy to "brownfield" investment projects.

Figure 3.2. Outlook for Kazakhstan's oil production by scenario



Source: IHS Markit, Eurasian Oil Export Outlook

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The IHS Markit base case tries to approximate a so-called P50 outlook: the actual results have an equal likelihood of being higher or lower than the basecase projections. The high-case figures approximate a P90 outlook: the actual results have a 90% probability that they will be lower than the outlook numbers.

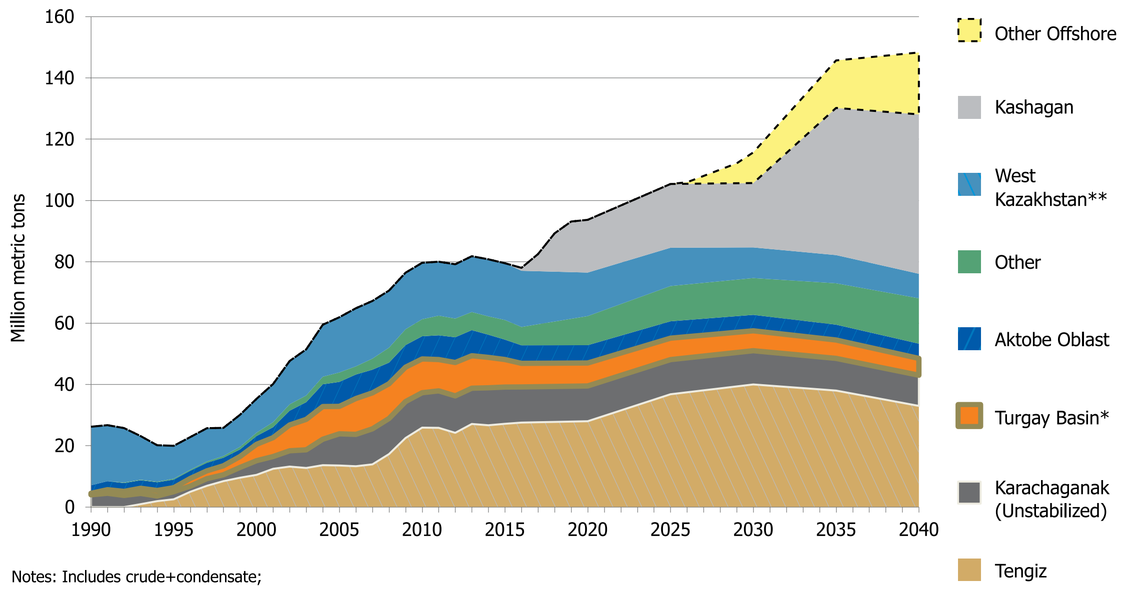
Similarly, the low case is intended to approximate a P10 outlook: the actual results have only a 10% probability that they will be lower than the outlook numbers. These probabilities are intended only as rough guides in interpreting the production projections.[8]

[8] For more details, see NER 2015, chapter 7.2., pp. 140–141.

[9] The overall IHS Markit forecast is built up from developments in eight main categories of producers, either major projects by themselves or grouped together by location, crude quality, or type of operation. These components are described in more detail in NER 2015.

Not surprisingly, Kazakhstan's overall oil production profile will continue to be largely driven by developments at the three "mega" projects: Tengiz, Karachaganak, and Kashagan (see Figure 3.3).[9] Kashagan is the main factor returning Kazakhstan to a production and export growth trajectory from 2017, although after 2020 the key boost to growth will come from the launch of the Tengiz expansion project. The major uncertainties underlying IHS Markit projections are whether Kashagan's phase 2 will go ahead, and whether a project to maintain liquids production at Karachaganak will come to fruition. Realizing the long-term potential of these major projects is in the interests of both the operators and the government of Kazakhstan, but doing so requires the introduction of prudent policies that stimulate further investment and allow for efficient operations. Importantly, the contracts for the three "mega" projects expire in 2033, 2037, and 2041, respectively, and contract extensions to provide sufficient payback periods or other contract adjustments maybe examples of such prudent policy.

Figure 3.3. Kazakhstan's oil production outlook, base case



Notes: Includes crude+condensate;
* Includes Amangeldy in Zhambyl Oblast
** West Kazakhstan production (not to be confused with the Kazakh oblast of the same name) covers the output of five legacy prod ucers: UzenMunayGaz, MangistauMunayGaz, EmbaMunayGaz, CNPC International/Buzachi Operating, and KarazhanbasMunay. These producers are grouped together because of their location, similar crude quality, and general production dynamics as mature operations.

Source: IHS Markit

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Besides the three mega projects, a host of smaller projects also figure in Kazakhstan's oil development going forward, albeit less prominently. Importantly, the IHS Markit outlook assumes the proliferation of new, smaller projects over the forecast period, and also a relatively slow (instead of more rapid) decline in Kazakhstan's older, existing fields as a result of the growing application of new technology and practices. Recently revised official outlooks from the Ministry of Energy for Kazakh oil production are generally less optimistic, reflecting the changed circumstances in global oil markets over the past several years. The latest Ministry outlook envisions national output rising by almost 4% in 2017, to 81 MMt (1.74 MMb/d), but foresees national output reaching a maximum of only 113 MMt (2.43 MMb/d) in 2030 and 91.5 MMt (1.83 MMb/d) in 2040 (see Figure 3.4).

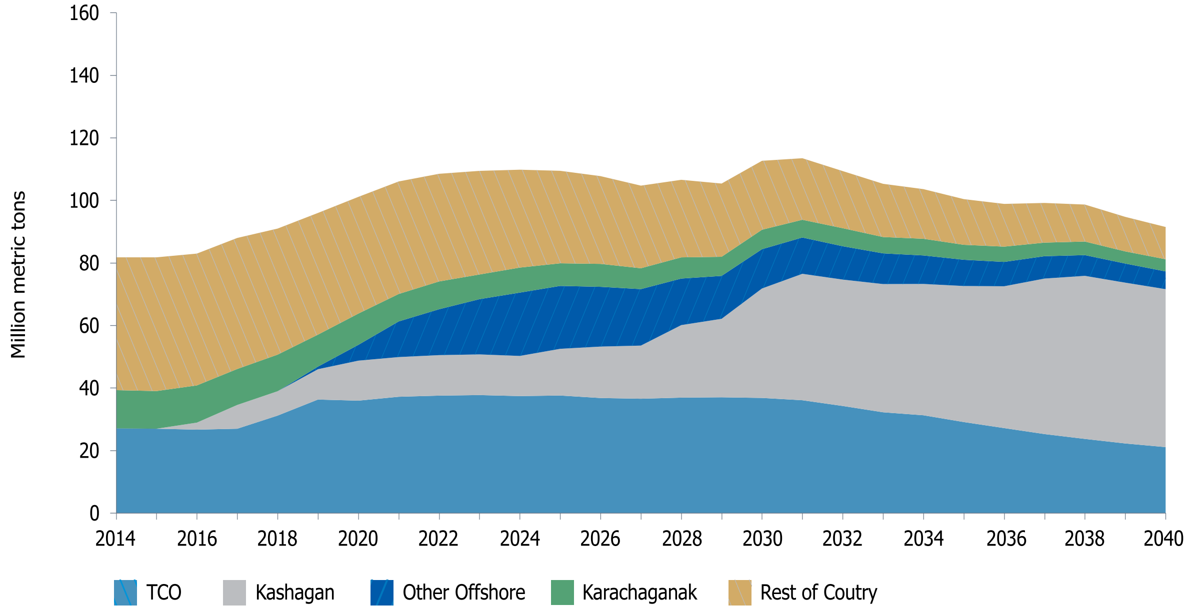
The key difference between the outlooks is the view on older fields: generally IHS Markit envisions a far more attenuated decline with the introduction of new technology that has proven successful in older fields elsewhere in the world, while the Ministry envisions a more rapid decline.[10]

Another difference is the outlook for offshore produc-

[10] For a detailed review of challenges faced by Kazakhstan's small producers that typically produce from small and often mature assets, see NER 2015, chapter 7.2 on crude oil.

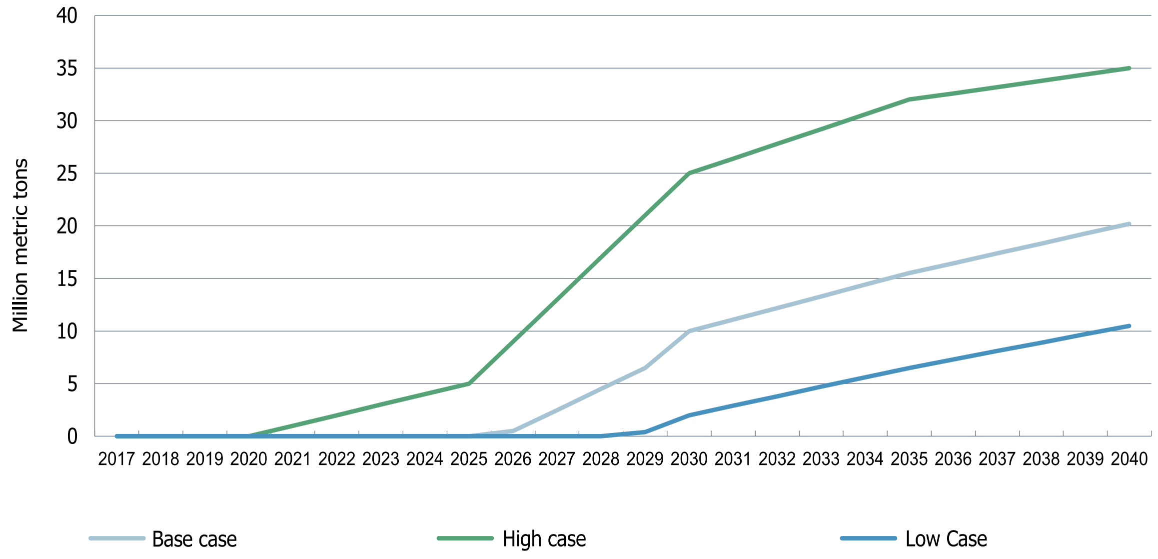
tion development. The Ministry expects “other offshore” production (meaning other than the Kashagan field), will come online quite quickly, as early as 2019 followed by a fairly rapid production ramp-up in the period to 2025, after which production begins to decline. IHS Markit sees the other offshore blocks coming on stream much later, around 2026, with a much slower ramp-up, reaching 20.2 MMt (429,000 b/d) by 2040 (see Figure 3.5).[11] But this is going to be a major challenge because of high costs and also high risks in offshore projects (see text box: Greater flexibility in cross-project operations to allow for facility sharing).

Figure 3.4. Energy ministry’s outlook for Kazakhstan’s oil-condensate production, march 2015



Source: Ministry of Energy

Figure 3.5. Outlook for Kazakhstan’s offshore oil production by scenario, excluding Kashagan

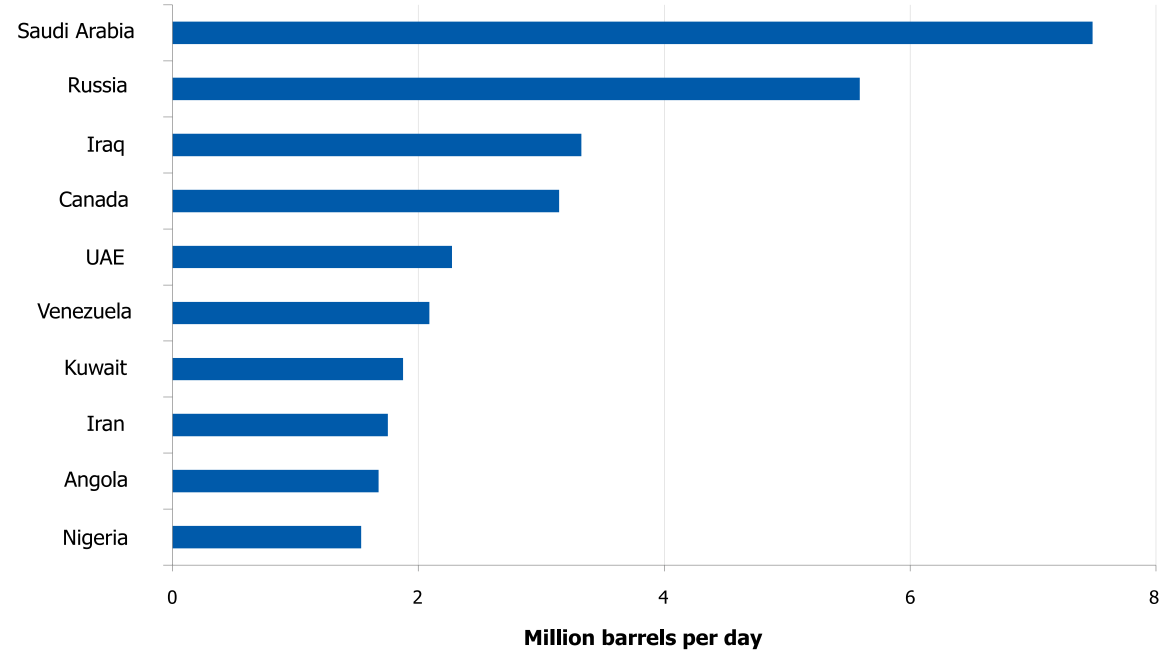


Source: IHS Markit, Eurasian Oil Export Outlook

[11] The “other offshore” category includes three types of offshore projects: (1) already-discovered fields within the North Caspian Operating Company license area (e.g., Kalmkas-More, Aktote, Kairan); movement on development of at least one of these other offshore fields has gotten under way, but obviously the timing and pace of development will be heavily influenced by larger Kashagan issues such as an extension of the production-sharing agreement; (2) joint 50:50 offshore projects between Russia and Kazakhstan (e.g., Tsentralnoye, Kurmangazy); and (3) other projects involving prospective offshore blocks, usually being pursued as JVs between KMG and international investors (e.g., Nursultan, Abay, Satpayev, Isatay).

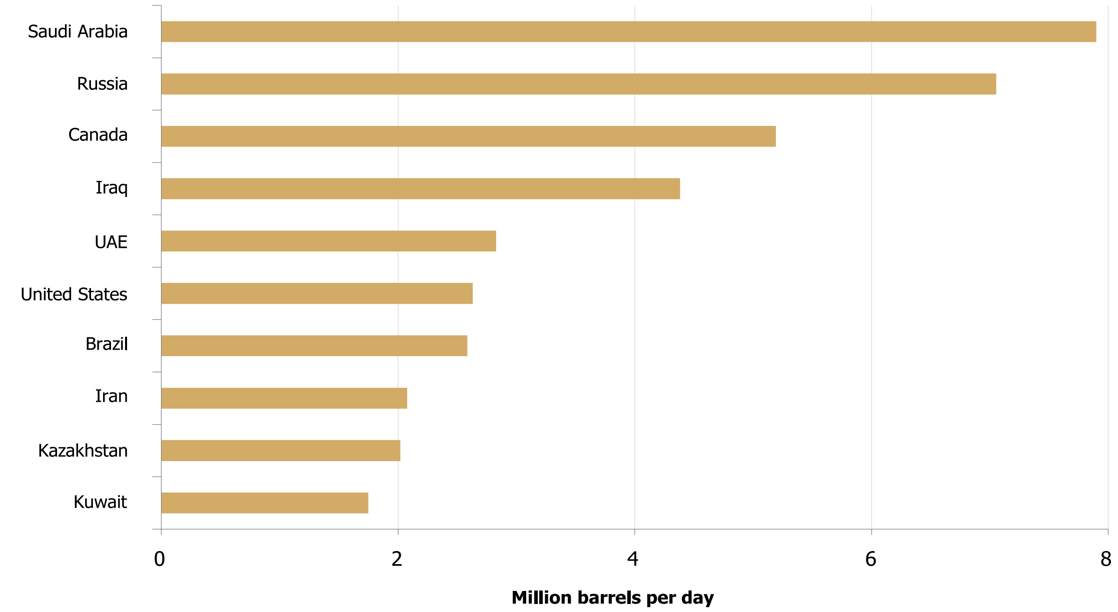
IHS Markit envisions that Kazakhstan could very well join the ranks of the top ten oil exporters by 2030, up from its current position in the top twenty. This forecast rests on a series of assumptions, including Kashagan phase 2 development and the application of new technology at brownfields. (Figure 3.6. and Figure 3.7). Thus, Kazakhstan’s future success as an oil exporter largely rests on its ability to create a competitive and attractive investment climate at home.

Figure 3.6. Top 10 crude oil exporters, 2016



Notes: Excludes segregated condensates
Source: IHS Markit

Figure 3.7. Top 10 crude oil exporters, 2030



Notes: Excludes segregated condensates
Source: IHS Markit

Greater flexibility needed in cross-project operations to allow for facility sharing

Given the "lower for longer" outlook for global oil prices, and the intense competition for upstream investment globally, cost-cutting and efficient project execution now lie at the center of oil and gas companies' strategies. Companies are moving in a variety of ways to reduce costs, including project redesign, opting for simpler and less expensive concepts, improvement of operational practices, such as optimizing well design and reducing the number of days to drill a well, and focusing more on the high-value end of their overall project portfolios. Cost-cutting is particularly important for new or "greenfield" projects, as these tend to have greater uncertainty and higher risks in execution.

Project redesign that allows for joint development and use of critical infrastructure across projects is an important mechanism to reduce costs, especially for smaller greenfield projects in a difficult operating environment, which would apply to the Kalamkas-More and Khazar offshore fields. The two license blocks are held respectively by the North Caspian Operating Company (NCOC) and Caspi Meruerty Operating Company (CMOC). Both of these projects also happen to be Production Sharing Agreements (PSAs).[12]

The cost-reductions achieved by co-development and joint use of infrastructure, such as pipelines, processing and storage facilities, could allow the development of these fields, both of which contain light, sweet crude, to become commercially viable, whereas under current economic conditions their separate development renders them uneconomic. However, Kazakhstan's existing Subsoil Code does not allow for the joint-development of licensed assets and creation of common infrastructure. The challenge is exacerbated by the "ring fences" that define the scope of activities of both PSAs. But it appears that their PSA contracts do not contains terms that per se would prohibit outright the creation of such arrangements.

There is considerable precedent for shared use of infrastructure between projects internationally. Shared use of infrastructure was a key enabling factor that allowed for the development of Qatar Petroleum's (QP) LNG projects. QP's subsidiary companies, Rasgas and Qatargas, entered into separate JVs with different IOCs that covered upstream production as well as liquefaction capacity. While the liquefaction plants are separate and operated by the individual JVs, storage, marine facilities, utilities, and offsite areas are shared by multiple JVs. Similarly, at the now-idle Egypt LNG (ELNG) facility, the ELNG consortium owns common facilities, while each liquefaction train is owned by a different holding company.

Beyond allowing shared use of infrastructure, governments are amending PSA terms to allow for commercialization of new, particularly high-risk projects. In 2011, the government of the Republic of Equatorial Guinea amended its contract with Ophir that incorporated previously unlicensed areas into Block R. This modification paved the way for Ophir to pursue further investment, as Block R is now slated to be feedgas for Fortuna FLNG, the first train of which is announced to come online in 2020.

Thus, recognizing the complexity and expenses involved in offshore projects in the Caspian Sea, in order to improve investment attractiveness and spur hydrocarbon development, the government of Kazakhstan should follow the examples of other governments to modify their legal and tax regimes terms in order to secure rise of investment for exploration activity and get additional investment through joint development.

Key points of importance to policymakers concerning the oil production outlook for Kazakhstan include:

• The three mega projects will supply the bulk of Kazakhstan's future oil production, so policy decisions should support activities that prolong stable (or rising) production at these projects.
• Kazakhstan should not disregard the potential of its mature fields. International experience shows that mature fields can be worked over much longer periods under smart policy regimes that support the introduction of appropriate technologies
• Kazakhstan must invest in exploration to support replacement of reserves and future production.
• Any significant future development of offshore assets beyond Kashagan will be driven largely by investment conditions – simply, how does Kazakhstan compare with the investment climate in other parts of the world? The government of Kazakhstan should adopt appropriate policies that enable development of these fields.

3.2.4. Oil exports and transportation

Oil exports

Kazakhstan has always exported the bulk of its crude production (80% in 2016). Its total crude exports have increased from 20.3 MMt (425,000 b/d) in 1992 to 62.3 MMt (1.25 Mb/d) in 2016, a more than threefold increase (see Figure 3.8). In 2016, 61.5 MMt of the 62.3MMtexported reached international (non-CIS) markets. Historically, most of Kazakhstan's crude has exited via Russia, and last year over 94% of Kazakhstan's international crude exports still transited Russia by pipeline or rail (see Figure 3.9). This relationship remains very important to both Kazakhstan and Russia. Most of Kazakhstan's pipeline exports via Russia move either through the CPC or via the Atyrau-Samara system operated by KTO and the Russian pipeline system operated by Transneft.[13]

Figure 3.8. Kazakhstan's crude oil and condensate exports, 1990-2016

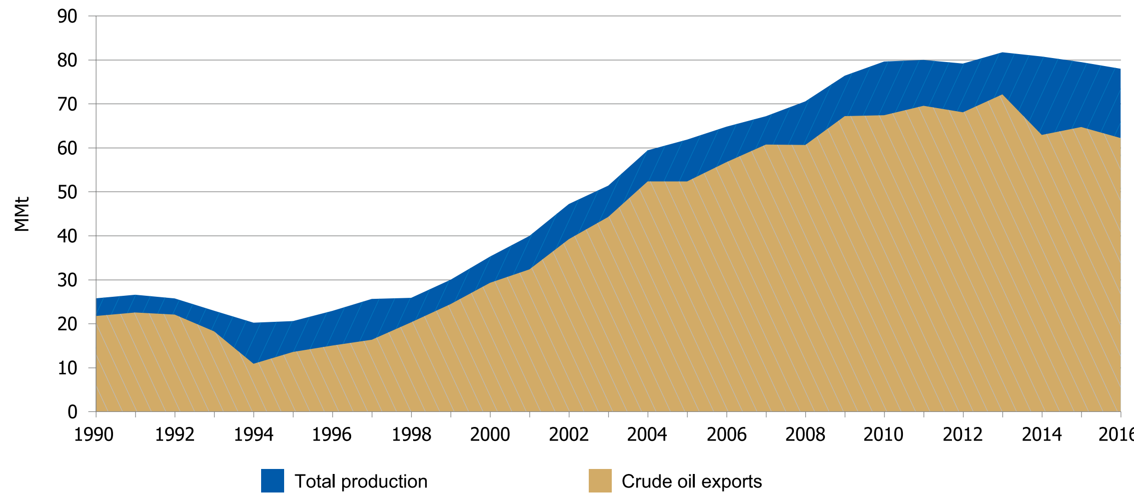
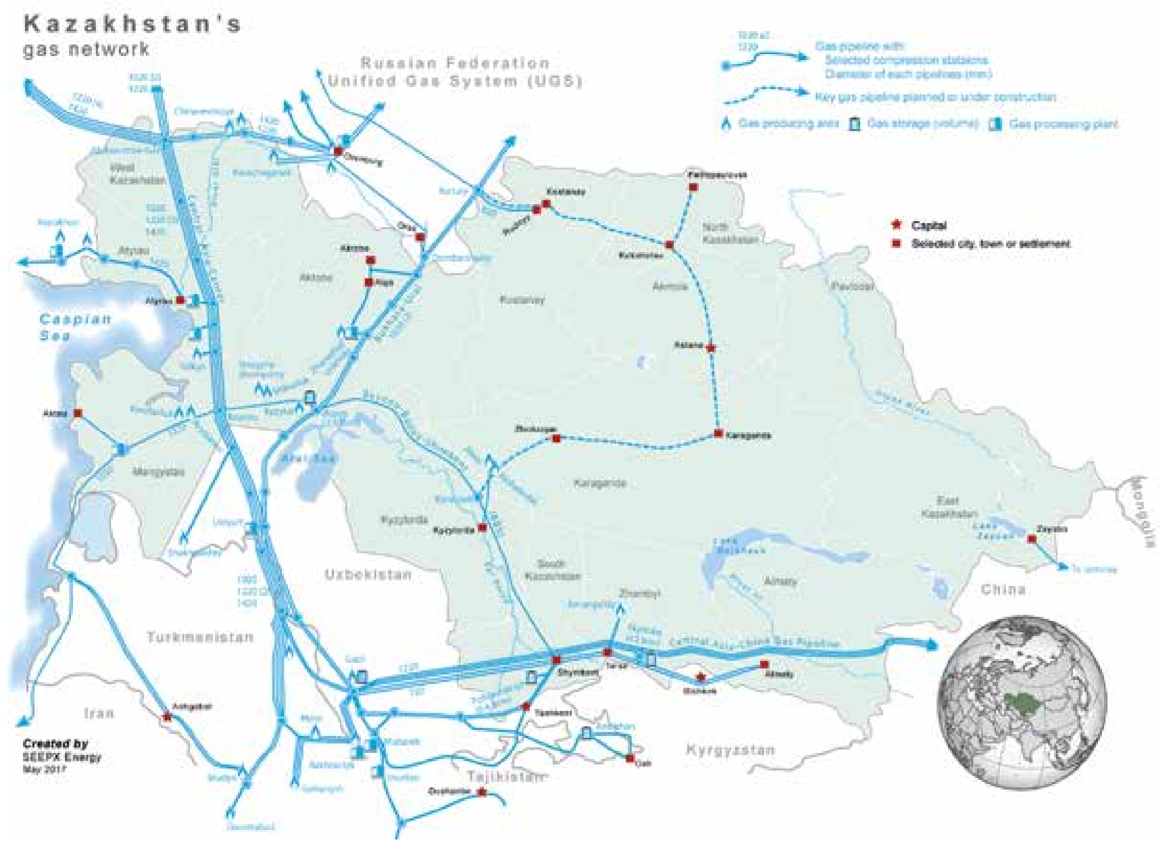


Figure 3.9. Kazakhstan's gas network

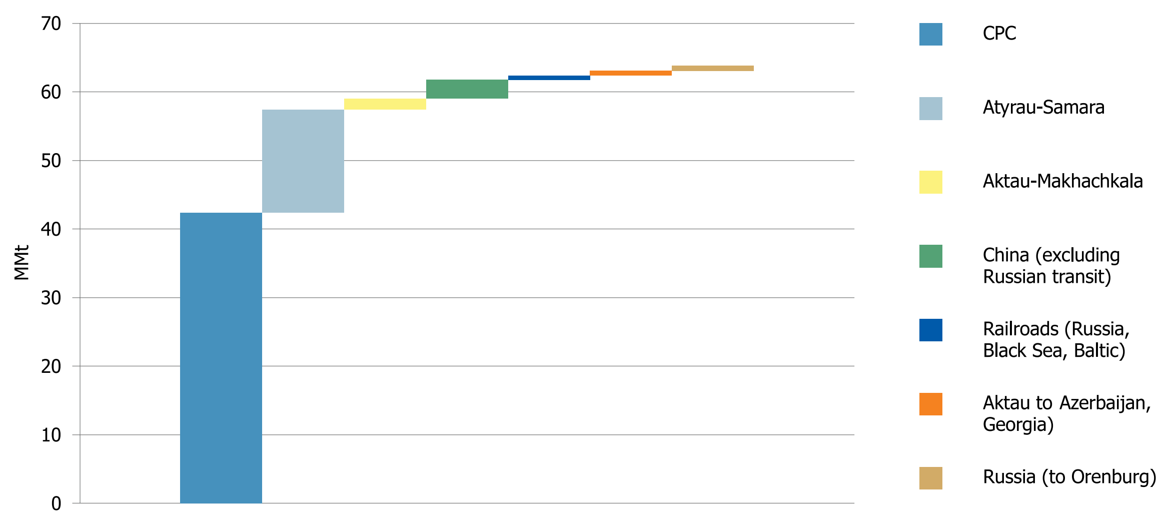


Kazakhstan has embraced a "multi-vectoral strategy" for its oil exports, utilizing multiple routes going north, south, east, and west (See Figure 3.9). The key export routes for Kazakhstan's crude oil (and condensate) in 2016 are shown in Figure 3.10, 2016.

[12] Formed in 2005, CMOC's shareholders include Shell (55%), KMG subsidiary company, KazMunaiTeniz (25%), and Oman Pearls Company Ltd. (20%). CMOC's licensed area includes two discovered fields, Ayuezov and Khazar.

[13] Kazakh crude enters the Transneft pipeline system either directly via the Atyrau-Samara pipeline or at Makhachkala after crossing the Caspian Sea from Aktau by tanker.

Figure 3.10. Distribution of Kazakhstan's crude oil exports by route, 2016



Source: IHS Markit

Caspian Pipeline Consortium (CPC)

Growth in Kazakhstan's crude exports via the CPC pipeline over the past two years exceeded the total growth of exports out of the country, as exporters redirected significant volumes from other routes to fill expanding CPC capacity. CPC handled 68% of total Kazakh crude exports (up from 63%) in 2016. Altogether, Kazakh exports via CPC jumped 9% in 2016, to 42.4 MMt/y (891,000 b/d) from 39 MMt in 2015. In 2017 exports are expected to reach ~55 MMt (see text box: CPC expansion).

CPC Expansion

Almost as soon as the CPC pipeline launched operations in 2001, discussions about its expansion also began. In December 2008 CPC shareholders signed an agreement to expand the pipeline from the existing nameplate capacity at that time of 28 MMt/y (560,000 b/d) to 67 MMt/y (1.3 MMb/d) (although it could be expanded further to 76 MMt per year with drag-reducing agents, DRA). Construction on the expansion program began in July 2011, but it has proceeded more slowly than expected. Completion of the three-phase expansion project is now expected by the end of 2017.

The initial phase of the expansion focused on the overhaul of the existing CPC facilities, including rehabilitation of five existing pumping stations and replacement of approximately 88 km of pipeline within Kazakhstan, as well as construction of a third tanker-loading buoy at the Black Sea terminal of Yuzhnaya Ozereyevka and three additional storage tanks with 100,000 cubic meters capacity each (from an initial four tanks). The second phase involved construction of five new pumping stations, and the third consisted of building five more new pumping stations and construction of three additional storage tanks of 100,000 cubic meters each (storage capacity at the tank farm at Yuzhnaya Ozereyevka is to be expanded from 400,000 cubic meters to 1,000,000 cubic meters). The total cost of the expansion project is estimated at $5.4 billion.

Kazakhstan–China Pipeline (KCP)

Shipments of Kazakhstan crude to China via the KCP pipeline (i.e., the 963 km Atasu-Alashankou section) fell in 2015, to 4.4 MMt; in 2016, the decline in Kazakh exports via KCP accelerated, with volumes down 37.5% to 2.8 MMt. As in 2014, the bulk of KCP throughput in 2015–16 was considered Russian crude, delivered via a swap arrangement with Rosneft that began in January 2014: Russian crude delivered to the Kazakh border, recorded as "deliveries to Kazakhstan" before 2014 and supplied to the Pavlodar refinery, has been subsequently relabeled "exports to China." Kazakh oil supply in the pipeline has been a combination of Kyzylorda (Turgay/Kumkol) production and crude from Aktobe Oblast, where output is falling (see above). The long-delayed reversal of flows in the Kenkiyak-Atyrau section of KCP (still carrying oil westward to Atyrau) is expected to occur in 2017–18, given the need to meet total crude requirements in eastern Kazakhstan for export to China and the two refineries.

Nonetheless, for producers in northwestern Kazakhstan, the export route to China still generally offers much lower netbacks than those for westward routes at prevailing transportation tariffs and prices; there is a limit to what can be done to reduce transportation tariffs given the distances involved, although a special "unit tariff" covering the entire route is eventually planned to be introduced. As a sign of potential future change, late in 2016 KTO and CNPC agreed to amend the pricing formula (which is tied to the Brent benchmark minus $5.83/bbl) for the delivered-at-place DAP-price at Alashankou.[14] Over the longer term, a revised Chinese DAP price should be more competitive than in the past relative to the other prices Kazakh producers obtain for export,[15] thus improving the netback.

In December 2016, Rosneft and CNPC extended and expanded their agreement to deliver Russian crude to China via the Kazakhstan-China route. The initial agreement was signed in 2013 to deliver 7 MMt per year during at least 2014–18. The December 2016 agreement extended that period to 2023 and expanded the volume to 10 MMt per year.

Taking into account the expected Atyrau-Kenkiyak section flow reverse (crudetransportation from the 663 km oil pumping station (OPS) to Kenkiyak OPS and further through KCP) as well as Atyrau-Kenkiyak and Kenkiyak-Kumkol pipelines expansion, the capacity of the pipeline to China can handle 20 MMt/y; however, the main obstacles to eastward crude supplies from the west of Kazakhstan are the price offered by China at the border with Kazakhstan and the subdued growth in reserve base.

Baku-Tbilisi-Ceyhan (BTC)

Kazakh crude exports via the BTC route stopped in July 2015 as additional CPC capacity became available. Total Kazakh exports via BTC in 2015 (i.e., prior to the July interruption) were 1.0 MMt (21,000 b/d), a decline of 58.3% year-on-year.[16] There were no flows of Kazakh crude via BTC in 2016. The ongoing drop in Azeri crude exports has led to even more surplus capacity in the pipeline. The BTC utilization rate in 2016 was 54.4%. In April 2017, the energy ministers of Azerbaijan and Kazakhstan discussed potential transportation of Kashagan oil via the BTC pipeline at a meeting in Baku. Kazakhstan also revived talks over the previously shelved Kazakhstan Caspian Oil Transportation System (KCTS) export route via the Caspian to BTC.[17]

Atyrau-Samara

Throughput on the Atyrau-Samara pipeline rose in 2015 (up 1.9%, to 15.6 MMt [330,000 b/d]), owing in large part to increased crude compensation deliveries to Russia, but throughput declined in 2016 to 15.0 MMt (300,000 b/d). The Kazakh oil entering Atyrau-Samara and other Transneft pipelines remains destined for international markets access via Russia's Baltic Ust-Luga export terminal or Novorossiysk.[18]

KTO began transporting Kashagan crude via the Atyrau-Samara oil pipeline section to Ust-Luga in October 2016. The initial shipments of Kashagan oil were transported via the Transneft system and mixed into Russian Urals Blend. However, from the start of 2017 Kashagan oil is transported in batches that preserve the quality of the crude. The crude is then added in the stream of low-sulfur Siberian Light crude to Novorossiysk.

It should be noted that Uzen-Atyrau-Samara pipeline is a "hot" trunk oil pipeline where the oil is heated along the entire length of the pipeline due to a significant amount of highly viscous (heavy) oil coming from the Mangyshlak and Buzachi oil-producing areas in Mangistau Oblast. It is expected that after the flow through Kenkiyak-Atyrau pipeline is reversed, the lighter oil that currently flows to Atyrau from Aktobe Oblast will be exported to China, and the quality of oil in the Uzen-Atyrau-Samara pipeline could deteriorate if a similar amount of similar crude is not injected from Atyrau-based production. Too much of a shift in composition to heavy crude could require the installation of additional oil heating facilities and some reconstruction of the existing pipeline. Also, a sizable variation in crude quality delivered to Samara would need to be settled with Russia.

Omsk-Pavlodar-Shymkent-Uzbekistan

On 23 March 2017, the Governments of Kazakhstan and Uzbekistan signed an agreement to use the existing Omsk-Pavlodar-Shymkent oil pipeline for exporting Russian and Kazakh crude to Uzbekistan. The agreement was signed by KMG and Uzbekneftegaz. The pipeline's existing extension from Shymkent to Bukhara is currently in disrepair, and oil is planned to be transported from Shymkent to Uzbekistan by rail. According to Kazakhstan's Minister of Energy, initial exports will be around 1 MMt (20,000b/d) per year, with possible increases in volumes.

[14] For more information on price dynamics at Alashankou, see NER 2015, chapter 7.2.

[15] State regulation does not apply to the oil export and transit tariffs.

[16] Shareholders in the BTC Pipeline Company are BP (30.1%), SOCAR (25%), Chevron (8.9%), Statoil (8.71%), TP (6.53%), Eni (5%), Total (5%), ITOCHU (3.4%), ConocoPhillips (2.5%), INPEX (2.5%), and ONGC Videsh Limited (2.36%).

[17] KCTS was initially conceived in 2007. The project would include construction of a pipeline from Eskene in western Kazakhstan, the landing point for Kashagan volumes, to a new port at Kuryk on the Caspian coast. From there tankers would carry the crude to ports at Baku, where it would be fed into BTC. In July 2010 KMG announced that KCTS would be delayed until 2018–19 as there was no need for an additional 25 MMt per year (500,000 b/d) of export capacity given the delay in the second phase of the Kashagan project.

[18] The pipeline's connection at Samara allows Kazakh exports to reach any of the western export points served by the Transneft pipeline system. Over the years, Kazakh crude has been exported via marine terminals on the Black Sea, but especially Novorossiysk, via the Druzhba pipeline to Eastern Europe, and via marine terminals on the Baltic Sea.

3.2.5.Regulation of pipeline transportation tariffs

Amendments introduced to Kazakhstan's Law "On Natural Monopolies and Regulated Markets" in May 2015 excluded services for oil transportation for transit through Kazakhstan and for export from Kazakhstan from the regulatory sphere of natural monopolies, meaning that these tariffs are determined by KTO independently. The oil transportation tariff for domestic shipments is still regulated by the Committee for Regulation of Natural Monopolies and Protection of Competition (KREMiZK).

Export volumes to which the export tariff applies provide the bulk of KTO's revenues. The decision to let KTO determine its tariffs comes amid strong competition from CPC for export volumes. In response, KTO is working to improve efficiency, competitiveness, and quality of service. In 2016, KTO transported 43.8 MMt of crude (including 7 MMt of Russian transit crude); the company transports around 47% of Kazakh crude (excluding Russian transit volumes).

For the domestic market, tariffs are calculated on a "cost-plus basis," where the tariff covers the costs of operating the pipelines and a small profit margin to ensure sufficient revenues for business functions. The regulator (KREMiZK) sets tariff ceiling levels. The methodology for calculating the domestic crude tariff via trunk pipelines is also approved by KREMiZK, with the current methodology approved in 2014. Tariffs are calculated for the transit of 1 ton of oil per 1000 km. The most recent ceiling levels for domestic tariffs were approved in 2015 for the period of 2015–19. This general approach to tariff-setting has generally provided a fairly stable and transparent structure for many years.

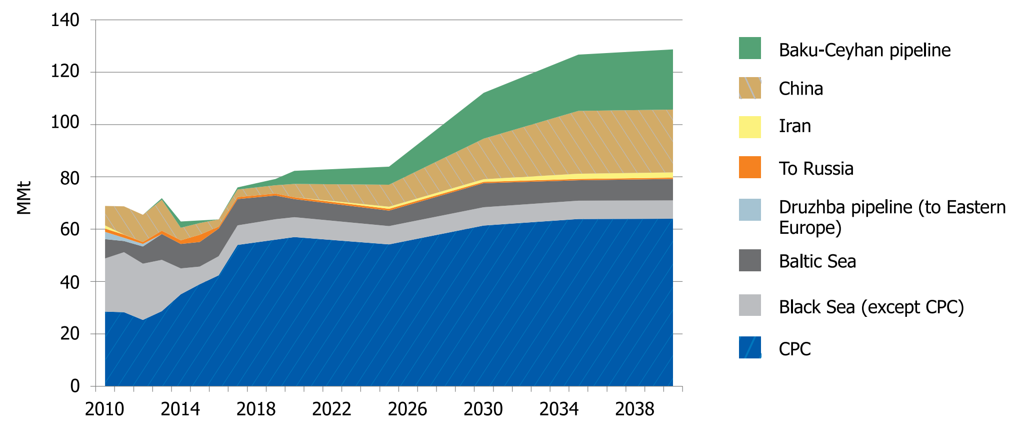
Tariffs for oil pipelines operated by joint-ventures (such as Atasu-Alashankou, Kenkiyak-Atyrau) have their own individual tariffs that are regulated by KREMiZK, although the Ministry of Energy also participates in special circumstances, as with the transit tariff for Russian crude going to China. The tariff for CPC is determined by a separate mechanism, set internally by the consortium as a part of its overall operating agreement.

To attract more oil transit volumes from Russia to China, a unit tariff was established in September 2012, covering the entire route from the Russian border to the Chinese crossing point, which included crude traveling through KTO pipelines and the JV pipeline section. Although initially established in tenge per ton (1,499.15 tenge per ton), it was changed to be paid in dollars in November 2014 (retroactively applying to shipments back to January 2014), effectively raising the tariff for Russian shippers because of the devaluation of the tenge. The latest tariff on the route was approved by the Ministry of Energy on 1 March 2017 for the period 2017–18 at $11.36 per metric ton exclusive of VAT for an annual volume of up to 10 MMt.[19]

3.2.6. Oil export outlook

Out to 2040, Kazakhstan's crude exports are expected to grow, driven by rising crude output and only modest domestic oil consumption growth. The IHS Markit base case scenario projects Kazakhstan's crude exports to expand to 112 MMt (2.2 MMb/d) by 2030 and reach 129 MMt (2.6 MMb/d) by 2040 (see Figure 3.11). Exports via the CPC, Kazakhstan-China, and BTC pipelines are expected to increase the most, while exports via Russia's Transneft system are expected to increase more slowly.[20]

Figure 3.11. Kazakhstan's crude oil exports outlook by route/destination till 2040



Source: IHS Markit

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[19] The tariff is the sum of charges for different sections of the route, including a KTO-operated section (Priirtyshsk–Atasu) at $3.11 per metric ton (exclusive of VAT); and the JV-operated section for the Atasu (Kazakhstan)–Alashankou (China) at $8.25 per metric ton (exclusive of VAT).

[20] Once the Kenkiyak-Atyrau pipeline section is reversed, increased Kazakhstan-China export flows can be achieved, but this oil will have to be attracted from western Kazakhstan. To flow east, the netback for crude from western Kazakhstan (realized sales price after transportation) needs to be the same or higher as from westward exports.

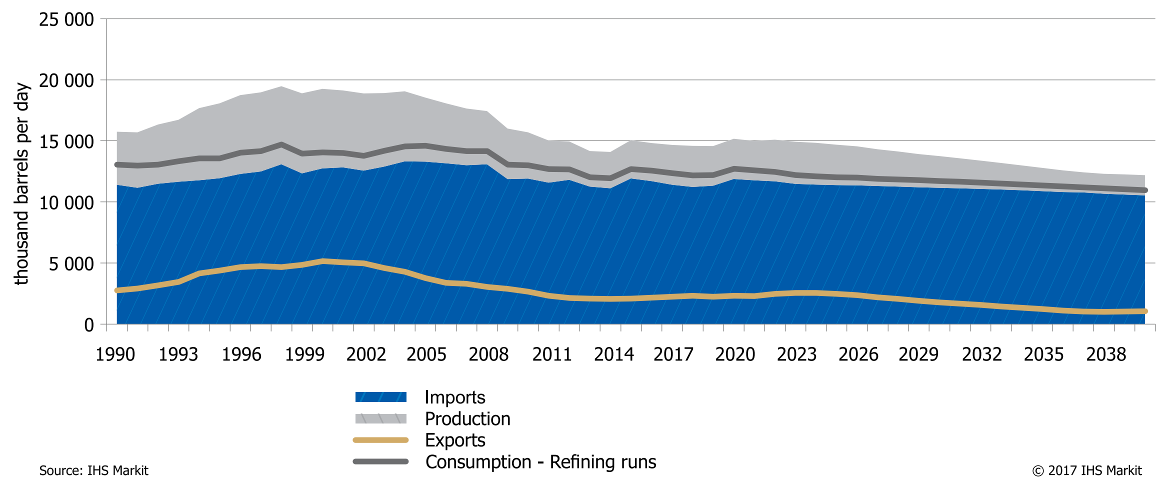
3.2.7. Global oil market developments and trends

A key strategic consideration for Kazakhstan with respect to longer term oil exports is the changing geography of global oil demand, particularly in regional markets that it has either historically supplied (Europe) or in which it is establishing a strong position (China). In Europe, the traditional market for Kazakhstan's crude oil, receiving 78% of its non-CIS crude oil exports in recent years, long-term oil demand is expected to slowly decline (see Figure 3.12). Due to a combination of factors—slower economic growth, decarbonization and energy efficiency policies, technological advancements in the transportation segment, social change, and economic restructuring—oil product demand growth has become almost negligible in recent years. European refined product demand is expected to gradually contract longer term, at an annual rate of around 0.4% through 2040, with product imports also declining (see Figure 3.13). Long-haul product imports, from Russia, the Middle East, and North America, among others, have been playing an increasingly important role in satisfying European product demand, but this is expected to ebb and give way to a growing share from indigenous refining.

Prior to 2014, European refining activity was on a downward decline, as product imports increased. Since 2014, however, refining activity has rebounded: total crude and condensate runs reached 12.6 MMb/d (625 MMt) in 2016, compared to 11.95 MMb/d (595 MMt) in 2014.

Longer term, IHS Markit expects demand for crude oil, and indigenous crude oil production, in Europe to slowly decline (see Figure 3.12). With falling European crude production, and a slower drop in crude demand (-0.6% per year on average to 2040), the European market is expected to remain relatively open to Kazakhstan's crude exports over the forecast period, for at least some incremental volumes.

Figure 3.12. Europe's crude oil and segregated condensate balance outlook



Source: IHS Markit

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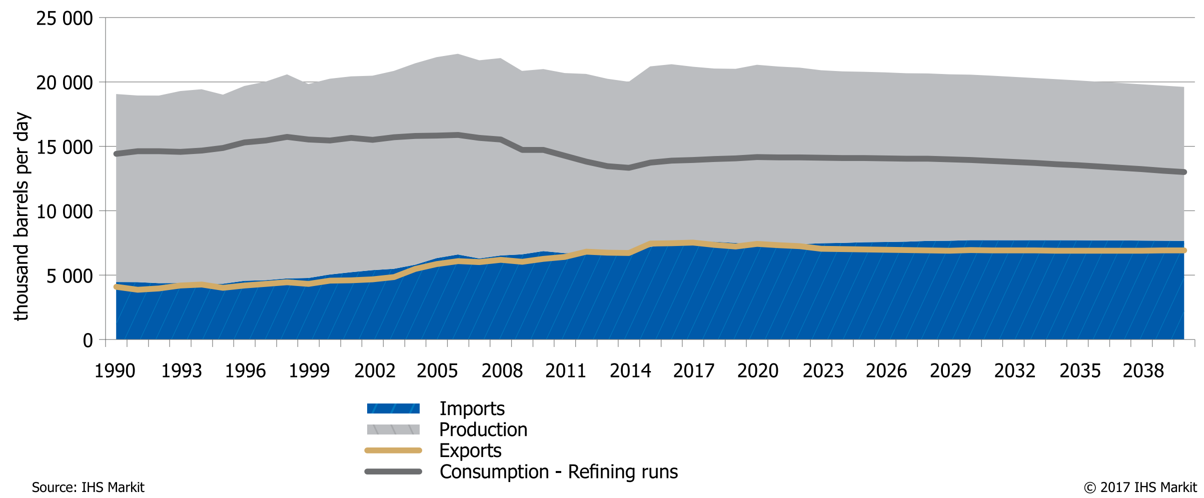
Figure 3.13. Europe's refined products balance outlook



Source: IHS Markit

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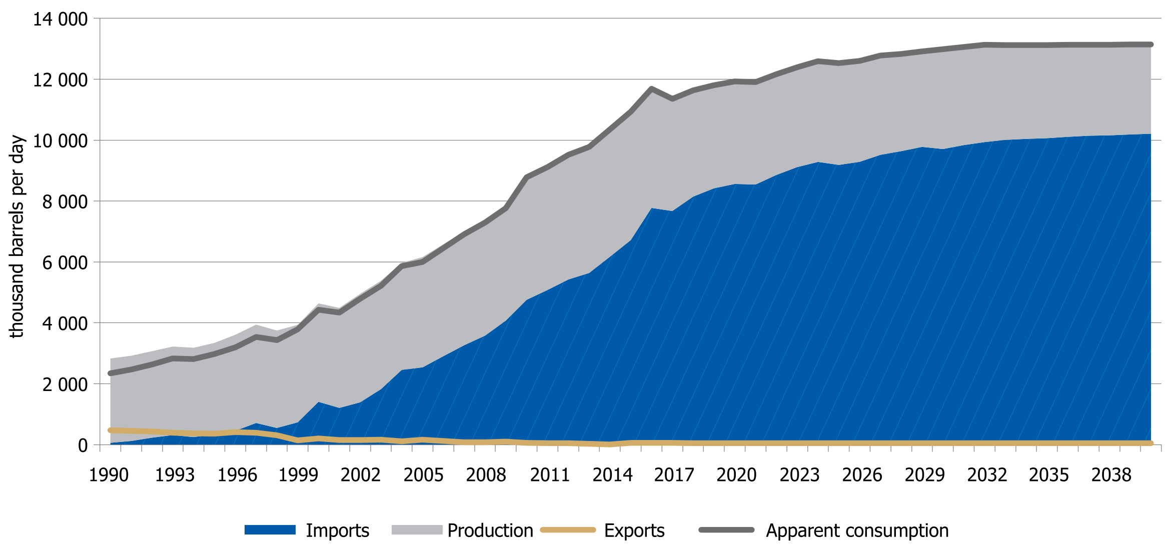
China, along with India and the United States, is considered one of the key pillars of demand growth for liquids worldwide, and it will accordingly remain an important crude export market for Kazakhstan. As China's economy matures, oil demand growth will slow of course. Growth in the transportation sector will ultimately decelerate due to the penetration of alternative fuels and vehicle powertrains, while demand in petrochemical production will likely remain more buoyant. As a result, in China, crude demand is projected to continue to increase: on average by 0.75% per year out to 2020, while its own indigenous production is expected to decline by about 1.2% per year on average. Therefore, China's crude oil imports will rise substantially over the forecast period (by 1.1% per year) (see Figure 3.14).
At present, Kazakhstan is not exporting large volumes of its crude to China (only 2.8 MMt (56,000 b/d) in 2016). However, longer term, exports to China are expected to rise substantially. IHS Markit expects crude deliveries through the Kazakhstan-China pipeline to reach 15 MMt (301,000 b/d) by 2020, and more than double to 34 MMt (683,000 b/d) by 2040 (see Figure 3.11).

Figure 3.14. China's crude oil and segregated condensate balance outlook



Source: IHS Markit

3.3. UPSTREAM EXPLORATION AND TECHNOLOGIES

3.3.1. Exploration Activity in Decline

One of the key challenges facing Kazakhstan's oil industry is the lack of growth in the reserve base, particularly new discoveries. Recent years have seen a significant decline in the exploration activity/success rates both in the Precaspian Basin and across Kazakhstan in general, and both by KMG and by international companies.[21] There have not been many significant recent discoveries despite the country's apparent large potential.
Not only did exploration spending and drilling reach a low point in 2016 (see below), but so did exploration results: the annual addition to oil reserves dropped to only 22% of annual production last year (i.e., about 17 MMt). Another indicator of this lack of success in discovering new fields is that the number of oil producers has stagnated as fewer and fewer new entrants are being attracted to Kazakhstan: listed oil producers numbered 90 in 2016 compared to 89 in 2015 and 87 in 2014. In contrast, the listed number of producers was only 45 in 2005 and 81 in 2010.
More specifically, in the "post-Kashagan" era—i.e., since the Kashagan consortium completed its extremely successful offshore exploration program in 2003—exploration results in Kazakhstan have been quite modest. The few significant discoveries made during the period include Truva North (oil: 500 MMb [68.5 MMt]), Ansagan (gas: 17.5 Bcm), Rozhkovskoye (gas: 17 Bcm), and Rovnoye (oil: 112 MMb [41 MMt] and gas: 80 Bcm). Continued offshore Caspian exploration has yielded many unsuccessful wells (e.g., Kurmangazy, Tyub-Karagan, Atash), while the few discoveries made (Zhambyl, Pearls Group, and Block N) have uncertain commerciality in the present economic environment.
Even so, all of these discoveries have been made by foreign investors, while the national oil company's own exploration program has not produced the desired results. KMG has managed to add only a few post-salt (shallow) discoveries in the Precaspian Basin to the state balance, while its ambition to drill deeper, targeting presalt plays, has not yet borne any fruit. Several deep wells have turned out to be dry (e.g. in the Zharkamys East and Karaton-Sarykamys blocks), some have never been completed due to technical problems (e.g., the Devonian play at Urikhtau), and some blocks were relinquished even before a well was drilled (R-9 and Temir).
There are several reasons for this lack of success. The geological reasons include the well-known difficulties of exploring the Precaspian, the country's most prospective basin: deep reservoirs under a thick salt layer, overpressure, unpredictable reservoir quality of the pre-salt carbonate plays, and the presence of sour gas. Exploring this basin requires relatively sophisticated drilling technologies, is costly, and involves high risk.
However, more important to the decline in exploration activity/success rates have been such problems as underinvestment in exploration more generally, with relatively low levels of external investment due to a combination of above-ground factors, including relatively unfavorable legislation. In the legislative and commercial arenas they include:

- the government's decision to no longer sign new stabilized contracts as a mode of upstream investment
- the increasing trend for greater state control over, and ownership of, petroleum assets
- the difficult, protracted negotiating process with the Ministry of Investment and Development and the Ministry of Energy, and other government bodies(particularly for offshore assets), as well as KMG
- the challenging business environment and lack of transparency.

Technological limitations have also played a role, including a persistent shortage of drilling rigs capable of operating in the shallow waters of the Caspian Sea, until very recently, and then demand essentially disappeared with the collapse in international oil prices.[22] The rig shortage slowed down not only wildcat exploration, but also the appraisal of existing discoveries. Limited access to geological information, both for potential investors and for the companies already active in the country, constitutes another hurdle impeding the development of new projects. High costs, both in the exploration and development phases, constitute another paramount issue.
Kazakhstan's authorities, although appearing to understand certain legislative and procedural obstacles to investment in the petroleum industry, have been slow to realize planned improvements. The issuance of a revised, new Subsurface Code has been delayed from 2016 to late 2017, with implementations scheduled to begin 1 January, 2018. Although the onshore bid round moratorium was lifted in 2013, only two competitive rounds have taken place since, and there is no clear understanding as to when the next one will be held, or what the frequency will be. The two rounds that were held allowed interested investors just one month to acquire the right to participate, evaluate the geological information packages, and to decide on bidding. Unsurprisingly, both failed to attract any of the industry's well-known names.

3.3.1.1. Hydrocarbon Prospectivity in the Precaspian Basin: Project Eurasia

The Precaspian Basin remains the country's main prospective area for conventional petroleum resources. According to Kazakh estimates, the basin holds around 80% of the country's undiscovered resources with the basin's presalt section holding the most promise. It is believed that its presalt carbonate platforms play still holds significant potential for large to medium-sized discoveries. However, the presalt exploration has significant operational challenges, including great depth, reservoir quality risk, overpressure, and presence of sour gas, all of which complicate development and increase costs.
The Project Eurasia initiative seeks to partly address the issue of the Precaspian Basin's remaining potential. The initiative was approved by Kazakhstan's government and was officially launched

[21] A significant decline in the exploration activity/success rates in Kazakhstan was identified as one of the primary shortcomings in the IHS Markit's proprietary PEPS investment attractiveness index discussed in Chapter 2 ("upstream activity" and "upstream success" variables). A recent example is the buyback by KMG EP of a 49% share of the 1670 km^2 Karpovskiy Severnyy block in July 2017 from Hungary's MOL for a nominal $1. The shares in the block, which is located northwest of Uralsk near the Russian border, had been acquired by MOL from KMG EP in 2012. However, with no commercial discovery, MOL decided to sell the asset. But when no buyers emerged, KMG EP took it back.

[22] For example, the unavailability of a suitable rig to drill in super-shallow waters forced the LUKOIL-Repsol consortium to relinquish the Zhambay block before even spudding a well. The first Kazakhstan-built jack-up rig became operational only in 2017. There is also the Caspian Explorer semi-submersible rig.

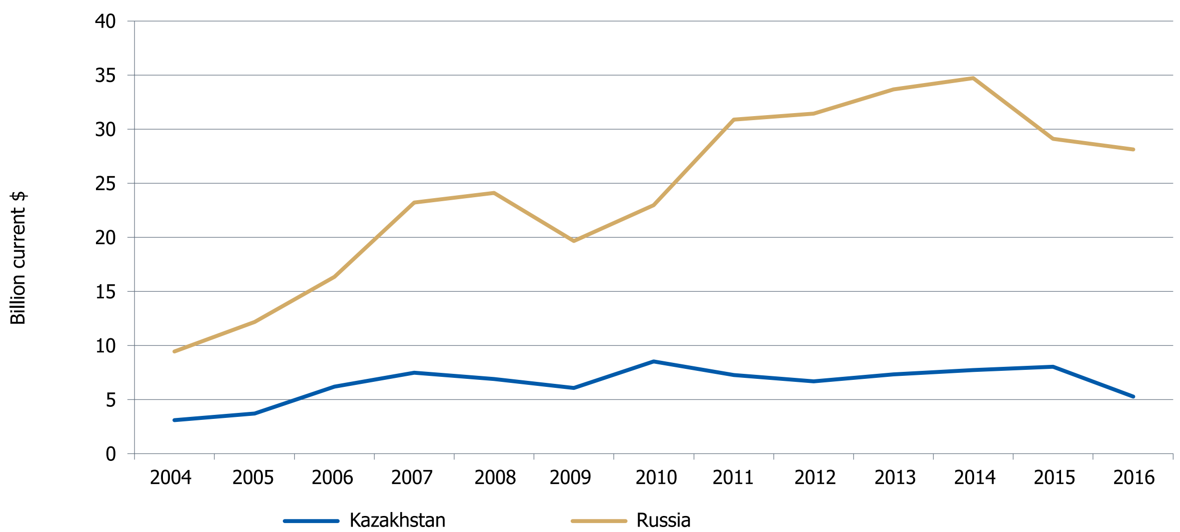
by the Kazakh and Russian presidents in October 2014. The project seeks to identify the Precaspian Basin's deep potential in the Kazakh and Russian sectors by drilling an exploration well up to 15 km deep. The project is expected to run through 2020 at an estimated cost of $500 million. It will be implemented by a consortium of Kazakh and international companies, which is in the process of negotiation for being formed. The start of the project was originally scheduled for 2016. The Energy Ministry held the first round table meeting about legal and contractual aspects of the Eurasia consortium project with Eni, Rosneft, CNPC, SOCAR, and NEOS GeoSolutions in February 2017, with a memorandum of understanding being signed in June 2017. The project would comprise three stages, the first being collection and processing of existing data. A second stage should acquire a series of regional seismic lines. Stage three would drill a new deep reference/stratigraphic test well. The president of the Association of Petroleum Geologists of Kazakhstan, Dr. B. Kuandykov, who also serves as the project coordinator, estimates the basin's deep potential to be around 40 billion tons of oil equivalent in up to 20 fields.

3.3.2.Kazakhstan's oil services and drilling trends

Service activities in Kazakhstan have grown steadily to address increasingly challenging local technical issues. In particular, drilling is a key segment of the services industry—along with associated construction and equipment. Drilling is an input into upstream production, and while it is important to reflect on the relative level of effort (the amount of inputs into the process), this does not always translate directly into actual results.

Kazakhstan's service sector is relatively small, but is growing steadily both financially and physically. Since 2000, fixed investment into Kazakhstan's petroleum extraction (a rough proxy for upstream expenditures for services) reached a high (so far) of $8.6 billion in 2010, but fell to $5.3 billion in 2016 (see Figure 3.15).[23] Compared to Russia, Kazakhstan's market for upstream services is much smaller: investment in Russia's upstream oil sector amounted to about $28.1 billion in 2016. Similarly, Russia's oil-related drilling, at 25.6 million meters in 2016, was nearly 23 times as much as in Kazakhstan, with only 1.1 million meters.

Figure 3.15. Investment in Oil and Gas Extraction, Kazakhstan vs. Russia



Source: IHS Markit; Rosstat; Statistics Committee RK

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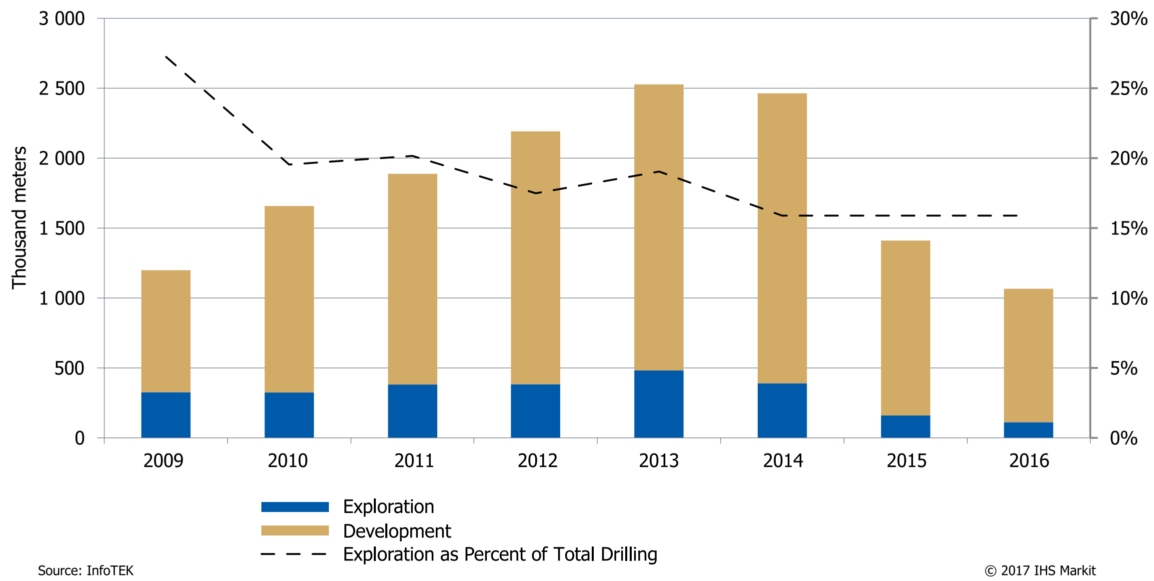
Total drilling activity in Kazakhstan recovered rapidly after the 2009 recession, reaching about 2.5 million meters in 2014, which is more than double the 2009 result (1.2 million meters), but drilling has contracted sharply since in 2015–16 (see Figure 3.16). Exploratory drilling has contracted the most, falling to only about 16% of total drilling activity. Consequently, Kazakhstan's operating well count initially grew somewhat after 2010, but has remained fairly steady at about 21,500 wells in the last few years (see Figure 3.17).

Figure 3.16. Exploration and development drilling in Kazakhstan, 2009-2016



Source: InfoTEK

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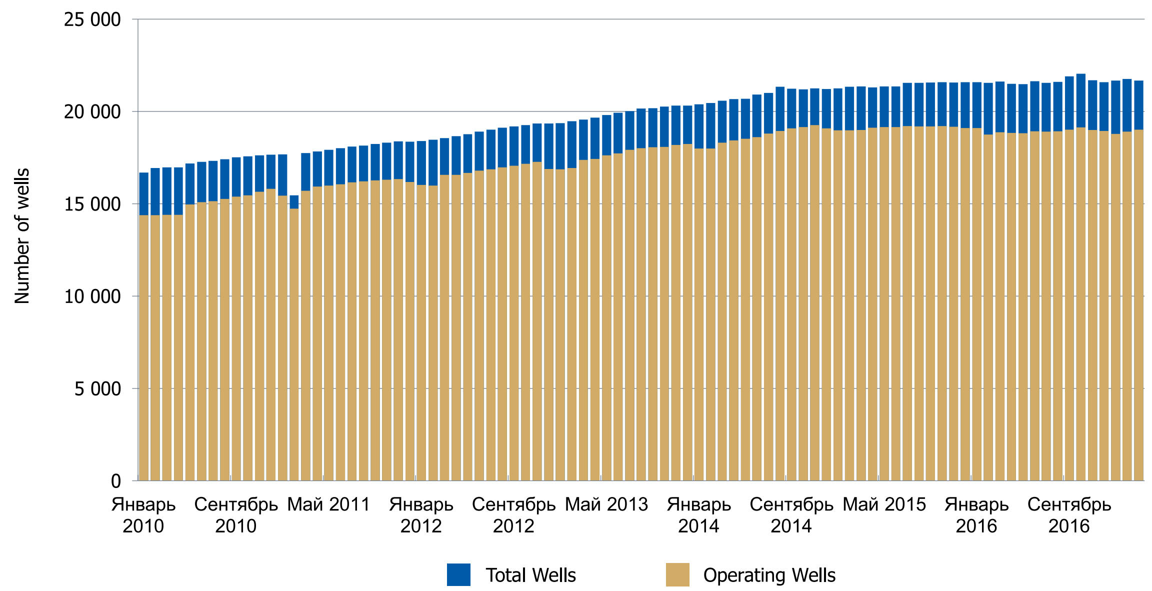
Figure 3.17. Operating well stock in Kazakhstan (end-of-month)



Source: InfoTEK; Ministry of Energy

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[23] Fixed capital investment by a firm is defined as investment in durable (fixed) assets such as buildings, machinery and equipment, or other infrastructure or structures that a firm holds for at least one year.

Exploration Spend by Global Companies Retrenches along with Global Upstream Spending Amid Low Oil Prices

One approach for evaluating the level of exploration spending in Kazakhstan is to look at the ratio of exploration spending to production of the so-called Global Integrateds—a group of international majors that includes BP, Chevron, ExxonMobil, Shell, and Total—as well as Eni and Statoil—since 2000. The key trends are:

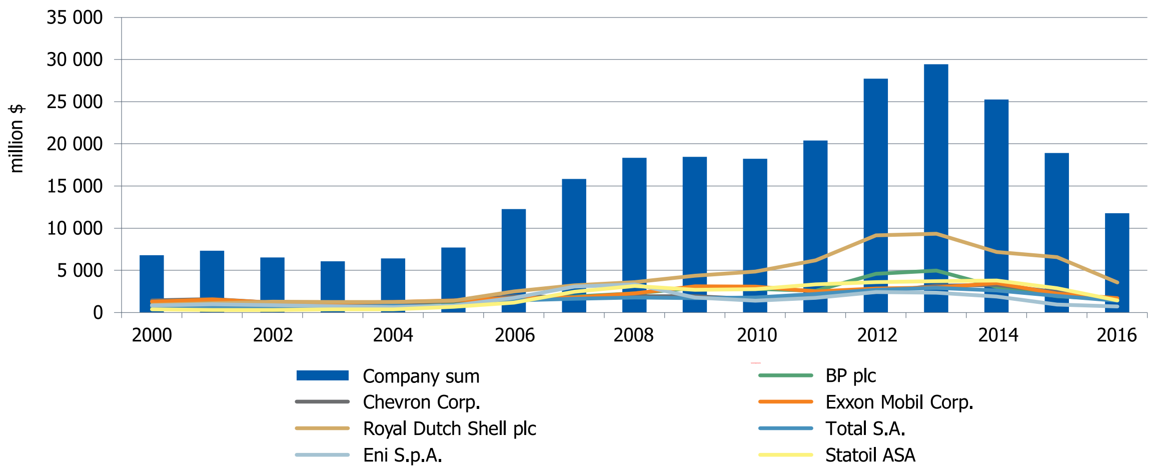
• Total combined exploration expenditures of these majors between 2000 and 2013 globally increased at a average annual rate of 11.9%, rising from $6.8 billion to a peak of $29.4 billion (in nominal dollars) (see Figure 3.18). Total expenditures then plummeted, reflecting the weak oil price environment and the general cutback worldwide in upstream spending, falling to just $11.8 billion for exploration in 2016. In 2016, annual exploration spending by the individual companies varied between $0.7 billion (for Eni) and $3.6 billion (for Royal Dutch Shell).

• But at the same time, aggregate production of hydrocarbons globally for these companies as a group, our size scalar, varied between 18.3 million barrels of oil equivalent (MMboe/d) and 20.2 MMboe/d, averaging 19.2 MMboe/d over this period (see Figure 3.19).

Therefore, scaling the companies' exploration spending by the amount of hydrocarbon production, the spend of the these companies on exploration globally increased from $ 1,024 per thousand boe (Mboe) produced in 2000 to a peak of $ 4,282 per Mboe in 2013 (and a low point of $860 per Mboe in 2003), but then declined to $ 1,640 per Mboe in 2016 (see Figure 3.20). The average over the period was $2,161 per Mboe.

In comparison, in 2016 KMG EP spent about 5 billion tenge ($15 million at the average annual exchange rate) on exploration in its core assets, which had a production last year of about 64.4 MMboe, so the ratio for the company is about $233 per Mboe, a level substantially lower than that of most international companies. There are two ways to look at Kazakhstan's exploration needs as a whole. One is to apply the 2016 international ratio, of $1,640 per Mboe, to Kazakhstan's hydrocarbon production of 745.9 MMboe, which means that the country would need to be spending about $1.2 billion per year on hydrocarbon exploration to be spending on par with the large international E&P companies. The second way is to apply the average ratio for the period, of $2,161 per Mboe, which means that Kazakhstan would need to spend about $1.6 billion per year on hydrocarbon exploration to match the effort of international companies. Both calculations arrive at very similar results.

Figure 3.18. Global exploration costs by selected global integrated majors



Notes: Costs incurred in identifying prospective areas that may warrant further examination in the search for hydrocarbons; includes geological and geophysical/seismic costs as well as exploration drilling costs.

Source: IHS Markit

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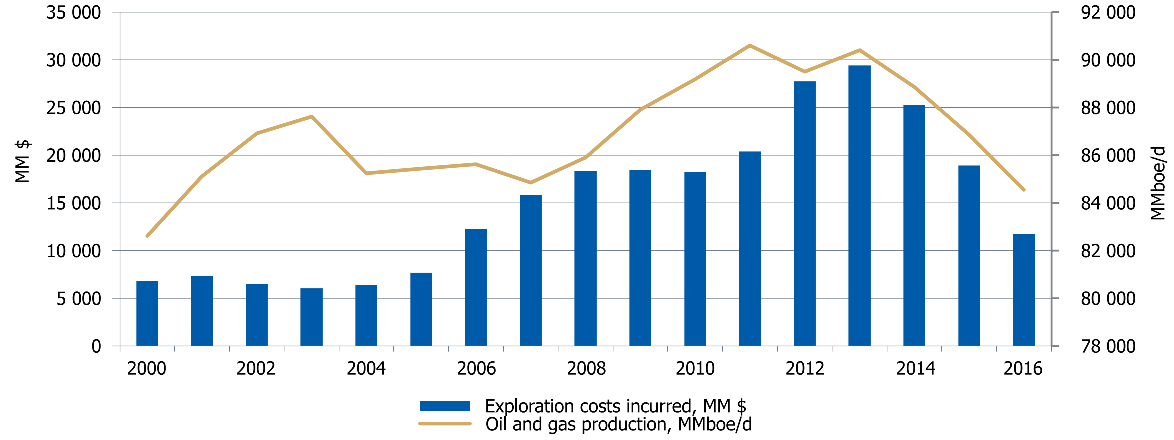
Figure 3.19. Global exploration costs vs global oil and gas production for selected international majors



Notes: Companies included are "Global Integrateds" (BP, Chevron, ExxonMobil, Shell, and TOTAL) plus Eni and Statoil

Source: IHS Markit

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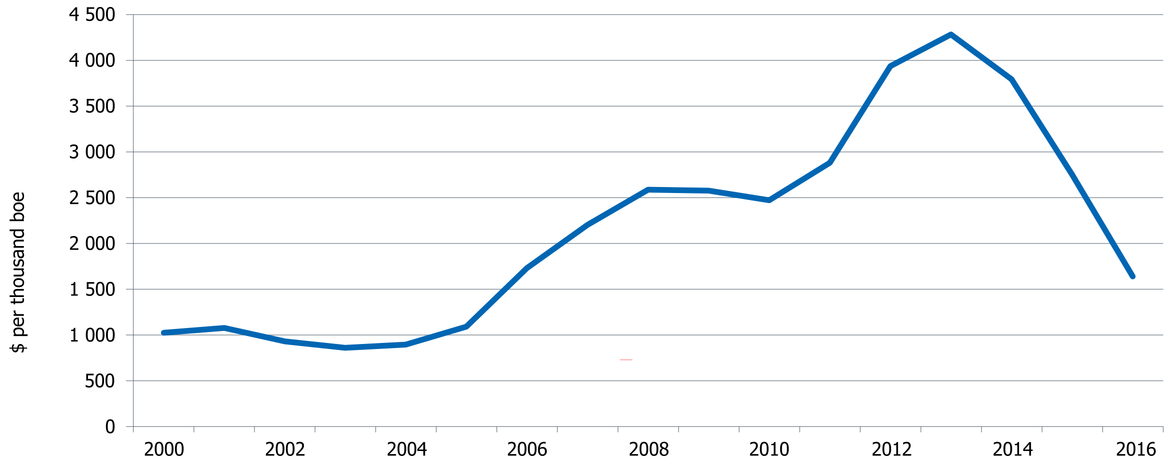
Figure 3.20. Exploration costs per unit of hydrocarbon production for international oil majors



Notes: Companies included are "Global Integrateds" (BP, Chevron, ExxonMobil, Shell, and TOTAL) plus Eni and Statoil

Source: IHS Markit

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3.3.3. Upstream technologies: general digitalization, smart wells, horizontal drilling, multi-stage hydraulic fracturing

Because oil and gas production is among the most capital and technical intensive of all industries, technological innovation is critical to supporting the discovery of economically viable new reserves and improving the efficiency of resource extraction. For example at older existing fields, international experience indicates that decline can be stemmed (and in some cases even reversed!) by a combination of improved, fairly simple production methods and innovative exploration techniques, with striking results.[24] Additionally, effective use of 3D or even 4D seismic surveys can significantly expand the reserve base to which the more advanced production methods can be applied. Major new technologies involved in the exploration, development, and production of oil and gas deposits include general digitalization, smart wells, horizontal drilling, multi-stage hydraulic fracturing, seismic, basic reservoir modeling, and careful placement of new wells to boost oil production and limit water extraction.

[24] Kazakhstan's mature fields currently appear to be producing at rates below their ultimate potential. The average recovery rate is below 25%, whereas geological experts estimate that recovery rates could reach 30–40% after some basic modifications.

These same techniques have also been successfully applied to achieve performance maximization at new greenfield acreages as well.

IHS Markit's Upstream Costs and Technology Service researches technology developments by E&P organizations worldwide to understand changing technology priorities as well as to gain early insights into broader industry strategy developments. E&P organizations include: commercial and state oil producers; oilfield services (OFS) firms; engineering, procurement, and construction (EPC) firms; universities; as well as independent research organizations. IHS Markit conducted the first inventory in 2012–13 by surveying 45 E&P organizations. This approach has some limitations, including a bias towards organizations that are more publication-prone; lack of coverage of sectors supplemental to E&P such as IT or automation and control technologies; and lack of direct correlation with budget or staff allocations by E&P organizations. However, the size and diversity of the survey helps to overcome these limitations to accurately reflect industry focus areas and trends.

IHS Markit has structured the results of its analysis in the form of an IHS Markit E&P Technology Classification Schema that details technology development under five major focus areas (see Table 3.3).

The change in upstream technology development focus areas between the surveys conducted in 2012–13 and in 2014–15 reflects the upstream industry's shift from growth to retrenchment in response to the oil price downturn, as E&P organizations moved away from long-term capital-intensive projects with uncertain outcomes to focus on technologies that rapidly deliver cost-effective short-term value and scale.

Specifically, in the low oil price environment companies reduced their emphasis on all aspects of well construction and intervention technologies (e.g., drilling, completion, reservoir stimulation). Drastic cuts in exploration activity likely contributed to the reduced focus on seismic acquisition technology, while investment continues to grow in seismic processing and interpretation technologies that can be applied to legacy seismic surveys in a cost-effective manner.

As companies emphasize efficiency to help manage capital and operating costs, as well as to protect base production levels, they have promoted digital and automation technologies, including oilfield mobility and connectivity technologies, robots and drones, and the installation of automated sensors and data-collection that allow for real-time data analytics and potentially, artificial intelligence (see also Chapter 2.2 on global investment trends). Another emphasis is on short-term, incremental facilities technology development, including electrification and dual-fuel engines to increase energy efficiency, advanced materials and miniaturization to reduce facility weight, and smart coatings and flow assurance to reduce maintenance.

The industry appears to be prioritizing increasing recovery from existing reservoirs, so recovery technologies such as IOR/EOR (e.g., waterflood-

Table 3.3. IHS Markit technology classification scheme

1. Subsurface & Imaging	2. Well Construction & Intervention	3. Facilities & subsea	4. Recovery	5. Digital
1.1 Seismic Acquisition Technologies & Methods (wide azimuth-like applications)	**2.1 Bit Technology** (laser drilling, …)	**3.1 Subsea Processing**	**4.1 Artificial Lift** (Subsea boosting, pump technologies, gas lift, compression,, …)	**5.1 Digital Oil Field of the Future** (reservoir management optimization, production optimization, surface facilities optimization, …)
1.2 Seismic Processing & Interpretation (improved subsalt imaging, …)	**2.2 Telemetry & Tools** (high bandwidth BHA communication, new LWD tools, improved geo-steering)	**3.2 Subsea Power** (generation, battery technology, …)	**4.2 Water Flooding**	**5.2 Integrated Characterization & Simulation** (reservoir, process, …)
1.3 Micro-seismic	**2.3 Automation (automated** drilling procedures, seafloor drilling, robotics for rigless intervention, …)	**3.3 Extreme Environment** Hardware (temperature, corrosive fluids, …)	**4.3 Gas and non-Miscible Chemical Flooding Methods**	**5.3 Big Data & Analytics** (prioritization of drilling/ workover/sidetrack candidates, injection program optimization, …)
1.4 Non-Seismic Remote Sensing Methods (CSEM, aeromagnetics, full tensor gravity gradiometry, satellite hyper-spectral, …)	**2.4 Coiled Tubing (drilling** intervention, well clean up, stimulation, …)	**3.4 Processing Technology** (heavy oil upgrading, **…**)	**4.4 Miscible Flooding Methods** (gas, gas cycling, polymer, solvent, nitrogen, CO2, surfactant, vapex, …)	**5.4 Standard Application & Data Platforms**
1.5 Time-lapse Methods (seismic and non-seismic)	**2.5 Drilling & Workover Fluids** (e.g. drilling mud, welborecleanup)	**3.5 Flow Assurance**	**4.5 Thermal Methods** (steam flooding, cyclic steam, THAI, combustion, SAGD and its derivations, ...)	**5.5 Sensors** (Fiber, PT, …)
1.6 Wireline Telemetry & Tools (e.g. resistivity, NMR)	**2.6 Completion Technologies** (expandable tubulars, multi-laterals, intelligent completions, …)	**3.6 Water Handling**	**4.6 In-situ & Wellbore Processing & Upgrading** (microbial methods, downhole separation, …)	
1.7 Rock property & Rock Correlation Tools (non wireline)	**2.7 Reservoir Stimulation** (hydraulic fracturing, chemical, laser, hyper-seismic, …)	**3.7 Gas Monetization Methods** (FLNG, CNG, mini-GTL, …)	**4.7 Tracers** (chemical tracers, nanobottechnology, …)	
1.8 Basin & Play Insight Tools		**3.8 Carbon Capture Storage and Use** (CCSU)	**4.8 Methane Hydrate Production Mechanisms**	
		3.9 Spill Response (dispersants, microbial, …)		
		3.10 Maintenance & Inspection		

ing, miscible flooding), and reservoir and production optimization remain prevalent. But even these operations could be optimized with greater use of digitized data monitoring and collection, as reportedly at some older fields, waterflooding is executed based on limited and likely inaccurate data points.
In terms of technology developments by resource class, E&P organizations have maintained a focus on two recent sources of global production growth—unconventionals (although the latest survey showed less focus on shale gas technologies) and deepwater—while shifting away from technology development for other high-cost and technically challenging asset types, especially heavy oil, but also Arctic, high pressure–high temperature, natural gas hydrates, and sour gas.
While Kazakhstan is affected by these global trends, there also are certain challenges that shape demand for technologies specifically in Kazakhstan. Subsurface challenges include complex reservoirs (sub-salt carbonate or terrigenous sediments with significant heterogeneity), high temperatures and pressures, and high hydrogen sulfide (sour) content.
Above-ground challenges include a harsh natural environment on the surface (broad temperature swings, shallow water offshore, ice formation, and low seabed temperatures) and logistics (the country's landlocked location complicates importing equipment and exporting time-sensitive materials such as cores, for lab testing). The view on technologies that are needed in Kazakhstan was systemized in the Kazakhstan Upstream Oil and Gas Technology and R&D Roadmap study carried out by Royal Dutch Shell between 2010 and 2013 (see text box: Kazakhstan Upstream Oil and Gas Technology and R&D Roadmap). The project identified and ranked specific challenges facing Kazakhstan's upstream sector, solutions to these challenges, and the way these solutions can be obtained.

Kazakhstan Upstream Oil and Gas Technology and R&D Roadmap

In order to help Kazakhstan focus its research and development (R&D) efforts and to contribute to the government's innovation agenda, Shell in collaboration with more than 300 representatives across the entire oil and gas industry (including both operators and R&D personnel), undertook the Kazakhstan Upstream Oil and Gas Technology Roadmap project between 2010 and 2013. The project's goal was to provide a coherent picture of the most urgent challenges facing Kazakhstan's upstream oil and gas in order to assign priorities for high-level decision making. Through the workshops, interviews, and expert panels, the project identified, screened, and ranked major technology challenges and proposed solutions.
The project's first phase resulted in the formulation of 15 prime challenges in five technology target areas, as well as 50 main solutions, all presented in May 2011. These five target areas are described below:
The reservoir characterization area includes the challenges of: (1.1) seismic data acquisition; (1.2) reservoir description—geology, rock, and fluid interpretation; (1.3) well logging and in-well monitoring; (1.4) core analysis and data interpretation; and (1.5) fluid property analysis. Kazakhstan was found to have moderate overall capability in this target area, with strong geological knowledge, good subsurface modeling capabilities, and developing capabilities in core and fluid analysis. In contrast, there is little R&D focus on seismic data acquisition and some lack of awareness of issues surrounding the handling of high-H_2S streams.
Field equipment encompasses the challenges of: (2.1) corrosion plus equipment and materials for sour service; (2.2) operating in the offshore ice and during cold weather; and (2.3) management of sulfur. Here the Roadmap survey determined that Kazakhstan is reasonably well situated. There are good capabilities in sulfur management and ice operations, and high quality field engineering design services. However, work on equipment and materials for sour service was found to be lacking in focus in the upstream area.
Fluid flow and processing comprises the challenges of: (3.1) flow assurance and sand control; and (3.2) water management. The assessment exercise highlighted technical weaknesses in this area in the upstream but noted much stronger flow assurance and water treatment capabilities downstream.
Wells and field management consists of the challenges of: (4.1) drilling and well costs; and (4.2) field management: optimized recovery including IOR/EOR (improved oil recovery/enhanced oil recovery). The roadmap assessment found capabilities in this area to be patchy. Institutes/laboratories were found to be generally weak, but some excelled in particular areas (e.g., drilling-fluid testing, use of waterflooding and EOR techniques to optimize recovery, dynamic modeling).
HSE and operations incorporates the challenges of: (5.1) emergency response and disaster recovery; (5.2) operational HSE (health, safety, environment) risk reduction under sour production conditions; and (5.3) environmental impact. The roadmap assessment found that little work was being done in the area of emergency response and disaster recovery or in operational risk reduction in sour conditions. In contrast, several institutes/laboratories were undertaking good work on environmental impact and are in a position to offer competitive impact assessment services.
During the second phase of the Roadmap Project, the detailed analysis of the first stage results was complemented by a technology readiness study that assessed the feasibility of the solutions' implementation in Kazakhstan. In addition, experts assessed Kazakhstan's research and development capabilities by visiting universities and research companies.
During the third phase, a workshop in June 2012 resulted in development of an outlook for the industry taking into account findings from the first two stages. Also, experts identified enablers (examples of best practices) by reviewing policy measures taken in Norway, Brazil, China, and Malaysia.
The fourth phase resulted in shaping the roadmap and formulating compelling recommendations for decision-makers in Kazakhstan with the help of consultants from the University of Cambridge. At this stage, all the challenges were ranked by technology experts in accordance with their potential, if addressed, to provide the maximum financial benefit (i.e., reduce costs and increase production), as well as to reduce risk and promote safety. Specifically, improved and enhanced oil recovery (challenge 4.2), equipment and materials for sour service (2.1), drilling and well costs (4.1), and water management (3.2) were judged to be the most pressing challenges, each yielding potential savings in excess of $5 billion. These were followed by ice/cold weather operations (2.2), health and safety risk reduction in sour conditions (5.2), and management of sulfur (2.3) each yielding potential savings in the $3–$4 billion range. The total value of successfully responding to all 15 challenges would be in the tens of billions of dollars. But what is also evident from the Roadmap's analyses of specific measures designed to address these challenges is that their implementation will be proportionately expensive.
Then the experts identified over 230 solutions, which were consequently bundled into a group of 75 solutions. These were ranked based on the cost and time required for implementation, opportunities to promote local content and local research and development, and the personnel qualifications required. Specifically, in terms of local content, the project identified that the most realistic opportunities are in the areas of steel and concrete structural design and fabrication, the provision of upstream chemicals, and well sand-screen manufacturing. In addition, the manufacture of corrosion-resistant alloys, the provision of special core analysis services, jack-up rigs for cold climates, ice-scouring design, as well as sulfur storage, transport, and products were identified as areas with further opportunities.
Finally, solutions were categorized depending on how these could be obtained under three scenarios: simply transferred to Kazakhstan, transferred to Kazakhstan but requiring significant adaptation, and would need to be invented.

The priorities identified by both the IHS Markit E&P Technology Classification Schema and the Shell Roadmap were generally confirmed in interviews conducted by IHS Markit analysts throughout 2017. Kazakhstan's upstream industry participants highlighted several specific technologies, the implementation of which would seem to be readily achievable in a relatively short period of time. The correct application of these technologies could solve issues that are considered to be "low hanging fruit". These include:

Data automation and digitization solutions. Installation of sensors on valves and pumps, and well-log digitalization allow for the real-time collection of information on temperature, pressure, and other features for analysis. Interpreted data, collected from smart-field technologies, can assist subsoil users to preemptively anticipate and avoid operational complications, improve HSE conditions, eliminate non-productive time, and identify potential new areas for drilling. Data automation and digitalization solutions can also assist in reservoir visualization, monitoring, and analysis; well performance monitoring and evaluation; artificial lift optimization; waterflood management; well log data; seismic modeling; and asset integrity management systems. More accurate data will lead to more effective operations and more efficient use of critical resources, such as water. Though, it is important to add that any move to digitize data must be complimented with personnel training so that the data is accurately interpreted.

Pipe leak detection systems. Leaks in oil pipelines both at the surface and downhole are a major issue in Kazakhstan's oil sector. Installing leak detection systems (so-called "internal" detection methods, also known as computational pipeline monitoring systems) would reduce losses and improve operational efficiency. Such systems use fast-scanning sensors to monitor pressure, flow, and temperature, and identify tell-tale indicators of leaks. Another promising approach is the use of fiber optic cable sensors in oil and gas pipelines.

The installation of distributed temperature and pressure sensors over completion intervals could help monitor inflows, and passive gauge data could assist in determining optimal flow rates, and identifying mechanical problems.

Corrosion management systems. Such systems are identified as particularly relevant at such major fields as Tengiz and Kashagan due to these fields' extreme weather, high pressure, and elevated levels of hydrogen sulfide and carbon dioxide. New and developing anti-corrosion technologies are now available that are less expensive than corrosion-resistant alloys currently utilized, and could be applied in Kazakhstan. For example, Mesocoat, a subsidiary of US-based Abakan, Inc. that focuses on subsurface engineering solutions, has designed a CermaClad high-speed technology that uses a high intensity light source to fuse anti-corrosion materials to large swaths of steel. Application of this innovation to the pipe-cladding manufacturing process could potentially provide a solution to the problem of providing more affordable, corrosion-resistant pumps in Kazakhstan.

For offshore operations, **remote assistance technologies**, such as Hitachi's ASSIST, allow workers on a rig or in the field to transmit information to a central office via live video streaming, and vice versa. Such a technology could prove useful in situations in which rapid decision-making is essential, should unusual circumstances arise. These remote communications systems would be particularly important in shared facilities, if co-development of offshore assets proceeds. Moreover, **communications interoperability platforms,** such as those operated by Motorola Solutions, could be very helpful for KMG to better coordinate messaging, information flow and instructions between headquarters in Astana and field leadership, as well as in training workers and contractors in the field.

Passive monitoring of producing oil fields is not conceptually a new technology, but is a relatively new and emerging analytical practice in E&P, specifically reservoir management. The driving concept behind the technology is that a reservoir is not static, and oil recovery, over time, affects the host rocks. Understanding of reservoir potential can thus be enhanced in real time by passively monitoring the host rock using a variety of technologies that do not activate a seismic source, but rather use already in-place sensors (geophones) to track subsurface changes. Passive seismic monitoring is often used to track, evaluate, and mitigate earthquake risk, reservoir deformation, and fluid leakage, as well as to optimize operations at an existing project. While passive seismic monitoring is not widely practiced as part of standard reservoir management, its use could proliferate in the future as the methodology is refined and the data retrieved from such operations support additional applications. Over the long term in Kazakhstan, such technology and analytical methods, when accurately applied in the appropriate context, could potentially promote discovery of additional reserves in already producing assets and better manage existing reserves.

Regardless of the type of equipment, technology is only a tool, and it is the correct application of the tool that renders it effective. Policymakers and energy executives in Kazakhstan must keep in mind that importing technology goes hand in hand with workforce education and development.

3.4. LEGISLATIVE BASE AND REGULATION OF KAZAKHSTAN'S UPSTREAM SECTOR

3.4.1. Subsoil Regulation

In addition to low exploration rates, another challenge of the Kazakhstan's oil sector is finding the right combination of subsoil and tax regulation to ensure continued success of the industry. The National Energy Report 2015 detailed the development and current situation in the subsoil and tax codes as they relate to the oil and gas industry, highlighting achievements and downsides of Kazakhstan's current tax and subsoil codes.

Financial aspects of the oil and gas industry are primarily governed by the Tax Code, which establishes the rules of subsurface use taxation, and the Subsoil Use Law, which contains the basic legal framework for granting, using, and assigning or terminating rights to a subsurface user as well as for subsoil operations.[25] Recognizing the acute global competition for investments in the oil and gas sector, the government of Kazakhstan has initiated a legislative review of both the Tax and Subsoil Use codes (see below). This review provides an opportunity to create a healthy environment for investment and effective resource development and to set up a more attractive long-term, stable investment framework. We encourage the government of Kazakhstan to take bold steps in this direction in the interests of long-term development of the national oil and gas industry.

3.4.1.1. Tax Code

Kazakhstan's Tax Code (introduced in January 2009) employs multiple tax instruments as opposed to only one or two; it also specifies levies on both sales and profits. This combination has the potential to provide a greater balance of interests between producers and the government over the life of a project. The introduction of Kazakhstan's Tax Code was a major step toward establishing a clearer framework for taxation of the energy sector, leading to greater certainty and transparency in Kazakhstan's taxation structure, although the timing was unfortunate, as it was introduced during the great global recession and financial crisis, when global oil prices fell from highs of about $130 per barrel in mid-2008 to only about $40 per barrel in early 2009.

Kazakhstan has generally been cautious to substantially amend the Tax Code. Nonetheless, there are a number of problematic components in Kazakhstan's existing tax regime, and tax reform must occur in order to reinforce the changes made in the proposed Subsoil Code. Chief among them are the relatively high total tax take compared to international experience, and the especially high upfront take by the government. This means that the tax burden is not proportional to the risks born by the investor, particularly at different stages of the project cycle. Also the Tax Code does not fully encourage the adoption of new technologies to arrest declines at mature fields. Finally, the current Tax Code lacks a stable long-term contractual framework for large, high-risk projects with long gestation periods for investment, such as for offshore blocks.

Kazakhstan's oil sector policy has moved in a positive direction overall in the wake of the recent world oil price collapse beginning in 2014, with one important consequence so far being reform of the crude export duty regime. Kazakhstan introduced a new crude export duty formula, effective 1 March 2016, based on a sliding-scale tax structure, with duty rates on crude oil exports linked to the average price of Urals and Brent blends during a monthly monitoring period—resulting in an initial export tax rate under the new fiscal system of $40 per ton. The export duty is imposed when crude oil prices are above $25/bbl, with duty rates rising faster when the price is above $105/bbl. In practice, the new formula did not lead to any immediate change in duty rates on crude oil—as the government's crude oil export duty was already $40/ton after it lowered the rate from $60/ton on 1 January 2016. The export tax policy shift is nevertheless a welcome change for oil companies operating in Kazakhstan. Previously, since introducing the oil export duty in 2008, the government had taken an ad hoc approach to making adjustments to the tariff level. The new formula makes government oil export tax policy more transparent and predictable.

A significant increase in investments is one of the key indicators of future oil production levels. Given that investment decisions are largely based on economics and profitability, government policy has

[25] That is, Law No. 291-IV of the Republic of Kazakhstan on Subsurface and Subsurface Use, dated 24 June 2010. Law No. 2350 of the Republic of Kazakhstan on Petroleum (of 28 June 1995), which had been in force previously, was superseded.

a direct impact on the development of the sector. Until now, Kazakhstan's approach to recognizing and rewarding initiatives on investments in marginal or mature fields has been somewhat lacking. Still, the Tax Code allows the government to administratively lower the Mineral Resources Extraction Tax (MRET) for selected high-cost or "hard-to-recover" fields or projects on a case-by-case basis. Initially, applications for relief were accepted only from companies where production was demonstrably unprofitable. A special commission exists to review each individual application. For example, the Karazhan bas field (in Mangystau Oblast) was reclassified as a low-profitability, high-viscosity, high water-cut, marginal, and worked-out field. Under a resolution of the Government of the Republic of Kazakhstan (18 June 2014), the MRET for the field was set at only 0.5%.[26]

In another example, in March 2016, UzenMunayGaz again submitted a request for the inclusion of its Uzen and Karamandybas fields (in Mangistau Oblast) in the category of unprofitable or low-profitability fields that are eligible for MRET relief. In September, the government granted tax breaks for both fields, reducing the MRET from the 2015 rate of 13% to 9% for all of 2016, on the condition that the fields turn out to be unprofitable.[27]

The new Subsoil Law (discussed below) proposes to establish norms that would automatically qualify a subsoil user for MRET relief without having to go through the existing bureaucratic procedure. These norms would be a part of a coordinated framework involving both the Subsoil and the new Tax Codes. Realization of these proposals will result in an initial revenue loss for the budget, but would ultimately stimulate subsoil users to turn marginal or mature and hard-to-work fields around and increase or maintain production, thereby broadening the oil production tax base. To incentivize production at mature fields, norms that create a threshold for profitability might need to be modified further, to ensure a certain level of profitability for the investor.

In line with President Nazarbayev's State of the Nation address in January 2017, the government has been developing a new draft of the Tax Code. The major change involves introducing a Tax on Financial Results for technologically complex projects, while streamlining taxation for exploration and production contracts:

- For **offshore projects and deepwater** projects with wells over 6 km depth, the draft envisions moving from the current revenue-based taxation to a tax on financial results (profits), as well as the abolition of "special payments," including the commercial discovery bonus and compensation for historical costs.
- For **deepwater projects with well depths between 2 km and 4 km**, the draft seeks to retain the current taxation scheme, but add concessions for marginally profitable fields.
- For **existing exploration contracts**, the draft plans to abolish requirements related to personnel training and R&D.
- For **new exploration contracts**, the draft's concept is to blur the line between the corporate income tax and excess profit tax by allowing enterprises to count exploration contract expenditures as company spending rather than as individual subsidiary expenditures. Producers will be able to allocate 25% of total exploration costs annually to such expenditures.
- For **new production contracts**, the draft retains the current taxation regime, but adds concessions for marginally profitable fields.
- Concessions for **marginally profitable fields** include lower MRET rates for fields that are depleted or with high water content or high-viscosity oil. Such fields automatically qualify for the lower tax rate, without having to go through a complicated administrative process.

3.4.1.2. Subsoil Code

The key law that sets the basic framework for regulation of Kazakhstan's upstream sector is the Law on Subsoil (2010), which replaced the Law on Oil (1995) and the previous Subsoil Law (1996). The Law on Subsoil specifies the rights and responsibilities of state entities involved in upstream operations, defines subsoil rights and rules for granting these rights, details the rights and responsibilities of subsoil users, sets terms for exploration and production activity (including for offshore), and establishes the regulatory foundation for environmental protection. The key drawbacks of the existing Subsoil Law include a large number of bylaws (currently, over 60), its frequent amendments (since the Law's adoption in 2010, it was changed 48 times), as well as a large number of applicable regulations from other legal domains, all of which complicate industry regulation. Following the aforementioned President's address in January 2017, a concerted effort to develop new subsoil legislation was accelerated. A new Subsoil Code is scheduled to be adopted by both houses of parliament by the end of 2017. It is important to note that the new legislation will be a code and not a law. In Kazakhstan's legal system, codes have a status superior to ordinary laws and therefore supersede them when contradictions arise. Codes, by their nature, provide more detailed regulation and require fewer bylaws, which should lead to a more effective and efficient legal framework. Amending a code is more complicated than amending a law; therefore subsoil legislation in the form of a code should ensure greater stability.

The ongoing drafting of a Subsoil Code provides Kazakhstan's lawmakers with an opportunity to address the challenges to the upstream sector posed by inadequate investment, insufficient geological exploration, and declining production from legacy fields. The July 2017 draft Code seeks to achieve several goals; chief among them:

- Improve the investment attractiveness of Kazakhstan's oil and gas sector in a low oil price environment
- Create conditions for the sustainable development of the oil and gas industry, recognizing its contribution to employment, social stability, and economic activity in the country
- Maintain a sufficient degree of state regulation and control in order to ensure the rational use of mineral resources, preserving environmental and human safety
- Ensure predictable and fair rule of law.

The draft Code contains several major proposed changes that seek to improve upstream regulations, including some recommendations made in the NER 2015:

- The draft Code provides for a combined contract for exploration and production, with clear conditions for the end of the exploration period and the transition to the production period. The draft Code also specifies terms for the issuance of a production contract at previously discovered fields. Under the new Code, investors have the automatic right to develop when exploration results are positive. This is not the case with the current Subsoil Law. This change eliminates a major disincentive to actually carry out exploration, and should incentivize continued field development following successful exploration.
- During the exploration phase, the new Code will not require investors to make expenditures for social purposes or to spend on local R&D and personnel training.
- The draft Code allows for open access of investors to geological information, except for cases that fall under the law on protection of state secrets.
- The Code envisions offering subsoil rights for hydrocarbons based on auctions. It also clarifies a set of criteria a potential subsoil user needs to satisfy, including solvency requirements and operational experience. The Code mandates auctions in case of an application for a given block from an interested investor and provides guidance for simplification of the auction procedures.
- Following a recommendation in the 2015 NER, the code explicitly outlines "in plain language" procedures and administrative obligations of subsoil holders, and provides a clear timetable of administrative procedures required for companies participating in auctions.
- The draft Code stipulates a model subsoil contract. The Code streamlines the way project documents are developed and approved; more specifically, technical documents are not required before a contract is signed, but can be developed, audited, and approved afterwards.
- The Code presents a "one window" approach for state experts to review reserves data at the time of project documentation for production. While there are a number of administrative procedures with stringent deadlines, the Code presents these steps clearly, in plain language.
- The draft Code establishes a new legal mechanism for geological exploration using private funds. This provision specifically establishes a legal framework for the implementation of the "Eurasia" project, specifying the parameters for international and private-state cooperation in subsoil development.
- Contracts are to be signed within 20 working days of announcing the auction winner (which should occur on the same day of the auction), without having to pass through other legal and/or economic reviews by authorities. The current Subsoil Law requires contracts to pass through both types of reviews, which could respectively extend the process by 30 days each.
- The draft Code eliminates the requirement of presenting a detailed work program (an amendment to the contract detailing related obligations) from an investor, as it duplicates the required project documentation. Instead the contract would only indicate the minimum amount of work (accepted by the winner of the competition). Production volumes are indicated only in the project documentation, not in the contract itself.
- The Code envisions gradual transition (with an interim period required for thorough preparation of state authorities, the expert community, and companies in the sector) to the SPE-PRMS international resource classification system for hydrocarbons (Step 74).[28]
- The status of the national oil and gas company, particularly with respect to managing strategic

[26] The MRET in Kazakhstan uses ad valorem rates that escalate based upon the annual production volume of the subsurface user, varying between 5% and 18% of sales revenues.

[27] In 2015 Uzenmunaigas (OMG) also applied but did not receive a temporary preferential rate for the mineral extraction tax for the Uzen and Karamandybas fields.

[28] The SPE-PRMS Petroleum Resources Management System was developed in 1997 by the Society of Petroleum Engineers (SPE) jointly with the World Petroleum Congress (WPC) and the American Association of Petroleum Geologists (AAPG). The current edition was adopted in 2011.

fields, is preserved.

• The draft Code also enhanced and clarified parameters of state regulation over issues of financial deductions (to a special escrow type account) for the liquidation of subsoil use consequences at the end of the production period (in order to minimize the risks and costs for the state).

• Base case project design documentation for hydrocarbon field development is subject to expert review by state authorities to ensure effective, rational, and environmentally responsible use of subsoil resources.

• The draft Code establishes penalties for violation of critical indicators of project documentation (up to the termination of the contract). The Code eliminates existing gaps in state control over the performance of contractual obligations.

However, the Code still retains certain provisions that have raised concerns among investors in the past, and introduces others that appear to be problematic:

• As in the current Subsoil Law, the Code requires investors to pay a signing bonus, and the size of this bonus is the principal factor the state considers when awarding subsoil rights through an auction. Given the auction format, the signing bonus is effectively the "price" of the new asset. Bonuses as guiding criteria have the advantage of being an easily understood and comparable indicator of the quality of the bid for the upstream use rights; they also ensure some up-front revenue for the government and may incentivize companies to explore and develop contract areas more rapidly. But generally, sizable up-front bonuses are usually suitable only in highly prospective areas where there is strong competition among investors for petroleum rights and the geology is relatively well known.

Although competitive processes for granting subsoil use rights (tenders and auctions) are widely used for hydrocarbon exploration and production globally, the bonus amount almost never is the main criterion for determining the winner. Other factors almost always are considered as equally important in determining the winning bid, and in many countries a bonus is not a factor at all.[29]

These other factors include: the technical competence and financial capacity of the applicant; plans for exploration and production in the area for which an exploration/production contract is sought; and the amount of investment promised. While these factors are more complex to administer and manage compared to a bonus-only merit system, Kazakhstan is certainly capable and should consider this more nuanced type of subsoil right granting mechanism due to the country's complex geology both offshore and onshore.

An additional problem with bonuses if they are particularly large is that, because of the (up-front) timing of the payment, they can have a deleterious effect upon project economics. IHS Markit maintains its recommendation that the government of Kazakhstan should consider abolishing the signing bonus, because it adds to the cost of an already risky undertaking, with often long lead times before the actual start-up of production. Abolishing the signing bonus does not mean that the competitive subsoil use granting system needs to be abolished, but it should focus on the quality, capability, and potential of the applicant to develop the auctioned area.

• The Code maintains the concept of a strategic field, under which the state has a priority acquisition right in case of disposition of ownership in such a field. In contrast to the existing Subsoil Law, the Code spells out criteria for a strategic field: "geological" oil reserves of more than 50 MMt, gas reserves of more than 15 Bcm, or an offshore Caspian field. Similar to the existing Subsoil Law, under the new draft Code the government has a priority acquisition right for any assets for which a subsoil use right is being relinquished. The state designates a national company to represent the state's interests. An obligatory condition for granting subsoil use rights for offshore hydrocarbon developments is at least a 50% participation share by the national company as a subsoil user. These constraints may limit the interest of major foreign investors in developing large and complex projects.

• The Code continues to heavily regulate the procurement activities of subsoil users (of equipment, services, etc.) in oil and gas projects (although it also tries to streamline these requirements to minimize corruption-related risks). Although the new Code does not require investors to make expenditures for social purposes or to spend on local R&D and personnel training during the exploration phase, these requirements are retained during the extraction phase, along with local content requirements.

• Article 29 in the revised draft references labor and migration laws, and specifies that no more than 50% of management in a firm should consist of foreign workers, and foreign workers should comprise no more than 50% of the total workforce, during both the exploration and production stages.

• The draft Code in its current iteration also limits the duration of exploration and extraction activities. For exploration the limit is six years, except for offshore exploration or complex projects requiring wells with a depth greater than 6 km and having high hydrogen sulfide content or an excessively high reservoir pressure (for which it is nine years). The exploration term can be extended only once (for three years, or six years for projects with deep wells) for assessment purposes and once (for three years) for test production. For extraction, the Code establishes a maximum period of 25 years for ordinary or 45 years for major and unique projects. After expiration of these periods, the government has the right to attach supplementary conditions for contract extension, in addition to those specified in the original contracts. Such conditions could entail new requirements for the investor, such as creation of new facilities, modernization of existing capacity, or marketing of production solely to domestic consumers.

The draft Subsoil Code has made a number of improvements to the existing regulation of the subsoil sector, including incorporating the recommendations of the 2015 NER, and significantly simplifying auction procedures and detailing various operational requirements. The draft Code also strengthens state oversight over operational activities in the sector. Although this aspect of legislation is understandable, it tends to echo an overall tendency of overregulation and control by the state in the economy and creates additional hurdles to new investments. In particular, proposals related to contract extension at projects of national significance could substantively increase the regulatory burdens at the three "mega" projects, and ultimately threaten incremental spending.

3.4.2. Review of program documents in the upstream sector

Under Kazakhstan's constitution, the President sets the strategic direction of domestic and foreign policy, while the government incorporates it accordingly into its economic, social, and other policies. Kazakhstan's strategic policy documents related to the upstream sector set a common goal—to further exploration and development of the country's abundant natural resources through adoption of advanced technologies and increased local content participation. In a 2012 speech delivered by Kazakhstan's president, he reflected on the importance of the oil and gas sector by sector referring to it as "a locomotive of the economy."

• During the same 2012 State of the Nation address, President Nazarbayev challenged Kazakhstan to join the ranks of the top 30 most developed countries in the world by 2050. He stressed that natural resources must be used as a strategic advantage to ensure economic growth and large-scale political and economic development. The speech also stressed the importance of Kazakhstan using its resources wisely, maximizing exports while prices are high and saving part of the proceeds to help weather periods of economic slowdown. Kazakhstan should remain a major player in the global hydrocarbon market, but alternative types of energy should be developed, and indeed applied, domestically. Nazarbayev also called for the creation of a strategic "reserve" of hydrocarbon raw materials, which could serve as a foundation of the country's energy security in the event of possible future economic upheavals. Most importantly, the President set a highly ambitious goal: for at least half of Kazakhstan's total energy consumption to come from alternative and renewable energy by 2050.

• This 2012 address became the foundation for a strategic plan—the Concept for Kazakhstan's becoming a top 30 most developed country in the world by 2050 from January 2014, which also emphasized the need to improve the efficiency of traditional extractive sectors. Identifying the oil and gas industry as one with a natural competitive advantage, the Concept stressed the need for new approaches to the management, extraction, and processing of hydrocarbons while maintaining the export potential of the oil and gas sector. The Concept called for establishing possible scenarios for oil and gas production. It also emphasized the importance of further developing the country's geological exploration industry, including through incentives for foreign investment.

• In November 2014, the President announced the "NurlyZhol" (Path to the Future) initiative, which emphasized investment in transportation and other infrastructure to offset difficult global market conditions for the economy. Among other benefits, the initiative is expected to facilitate oil and gas field development and exports through general transport and infrastructure improvements.

[29] The factors used in Norway for granting production licenses include "the technical competence and financial capacity of the applicant" and "the applicant's plan for exploration and production in the area for which a production license is sought"; the signature bonus or another fiscal factor is not specifically mentioned. In Europe more generally, such factors as "the technical and financial capability" of the bidders and "the way in which they propose to prospect, to explore and/or to bring into production" also affect decision-making on granting of subsoil rights (see Directive 94/22/EC). In Brazil, the signature bonus is accompanied by two other factors – minimum exploration program and local content percentage – in making the decision to grant concessions. In Australia, each state has its own petroleum legislation and although it uses competitive subsoil granting processes, only a few states include a fiscal factor in the bidding process.

Table 3.4. Government projections for oil and gas production (various years)

	Projection	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2025	2030
Oil (MMt)	The Energy Sector Development Concept to 2030 (Apr-14)			83	84	85	91	96	99	101,5		111,5	118,1
	Energy Ministry's Strategic Plan to 2018 (Oct-14)	79	82	82	79	76	79	82					
	Energy Ministry's Strategic Plan to 2021 (Dec-16)				79	76	81	86	87	87	87		
Bcm	The Energy Sector Development Concept to 2030 (Apr-14)				44,2					62			59,8
	Energy Ministry's Strategic Plan to 2018 (Oct-14)	40	42	41	44	44	45	48					
	Energy Ministry's Strategic Plan to 2021 (Dec-16)				45	44	44	45	47	48	49		

Source: Ministry of Energy RK

• In May 2015, the President outlined the 100 concrete steps program, aimed at implementing five broad institutional reforms to propel Kazakhstan into the ranks of the 30 most developed countries of the world. Steps 74 and 75 are directly related to the upstream sector: step 74 calls for the implementation of the international reserves classification system in Kazakhstan, while step 75 highlights simplified procedures for subsoil use contracts.

• The latest State of the Nation address from January 2017 outlined a new direction and accelerated technological modernization of the economy. The President pointed to the ongoing "fourth industrial revolution" characterized by digitalization, which spans the globe and impacts all industries and economic activities. The energy sector is already characterized by a high level of technological penetration and consumption, but there are ever-present opportunities for expansion in this respect. Among key priorities, the President mentioned the need to create incentives to encourage technological innovation and attract new technologies to Kazakhstan and to improve investment attractiveness through adopting new Subsoil and Tax Codes. The President also highlighted that the mining-metallurgical and oil-gas complex of the country should retain its strategic importance in order to underpin sustainable economic growth.

The key government-developed concepts for the upstream sector, based on the direction set by the President include:

Concept of development of the fuel and energy complex of the Republic of Kazakhstan to 2030 [30]

The Concept of development of the fuel and energy complex (FEC) to 2030, developed in June 2014, is a key document setting strategic goals for the upstream sector, including the intensification of exploration activity by attracting investment, as well as developing resources that are not financially and/or technically viable under the current tax regime through the creation of fiscal stimuli, that would allow companies to apply resource recovery technologies. In addition, the concept called for changes in existing sector policies. Specific measures include: informing investors about upcoming changes in subsoil and tax regulations to 2030; studying the harmonization of fiscal terms with Russia under the framework of the Eurasian Economic Union (EAEU); setting export duties for oil and products to incentivize domestic oil refining; developing fiscal stimuli to promote investments in exploration (including through ring-fencing, securing priority rights for the development of resources in the event an investor succeeds in exploration, releasing investors in exploration projects from social spending obligations), incorporating regulations to promote rational development of upstream projects, renewing building and construction standards, and including yearly production and technology plans for an upstream project's development into the terms of the subsoil license tender.

Concept of the development of the geological industry of the Republic of Kazakhstan to 2030

The Geology Sector Development concept from August 2012 identified several problems facing Kazakhstan's geological industry, including: the lack of skilled local specialists; a lack of activity by local research, scientific, and industry players; the inefficient organization of the exploration sector; and a lack of access to geological information. While the concept's realization was expected to result from mineral resource development programs to be developed by the government every five years, only one such program (for the period 2010–2014) has yet to be compiled.

Strategic plans of the Ministry of Energy of the Republic of Kazakhstan

Strategic plans formulated by the Ministry of Energy of the Republic of Kazakhstan set more specific goals for each energy subsector. The strategic documents set projections of oil and gas production over time and are periodically adjusted in light of changing conditions. The most recent Strategic Plan to 2021 (issued in December 2016) outlines the following objectives for the oil industry:

- Production of crude oil to reach 86 MMt (including Kashagan) in 2018 and 87 MMt in 2021. The longer term forecast is now being revised to reflect the expectations of a "lower for longer" price forecast. The long-term forecast from April 2014 had envisioned crude output reaching 118 MMt in 2030 (See Table 3.4)
- The document envisions that the depletion of oil and gas reserves after 2050 could leave Kazakhstan with an average annual liquids production of only around 55 MMt. To avoid such an outcome, the FEC concept calls for the active development of geological exploration through the attraction of investments and possible future development of subsurface resources not financially attractive under current tax conditions. It envisions that the share of FDI in the oil sector will exceed 30% by 2020, and will continue at this level to 2030.
- FEC 2030 forecasts Kazakhstan's crude oil exports to Europe will increase very slowly, at a rate of 0.8% per year. However, it projects that demand for Kazakh crude in Asia Pacific markets, including China and India, will grow more briskly, by 2.1% annually to 2030. The 2030 strategy stipulates that in this context it is important to create a unified Kazakhstan-China pipeline sourced by crude production from Caspian fields.[31]

3.4.3. Recommendations on development goals and regulatory system

Hydrocarbon policy reform does not mean that Kazakhstan's authorities need to unnecessarily compromise legitimate national security, budgetary, and other concerns, but it does imply a general rebalancing of state and oil industry interests. The goal of reform should be to stimulate growth in the industry, which should help "lift all boats"–both state revenues and companies' returns on their invest-

[30] In September 2014 the government developed a draft Concept of effective management of natural resources. Although the draft was offered for Nazarbayev's consideration, it has never been signed. In relation to the upstream sector, the concept set such goals as more extensive resource exploration, increasing production and exports of natural resources (in response to high global demand), attracting foreign investments provided these bring in modern technologies and/or develop local manufacturing, and ensuring that production does not endanger the environment.

[31] Another strategic goal outlined in FEC 2030 is refinery modernization.

ments. In order to further incentivize investment by oil companies of all sizes, a number of mid-course corrections, spanning several major policy areas, need to be implemented. Some of these changes are already being considered in the current legislation. Top policy priorities are categorized by topic as follows:

Movement toward international practices of licensing and reserve classification

Kazakhstan's legislation needs to reflect the industry's importance to the economy, as well as the increasingly competitive global upstream environment in which outside investors have grown accustomed to widely followed international practices concerning the issuance of licenses, the classification of reserves, and other administrative measures. Such practices include:

- Simplification of access to subsoil use contracts (Step 75 in the 100 concrete steps program).
- Increased transparency/availability of geological data
- Improved incentives for companies with licenses/contracts for taking on exploration risk; implement combined exploration/production licenses/contracts
- Provide durable guarantees of contract predictability
- Adoption of the international reserves classification system that reflects economics as well as geology (Step 74 in the 100 steps program)
- Reduction of administrative barriers, unnecessary procedures, and unreasonable deadlines.

More specifically, to revive the interest of international companies in its exploration sector, Kazakhstan should apply internationally recognized best practices used by leading hydrocarbon-producing countries, including having a designated "Competent Body" responsible for tendering. Another key measure is to establish a separate specialized entity that compiles and maintains geological information. Some of these recommended measures and practices are already embodied in the new draft Subsoil Code.

A next step, following successful exploration, would be for Kazakhstan to adopt standard international practice is reserve classification. Kazakhstan's legacy reserves classification system calculates reserves from what is possible to extract under the *best possible* conditions. The international approach is different, as it looks at what is *economically feasible* to recover. The difference in conceptual framework is reflected in the Subsoil Code, where partial development of a deposit is not permitted if the rest of the reserve may be impaired, even if it is not economic to produce. Such an approach does not consider the potential for future technological advances that can make marginal, "impaired" deposits recoverable.

Kazakhstan therefore should follow through with its plan to change its reserves reporting system (at a reasonable pace over several years) to the widely used international classification of hydrocarbon reservessystem SPE-PRMS. There is little (if any) advantage to remaining with the existing legacy system inherited from Soviet times. Such a change would eliminate the need for companies (and the government) to maintain two sets of books, and the inherent incompatibility between the two systems.

Improved investment attractiveness and tax stability

Improving attractiveness to investors, both domestic and foreign, and offering tax stability are two key factors that can help reverse the decline in upstream exploration and mature field production. This can be done by:

- Letting the companies have more control and the government less in key economic aspects and operational decisions on project development
- Because using of hefty (signing/discovery) bonuses acts as a major disincentive to exploration activity and spending, Kazakhstan should consider focusing the auction awards on technical and financial capabilities and offerings of the applicants and eliminate or at least reduce the emphasis on the size of the singing bonus; positive movement on this front is that the draft Subsoil Code proposes elimination of the discovery bonus altogether
- Reduce high levels/multiple forms of government tax take (e.g., export duty and export rent tax)
- Ensure tax stabilization in the new Tax Code to help reduce uncertainty

Over the longer term, supportive fiscal measures could include reducing the importance of export taxes in favor of direct upstream taxes that more closely reflect the cost conditions faced by individual producers. This may raise the price of oil on the domestic market, but it will also more closely reflect investment costs. Modification of the crude export duty regime in March 2016—with duty rates on crude oil exports linked to average international oil prices during a monthly monitoring period—is a step in this direction.

The government of Kazakhstan should also consider adjusting the tax treatment of mature fields, which would particularly help NC KMG as it prepares for an initial public offering (IPO). KMG is one of several global energy companies preparing for an IPO by 2020, along with Saudi Aramco and Kuwait Energy, so the competition for international investors is going to be fierce. These governments are taking active measures to increase the attractiveness of their national champions to outside investors. For example, in March 2017, the Saudi government reduced Aramco's income tax rate from 85% to 50%.

Improvement in the operating environment

A wide variety of measures should be considered in an effort to create a more favorable environment within which oil and gas companies can carry out their day-to-day operations. A typical complaint worldwide from such companies involves bureaucratic "red tape." Kazakhstan should continue to pursue efforts to rationalize and streamline the regulatory apparatus in instances where multiple layers of government bureaucracy and excessive paperwork requirements complicate routine company operations. Labor and current domestic content requirements, especially in such cases where these impede raising capital during early stages of exploration and production and jeopardize timely implementation of upstream project schedules, should be revised.

Another related area for improving operations is increasing the level of domestic R&D and labor force training. KazMunayGaz (NC KMG) should make human resource development a strategic priority, and invest in establishing internal research capacities, new technologies and workforce development programs (such as internships and externships, and short-term courses). Investing in research is important for establishing KMG's operational capacities and achieving long-term goals for national development as set forth by the President.

Environmental compliance also is an area frequently cited by industry executives as a headwind to efforts to improve operational efficiency. In Kazakhstan, there is a need to balance the current tendency in environmental policy for punitive measures with implementation of some incentives as well. One of these might be compensation of oil companies' associated gas processing costs (along the lines indicated in existing legislation). In addition, Kazakhstan is currently studying the feasibility of offering integrated emissions permits (IEPs) instead of the current rather complex regime of individual emissions permits, which require complicated monitoring and frequent renewals. Although widely used internationally, and authorized in Article 79 of Kazakhstan's Environmental Code, IEPs have not yet been implemented in Kazakhstan. An IEP is a single document that certifies the right to environmental emissions as long as the best available technologies (specified in Ministry of Energy Order 37 of 23 January 2015) are used and product-specific benchmarks (emissions coefficients per ton of output) are met, and greatly reduce the paperwork involved in environmental compliance.[32] IEPs have proven to be among the more effective ways of achieving pollution control because the permits are linked to specific technologies known to be effective in lowering emissions.

Measures should be adopted to decriminalize activities that are considered standard in the oil and gas industry, such as technically unavoidable gas flaring (see the text box in Chapter 5 entitled "Flaring of Associated Gas"). Rigorous and excessively punitive measures for modest levels of flaring are not only unattractive to a company, but more importantly, create a culture of uncertainty for field workers, who fear possible imprisonment for doing their jobs. Violations of environmental regulations should for the most part be treated as administrative violations, not criminal offenses, and government responses should accordingly be adjusted to reflect this.

Amendments to subsoil legislation

In addition to the recommended changes involving the adoption of international standards, increasing the sector's investment attractiveness and tax regime, and improving the operational environment, lawmakers in Kazakhstan should strive to craft and implement legislative changes in a transparent manner. To that end, Kazakhstan should increase the commenting period on draft legislation. Often, industry players are granted less than a week to review and comment on draft legislation. Extending the commentary period so as to allow for greater input from industry professionals will help to eliminate unforeseen negative consequences following the implementation of a new law, and promote investor confidence in Kazakhstan's legislation.

In addition to these changes, other important modifications to the Subsoil Code and related legislation that should be considered involve projects operating under PSAs.[33] Given that the contracts for the three "mega" projects—Tengiz, Karachaganak, and Kashagan—expire in 2033, 2037, and 2041, respectively, to ensure that the long-term productive potential of these projects is realized, legislation and policy need to include provisions for continued investments and effective operation of these and other high-risk projects. These may include contract extensions to provide sufficient payback period and other contract adjustments (specifically, project redesign in the form of so-called cross-PSA agreements [sharing of infrastructure] and provisions that would allow previously unlicensed areas to be incorporated into the framework of an existing PSA).

[32] See OECD, Multi-dimensional Country Review of Kazakhstan, Vol. 2, p. 180.

[33] PSAs provide a legal framework wherein the host state, as the owner of the subsurface resources, enlists companies (as contractors) to explore, develop, and ultimately monetize an upstream asset. PSAs allow the host country to retain ultimate ownership of the asset base, while providing tax rate predictability, cost-recovery, and a special regulatory framework for the investors. The investor companies assume nearly all of the risk for exploration—if no commercially viable resource base is discovered, then they absorb all of the losses. PSAs provide a stable, predictable framework for companies to take on risk when developing high-cost, technologically complex assets. The first PSAs were created in Indonesia in 1966, and there have since been hundreds of PSAs signed worldwide.

4. KAZAKHSTAN'S OIL REFINING SECTOR

4. KAZAKHSTAN'S OIL REFINING SECTOR

4.1. KEY POINTS

• **Kazakhstan has three main oil refineries as well as a number of mini-plants; total primary distillation capacity for the three main plants is currently listed as 15.35 million metric tons (MMt) per year (307,000 barrels per day [b/d]).** Although these plants have some conversion capacity, the Kazakh refining system is relatively unsophisticated, so the output structure remains heavily skewed towards mazut (residual fuel oil), which no longer matches the country's refined product needs.

• **In aggregate, Kazakhstan's refineries currently cover only about 85% of domestic product consumption,** with imports covering about 15%.[1] But this is because Kazakhstan exports a large proportion of its own output (mostly heavy products such as mazut), while it must import light products (motor fuels), mostly from Russia, to meet domestic demand.

• **A major refinery modernization program is underway,** which when completed will significantly alter the product slate towards light products (motor fuels). Demand has shifted decisively toward light products—gasoline, diesel fuel, and jet kerosene—with the modernization of its economy since independence. The resulting mismatch between production and consumption has led to an increasing dependence upon imported products, especially of high-octane gasoline and jet kerosene. However, refinery modernization, when completed, should help correct the mismatch and significantly reduce the need for imports of light products. In Kazakhstan, we project that aggregate refinery throughput will expand to about 17 MMt per year by 2030, an amount sufficient to cover gasoline and diesel consumption, following refinery modernization. A sizable increase in the output of gasoline and diesel is expected from the existing refineries, while the production of mazut is expected to contract. Because of the expectation of relatively modest growth in aggregate consumption of light products, the construction of another major refinery in Kazakhstan would result in significant excess capacity for domestic needs; there also are only fairly limited possibilities for refined product exports given the country's inland location.

• **The government has moved towards liberalizing its refined product market, as it has lifted retail price regulation for gasoline and diesel fuel;** prices remain regulated for A-80 gasoline and LPGs, but these are expected to be deregulated as well in 2017–18. But the refineries remain insulated from market forces; they do not operate as market actors, buying crude and selling refined products: instead, they receive a tolling fee for the crude that they process that is determined by the national oil company KazMunayGaz (KMG). The refining sector remains highly administered.

• **The refineries are slated to be privatized.** The refineries were listed in the planned privatization of a number of state-owned assets before 2020. But the status of this program remains uncertain.

4.2. REFINED PRODUCTS: SUPPLY AND DEMAND

4.2.1. Structure of the refined products sector

Kazakhstan has three main refineries (Atyrau, Pavlodar, and Shymkent), a specialized bitumen plant, and over 30 mini-refineries.[2] Crude distillation capacity for the three main plants is currently listed as 15.35 (MMt) per year (307,000 barrels per day [b/d]). Two of the large refineries—Atyrau and Pavlodar—are wholly owned by KMG, while the ownership of Shymkent is shared on a parity basis between KMG and China's CNPC.[3] The bitumen plant is also owned on a parity basis, but by KMG and China's China International Trust and Investment Corporation (CITIC).

Kazakhstan's refineries operate commercially based on a processing scheme, so they remain insulated from market forces. Before a January 2017 deregulation, these processing tariffs were set by the regulator, KREMiZK.[4] Starting from 2017, the processing tariffs for Atyrau and Pavlodar refineries are set by KMG's Board of Directors, while the tariff for the Shymkent refinery is set by the Board of Directors of the managing company, PetroKazakhstan. The sizable increase in the processing tariff in 2017 is due to inclusion of an investment component to compensate for refinery modernization.

Dozens of large and small tolling (give-and-take) providers work with the refineries: they purchase oil from subsoil users, transport it to the refineries, get it processed, and then sell the resulting products. KMG EP is the largest crude oil supplier to Kazakhstan's refineries (2.9 MMt in 2016). In accordance with the agreement between KMG and KMG EP signed during KMG EP's IPO in September 2006 (and valid through 2015), KMG EP was obligated to supply certain amounts of crude oil to KMG's refining and marketing subsidiary (KMG RM). In April 2016, the commercial relationship between KMG EP and KMG RM changed. Previously crude oil for refineries was purchased from the upstream company at set prices by KMG RM. However, now KMG EP has changed over to a tolling scheme, where it supplies crude and retains title to the resulting refined products for subsequent sale. Changes in the scheme of cooperation were due to disagreements with regard to the oil price. After expiration of the agreement between KMG EP and KMG RM in 2015, KMG RM suggested buying crude oil for the Atyrau and Pavlodar refineries at prices significantly lower than before, which was unacceptable for KMG EP. It is important to note that KMG EP may lose its export license if it fails to meet its obligations to supply crude to domestic refineries. Due to the disagreement over the price, KMG EP decided to switch to the oil processing scheme, where the company supplies crude to refineries and then sells the resulting products in the domestic market through KMG RM.[5]

In the retail segment, the organizational structure is more diverse, with the four biggest players holding only a 32% share of the total market (by volume) as of the end of 2016. The largest player—a subsidiary of KMG, KazMunaiGas Onimderi LLP—held a 17% share selling products through 325 retail stations; it is followed by the Helios retail network of 360 stations with 9% of the market, the SINOOIL network of 105 stations with 5% of the market, and Gazprom Neft, which holds 1% of the market selling products from 30 stations.

4.2.2. Domestic crude oil consumption

In recent years,apparent crude oil consumption in Kazakhstan has been in a general range of about 17 MMt per year, with the figure in 2016 being 15.8 MMt.[6] This represented about 20% of national crude oil production in 2016. The bulk of national output (over 80%) has traditionally been exported.

KMG subsidiaries (including KMG EP) are the main suppliers of crude oil feedstock to the Kazakh refineries.[7] However, the main production assets of these subsidiaries are mature fields now in decline: over the past decade production at KMG's 100%-owned entities declined by about 12%, amounting to about 8.4 MMt

[1]Aggregate throughput (considered equivalent to gross output) was 14.9 MMt in 2016, product exports were 3.9 MMt, and imports amounted to 1.8 MMt, so apparent consumption (including refining losses and fuel use) was 12.9 MMt. In aggregate, 11.1 MMt of this (86%) was covered by domestic production.

[2] According to the Ministry of Energy of RK there are 32 small refineries, each with less than 800,000 tons/y of processing capacity. Collectively, these 32 plants have 6.5 MMt/y of capacity, but reportedly processed only about 450,000 tons of feedstocks in 2016. These small plants contribute little in terms of domestic supply of finished products. Apparently the only one with any secondary processing capacity is Aksay-based Kondensat, which recently commissioned a vacuum distillation unit, part of a $170 million investment program to upgrade the plant. It launched the production of Euro-5 grade gasoline in December 2016. In April 2016, the introduction of amendments into the Law on Regulation of Petroleum Products Sales largely shut down these small plants because of a ban on selling semi-processed products, but an order issued by the Ministry of Energy in April 2017 reduced the number of these products, legally allowing the small refineries to resume operations.

[3] KMG owns 99.5% of the shares of the Atyrau refinery, 100% of Pavlodar refinery, and 49.8% of Shymkent.

[4] Most recently, this happened in October 2015, when the tariffs were approved at 20,501 tenge ($74) per ton for Atyrau, 14,895 tenge ($54) per ton for Pavlodar and 11,453 tenge ($42) per ton for Shymkent.

[5] As a result of KMG RM's disbandment in 2017, the functions of the agent under the agency agreement with KMG EP are likely to be transferred to KazMunayGaz Onimderi or to the relevant administrative department within KMG.

[6] This is calculated as crude (and condensate) production minus exports plus imports. This includes field losses as well as any changes in stocks. See Table 3.2. Of the 15.8 MMt of apparent crude oil consumption in Kazakhstan in 2016, 14.9 MMt were supplied to the refineries, and the remaining 0.8 MMt constituted field losses, changes in stocks and own use.

[7] However, the Pavlodar refinery (petrochemical plant) processes West Siberian crude supplied throughthe Omsk-Pavlodar-Shymkent pipeline from the Russian Federation. However, since it is supplied via a swap arrangement, from a commercial point of view, the crude delivered to the Pavlodar refinery is effectively purchased from Kazakhstan suppliers. A small amount of the crude delivered from Russia is officially considered to be Kazakh crude from KMG EP (Embamunaygaz) which goes through the Russian pipeline system (from Samara via Tuimazy-Omsk-Novosibirsk pipeline), but the bulk of the deliveries is simply compensated to the Russian supplier (Rosneft) by making the same amount of crude as delivered to the Kazakhstan-Russia border available at the Kazakhstan-China border. According to KMG EP's annual report, the company supplied 22% of the total crude volume delivered to Pavlodar refinery in 2016.

in 2016.[8] Over the longer term, production at these assets is expected to continue its secular decline, generating concern over the availability of crude supplies to meet the country's oil demand in the 2020s. The main crude production centers outside these legacy fields are the three "mega" projects operated by TCO, KPO, and NCOC. The key sources of growth in Kazakhstan's oil production are, in fact, these international projects. Given the declining output trajectory of the key producers supplying the domestic market, Kazakhstan's refineries may need to attract some crude from these other producers longer term. These producers would be interested in supplying the domestic market only if offered a price commensurate with the export options available for this crude. In other words, the domestic price would have to be at export parity (i.e., quoted international prices minus marine freight, pipeline and other transport costs, and applicable export taxes). Currently, however, the effective price at which crude is supplied to domestic refineries is much lower than export options, and the gap has even widened somewhat in the last two years even though international oil prices declined (see Table 4.1). Domestic crude oil prices were about 40% of the average Urals (Mediterranean) prices for exports by producers in 2013–14, but dropped to about 33% in 2015 and 25–29% in 2016. When transit fees and export duties are added to the equation, average realized prices for producers on their domestic sales dropped from about 50% of export netback parity in 2013–14, to only about only about 43% in 2015, and 32–37% in 2016.[9] Therefore, by either metric most oil producers in Kazakhstan prefer to export than to sell to the domestic refineries. However, in the summer of 2017 the netbacks realized from crude delivery to a domestic refinery and subsequent sale of refined products exceeded the netbacks on exported crude.

Table 4.1. Comparison of domestic crude prices versus export prices and exports netbacks in Kazakhstan, 2012-16

($ per ton)	**June 2012**	**June 2013**	**June 2014**	**June 2015**	**June 2016**	**December 2016**
Urals Blend (Mediterranean)	680,7	806,4	780,2	449,5	335,5	386,2
Transportation costs from Atyrau	38,3	56,7	51,7	51,2	36,1	37,4
KTO pipeline (Atyrau-Samara)	10,8	16,8	14,1	16,7	9,2	9,3
Transneft pipeline (Samara-Novorossiysk)	17,2	27,7	24,6	17,5	14,6	15,3
Novorossiysk port fee	2,6	2,6	3,2	3,2	3,2	3,2
Marine freight	7,7	9,7	9,8	13,7	9,1	9,6
Export duty	0,0	60,0	80,0	60,0	40,0	40,0
Export netback value at Atyrau	642,4	689,7	648,5	338,3	259,4	308,8
Effective realized domestic price by producers on crude sales in the domestic market (excluding excise and VAT)	436,8	324,2	328,2	146,9	82,2	112,7
Domestic price as percentage of international price	64,2	40,2	42,1	32,7	24,5	29,2
Domestic price as percentage of export netback value	68,0	47,0	50,6	43,4	31,7	36,5

Source: IHS Markit

At the same time, the Ministry of Energy, vested with regulatory responsibility in the oil and gas sector, determines the quantities of crude oil that subsoil users (except major projects with stabilized contracts) need to supply to the domestic market to cover the needs in fuel and lubricants. Therefore, such subsoil users supply their crude oil as a matter of priority to Kazakhstan's refineries and can only export the volumes remaining after these obligations have been met.[10] For example, in 2016, KMG EP supplied 1.0 MMt of crude oil to the Pavlodar refinery and 1.9 MMt to Atyrau, which amounted to 22% and 40% of total crude runs at these refineries, respectively.

In spite of deregulation of domestic prices for basic light products (with the exception of A-80 gasoline), state regulation of the market still continues. Given the problems with crude supplies from the traditional suppliers and probably the emerging need to attract crude to the domestic refineries from other sources, domestic crude will need to rise to export netback parity, which is achievable through introduction of more market mechanisms and liberalization.

[8] KMG's equity production (the aggregate of all entities in which it holds a stake, weighted by KMG's ownership share in each) is much higher, and has been rising: the calculated amount was 22.1 MMt in 2016, representing 28.3% of Kazakhstan's total national production last year.

[9] Netback is calculated as quoted prices in the Mediterranean minus both transportation (pipeline and marine) costs for the Atyrau-Samara export route and export duties.

[10] Crude supplies for the Shymkent refinery are mainly sourced from producers in Kyzylorda Oblast that are joint ventures between KMG and Chinese companies. Therefore, a somewhat different commercial arrangement applies.

4.2.3. Refining operations and output

Reported aggregate output of refined productsin Kazakhstan declined to 12.9 MMt in 2016, even though crude throughput remained about the same as in 2015 at 14.5 MMt (see Table 4.2). The three major refineries have quite different product slates, reflecting their different refining configurations and the type of crude that they run (see Table 4.3). The aggregate output slate of the country, however, has improvedslightly in recent years, even though much of the refinery modernization program remains to be realized. The share of light and middle distillates compared to throughput increased somewhat: the share of gasoline rose from 20.9% in 2014 to 22.8% in 2016, and the share of diesel went from 34.9% to 36.3%; the share of mazut declined from about 29.0% to 24.8% (see Table 4.2). The depth of refining (conversion ratio) for all three of the major refineries has been rising; Atyrau's improved by 6.04% in 2016, reaching 65.2%; for the other two, the improvement was only 1-4%, with Pavlodar's depth increasing to 76.6%, and Shymkent's to 75.4%.[11]

Table 4.2. Kazakhstan's refined product balance, 2010-16

	2010	2011	2012	2013	2014	2015	2016
Production							
Throughput	13,7	13,7	15,1	15,3	16,4	15,0	14,9
Output of products (reported)	12,8	13,4	13,7	13,8	14,5	13,5	12,9
Gasoline	2,9	2,8	2,9	2,7	3,0	2,9	3,0
Kerosene	0,5	0,4	0,4	0,4	0,4	0,3	0,3
Diesel fuel	4,4	4,6	4,1	5,1	5,0	4,6	4,7
Mazut	4,5	4,3	3,9	4,0	4,2	4,1	3,2
Fleet	-	-	0,3	0,3	0,3	0,3	0,2
Furnace fuel	4,5	4,3	3,6	3,7	3,9	3,8	3,0
Lubricants	-	-	-	-	-	-	-
Other (includes LPGs, VGO, etc.)	0,5	1,3	2,4	1,5	1,8	1,7	1,8
Petroleum coke/bitumen/other residual	0,4	0,5	0,5	0,6	0,9	0,8	1,0
Apparent consumption							
Total (all refined products)	10,3	10,8	12,3	12,5	13,4	12,0	12,9
Gasoline	3,7	3,5	4,0	4,0	4,2	4,3	4,1
Diesel fuel	3,2	4,1	3,9	5,5	5,3	4,6	5,1
Mazut	1,4	0,7	-0,4	-0,7	-0,6	-0,6	-0,4
Other	2,0	2,4	4,8	3,7	4,5	3,8	4,1
Net exports							
Total (all refined products)	-3,3	-3,0	-2,8	-2,7	-3,0	-3,0	-2,1
Gasoline	0,8	0,8	1,2	1,3	1,2	1,4	1,1
Diesel fuel	-1,2	-0,6	-0,2	0,4	0,3	0,0	0,4
Mazut (including VGO and other "zhidkoye toplivo")	-3,0	-3,5	-4,3	-4,7	-4,8	-4,7	-3,6
Other	0,1	0,4	0,5	0,3	0,3	0,3	0,1
Exports							
Total (all products)*	5,1	4,4	4,8	5,3	5,1	4,9	3,9
Gasoline	0,1	0,0	0,0	0,0	0,0	0,0	0,0
Diesel fuel	1,6	0,8	0,3	0,2	0,2	0,2	0,0
Mazut (including VGO and other "zhidkoye toplivo")	3,0	3,6	4,5	5,0	4,8	4,7	3,6
Other	0,4	0,0	0,0	0,1	0,0	0,0	0,2
Imports							
Total (all products)*	1,8	1,5	2,1	2,5	2,1	1,9	1,8
Gasoline	0,9	0,8	1,2	1,3	1,2	1,4	1,1
Diesel fuel	0,4	0,2	0,1	0,6	0,5	0,2	0,4
Mazut (including VGO and other "zhidkoye toplivo")	0,0	0,1	0,2	0,3	0,0	0,0	0,0
Other	0,5	0,4	0,6	0,4	0,4	0,3	0,2

* Total exports and imports excludes LPGs; reported exports of heavy liquid fuels ("zhidkoye toplivo") includes a variety of other products, including VGO, so calculated apparent consumption has been negative since 2012.

Source: Statistical Committee of RK; IHS Markit

[11] This indicator, defined as the share of "premium products" (essentially light products and lubes) in the output mix, was 74.2% for Russian refining overall in 2015 and improved to 79.1% in 2016 versus 71% in 2000–02; but this is still well short of the 85–90% levels in advanced Western countries such as the US and Germany.

Table 4.3. Product output by Kazakhstan's major refineries

	2012	2013	2014	2015	2016	2017
Atyrau:						
Crude throughput	4 423	4 430	4 920	4 868	4 761	4 650
Motor gasoline	506	505	614	605	643	771
Diesel fuel	1 218	1 222	1 344	1 207	1 391	1 351
Jet kerosene	57	38	23	21	20	22
Benzene	-	-	-	1	7	8
Heating oil	143	124	166	160	68	81
Mazut	1 543	1 512	1 510	1 650	1 362	1 374
Vacuum gas-oil	606	652	779	739	842	518
Petroleum coke	75	95	137	111	121	116
LPG	14	20	28	29	36	34
Sulfur	1	1	2	3	3	3
Pavlodar:						
Crude throughput	5 037	5 010	4 926	4 810	4 590	4 790
Motor gasoline	1 332	1 117	1 259	1 249	1 225	1 291
Diesel fuel	1 514	1 473	1 509	1 457	1 524	1 577
Jet kerosene	100	133	125	11	-	-
Mazut	810	763	668	822	560	732
Vacuum gas-oil	123	400	192	123	29	27
Petroleum coke	147	146	152	126	224	201
LPG	244	215	239	263	244	274
Sulfur	24	23	25	30	28	31
Bitumen	186	219	244	246	202	132
Shymkent:						
Crude throughput	4 754	4 857	5 065	4 493	4 501	4 360
Motor gasoline	1 046	1 038	1 126	988	1 032	948
Diesel fuel	1 336	1 376	1 346	1 192	1 203	1 145
Jet kerosene	275	231	279	254	236	220
Mazut	902	968	1 013	889	869	872
Vacuum gas-oil	798	827	884	827	811	782
Petroleum coke	146	148	142	113	120	106
LPG	-	-	-	-	1	0
Sulfur	-	-	-	-	-	-

Note: Ministry projection for 2017.

Source: Ministry of Energy of RK

4.2.4. Domestic refined products consumption

Kazakhstan's apparent consumption of refined products increased to 12.9 MMt in 2016 compared to 12.0 MMt in 2015.[12] The increase was led by diesel and "other" (see Table 4.2). Apparent consumption of motor gasoline was less buoyant, actually declining slightly. Actual reported consumption of all refined products in Kazakhstan (excluding LPGs) was 9.8 MMt in 2015. This was comprised of 62% diesel (used mainly in the transport sector for road and rail transport, as well as in agriculture), 14.9% motor gasoline, 13.4% mazut, 4.3% kerosene, and 4.0% bitumen.

[12] Apparent consumption is calculated as production minus exports plus imports (for which the categories do not precisely align), so it includes any changes in stocks.

4.2.5. Exports and imports of refined products

Kazakhstan exports low value-added (heavy) products while importing premium products, a function of its outdated refined product slate, which the current modernization program is meant to address. Overall, product exports (as reported by customs statistics) declined from 5.1 MMt in 2014 to 3.9 MMt in 2016—the lowest level observed since 2008. Fuel oil (together with VGO and other heavy products) remains the major refined product export, as its share in the overall products' exports amounted to 92% in 2016, compared to 94% in 2014. Kazakhstan does not export light products outside the Customs Union, in connection with the current ban under an agreement with the Russian Federation.[13] Overall product imports dipped to 1.8 MMt in 2016. Imports of gasoline decreased to 1.1 MMt in 2016. High-octane automotive gasoline continued to be the major import product.

4.2.6. Refined product consumption outlook

According IHS Energy's base case forecast, gasoline and diesel demand are set to grow only modestly through 2030, lifting up aggregate oil product demand. Apparent gasoline consumption will grow from 4.1 MMt in 2016 to 4.5 MM tin 2030, and diesel consumption will increase from 5.1 MMt (2016) to 6.5 MMt in 2030. Aggregate apparent product demand is expected to reach about 14.1 MMt in 2030 (see Table 4.4). Actual mazut consumption will continue to decline, albeit slowly, as mazut is important to Kazakhstan's electric power sector, mining, and heavy industries;[14] demand by these industries is forecast to hold relatively steady at about 1.0 MMt in 2030.[15]

Table 4.4. Outlook for Kazakhstan's refined product balance

	2010	2015	2020	2025	2030	Average Annual Percent Change 2015-30
Production						
Throughput	13,7	14,5	16,0	16,3	17,0	1,1
Output of products (reported)	12,8	13,5	15,2	15,6	16,5	1,3
Gasoline	2,9	2,9	4,0	4,4	4,8	3,5
Kerosene	0,5	0,3	0,5	0,7	0,9	7,7
Diesel fuel	4,4	4,6	6,2	6,6	7,3	3,2
Mazut	4,5	4,1	2,9	2,4	1,7	-5,7
Other (includes LPGs, VGO, etc.)	1,4	2,6	2,5	2,2	2,2	-1,1
Petroleum coke/bitumen/other residual	0,4	0,8	1,0	1,5	1,8	5,4
Apparent consumption						
Total (all refined products)	10,3	11,5	13,0	13,5	14,1	1,4
Gasoline	3,7	4,3	4,3	4,4	4,5	0,4
Diesel fuel	3,2	4,6	5,6	6,0	6,5	2,4
Mazut	1,4	-0,6	1,1	1,1	1,0	
Other	2,0	3,2	2,1	2,0	2,0	-3,2
Net exports						
Total (all refined products)	3,3	3,0	3,0	2,8	2,9	
Gasoline	-0,8	-1,4	-0,3	0,0	0,3	
Diesel fuel	1,2	0,0	0,6	0,6	0,8	
Mazut (including VGO and other "zhidkoye toplivo")	3,0	4,7	1,8	1,4	0,7	
Other	-0,1	-0,3	0,9	0,8	1,2	

Source: IHS Markit, Statistical Committee of RK, Ministry of Energy of RK

[13] Another tool widely used by the Kazakhstan authorities in order to influence the domestic market and pricing is periodic introduction of administrative bans on exports of certain refined products. Such bans mostly apply to light and middle distillates. Initially designed to help meet demand in agriculture during peak periods (sowing in spring and harvesting in autumn), these bans were applied year after year. The most recent was introduced by the Order of the Minister of Energy of the Republic of Kazakhstan from June 26, 2015 No. 437 "On the introduction of a temporary ban on the export of oil products" for a period of six months. Only small volumes of diesel fuel are allowed to be exported in the off-periods of low demand.

[14] According to 2015 data, mazut consumption by power plants and large boiler houses amounted to 443,000 metric tons.

[15] These projections are based on IHS Markit base-case macroeconomic assumptions that envision average annual GDP growth in Kazakhstan to 2030 at 2.6%, with a general assumption of gradually slowing growth over time, reflecting the larger economic base.

Given this demand picture, refinery throughput is expected to expand to only about 17 MMt in 2030 (see Table 4.4). This amount of crude runs is more than sufficient to meet domestic demand for gasoline with the changed product slate following refinery modernization. The IHS Markit outlook assumes that enough crude oil is processed by the domestic refineries to balance gasoline demand without resorting to imports, although the country would still export and import some oil products because demand for the overall product slate is never perfectly balanced by refinery production. Given limited projected growth in domestic products demand, the construction of another major refinery would lead to aggregate oversupply and low national refining capacity utilization. Also, given Kazakhstan's inland location, possibilities for refined product exports are quite limited.

4.3. INFRASTRUCTURE AND TECHNOLOGIES: KEY CHALLENGES, IDEAS AND SOLUTIONS

4.3.1. Kazakhstan's refinery modernization program

Kazakhstan's $6 billion refinery modernization program was officially approved in 2010 with three key objectives: to improve the refining slate by increasing production of light products (high-octane gasoline and diesel) and eliminating the need for Russian light product imports; to improve fuel quality to comply with the principles and rules of technical regulation within the framework of the Eurasian Economic Union; and to increase the refineries' throughput capacity. The modernization program is expected to be completed at the Pavlodar and Atyrau refineries by the end of 2017, and at Shymkent by the end of 2018 (see Table 4.5).

Table 4.5. Installed processing capacity at Kazakhstan's main refineries (thousand metric tons per year)

	Atyrau		Pavlodar		Shymkent		Sum for Three Main Refineries	
Type of capacity	Pre-Modernization	Post-Modernization	Pre-Modernization	Post-Modernization	Pre-Modernization	Post-Modernization	Pre-Modernization	Post-Modernization
Crude distillation capacity (MMt)	5,00	5,50	5,10	5,10	5,25	6,00	15,35	16,6
Vacuum distillation	3 000	3 000	4 000	4 000	1 440	1 440	8 440	8 440
Catalytic cracking (FCC)	-	2 389	2 000	2 000	-	2 000	2 000	6 389
Visbreaking	-	-	1 500	1 500	1 000	1 000	2 500	2 500
Coking	720	720	640	640	-	-	1 360	1 360
Catalytic reforming (CCR)	420	1 420	1 000	1 000	1 000	1 000	2 420	3 420
Hydro-treating	1 300	5 218	5 000	5 000	2 430	5 378	8 730	15 596
Isomerization-C5/C6			-	570	-	600	-	1 170
Bitumen production	-	-	367	367	-	-	367	367
Sulfur production	-	-	-	59,4	-	4 000	-	4 059
Alkylation (and transalkylation)	-	1 050	-	-	-	-	-	1 050
Naphtha splitter	-	-	-	1 961	-	-	-	1 961
Amine regeneration	-	-	-	2 890	-	1 345	-	4 235
Oxygenates-MTBE	-	-	0	0	0	244,8	-	245

Source: KMG

Following modernization, the three main refineries will be capable of fully satisfying Kazakhstan's domestic demand through at least 2025. According to Deputy Energy Minister Aset Magauov, modernization will increase gasoline yield to 32% (from 20%) per ton of crude oil, and 29% for diesel, while jet kerosene will grow from 2% to 5%. Total production of gasoline and diesel fuel could exceed 10 MMt/y, perhaps providing some surplus for export. However, until the modernization program is completed, Kazakhstan will continue relying on imports of light products from Russia.

Modernization might address some of the fuel use and losses at the refineries, such as from deteriorated steam pipeline thermal insulation as well as optimization of furnace and boiler operation. However, it can be expected that implementation of deeper conversion technologies and increased refinery capacity as a result of modernization may lead to higher fuel consumption (own use). Collectively, the three main refineries and the bitumen plant incurred losses and fuel use of 7.3% of crude runs in 2016, varying from 11.2% for Pavlodar to 1.8% for the bitumen plant (6.2% at Atyrau and 5.3% for Shymkent). These figures do not seem excessive in international perspective. Average refining losses and own consumption as well as fuel use in Russia as a whole were 6.3% in 2015, but these vary from only about 2–4% for simple hydroskimming refineries up to 6–8% for full conversion refineries; the presence of associated petrochemical facilities naturally increases losses and fuel use. In Europe, high conversion plants with catalytic cracking and hydrocracking have fuel use and losses in the range of 7.5–8.5%, while simply hydroskimming refineries are in the range of 4.5–4.7%.

The potential for energy efficiency improvements at the three refineries is quite high (up to 10%). However, the implementation of energy-saving measures faces the problem of missing incentives by the refineries, as the cost of oil and refined products used in the process of refining and for losses is borne by the crude suppliers, not the refiners themselves. Under the tolling scheme the fuel oil (mazut) and the refinery gas consumed at the refineries do not really have any value (cost) for the refineries. Therefore, there is no incentive to ensure savings and reduce energy losses. Loss reductions and efficiency improvements will be incentivized if they affect the refineries' revenue, for example, if the refineries buy feedstock (crude oil) and sell the refined products, i.e., function as independent market companies. In such a situation, refinery efficiency improvements become a strategic task in increasing profitability.

Pavlodar refinery

Built in 1978 to process West Siberian crude, the Pavlodar refinery is the most technologically sophisticated of Kazakhstan's refineries. Its conversion ratio is 76.6%, with a Nelson complexity index calculated by IHS Markit at 7.4. In 2016, the share of gasoline and diesel in the total output of refined products was 68%, while the share of mazut (fuel oil) was 14% (see Table 4.3).

Pavlodar's refinery modernization got underway in 2011 and is expected to be completed by the end of 2017, with production of K4 and K5 fuels beginning in 2018 (see the text box: Kazakhstan's tightening fuel standards). Prior to 2015, Pavlodar's modernization envisioned an increase of annual throughput capacity from the current 5.1 MMt to 7.0 MMt, reconfiguring the plant to refine domestic (Kazakhstan's) crude, as well as improving the quality of product output (to produce K4 and K5 fuels). However, in 2015 the modernization project was scaled back,and now is aimed only at improving the quality of products, not expanding distillation capacity or reconfiguring the refinery for a different type of crude. Total capex for Pavlodar's modernization is $831 million, of which $409 million in financing was provided by a short-term loan from KMG and a long-term loan from the state-owned Development Bank of Kazakhstan.

Kazakhstan's tightening fuel standards

Kazakhstan has been moving toward tighter fuel specifications to improve air quality, adopting similar standards to the European Union (EU) progressively in several steps. Kazakhstan's fuel specifications are now determined via its Eurasian Economic Union agreements. Following the conclusion of the Agreement on Unified Principles and Rules of Technical Regulation between Russia, Belarus and Kazakhstan, the Customs Union Commission introduced Technical Standards for automotive fuels in October 2011. However, these agreements provide a more relaxed timeline for Kazakhstan, given its delayed refinery modernization program, with the transition to more stringent specifications in Kazakhstan lagging well behind Russia and Belarus. The specifications correspond to Russia's "class" benchmarks, which are similar to the Euro standards (the difference being that the Russian and Kazakh class benchmarks allow for lower octane fuels) (see Table 4.6). K-4 and K-5 gasolines have regulated octane levels while the octane levels in Euro-4 and Euro-5 gasolines are not.

Table 4.6. Technical specifications for gasoline and diesel fuel

Gasoline								
Type	**EURO 2**	**EURO 3**	**EURO 4/ EURO 5**	**EURO 5**	**K2**	**K3**	**K4**	**K5**
Standard	EU 228 (1993)	Dir 98/70 (2000)	Dir 2003/17 (2005)	Dir 2009/30 (2009)	TP TC 013/2011	TP TC 013/2011	TP TC 013/2011	TP TC 013/2011
Sulfur (ppm), maximum	500	150	50 (10)	10	500	150	50	10
Benzene (vol%), maximum	5	1	1	1	5	1	1	1
Oxygen (wt%), maximum		2,7	2,7	3,7		2,7	2,7	2,7
Aromatics (vol%), maximum		42	35	35		42	35	35
Olefins (vol%), maximum		18	18	18		18	18	18
Lead (mg/dm³), maximum	13	None	None	None				
Research Octane Number, minimum		91	91	91	80	80	80	80

Diesel									
Type	**EURO 1**	**EURO 2**	**EURO 3**	**EURO 4/ EURO 5**	**EURO 5**	**K2**	**K3**	**K4**	**K5**
Standard	EN 590 (1993)	EN 590 (1996)	Dir 98/70 (2000)	Dir 2003/17 (2005)	Dir 2009/30 (2009)	TP TC 013/2011	TP TC 013/2011	TP TC 013/2011	TP TC 013/2011
Sulfur (ppm), maximum	2 000	500	350	50 (10)	10	500	350	50	10
Poly Aromatics (vol%), maximum			11	11	8		11	11	8
Cetane number, minimum	49	49	51	51	51	45	51	51	51
Flash point (°C), minimum	55	55	55	55	55	40	40	55	55

Source: IHS Markit

The Euro-3 (or K3) standard was introduced in Kazakhstan from 1 January 2012, replacing Euro-2 which had become effective on 15 July 2009. For the refineries the introduction of Euro-4, which had been planned for 1 January 2014, was pushed back to 2016, although foreign cars imported into Kazakhstan or cars manufactured within the country were required to meet the Euro-4 standard as of 1 July 2013.[16]

It should be noted that the introduction of refined product quality standards as such has not fully solved the problem of the quality of the fuel sold to consumers. Quite often, quality checks of the fuel sold at filling stations revealed noncompliance with the established standards. This was mainly due to fuel falsification by the filling station owners, including mixing with fuels of inferior quality and using additives to increase octane levels.

The introduction of a moratorium on small and medium business inspections from February 2014 limited state control functions; the moratorium was aimed at improving business conditions. But because of the need to monitorfuel quality throughout the value chain, in March 2016 new rules and requirements were introduced for equipping storage tanks at refineries, product depots, and filling stations with meters measuring the quantitative and qualitative characteristics of petroleum products. The requirements stipulate installation of meters at Kazakhstan's filling stations and refined product storage facilities by 1 January 2018. However, due to unavailability of technical specifications for the meters and the metering procedure, and the significant costs involved, further work is needed to refine the relevant regulatory framework.

Pavlodar's existing units will be upgraded and new piping and instrumentation installed; in addition, a new isomerization unit (570,000 tons/year), a naphtha splitter (1,961,000 tons/year), and a sulfur production block with gas recovery, sulfur granulation, and amine regeneration units will be installed (see Table 4.5). KMG's selected technologies for the upgrade include Honeywell UOP's RCD Unionfining for sulfur removal, the PENEX catalytic process in its existing catalytic reformer,Merox to remove mercaptans from LPGs, and ExxonMobil's MIDW technology to increase yields of diesel. KMG contracted Romania's Rominserv and China's NFC to implement the project. Construction is expected to be completed in mid-2017, with commissioning to begin in late 2017. K4 motor fuel production is scheduled to begin in 2017, and K5 in 2018. High-octane gasoline production is expected to increase from the current level of 1.2 MMt/y to around 1.5 MMt/y.

[16] From January 2016, Kazakhstan's cars must meet the K5 (Euro-5) standard, with the production of A-80 ("normal") gasoline grade planned to be phased out altogether. Russian refinery production changed to Euro-5 specifications in January 2016, but there is not yet a specific mandate for Kazakhstan's refineries to produce only K5 (Euro-5) grade fuels.

Atyrau refinery

Built in 1945, the Atyrau refinery is Kazakhstan's oldest and the least sophisticated refinery (its current Nelson complexity index is calculated by IHS Markit at 4.1). In 2016, the share of gasoline, diesel, and jet kerosene in the total output of refined products was just 46%, while the share of fuel oil and heating oil (the refinery is the only one that produces heating oil) was 32% (see Table 4.3).

Consequently, Atyrau's modernization program is the most technically ambitious and expensive, involving $3.38 billion in capital expenditure, of which $2.05 billion alone is devoted to the advanced-refining complex (KGPN) that is being installed and $1.33 billion for an aromatics production complex. Upon completion of modernization in early 2018, the Atyrau refinery's annual crude processing capacity will grow from 5.0 MMt/y to 5.5 MMt/y, and its Nelson complexity index will increase to 11.3.

In 2015 a catalytic reformer (CCR) with a capacity of 1.0 MMt/y was commissioned within the framework of the Aromatics Production Complex (APC) Project Phase 1.

The licensor's commitments (guarantees) with regard to the CCR were met.

The launch of CCR allows for:

- obtaining motor gasoline blendstock with an octane rating of 103 (research method);
- increasing high-octane gasoline production from 264 Mt/y to 604 to Mt/y;
- reducing benzene content in motor gasoline (1%);
- obtaining 99.9% pure benzene.

Besides, additional volumes of hydrogen produced by the CCR allowed for 100% production of environmentally clean diesel fuel and increase in the share of diesel fuel with a low (-35°C) pour point from 13% to 28%.

In 2016, benzene (133 Mt/y) and paraxylene (PX; 496 Mt/y) production facilities were commissioned within the framework of the APC Project Phase 2.

The work was carried out by Sinopec Engineering and KazStroyServis and was financed by the Development Bank of Kazakhstan and China's ExIm Bank. The aromatics production unit allows producing high value-added petrochemicals.

The aromatics complex uses the ParamaX BTX suite of technologies by France's Axens, including continuous catalyst regeneration (CCR) reforming, Morphylane (aromatics extraction), Eluxyl (paraxylene purification), XyMax (xylene isomerisation), and TransPlus (aromatics transalkylation) (see Table 4.5).

Taking into account the priority task of providing gasoline for the domestic market, the start of the entire APC operation in the petrochemical mode with maximum production of benzene and paraxylene is possible after the KGPN facilities are commissioned. Currently, the complex is operating in fuel production mode.

The KGPN project, launched in 2011, is being implemented by China's Sinopec Engineering, Japan's Marubeni, and Kazakhstan's KazStroyServis. The project drew external financing from Development Bank of Kazakhstan, China's ExIm Bank, and Japan's JBIC. KGPN involves the construction of 12 new process units, allowing the production of K-4 and K-5 quality fuels.

KGPN units use technologies by France's Axens. The catalytic cracker (2.4 MMt/y capacity) uses that company's R2R proprietary technology, while the LPG desulfurization unit uses Sulfrex technology. Axen's Alkyfining technology is used for upgrading the LPG cuts, while oligomerization technology is used for converting olefinic fractions into gasoline. It is capable of handling a variety of heavy feedstocks, including atmospheric residue, heavy gasoil, vacuum gasoil, and heavy gasoil, converting them into lighter, high-value products such as LPGs, light gasoil, and gasoline. The KGPN project is on track to be completed by late 2017, with production of K-4 and K-5 diesel fuel commencing in 2018. The plan is for the refinery to produce 1.745 MMt of gasoline, 1.64 MMt of diesel, and 0.244 MMt of jet kerosene after modernization is complete.

Shymkent refinery

In 2016, the share of gasoline, diesel, and jet kero in the total output of refined products at the Shymkent refinery (PKOP) was 58%, while the share of fuel oil was 32% (see Table 4.3). A key goal in Shymkent's modernization is debottlenecking, so that the plant can go back to its original designed capacity of 6 MMt/y, as well as to improve fuel quality and increase production of light products. The modernization project, with an outlay of $1.85 billion, is financed and executed by the plant's joint owners, KMG and CNPC, with the main contractor being China Petroleum Engineering & Construction Corporation (CPECC). Once completed, the Shymkent refinery's installed crude distillation capacity will reach 6 MMt, and its Nelson score will increase to 8.2, while producing K4 and K5 quality motor fuels. The refinery is expected to become operational at its full post-modernization capacity in Q4-2018, after the completion of the catalytic cracking complex.

The Shymkent refinery modernization includes two stages. The first stage is aimed at improving product quality and producing K4 and K5 type fuels and involves the installation of an isomerization unit, diesel hydrotreater, and a sulfur production unit. The second stage involves increasing throughput capacity and installing a catalytic cracking unit, gasoline hydrotreater, sulfur production unit, LPG demercaptanization unit, and a hydrogen purification unit.

The licensor companies' – UOP (USA) and Axens (France) – refining technologies are used for project implementation: PENEX isomerization processes, Merox process to remove mercaptans from LPG, residual fluid catalytic cracking (RFCC) process to produce high-octane gasoline and Prime-G catalytic cracking gasoline hydrotreating process.

Within the framework of the project's first stage, the redesigned diesel fuel hydrotreater was commissioned in September 2015, the sulfur production unit launched operations in December 2015, and startup of the light naphtha isomerization unit took place in June 2017. This unit is particularly important, as it will allow the refinery to enhance octane while reducing benzene fractions in gasoline.

Currently, the second stage is under active implementation. This stage is the most difficult in terms of technology and includes construction of a catalytic cracking complex for complex oil refining with a capacity of 2.0 MMt/y to produce high-quality and environmentally friendly motor fuels, jet kerosene and LPG.

4.3.2. Deregulation of the refined products market

In general, the downstream sector in Kazakhstan remains highly administered, overlain with strong demand planning. The existing system of downstream market regulation in Kazakhstan reflects the sector's struggle to meet light product demand, involving direct control and regulation in different segments by a variety of state bodies, including the Ministry of Energy, the Ministry of Finance (which is responsible for refined products trade control), the Ministry for Investments and Development (which is responsible for technical standards and safety), and the Ministry of Agriculture (which regulates refined products supply for the agricultural sector).

Currently, the state regulates:

- Schedules of crude supplies by oil producers to refineries
- Annual volumes and monthly schedules of refining
- Annual volumes and monthly schedules of supplies by producers of refined products with retail prices regulated by the state to the regions of Kazakhstan
- Retail prices for certain refined products
- Procedure of access to refining facilities by oil producers

The state approves:

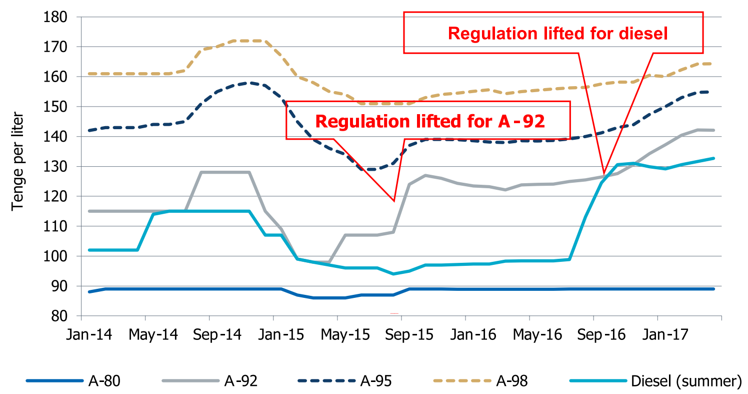
- Refinery maintenance schedule
- Refining companies' investment programs

Imports and exports are also tightly controlled. In accordance with the Agreement between the Government of the Russian Federation and the Government of the Republic of Kazakhstan from December 9, 2010 on trade and economic cooperation in the field of oil and oil products supplies to the Republic of Kazakhstan, the import volumes are set by the statewhile exports of light and middle distillates outside the customs territory of the Customs Union are prohibited from 1 January 2014.

However, it should be noted that Kazakhstan has made further progress towards market liberalization. First, the number of products for which prices are regulated was reduced: in December 2014 the list of regulated products consisted of gasoline grades A-80, A-92, A-93 as well as diesel and LPGs, while in September 2015 gasolines A-92 and A-93 were excluded, and in July 2016 diesel was also excluded. This leaves retail price regulation applying only to gasoline A-80 and LPGs.

Deregulation of retail price caps for gasoline grades A-92, A-93, and diesel fuel allowed prices to rise slightly. Specifically, average retail prices for gasoline A-92 and A-93 increased from 108 tenge ($0.36) per liter in September 2015 to 124 tenge ($0.38) in October, while prices for diesel increased from 99 tenge ($0.29) per liter in July 2016 to 113 tenge ($0.34) in August 2016, and reached 131 tenge ($0.39) per liter in October 2016 (see Figure 4.1). However, the worries of the market participants with regard to potential initiation of an investigation by the regulatory authority (KREMiZK) and the consequences thereof is limiting any significant increase in deregulated fuel prices.

Figure 4.1. Retail prices for refined products in Kazakhstan



Notes: Gasolines A-95 and A-98 were never regulated

Sources: IHS Markit; Statistical Committee of RK

Secondly, state regulation of refinery processing tariffs was abolished. In particular, Step 53 of the program "One Hundred Steps" put forward by President Nazarbayev in 2015 changed the concept of the work of the antimonopoly service in order to ensure compliance with OECD standards. In January 2017, KREMiZK's Register of Dominant (Monopoly) Players (for which price regulation is applied), which in cluded the country's three main refineries,was officially abolished. Therefore, refinery processing tariffs were freed from direct state regulation and are now set by company management (see above).

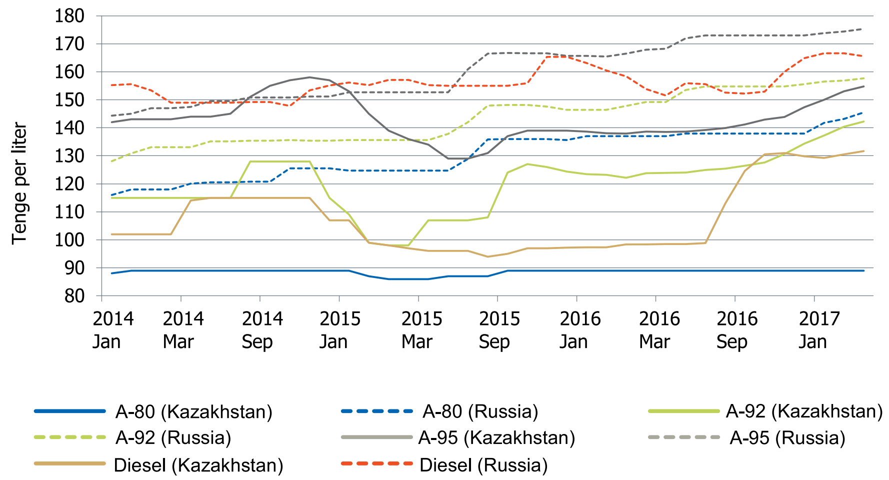
The government will continue to administratively influence the prices for certain types of refined products, especially until refinery modernization is completed. After modernization, retail prices (A-80 and LPG) are expected to be deregulated and the restrictions on refined products export and import are expected to be lifted. The prices for refined products in the domestic market will be moving towards parity with prices for Russian products (taking into account the differences in taxes) within the single economic space.

To compensate for significant investments in modernization, refinery processing rates have been increased and are expected to grow even more. As of 1 April 2016, the processing tariffs were confirmed by KMG's Board of Directors at 20,501 tenge/ton ($59.9/ton) for crude to Atyrau, and 14,895 tenge/ton ($43.5/ton) for Pavlodar. From April 2017, the processing fees were raised to 24,512 tenge ($81.7) per ton at Atyrau and 16,417 tenge ($52.6) per ton at Pavlodar. These processing tariffs, which essentially are the refineries' operating margin (at $11.2/bbl and $7.2/bbl), are quite high compared to the margins prevailing in the global market, including Russia (see the text box: Global Refining Margins). In the next few years, the processing rates at Kazakhstan refineries are expected to be raised to $115/ton ($15.8/bbl).

The necessity of a tariff increase for loan repayment is evident from both the refinery operation point of view and the state refining sector strategy point of view. However, such a high level of processing tariffs will have a negative impact longer term. First and foremost, high refinery tariffs mean that price liberalization or even a significant increase in crude oil prices in the domestic market becomes difficult, as refined product prices are effectively capped by parity with Russian (imported) products, so higher crude acquisition costs cannot be simply passed through to refined product prices (see Figure 4.2).Therefore, careful attention should be paid not only to the financial liabilities of the refineries, but also to the interests of the producers supplying crude to the refineries.

The potential for growth in crude oil prices is much greater than in refined product prices through market integration with Russia. It will become increasingly difficult for Kazakhstan's refineries to obtain crude without lower processing tariffs.

Figure 4.2. Refined product prices in Kazakhstan and Russia



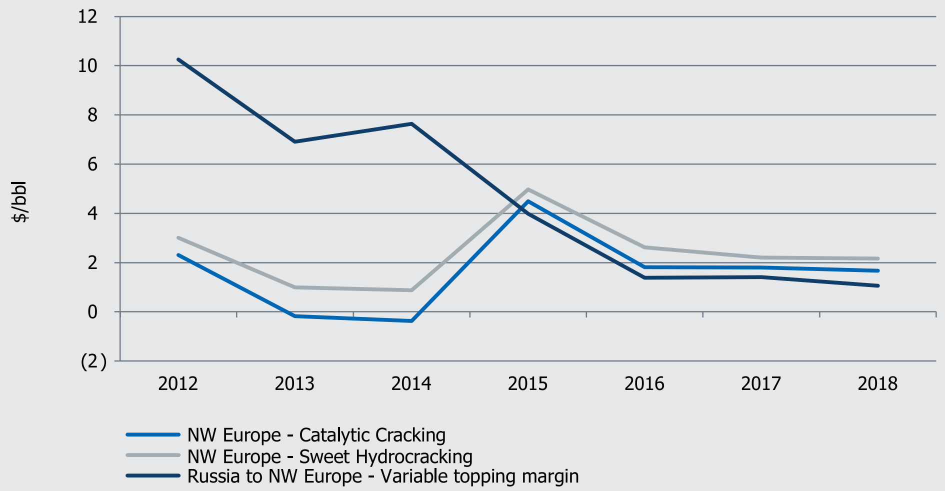
Notes: For Russia, light wholesale prices are for Omsk region converted to Tenge at average monthly exchange rate by Kazakhstan Central Bank. For Kazakhstan, light wholesale prices are country's average

Sources: IHS Markit; Statistical Committee of RK

Global refining margins

Refining margins around the world have plummeted since 2015 due to global crude oversupply, low crude prices, and high levels of installed refining capacity (see Figure 4.3). Shrinking margins can force less competitive refineries (typically small, unsophisticated plants) to shut down altogether. Between 2009 and 2016, global refinery rationalization led to the closure of almost 8 MMb/d (400 MMt) of refining capacity.

Figure 4.3. Refining margins in Northwest Europe



Source: IHS Markit

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Refining margins in Northwest Europe have fallen from $5/bbl in 2015 to less than $2/bbl in 2016. In Russia, the tax maneuver eliminated the substantial subsidy the refining sector received on exports of heavy refining products, and refining margins fell from nearly $8/bbl in 2014 to less than $2/bbl in 2016.

The average refining margin in Northwest Europe is now around $1.4/bbl, and is expected to remain low—between $1.00 and $1.50/bbl over the next few years. In Northwest Europe, the average full-cost FCC refining margin isexpected to be $1.80/bbl and $1.67/bbl in 2017 and 2018, respectively, while hydrocracking margins will likely be $2.20/bbl and $2.17/bbl over the same period.

In the near term, global refining margins will remain flat as inventories remain high. Over the medium term (2019–25), refining margins are expected to rebound slightly due to the impact of the change in IMO bunker fuel specifications. The product differential between light products and heavy sulfur fuel oil (HSFO) will grow as HSFO will need to be priced at thermal parity to coal and heavy products.

Margins for some secondary processes, notably coking and hydrocracking, will increase more rapidly than FCC margins, as these technologies are critical for converting high–sulfur fuel oil into lighter streams. In contrast, sour cracking conversion and heavy sour simple conversion will be under enormous duress and at risk for shut-in around 2020, as their net margins will barely breakeven. After 2025, over the long term, refining margins remain fairly flat, if not enter a period of terminal decline, as transportation efficiency gains and greater consumption of alternative fuels will dampen products demand growth.

4.3.3. Refined product taxes

In addition to VAT that applies to all goods and services sold in Kazakhstan, two other types of taxes affect refined products: export duties and excise taxes. Kazakhstan levies export duties on many types of goods, particularly crude oil, but export duties also apply to refined products that might be exported, such as fuel oil. Since 2014 the government has set the export duty for oil products as a fixed dollar amount per ton: $169 for gasoline, $169 or $113 for diesel (depending on the specific fuel type), and $113 for fuel oil. The export duty for diesel and fuel oil was subsequently reduced to $60 per ton in March 2015. In March 2015 Kazakhstan did tie the duty rate on oil products to the international price of crude oil, but this arrangement was short-lived as in May 2015 the formula was revoked. The government introduced a formula again in February 2016, but it has not yet been implemented and the export duty remains simply a fixed amount per ton. Historically, export duties in Kazakhstan on refined products were much lower than in Russia, but this has changed with the latest elements of Russia's phased tax maneuver and lower global oil prices (Russian duties are set as percentages of export prices for crude oil): although Russian export duties on heavy products remain higher than they are in Kazakhstan, they are now much less than in Kazakhstan on light products (see text box: Russian export duties on refined products.)

Russian export duties on refined products

One of the major drivers of Russian tax reform in recent years has been reducing economic incentives for export-oriented "opportunistic" refining that either destroys or adds little aggregate value; it emerged because of the much lower export duties imposed on refined product exports than on crude oil since 2004. This type of refining activity usually employs simple crude refining capacity (primary distillation atmospheric units) and produces semi-finished products, such as straight-run gasoline, basic middle distillates and, most importantly, large quantities of heavy fuel oil, for which there is little demand in Russia. The main purpose of such export-oriented refining is to take advantage of the generous subsidy for the export of refined products, especially fuel oil, provided by the Russian state in the form of relatively high export taxes on crude relative to refined product exports. But the subsidy facilitating export-oriented refining has become increasingly untenable for the Russian government in recent years for a variety of reasons, one of them being the need for more revenue, and is also at odds with policymakers' longer-term goal of Russian refinery modernization.

The first key turning point of recent years in the Russian government's approach to taxation of crude and refined product export streams was the so-called "60-66" tax reform introduced in October 2011, which represented a critical initial step in reducing preferential export tax terms for lower-quality products. The "60-66" regime, which came into effect in late 2011 and lasted until 2014, reduced the marginal crude export tax rate from 65% to 60% of the Urals price and unified most refined product export duties at the rate of 66% of the crude export tax (the gasoline export duty was set higher, at 90%, in an effort to curb domestic gasoline shortages). The 66% rate represented a slight decrease in the tax burden for the higher-quality export streams to which it applied but was at the same time a substantial export tax increase in the case of fuel oil. Exports of fuel oil nevertheless remained profitable under the new tax regime; just less profitable than before. Overall, this reform left Russian refiners with a refined product export tax subsidy of about $17 per barrel (at an average global crude oil price of $100 per barrel), and facilitated an additional increase in primary refining to support higher exports of diesel as well as fuel oil.

With the latest round of the tax maneuver, particularly the equalization of the export duty on fuel oil with crude oil, the privileged export tax regime for most heavy refined products was eliminated, to both stimulate a lightening of the Russian refinery slate and reduce the massive state subsidy to the Russian refining sector. State support for the refining sector is set to continue under terms of the maneuver, but at greatly reduced levels and mainly for lighter product streams; e.g., in the form of reduced gasoline and diesel export tax rates relative to the crude export duty rate. In January 2017, the export tax rates for oil and oil products were changed as follows:

- A 30% marginal rate for crude oil (down from 42% in 2016);
- Rates for refined products (as a percentage of the crude oil duty rate) became 30% for gasoline and 55% for naphtha (down from 61% in 2016); 30% for medium distillates (down from 40% in 2016); and 100% for heavy products (up from 82% in 2016).

Therefore, currently (as of August 2017), the regular export tax on crude oil changed to $74.4 per ton, while the export tax on most light and refined products changed to $22.3 per ton, while for heavy products this became $74.4 per ton, the same as for crude oil; the export duty for straight-run gasoline (naphtha) became $40.9 per ton, while for automobile gasoline it changed to $22.3. per ton, while the export tax on LPGs (propane, butane) remained at zero.

Another urgent issue for Kazakhstan is excise tax harmonization with Russia because of the importance of imported gasoline in Kazakhstan's consumption. To a certain extent, this applies to VAT as well, where different rates are applied. Fiscal harmonization is always a major issue in regional integration schemes, such as the Eurasian Economic Union (EAEU). Differences in excise duties among countries can have a major impact on the competitiveness of their refined products within the unified economic space, and are also major sources of government revenues. For example, within the European Union, an agreement on harmonization of excise duties for petroleum products was only reached in June 1991. Because of the contentiousness of the issue, several previous attempts to harmonize at specific levels and then within specified bands failed. The agreement reached sets minimum rates above which member states are free to set their own taxes (see text box: Harmonizing Excise Taxes on Refined Products).

Harmonizing excise taxes on refined products

Fuels subject to excise tax in Kazakhstan include motor gasoline (excluding aviation gasoline), diesel fuel, and crude oil/gas condensate; other refined products are not excisable. Currently, crude oil and gas condensate have zero excise tax. Excise taxes were established in the 2009 Tax Code, but since 2015 the tax rates are set separately by the government. For some time after being established in the Tax Code in January 2009, excise tax rates remained at 5,000 tenge per ton on gasoline and 600 tenge per ton on diesel fuel. These are the total rates that apply to retail prices. Refineries (or wholesale participants) paid excise taxes at a rate of 4,500 tenge per ton for gasoline and 540 tenge per ton for diesel on all their domestic sales. Retail sellers were responsible for the remaining excise (500 tenge per ton for their gasoline sales and 60 tenge per ton for their diesel sales). If refineries (or wholesalers) engage in direct sales to consumers, then they pay the entire excise amount.

In November 2015, the excise tax on gasoline was raised to 11,000 tenge per ton (10,500 tenge at the wholesale level and 500 tenge at the retail level) while the excise tax on diesel remained unchanged at 600 tenge per ton (540 tenge wholesale and 60 tenge retail) (see Table 4.7). However, starting from October 2016, excise taxes on diesel were made seasonal: between November and March the rate is reduced to 600 tenge per ton (540 tenge wholesale and 60 tenge retail), while between April and October the rate of 9,360 tenge per ton (9,300 tenge wholesale and 60 tenge retail) is applied. In March 2017 the government expanded the period of reduced diesel excise taxes to last from November to May.

Since 2011, Russia has employed a differentiated approach to excise taxes, aimed at stimulating conversion to higher grades with lower excise and punishing lower grades of product with higher excise.

Kazakhstan's excise tax rates remain much lower than Russia's. Through 2014, gasoline excise was little more than 10% of the Russian level, and for diesel it was only 1–2% (see Table 4.7). These ratios jumped to 24% for gasoline and 6% for diesel in 2015 (driven by a decrease in Russia's diesel excise tax in 2015). By 2017 the ratio had fallen back to 15% for gasoline (as excise tax in Russia went up), but sharply increased to 25% for diesel following the seasonal raise of the tax in Kazakhstan.

4.3.4. Privatization

In January 2016, the Ministry of National Economy published a list of more than 360 state- and municipally-owned companies targeted for eventual privatization in the 2016–20 program. The ambitious program, part of the government's anticrisis plan, aims to privatize 5% of all municipal enterprises in the country and 15% of all state enterprises, reducing the overall role of the state in the economy. The role of the refineries in this program remains ambiguous. They are listed as part of the key energy assets the state plans to divest. However, it was subsequently decided that the refineries should only be privatized after the modernization program is completed. It also remains unclear whether they will be privatized as a group, with a sizable stake in an overall holding being sold, or whether the refineries will be sold individually.

4.3.5. Key recommendations

- As the state is gradually loosening its administrative control over the downstream sector, Kazakhstan needs to continue to move forward in market liberalization. The country needs to commit to further relaxation of still existing administrative measures, including full price liberalization for all refined products (A-80 and LPG), lifting controls on exports and imports, and abolishment of planning of refining volumes and oil supplies to refineries as well as scheduling refined products supply to the domestic market.
- In particular, domestic crude prices need to be allowed to rise to export netback parity. In time, this will provide sufficient incentive for crude producers to supply domestic refineries.
- Given limited projected growth in domestic products demand, the construction of another major refinery within the period to 2030 would lead to aggregate oversupply and low national refining capacity utilization; possibilities for refined product exports are quite limited.
- For a number of reasons, including the planned privatization program and stimulating greater energy efficiency at the refineries, it is recommended to make the refineries merchant operators, buying crude and selling refined products rather than remaining on a tolling scheme.
- The mechanism of subsidizing agricultural producers at the expense of other refined products market participants, when refined products (mainly diesel fuel) are supplied at special low prices during the sowing and harvesting campaigns, should be abolished; agricultural enterprises should pay regular market prices for their fuel supplies.
- As shown by the historical example of the EU, regional integration is most effective when member states liberalize domestic policies and cross-border arrangements. Therefore, as a member of the EAEU, in the long term, Kazakhstan should introduce market mechanisms and refrain from establishing restrictive administrative mechanisms with regard to refined products production, distribution, and trade. In a liberalized market, any company should be able to sell refined products in any part of the country.
- Longer term rates of export duties and excise taxes should be aligned with those in Russia as a part of the single economic space.
- Although there is a desire for a revision of railway tariffs with elimination of cross-subsidies for other goods traffic at the expense of oil products, this item need not be highest on the actionable priority list. The gain for oil participants is much less than the sizable business impact from higher rail tariffs on other commodities such as coal.[17]
- Develop a mechanism for the member states of the Eurasian Economic Union, especially Kazakhstan and Russia because of the long shared border and the high volume of product trade, to harmonize their excise tax rates for refined products.

[17] See section 6.2.7 on"Coal transportation" in this report's Chapter 6 on coal.

Table 4.7. Refined product excise taxes in Kazakhstan and Russia

	January 2012	January 2013	January 2014	January 2015	January 2016	January 2017
	in percent	in percent	in percent	in percent	in percent	in percent
Kazakhstan excise taxes as percent of Russian excise taxes*						
Motor gasoline	**14,3**	**10,3**	**10,2**	**53,4**	**22,3**	**15,1**
Diesel fuel	**3,1**	**2,1**	**2,0**	**6,2**	**48,0**	**24,8**

* Calculated against comparable Russian fuel grades (i.e., class 3 for 2012-15; class 4 for 2016-17.

	January 2012			January 2013			January 2014		
	(rubles/ ton)	**(dollars/ ton)**	**Exchange rate (per dollar)**	**(rubles/ ton)**	**(dollars/ ton)**	**Exchange rate (per dollar)**	**(rubles/ ton)**	**(dollars/ ton)**	**Exchange rate (per dollar)**
Russia:									
Straight-run gasoline (naphtha)	7 824	250,4	31,24	9 617	318,1	30,23	11 252	333,1	33,78
Low-octane automobile gasoline									
Class 1 and 2	7 725	247,3		10 100	334,1		11 110	328,9	
High-octane automobile gasoline									
Class 3	7 382	236,3		9 750	322,5		10 725	317,5	
Class 4	6 822	218,4		8 560	283,2		9 916	293,5	
Class 5	5 143	164,6		5 143	170,1		6 450	190,9	
Diesel fuel									
Class 1 and 2	4 098	131,2		5 860	193,8		6 446	190,8	
Class 3	3 814	122,1		5 860	193,8		6 446	190,8	
Class 4	3 562	114,0		4 934	163,2		5 427	160,7	
Class 5	3 562	114,0		4 334	143,4		4 767	141,1	
Heating oil	--			--			6 446	190,8	
Aviation kerosene	--			--			--		

	January 2015			January 2016			January 2017		
	(rubles/ ton)	**(dollars/ ton)**	**Exchange rate (per dollar)**	**(rubles/ ton)**	**(dollars/ ton)**	**Exchange rate (per dollar)**	**(rubles/ ton)**	**(dollars/ ton)**	**Exchange rate (per dollar)**
Russia:									
Straight-run gasoline (naphtha)	11 300	173,4	65,15	10 500	134,7	77,93	13 100	219,7	59,63
Low-octane automobile gasoline									
Class 1 and 2	7 300	112,0		10 500	134,7		13 100	219,7	
High-octane automobile gasoline									
Class 3	7 300	112,0		10 500	134,7		13 100	219,7	
Class 4	7 300	112,0		10 500	134,7		13 100	219,7	
Class 5	5 530	84,9		7 530	96,6		10 130	169,9	
Diesel fuel									
Class 1 and 2	3 450	53,0		4 150	53,3		6 800	114,0	
Class 3	3 450	53,0		4 150	53,3		6 800	114,0	
Class 4	3 450	53,0		4 150	53,3		6 800	114,0	
Class 5	3 450	53,0		4 150	53,3		6 800	114,0	
Heating oil	3 000	46,0		3 000	38,5		7 800	130,8	
Aviation kerosene	2 300	35,3		3 000	38,5		2 800	47,0	

Note: Excise tax differentiated in Russia by classes beginning in 2011.

	January 2012			January 2013			January 2014		
	(tenge/ ton)	**(dollars/ ton)**	**Exchange rate (per dollar)**	**(tenge/ ton)**	**(dollars/ ton)**	**Exchange rate (per dollar)**	**(tenge/ ton)**	**(dollars/ ton)**	**Exchange rate (per dollar)**
Kazakhstan:									
Automobile gasoline (all grades)	5 000	33,7	148,38	5 000	33,2	150,73	5 000	32,3	154,96
Wholesale	4 500			4 500			4 500		
Retail	500			500			500		
Excise on imported Russian gasoline	4 500			4 500			4 500		
Diesel fuel (all grades)	600	4,0		600	4,0		600	3,9	
Wholesale	540			540			540		
Retail	60			60			60		
Excise on imported Russian diesel	540			540			540		

	January 2015			January 2016			January 2017		
	(tenge/ ton)	**(dollars/ ton)**	**Exchange rate (per dollar)**	**(tenge/ ton)**	**(dollars/ ton)**	**Exchange rate (per dollar)**	**(tenge/ ton)**	**(dollars/ ton)**	**Exchange rate (per dollar)**
Kazakhstan:									
Automobile gasoline (all grades)	11 000	59,9	183,7	11 000	30,1	365,83	11 000	33,2	331,14
Wholesale	10 500			10 500			10 500		
Retail	500			500			500		
Excise on imported Russian gasoline	4 500			4 500			4 500		
Diesel fuel (all grades)	600	3,3		9 360	25,6		9 360	28,3	
Wholesale	540			9 300			9 300		
Retail	60			60			60		
Excise on imported Russian diesel	540			540			540		

Note: Changes in excise taxes went into effect in December 2015 and April 2017. Diesel excise tax in April 2017 became seasonal: 9,360 tenge/ton is applicable between June and October, while a rate of 600 tenge/ton is applicable between November and May.

Source: IHS Markit

5. NATURAL GAS

5. NATURAL GAS

5.1. KEY POINTS

Kazakhstan has sizable reserves of natural gas, but the bulk of this is high-sulfur associated gas, which is expensive to process and whose output is essentially tied to liquids production. Consequently, development and use of this gas remains problematic, complicated by low producer prices, limited ability of consumers to pay for higher priced gas, the need to transport it long distances within Kazakhstan to many markets, and limited (to date) export opportunities. A relatively high share of natural gas extraction (36% of gross output in 2016) continues to be reinjected to support recovery of oil. But the share of gas in primary energy consumption has been rising; currently natural gas is viewed as a key "bridge fuel" in power generation between baseload coal and intermittent renewable energy sources, addressing the growing need for additional flexible capacity while producing less greenhouse gas emissions than coal.

For natural gas to decisively increase its role in the national economy, prices for natural gas in Kazakhstan will need to increase, both at the upstream level and at the end-consumer. This will incentivize upstream suppliers to make more gas available and will cover the additional costs of transporting gas to more distant consumers. However, some form of state support for gas may be necessary (similar to the mechanisms supporting renewable energy), given the challenges for gas to be competitive, especially in power generation because of Kazakhstan's very low-cost domestic coal. Another important aspect of gas pricing policy is the need to harmonize Kazakhstan's end-user prices with those in Russia as part of the general movement towards creating a single economic space within the Eurasian Economic Union.

To expand domestic gas consumption, promote "greener" energy, and boost the economy's international competitiveness, the government of Kazakhstan placed responsibility for development of the domestic gas market with a "national operator" by creating a single-buyer model in the Law on Gas and Gas Supply in 2012. Since then, KazTransGas (KTG), the specialized gas subsidiary of national oil company KazMunayGaz (KMG), essentially functioned in this role, as it included various subsidiaries within its structure that operated the centralized trunk pipeline infrastructure and distribution systems, bought and sold gas domestically, and carried out gas exports and imports. Under the Law on Gas and Gas Supply the national operator has a pre-emptive right to purchase processed associated gas from producers. But with the decision to phase out KTG as a centralized holding (see below), the role of national operator presumably will shift to either KMG itself or directly to KTG's specialized gas subsidiaries.

Other key updates include:

- *Production*. Gross gas production in 2016 increased 2.4%, to 46.4 billion cubic meters (Bcm), continuing a three-year trend in rising production despite falling oil liquids production during this period. Total commercial production in Kazakhstan has also been on the rise, reaching 29.5 Bcm in 2016, a 6.4% increase over 2015. Over three-fourths of Kazakhstan's current gas output comes from the Karachaganak and Tengiz projects, with gross output at the former being basically flat over the last four years, compared to a gradual three-year increase at the latter. Aggregate output growth by other gas producers was the main driver of Kazakhstan's gas production growth in 2015–16, although the major increment to production in 2017 is expected to come from Kashagan.
- *Upstream developments*. A proposed third phase for Karachaganak development is being discussed, targeting a scaled-back project. A decision is still expected to be announced by the end of 2017, with the launch planned for 2022. In July 2016 the TCO consortium operating the Tengiz project approved the FID for the TCO Future Growth Project (FGP)–Wellhead Pressure Management Project (WPMP). Although the prime driver for the decision to expand operations was to increase oil production (beginning in 2022), gross gas extraction is also poised to increase, although most of the increment is planned to be reinjected.
- *Production outlook*. IHS Markit projects that gross output will reach about 48 Bcm per year in 2020, 72 Bcm in 2030, and 77 Bcm in 2040 in the base case, while volumes of commercial gas are expected to increase to about 27 Bcm per year in 2020, 35 Bcm in 2030, and 47 Bcm in 2040. The key factor in determining Kazakhstan's overall gas production outlook is the country's overall oil production outlook, as this is the principal driver for gas production.
- *Processing and transportation*. With the launch of processing capacity for Kashagan gas (Bolashak), Kazakhstan now has four major gas processing plants, with a combined capacity of 23.8 Bcm/y.In aggregate, together with the availability of Russian capacity at Orenburg, this amount appears adequate to handle the bulk of Kazakhstan's expected volumes of commercial gas for the next decade or so. One of the major developments in Kazakhstan's gas transportation sector was the 2015 completion of the remaining segment (Beyneu-Bozoy) of the Beyneu-Bozoy-Shymkent (BBS) pipeline, which allows gas produced in the western part of Kazakhstan to reach the country's southern area and paves the way for eventual large-scale gas exports to China.

5.2. NATURAL GAS SECTOR UPDATE

Although the production of natural gas (both associated and nonassociated) has been increasing in Kazakhstan over the past several years, interest in and concerns about gas availability and use remain high. KTG, the state-owned entity broadly responsible for the domestic gas market (see below), has been hard at work gasifying more places, linking the country's gas-producing and gas-consuming regions, and creating the technical preconditions for the launch of large-scale exports to China. In particular, natural gas is now viewed as a bridge fuel in power generation between baseload coal and intermittent renewable energy sources, addressing the growing need for additional flexible capacity while producing less greenhouse gas emissions than coal. The key question that frequently arises is whether Kazakhstan has enough gas to support both growing domestic consumption and its export commitments.

As mentioned above, Kazakhstan has plentiful reserves of gas, but the bulk of this gas is high-sulfur associated gas, which is expensive to process and remains tied to liquids production. Pricing policy is going to play an important role in the future development of the industry. Currently, producer prices for gas are quite low, which helps keep prices down for end-consumers, although not necessarily in the areas that rely on imported gas (the north and especially the south of the country), where gas tends to be more expensive. Additional indigenous supplywill require more processing, which increases its cost, and to make gas more widely available, it will need to be transported over long distances, which also adds to costs. What is clear is that the prices for natural gas will be under upward pressure to stimulate additional supply.

5.2.1. Overall vision and organizational structure

President Nursultan Nazarbayev initiated a process of widespread, corporate transformation across national wealth fund Samruk Kazyna's 13 subsidiary companies in an October 2014 speech, in which he emphasized the imperative to increase the fund's value and to advance Kazakhstan's overall economic well-being. The most important of these subsidiaries, national oil company KMG, incorporates KTG within its structure. For KMG, a key transformation goal is to improve operational performance, efficiency, and monetary value. To help achieve these goals, in November 2016, KMG Chairman Sauat Mynbayev announced that KTG would be abolished as an administrative management company, while KTG's key subsidiaries, such as KTG Aimak and Intergas Central Asia, would function as direct subordinate companies of KMG.

Law on Gas and Gas Supply

Since passage of the Law on Gas and Gas Supply in January 2012, Kazakhstan's domestic gas market has been increasingly moved into the hands of state-owned KTG, as the "national operator" for the county's single-buyer model. KTG operates most of the gas infrastructure in the country, and under the legislation has preferential rights to purchase associated gas from producers. KTG also sells gas on the local market and exports gas abroad.

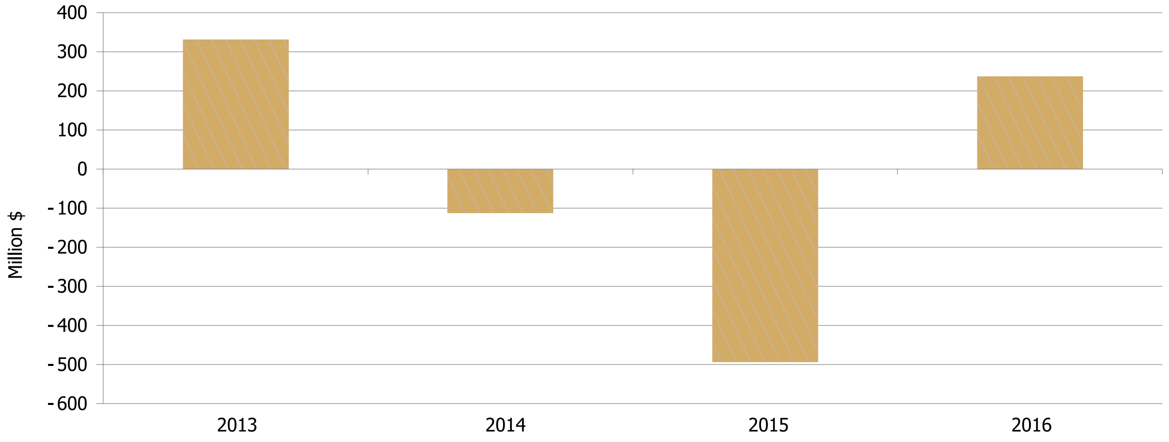
The logic of the Law on Gas and Gas Supply appears to be that it puts Kazakhstan's gas production at the disposal of a single national operator through administrative means and specifically empowers that entity to develop the domestic market and pipeline infrastructure. This reflects the fact that the bulk of gas production in Kazakhstan occurs as a byproduct of liquids production (either associated gas or condensate-related gas), and the view that gas supply would not respond to (gas) market conditions directly. Government policy also appears to be aimed at having the state-owned entity capture any upside from higher domestic end-user prices and export prices, while maintaining a single channel for exports so as to balance the near-monopoly conditions in two neighboring gas-purchasing countries, Russia and China.

While this type of market structure probably can work in Kazakhstan, where aggregate supply (associated gas) is not as strongly linked to actual conditions in the gas market, it means that Kazakhstan will likely forgo some natural gas development, since companies would have little incentive to pursue pure dry gas plays in their upstream endeavors. Of course, targeted incentives could be provided if needed to drive dry gas development in parts of the country where gas is needed or where dry gas plays dominate.[1]

KTG and its subsidiaries delivered nearly 100% of all piped gas that reached domestic consumers, with more than 95% of all gas delivered to domestic consumers traveling through KTG's trunk pipelines. KTG delivers piped gas to consumers through its distribution subsidiaries. Previously, these distributors supplied gas to only 7 of the 10 provinces that receive natural gas by pipe, but this has now become all 10.[2] KTG has displaced the private gas trading companies that previously operated in various parts of Kazakhstan, buying gas from producers and selling it to consumers.

Despite the ambitious goals for gas in Kazakhstan, and especially its envisioned role in sustainable energy, the general inadequacy of much of state gas policy, particularly gas pricing policy, is indicated by KTG's generally precarious financial position resulting from its diverse roles and responsibilities at the center of the sector. Large financial losses were incurred by KTG in 2014–15, although the company returned to profitability in 2016. KTG's consolidated financial results for 2013–16 show the impact on the company's gross revenues of the general decline in oil and gas prices, which failed to be compensated for in other parts of the value chain (see Figure 5.1, Table 5.1). Consolidated This reflects the fact that the bulk of gas production in Kazakhstan occurs as a distress was also tenge devaluation and what it did to financing expenses, as much of the company's outstanding loans were dollar-denominated.

Figure 5.1. Net Income of KazTransGas



Source: IHS Markit

[1] An example of this is KTG's offtake contract with Tethys Petroleum for its (shallow, dry) gas production in Aktobe Oblast. In December 2014, a new gas sales contract with KTG was announced, which increased the purchase price of gas by 42% to $75 per thousand cubic meters (Mcm), which was more than double the national average producer price for gas at the time.

[2] Historically, only 9 oblasts received piped gas, but this became 10 in 2015 with the launch of deliveries in East Kazakhstan Oblast.

Table 5.1. Consolidated financial summary for KazTransGas

thousand tenge	2013	2014	2015	2016
Revenues	288 317 189	328 972 045	374 319 323	501 958 495
Cost of sales	-209 677 956	-242 473 336	-277 605 060	-348 453 622
Net operating expenses	-24 598 896	-29 083 332	-24 815 259	-30 333 883
Operating Income	**54 040 337**	**57 415 377**	**71 899 004**	**123 170 990**
Financial expenses	12 166 124	-64 458 397	-179 848 856	-15 244 294
Income tax	-15 753 117	-13 124 799	-1 534 705	-26 531 702
Net Income	**50 453 344**	**-20 167 819**	**-109 484 557**	**81 394 994**
Year-end exchange rate (KZT/USD)	152,13	179,19	221,73	342,16
million $	**2013**	**2014**	**2015**	**2016**
Revenues	1 895	1 836	1 688	1 467
Cost of sales	-1 378	-1 353	-1 252	-1 018
Net operating expenses	-162	-162	-112	-89
Operating Income	**355**	**320**	**324**	**360**
Financial expenses	80	-360	-811	-45
Income tax	-104	-73	-7	-78
Net Income	**332**	**-113**	**-494**	**238**

Source: KazTransGas

KazTransGas consolidated financials include the following subsidiaries:

Subsidiary	KTG ownership 2016	2015	Business line
Intergas Central Asia	100%	100%	Trunk pipeline transportation
KTG Aimak	100%	100%	Gas sales and distribution
KTG Tbilisi (Georgia)*	100%	100%	Gas sales and distribution
KTG Onimerdi	100%	100%	Transportation
Amangeldy Gas	100%	100%	Gas (and condensate) production
Astana Gas KMG	100%	100%	Construction of trunk gas pipeline to Astana (West-North-Center)
KTG Kansu Operating	100%	100%	Upstream exploration
Intergas Finance BV (Netherlands)	100%	100%	Issue of Eurobonds
KazTransGas Bishkek (Kyrgyzstan)	100%	100%	Repair/refurbishment/modernization of Tashkent-Bishkek-Almaty gas pipeline
KTG Almaty	--	100%	Gas sales and distribution
Asia Gas Pipeline	50%	50%	Construction and operation of Kazakhstan-China gas pipeline system
Beyneu-Bozoy-Shymkent Pipeline	50%	50%	Construction and operation of the Beyneu-Bozoy-Shymkent pipeline
AvtoGaz	50%	50%	Constructon, operation, and maintenance of gas filling stations

* KTG has not exercised effective control over the Georgian subsidiary since a Georgian court ruling in 2009.

5.2.2. Natural gas reserves

Kazakhstan's State Commission on Reserves (GKS) listed the country's gas reserve base (state balance) as of 1 January 2016 at 4.01 trillion cubic meters (Tcm). This is roughly the same figure as has been reported for the past several years.[3] Of this, 2.27 Tcm is "solution" gas (held in solution with liquid hydrocarbons in the reservoir) and 1.74 Tcm is "free" gas.[4] Most (3.72 Tcm) of the country's reserves are concentrated in the North Caspian Basin, and approximately 98% of the country's gas reserves are

[3] This is reported according to the domestic definition (in categories A+B+C1+C2) and appears to roughly correspond to the international equivalent of proven + probable ("2P") reserves. IHS Markit estimates Kazakhstan's remaining 2P gas reserves at 134 trillion cubic feet (3.8 Tcm).

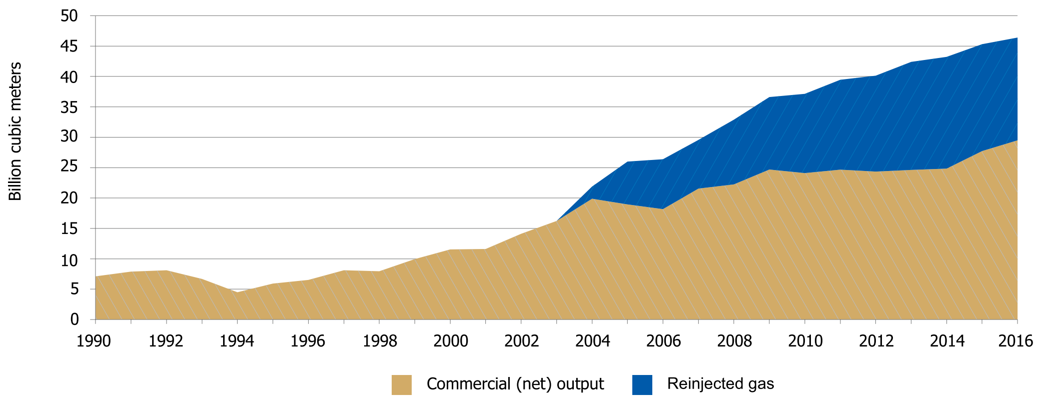
[4] By international definitions for just "proven" ("1P") reserves, Kazakhstan is considered to possess 1.0 Tcm as of the end of 2016, or 0.5% of the global total (BP Statistical Review of World Energy, June 2017). By this measure Kazakhstan ranks fifth among CIS countries (after Russia, Turkmenistan, Uzbekistan, and Azerbaijan) and 26th in the world.

located in western Kazakhstan (Mangistau, Atyrau, West Kazakhstan, and Aktobe oblasts).About 85% is found in just a few large fields (e.g., Tengiz, Kashagan, Karachaganak, Zhanazhol, Imashevskoye), mostly in deep subsalt deposits (up to 5 kilometers), multi-component composition, and high sulfur content, all of which greatly complicate development and production. The official state balance for 2015 identifies reserves in 228 fields, of which 68 were reportedly in production.

5.2.3. Historical gas production trends

In 2016, for the third year in a row, Kazakhstan's gross gas production (including reinjected volumes) diverged from liquids production trends, even though nearly half of Kazakhstan's gas is produced with oil at oilfields as associated gas (see Figure 5.2).[5] In 2016, gross gas production increased 2.4%, to 46.4 Bcm, in contrast to a 1.9% decline in oil (including condensate) output. So far in 2017 gas production is growing robustly, increasing by 15.4% in the first half. Commercial production (gross output minus reinjection) in Kazakhstan has also been on the rise. In 2016, "commercial" output (defined by the state statistical agency to also include field use) reached 26.8 Bcm, with 11.4 Bcm being reinjected to sustain liquids production (see Table 5.2).

Figure 5.2. Historical gross and commercial gas production in Kazakhstan



Notes: Gross production, including reinjected volumes. Data presented as reported by official entities.
Source: Statistics Committee RK; Ministry of Energy

Table 5.2. Kazakhstan's gas supply and demand balance (billion cubic meters)

Total extraction	*45,3*	*46,4*	*48,1*
Use of raw gas at the field for internal needs	20,5	19,6	21,2
Own needs (including on-site electricity generation)	8,3	8,2	7,8
Reinjection into reservoir	12,3	11,4	13,4
Commercial gas available for distribution	24,8	26,8	26,9
Internal consumption (end-of-pipe)	12,1	13,1	13,2
Gas exports*	12,7	13,7	13,7

*Including swaps

** Estimated for 2017.

Source: Statistical Committee of RK

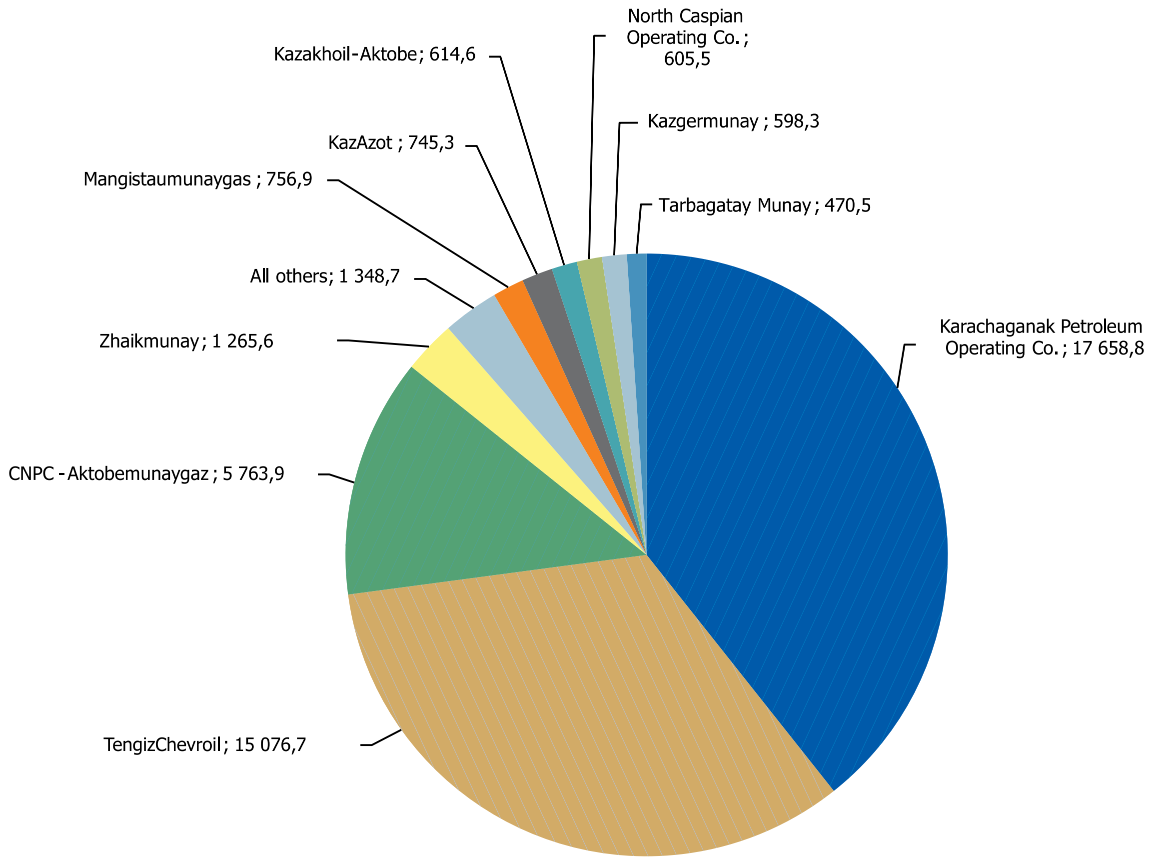
[5] Gross production includes total volumes extracted from the reservoir, so it also includes all non-methane components, including hydrogen sulfide, carbon dioxide, nitrogen, etc. It also includes reinjected volumes. In standard international statistical practice, reported production does not include reinjected volumes, but only "commercial" output available for project use and distribution to consumers.

Karachaganak

Kazakhstan's gas output comes mainly from the Karachaganak and Tengiz projects, which together account for over 75% of Kazakhstan's total production (see Figure 5.3).[6] The Karachaganak field (in West Kazakhstan Oblast) is the largest producer (see Figure 5.4).

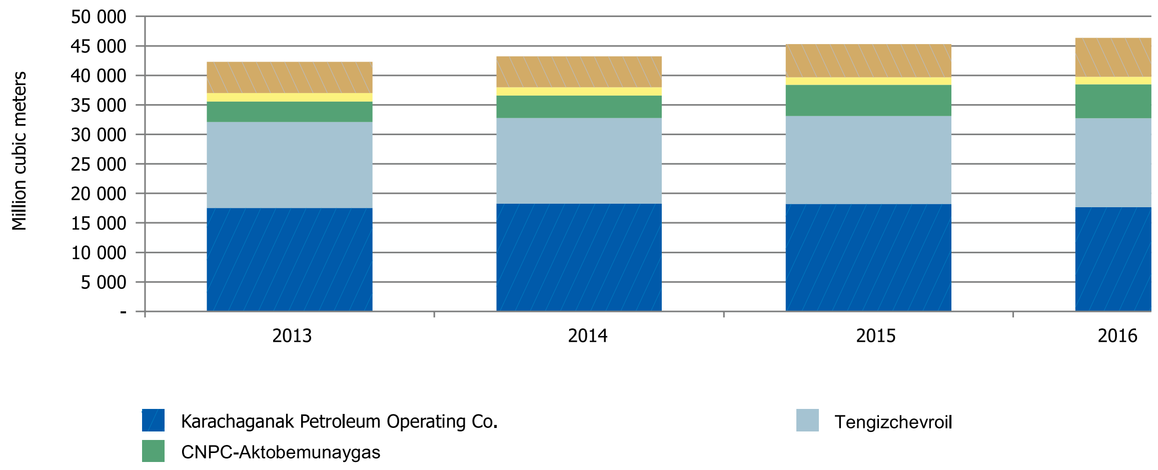
Gross production by the Karachaganak Petroleum Operating (KPO) consortium, however, has been basically flat over the last four years.[7] It increased from

Figure 5.3. Kazakhstan's (gross) natural gas production by largest producers in 2016 (million cubic meters)



Source: IHS Markit; Ministry of Energy

Figure 5.4. Kazakhstan's gross natural gas production by major producers, 2013-2016



Source: IHS Markit; Ministry of Energy

[6] Karachaganak Petroleum Operating has been developing the Karachaganak field since 1997 on the basis of a 40-year production-sharing agreement (PSA). TengizChevroil JV has been operating the Tengiz and Korolevskoye fields since 1993 on a 40-year JV contract.

17.5 Bcm in 2013 to 18.2 in 2014–15 and declined to 17.7 Bcm in 2016. About half of the gross output has been reinjected, although reinjected volumes have declined slightly: for example, in 2013 the share of reinjected gas was 53%, but by 2016 it had declined to 46%.The field's commercial output has been flat at about 9.6 Bcm over 2015–16.

Nearly all of Karachaganak's raw (high-sulfur) gas output is sent across the border to Russia for processing at Gazprom's large Orenburg gas processing plant under a long-term agreement with KazRosGas, a joint venture between KMG and Russia's Gazprom, signed in 2007. In June 2015, KPO and KazRosGas extended that deal through 2038, securing an outlet for the bulk of KPO's current gas production for the remaining period of the field's PSA.[8]

The planned next phase for Karachaganak development remains under discussion, but the scope is being scaled back considerably. In June 2017 it was reported that costs have been reduced to $4.5 billion. In September 2016, Kazakhstan's Energy Ministry, KMG, KTG, and Shell (a new stakeholder in the KPO consortium after its acquisition of BG) signed a memorandum of cooperation in gas processing and petrochemicals market research.[9] Energy Minister Bozumbayev indicated that on-site processing of Karachaganak gas will be considered again.[10]

TengizChevroil (TCO)

TCO's gross gas output has been rising over the past three years to reach an all-time high of 15.1 Bcm in 2016.[11] About 52% (or 7.8 Bcm) of gross output was reinjected in 2016, leaving 7.2 Bcm available for actual consumption. Gross gas output for Tengiz is expected to remain at current levels until about 2022, when the next phase of expansion (the FGP-WPMP) at the field is completed.[12] While this will raise gross gas extraction, much of the increment is planned to be reinjected, so little additional commercial gas is expected to be produced.

Production by other gas producers

Aggregate output growth by other gas producers was the main driver of Kazakhstan's gas production growth in 2015–16. Aggregate production by other producers increased by 16.8% year-on-year in 2015 to about 12.2 Bcm, and 11.8% year-on-year to 13.6 Bcm in 2016 (see Figure 5.4). The largest among these is CNPC-Aktobemunaygaz, the third-largest gas producer in Kazakhstan. Its production expansion became possible with the completion of a third train at the Zhanazhol gas processing plant, raising the plant's total processing capacity to 7 Bcm/y.

5.2.4. Gas production outlook

Gas production in the country is expected to remain closely tied to oil production trends longer term. It is unlikely that material upstream developments will be pursued aimed at producing natural gas alone. This is largely because the domestic gas market does not provide strong incentives for such development given relatively low gas prices in the domestic market.

The Ministry of Energy is currently revising its long term gas output forecast, previously outlined in the Gas Industry Concept to 2030 in three scenarios: optimistic, realistic, and pessimistic. An updated mid-term forecast to 2021 has already been released (see Table 5.3). Importantly, the mid-term gas output forecast has been adjusted downward, essentially aligning with the low (pessimistic) outlook laid out two years ago in the Gas Industry Concept; it is now expected to reach about 47.5 Bcm in 2020 rather than 62 Bcm envisioned in the Concept's "realistic" scenario (medium case) (see Table 5.3). Commercial gas volumes are now expected to be about 28.4 Bcm in 2020 in this most recent update.[13]

IHS Markit's own outlooks envision that both gross gas production and commercial gas production will be slightly higher than in the Gas Industry Concept longer term. We project that gross output will reach about 48 Bcm per year in 2020, but 72 Bcm in 2030 and 77 Bcm in 2040 in our base case, while volumes of commercial gas are expected to increase to about 27 Bcm in 2020, 35 Bcm in 2030, and 47 Bcm in 2040 (see Table 5.4); and Figure 5.5). The main factor explaining the difference is that IHS Markit envisions a higher level of oil production than the Ministry, which results in more associated gas (see Chapter 3).

The three mega-projects will continue to dominate Kazakhstan's gas production, and much of the future increase in output is expected to come primarily from Kashagan (the North Caspian Operating Company or NCOC) (see Figure 5.6).However, more than 50% of Kashagan's gross gas extraction is planned to be reinjected. An onshore gas processing plant with 6.2 Bcm/y capacity was built to process Kashagan's raw gas, which contains significant amounts of sulfur (about 18% H_2S and 4–5% CO_2).[14] In August 2013, NCOC and KTG signed a long-term purchase agreement whereby KTG would buy 2.5–3.0 Bcm of Phase 1 processed dry gas annually through 2041 (the current expiration of the PSA).

[7] KPO shareholders are Eni 29.25%, Shell 29.25%,, Chevron 18%, LUKOIL 13.5%, and KMG 10%.

[8] Historically, about 8.0–8.5 Bcm annually went to Orenburg, and under the previous contract was slated eventually to rise to 16 Bcm. However, the new contract reduces annual deliveries to no more than 9 Bcm.

[9] KPO's ownership structure changed with Shell's takeover of BG (one of KPO's original stakeholders), announced on 8 April 2015 in a cash-and-shares offer valued at £47 billion ($73.9 billion), and completed in February 2016; Shell now holds the entirety of BG's original 29.25% share.

[10] The Karachaganak consortium and the government have studied possibilities for building a 5 Bcm per year domestic gas processing facility at the field as part of the planned third expansion phase. However, the construction cost for the plant was estimated at $3.7 billion, so in 2014 the plans were put indefinitely on hold.

[11] TCO shareholders are Chevron 50%, ExxonMobil 25%, KMG 20%, and LUKOIL 5%.

[12] In July 2016 the TCO consortium approved the final investment decision (FID) for the TCO Future Growth Project (FGP)–Wellhead Pressure Management Project (WPMP), which sets the stage for the addition of 12 MMt/y (260,000 b/d) of field production. The project's costs are estimated at $36.8 billion. TCO plans to drill around 100 wells for the project.

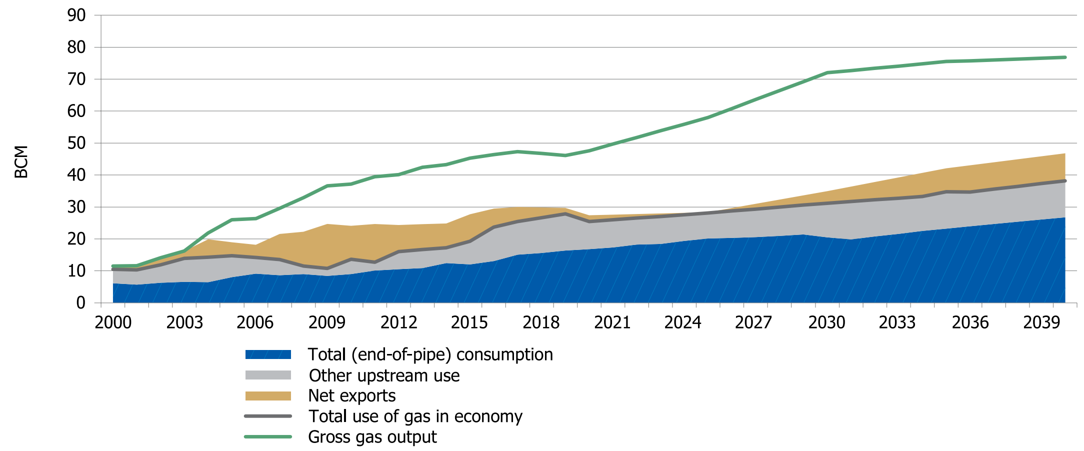
[13] The Ministry's definition of commercial gas volumes is the amount available for distribution to consumers after taking out upstream and midstream usage.

Table 5.3 Kazakhstan's gas supply forecasts by Ministry of Energy of RK

(billion cubic meters)							
A. Republic of Kazakhstan Gas Supply to 2030 (Realistic Scenario)							
	2015	**2020**	**2025**	**2030**			
Total gas production (gross volumes)	44,2	62,0	61,0	59,8			
Gas reinjection	12,5	22,8	24,8	25,1			
Other upstream use for internal needs (including flared volumes)*	5,6	5,9	5,5	5,3			
Total commercial gas production	26,1	33,3	30,7	29,4			
Fuel gas for pipeline use, including gas compressors*	3,9	8,6	8,5	8,4			
Commerical gas for distribution (to consumers, export, etc.)	22,2	24,7	22,3	21,0			
* The Ministy of Energy presents the own and internal use data breakdown as Other Upstream use and separately fuel for gas pipeline use, including gas compressors.							
Source: Ministry of Energy report, Republic of Kazakhstan Gas Supply to 2030, 5 December 2014.							
B. Strategic Plan of the Ministry of Energy for Kazakhstan national gas production for 2015-21							
(billion cubic meters)							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Gross gas production	45,3	44,0	44,4	45,3	46,6	47,5	49,4
Commercial gas production	27,1	26,0	26,5	27,1	27,9	28,4	29,6

Source: Ministry of Energy, 2016

Figure 5.5. Kazakhstan in expected to remain a net gas exporter



Source: IHS Markit

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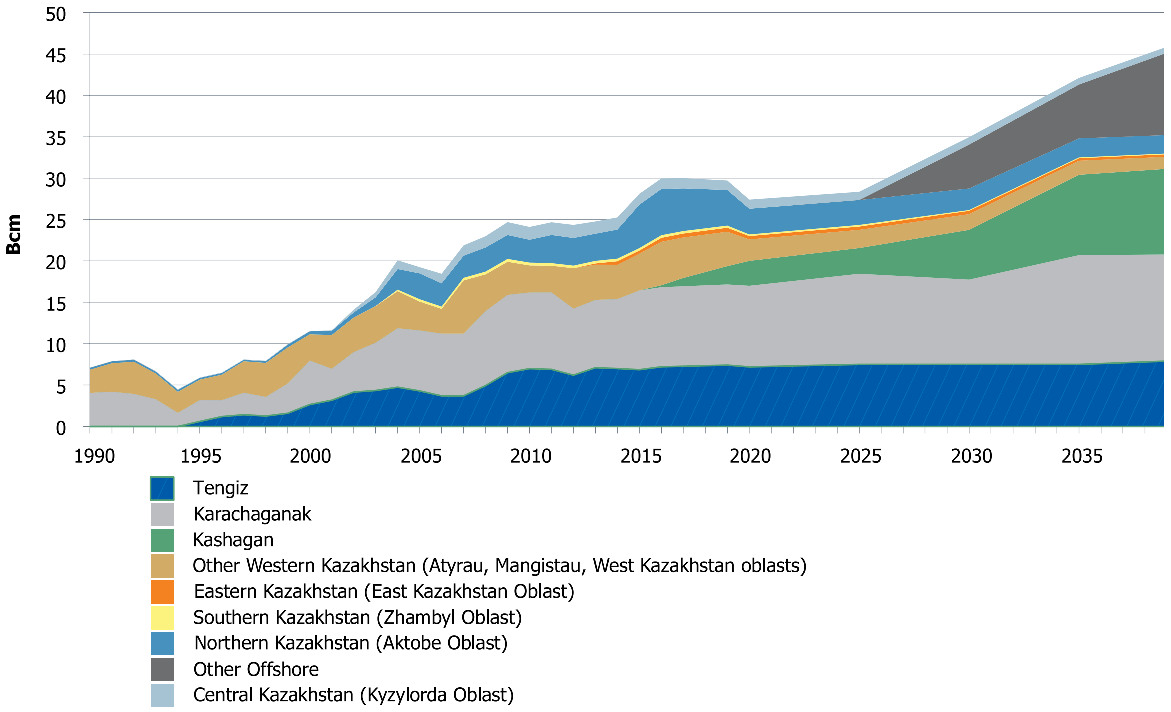
[14] Processing capacity at Kashagan was planned to expand to 9 Bcm/y eventually (under the second phase of the project).

Table 5.4. Kazakhstan's gas balance: outlook to 2040 (IHS base case) (billion cubic meters)

						Forecast				
	2000	2005	2010	2015	2016	2020	2025	2030	2035	2040
Production (total as reported; gross volumes)	11,5	25,0	37,4	45,3	46,4	47,6	58,0	72,0	75,5	76,8
Production (excluding reinjected volumes)	11,5	18,9	24,7	27,7	29,5	27,4	28,4	34,9	42,1	46,8
Reinjected volumes	0,0	6,0	12,7	17,6	16,9	20,2	29,6	37,1	33,4	30,0
Exports**	5,2	7,7	12,4	10,9	12,8	8,0	7,0	9,8	13,3	14,6
Imports**	4,2	11,2	4,0	4,9	6,9	6,0	6,7	6,0	6,0	6,0
Consumption (apparent; gross)	10,5	28,5	29,0	39,3	40,4	45,7	57,8	68,3	68,2	68,2
Consumption (apparent; excluding reinjection)	10,5	22,5	16,3	21,7	23,5	25,5	28,1	31,2	34,8	38,2
Reported deliveries*	6,1	7,3	9,0	12,0	13,1	16,6	19,8	22,0	24,8	28,1
Other consumption***	4,4	15,2	7,3	9,7	10,5	8,9	8,3	9,2	10,0	10,1

Source: Ministry of Energy; Statistical Committee of RK; IHS Markit (Eurasian Gas Export Outlook)

Figure 5.6. Outlook for Kazakhstan's gas production, base case (commercial volumes)



Source: IHS Markit

5.2.5. Gas processing

The bulk of Kazakhstan's gas output requires processing. There are four major gas processing plants (GPZs) in Kazakhstan, a number of smaller plants, and also an important arrangement for the processing of Karachaganak's gas across the border at Russia's Orenburg gas processing plant. The four main plants are the old Kazakh plant owned by KMG (2.9 Bcm/y capacity in Mangistau Oblast), Tengiz (7.9 Bcm/y capacity in Atyrau Oblast), Zhanazhol (7 Bcm/y capacity in Aktobe Oblast), and Bolashak (6 Bcm/y capacity in Atyrau Oblast). With the addition of Kashagan (Bolashak) processing capacity, these four plants now have the capacity to process 23.8 Bcm/y. In aggregate, together with the availability of Russian capacity at Orenburg, this amount appears adequate to handle the bulk of Kazakhstan's expected volumes of commercial gas for the next decade or so.

5.2.6. Gas transportation

Over the past several years Kazakhstan has expanded its national gas transmission system and local pipeline distribution networks to increase the overall level of gasification in the country and to create a unified national pipeline transportation network. This has been a long-held ambition of the government in order to improve energy security as well as to make the economy more "green." Improving and developing the country's gas infrastructure was the primary responsibility of KTG. In 2015, KTG reported that it operated a system of 39,300 km of gas pipelines (including both high and low pressure).

stations on the BBS pipeline—Bozoy (Aktobe Oblast) and Karaozek (Kyzylorda Oblast)—which increased BBS throughput capacity to 10 Bcm/y, potentially allowing deliveries of larger gas volumes to southern Kazakhstan and exports to China. Karaozekis also the connection to a planned pipeline that would extend to the capital Astana (SaryArka pipeline). In the future, the capacity of BBS is slated to reach 15 Bcm/y, following the completion of compressor stations at Shornak, Aksuat, and Saksaulsk.

The BBS pipeline links to Line C of the CAGP, which would allow Kazakhstan's gas to be exported to China. In 2016, compressor stations No. 4 and No. 8 on Line C went online, bringing the line's total capacity to 20 Bcm/y and total CAGP capacity (Lines A, B, and C) to 55 Bcm/y.

Table 5.5. Trunk gas pipelines in Kazakhstan

	2010	2011	2012	2013	2014	2015	2016
Length (km)	12 269	12 318	12 318	12 318	14 895	15 265	15 256
Shipments (Bcm)	103,7	116,0	115,7	119,8	115,6	105,1	96,2
Average shipment length (km)	327	386	462	492	500	512	577
Source: Statistical committee of RK							
Shipments (million tons of standard fuel)	89,4	100,0	99,7	103,3	99,6	90,6	82,9
Turnover (billion ton-km)	29,2	38,6	46,1	50,8	49,783	46,4	47,8
Average length of haul (km)	326,6	386,0	462,4	491,8	499,6	512,1	576,6

National gas transmission system

The national trunk gas transmission system reached 15,265 km in 2015–16 (see Table 5.5). Together with the main underground storage facilities, these are owned and operated by KTG's specialized subsidiary Intergas Central Asia. The trunk transmission system carried 96.2 Bcm in 2016, the bulk of which was actually transit gas (see below).

One of the major recent developments in gas transportation was the 2015 completion of the BBS pipeline.[15] This pipeline allows gas produced in the western parts of Kazakhstan to reach not only the southern regions, but it also paves way for the start of large-scale gas exports to China. Gas flows via BBS to southern Kazakhstan have increased, from a mere 300 MMcm in 2013 to 1.6 Bcm in 2014 and to 2.1 Bcm in 2016.

In 2016, KTG completed an important booster compressor station at Akyrtobe, designed to pump up to 6 Bcm/y of gas between the Bukhara-Tashkent-Bishkek-Almaty pipeline and Line C of the Central Asia Gas Pipeline system (CAGP). This booster station provides increased energy security, as it establishes an alternative route for uninterrupted gas supply to Almaty that bypasses the territory of Kyrgyzstan.The booster station is unusual because the pipelines operate at different pressures: 55 kilogram-force (kgf)/cm^2 for the older pipeline and 100 kgf/cm^2 for Line C.

Also in 2016, KTG completed two gas compressor

Gas supplies for BBS are initially being sourced from Aktobe Oblast, including China National Petroleum Corporation's (CNPC) Zhanazhol gas processing plant. Other gas supply sources include the Urikhtau and Shagyrly–Shomyshty gas fields. In September 2016, KMG decided to build a 168 km pipeline from the Kozhasay field to compressor station No. 12 on the Bukhara-Urals trunkline to make more gas available for BBS and to reduce gas flaring at the field (250–300 MMcm/y). The construction of the pipeline is expected to be completed in 2017. Additional gas for BBS also now also is potentially available from Atyrau and Mangistau oblasts following completion of the section from Beyneu, including from the Kashagan field.

To further increase flexibility in supplies, KTG built a small bypass line between the Orenburg-Novopskov and the Central Asia–Center-4 (CAC)-4 pipelines to allow Karachaganak gas coming from Orenburg (after processing) to flow south on the CAC system without leaving Kazakhstan's territory. KTG also invested in reverse flow capacity on the CAC-4 line. But so far, this option has not been used to divert Karachaganak gas to southern Kazakhstan, probably due to

[15] The portion of the pipeline between Bozoy and Shymkent (1,166 km) was completed in September 2013, with the Beyneu-Bozoy segment completed in 2015.

the long distances involved. The distance gas would have to travel between Orenburg (after processing) and Shymkent would be 2,704 km (503 km between Orenburg and Aleksandrov-Gay, 726 km between Aleksandrov-Gay and Beyneu, and 1,475 km on BBS), of which about 2,580 km would be on Kazakh territory). Currently, tariffs for domestic shipments on most trunk pipelines are set by the regulator as post stamp-type tariffs that do not reflect distance. For example, the tariff that went into effect in January 2017 was 2,231 tenge/Mcm (~$6.7/Mcm).[16] Given the average length of gas shipments in Kazakhstan (577 km in 2016—see Table 5.5), the average tariff rate for domestic shipments would be about $1.16/Mcm/100 km, which is somewhat higher than average rates in other large systems in countries such as Russia, US, Britain, or France.

Given all these improvements, Kazakhstan's gas pipeline infrastructure is now technically capable of delivering gas from fields in northwest Kazakhstan to southern areas such as Shymkent and Almaty, with settlements were gasified in 2016 in West Kazakhstan, Kostanay, Zhambyl, Mangistau, Aktobe, and Kyzylorda oblasts alone. KTG plans to bring gas to eight more settlements in 2017, including Taldykurgan.

KTG has expended considerable effort in South Kazakhstan Oblast:

- In 2017, the Ministry of Energy allocated 500 million tenge to build local gas pipelines to link up to the BBS trunk line.
- In 2015, KTG completed the modernization of the gas distribution system in Shymkent, an undertaking launched in 2009. The project increased the carrying capacity of the gas system from 85 Mcm/hour, to 258 Mcm/hour.
- Other efforts to modernize gas networks in South Kazakhstan Oblast included the replacement of dilapidated gas pipelines with new polyethylene ones, replacing old gas distribution points with new ones, optimization of gas distribution networks based on updated hydraulic calculations, introduction of automated systems measuring gas

Table 5.6. Length of gas distribution pipelines in Kazakhstan (kilometers)

Oblast	2007	2008	2009	2010	2011
Total for Kazakhstan	13 902,8	14 694,8	16 260,0	17 773,4	20 248,8
Akmola	–	–	–	–	–
Astana city	–	–	–	–	–
Aktobe	748,4	747,0	866,9	926,7	937,6
Almaty	363,0	417,0	476,0	503,7	517,5
Almaty city	405,7	443,8	602,2	647,5	664,4
Atyrau	1 943,7	2 224,3	2 882,1	3 432,3	3 802,9
West Kazakhstan	2 904,1	2 920,7	2 940,8	2 971,5	3 069,8
Zhambyl	543,1	544,8	747,8	755,3	771,7
Karaganda	–	–	–	–	–
Kostanay	1 872,0	1 898,2	1 901,0	2 096,2	2 186,4
Kyzylorda	144,4	158,6	158,6	339,3	823,3
Mangistau	1 285,3	1 447,3	1 560,4	1 645,5	1 680,8
South Kazakhstan	3 693,1	3 893,1	4 124,2	4 455,4	5 794.4
North Kazakhstan	–	–	–	–	–
East Kazakhstan	–	–	–	–	–

Source: Statistics Committee RK (Housing and Communal Economy).

KTG noting that for the first time in 2016 Kazakhstan has the capability to do without imported gas in the south.

Distribution pipeline system

The length of distribution pipelines in the country reached 27,113 kilometers (km) in 2015, with about 9,340 km added since 2010 (see Table 5.6). The largest distribution networks are in South Kazakhstan, West Kazakhstan, and Atyrau oblasts; the largest additions to pipeline networks in recent years were in Atyrau and Almaty oblasts. Overall the number of gasified settlements increased from 891 in 2014 to 976 in 2016, raising Kazakhstan's level of gasification from about 43% in 2014 to 46% in 2016. Over 50

consumption at various points in the distribution system, and installation of electronic meters.

Other upgrades to distribution pipeline infrastructure in southern Kazakhstan include:

- In 2015, 1,276 km of gas pipelines were laid and compressor stations upgraded in Kyzylorda Oblast, and in 2016, KTG and APL Construction began construction on a gas pipeline and gas compressor station in Zharkent (Almaty Oblast).
- In Zhambyl Oblast, the Akimat allocated 449 million tenge ($1.3 million) to gasify 150 population centers by 2018.

In western Kazakhstan, KTG worked to expand and improve gas infrastructure in already gasified Mangistau and Aktobe oblasts:

[16] This is without VAT. In comparison, the general tariff that went into effect in January 2014 was 1,380 tenge/Mcm (~$8.9/Mcm).

- In Mangystau Oblast, 71.3 km of pipelines were laid, and seven sets of gas control points and five gas distribution units were installed.
- In Aktobe, 252 km of pipelines were installed, while two gas distribution units were put in place.

It is important to note that financing for these projects has come largely from multinational development banks such as the EBRD and the Development Bank of Kazakhstan (DBK). The DBK opened a credit line for KTG Aimak JSC to build gas supply infrastructure in Kyzylorda for 24.7 billion tenge, which covered around 30% of the project costs. KTG also plans to spend over 7 billion tenge (~$20 million) for gas infrastructure in Kostanay Oblast. Furthermore, the EBRD will provide a €294 million loan to KTG to finance the modernization and overhaul of the underground gas storage facility at Bozoy (€242 million euro), and for the modernization and upgrade of the existing gas distribution infrastructure and construction of new domestic gas supply pipelines in Mangistau and Aktobe regions (€52 million).

5.2.7. Domestic gas consumption: historical trends

In 2016, total *apparent* consumption of natural gas in Kazakhstan (defined as commercial production minus exports plus imports) was about 23.5 Bcm, of which 13.1 Bcm was reported being delivered at the "end-of-pipe" to consumers (see Table 5.4).[17] The difference represents other domestic disappearance, including field use (including for on-site power generation) and processing losses (gross extraction includes the non-hydrocarbon volumes which are removed during processing), pipeline use, changes in stocks, etc.

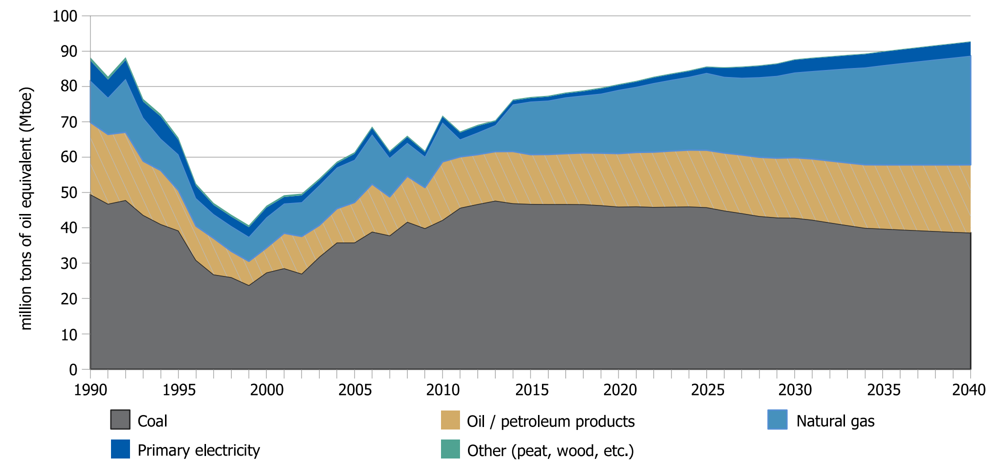
Actual gas consumption ("end-of-pipe" deliveries to consumers) has steadily increased in recent years, reaching 13.1 Bcm in 2016 compared to 9.0 Bcm in 2010 (see Table 5.4). The most significant growth in gas consumption occurred in oblasts in the main gas-producing region in the west, especially in West Kazakhstan, Mangistau, and Aktobe oblasts, where gas consumption grew by an average annual rate of 9%, 3.5%, and 11.3%, respectively, between 2012 and 2016 (see Table 5.7). But gas consumption has generally been growing in all oblasts that have piped gas available; the sole exception is Kostanay Oblast.

Particularly notable is Kyzylorda Oblast, where consumption has risen by an annual average rate of 13% during 2012–16, albeit from a small base, mostly due to significant gasification efforts.

The share of gas in the country's primary energy consumption lags well behind coal: coal accounted for 55% of primary energy consumption in 2016, while gas accounted for 23% (see Figure 5.7). However, natural gas did surpass oil (19%) in its share of primary energy consumption.

In terms of the structure of consumption among the various sectors, KTG reported that of the total amount of gas it sold to consumers in 2016 (11.2 Bcm), about 3.3 Bcm (29.7%) was used by industry, 4.3 Bcm (38.7%) was used in the electric power sector to produce electricity and heat, and 3.5 Bcm (31.6%) was used by a combination of residential and commercial/municipal sector consumers. The sectoral shares for the larger total for end-of-pipe consumption in 2016 (13.1 Bcm) was similar: about 39% in electric power, 19% in industry, and 39% in the residential-commercial-municipal sector.

Figure 5.7. Kazakhstan's primary energy consumption outlook



[17] A major issue in the calculation of apparent consumption is the volume of exports. National customs statistics report exports as exceeding 20 Bcm in 2011–16, an amount nearly as large as total commercial volumes available (see Table 5.4). Nearly all of Kazakhstan's gas exports go north, to Russia, but Russia reports that it receives only 10–12 Bcm from Kazakhstan at its southern border. According to operational data reported by Kazakhstan's Energy Ministry (based on shipments reported by the pipeline operator), only 10–12 B cm of gas is exported from Kazakhstan. The reason for these sizable discrepancies in reported export stems from the statistical treatment of Karachaganak gas flowing to Orenburg, which may be recorded once as raw gas when it leaves Kazakhstan and then included again when it reenters Russia after being processed under the existing swap arrangements with Gazprom.

Table 5.7. Consumption of Natural Gas Delivered by Pipeline (million cubic meters)

	2004	2007	2008	2012	2013	2014	2015
Akmola Oblast	--	--	--	--	--	--	--
Aktobe Oblast	1 100	1 273	1 236	1 506	1 653	1 832	1 883
Almaty Oblast	700	963	903	1 337	1 356	1 644	1 552
Atyrau Oblast	600	909	982	1 332	1 482	1 571	1 525
West Kazakhstan Oblast	500	513	504	695	736	847	831
Zhambyl Oblast	300	1 197	1 434	944	1 048	1 395	1 303
Karaganda Oblast	--	--	--	--	--	--	--
Kostanay (Kustanay) Oblast	800	862	810	930	886	867	757
Kzylorda Oblast	30	133	120	261	261	234	296
Mangystau Oblast	1 200	2 096	2 241	2 422	2 495	2 838	2 852
Pavlodar Oblast	--	--	--	--	--	--	--
South Kazakhstan Oblast	100	712	762	1 081	1 021	1 230	1 100
North Kazakhstan Oblast	--	--	--	--	--	--	--
East Kazakhstan Oblast	--	--	--	--	--	--	--
Astana City	--	--	--	--	--	--	--
Kazakhstan total (regional sum)	**5 330**	**8 658**	**8 992**	**10 508**	**10 937**	**12 458**	**12 100**
Eastern Kazakhstan	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Southern Kazakhstan	1 130,0	2 872,0	3 099,0	3 623,5	3 684,9	4 503,4	4 251,3
Other Kazakhstan	4 200,0	5 786,0	5 893,0	6 884,3	7 251,8	7 954,9	7 848,9
Western Kazakhstan	2 300,0	3 518,0	3 727,0	4 448,7	4 712,9	5 255,8	5 208,1

Source: Oil and Gas Kazakhstan, No. 9, 2009 ,p .101; data for 2012-16 from KTG.

5.2.8. Domestic gas supply

While much of domestic consumption is met with its own indigenous production, Kazakhstan also imports some gas from Uzbekistan and Russia, in the south and north of the country, respectively.[18] In 2016, Kazakhstan reported its total imports as 6.9 Bcm, which would represent about 30% of total apparent consumption. Russia's Gazprom Export reported that it delivered 2.9 Bcm to Kazakhstan last year. Gazprom's Annual Report for 2016 says that it supplied a total of 4.7 Bcm to Kazakhstan in 2016, of which 1.9 Bcm was Uzbek gas delivered to southern Kazakhstan. Kazakhstan's national customs statistics report that it imported 3.9 Bcm from Russia, 1.7 Bcm from Uzbekistan, and 1.3 Bcm from Turkmenistan in 2016.[19]

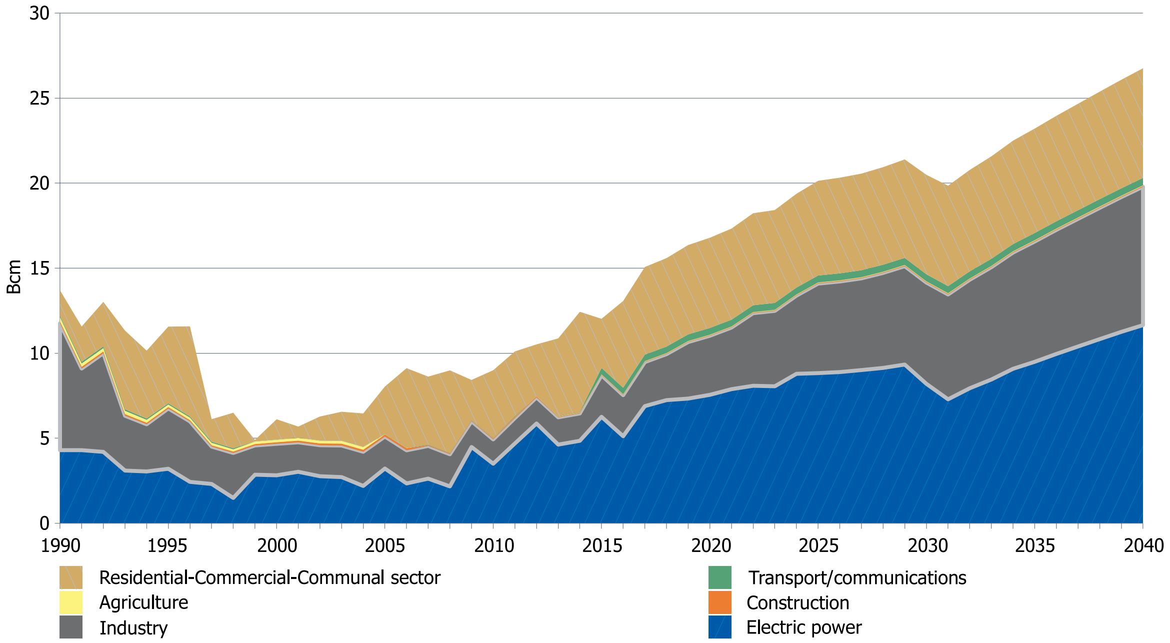
5.2.9.Domestic gas consumption outlook

Longer term, the role of gas in the national economy is expected to grow and to become more prominent in the overall energy balance. This growth is expected to occur on a number of fronts, including growing industrial consumption, conversion of some coal-fired combined heat-and-power plants (TETs) to gas, and construction of new gas-fired generation capacity; this will require expansion of both the trunk pipeline system as well as local distribution networks. IHS Markit expects the share of gas in national primary energy consumption to increase to about 26% by 2020, 30% by 2030, and 38% by 2040 (see Figure 5.7). Gas consumption (end-of-pipe deliveries) is projected to increase at an average annual rate of 2.9% between 2016 and 2040, to reach nearly 21 Bcm in 2030 and 27 Bcm in 2040 (see Figure 5.8) in Kazakhstan).[20] The greatest natural gas consumption growth is projected to occur in industry, which in the IHS Markit

[18] Kazakhstan imports Uzbek gas through a gas swap agreement with Uzbekistan and Russia's Gazprom. Some Uzbek gas is delivered to Kazakhstan by Gazprom, and Kazakhstan in turn ships the same volume of gas to Russia, with up to 4 Bcm per year involved in this arrangement.

[19] Kazakhstan's imports from Turkmenistan were traditionally part of a seasonal arrangement, whereby Kazakhstan draws the gas for domestic use in the winter and then supplies equivalent volumes in the flow to China in the summer. But as expected, the import amount is becoming larger and more routine, as Uzbek supply remains restricted due to its own tight gas balance.

Figure 5.8. Outlook for gas consumption (deliveries) in Kazakhstan



Notes: Sectoral composition based on the historical breakdown provided by Kazakhstan statistical agency.
Source: IHS Markit

outlook increases at an almost 5% annual average to 2040. Other sectors with expanding gas consumption are electric power and residential-commercial (2.2% and 2.5%, respectively). IHS Markit expects that in 2040 electric power will account for about 43% of actual gas consumption (deliveries), residential-commercial users about 22%, and industry about 33%. In addition, there is another component of domestic use that includes upstream use and processing losses as well as midstream uses (pipelines and any changes in stocks) (see Figure 5.5).

The key question for domestic consumption involves solving the disparity between growing demand in areas such as southern Kazakhstan and the location of domestic gas production, mainly in western Kazakhstan. The answer lies in either moving more gas long distances between sources of production and consumption or to increase imports, and one of the considerations for this is the price of gas. Because Russia is long on gas, there should be no particular problem in continuing imports from the north. However, in the south, Uzbekistan's gas balance is becoming increasingly tight (due to rising domestic consumption), so in the south the main supplier is likely to become Turkmenistan rather than Uzbekistan. Turkmenistan is also long on gas and should be interested in making it available to Kazakhstan on regular commercial terms.

According to the Ministry of Energy's long-term forecast as specified in the country's official gasification program (currently under revision), the amount of commercial (end-of-pipe) gas available to consumers by 2030 is about 21 Bcm (see Table 5.3). About 18.1 Bcm of the available commercial gas in 2030 is projected to be consumed domestically, under the "realistic" scenario, while the remainder is expected to be exported. In 2030, the sectoral breakdown of consumption is expected to be as follows: industrial enterprises are projected to consume about 5.7 Bcm, electric power plants about 7.2 Bcm, and residential-commercial users 5.2 Bcm. Geographically, 35% of consumption in 2030 is forecast for western Kazakhstan, 42% in southern and eastern Kazakhstan, and 23% in northern Kazakhstan.

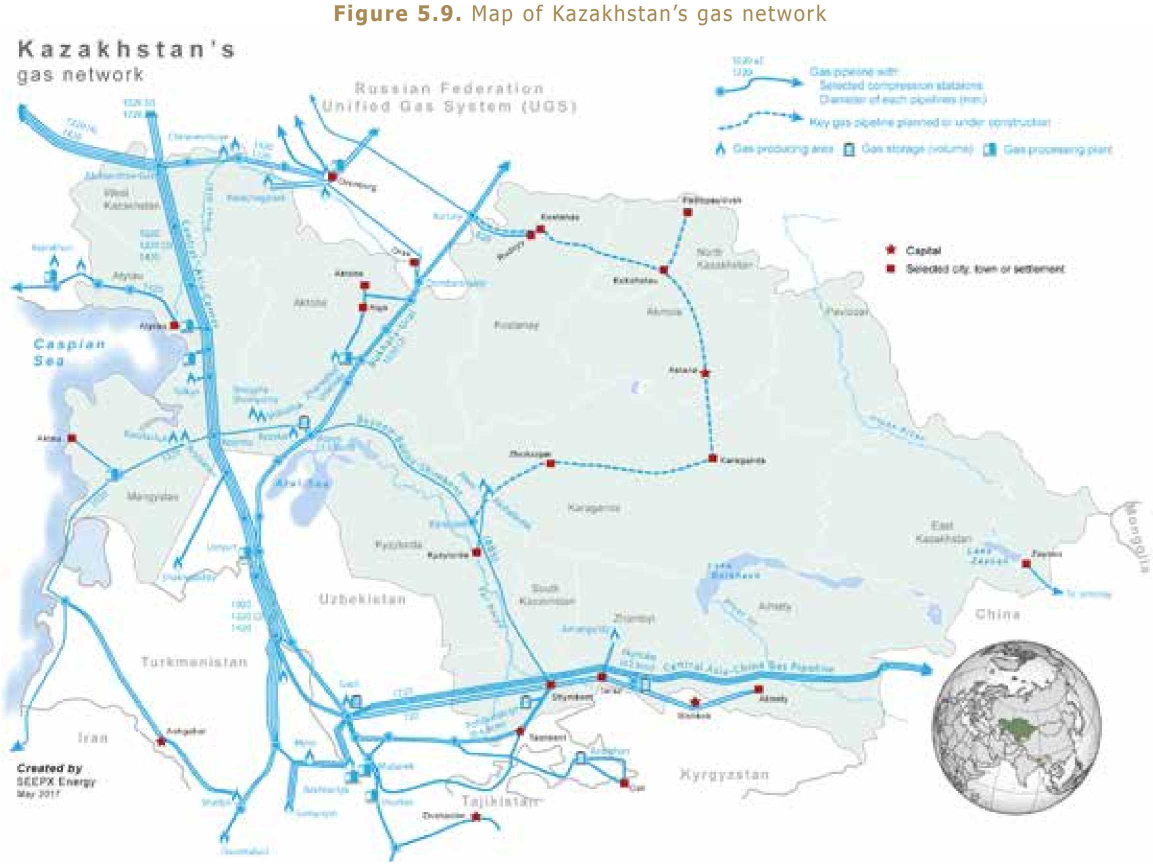
State gasification program

Among the more ambitious goals of the drive to increase the share of gas in the country's future energy consumption is the gasification of the Astana region. A number of plans have been proposed in recent years. In 2012, President Nazarbayev called for the construction of an 895 km pipeline connecting Kartaly (in Russia's Chelyabinsk Oblast) with Astana. The pipeline, which originally would source Russian

[20] Apparent consumption (domestic disappearance) of commercial volumes of gas, which includes a residual category of other consumption comprised of pipeline use, changes in stocks, and upstream use and losses, is projected to reach about 28 Bcm in 2030 and 35 Bcm in 2040.

gas at Kartaly and include an already-existing spur line from Kartaly to Rudnyy (Kostanay Oblast), ultimately would source Kazakh gas from Karachaganak after a new gas processing plant would be completed there. By late 2014, however, the unfavorable external economic environment made the combined cost of constructing the pipeline and processing plant prohibitive and the project was postponed.[21]
At roughly the same time, consideration was given to supplying the city with LNG produced from coal-bed methane (CBM) at a large liquefaction plant (or plants), and delivered to the city by truck or rail. Support for these plans appears to have waned recently as well, as CBM resource development projects have lagged, and small-scale LNG imports from Russia (Yekaterinburg) have commenced to supply selected users in Astana (see section 5.3.3 below on coal bed methane development).
Another alternative now in development is phase 1 of the SaryArka pipeline (1,076 km), which would source western Kazakhstan natural gas from the existing BBS pipeline and deliver it to Astana, with the additional benefit of supplying the industrial cities of Zhezkazgan and Karaganda en route (see Figure 5.9).[22] Because the total transport distance (including along roughly half the length of BBS) is quite long, SaryArka could potentially deliver gas from western Kazakhstan (Atyrau-Mangistau oblasts) to Astana at a cost of ~$140–145/Mcm (assuming procurement cost of gas from producers at ~$32/Mcm) (see Figure5.10). The shorter, previously proposed Kartaly-Astana pipeline could potentially deliver gas to Astana from Russia at a cost of ~$147/Mcm, assuming Russian gas can be procured at an average import price of ~$50/Mcm.[23] SaryArka's lower projected capital costs appear to provide a major advantage, partly because no gas processing plant would need to be constructed and partly as a result of the lower overall cost environment following the tenge devaluation in 2015. Total capex for phase 1 of SaryArka is expected to be $756 million versus $1.3 billion estimated in 2014 for Kartaly-Astana (see Table 5.8). The indicative cost recovery tariff for SaryArka phase 1 would be $47/Mcm compared to $81/Mcm for Kartaly-Astana.[24]

Figure 5.9. Map of Kazakhstan's gas network



[21] The cost of the gas processing plant at the time was estimated at $3.7 billion, and the pipeline itself at $1.3 billion.

[22] SaryArka phase 2 would extend northward another 450 km from Astana to Kokshetau and Petropavlovsk.

[23] The cost of constructing the Kartaly-Astana pipeline, estimated in 2014 at $1.3 billion, likely would also be lower now after tenge devaluation.

[24] This is the minimum amount needed to cover capital costs, operating costs, and 12% VAT based upon average expected throughput volumes over 20 years.

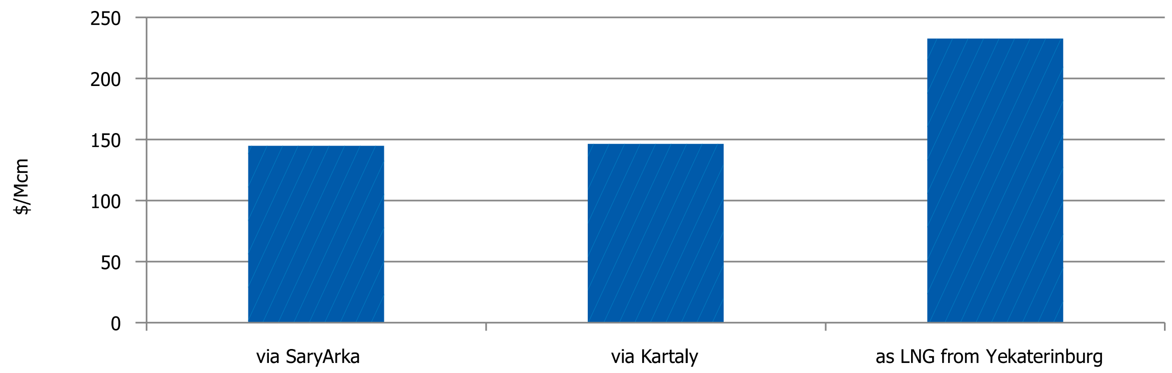
Table 5.8. Estimates for gas pipeline cost recovery tariffs

Pipeline	Pipeline route	Length (kilometers)	Capacity/Average flow (Bcm per year)	Indicative cost recovery tariff ($ per thousand cubic meters)	Estimated Minimal Tariff Rate ($ per thousand cubic meters per 100 km)
SaryArka phase 1	Karaozek-Zhezkazgan-Karaganda-Astana	1076	3,0	47,0	4,4
SaryArka phase 2	Astana-Kokshetau-Petropavlovsk	450	3,0	19,7	4,4
Kartaly-Astana	Kartaly-Kokshetau-Astana	895	3,0	80,9	9,0
BBS	Beyneu-Bozoy-Shymkent	1475	6,0	120,7	8,2

Total cost of gas to Astana via SaryArka	$	144,93
Total cost of gas to Astana via Kartaly	$	146,60
Total cost of LNG to Astana from Yekaterinburg	$	232,89

Source: calculations by IHS Markit

Figure 5.10. Estimated cost of gas delivered to Astana



Notes: *Includes cost of gas, transportation, and 12% VAT

Source: IHS Markit

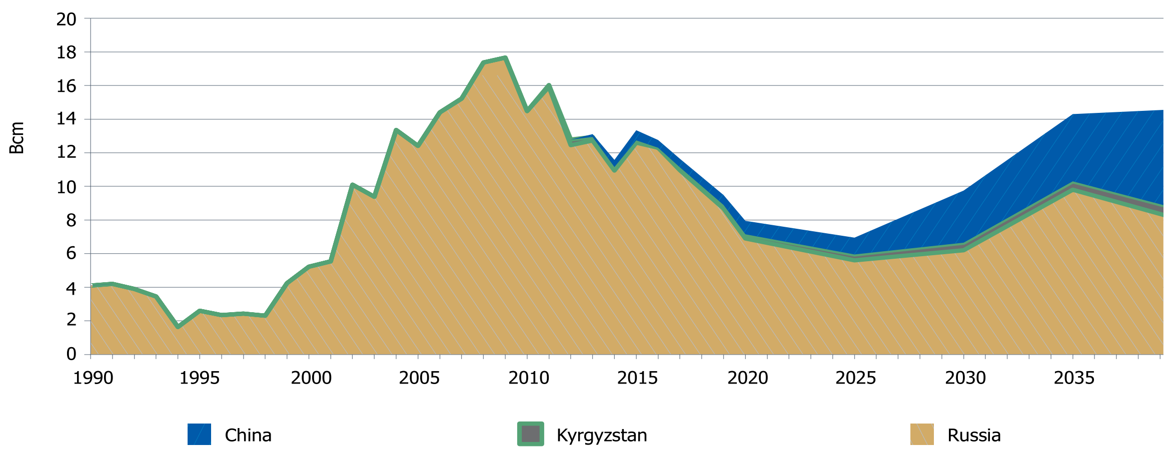
5.2.10. Outlook for natural gas exports

Kazakhstan's "operational" exports of natural gas in 2016 amounted to 12.7 Bcm (invoiced exports are much higher, 21.6 Bcm in 2016—see above). Kazakhstan exported 12.3 Bcm northward, essentially to Russia (of which Karachaganak gas was 9.6 Bcm), and 0.5 Bcm went east to China. Kazakhstan currently exports small volumes of natural gas to China from the small and remote Sarybulak field in eastern Kazakhstan to a small gas liquefaction plant in western China. These small-scale exports to China commenced in 2013.
Kazakhstan's gas exports to Russia are expected to remain important as part of the established relationship with the Orenburg gas processing plant (expected to continue), although the overall volumes are projected to decline slightly longer term. Exports to China (via CAGP) are projected to start relatively soon (probably by 2019–20), but volumes will remain small both because of a relatively low availability of commercial gas volumes in Kazakhstan and because of China's diversified supply portfolio and current market oversupply.[25] In June 2017, KMG and China's CNPC signed a deal to supply up to 5 Bcm of Kazakhstan gas to China over the next two years. This is a reaffirmation of the intergovernmental agreement between Kazakhstan and China, initially signed in 2007 to deliver up to 10 Bcm/y to China. However, this much gas is unlikely to be available for export in the period to 2030.
In our base case, total exports shrink to about 7 Bcm in 2025, but rise thereafter, reaching about 15 Bcm in 2040. Russia remains the major destination, with Chinese exports reaching a maximum of 6 Bcm in 2040 (see Figure 5.11).
Longer term IHS Markit expects Kazakhstan to remain a net gas exporter, although for some regions continued imports will remain economically beneficial due to logistics and costs; in particular, it will make sense to continue to import gas from Uzbeki-

[25] In 2016, with the installation of the Bozoy and Karaozek compressor stations, gas exports to China from Kazakhstan became technically possible.

stan and (increasingly) Turkmenistan in the south of the country (despite the availability of BBS) and Russian gas in the north to Kostanay Oblast.[26]

Figure 5.11. Outlook for Kazakhstan's gas exports (base case)



Note: Exports are shown only to those countries for which there is a contractual relationship (e.g., Russia, Kyrgyzstan, China), rather than those for which exp are reported by trade statistics.

Source: IHS Markit; Statistical committee of RK

5.2.11. Outlook for gas transit

The volume of transit gas reportedly passing through Kazakhstan amounted to 74.6 Bcm in 2016, with 37.1 Bcm going to China from Turkmenistan and Uzbekistan, 6.2 Bcm were shipments from Central Asia to Russia, and the remaining 31.3 Bcm must involve the transit of Russian gas (see Table 5.9).

Kazakhstan's role as a transit country for natural gas has shifted over time, from primarily carrying Central Asian gas north to Russia to increasingly carrying Central Asian gas east to China. The volume of gas transported north to Russia peaked at about 53 Bcm in 2007–08, but subsequently fell to about 6 Bcm in 2016. At the same time, Central Asian gas moving east to China increased from zero in 2009 to reach 37 Bcm in 2016. Volumes of the latter are expected to increase over time, although some of the total flow between Turkmenistan and China is planned to eventually be moved by Line D, which transits Tajikistan and Kyrgyzstan but not Kazakhstan. The Central Asian transit volume across Kazakhstan, in our base case, is expected to reach about 45–50 Bcm 2040 (via Lines A, B, and C), which would account for the overwhelming majority of Kazakh transit in that year. In contrast, IHS Markit expects that northward flows to Russia will continue, but at a level of only 2–3 Bcm per year at that time.

Table 5.9. Kazakhstan's gas transit (billion cubic meters)

	2010	2011	2012	2013	2014	2015	2016
Kazakhstan's total reported gas transit	76,9	77,0	76,6	76,0	88,7	83,3	74,6
Shipments via CAGP to China	3,9	15,5	23,7	29,7	30,8	32,4	37,1
from Turkmenistan	3,9	15,5	23,5	26,5	28,1	30,7	32,4
from Uzbekistan	0,0	0,0	0,2	3,1	2,7	1,7	4,7
Shipments to Russia from Central Asia	22,2	15,9	19,2	16,6	14,6	6,6	6,2
from Turkmenistan	10,7	9,5	10,9	10,9	11,0	3,1	0,0
from Uzbekistan	11,4	6,4	8,3	5,7	3,6	3,5	6,2
Residual (Russian gas)	50,8	45,6	33,6	29,7	43,3	44,3	31,3

Sources: IHS Markit, InfoTek

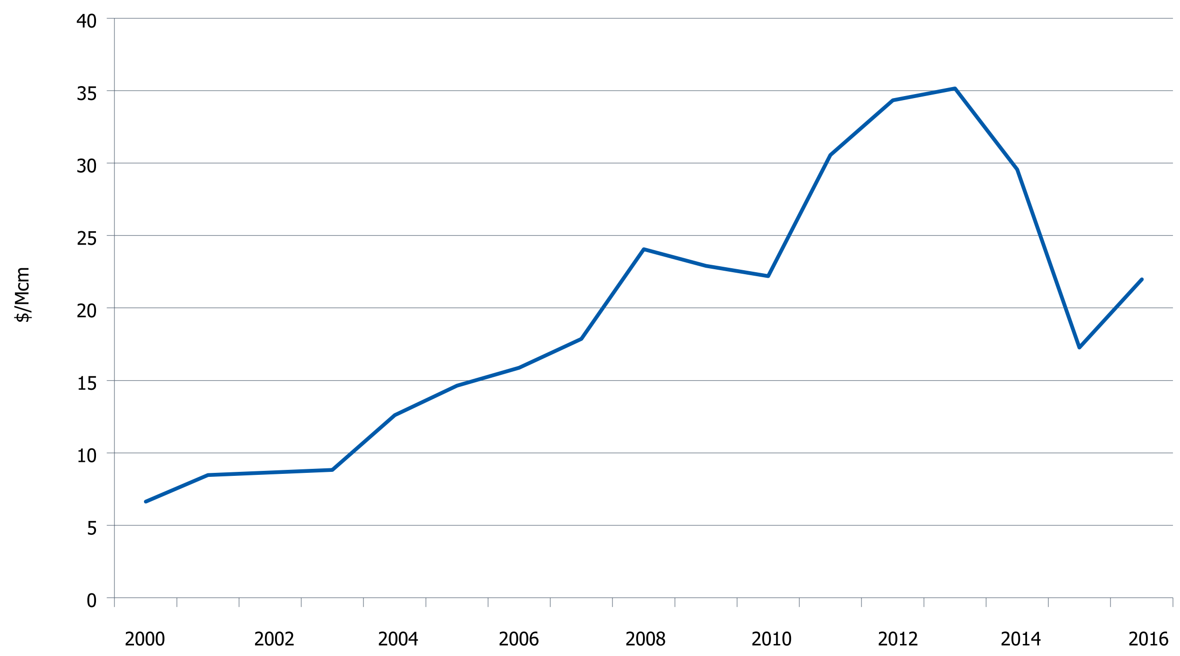
[26] Besides the question of gas availability to fill the BBS pipeline, the tariff for BBS was set by the regulator at 18.071 tenge/Mcm, or the equivalent of about $52.4/Mcm. This is relatively expansive compared with the general trunk pipeline tariff of $6.7/Mcm, although it is only about 43% of the estimated tariff needed to actually recover costs (see Table 5.8). Even so, current prices for industry in southern Kazakhstan are about $75/Mcm, so KTG loses money on gas volumes delivered to southern Kazakhstan via BBS: acquisition costs in western Kazakhstan are only about $22/Mcm, but when added to the BBS tariff already brings cost up to about $75/Mcm, without including VAT, distribution costs, etc. In comparison, in 2016, the average import price for Uzbek gas was about $65/Mcm, although the import price for Turkmen gas was considerably higher, at over $150/Mcm.

5.2.12. Gas pricing in Kazakhstan

Kazakhstan's gas procurement prices for producers are governed by the rules set out in the 2012 Law on Gas and Gas Supply, which prescribes that they should include the cost of producing and processing gas as well as the transportation costs to the point where the "national operator" (still apparently KTG) takes title, and a profit margin no higher than 10%. However, there has been some concern that it will be hard to ensure that these costs are in fact covered by the offered purchase price, since the state-owned buyer holds a much stronger bargaining position. At the end of 2016, the average gas price received by Kazakhstan's producers was only $22 per Mcm (see Figure 5.12). For a Kazakh producer of dry gas, which requires minimal processing, current prices may still yield a positive return. However, for higher cost producers, particularly those that need to gather and process their associated gas, the current price does not really cover costs.

At the consumer level, gas prices are regulated by the

Figure 5.12. Average producer price for natural gas in Kazakhstan (in December each year)



Source: IHS Markit; Statistical committee of RK

State Committee for Regulating Natural Monopolies and Competition Protection (KREMiZK). KREMiZK's concern is to keep prices affordable for consumers, and it views the current level of producer prices as being too high to effectively achieve this objective. KREMiZK also regulates tariffs for domestic gas transport and storage.

Kazakhstan's consumer gas prices vary within the country and are affected by several important factors. The first is the acquisition cost of natural gas. In oblasts that depend on imported gas, end-user prices reflect higher acquisition costs, while in oblasts with domestic gas supply end-user prices are lower. Prices of imported gas have risen steadily over the past decade. The average price for imported gas was about $55 per Mcm in 2008, while in 2013 it increased to about $95/Mcm before falling to $69/Mcm in 2016. The second factor is the transportation component, or the distance gas must travel to reach consumers, as this affects KTG's costs, and finally an investment component that reflects what is being spent on gasification in each region. There is also some differentiation between industrial and household gas prices. Generally, industry prices are higher, although in the import-dependent regions the difference is less significant (see Figure 5.13).

Figure 5.13. Trends in domestic gas prices in Kazakhstan (reported at year)

Source: IHS Markit; Statistical committee of RK

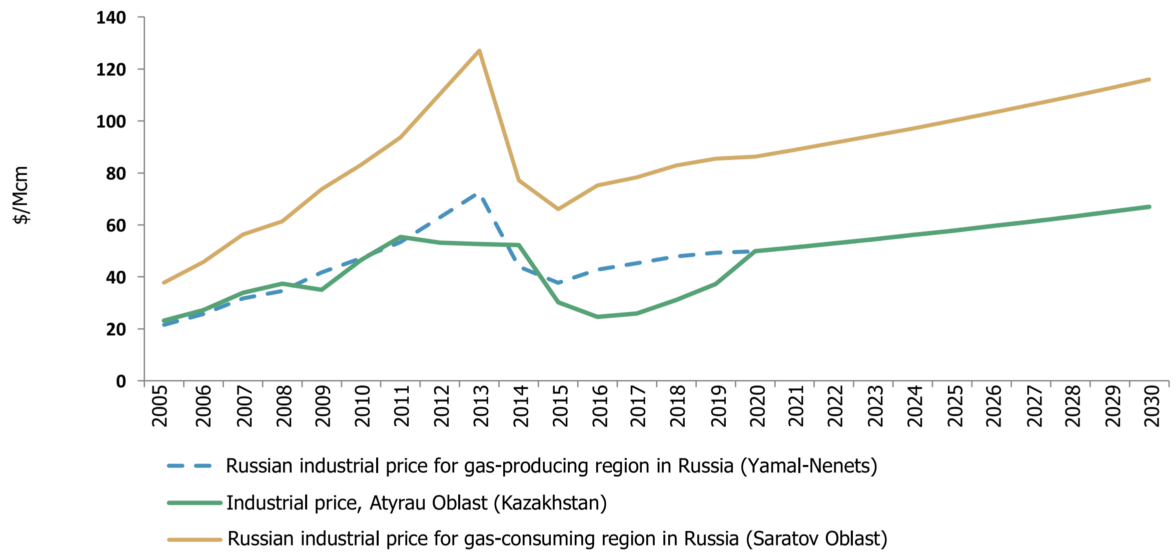
Over the longer term, end-user natural gas prices are planned to be harmonized with those in the Russian Federation as part of a general movement towards the open economic space within the Eurasian Economic Union. This concept was reinforced with the 2011 ratification of the agreement "On the Rules for Granting Access to the Services of the Natural Monopolies in the Gas Transportation Sector and on the Pricing and Tariff Policies in the Countries Participating in the Common Economic Space," which is supposed to lead the way toward price harmonization. Given that gas production, trade, and the size of the domestic market in Russia is much larger than in any other EAEU members, it stands to reason that domestic prices in Kazakhstan will converge with the domestic prices in Russia rather than vice-versa. The process of forming the EAEU's unified gas market is proceeding along a path agreed upon by the member states (see text box).

As Kazakhstan continues toward end-user gas price harmonization, the key question for policymakers is with which Russian pricing zone should Kazakhstan's domestic prices be harmonized (especially in western Kazakhstan)?[27] Russian industrial consumers in the gas-producing area of the Yamal-Nenets Okrug in West Siberia paid $42.8/Mcm in late 2016, compared with an industrial price of $75.1/Mcm in Saratov Oblast, a gas-consuming province in European Russia that neighbors Kazakhstan to the northwest—a difference of about 75%. Such regional disparities around the mean price within Russia are expected to continue going forward. In the gas-producing areas in western Kazakhstan, domestic prices paid by industrial consumers were roughly equivalent to the prices paid by industrial consumers in the gas-producing Russian price zones: for example, prices in Atyrau Oblast at the end of 2015 were $30.2/Mcm, compared with $37.7/Mcm in Yamal-Nenets (see Figure 5.14); however, at the end of 2016 this had dropped to $24.6/Mcm in Atyrau versus $42.8/Mcm in Yamal-Nenets Okrug.

Kazakhstan should harmonize its prices with the lower industrial prices found in gas-producing zones in West Siberia and not with the higher prices in consuming regions in European Russia. This would allow industry in western Kazakhstan to remain competitive within the broader economic space of the EAEU and will make for an easier adjustment for consumers. In this scenario, gas prices in western Kazakhstan would follow essentially the same trajectory as the Yamal-Nenets Okrug in Russia, with prices moving upward basically at the rate of domestic (Russian) inflation after closing the gap back up in 2017–20 (see Figure 5.14).

[27] In Russia, as in Kazakhstan, prices for industrial consumers located in gas-producing regions are much lower than prices for enterprises in more distant, non-producing regions, mainly because of the transportation component.

Figure 5.14. Price Outlook for Natural Gas for Industry in Western Kazakhstan: Harmonized with Yamal-Nenets



Notes: Note: Assumes average Russian domestic gas prices indexes annually by 2% with 1% appreciation
Source: IHS Markit

Achieving a unified gas market within the Eurasian Economic Union

The Eurasian Economic Union (EAEU) - the next stage of economic integration after the Customs Union (2010) between the three founding members Russia, Kazakhstan, and Belarus - began operating on 1 January 2015, with Armenia joining on 2 January and Kyrgyzstan formally joining in August 2015. The Union seeks to create a common market and ensure free movement of labor, capital, goods, and services within its borders.

The process of forming the EAEU's unified gas market is proceeding upon an agreed path formulated in the Concepts for the EAEU Gas Market (completed in 2016), to be followed by development of programs for each national market by 1 January 2018 (specifying explicit actions to be taken by EAEU countries).[28] Finally, international legal agreements among the countries are to be concluded by 1 January 2024 and put in force by 1 January 2025.[29]

The approved EAEU gas market Concept sets a three-stage integration path (see Decision No. 7 of the Supreme Eurasian Economic Council dated 31 May 2016). The first stage, which is to be implemented by the year of 2020, envisions:

- harmonizing the legislation of the Member States with regard to the EAEU common gas market regulation;
- ensuring availability (accessibility) and complete disclosure of information on available (free) capacities in the gas transportation systems located in the territories of the Member States
- unifying gas-related standards and regulations of the Member States as well as engineering/technical standards, regulations, codes and specifications governing operation of the gas transportation systems located in the territories of the Member States
- creating an information exchange system providing information on domestic gas consumption as well as gas transportation and supply pricing in the territories of the Member States, including wholesale gas prices and tariffs for gas supply through gas transportation systems;[30]
- developing and approving common rules of access to the gas transportation systems located in the territories of the Member States;
- establishing the procedure for gas exchange trading in the EAEU common gas market approved by the competent authorities of the Member States;[31]

[28] Articles 83 and 84 of the EAEU Agreement from 29 May 2014 identify the steps for the gas, and oil and oil products markets, respectively.

[29] Approval of the Concept on Gas Markets by the EAEU Supreme Eurasian Economic Council occurred on 31 May 2016, while the EAEU's Intergovernmental Council approved the draft of the oil and oil products markets Concept on 20 May 2016.

[30] Each country will determine its own transportation tariff.

[31] The right of equal access to the EAEU gas pipeline infrastructure means that companies from one EAEU country have the same right to access pipeline infrastructure in another EAEU country as do that other country's gas producers who are not owners of the pipeline infrastructure; this implies that Gazprom still might have priority accessing its own pipelines in Russia, for example.

- preparing an indicative (forecast) EAEU gas balance; [32]
- identifying infrastructure limitations in terms of gas transportation between the Member States and developing proposals on how to eliminate such limitations.

By 2021, the Concept's second stage envisions:
- providing for the operation of one or more commodity exchanges within the EAEU where gas trading can take place;
- providing non-discriminatory access for the EAEU common gas market participants to gas trading at the commodity exchanges of the Member States;
- providing access for the EAEU common gas market participants to the gas transportation systems located in the territories of the Member States for the purposes of gas transportation and supply between the Member States, taking into account the agreed indicative (forecast) EAEU gas balance;
- using a variety of mechanisms, including long-term bids by gas suppliers and consumers, in order to develop the capacities of the gas transportation systems located in the territories of the Member States;
- increasing the investment activities of the businesses (entities) of the Member States in the EAEU common gas market, also through joint infrastructure project implementation;
- consulting with the Member States with regard to gas transportation and supply to third countries in the areas of supply where the Member States compete or may potentially compete with each other.

At the final third stage, to occur no later than 1 January 2025, the Concept postulates the EAEU Agreement on the Formation of a Common Gas Market coming into effect for the entire EAEU. Also at this stage Member States will:
- provide unobstructed supplies of gas purchased under direct contracts or through commodity exchange trading between the EAEU common gas market participants in the necessary amounts and destinations;
- maintain market prices ensuring profitability of gas sales in the EAEU common gas market;
- provide a coordinated decision-making framework on transition to equal-netback gas prices (gas prices established on a netback parity basis) in the territories of the Member States.

The EAEU Agreement on the methodology of forming indicative energy balances, including the gas balance, was signed in April 2016. The first energy balances of EAEU member countries are scheduled to be compiled by October 2017.

In April 2017 the common gas market Program's draft was approved by the Consulting Committee on oil and gas under the EAEU Economic Commission's Board on Energy.[33]

The development of technical standards is also moving forward: in April 2016 the Consulting Committee approved the draft standards for natural gas.

5.2.13. LPG: production, consumption, transportation, and global trends

Production of liquefied petroleum gases (LPGs; propane and butane) in Kazakhstan increased from 2.5 MMt in 2014 to 2.7 MMt in 2016. The change is mainly due to a 194,000 ton increase in output by the Zhanazhol gas processing plant (owned by CNPC-Aktobemunaygaz). Accordingly, the share of Zhanazhol's output in total LPG production increased from 10% in 2014 to 17% in 2016 (see Figure 5.15). While most of the produced LPG continues to be exported, export volumes are decreasing: exports amounted to 2.1 MMt in 2016 compared to 2.3 MMt in 2014. In terms of destination countries, Turkey remained the leading buyer of LPG from Kazakhstan, purchasing 0.5 MMt in 2016 (compared to 0.6 MMt in 2014), followed by Poland (0.4 MMt in 2016) and Tajikistan (0.3 MMt).[34]

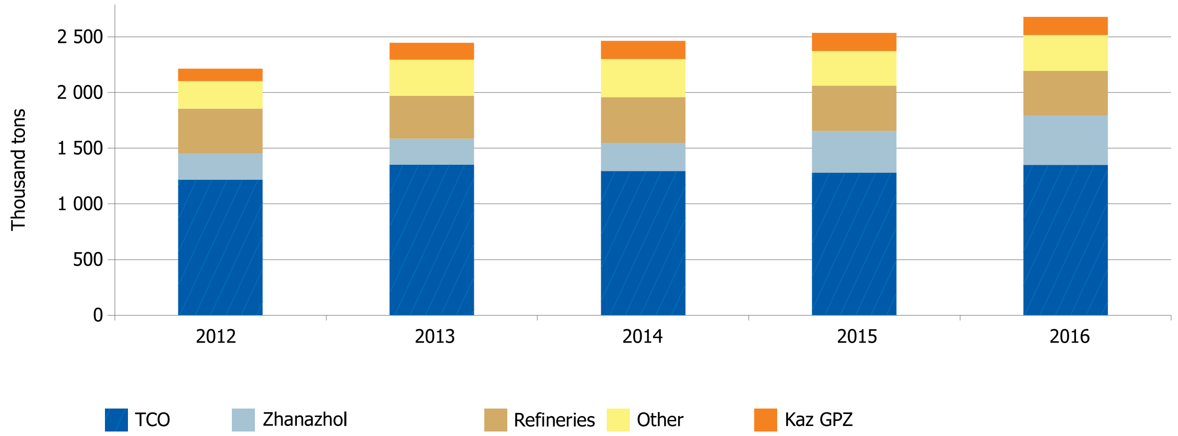
Higher LPG production, coupled with lower exports, indicates that the apparent consumption of LPG in Kazakhstan grew substantially, from about 270,000 tons in 2014 to 620,000 tons in 2016.

Wholesale prices in the domestic market and domestic delivery volumes remain under state regulation (Law on Gas and Gas Suppy) and are set on a quarterly basis. In September 2014, authority over LPG market regulation was transferred to the Energy Ministry, including the authority to set a wholesale price ceiling and to develop a monthly domestic supply schedule.

Amendments made in February 2015 to the formula that sets the wholesale price ceiling changed the discount coefficient: instead of comparing per capita income in Kazakhstan with that in Russia, the coefficient now reflects the level of gasification in Kazakhstan. As a result of this amendment and following the collapse of oil prices, in February 2015 the wholesale price ceiling was reduced from 32,000 tenge ($172.6) per ton to 11,000 tenge ($59.3) per ton (effective from March 2015). The formula for the price ceiling calculation was again amended in June 2016. First, the reference to external market prices was changed: instead of referring to LPG prices on the Belarus-Poland border (DAP Brest), the formula now refers to LPG prices on the Tajikistan-Uzbekistan border (DAP Bekabad). Second, the reference period was changed: instead of taking an arithmetic mean of daily prices for the previous quarter, the current formula averages daily prices during the first month of the current quarter. As the result, wholesale price ceilings increased from 11,000 tenge (~$33) per ton in Q2-2016 to 23,000 tenge (~$67) in the following quarter, to 28,000 tenge (~$86) in 1Q-2017 (see Figure 5.16). This administrative approach to the LPG market has led to periodic regional deficits as well as surfeits, as real demand has significantly deviated from the schedules compiled by the Ministry of Energy of RK. Market liberalization would address these recurring problems.

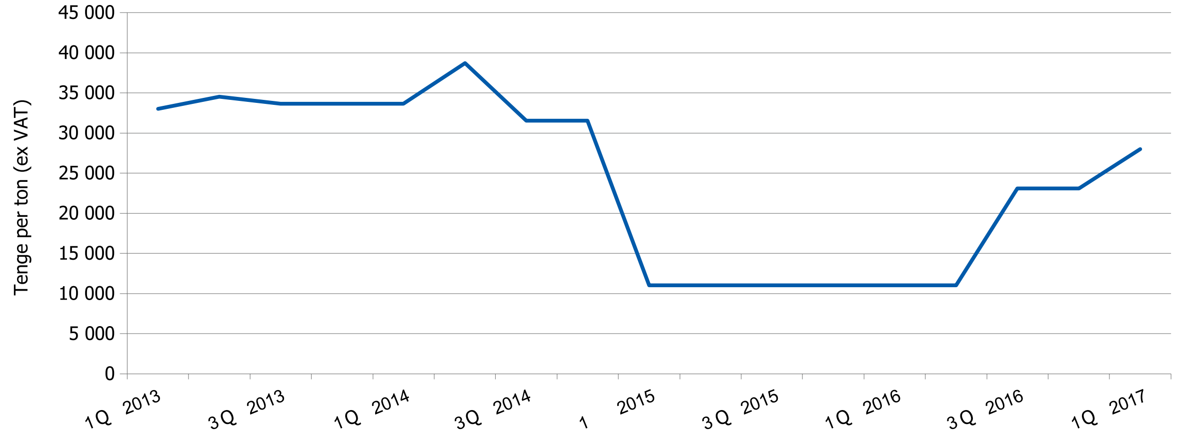
According to the Statistics Committee, there were 3,683 LPG-consuming vehicles (including buses,

Figure 5.15. Kazakhstan's LPG output by producer



Source: IHS Markit, Ministry of Energy of RK

Figure 5.16. Regulated upper limits for LPG wholesale prices in Kazakhstan



Source: IHS Markit

vans, and trucks) in Kazakhstan by Q2-2017, or 0.9% of the registered light vehicle fleet of 3.85 million. Meanwhile, the number of mixed use vehicles (presumably mainly LPGs) doubled from 67,761 vehicles in 2015 to 133,786 vehicles at the beginning of 2017, or 3.5% of the total fleet. Regionally, Mangistau Oblast has the highest share of mixed vehicles (~40%), followed by Aktobe at 14%. For LPG-only vehicles, around 18% were registered in Almaty City, 9% in Almaty Oblast, and 11% in Aktobe Oblast.

Kazakhstan's LPG retail market is dominated by specialized retail players. Some major ones include Bey-

[32] Meeting domestic consumption in each Member State has priority over exports.

[33] The Consulting Committee is a working group developing proposals and recommendations on strategic issues in related markets.

[34] Besides Turkey, other countries that recorded substantial decreases in imports were Ukraine and Poland, which cut LPG purchases by 123,000 tons and 115,000 tons, respectively. In turn, the largest increase of LPG exports was to Afghanistan (by 76,000 tons), followed by China (74,000 tons) and Malta (56,000 tons).

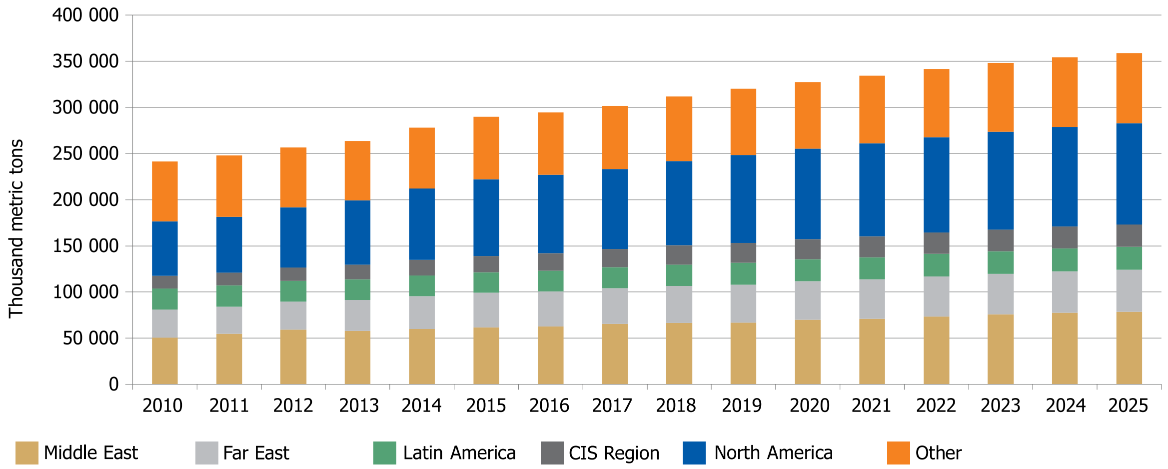
bars Gas with over 220 stations, Gas Energy with 100 stations, Gazoil with 42 stations, and Zhigergaz with 19 stations. In contrast, the mainstream retail motor fuel operators, including KazMunayGaz Onimderi, Helios, SINOOIL, and Gazprom Neft, do not have a strong presence in the LPG fuel market: of their 850 retail filling stations in Kazakhstan, only 40 stations, or 4%, offer LPG.

Global LPG trends

The world's total LPG supply expanded by 17 MMt to 295 MMt between 2014 and 2016, as global propane output increased by 8 MMt to 159 MMt, while production of butane grew by 8 MMt to 136 MMt (see Figure 5.17). This increase has been driven largely by growing hydrocarbon output from unconventional plays (shale gas and tight oil developments) in North America. Specifically, since 2013, North American LPG production grew by 15 MMt, reaching 85 MMt in 2016. Global demand growth in concentrated mainly in China and India; demand in Europe, North America, and the Middle East actually declined marginally.

The massive increase in US LPG production has impacted trade patterns. US propane exports, most of which went to China, increased from 13 MMt in 2014

Figure 5.17. Global LPG supply by region



Source: IHS Markit

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(23% of the world's total propane exports) to over 18 MMt in 2016 (28%). China's growing domestic demand has driven import demand up to 13 MMt in 2016 from 5 MMt in 2014, surpassing imports to all of Latin America (10 MMt in 2016). In Europe, propane imports from the US displaced propane originating in the Middle East and Africa, while imports from the CIS grew incrementally from 3.5 MMt to 4.1 MMt. Growth in butane demand came primarily from the Far East and India, and was met mainly by exports from the Middle East.

Going forward, IHS Markit projects that global LPG production will grow from 295 MMt in 2016 to 360 MMt in 2025. Almost 40% of this increase is expected to come from unconventional plays in North America, and one quarter from the Middle East. Absorbing this increase will be a challenge, but 40% of the demand growth during this period will be in the Far East region (primarily China), and another 18% from India. In terms of sectors, 60% of the projected increase in demand is expected to come from the residential/commercial sector, and 30% from the petrochemical sector. China will remain the major propane importer, with its share of total world imports growing from 19% in 2016 (13 MMt) to 29% in 2025 (25 MMt), while India, Latin America, and the Southeast Asian countries will also increase propane imports.

The sizable growth in expected output, as noted previously in the National Energy Report 2015, is likely to put downward pressure on prices for LPG—which traditionally has been priced as a specialty refined product rather than as a gas-based fuel—in particular regions. These traditional pricing arrangements have been coming under increased pressure, particularly in North America, and it is not inconceivable that a similar situation could unfold in Europe, as intensifying competition between US and Middle East exports leads to weakening LPG prices.[35]

A move towards gas-based, rather than niche (refined product) pricing of LPG in Europe would have important consequences for Kazakhstan. Kazakhstan is a relatively small supplier and therefore a price

[35] See The National Energy Report 2015, p. 191–192.

taker. Kazakhstan presently absorbs only a limited amount of the LPG it produces, exporting roughly three-fourths of its total output. It thus seems prudent for policymakers to undertake contingency planning focused on additional measures to increase LPG consumption domestically where possible: further expanding its use in the transport sector, extending its availability to residential/commercial consumers in areas where piped gas is unavailable, and developing a petrochemical industry in sectors that utilize LPG as a feedstock.[36] Policymakers should implement fiscal incentives to fueling station owners to install necessary infrastructure to purchase, store, and sell LPGs. Kazakhstan should also consider offering tax credits to consumers who either refurbish their cars, to handle cleaner fuel, or purchase new cars with engines capable of handling LPGs (see Recommendations).

5.2.14. Sulfur utilization update

Kazakhstan's sulfur production has continued to grow in recent years, reaching 2.54 MMt in 2016. TCO continued to be the largest sulfur producer, with an output of 2.33 MMt in 2016, compared to 2.4MMt in 2014–15. The Future Growth Project (FGP) is not expected to cause sulfur output to increase significantly, as the associated gas will be reinjected to maintain reservoir pressure for oil production. At Kashagan, sulfur production is expected to reach about 1.1 MMt/y with phase 1 oil output.

Recent upgrades at the Shymkent and Atyrau refineries have also increased the country's sulfur production capacity (see Chapter 4). A 4,000 tons/y sulfur production unit in Shymkent was commissioned in December 2015. The unit produced 534 tons of sulfur in 2016, and is expected to produce 481 tons in 2017.

5.3. INFRASTRUCTURE AND TECHNOLOGIES: KEY CHALLENGES, IDEAS AND SOLUTIONS

Natural gas is widely considered to be an important fuel bridging the transition from high-carbon-emitting coal to renewables. Natural gas is viewed as taking on the important role of providing flexible power while displacing coal in power generation. However, the role of gas as a bridge fuel globally has come into some question as a result of the recent rapid build-out of renewable power worldwide. A hotly debated topic is now the price of future electricity from renewables. Can the costs of renewables continue to come down, ultimately to levels below those of coal or natural gas? Proponents of renewables say yes, whereas sceptics are undecided or negative. It is important, however, when considering this question to add the broader costs of renewables into the equation (beyond generation costs, there are costs associated with back-up generation and connection to the grid).

One factor that could conceivably disrupt or attenuate the seemingly indispensable role allotted to natural gas as a bridge fuel is more rapid than expected development of grid battery storage technology. Views vary greatly on the likelihood and timing of such disruption. IHS Markit does not expect batteries to have a significant impact on the industry until after 2050. But this is the technology that everyone is now watching.

Even if the transition to renewable energy is more rapid than currently anticipated (and advances in battery storage capacity proceed apace), natural gas will still have a role to play. Natural gas is considered to be a perfect back-up fuel for the intermittent renewables, ready to promptly to enter the grid when needed. The proliferation of renewables is often predicated on ensuring that sufficient backup generation capacity exists (e.g., during dark, cloudy, and windless periods), and if new capacity is needed, natural gas often is the most obvious choice.

5.3.1. Gas in petrochemical applications

Ambitious plans to establish a major gas-based petrochemical industry at two sites in western Kazakhstan (Tengiz and Karabatan) have suffered a major setback in the current difficult economic environment. The big blow was the announcement by LG Chem, South Korea's largest chemicals company, to pull out of a planned project to build a $4.2 billion ethylene-polyethylene facility at Karabatan, near Atyrau.[37] This announcement was made at the end of 2015, citing rising costs and falling oil prices, despite the fact that Karabatanis located within the boundaries of a National Industrial Petrochemical Technopark (special economic zone) set up by presidential decree in 2007 that would enjoy significant tax benefits and other privileges.

The planned complex was to produce olefins (ethyl-

[36] See The National Energy Report 2015, p. 197.

[37] The project, finalized in 2011, was part of a 50-50 joint venture with two Kazakh companies, state-owned United Chemical Company (UCC) and SAT, a private company.

ene and propylene) from a large steam cracker (pyrolysis unit), and then convert them into polypropylene and polyethylene. Plans also call for other related products, such as ethyl benzene, ethylene glycol, polyethylene terephthalate, and polyvinyl chloride, to be added eventually. The ambitious project is being led by UCC, a specialized subsidiary of the national wealth fund, Samruk Kazyna.

Petrochemical (olefin) production in western Kazakhstan is to be based on feedstock-rich gas—and on the competitiveness of relatively cheap and potentially large volumes of natural gas liquid (NGL)-rich associated gas. The gas will be run through a separation plant to extract ethane and other natural gas liquids for petrochemical use, while the methane will be returned to be available for other uses.

Globally, the main element determining costs of integrated polyolefin production and the relative competitiveness of a particular plant is the cost of the feedstock (see Chapter 4 of NER 2015). Therefore, the low-cost feedstock available to Kazakhstan's planned plants makes them very competitive globally, even on a delivered cost basis (i.e., including transportation costs), either to European or Asian markets. Their projected costs of operation are lower than nearly all other producing regions around the world; the exception is ethane-based manufacture in Saudi Arabia.

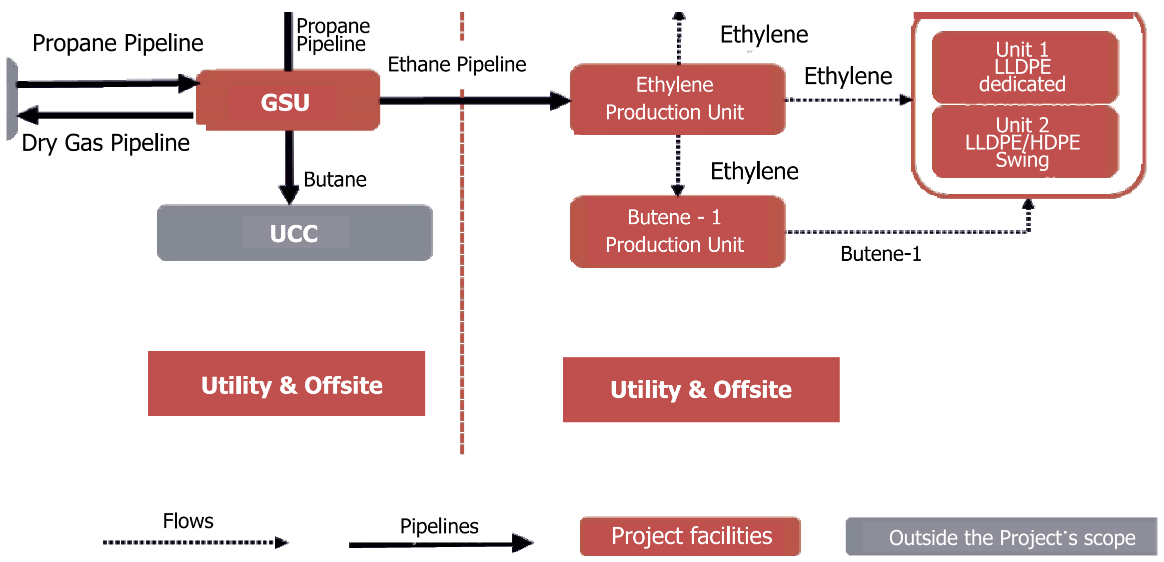
Therefore it appears that a major reason for the reluctance of investors to proceed in Kazakhstan is the general global business climate and related uncertainties of demand and pricing for petrochemicals, although it must be recognized that major investments are proceeding in other low-cost feedstock locations such as the US Gulf Coast and Middle East. The main issue for the hesitancy to invest in Kazakhstan's petrochemical development seems to be the high costs of construction due to the country's remote location, as equipment costs tend to be very similar globally (essentially being procured from a small number of equipment providers). Evidently, tenge devaluation did not help ameliorate local construction costs, implying that this segment is relatively internationalized. The other issue appears to be the general (and more intangible) regulatory and fiscal risks of doing business in Kazakhstan, particularly for external investors and financial institutions.

The petrochemical complex was planned to be developed in two phases:

- Phase 1 involves the construction of a polypropylene production line with a capacity of 550,000 metric tons per year and associated infrastructure and facilities. Phase I was being developed by LG Chem and KPI (Kazakhstan Petrochemical Industries), a partnership between UCC (51%) and Almex Plus (49%).
- Phase 2, which was being developed by the LG Chem/UCC/SAT consortium, and was planned to involve the construction of a polyethylene production line with a capacity of 800,000 metric tons per year and needed infrastructure elements. It also included a 1 MMt/ year ethylene cracker and a gas separation unit (GSU) (see Figure 5.18).

In addition to the Karabatan site, the petrochemical complex was planned to include facilities at Tengiz: the gas separation GSU, NGL fractioning unit, and associated utilities, whereas the steam cracker, butene-1 unit, and the polypropylene and polyethylene production units would be located at the Karabatan site. A 200 km pipeline was planned to transport ethane extracted in the GSU to Karabatan, while rail transport was to be used for the extracted propane (see Figure 5.18).

Figure 5.18. Gas-based petrochemical industry complex at Tengiz and Karabatan



The withdrawal of LG Chem has effectively stopped progress on phase 1 for now, but UCC announced that it still plans to proceed with the other part of the complex. UCC announced in August 2016 that it was still planning to complete the polypropylene production line, a unit for producing technical gases (evidently using the Solvay process), and a gas turbine power plant with a generating capacity of 310 MW.

Importantly, UCC did launch a new polymer products plant in Atyrau oblastin august 2016. The plant produces 4,125 tons per year of polyethylene film and 48 million polypropylene bags per year. It will also turn out 14,738 tons per year of biaxially oriented polypropylene (BOPP) film. Key financing for the plant came from an $85 million loan from Russia's Sberbank.

But prospects for the heart of the planned petrochemical complex, the ethane-based pyrolysis plant for ethylene production, remain uncertain. The complex was planned to use about 7 Bcm of gas that would be sourced from the Tengiz field operated by TCO. The dry gas would be processed by the GSU to extract the ethane necessary for the production of ethylene. Propane and butane would also be extracted to supply the phase 1 facilities.

5.3.2. Use of natural gas in transportation and other potential uses for natural gas

Global trends in use of natural gas in transportation

The use of cleaner alternative transportation fuels, including natural gas, has been promoted by many governments, as concerns of pollution and human impact on the environment became more prominent in public discourse. Use of natural gas in transportation also answers a key strategic policy goal for the leadership of many countries, as it increases energy security by both diversifying transportation fuel supply and increasing use of domestic resources.

Over the past decade the use of natural gas as a motor fuel has been gaining momentum globally. A large gap between relatively high oil prices and natural gas prices has been a key driver of this development, particularly in China (see text box on LNG in Trucking and small-scale LNG). Although with the narrowing price gap between the fuels in the past few years with much lower oil prices, the rate of penetration of gas vehicles has slowed.

In addition to liquefied petroleum gases (LPGs; i.e., propane and butane), which already are used widely in automobiles in Kazakhstan and elsewhere, there are two forms in which natural gas (methane) has been used in motor vehicles globally: compressed natural gas (CNG) and liquefied natural gas (LNG). Unlike oil and oil products, which can be easily transported and stored for essentially unlimited periods of time, and used in a variety of machines, the properties of natural gas require special vehicles, storage, and supply-chains. Promoting greater CNG/LNG use in Kazakhstan will therefore require significant investments by private and public actors throughout the value chain, including transportation, liquefaction (if using associated gas from domestic fields), transportation, regasification, and end-markets (building demand by encouraging vehicle switching). Globally, the following trends have emerged with respect to fostering greater LNG/CNG use in transportation:

- **CNG/LNG use is challenged in light-duty vehicles (passenger cars)**, due to fuel density and on-board storage issues, as the fuel tank occupies much of the useful space and the vehicle still would not be able to travel more than 100–200 km without refueling.
- **The switch to CNG/LNG can be more easily made for medium- and heavy-duty vehicles (trucks and buses):**
  - **CNG, for example, is widely used in urban/commercial fleets** that have only a short range and return to the same base each day, such as garbage trucks and city buses. These types of vehicles have a predictable and relatively short routes that makes both of the key challenges for CNG use in transportation—storage/fueling infrastructure and travel distance—more manageable. Additionally, these larger fleets tend to be managed by a company that is able to take advantage of economies of scale when fueling and operating the vehicle fleet.
  - **LNG, on the other hand, has found its widest use in long-haul trucking.** This is because an LNG tank holds more fuel than a CNG tank, as the natural gas is held in a denser, liquefied form.

IHS Markit projects that globally the use of natural gas in road transportation will grow at an average rate of 5.9% annually between 2016 and 2040 (albeit from a small base), reaching 78 MMtoe in 2025, 116 MMtoe in 2030, and 184 MMtoe in 2040. The share of natural gas in road transportation will remain relatively small, however: only 7.2% in 2040, with the majority share still held by gasoline at 49% and diesel at 41%.[38]

[38] LNG use is expected to slightly increase in the shipping industry, as vessels adjust to the IMO low sulfur fuel 0.5% requirement by 2020. IHS Markit estimates that vessels navigating shorter point-to-point routes with frequent bunkering are the most likely to switch to LNG, along with those operating in special environmental regions (such as the Baltic Sea). As of mid-2017, only 185 vessels, out of 12,000 globally, use LNG, and by 2020, IHS Markit expects that LNG will constitute only 1% of fuel oil bunker demand.

Over the short term, higher upfront CNG and LNG vehicle purchase costs and limited refueling infrastructure are the primary barriers to natural gas adoption within commercial fleets, particularly those consisting of long-haul commercial tractor-trailers used in trucking. Additionally, current narrow diesel-to-natural gas price differentials, fewer CNG or LNG vehicle product offerings, limited vehicle maintenance and business infrastructure knowledge, and longer refueling times are also headwinds to the adoption of natural gas in commercial fleets. However, the much higher annual travel mileages and more rapid vehicle turnover in commercial fleets accelerates the impact and enhances the economic advantages of adopting such new technologies and fuel choices.[39]

One key aspect of the proliferation of gas as a transportation fuel is the consumer's willingness to buy gas-fueled vehicles. However, this only happens if there is infrastructure to support them. At the same time, infrastructure build-up does not occur until developers feel confident that there is sufficient demand from consumers to cover the costs and the risks of investment. In China, the initial development of infrastructure and retrofitting of trucks occurred simultaneously when such companies as Guanghui Investments acted as both investors and consumers in the market. This jump-started the development of LNG use and infrastructure, and is the main reason why China has been more successful than other countries in switching to LNG (see text box: LNG in trucking and small scale LNG).

LNG in trucking and small-scale LNG: China andglobal trends

China has been leading the global shift to LNG in trucking, due to a large price differential between diesel and natural gas historically, demand for flexible gas supplies (especially during peak times of usage or by residential users currently outside gas grid coverage), as well as the need to establish an entirely new supply infrastructure in any case, instead of trying to adapt a large existing one. However, the rate of penetration is slowing, following gas price reforms (beginning in 2013) that raised gas prices while oil prices have declined. Earlier, consumers were highly motivated to either retrofit their diesel-fired trucks or buy new factory-built models to run on LNG because the payback time for such investment was under 12 months. But as the price gap began to narrow, the payback period of the higher investment rose, lessening the overall appetite for switching from diesel to LNG. Although payback periods in key regions in China are still favorable, the concerns over future price reform and its implication for the truck fleet operators' bottom line began to slow the growth of LNG transport in China. Also, on the gas supply side, Chinese buyers have committed to record levels of LNG contract volumes. With the global gas market expected to be in oversupply through 2023, China will be importing LNG at extremely competitive prices, which will be competing with domestic small-scale LNG delivered to consumers in coastal provinces; large-scale LNG imports grew by almost 38% in 2016.

Nonetheless, tightening fuel and emissions standards in China have helped retain the relative competitiveness of natural gas versus diesel in trucking. Another factor helping sustain gas competitiveness in this sector is that the Chinese government raised oil taxes during the low oil price environment of late 2014 through mid-2016, so the diesel price for end-consumers did not fully reflect the decrease in global oil prices. The increase of LNG-fired trucks in China is impressive: from essentially zero LNG-fueled vehicles in 2008; there were ~260,000 LNG trucks on the road in 2016. By the end of 2016, there were about 2,700 LNG fueling stations in China, supported by a sizable small-scale inland liquefaction capacity (i.e., in addition to the large coastal import facilities) of 26.9 MMt.

Despite the continued positive developments in trucking, recent changes in market fundamentals have adversely impacted China's small liquefaction business more generally. China's gas market has quickly turned from supply constrained to oversupplied, reducing the need for gas outside of the traditional pipeline system. Declining prices of competing fuels—such as diesel and LPG—and other gas supply sources (e.g., coal) also reduce the cost competitiveness of domestically produced LNG. In 2016, only 2.9 MMt of small liquefaction capacity was added in China, representing only 12% annual growth, dropping from 25% in 2015 (and compared with 49% average annual growth in 2010–14). A further 15–16 MMt is currently under construction, and 10.1 MM is in the planning phase, although some may face serious delay or cancellation. Attesting to the growing oversupply situation, utilization of this capacity has been somewhat low, falling from around 56% in 2014 to 38% in 2016. Since 2014, gas production from small LNG plants in China has remained relatively stagnant, accounting for 6.4% of total gas supply in 2016.

If before 2008 most of China's small LNG supply came from "stranded gas" in small fields, at present an increasing number of new LNG plants are using unconventional gas as feedstock. Several plants are using CBM, taking advantage of CBM volumes that have struggled to find pipeline access to the market. The first liquefaction facility to use shale gas as a feedstock came online in early 2015 and a second is now under construction. A few plants also use coking gas as feedstock.

The importance of state policy in shaping gas use in China's transportation sector is not an anomaly. Government subsidies and policies have been a prime reason for the adoption of CNG and LNG as a transport fuel worldwide. In China, policy support for natural gas in transport recently was further strengthened in the National Development and Reform Commission's 13th Five-Year Plan for Natural Gas Development. For the first time, the 13th FYP specifically mentions supporting policies for natural gas vehicles and vessels and sets targets to increase the total natural gas vehicle fleet (of all types) to more than 10 million by 2020 and the total number of vehicle refueling stations (CNG and LNG) to more than 12,000 by end-2020 (up from 6,500 at the end of 2015).

Although nowhere else has the scale of conversion matched that of China, other countries have seen some shift to natural gas in transportation as well. In the United States, lack of fueling infrastructure is inhibiting sales of LNG trucks, despite the wide price differential in fuels, although limited LNG infrastructure is now in place as a launching pad for further development. LNG is facing a major new challenge in the US from CNG "long-range solutions," where CNG can be used in long-haul trucking. Some developers see greater potential in CNG and are thus expanding the number of CNG fueling stations along major trucking routes; but use of CNG in municipal public transport is already fairly widespread in the US, where legislation requires all state-funded organizations to purchase gas-powered vehicles when renewing their fleet.

In the US passenger car market, however, consumers looking to save on fuel costs are more likely to opt for hybrid or battery electric vehicles than those powered by natural gas, at least over the near term. Natural gas vehicles are both more costly up front (by roughly $8,000) than conventional vehicles and have a narrower (by up to 40%) driving range. Further, only about 1% of conventional fueling stations for light-duty vehicles are equipped for natural gas. However, in US commercial fleet operations, the prospects for adoption of natural gas will continue to be favorable even in the current low oil price environment. Although commercial fleet owners face few options that can match the power, efficiency, and reliability of the diesel engine, lower and less volatile natural gas pricing will likely lead to a gradual erosion of diesel demand growth.

In Europe the focus has been not so much on vehicle transportation but on the bunker market (ships), mainly in Northwest Europe, while the LNG trucking market is still in its infancy. CNG is slightly more widely used in Europe, although the situation differs by country. For example, Italy has over a thousand CNG stations, while in the UK there are less than 20. EU countries offer selective tax breaks for gas-powered transportation. For example, in Italy, alternative-fueled vehicles (including natural gas) have a three-year tax exemption and all newly built fuel filling stations must be equipped with a compressed gas filling unit. Meanwhile, France prohibits the use of diesel fuel for municipal public transport and waste collection.

In 2013, the European Commission unveiled a package of measures to encourage the use of alternative clean fuels in Europe, including proposals for common standards governing the design, use, and distribution of such fuels. The measures include potentially binding targets for countries to construct a minimum level of infrastructure for clean vehicle fuels such as electricity, hydrogen, and natural gas. A core component of the clean fuel strategy is the use of LNG and CNG in transport. The Commission proposes that LNG refueling stations be installed every 400 km along the roads of the Trans-European Core Network by 2020. For CNG-powered vehicles, the Commission aims to ensure that refueling points are available Europe-wide with maximum distances of 150 km by 2020.

In Russia, natural gas has been used for transportation since the 1980s, mostly as CNG, although its use dropped sharply in the 1990s. In recent years, interest in CNG and LNG has revived, especially from Gazprom, as the company is looking at various ways to monetize its gas by expanding domestic gas consumption. Gazprom has launched a special-purpose company Gazprom Gazomotornoye Toplivo and plans to step up CNG infrastructure investments. This initiative has found strong political support as well, with the government promulgating plans for expansion of CNG for urban fleets.[40]

[39] In the United States, a long-haul tractor trailer typically logs between 75,000 and 175,000 miles per year over a typical service lifetime of three to five years.

[40] In 2014, KTG and Gazprom Gazomotornoye Toplivo signed a memorandum of understanding on cooperation and advancement of natural gas use in transportation, including creation of a unified technical policy between the two countries and increasing personnel training in this area.

Potential Use of Natural Gas in Transportation in Kazakhstan

Use of natural gas as a motor fuel in Kazakhstan could help achieve a number of important policy goals. First, together with Kazakhstan's refinery modernization program (see Chapter 4), natural gas use may help alleviate a shortage of refined products for transportation.[41] Second, it would help utilize local resources, increasing energy independence and supporting the local economy. Third, it could potentially help monetize stranded gas resources that are not connected to the main gas pipelines. Finally, it would mitigate the environmental impacts of vehicle fuel consumption on urban air quality, and with gas being less carbon-intensive than oil products this could also help the country meet its CO_2 emissions reduction targets. Formulation of a general policy that links these four policy goals in order to promote their coordinated development is critical to enabling CNG/LNG use to progress beyond the "niche" stage. IHS Markit calculates that by 2020 at least 0.5 Bcm/y of natural gas will be used as transportation fuel in Kazakhstan (see below).

The Concept of gas industry development to 2030 envisions the share of natural gas in motor fuel consumption by public and utility transport to reach at least 30% in Almaty and Astana and at least 10% in cities that are oblast centers by 2020, growing to 50% in Almaty and Astana and at least to 30% in the oblast centers by 2030. A network of CNG fueling stations is planned to be developed along the Kazakh section of the planned Europe–China transit corridor.

Kazakhstan has already begun to use natural gas in transport, although activity remains quite limited at present. By the end of 2015, there were 5 CNG stations in Kazakhstan. Almaty Oblast had the highest number of stations. KTG has a CNG Network Development Plan to 2022, with specialized subsidiaries—KTG Onimderi and AvtoGaz—responsible for the construction, operation, and maintenance of CNG filling stations and related infrastructure. Astana's first CNG fueling station opened in 2017, fueling shuttles that carry visitors to the EXPO-2017 exhibition as well as vehicles used in general city transport.

The planned gasification of Astana, beginning with small-scale LNG, is already underway. Gazprom Export and Global Gas Group signed a contract in December 2016 for the delivery of 320,000 tons per year (0.43 Bcm) of LNG from Gazprom Transgaz Yekaterinburg over three years.[42] In February 2017, Global Gas Group received its first shipment of Russian LNG at Kazakhstan's first and only regasification terminal, at Nazarbayev University. The regasification terminal has a heating capacity of 25 Gcal per hour and cost 2 billion tenge (~$5.6 million) to construct. The University uses the LNG for heating. The parties involved also expressed hope that the contract would provide a foundation for further cooperation in the field of small-scale LNG supplies nationwide, and to use gas as a motor fuel for public transport in Astana.

Global Gas Group plans to build another six regasification terminals that will be operated by local company SPK Astana.[43] While the existing contract calls for the delivery of 320,000 tons of LNG, Gazprom projects a gradual ramp-up in LNG deliveries to Kazakhstan, totaling 5,000 tons in 2017 and reaching 320,000 tons (the equivalent of ~0.5 Bcm of dry gas) in 2021. To meet these supply obligations, Gazprom plans to carry out a design study for a 35,000 ton liquefaction facility in Yuzhnouralsk, and plans to build a bigger facility in Chelyabinsk than the existing one in Yekaterinburg.

In Kazakhstan, the gas–oil price gap may enable the expansion of LNG-fueled transportation, although much depends on the cost of the sourced natural gas. A significant price gap still exists between the fuels, as prices for oil products have been deregulated while natural gas prices are still regulated. In April 2017, the average retail diesel price was the equivalent of $10.4 per MMBtu, while the average natural gas price paid by households was only $1.5 per MMBtu. For an industrial consumer, such as a small liquefaction plant, the acquisition price it would pay for gas would be higher than for households, but still was only $1.8 per MMBtu in April 2017. This was significantly lower than the diesel equivalent (see Figure 5.19).[44] However, growing diesel consumption in Kazakhstan, especially in transportation, represents an opportunity for LNG sales to substitute for some of the diesel consumption in trucks. Kazakhstan's diesel demand has been growing and is already the largest component of Kazakhstan's product demand balance, with trucks accounting for the largest share of diesel consumption (~30%). Extractive enterprises in the mining sector could potentially benefit from switching their quarry equipment from diesel fuel to LNG. Another option for future LNG use is rail transport.

By IHS Markit estimates, even a liquefaction plant based on more expensive imported Russian gas (as is the case with Yekaterinburg small-scale LNG) would seem to have strong economic prospects, at least when the output can be sold as a refined product. The addition of announced capex and estimated opex for building a new facility to the industrial acquisition costs for gas still results in total costs of $6.0 per MMBtu, which provides considerable room to compete with diesel fuel in the local market (see Figure 5.20).[45] But these costs reflect the LNG supplier costs only, which include the cost of feedstock gas and cost of conversion into LNG. Promoting LNG use in Kazakhstan must be analyzed at a systemic level that would account for the costs incurred downstream, including the expenses to retrofit an LNG truck or fleet, modify fueling stations, adjust supply chains, and install regasification terminals.

The relatively high costs of delivered LNG from Yekaterinburg, reflecting technology and transportation

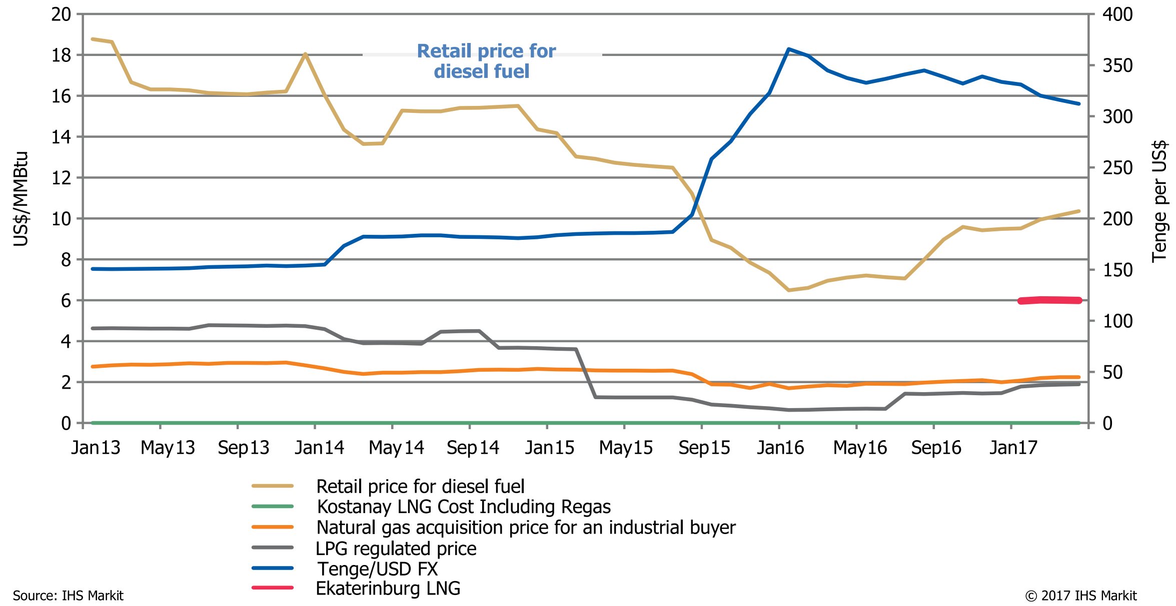
[41] Kazakhstan's demand for gasoline and kerosene has been growing since the 2000s, and has been met by increasing imports, mostly from Russia.

[42] The company, a subsidiary of Gazprom, transports and distributes gas in Russia's Sverdlovsk, Chelyabinsk, Kurgan, and Orenburg regions.

[43] https://informburo.kz/novosti/nazarbaev-universitet-budet-zhit-i-rabotat-na-rossiyskom-gaze.html

[44] The industrial acquisition price is what an LNG plant would pay for its source gas to make LNG fuel for transportation. Then it would sell this product at a fueling station. As LNG would compete mostly with diesel, comparisons to the diesel retail price are the most relevant.

Figure 5.19. Natural gas–diesel price differential: potential for LNG - fueled transportation



Source: IHS Markit

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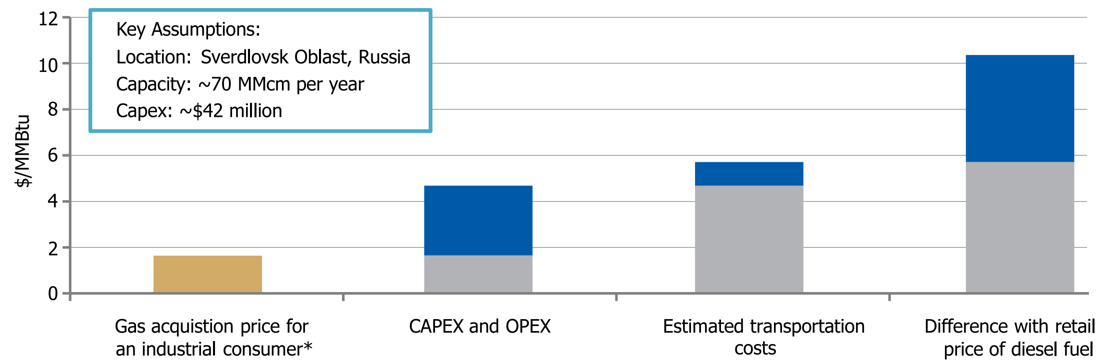
Figure 5.20 Comparative economics of importing small - scale LNG from a plant in Sverdlovsk Oblast versus diesel fuel in Astana



*Source gas assumed to be Russian gas in Sverdlovsk Oblast

Source: IHS Markit

© 2017 IHS Markit

distances, mean that at least some end-consumers are able and willing to pay the higher prices for the cleaner, albeit pricier, fuel. Niche buyers willing to incur such expenses could include industrial and commercial users for the production of high value-added chemical or glass products or services, for peak-shaving needs, and even selected residential consumers. However, even if the end-consumers are willing to pay gas prices high enough to cover additional operational costs (e.g., remote locations where the competing fuel for heating is refined products, such as gasoil or fuel oil), the obvious competitor to LNG would be LPG. LPG is the general fuel used in situations where piped gas supplies are unavailable. The limited consumer power of end-users in Kazakhstan, particularly in remote rural regions, renders the use of small-scale LNG for general gasification of households and small industries rather unlikely.

LPG prices continue to be regulated by KREMiZK, and in recent years have been consistently lower than other forms of fuel, including natural gas (see Figure 5.19). As a result, the number of vehicles running on LPGs or a mix of gasoline and LPG has been growing. In such a price environment LNG in transport and residential use will likely continue facing considerable competition from LPG.

There are a number of practical issues that need to be taken into consideration with use of LNG in transportation and in liquid form. First, LNG has a shelf-life. While holding tanks at refilling stations can maintain cryogenic temperatures necessary to store LNG indefinitely, trucks can only hold the LNG for five to seven days before complete boil-off occurs. Thus, once delivered, LNG must be used immediately. Second, vehicle storage tanks for LNG are significantly heavier than those for diesel, which puts additional stress on paved roads. The Transportation Committee under the Ministry for Investments and Development would need to improve the quality of road-building materials such as concrete and asphalt, and upgrade roads

[45] This cost does not include transportation of LNG to a different consumption point; delivery to a customer ex-plant is assumed.

so they are capable of handling heavier vehicles on a regular basis. Meanwhile, LNG trucking companies and fueling station operators must carefully organize delivery systems in order to prevent boil-off without jeopardizing a breakdown in supply.
Some measures can be taken to encourage LNG use. For example, after regasification, does the gas entering the gas pipeline become subject to the pricing policies of KTG, or should it be treated differently because of the extra costs involved? In an area where LNG can compete, in heavy trucking, for example, vehicle CO_2 emissions are not part of the carbon quotas and general emissions trading scheme, but existing enterprises with large fleets can be further incentivized to switch to LNG by giving them the opportunity to earn carbon credits that can be traded.[46]

5.3.3 CoalBed Methane

Global experience has shown that successful, commercial CBM development is relatively expensive, involves long lead times, and requires a variety of economic, structural, and geological preconditions. The economics of CBM recovery are influenced by depth, permeability, seam thickness, as well as water disposal/processing costs, proximity to gas processing facilities and pipelines, and favorable gas prices.
In China, which is estimated to contain over 59 trillion cubic meters (Tcm) in reserves, coal mine methane (CMM) recovery began in the early 1990s primarily to enhance coal mine safety and to diversify energy supply. Gas production from CBM only began in the mid-2000s. By 2015, total CBM commercial production was 8.2 Bcm (of which 4.4 Bcm was above-ground CBM), far below the government targets of 16 Bcm above-ground CBM at 100% utilization rate and 14 Bcm CMM at 60% utilization rate.
In the US, the Windfall Profit Act of 1980 created the fiscal terms for unconventional resources, including generous tax concessions, which allowed for the development of CBM in the Powder River Basin. Similarly, in China, companies engaged in domestic CBM production are exempt from paying a resource tax on above-ground extraction, and receive a subsidy of 0.3 renminbi (RMB) per cubic meter (cm) (or $1.20/MMBtu) during the 13th Five Year plan period (2016–20). In coal-rich Shaanxi province, the regional government granted an additional 1 RMB per cubic meter ($3.99/MMBtu) subsidy to CBM producers to spur development.
Despite such tax concessions, high costs and limited pipeline access have largely curtailed the growth of CBM production. In China, for example, IHS Markit estimates that CBM production costs are still among the highest for gas supply in China: in 2016 CBM costs were ranging between $10 and $15/MMBtu ($0.35–0.52/cm), much higher than the regulated citygate in Shaanxi and Inner Mongolia at $5.35/MMBtu ($0.18/cm), and Shanxi at $7.62/MMBtu ($0.26/cm). Although wholesale prices of unconventional gas are not regulated, the citygate gas prices still serve as an important benchmark, especially now that the domestic gas market is largely oversupplied.
In Kazakhstan, the economics of CBM recovery have been challenging thus far, but the government has exercised considerable due diligence in exploring the long-term feasibility of utilizing this potentially abundant resource. An Instruction from the President of Kazakhstan in January 2010 paved the way for state support of CBM production and initiated related legal and administrative changes. In 2013 Samruk-Kazyna assigned KTG the task of leading the development of CBM resources, and in March 2014 the government approved a roadmap plan for implementation of the President's instruction.
Several legislative changes were enacted, aimed at promoting CBM production. Amendments to the Entrepreneurial Code in April 2016 implied that investment projects related to CBM production would be eligible to receive investment preferences from the state (although the government has yet to include CBM production in the list of prioritized activities that receive such preferences). The Subsoil Law was amended to include the definition of coal bed methane. In September 2016 Ministry of Energy of RK approved a plan for the organization of CBM exploration and production. To promote research supporting CBM production, Karaganda State Technical University opened a dedicated research laboratory in November 2016 with financing from Kazakhstan's National Fund.
Much of the recent interest in the development of CBM has been tied to plans for the gasification of Astana. At the time of the publication of The National Energy Report 2015 a number of options (in addition to the suspended Kartaly-Astana natural gas pipeline project) for the gasification of the Astana region were being studied. A major focus of attention at that time was on the CBM resource associated with coal deposits in nearby Karaganda Oblast. In April 2015, KTG and the Saryarka Social-Entrepreneurial Corporation (SEC Saryarka) launched a feasibility study to determine the potential for CBM production in the Karaganda Basin to supply the gas needs of that region as well as that of Astana. The goal was to determine whether CBM resources in suitable proximity to potential consumers were of sufficiently high methane content for LNG production or other applications. One variant of the concept envisioned the construction of a local liquefaction plant that would convert CBM into LNG for transportation by either rail or truck to Astana and other cities in the region.
Exploration activity at the Sherubay-Nurinsky block, the license for which belongs to SEC Saryarka, involved KTG drilling five experimental production wells (where hydrofracking was carried out), and three exploration wells during 2015 and 2016; three more wells are planned to be drilled in 2017. The analysis of core samples suggested methane content of 10–12 cubic meters per ton of coal. Baker Hughes in association with Kazakh Institute of Oil and Gas is undertaking a feasibility study of the project's full-scale development. If the study is deemed successful, KTG plans to implement the project with China's Xinjiang Guanghui Petroleum Company.
The Taldykuduk-Gas Joint Venture between SEC Saryarka and Gas Production Company carried out further exploration at Taldykuduk acreage, drilling two exploration wells in 2015 and two experimental production wells 2016.[47] In February 2017 SEC Saryarka also announced tenders seeking investors to participate in exploration of two allotments—Tenteksky and Karazharo-Shakhanskiy—the licenses for which the Corporation received in April 2014 and December 2015, respectively. To finance exploration activities, SEC Saryarka applied for 5.8 billion tenge ($18 million) of state budget financing.
Not surprisingly, piped gas remains the most likely source of supply for Astana rather than CBM. In March 2017, Minister of Energy Kanat Bozumbayev announced that KTG had completed a feasibility study for the construction of a natural gas pipeline (an extension from the BBS pipeline) to supply Astana. However, because the pipeline extension will also supply the industrial centers of Zhezkazgan and Karaganda before reaching Astana (and then Kokshetau), it appears to have significant implications for plans to develop long-term CBM supply in the region. Rather than being a primary source of power for industry and the municipal-domestic sector in the capital region, CBM, because of its lower heating value than natural gas, and higher costs appears destined for more limited applications. These include use as a fuel in small boilers and in small-scale electrical generation at the sites of coal production (e.g., much in the same way as associated gas is used as a power source in oil production), with the added benefit of reducing the explosion risk in underground mines.[48]
This reassessment, involving a more limited role for CBM, appears to reflect the recognition that CBM recovery is technologically difficult. Large-scale CBM recovery (as in the pilot projects discussed above) would probably require bringing in an experienced foreign partner, along with its technology and workforce.
CBM recovery is also a relatively dirty process, as the dewatering of coal seams to reduce pressure for gas extraction generates significant volumes of saline water that must be processed or otherwise disposed. The dewatering of non-saline aquifers could affect freshwater resources. Given that water scarcity is already an impending issue and given Kazakhstan's efficiency objectives with respect to water usage specified in the policy, "On the Transition to a Green Economy," CBM development in Karaganda would likely be counter-productive to Kazakhstan's sustainable development goals.
Even with limited data on the permeability of coal basins in Karaganda, the challenges of water treatment, high development costs, and limited pipeline access combine to make CBM recovery in Karaganda a costly, protracted, and perhaps environmentally unsustainable endeavor. While CBM is now included in Kazakhstan's Subsoil Code, Kazakhstan still lacks proper regulation with respect to taxes for unconventional resources and water disposal procedures for such operations. A simpler solution to gasification of the region would be structural reform of the natural gas sector through increasing end-consumer gas prices and reforming the Subsoil and Tax codes in a manner consistent with the recommendations presented in this report.

5.4. REGULATION OF KAZAKHSTAN'S GAS SECTOR

5.4.1. Review of Kazakhstan's relevant legislation and national and international goals and targets in the gas sector

The key goals for the gas industry as outlined in the various gas industry development concepts (reviewed below) include:

- Expanding the resource base for natural gas production
- Modernization and expansion of gas processing capacities; full use of all components of natural gas and associated gas
- Increasing the output of pipeline-quality dry gas and also gas as feedstock into petrochemicals
- Development of gas transportation infrastructure: pipelines, compressor stations, new ways of transporting gas (LNG), as well as technologies for using gas as a transportation fuel
- Gasification of the capital Astana and general increased gasification of the country[49]
- Increasing the investment attractiveness of the gas industry
- Increasing domestic demand for natural gas, including new categories of consumers
- Resource savings through reducing losses in all sectors of the gas industry

[46] See "National plan on quota distribution on GHG emissions 2016-2020" and additional changes introduced on 7 May 2012, No. 586 "Confirming the plan of distribution of quotas for GHG emissions."

[47] In early March 2017, Saryarka announced that preliminary exploration at Sherubay-Nurinsky and Taldykuduk provided the basis for an inferred methane resource estimate of about 150 Bcm in the Karaganda coal basin.

[48] For details, see The National Energy Report 2015, section 8.7.

[49] Initially the West-North-Center gas trunk pipeline was viewed as the potential answer to this goal; however, currently the SaryArka pipeline to Astana via Kyzylorda Oblast is considered the leading option.

• Increasing international gas transit volumes through the gas trunkline system
• Achieving gas energy independence and meeting the needs of the domestic market
At the same time, the key challenges for gas development are also identified:
• A large share of gas reserves is gas associated with liquids production
• Low prices producers receive for their gas often makes processing of associated gas uneconomical
• Limited gas infrastructure in key regions of the country
Other challenges include:
• Some categories of consumers pay higher prices for gas than others
• Possible loss of competitiveness for industries that shift to gas in place of abundant, low-cost coal
• Long distances gas must travel from the gas producing regions of the country
• High costs for new gas transportation infrastructure

The development of the gas industry is guided by the following legislation and major program documents:

The Law on Gas and Gas Supply (January 2012) regulates relations in the area of gas supply and puts Kazakhstan's gas production at the disposal of a single national operator, empowering KTG to develop the domestic market and necessary pipeline infrastructure. KTG operates most of the gas infrastructure in the country and has preferential rights under the legislation to purchase associated gas from producers. KTG also sells gas on the local market and exports gas abroad. Government policy also appears to be aimed at having the state-owned entity capture any upside from higher domestic end-user prices and export prices, while maintaining a single channel for exports so as to balance the near-monopoly conditions in two neighboring gas-purchasing countries, Russia and China. The law will need to be amended after KTG is dissolved as a management company.

The General Plan for Gas Infrastructure Development in the Republic of Kazakhstan in 2015–2030 (adopted in late 2014) codifies Kazakhstan's long-held plans to increase domestic gas consumption. This program calls for the extension of piped gas supply to 13 oblasts from the current 10 by 2030. It projects that domestic deliveries will rise to 18 Bcm by 2030 under its "realistic" scenario. The objective of the program is to create conditions for phased development of the gas transportation system and to increase domestic gas demand as an environmentally clean fuel, mainly using domestic natural gas resources.

The 2010 Subsoil and Subsoil Use Law regulates the usage rights of natural resources and is the primary tool for influencing the expansion of the resource base for natural gas production. This Law also provides specifications related to utilization of associated gas. It is advisable to ensure that no provisions in the forthcoming Subsoil Code impede exploration and development of gas fields by providing an acceptable return to investors for undertaking risk while underpinning their ability to market any produced gas.

Strategic plans formulated by the Ministry of Energy offer more frequent (usually annual) updates on the direction of the energy and fuel complex as a whole and the gas industry in particular. These plans adjust the general direction set in the General Plan for Gas Infrastructure Development, identifying short-term goals and targets for the country. The latest Strategic Plan was issued in 2016 with an outlook to 2021. Its specific goals include targets for residential gasification, associated gas utilization, gross and commercial gas production, and labor productivity.

Other important legislation that governs development and regulation of Kazakhstan's gas industry includes the following:
• The Plan on Activities on Gas Production from CBM (2016) provides an action plan for developing CBM in the Karaganda region
• The Law on Natural Monopolies and Regulated Markets (1998) defines the legal basis for state regulation of natural monopolies (i.e., network industries such as gas and power, railroads, etc.)
• The Law On Energy Saving and Energy Efficiency Improvement (January 2012) sets the strategic direction of state policy related to energy efficiency, spells out the authority of various state entities, and identifies requirements for achieving efficiency improvements

Legislation on Kazakhstan's gas industry clearly states that a balance needs to be found between the interests of consumers and producers. But in order to stimulate wider use of natural gas in the economy, a number of changes to current legislation need to occur:
• The most important change involves gas prices. To have more dry gas available to domestic consumers, prices for producers need to be higher. But there also needs to be a market for the gas at these higher prices. If consumers are unable to pay higher prices and the government wants to encourage higher gas consumption, then some type of support policies (subsidies) will have to be developed. Higher gas prices also can help encourage energy efficiency and energy savings in the economy.
• Coal's current low cost of production and delivery offers very stiff competition to higher cost gas. Given that the coal industry is also extremely important to the economy, making drastic changes that would hurt the coal industry and at the same time dramatically raise coal prices could damage the broader economy. But introduction of a carbon price could improve the competitiveness of gas versus coal.
• Another issue is effectively disposing of small volumes of stranded gas in remote fields where oil is the main product. Higher prices would make recovery of such gas more attractive. But regulation also can play a role: if strict flaring or utilization requirements are enforced, these small producers might effectively shut in their production completely. The goal rather should be to devise policy in such a way that it incentivizes conservation/use of associated gas (for example through higher domestic gas prices) rather than simply punishes the lack of an effective outlet.
• Use of natural gas (LNG in heavy-duty trucking) and LPGs in transportation through an infrastructure build-out is another avenue for increased gas utilization. While LNG seems most appropriate in heavy-duty trucking, LPG is suitable for fleets of light- and medium-duty vehicles. The domestic LPG market, including pricing, needs to be liberalized. The General Plan for Gas Infrastructure Development calls for development of the gas motor fuel market in Kazakhstan. It is recommended that this initiative receives appropriate supporting legislation (e.g., differential excise taxation between refined products and natural gas used as motor fuels, alternative fuel vehicle tax credit).

5.4.2. Flaring of associated gas: a case for regulatory reform

Flaring—the burning of natural gas in an open flame at production sites—has long been part of the process of hydrocarbon extraction in the global petroleum industry. Thousands of gas flares at oil production sites worldwide burned about 149 Bcm of natural gas in 2016.[50] In some instances flaring is an important safety measure during drilling operations and at natural gas facilities; flaring safely disposes of gas during equipment failures, power outages, and other emergencies or disruptions in drilling or processing operations when the gas might otherwise pose hazards to workers or nearby residents. However, the continual (routine) flaring of natural gas deemed to be unmarketable because of lack of gathering infrastructure, distance from pipelines and markets, low prices, or other factors, wastes a potentially valuable resource and produces GHG and other emissions that can negatively affect human health and the environment.[51]

Producers in Kazakhstan have been adjusting to changes in gas flaring legislation since 2005, when Kazakhstan prohibited gas flaring for all subsoil contracts signed after 1 December 2004. Since then, regional and local agencies have increased monitoring and fines for gas flaring. The Subsoil Law passed in 2010 goes one step further by prohibiting commercial development of a field without a plan for utilization and processing of the gas that is produced; the law defines utilization as including reinjection. The amount of flaring has been reduced dramatically in Kazakhstan since the legislation was introduced. On a country level, Kazakhstan's performance is quite good; data collected by Kazakhstan's Oil and Gas Information-Analytical Center indicate that in 2016 only 2.2% of Kazakhstan's overall associated gas extraction (or just over 1 Bcm of 46 Bcm of total gas produced) was flared. This places it squarely within the group of countries exercising world "best practice" according to this indicator.[52]

Nonetheless, the problem of associated petroleum gas (APG) processing and utilization in Kazakhstan remains a concern. Although some APG is consumed as "own use" in the upstream projects themselves (reinjection to maintain reservoir pressure, heat and electricity generation, etc.), the limited market and low prices for commercial gasalso results in some gas being flared. Another contributor is that remote small oil fields are far from gathering systems and trunk pipelines and the volumes produced are too small to warrant the construction of lengthy pipeline connections.

Here it is useful to selectively review the international experience in regulation of gas flaring, with an initial focus on the United States and Russia. The US, like Kazakhstan, is confronted with the question of how to effectively dispose of a growing volume of APG accompanying its resurgent (unconventional) oil production.

US Bakken Formation

A good US case study is the Bakken Formation (pri-

[50] This is the estimate of the World Bank using the US National Oceanic and Atmospheric Administration's (NOAA) infrared satellite technology to measure gas flares as part of the GGFR program. According to these estimates (which often vary considerably from national statistical reporting), the largest flarer remains Russia at 24.1 Bcm in 2016, followed by Iraq at 17.7 Bcm and Iran at 16.4 Bcm. Kazakhstan ranks 14th in the world in these estimates, flaring 2.7 Bcm in 2016 (versus 1.0 Bcm in national statistics), a significant decline from 3.9 Bcm in 2014.

[51] Complete combustion of pure natural gas (methane or CH_4) produces only CO_2 and water. However, combustion in flares and incinerators is seldom 100% complete. Unprocessed natural gas usually contains a mixture of hydrocarbons and other substances, which can form a variety of chemical compounds during combustion. These include the greenhouse gases carbon monoxide (CO) and nitrous oxide (N_2O). Flaring is nonetheless preferable from an environmental standpoint to venting (release of unprocessed gas into the air without combustion), because venting releases components such as propane and butane, which are flammable and thus an explosion hazard, as well as methane, which is a much more potent greenhouse gas than CO_2.

[52] At the enterprise level, performance varied widely, ranging from 2% and below at two of the three "mega" projects (Tengiz and Karachagank) to over 50% at several small producers

marily in western North Dakota), which registered rapid growth in oil and associated gas output between 2008 and 2014 as a result of the adoption of unconventional recovery methods. From less than 200,000 b/d (9.9 MMt) of crude oil production in 2008, output reached over 1.2 MMb/d in 2014–15 (59.7 MMt), before declining slightly to about 1.0 MMb/d (49.8 MMt) currently. Accompanying the oil output growth was a steady rise in associated gas production, from around 100 million cubic feet/day (1.0 Bcm/y) in 2008 to 1.78 billion cubic feet/day (18.4 Bcm/y) in May 2017. Although this is not a large volume compared to many other gas-producing areas, it was initially accompanied by an outsized level of flaring typical of a new pioneering play, where infrastructure development lags well behind.[53]

As in Kazakhstan, there are regulations that restrict flaring by commercial oil producers in the Bakken. Flares in the oil industry are typically used for a short period while drilling and completing a well. During the early stages of production, gas volumes are usually not of sufficient quantity or quality to market, and state regulations tend to reflect this reality.[54] Flaring regulations in more mature producing areas such as Texas and Wyoming allow operators to flare for 10 and 15 days, respectively, before requiring permits (although average actual periods of flaring allowed were somewhat longer—up to 60 days in Texas, and six months in Wyoming). In North Dakota, a state not traditionally associated with oil production until the unconventional revolution, the North Dakota Industrial Commission (NDIC, the state's oil and gas regulator) has developed more flexible flaring-related regulations, reflecting the difficulty most operators have in connecting gas streams to gathering lines in the Bakken.

North Dakota oil and gas regulations require that tax and royalties be paid for all natural gas flaring beyond a well's first year of production. During the first year of production, gas production is limited by field rules, which restrict the amount of oil produced until the well is connected to a gas gathering system.[55] Once a well's first year of production ends, operators are required to cap the well, or connect it to a natural gas gathering line, or equip the well with an electrical generator that consumes at least 75% of the gas from the well, or find another approved approach that reduces flaring. However, these regulations have been flexibly enforced, allowing unconventional short-cycle shale oil production in the Bakken to ramp-up much more rapidly than associated gas capacity could be installed.[56]

For several years the existing infrastructure for the collection, processing, and transportation of gas was inadequate, with the volume of gas flared in North Dakota between 2008 and 2012 increasing by over 200%, to 228 million cubic feet per day (2.4 Bcm/y)—representing an economic loss of $560 million and a level of GHG emissions (7–9 MMt of CO_2 equivalent) equivalent to that of a large coal-fired power plant. Levels of flaring from the field have been quite high in relative terms as well (32% of all produced gas in 2012 and 36% as recently as January 2014).[57]

This reflects, first, the greater technological requirements/complexity of gas processing vis-à-vis oil extraction, which means that "first oil" typically can be produced long before processing of the gas associated with it. Oil infrastructure typically consists of production separators, storage, and loading and off loading facilities, whereas associated gas requires dehydration and treatment to remove contaminants, compression, and processing to produce pipeline-quality natural gas for the end-use market. "Dry" or residue gas (methane) following processing is delivered to end users almost exclusively via pipeline. Natural gas liquids (NGLs—such as ethane, propane, butane, and natural gasoline), separated from the dry gas during processing, require additional recovery as well as dedicated storage and transport capacity to reach markets.

Finally, the timing of incremental gas supplies from the Bakken was unfortunate in the sense that it coincided with a period of very low gas prices. Although the average annual Henry Hub gas price between 2001 and 2007 was $5.91 per MMBtu, with a low of $3.34 in 2002 and a high of $8.80 in 2005, since 2007 the market became oversupplied with natural gas and fell to $2.75 in 2012. Prices have improved only marginally since.

Confronted with this initial gap between associated gas production and the requisite gathering/processing/transport infrastructure, the North Dakota Industrial Commission instituted a phased flaring reduction regime, which sought to gradually reduce the share of total output flared while allowing oil and gas operators and independent mid-stream companies to make incremental investment decisions about gas gathering. An operator can consider whether to recover and market associated gas "on the fly," after the decision to drill has already been made, based on the expected rate of return for oil recovery alone. If the cost to build a gathering pipe for gas is uneconomic in its own right, meaning that the cost exceeds the revenue stream plus an acceptable rate of return from the sale of gas, an operator can often claim "economic infeasibility" and continue to flare associated gas—and in some cases even avoid paying taxes on its value. The Commission first established targets for the percentage of natural gas to be flared in April 2014: flaring was to be limited to 22% of total extraction through January 2016, and then 15% through 2021. However, these targets were revised in September 2015 by extending the compliance targets, allowing 22% to be flared through Q1-2016, 20% in Q2 and Q3 2016, 15% for November 2016 through October 2018, 12% for November 2018 through October 2020, and ultimately to 9% beginning in November 2020.

This flexible and extended compliance regime was administered with the Commission's knowledge of the state of construction of gas processing and transportation infrastructure underway in the state. On 1 July 2013, new legislation in the form of North Dakota House Bill 1134 (HB 1134), went into effect, which relies on incentives rather than a punitive approach to the reduction of flaring. HB 1134, rather than focusing on flaring restrictions that force the economics of flaring to be tied to oil production (as other states have done), provides tax incentives for building gas-gathering and processing infrastructure and for systems that utilize gas at the wellhead. Although it will take time for such incentives to be fully realized in investments by upstream and midstream companies, a critical mass now appears to have been achieved. The US Energy Information Administration (EIA) reported that, by the beginning of 2014, the rate of growth in natural gas processing infrastructure had caught up with overall natural gas production growth in the Bakken, and in the following year gas processing capacity had reached parity with total gross gas extraction. As a result, levels of flaring have now begun to fall rapidly—to 21% in 2015 and to 10% by March 2016—well ahead of schedule to meet the revised regulatory targets.

Whether further progress in flaring reduction can match the recent pace is questionable, however, as the spot price of gas is now so low in the US that the incentives for further monetization of gas from Bakken and other fields is greatly reduced. Henry Hub natural gas spot prices reported by EIA for 17 May 2017 were $3.16 per MMBtu, and were $3.19 on the New York Mercantile Exchange (NYMEX). This suggests that maximization of gas use in field operations, such as electrification and heat generation, may be a wiser approach near term in the Bakken than commercial sales to outside markets.

Russia

Russia too is seeking to curtail flaring of associated petroleum gas (APG). During 2000–13, gross APG extraction in Russia (including flared volumes) more than doubled, from 35.6 Bcm to 74.6 Bcm. This growth occurred on the back of a 62% increase in Russia's oil output during the same period: from 323.6 MMt to 523.3 MMt. Flaring stubbornly remained a major problem, accounting for up to 25% of gross APG extraction throughout that period, mainly because of the continued shift in Russian oil production to new fields in pioneering regions such as East Siberia and the Krasnoyarsk-Yamal cluster, far from existing gas infrastructure and where associated gas-to-oil ratios (GORs) are particularly high. According to the US National Oceanic and Atmospheric Administration and the Global Gas Flaring Reduction initiative (see note 50 above), Russia has led the world in the absolute volume of natural gas flared(over 20 Bcm/y)for the past several years.

Russian policymakers, in recognition of the economic losses from the wasted resource (estimated at $13 billion annually as early as 2007) and the dangers of greenhouse gas emissions for the environment, introduced tough new measures in 2009 aimed at quickly increasing utilization rates for all companies to 95% by 2012.[58] As in North Dakota, a combination of "sticks" and "carrots" are part of the regulatory effort to reduce flaring. Among the punitive measures are heavy penalties for above-limit flaring and lack of metering equipment. These are augmented by recently enacted incentives that include elevating oil companies' associated gas production to the top of the domestic sales merit order, as well as according the derived dry gas priority access to the pipeline network. The effort to reduce flaring also has been assisted by the reduced pace at which new oil projects are launched in eastern and northern frontier provinces in Russia (where recovery and processing infrastructure are lacking) in the recent low oil price environment, giving the industry a chance to catch up and match its oil productive capacities with the necessary gathering and processing infrastructure for APG utilization.

A case in point is the realization of a utilization program at the Vankor oil field in Krasnoyarsk Kray by Rosneft, which until recently was the largest single source of APG flaring in Russia. Beginning in April 2014, gas volumes at Vankor (above the amount

[53] According to World Bank estimates, the US was the sixth largest gas flarer in the world in 2016, flaring a total of 8.9 Bcm in 2016, significantly less than the 11.8 Bcm flared in 2015.

[54] In the US, the individual states largely regulate oil and gas production not occurring on federal or tribal lands.

[55] Wells are typically allowed to produce at maximum efficiency rate for the first 60 days, which averages around 360 b/d for a Bakken oil well. After this time, field rules restrict production to 200 b/d for the next 60 days, 150 b/d for an additional 60 days, and then 100 b/d until connected to a gas-gathering system. The NDIC may grant "field rule" exemptions (for six to nine months duration) to these production limits if marketing the gas is uneconomic.

[56] After the end of the one-year period, operators not already able to extend the period of flaring through field rule exemptions can file for an economic infeasibility tax exemption with the NDIC, which releases them from making tax or royalty payments on the value of the flared gas when the gas is uneconomic to market.

[57] Flaring from the Bakken was believed to have amounted to over half the US total flared volume (11.3 Bcm) in 2014. The Bakken experience in some ways is reminiscent of the USSR's pell-mell rush to bring on West Siberian oil. There was a lag of nearly a decade between the initial development of the major West Siberian oil fields and the launch of the first gas processing plant in 1975 to utilize the associated gas. Even by 1980, only half of the associated gas being extracted in West Siberia was being utilized (see John C. Webb, Sergej Mahnovski, and Matthew J. Sagers, Russian Oil Companies Widen Efforts to Extract Value from Growing Natural Gas Stream, IHS/Russian and Caspian Energy, Private Report, 2007, p. 15).

[58] IHS Markit forecasts that Russia will attain this target by 2019; see Vitaly Yermakov, Is a Solution to Russia's Petroleum Gas Flaring within Reach? IHS Markit Insight, 6 February 2015.

that can be economically used for on-site power generation and reinjection) were delivered to Gazprom's trunk pipeline network through a pipeline that connects to a LUKOIL gas field, Nakhodkinskoye, which is, in turn, linked to the main gas pipeline network at Yamburg. Rosneft struck a 30-year deal with LUKOIL that calls for Rosneft to deliver a total of 94 Bcm of (dry stripped) gas from Vankor to the Unified Gas System (UGS) entry point at Yamburg.

This single project is primarily responsible for the spectacular increase in APG utilization in 2014 for Russia as a whole (to 87% in November 2014 from an annual rate of 79% in 2013). New projects slated for completion in 2015–16 are set to bring the APG utilization level even closer to the established target.[59]

In terms of its flaring intensity (cubic meters of gas flared per barrel of oil produced), Russia is on a par with Kazakhstan and among the better performing countries in the world.

Global Gas Flaring Reduction: Public-Private Partnership

Turning to the global experience more broadly, international efforts to address the problem of flaring have been coordinated under the framework of the GGFR Public-Private Partnership, established at the World Summit on Sustainable Development held in Johannesburg in August 2002. The World Bank plays a major role in the GGFR, and has introduced a "Zero Routine Flaring by 2030" initiative that coordinates the efforts of interested governments, oil companies, and development institutions worldwide to eliminate routine flaring at existing oilfields by 2030. Governments and companies that endorse the initiative will publicly report their flaring and progress toward flaring reduction on an annual basis. Eighteen countries/regions (including Kazakhstan, the United States, and Russia's major Khanty-Mansiysk oil-producing region) and 13 major oil companies currently are involved in the Partnership.

Two of the major thrusts of GGFR activity have involved the global satellite-based monitoring of flaring and research on technologies for associated gas utilization. We focus on the latter here to identify practices that might be worthy of regulatory incentives.

An early GGFR study,[60] based on case studies in Chad and Ecuador, examined the feasibility of four options for using associated gas that otherwise might be flared: (1) power production at the oil field for transmission to the existing power grid (medium-scale); (2) power production at the oil field for electrification of a non-electrified rural area (small-scale); (3) supply of piped gas to larger consumers, such as heat and power plants and industries (medium-scale);[61] and (4) liquefied petroleum gas production (LPG), alone or in combination with other means of use (small-scale). Note that one option not considered—electricity generation for own use by producers in the field—is de facto already a viable economic option, albeit a limited one. But own use typically would be able to consume only about a third of the electric power that a field's APG output could generate.

The study concluded, in general, that power supply from generators established at the oil field and gas supply via pipeline to a load center for fuel substitution in power production and local industries were both feasible end-use options (not requiring subsidies), provided that:

- Markets are nearby (for a medium-sized oil field it would be feasible to move the gas or power as far as ~500 km to reach a market); for smaller fields delivery distances could shrink to ~50 km, depending on other parameters
- Gas volumes are sufficiently large (model calculations indicate that gas utilization from oil fields with gas yields over 2,500–5,000 m^3 per day could be viable) and the cost of the fuel substituted is high (e.g., imported diesel oil transported over a considerable distance)
- Prices are not distorted by domestic fuel subsidies.

The analysis also indicated that there was little economic difference between (a) transporting gas in pipelines to an industrial gas customer or an existing power plant and (b) power generation at the site and then transmission of power, by way of power lines to the load center.

PFC Energy conducted a similar study for GGFR and the World Bank on the economics of various options for associated gas utilization in Russia shortly thereafter, which tends to echo the findings of the GGFR study.[62] It concluded:

- For small fields flaring 0.1 Bcm/y or less, distributed (local) power generation is the most economic option (for other options at small fields, see the text box "New Gas Utilization Technologies for Small Producers")
- For medium-sized fields flaring 0.1–0.5 Bcm/y, the most economic option is gas processing and subsequent export of dry gas via the Gazprom pipeline system, provided inlet gas prices (at the processing plant) are at least \$35/Mcm.
- The most economic option for large fields flaring more than 0.5 Bcm/y is power generation using a combined-cycle gas turbine and sale of electric power to the grid.

New gas utilization technologies for small producers

One of the major challenges to increasing natural gas utilization (and reducing flaring) near sites of production is one of scale, or rather the cost of infrastructure in fields where output may be relatively small and derived from a number of widely scattered wells. In the Bakken, for example, the economics of gathering and moving associated gas from the field to a central collection point and then to a gas processing plant depends on the distance (and costs) versus the revenue stream created from the gas stream after dehydration, treatment, and processing. The Bakken's high geographic spread and low gas deliverability per square mile leads to higher pipeline mileage costs and correspondingly a much higher unit cost of gas gathering. Several cases in the Bakken demonstrate that it is difficult to economically justify gas gathering or electric generating infrastructure to utilize associated gas from widely scattered, small-volume producing wells. This technological challenge is now starting to be addressed in North America through small modular units that produce either electric power (microturbines) or liquid fuels ("mini" GTL) from the gas.

In Alberta province (western Canada), for instance, microturbines—which have few moving parts, low maintenance requirements, and can burn low-quality gases including some sour gas—came on the market in the late 1990s. The electricity they produce is used to provide power for industry operations (such as pumping, compression, or gas processing) or sold to the regional grid. In co-generation applications, the microturbines also produce steam for industry operations or nearby activities such as drying grain or heating greenhouses. One method used to support adoption in Alberta was the waiver (introduced in 1999) of royalties on natural gas used for electricity or steam generation if the gas would otherwise have been flared.

Another new direction is the production of synthetic crude or refined petroleum products from associated gas, such as ultra-clean diesel fuel, using gas-to-liquids (GTL) technology, or the manufacture of methanol. For a long time, GTL technology has been utilized in a number of large-scale plants globally (e.g., Shell Pearl, Sasol). This technology, based on the Fischer-Tropsch process, is associated with high capital expenditures per ton of finished product and relatively large feedstock requirements for gas. However, in recent years new technologies are emerging for small-scale "mini" GTL—modular units that use small amounts of gas (e.g., as little as 5 MMcm per year) and a wide range of gas compositions. These plants also reduce the marketing problem for product since it is possible to deliver an end product, such as diesel fuel, directly to consumers by truck. Depending upon feedstock characteristics and the particular catalysts that are used, in addition to diesel fuel, the mini-GTL technology can also yield various by products such as paraffins, heavy petroleum fractions, etc.

Previous research by the Kazakh Institute of Oil and Gas (KING) shows (based on the Kumkol group of fields in Kyzylorda Oblast that were analyzed) that given then-current capital and operating costs, an acceptable payback period (three to four years) could be achieved, mainly due to low APG acquisition costs at the field.[63] However, a danger would be pressures to maintain low acquisition prices for APG to preserve the economics of mini-GTL once an investment had taken place, which could actually backfire by failing to incentivize long-term recovery of APG.

Microturbines (scalable from 30 KW to 30 MW capacity) and "mini" GTL are among the rapidly burgeoning technologies for utilization of field APG detailed in a 2017 GGFR report that provides a listing of "state-of-the-art" commercial products for reducing gas flaring at fields producing small volumes of associated gas, which would not be sufficient to warrant installation of large-scale gas processing infrastructure.[64] In addition to microturbines and mini-GTL, the specific products listed include: (1) scalable and modular flare recovery and gas processing units (integrating dehydration, compression, cooling, and conditioning operations) providing feedstock for syngas, LNG, and NGL production; (2) fuel preparations skids for making flare gas usable in turbines or engines; and (3) small-scale CNG and LNG technologies used to compress or liquefy associated gas to increase its energy density, thereby allowing transport of the gas by truck to power plants and industrial and domestic gas users where a pipeline may be uneconomic or not yet constructed, or for use as a fuel for motor vehicles.[65]

[59] The key uses of APG in Russia in 2013 included: (1) supplies to gas processing plants, to produce dry, network-quality gas for injection into Gazprom's national pipeline system (Unified Gas System [UGS]) (46%); (2) flaring (21%); (3) supplies to booster compressor stations (this is also necessary for using APG for reinjection, which is itself another method of gas utilization, or for moving gas further downstream since APG is generally low-pressure gas) (17%); (4) own use at production sites for power and heat generation (6%); (5) use by local consumers, including power plants and utilities (6%); and (6) direct deliveries to UGS trunk gas pipelines (4%).

[60] GGFR/World Bank Group, Flared Gas Utilization Strategy: Opportunities for Small-Scale Uses of Gas, Washington, DC: IBRD/World Bank, Report No. 5, May 2004.

[61] The report noted that this solution was deemed most suitable for cold climates "such as in Siberia, Kazakhstan, and Northern China, where the associated gas might substitute oil in district heating plants."

[62] PFC Energy, Using Russia's Associated Gas, 10 December 2007, p. 39.

[63] See The National Energy Report 2015, p. 188–189.

[64] GGFR, GGFR Technology Overview: Utilization of Small-Scale Associated Gas, April 2017.

[65] Included in this category is General Electric's modular "CNG in a Box" technology that enables the rapid build-out of a network of CNG fueling stations.

Summary

We believe Kazakhstan's successful program for flaring reduction will benefit from these recent technological advances that make a wide range of potential gas utilization strategies available to even small producers. The ultimately (if belatedly) successful implementation of a flexible and phased flaring reduction program in the rapidly developing Bakken field in North America, as well as Russia's policy for combining incentives and sanctions to encourage flaring reductions, may also suggest strategies for fine-tuning of policy. As opposed to a largely punitive or sanctions-based policy for producers not meeting flaring targets, a somewhat more flexible approach may be worthy of consideration when dealing with smaller producers with limited capital or that operate small fields remote from gas infrastructure and markets. For these "hard-core flarers," some combination of penalties and incentives might be tested to turn them in the direction of reduced flaring. Measures that might be utilized as alternatives to (or in conjunction with) fines, taxes, and royalties might include, but not be limited, to exemptions for certain producers, requirements for improving the technical efficiency of flaring for such exempted producers, and a program of financial incentives to assist small producers incorporate new modular and scalable technologies for small-scale gas utilization into their operations (more specific recommendations are offered in the following section 5.4.3).

5.4.3 Recommendations on development goals and regulatory issues

• To better analyze Kazakhstan's gas balance and future needs, the country needs to modify its statistical reporting to provide production and consumption figures consistent with international norms and practices. This should include publishing on a regular basis a consistent historical series on gas production that excludes reinjected volumes, but includes all useful volumes, including those used for internal needs by the producers themselves. Data on exports should primarily reflect actual physical flows, not just customs reporting.

• Gasification of the domestic economy should continue to be pursued along the general lines currently being implemented, especially in areas served by existing trunk pipelines.

• In order to incentivize producers to supply gas to the domestic market, upstream procurement prices must be high enough to fully cover costs involved in producing, processing, and delivering natural gas to consumers. Higher end-user prices will motivate consumers to use natural gas more efficiently, and are in concert with the objective of harmonizing Kazakhstan's prices with those in Russia as part of the general movement toward the open economic space of the Eurasian Economic Union. Some form of state support for higher gas prices may be necessary over the near term, given competition in power generation from much cheaper domestic coal.

• Given the goal of creating a common gas market in the EAEU by 2025, and gas pricing developments in Russia (harmonization of prices), prices in western Kazakhstan should be set at a level approaching those in Russian gas-producing regions (e.g., Yamal-Nenets Okrug) rather than in that country's neighboring gas-consuming regions (Saratov Oblast); this will help ensure the competitiveness of Kazakhstan's gas in the common economic space.

• Because the transport sector is not included in Kazakhstan's emissions trading system, it is important that the government of Kazakhstan also addresses emissions in this sector through a variety of measures designed to support LNG and LPG demand in transportation, such as an alternative fuel vehicle (AFV) tax credit or differentiated excise taxes.[66] Similarly, by expanding the list of sectors eligible to receive funding from the Entrepreneurship Development Fund of Kazakhstan (Damu), an entity designed to support small businesses and entrepreneurs, private owners of conventional fueling stations could be eligible for subsidized loans that would allow them to convert conventional fueling stations into ones capable of handling LNG/CNG and even LPGs.

• Given that Kazakhstan presently absorbs only a limited amount of the LPG it produces (exporting roughly three-fourths) with export markets looking increasingly saturated, policymakers should explore additional options for increasing LPG consumption when economically feasible. In addition to further use in the transport sector, this might include extending LPG availability to residential/commercial consumers in areas where piped gas is unavailable, and developing a petrochemical industry that utilizes LPG as a feedstock.

• As opposed to a largely punitive or sanctions-based policy for producers exceeding targets for gas flaring, a more flexible approach should be considered when dealing with smaller producers with limited capital or that operate in small fields remote from gas infrastructure and markets. Exemptions from fines, taxes, and/or royalties on natural gas flaring should not be ruled out for certain producers, especially when there is no other economically viable solution for disposing of their relatively small gas volumes.

• When such flaring exemptions are granted, producers should be required to take measures to greatly improve the technical efficiency of flaring, such as enhancing burner tip design, monitoring the heating value of the flared gas to maintain a stable flare, and ensuring that liquid separation tanks (knockout drums) are emptied more frequently.

[66] In the state of Louisiana, in the US, for example, the state offers an income tax credit of 36% of the cost of converting a vehicle to operate on an alternative fuel. A taxpayer could also opt to receive a tax credit of 7.2% for the cost of a new motor vehicle, up to $1,500. In Utah, the state offers tax credits of $15,000-$25,000 (depending on the year) for purchasing a new vehicle that runs on natural gas, electricity, or hydrogen.

• Given the widespread commercial availability of new modular and scalable technologies for small-scale gas utilization, the government, through DAMU or a number of other agencies, could provide low-interest financing, insurance guarantees, or credit backing to small producers that are willing to incorporate such technologies into their operations. Such measures employed elsewhere include waivers of royalty payments on natural gas used for small-scale electricity generation (as in Alberta, Canada) or liquids production, tax incentives for building gas-gathering and processing infrastructure and for systems that utilize gas at the wellhead (North Dakota), or granting priority access of APG to the pipeline grid (Russia). Additional benefits could include eliminating duties on imported equipment used in this area. Where possible, the government should try to involve existing organizations in these initiatives, instead of setting up entirely new bodies.

• In the interests of operational safety, consider increasing the volume of permitted technically unavoidable gas flaring on steady-state operations from the current 0.5% to at least the international industry benchmark of 1–2%.

• The Ministry of Energy should re-activate a special Working Group to study the problem of APG use (by both large and small producers), with the goal of formulating more clearly targeted regulatory incentives and moving away from selective fines and tax penalties. The issue of disposal of associated gas continues to concern both domestic producers and outside investors, and requires further attention.

6. COAL

6. COAL

6.1. KEY POINTS

For Kazakhstan's coal industry, the story is not one of growth, but of managing a gradual decline.

• Production and consumption of coal in Kazakhstan in 2016 declined for the fourth straight year, reflecting weak domestic economic growth and limited prospects for expanding exports. Nonetheless, Kazakhstan remains a major world producer and coal is an essential component of the country's energy profile, accounting for 55% of its primary energy consumption in 2016 and covering 66% of electricity generation.

• The near-term global market environment is somewhat more favorable than in recent years, due largely to events in China, where efforts to curb domestic production led to a sudden increase in import demand in early 2016 and a jump in global coal prices. However, large uncertainties surround future global demand, preventing most producers from adding new capacity.

• Although apparent levels of coal consumption in Kazakhstan are expected to decline slowly from current levels, dropping to less than 70 MMt by 2040 (compared to over 80 MMt in 2014), power-sector coal demand as a share of total demand is expected to remain relatively steady at around 60% (in standard fuel units).

• A relatively new direction for coal-sector development is coal-bed methane (CBM) production, including coal bed degassing in preparation for coal mining. Small-scale CBM production in the Karaganda coal basin is one of the options being explored for supplying gas for selected industrial applications in the local region (mine and local boiler power generation); however, the question of more widespread use of CBM for gas supply further afield (i.e., to the city of Astana) appears unlikely. At the moment, a key action needed for the development of CBM production is to establish requirements for coal bed degassing (Subsoil Code) together with requirements on restricting (capping) methane emissions by subsoil users.

• The adoption of so-called "alternative" coal technologies such as coal-to-gas (CTG) and coal-to-liquids (CTL) are facing headwinds due to the new low price environment for competing fuels (oil and natural gas) and the greenhouse gas reduction commitments of the Paris climate accord. However, some in the industry now view the climate accord as an opportunity to put advanced coal technologies such to carbon capture and storage (CCS) on an equal policy footing as support for renewables and energy efficiency improvements (discussed in Chapter 9).

6.2. COAL SECTOR UPDATE

Kazakhstan now appears to have reached a crossroads in terms of its strategy for the country's coal industry going forward. As former Soviet Central Asia's largest coal producer, consumer, and exporter, the country's reserves and production capacity are robust and could support considerably higher levels of output than recorded in recent years. However, domestic consumption trends (strongly tied to electricity generation) turned slightly negative after 2012, a development reflecting weak economic growth following the decline in oil prices in mid-2014.[1] In addition, exports have been challenged by the unique physical characteristics of Kazakhstan's coal, the long overland distances involved in its transit to export markets, policies of neighboring countries (e.g., Russia, China) promoting energy independence or reduced dependence on imported coal, efforts to increase generation from less carbon intensive sources, as well as heightened uncertainty over global market conditions(see text box on global price environment dynamics in 2016–17). How best to utilize this abundant resource to the maximum advantage for Kazakhstan remains a difficult question.

Global Price Environment Dynamics in 2016–17

In early 2016, after a prolonged period of ample supply and muted demand growth, global thermal coal prices fell to a 12-year low.[2] Global supply had become calibrated to meager consumption growth in the developed countries in the aftermath of the Great Recession of 2008-09 and to the accelerated rollout there of alternative sources of electricity generation (e.g., renewables and natural gas). In the major developing-country export market of China, deceleration of economic growth and constraints on coal-fired generation in more densely settled eastern provinces of the country also had led to lackluster (and sometimes even negative, as in 2014) demand growth.

However, in Q1-2016 an unexpected surge in Indian demand, followed by a sudden increase in imports by China in Q2, led to a rapid price rebound in thermal coal prices, as the limited excess capacity globally was inadequate to respond to the immediate demand increase. The catalyst for the spike in Chinese prices (where the domestic price rose from RMB 370 per ton to nearly RMB 600 in Q3-2016 and the import delivered price to southern China rose from $46 to $75 per ton by early October) were government efforts to support the domestic coal price by curtailing domestic oversupply through cutbacks in the number of days domestic producers were allowed to operate (from 330 to ~270 days). As a consequence, Chinese imports of thermal coal in 2016 rose from 132 MMt in 2015 to 169 MMt in 2016. The restrictions on domestic production appeared to have overshot the mark, and by August 2016 production regulation was refocused on increasing domestic production in an effort to limit further price growth. By early October all of the previously imposed production restrictions had been lifted.

Various global benchmarks for steam coal followed the Chinese prices upward in 2016, some (e.g., Newcastle 6,000 kcal/kg NAR) more than doubling (from $53.37/t to $107.14/t) until analysts in November began to observe a reversal in the price trend (decreasing to $92.74/t in December) as a result of robust Q3 Chinese domestic production growth. The outlook for 2017 thus presents a number of uncertainties for major producers, including continuing global supply constraints (the reluctance of producers to add additional capacity in the face of uncertain demand growth) and the potential for wildly fluctuating prices following any future Chinese government interventions in domestic production intended to support predetermined price targets.[3] The continuing relatively high price levels (Newcastle prices are projected to average $72 per ton in 2017) are, ceteris paribus, expected to constrain global coal demand growth. However, any significant reduction in prices in China could lead exporters to reduce their prices as well, either in an attempt to sustain market share there or to compete in alternative markets, such as India. Thus, by regulating its production, China now effectively plays a key role in setting international coal prices, rendering the medium-term coal price outlook relatively volatile (see Figure 6.1).

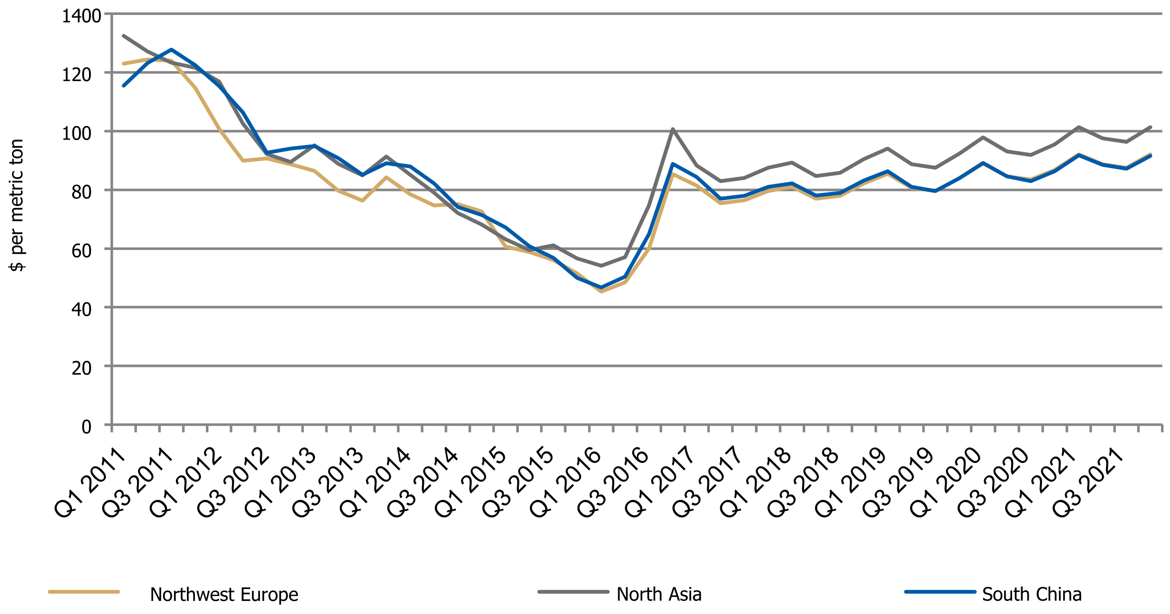
Outside of developing Asian markets, demand elsewhere in the world is projected to range from largely flat to negative. So, despite the recent improvement in the price environment, the incentive for producers to add capacity to boost exports is limited.

[1] As noted earlier in the report, Kazakhstan's GDP grew by 1.2% in 2015 and 1% in 2016; in February 2017 the Ministry of the National Economy upgraded its projected 2017 GDP growth estimate to 2.5% (from 2%), following a similar forecast by the International Monetary Fund.

[2] IHS Markit Coal, Global Steam Coal Forecaster, No. 84, Vol. 3, 2016.

[3] For 2017, the Chinese government plans to intervene in production, transport, or pricing only when prices for long-term contract coal fluctuate by more than 12% above or below a baseline price of RMB 535 per ton of 5,500 kcal/kg coal; see China Coal Market Briefing: First Quarter 2017, IHS Markit: Regional Power, Gas, Coal and Renewables, March 2017.

Figure 6.1. Coal prices, history and outlook



Source: IHS Markit

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6.2.1. Market Structure

Kazakhstan's coal industry is currently the main supplier of energy to the domestic economy, accounting for 55% of the country's primary energy consumption in 2016. Kazakhstan is engaged in almost the entire spectrum of coal production, ranging from lignite and sub-bituminous coal production for power generation to the mining of metallurgical coal. The coal industry's management structure is decentralized, with 29 companies currently listed by the Ministry of Energy as engaged in coal-mining operations; over three quarters of national output is accounted for by five large companies (see below). Industry regulation is performed by the Department of Electric Power and the Coal Industry of the Ministry of Energy (the latter formed in 2014 as part of a consolidation of energy regulatory functions within a single ministry).

6.2.2. Coal reserves

With proven reserves of 33.6 billion tons at 47 fields (recoverable "balance sheet" reserves are 34.1 billion tons)amounting to almost 4% of the world's total, Kazakhstan is a major world producer and consumer of coal.[4] The country possesses the eighth largest reserves of coal globally, sufficient to last at least 300 years at current rates of production. Bituminous and sub-bituminous coal (the two types categorized as "hard coal" in Kazakh nomenclature) account for 64% of Kazakhstan's reserves (21.5 billion tons),and the remainder of reserves consists of lignite (or "brown coal" at 12.1 billion tons).[5] The largest basins are located in the central and northern parts of the country: Ekibastuz (12.5 billion tons), Karaganda (9.3 billion tons), and Turgay (5.8 billion tons). Deposits in the Ekibastuz basin in particular stand out in terms of the low cost at which they can be produced; the seams are thick and located near the surface, making them easy to mine using open pit methods.

Although Kazakhstan's coal reserves are large, most deposits have high moisture content and relatively low heating values, as well as high ash and sulfur content. The latter means that their combustion (if untreated) is associated with substantial emissions of particulate matter and sulfur dioxide. At Ekibastuzthe ash content is particularly high (42-44%), and the specific structural properties of the coal have rendered its enrichment uneconomic to date.

[4]The first figure is reported in the BP Statistical Review of World Energy as of the end of 2015, whereas the second figure is reported by Kazakhstan's Geological Committee.

[5] Slightly over 5 billion tons of this figure is higher grade coking coal, used to produce coke for ferrous metallurgy.

[6] The reported total is for run-of-the-mine output. The total does not include coal concentrate, as is the Kazakh statistical practice. Coal concentrate is a product of processing (in washeries) that removes impurities such as stone and dirt. Coal concentrate production in Kazakhstan was 6.0 MMt in 2016.

This limits its ability to penetrate many export markets (e.g.,the European Union) in which stringent emissions controls or coal standards are enforced. An exception to this general situation is the Shubarkol basin, where coals have much lower ash and sulfur levels (5-15% and 0.5%, respectively) and a higher heat value (5,600 kcal/kg).

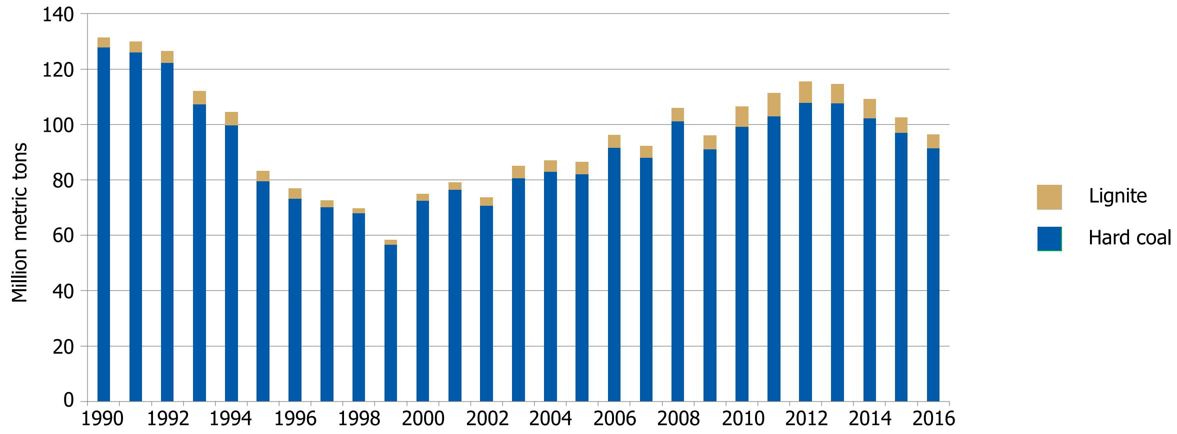
6.2.3. Coal production

Kazakhstan ranks tenthamong the leading coal producing countries in the world. In 2016 aggregate coal production was 96.4MMt, a 6% decrease from 2015 (102.6 MMt) (see Figure 6.2). The decline in output continuesa downward trend in place since 2012 (115.7 MMt), which was the highest level recorded since 1993).[6] As in previous years, the majority of output (almost 95%) was considered hard coal; included in the hard coal total is 5.1 MMt of coking coal, used in metallurgy.

Most of Kazakhstan's coal is produced at three giant open pit mines (Bogatyr, Severnyy, and Vostochnyy) in the Ekibastuz basin in Pavlodar Oblast and in four open pit mines (Borly, Shubarkol, Kushoky, and Saryadyr) in Karaganda Oblast.[7] Most of the remaining output is from underground mines in the Karaganda basin (supporting local metallurgy) and lignite production in the Maykuben basin.

Disaggregated by company, Kazakhstan's largest producer is the Bogatyr Komir LLP, which mines the gigantic Bogatyr pit in the Ekibastuz basin. It accounts for approximately two fifths of national output. In 2016 coal production increased by 3.5% to 35.1 MMt from 33.9 MMt in 2015, despite the overall decline in coal output in the country as a whole.The second-largest producer is the Eurasian Energy Corporation JSC (one fifth of national output). Three additional producers collectively account for another one-fifth: the ArcelorMittal Temirtau Coal Company (underground mine production in the Karaganda basin), the BorlyCoal Company, and Shubarkol Komir JSC. ArcelorMittal Temirtau is the only company that produces coking coal.

Figure 6.2. Kazakhstan's coal production



Source: Statistical Committee of RK; IHS Markit

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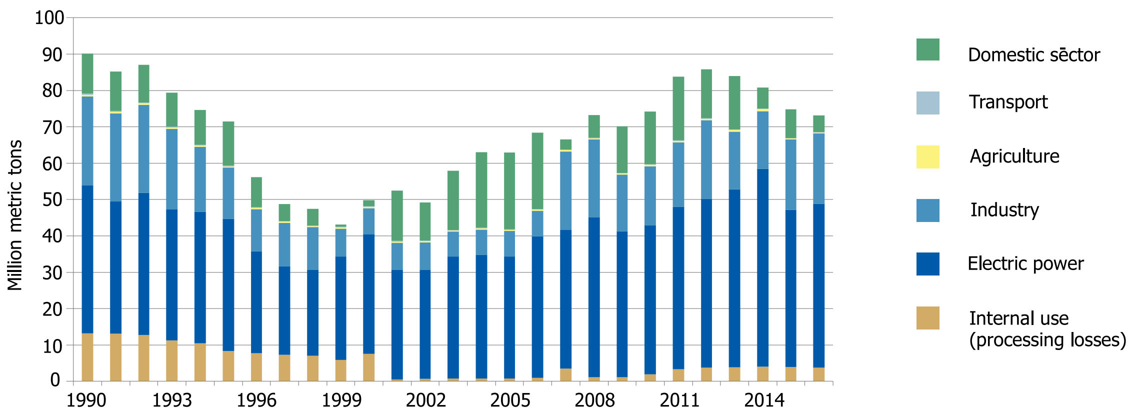
6.2.4. Domestic coal consumption

The use of coal is ubiquitous in Kazakhstan's economy, especially in power generation, heavy industry, mining, and other resource extractive activities, and is present even in the residential-commercial-municipal sector. In fact, the country has the highest dependence on coal in its energy mix of any of the former Soviet republics. Since 1990 the share of coal in the total primary energy consumption balance generally

[7] Together Pavlodar and Karaganda oblasts accounted for 89.8 MMt (93.2%) of total coal production in the country in 2016.

has fluctuated at between 50% and 60%. This share is expected to gradually decline, falling below 50% by 2020 and to less than40% in 2040.[8]
Apparent consumption (production minus exports plus imports) in the late Soviet period was 90 MMt (1990), but declined steadily during the upheavals of economic transition, reaching a nadir in 1999 (at 43 MMt). From there, consumption recovered more or less steadily until 2012 (85.8 MMt), but has fallen since then, to 74.8 MMt in 2015 and 73.2 in 2016 (see Figure 6.3). This appears to reflect a combination of muted economic growth in the post-2014 oil price environment, nascent energy efficiency improvements, and gradual shifts toward alternative fuels such as natural gas and liquefied petroleum gas (LPG).

Figure 6.3. Kazakhstan's apparent coal consumption by sector, 1990-2016



Source: Statistical Committee of RK; IHS Markit

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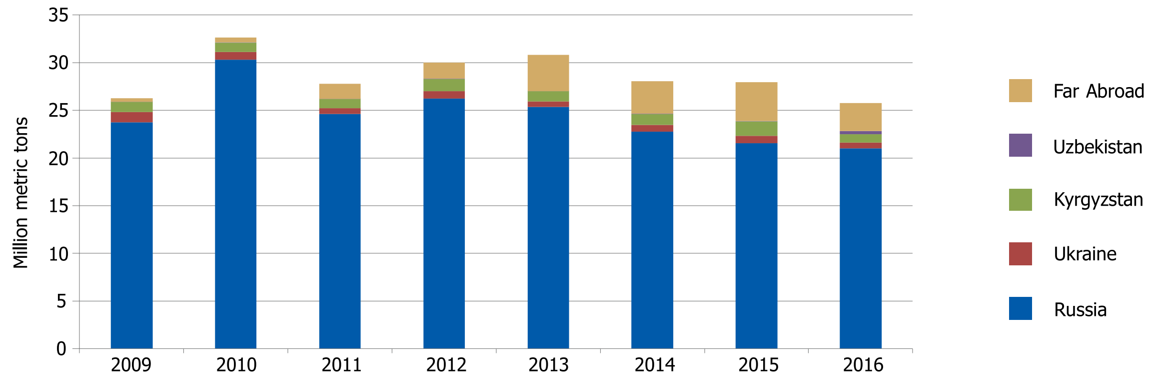
Electric power stations continue to be the largest consumers of coal, responsible for over half of total consumption; more specifically, in 2016 the electric power sector accounted for about 65%. However, in absolute terms power sector coal consumption appears to have peaked in 2014; going forward, other energy sources (natural gas, renewables, and perhaps nuclear) are expected to displace some coal (average rates of coal consumption in the power sector are projected to decline by 1.5% annually over the period 2015–2040). For the industrial sector, IHS projects modest growth (1.5% annually) in the consumption of coal through 2040. Consumption in the residential and commercial sector will almost certainly decrease, with consumers switching to natural gas (or LPG) when possible for reliability and convenience, as has been the case in other industrialized countries. Thus, while apparent levels of coal consumption are expected to decline slowly from current levels, the power sector's share of total coal demand is expected to remain steady at about 60-65%.

6.2.5. Coal exports

Since the mid-2000s, Kazakhstan's coal exports have fluctuated in the range of 24–34 MMt annually (representing 25% or more of Kazakhstan's total output). However, since 2010, exports have been slowly declining (from 32.6 MMt in 2010 to 27.8 MMt in 2014 to 25.8 MMt in 2016). Considerably more coal likely could be sold abroad if not for the remoteness from large export markets (see below). Russia has been the primary destination, accounting for roughly 80% of Kazakhstan's exports in most years (see Figure 6.4). Ekibastuz coal accounts for over 90% of these exports (primarily to seven power stations in the Urals as detailed in The National Energy Report 2015). To some extent, this represents a legacy arrangement, in that some power plants constructed during the Soviet period in Russia were expressly designed to burn Ekibastuz coal. A coal balance agreement between Russia and Kazakhstan envisions that Kazakh coal exports could continue to supply these plants with deliveries of about 29 MMt per year; however, exports to Russia in 2015 and 2016 (22 and 21 MMt, respectively) fell well below the figure specified in the agreement. Bogatyr Komir LLP, the primary Ekibastuz producer that exports to Russia, reported a 12.8% decline in such exports in 2016 (down to 9.2 MMt), as "some of the company's customers switched to gas technology, [leading to] a decline in coal sales."[9]
Demand at the Russian plants consuming Kazakh coal also has been affected in recent years by reduced levels of electricity generation resulting from the recent economic downturn in Russia. In any event, industry officials now fear that, given the emphasis on energy independence in Russia's Energy Strategy for the Period to 2030 (released 13 November 2009), coal exports to only three of these power stations (Reftinsk GRES, Omsk TETs-4, Omsk TETs-5) will continue beyond 2020.
Kazakhstan also exports some coal to Ukraine and Kyrgyzstan, and small amounts are delivered to Belarus, Georgia, Uzbekistan, Tajikistan, and even some EU countries on occasion (e.g., Poland, UK, Romania, Finland). The EU exports tend to be limited to Shubarkol coal, which meets the EU's specifications for ash content and heating value.
In addition to thermal coal, small quantities of coking coal from the Karaganda basin have been exported to Russia and other countries. In January 2015 ArcelorMittal announced that it had sold its interest in West Siberian mines in Russia (used to supply steel mills it owns in Ukraine) because it could now meet the coal needs of those mills entirely (0.7 MMt annually) with output from its Karaganda operations. Upgrades to ArcelorMittal's Vostochnaya Coal Washing Plant (including installation of two Jameson flotation cells and a horizontal belt vacuum filter) are projected to enable it to nearly double coal concentrate output in 2017 (from 2.6 MMt in 2016 to 4.7 MMt); output in Q1-2017 was up 21% year on year. The coking coal concentrate is consumed by the company's steel mills in Karaganda as well as exported.

Figure 6.4. Kazakhstan's coal exports by destination



Source: Source: Kazakhstan foreign trade statistics; 2016 data from Ministry of Energy

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6.2.6. Competitiveness of Kazakhstan's coal in international markets

The factors affecting the competitiveness of Kazakhstan's coal exports have remained relatively constant over recent years and include production costs, quality of coal, transportation costs to international markets, and competition from other fuels in the consuming markets, such as oil, gas, and even renewables. One of the main advantages of Kazakh coal continues to be its abundance and low cost of production (especially in the Ekibastuz basin). Although production costs in absolute terms have more than tripled since 1996, they remain comparatively low. The average cost of producing coal in Kazakhstan is only one-half to one-third that of other major world producers.[10] Yet despite low production costs, by the time coal reaches foreign consumers its price increases substantially due to transportation costs (discussed in section 6.2.7).
Kazakh coal has disadvantages other than high transportation costs. Coal that has a low calorific value is always sold at a substantial discount to standard 6,000 kilocalorie-per-kilogram coals, and Ekibastuz coal is relatively low in calorific value (3,800–4,000 kilocalories per kilogram). Although it is an important source

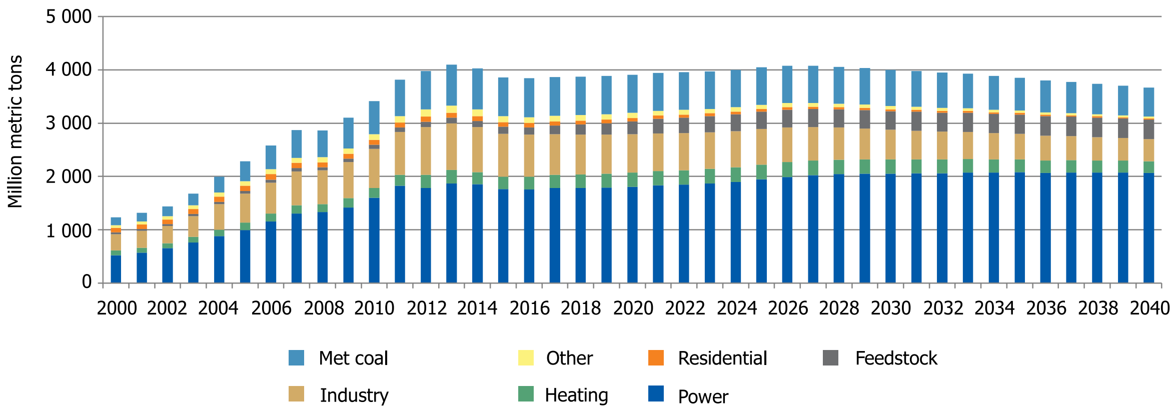
[8] This expectation is derived from the IHS integrated energy balance model, employed in this report, it explicitly accounts for total energy demand and for development of other energy sources (gas, nuclear, renewables) in the economy.

[9] The National Energy Report 2015, p. 245 notes that three of the Russian plants importing Kazakh coal (Verkhnetagil GRES, Yuzhnouralsk GRES, and Serov GRES) have gas infrastructure in place and can already switch between natural gas and coal as a main fuel.

[10] See Table 8.1, 2014 on page 237 of The National Energy Report 2015. Data from Kazakhstan's Ministry of Energy indicate that in 2017, the average lifting cost of Grade D long-flame steam coal is 4600 tenge ($14.80 at the current exchange rate) per ton; for Grade B lignite this cost amounted to 4000 tenge ($12.87). For underground mining of metallurgical and specialty coals the costs varied more widely, from $23.38 to $58.88 per ton.

of coal for thermal power generation, it is less useful in industrial applications. Karaganda's bituminous coal is of higher quality and can be used for coking; at the moment though it is mostly consumed domestically.
As noted above, there is concern about weakening Russian demand for Kazakh coal by 2025, as some of the Russian generating capacity currently designed to be fueled by Ekibastuz coal becomes outmoded and will need to be replaced. Even before that point, Kazakh coal already is facing much greater competition in Russia from Kuznetsk basin coal or domestically produced natural gas. Ruble depreciation also undermined Kazakh coal's competitiveness in the Russian market in 2014–15, but this was alleviated after the August 2015 free float of the tenge.
Plans to launch Kazakh coal exports to China are also challenged to be economically viable, given the relatively low quality of the coal and the very high transportation costs that would be involved over such long distances (China's main coal consumption centers are in the east, while its own coal is mined inland, in western China). Furthermore, coal demand growth in China is expected to decelerate over the next decade as a result of a variety of factors, including moderating economic growth, fuel diversification, and public pressure to reduce air pollution levels in some areas—now manifest in a specific commitment by China's State Council to cap coal consumption growth by 2020. In fact, coal demand already is showing signs of weakening. Total coal consumption in the country declined by 2.2% in 2014, by 1.5% in 2015, and by 0.4% in 2016 and expected to essentially plateau longer term (see Figure 6.5).

Figure 6.5. China raw coal demand outlook

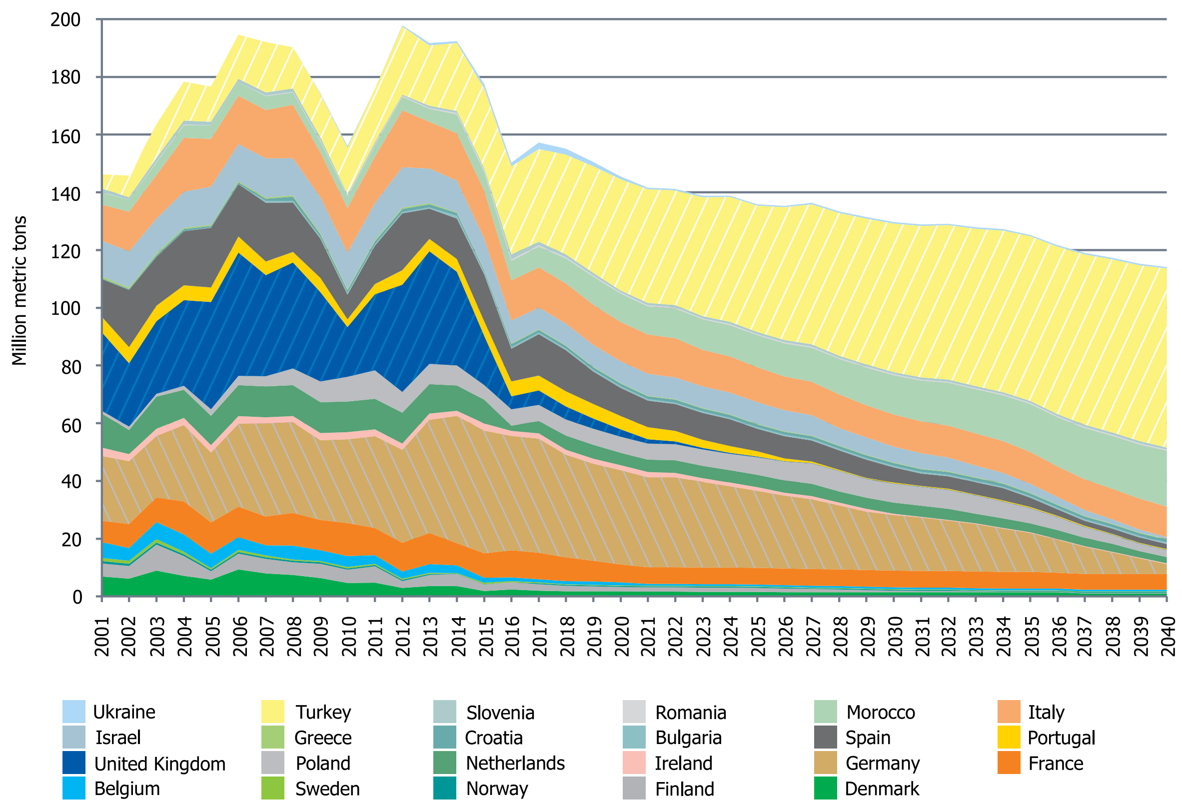


Source: IHS Markit

As part of the effort to reduce air pollution in its eastern provinces, China also intends to shift some coal-fired generation capacity to interior locations and especially to its energy-rich Xinjiang Province and Inner Mongolian Autonomous Region in the northwest and north, respectively. This has become possible as a result of advances in long-distance electricity transmission via extra high-voltage and ultrahigh-voltage lines. Although Kazakh coal would certainly be geographically nearer to power plants in Xinjiang than in Beijing or Shanghai, China plans to fuel its western plants with locally plentiful coal, natural gas, and wind energy, not imported coal. With Chinese domestic coal prices essentially setting the ceiling for what Kazakh coal can fetch in Chinese markets, it thus appears that delivered costs of Kazakh coal would be much higher than prevailing domestic prices in China. Due to its high ash content, the use of Ekibastuz coal at power plants and boiler houses requires development of special boiler designs or reconstruction of the existing boilers for coal burning as well as additional amounts of fuel oil (mazut) to stabilize coal combustion.
Exports to the neighboring Central Asian region might be increased, especially now that Kyrgyzstan (which currently accounts for 3.4% of Kazakhstan's coal exports) has acceded to the Eurasian Economic Union. Another existing customer, Ukraine (2–3% of Kazakhstan's coal exports) might import marginally more coal as well, as a result of a formal blockade announced on 15 March 2017 by Ukraine's President Petro Poroshenko on all non-humanitarian road and rail trade between Ukraine and separatist-controlled regions in the east (which are major coal producers). The primary commodity would be coking coal, as Kazakh thermal coal is largely unsuitable for use in Ukrainian coal-fired plants. Kazakhstan's coal exports to Ukraine since 2012 have generally been marginal, at levels of 0.8 MMt or below (e.g., 596,000 tons in 2016).
Limited exports to Europe might also continue, if economic growth there accelerates and there is a

need for greater baseload generating capacity to accommodate renewable capacity additions. However, this may be challenging considering the EU focus on meeting carbon emission targets and overall declining coal demand outlook and thermal coal imports outlook (see Figure 6.6).Another potential market is Turkey. Turkey continues to build out its fleet of coal-fired power plants, fueled both by domestic coal and imports. In 2015, Turkey imported 31.5 MMt of hard coal for its thermal plants, steel production, industry, and domestic heating purposes—one third from Russia, one third from Colombia, and smaller quantities from South Africa (15%), Australia (8%) and elsewhere. These imports by Turkey are expected to increase in the future.
The situation with respect to coking coal, for which there is a more specialized market, could prove more favorable (especially if there is a recovery in demand for coking coal in metallurgical plants in Russia). We have already noted the development of a dedicated supply from Arcelor Mittal's mines in Karaganda Oblast to the company's steel mills in Ukraine. This could stabilize fluctuations in exports on the downside, but it is not yet clear what effect this will have on overall exports.

Figure 6.6. European thermal coal import demand outlook to 2040



Source: IHS Markit

6.2.7. Coal transportation

The most significant obstacle to increasing exports of Kazakh coal are high transportation costs, which render Kazakhstan's coal relatively expensive to consumers and reduce its competitiveness even in the nearest major export market, Russia. Transportation accounts for over 40% of the total delivered costs to Russian coal buyers.
Rail transport figures prominently in the movement of key energy commodities in Kazakhstan, including coal. In recent years coal has accounted for more than one-third of freight tonnage carried by Kazakhstan's rail system, operated by the state-owned national railroad company Temir Zholy. However, oil and oil products shipments are the most profitable large-

volume freight segment, and effectively "subsidize" the transport of coal and other bulk commodities.[11] However, three factors are expected to change rail tariffs in the future. First, the construction of additional pipeline capacity has shifted much of the lucrative transport of crude oil (and perhaps later, oil products) from the rail system. Total shipments of oil and oil products by rail had risen steadily between 2005–13, as export capacity on preferred routes tightened and shippers sought to preserve crude quality. However, oil shipments by rail declined sharply in 2014, falling from 8.7 MMt in 2013 to 0.5 MMt in 2016, mostly owing to the expansion of the CPC pipeline and the decline of rail exports of crude to the Black Sea. Second, Kazakh refineries are expected to produce less mazut and shift from exports of excess mazut (mainly to the EU) to delivery of more light products to the domestic market. Overall shipments of refined products may not increase substantially, but because of the shorter distances the products are moved, this means less high-value shipments and less total revenue for the rail system. Finally, government proposals to harmonize transportation tariffs for exports and domestic shipments across the Eurasian common economic space will push down real effective tariffs for oil and oil products because of similar trends within the Russian rail system. Ultimately, these three factors could place upward pressure on rail tariffs for coal, which are currently just slightly above break-even levels for the rail industry. However, the significant share of coal in the overall volume of rail shipments offers the coal industry additional leverage in the process of the setting of a new rail tariff structure, expected in September 2017, by the Committee for Regulation of Natural Monopolies and Protection of Competition (KREMiZK).

High rail transportation costs were a major factor underlying the decision to construct large mine-head power stations in north-central Kazakhstan based on Ekibastuz coal during the Soviet period; planners calculated that it was cheaper to transmit energy in the form of electricity to consumers in the Urals and West Siberia than it was to transport the coal used to generate the electricity there. Given recent advances in ultra high voltage transmission of electricity in China and elsewhere, it might at first seem prudent for coal-industry officials to give more consideration to this option (electricity exports) for monetizing coal assets otherwise stranded by high surface transportation costs of high-ash coal.[12]

Other options for exporting coal-generated electricity might involve limited exports (or power swaps) with neighboring countries in the south (e.g., Kyrgyzstan, Tajikistan, and Uzbekistan) on a bilateral basis or Kazakhstan's possible eventual participation in the CASA-1000 transmission project to South Asia. The latter project as currently conceived envisions the transmission of 1300 MW of surplus hydroelectric power generated in Kyrgyzstan and Tajikistan during the summer southward via Afghanistan to Pakistan, where summer power demand is high for air conditioning. Although geopolitical risks are substantial until stability returns to Afghanistan and western regions of Pakistan, the demand for electric power is great year-round in the Pakistan market, potentially affording Kazakhstan an opportunity to supply power in the winter months (when a market would exist not only in Pakistan, but in Kyrgyzstan and Tajikistan as well).[13] This might entail transmission of large amounts of electricity along Kazakhstan's north-south corridor (or in any event across the southern portion of the country from new coal- or gas-fired capacity), perhaps with great seasonal variations, and thus would require careful study in terms of possible effects on the national grid. Electricity exports will be considered in more detail in Chapter 8 (Section 8.3.2.1).

In addition to considering ways of expanding exports of coal or coal-fired electricity, industry officials have been exploring options for the further utilization of coal in Kazakhstan's domestic economy (see below).

6.2.8. Coal balance outlook

Projections of Kazakhstan's coal balance out to 2040 reveal several important trends. Coal production slowly declines to less than 80 MMt in 2040 (see Figure 6.7). Apparent consumption follows a similar trajectory, slowly declining from over 70 MMt in 2016 to about 60 MMt in 2040 (see Figure 6.8). These trends are consistent with an outlook for an economy that is gradually utilizing energy more efficiently, slowly

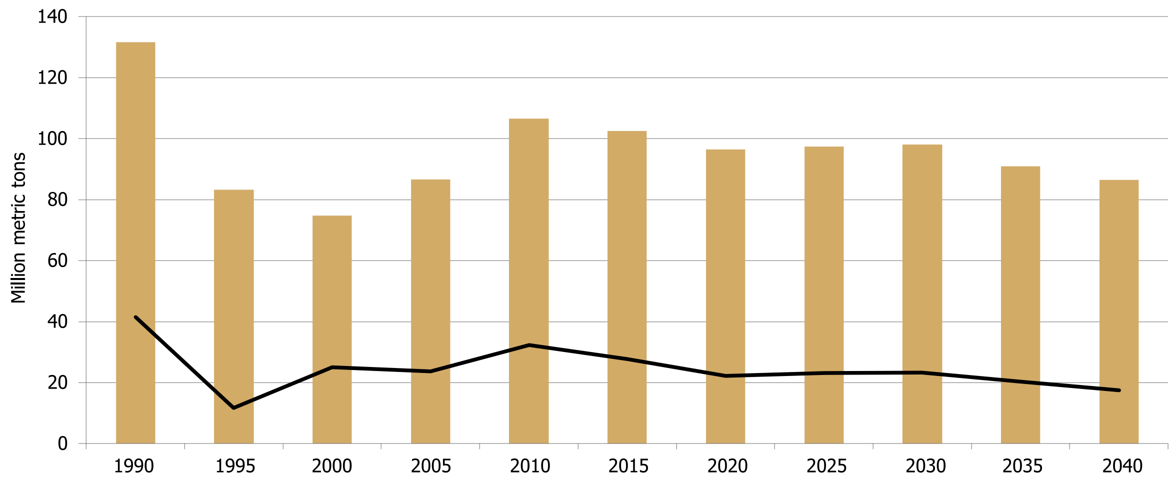
[11] Coal in Kazakhstan is shipped for roughly 30–50% less than oil and oil products for similar distances (on a ton-km basis).

[12] Coincidentally, in early 2017 Kazakhstan's Samruk-Energy company announced plans to double its electricity exports to Russia (to 4 billion kWh) from its Ekibastuz GRES-1 and GRES-2 power stations (the latter co-owned with Russia's Inter RAO UES). However, opportunities to significantly expand electricity exports to the Russian market are quite limited in the long term—due to the Russian Energy Strategy's emphasis on energy independence, the addition of substantial generation capacity in Siberia (with a new 500 kV connection to the Urals region), and the Russian conceptualization of power trade between the two countries as being only for system balancing purposes.

[13] Pakistan's current power shortfall is 6 GW on an annual basis. CASA-1000 as currently conceived would meet only 20% of Pakistan's current power deficit. Policymakers expect Pakistan's peak power demand to rise from 20.8 GW in 2015 to 32 GW in 2020 and 45 GW in 2030 (see Christopher de Vere Walker, Overview of Major Infrastructure Projects: CASA-1000 Transmission Line and Pakistan–UAE Water Pipeline, IHS Energy, Russian and Caspian Energy Presentation, Abu Dhabi, UAE, 4 April 2016.

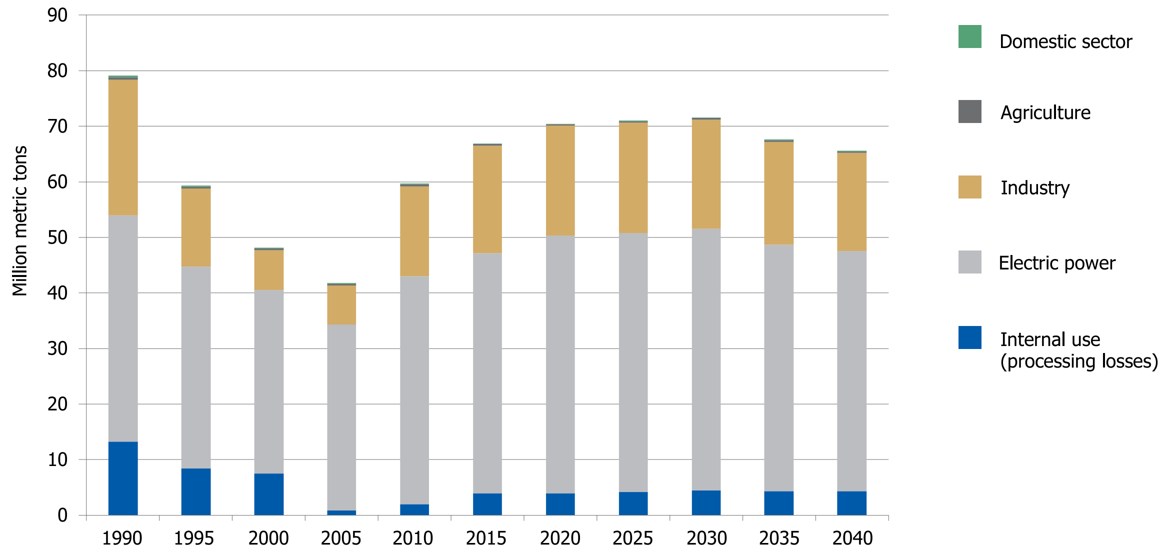
increasing its gas consumption, and possibly adding some nuclear generation capacity in the electric power sector after 2030. Indeed, one of the key global trends observed in recent years inhibiting the growth in coal demand has been the declining energy intensity of economic growth in the developed world, whereby less energy consumption growth is necessary to support the same levels of GDP growth. This

Figure 6.7. Kazakhstan's coal production and exports outlook



Source: IHS Markit, Statistical Committee of RK

Figure 6.8. Kazakhstan's coal consumption outlook by sector



Source: IHS Markit, Statistical Committee of RK

dynamic is now extending to the developing world as well. China's coal demand has fallen for three consecutive years, despite rates of GDP growth in excess of 6%, whereas India's growth in electricity demand (primarily coal generated) of 5% annually has lagged behind GDP growth (7% annually). In these and other countries, among the more important explanatory factors include structural economic change (from heavy industry toward services) as well as the use of more energy efficient devices (e.g., home appliances,

LED lighting).
In Kazakhstan, the balance of coal production and consumption appears to be closely linked to electric power generation. This reflects the inertia built into the existing structure of the electric power sector. Even with the continued gradual growth in gas-fired power generation and the phasing in of some renewable and perhaps nuclear capacity, coal will remain the dominant fuel in the power sector for some time to come.

6.2.9. Conclusions, notable changes since 2015

In the absence substantive improvements in prospects for increasing coal exports, the following developments represent at least limited avenues for increasing the contribution of coal to national economic activity:

- Although further growth in electricity exports to Russia does not appear likely, it is at least possible that other options for exporting coal-generated electricity might be explored, either to Central Asia on a bilateral basis or over the longer term as part of an international project such as CASA 1000.
- Ukraine might offer at least a near-term opportunity for Kazakhstan to export more coking coal. However, such shipments would likely require rail transit via Russia, so it is not presently clear to what degree (if any) these exports could be constrained by geopolitical issues.
- Another potentially promising market could be Turkey, which imports substantial quantities of coal for power generation and industrial uses.

6.3. INFRASTRUCTURE AND TECHNOLOGIES: KEY CHALLENGES, IDEAS, AND SOLUTIONS

6.3.1. Efficiency and improved coal use

Because coal has a limited number of clearly defined uses in Kazakhstan's economy, this section focuses on efforts to increase coal-use efficiency in each of three major sectors: electric power and heat generation (accounting for 60-65% of coal consumption nationwide); industry, including metallurgy (28%); and the domestic sector (6%). The ubiquitous use of coal in Kazakhstan is explained by its abundance and low cost of production. However, most new technologies that make coal enterprises more efficient and clean inevitably raise the cost of coal and make it less competitive with other fuels, such as natural gas, mazut, and LPG. In some circumstances expenditures on coal upgrades can be economically justifiable; however, this is not a given and will be an important factor in proliferation of the technologies listed below.
Electric power. Given the preponderance of coal-fired capacity in the electric power sector, improvements in the generation, transmission, and distribution of electricity, more than any other conceivable measure, will increase the efficiency of overall coal use in the economy. A key issue for the optimal level of specific fuel consumption for coal in Kazakhstan is long-term load planning and adjustment of capacity construction plans aimed at maintaining an acceptable level of power plant load at coal-fired plants and preventing formation of significant excess capacity.
When new coal-fired capacity is added, the adoption of new coal combustion technologies should be considered. One such technology is **the ultra-supercritical steam cycle** (now operational in Denmark, Germany, and Japan, as well as the United States). Conventional coal-fired power plants, which make water boil to generate steam that activates a turbine, have efficiency of about 32%. Supercritical (SC) and ultra-supercritical (USC) power plants—also known as high-efficiency, low emission (HELE) coal-fired power plants—operate at temperatures and pressures above the critical point of water, i.e. above the temperature and pressure at which the liquid and gas phases of water coexist in equilibrium, at which point there is no difference between water in gaseous or liquid form. This results in higher efficiencies—above 45%. Supercritical (SC) and ultra-supercritical (USC) power plants require 5–7% less coal per megawatt-hour, leading to lower emissions (including carbon dioxide and mercury), higher efficiency, and lower fuel costs per megawatt.
Although the upfront cost of such technologies is 20%–30% more expensive than a traditional subcritical unit, the additional costs are more than offset by the improved net thermal efficiency levels and by reduced emissions (in countries where carbon is taxed or traded.[14] The technologies are based on the burning of pulverized coal at very high temperatures, obtaining USC steam parameters (280 atm and 600°C), and also (over the longer term) cycles with even higher steam parameters (380 atm and 700oC). An example of coal-fired power plant with ultra-supercritical steam parameters in Kazakhstan is Unit 3 of Ekibastuz GRES 2.
It is important to note that, with USC now well established, R&D is now underway to increase steam temperatures beyond 700°C, which could achieve coal-fired efficiencies as high as 50%. Known as advanced ultra-supercritical technology (AUSC), such high pressures and temperatures will require more advanced (nickel or nickel-iron) superalloys that are expensive and currently present fabrication and welding challenges. In early 2014, Alstom and Southern Company (US) announced a milestone in the development of AUSC, with steam loop temperatures maintained at 760°C for 17,000 hours during a trial at Plant Barry Unit 4 in Alabama. The loop contained an array of different superalloys and surface coatings that enabled it to withstand the exceedingly high temperatures within the boiler. Further advances in material science will be necessary for these AUSC technologies.
Another promising new coal combustion technology is **the integrated gasification combined cycle (IGCC)**, which instead of burning the coal directly uses a gasifier to convert it to syngas (H_2 and CO_2). The resulting gas (after treatment) is burned in a gas turbine, and the heat of the exhaust flue gases (combustion products) is used to generate steam and electricity in the steam turbine cycle. However, the technological efficiency of the IGCC technology is not very high (about 43%)—much lower than the similar figure for CCGTs using natural gas (57%). In addition, construction of such power plants is much more expensive than construction of conventional coal- and gas-fired plants, since the gasifier and the gas treatment system are the most metal-consuming and capital-intensive parts of the IGCC technology.[15] IGCC technologies are at the stage of pilot testing and research, as there are a number of unresolved problems, including operation of gasifiers under pressure and high-temperature gas treatment before supply to gas turbines.
Overall, it should be noted that in coal-fired power generation there is a trend towards increasing the efficiency of the conventional pulverized-coal cycle through maximizing the steam parameters, which allows achieving an efficiency of 45–47%. Existing coal-fired power plants with 300-500 MW generating units in Kazakhstan were designed for operation with supercritical steam parameters (237 atm, 540°C) and register efficiency of 31-35%. Raising the steam parameters to ultra-supercritical through technology upgrades (re-equipment) will increase the units' efficiency by about 4%. With gradual modernization and technology upgrades at existing coal-fired power plants, the efficiency of coal use will grow, and, therefore, the volumes of environmental emissions and coal consumption will decrease.
District and building-level heating. In the domestic sector, a major use of coal is for the heating of urban districts and buildings. Often provision of heat and electricity are combined, when generation is from a combined heat and power plant (e.g., termoelektricheskiy tsentral or TETs). More than 80% of the district heating capacity in Kazakhstan is coal-fired. As in the electric power sector, heat generation capacity is aged (e.g., 41% of TETs have been in service for over 30 years), and nearly two-thirds are in need of some type of repair or modernization.
Replacement and modernization of boilers at coal-fired boiler houses and TETs results in increased coal use efficiency. It is also possible to increase boiler efficiency by installing supply monitoring and control systems. If air excess in the boiler is significantly higher than the optimum value for combustion of a given grade of coal, efficiency falls due to heat loss via excess air in exhaust flue gases. Air excess control systems can determine the optimum amount of air supply in order to achieve the maximum boiler unit efficiency. Such systems have been already installed at some TETs and boiler houses in Kazakhstan and resulted in lower fuel consumption.
Although natural gas is increasingly the fuel of choice in the residential sector, in unique instances alternative uses of coal, such as coal-water slurry (CWS) and coal briquettes could be possible for heating purposes. Coal-water slurry is a finely divided mixture of fine coal fraction (60–70% of mass), water (30–40%) and, in some cases, a stabilizing agent (plasticizer). CWS combustion in small boiler houses allows fuel supply automation and nitrogen oxide emission reduction; in some cases an increase in fuel combustion efficiency is recorded. Coal briquettes are produced by compressing the fine coal fraction (otherwise typically viewed as coal waste) in the presence of binders and usually have a uniform shape. Briquettes have a relatively high calorific value. In Kazakhstan, the first commercial production of coal briquettes has been launched at the Sarykol field. However, due to the already low costs of briquettes in potential export markets for briquettes, such as China, South Korea, and Vietnam (and the fact that they can be fabricated from a variety of locally ubiquitous materials such as recycled paper, wood charcoal, sawdust, and rice and peanut chaff), it will likely be difficult for Kazakh products to compete with locally produced briquettes in these markets.
Industry. Industry (mostly coking) accounts for about 28% of overall coal consumption in Kazakh-

[14] For instance, the Isogo thermal power station near Yokohama, Japan houses two coal-fired units. Combined, the facilities emit 50% less sulfur, 80% less nitrogen, 70% less particulates, and 17% less CO_2 than the previous subcritical units using a regenerative activated coke dry-type control technology (ReACT).

[15] The largest IGCC plant (Puertollano), with a capacity of 335 MW, is currently in operation in Spain.

stan. The focus here is on the industrial enterprises that consume large quantities of coal to produce heat energy or in which coal itself serves as a vital component in the industrial process (e.g., coking coal in metallurgy). Heavy industrial coal users include mining and metallurgical enterprises and foundries.

In ferrous and nonferrous metallurgy, more than 90% of energy consumption is directly related to process technologies. The main potential for energy saving thus lies in a full upgrade or replacement of the process equipment, which is actually equivalent to construction of a new plant. Therefore, the potential for energy savings in metallurgy is relatively limited. In the mining sector, energy efficiency improvements can be achieved mainly through asset (core equipment) modernization and introduction of systems for optimizing fuel consumption during ore extraction, handling, and processing.

In the country's coal-rich regions, the potential also exists for industry to use coal mine methane or coal bed methane as a power source. As recently as 2013, CBM accounted for almost 2% of total combined (gas and CBM) production in the world. CBM production is most developed in the US (which accounted for 62% of total world output), Canada, China, Australia, India, Indonesia, and some other countries (see The National Energy Report 2015, pp. 250–253 for background). Estimates of global CBM gas in place range widely depending upon the economic assumptions that are employed, from 78 trillion cubic meters (Tcm) at the low end to as much as 959 Tcm. Of these amounts, some 30–60% constitute recoverable reserves.[16] A recent estimate cited a global reserve figure of 260 Tcm.[17]

Unlike gas in conventional deposits, methane in coal is not trapped under pressure in the coal-bearing strata. Moreover, less than 10% typically exists as "free" gas within fractures and joints. Rather most CBM is adsorbed within the micro-porous matrix of the coal itself.

These properties mean that when the methane itself is viewed as the resource to be developed (and not the coal), it is commonly extracted using enhanced recovery techniques similar to the hydraulic fracturing now responsible for the rapid rise in unconventional oil and gas production, although the mechanics and rates of flow of the gas to the production wells are different. A fracturing fluid (typically water but sometimes also acids and other additives) and a "proppant" (an agent that props open the fractures, typically sand, after the injection fluid is removed) are injected into the targeted coal zones at high pressure.

The technology generally enlarges already existing fractures (or "cleats") present in the coal, and increases the connections between natural fracture networks and between these networks and the production wellbores. CBM production technologies require drilling many more wells as compared to conventional gas fields. The types and characteristics of production wells depend on many factors – the coal bed geology, depth and pressure, permeability, and gas saturation – but are ultimately determined by the cost of the CBM deposit development option.

Environmentally safe substances (e.g., potassium chloride) can be used as chemical reagents for hydraulic fracturing, but in any case CBM production is associated with the issues of the cleaning and disposal of production water, and the solution of this issue depends among other things, on the requirements of applicable laws and regulations. The cost of production water disposal is a significant element of CBM production in many countries, as the need to comply with tough environmental regulations affects the fields' capital and operating expenditures. CBM production is also characterized by low pressure levels of the gas produced, and, therefore, requires compressors for gas pumping even within the deposit. The lifetime of CBM production at a well does not usually exceed 15 years: at first the gas production rate tends to increase, while at later stages of well operation it decreases to minimum values.

According to a feasibility study on CBM production in the Sherubay-Nurinsky (Churbai-Nura) coal province of the Karaganda coal basin, the estimated cost of producing CBM in a selected area of previously developed mines (now flooded) is about $150 per Mcm and the methane content in the gas produced is 94% or higher with an insignificant sulfur content. This price appears to be too high for commercial feasibility for use in the residential sector (conversion to LNG) or as a transportation fuel. It is possible, however, that better methane production characteristics could be encountered during development of other areas of the Karaganda coal basin. Potentially more promising would be own generation by industrial consumers located in the immediate proximity to CBM production areas. In summary, CBM production could eventually expand the range of fuel options available to industrial users in the country's central regions, but its export through a gas pipeline to nearby urban areas is unlikely due to the high cost of the original (feed) gas and the capital expenditures associated with pipeline construction.

In addition to CBM production, underground coal mining can also contribute to an increase in methane production in the course of degassing planned coal mining areas. At present, about 200 cubic meters of methane are discharged into the atmosphere during degassing, and if gas separation units are installed, these methane volumes could be economically captured, since the methane content in the gas released during degassing is about 30%.

[16] Pramod Thakur, Advanced Reservoir and Production Engineering for Coal Bed Methane, Houston: Gulf Professional Publishing, 2017, Chapter 1.

[17] Shen Baohong, The Status and Development of CBM Technology of Mining Area, Beijing, June 2014.

6.4. REGULATION OF KAZAKHSTAN'S COAL SECTOR

6.4.1. Review of program documents and legislation

As is evident from the discussion of overall trends in coal production and growth, as well as the heretofore limited prospects for the exports of coal and the electricity generated from it, the coal industry's trajectory is not one of growth, but rather of gradual decline. Given this trajectory, it is important for Kazakhstan's legislation to provide a framework of support for the industry, given its size and importance to the country, to ensure a smooth transition.

The principal legislative act governing coal mining activity in Kazakhstan is the Republic of Kazakhstan Law on Subsoil and Subsoil Use No. 291-IV of 24 June 2010 (henceforth "Subsoil Law"). In addition, numerous directives issued by the Ministry of Energy and governmental regulations address other issues that can be related to coal mining.[18] The latter include state codes on taxes, labor, the environment, land, water, and customs, procurement of goods and services, as well as health and safety regulations.

Another aspect of the Subsoil Law eliciting concern among outside investors is Article 12.2 of the Subsoil Law (State's Pre-emptive and Priority Rights in Subsoil Use Sphere). Under this provision, for projects deemed to be of national strategic significance, the state has the priority right to acquire subsoil use rights in full or in part (e.g., the "right of first refusal" when an outside investor seeks to transfer ownership shares to a third party.

A first draft of a new Subsoil Use Code (to replace the Subsoil Law) is currently under discussion, prior to planned submission to Kazakhstan's parliament for approval in late 2017. It contains provisions that are expected to ease some of the license issuance procedures and will introduce the international system for reporting of mineral resources and reserves. Under the proposed Code, the Ministry of Energy will continue its efforts to lower administrative barriers: the number of required project documents will be reduced; some permits will be canceled; the document approval processes will become shorter and easier; and subsoil users will gain the right to suspend exploration and production activities, for example, in response to a significant drop in raw material prices. Practically all other areas of law pertaining to natural resources are codified in some way (e.g., Land, Water, and Forest Codes), and it is believed that the promulgation of a new Subsoil Use Code will be more effective in resolving contradictions in legislation at different levels than would revision of the extant Subsoil Law.

In addition to the regulation of mining activity, the state also collects revenue from the development of coal and other mineral deposits through a number of financial instruments, which typically include but are not limited to: (1) signing bonus upon the granting of a subsoil use contract; (2) commercial discovery bonus; (3) reimbursement fee for historical (exploration and/or development) costs; (4) Mineral Extraction Tax (royalty based on volume of production); and (5) Excess Profits Tax (calculated annually).

Bonuses are perhaps the most troublesome fiscal instrument for investors because the payment is made up front, well before production even begins, and in many cases even before a discovery has been made. Because of the timing of the payment, bonuses can have a deleterious effect upon project economics, particularly if they are sizable. But they have the advantage of ensuring some up-front revenue for the government and may incentivize companies to explore and develop contact areas more rapidly. But in general, sizable up-front bonuses are usually suitable only in highly prospective areas where there is strong competition among investors for petroleum rights.

In 2017, Kazakhstan's Ministry of National Economy is expected to propose a new Tax Code that will improve VAT collection mechanisms, ease tax administration processes, and improve the tax regime for the mineral resource companies (thereby expanding the country's mineral resource base). Moving away from signing bonuses has also been discussed.

The coal industry figures prominently in the Concept for the Development in the Fuel and Energy Complex to 2030, approved by the government on 28 June 2014. The Concept provides a general picture of what the state envisions as the path of the sector's future development. It is based on a presumption of moderating domestic growth in coal consumption, limited opportunities for export growth, and a gradual incorporation of natural gas and renewable energy sources in electric power generation. In this environment, the Concept envisages: "restrained" growth of thermal coal production (to only 113.0 MMt) by 2030, but its more efficient production; modernization and use of new technologies, especially more widespread coal enrichment; deeper processing of coal to yield a number of new products (synthetic liquids and synthetic natural gas); and development of technologies and infrastructure for the use of coal bed methane. In addition to these general goals, more specific objectives to be achieved by 2030 include: the launch of production in the Turgay basin, where coal reserves lie very near the surface; production of synthetic liquids and synthetic natural gas to levels meeting 10% of total demand in their markets (liquid fuels and natural gas, respectively); and generation of as much of 10% of electricity from coal bed methane.

[18] The Ministry of Energy has jurisdiction over the coal and uranium industries, whereas the Ministry of Investment and Development has jurisdiction over other solid minerals (e.g., metallic ores). Locally abundant, commonly occurring raw materials such as sand and clay are administered by local government councils (akimats). The terms of the Subsoil Law also apply broadly to the oil and gas industry, with partial exceptions for the three megaprojects governed by PSAs or similar contracts.

Achievement of the goals is to be supported by the phased rollout of a fiscal and regulatory framework in accordance with the law "On Natural Resources and Natural Resource Use" (24 June 2010) and the Law "On Technical Regulation" (9 November 2004). However, even this more measured development plan may still be too optimistic for the coal industry.

Finally, a major state program devoted specifically for the coal industry (Roadmap for the Development of the Coal Industry and Its Prospects to 2030) has now (2017) been elaborated by the Ministry of Energy. Some indications of the directions envisioned by the Roadmap were revealed by Energy Minister Bozumbayev in January 2017. He stated that priority would be accorded to measures to reduce adverse environmental impacts in areas of coal production and to increase the output of coal products of high quality. At the same time he stressed the importance of maintaining the current level of coal production through more comprehensive processing of coal to increase the diversification of products and uses, including the production of diesel and other synthetic liquids from coal (CTL) and the use of coal mine methane as a local power source for electricity generation. Bozumbayev also advocated efforts to diversify the economies of "company towns" (monogorody) engaged in the production of coal, such as Ekibastuz, where projects already have been launched in such activities as transportation machinery building and the construction industry.

6.4.2. Key recommendations

Coal will remain an important part of Kazakhstan's energy sector for many years to come, although it is not a growth story. With this in mind, we believe some of the same recommendations offered in The National Energy Report 2015 retain their relevance today:

- Pursue careful policy implementation so as to not undermine coal's competitiveness unnecessarily. Particular attention should be devoted to the impacts of carbon pricing and changes in rail tariffs on coal exports and consumption of coal in the domestic economy.

- Continue research on ways to use coal more cleanly and efficiently, especially in power generation by incremental improvements, such as reducing emissions through improving efficiency of fuel utilization and retrofitting older capacity with stack filters. If demonstrable progress can be demonstrated on the carbon footprint, the timetable for coal's replacement by other fuels can be stretched out.

- Although the most efficient use of Ekibastuz coal is power generation, continue technical and economic studies on the feasibility of cleaning and standardization of bituminous and brown coals from other deposits so that coal of consistent and predictable quality, emissions characteristics, and heat content will be available to potential export markets.

To these recommendations, we would add the following:

- Similar to measures taken worldwide to encourage the reduction of associated gas flaring during oil production, consider introducing legislation providing incentives: to discourage emissions of methane and other gases during coal mining and to encourage recovery of these gases for uses in electric power and heat generation, if economically feasible. Such measures might include a reduction of the tax burden on subsoil users producing and utilizing (rather than emitting) unconventional gas.

- Given Kazakh coal's high transportation costs and challenges to competitiveness in major export markets, explore the potential for greater utilization of Kazakhstan's coal to generate electricity domestically for export, such as to Central Asia and South Asia. The CASA-1000 project's goal of adding regional thermal generating capacity to support hydroelectric generation in Tajikistan and Kyrgyzstan may open avenues for Kazakhstan's participation in that project.

7. URANIUM

7. URANIUM

7.1. KEY POINTS

- Kazakhstan is the world's leading uranium producer, accounting for about 40% of global production. Unprecedented growth of uranium production from 2003 to 2016 by more than sevenfold will be followed for the first time by a decrease in production in 2017 by 10% in order to restore prices in the uranium market. The market situation associated with the fall in the price of uranium in 2016 by 40% has seriously affected the industry, even though Kazakhstan has the lowest cost of uranium mine production in the world due to the efficient and environmentally friendly in-situ leaching technology (ISL).[1]
- The global uranium market currently can be characterized as a "buyer's market" (demand constrained), with a relatively small number of producers supplying a similarly small number of major clients. Kazakhstan's effort to support uranium prices by announcing plans to cut its production by over 2,000 tons (Mt) in 2017 appears to have had limited impact to date. Globally, most production is sold under long-term contract prices (less sensitive to near-term production fluctuations), and there is no indication yet that other producers are ready to move with coordinated production cuts along with Kazakhstan. However, Kazakhstan may have the capacity to affect spot prices by storing product and thus limiting supply. When making decisions about how to limit supplies to market, the choice between storing uranium and cutting production should be based upon the underlying economics, and on how long the chosen strategy can be feasibly pursued (for example, on how long a producer can bear increases in variable costs in case production is cut, compared to costs of storage and financing, etc.)
- In the long term, the growth in the number of nuclear power plants in the world will be accompanied by an increase in demand for uranium. It is the new developing markets that will determine the demand for uranium in the future, whereas in developed countries, the decommissioning of nuclear power plants will significantly exceed the launch of new reactors. According to the World Nuclear Association as of May 2017, 60 reactors with a total capacity of 64.5 GW are under construction, while another 164 reactors (with a capacity of 170.8 GW) are planned for construction.
- A prolonged search for a consumer of fuel pellets by the national nuclear company Kazatomprom, following the suspension by Russia of the purchase of fuel pellets made at the Ulba Metallurgical Plant (UMP), is nearing an end. According to an agreement reached with the China General Nuclear Power Corporation (CGNPC), a production line for manufacturing fuel assemblies (containing fuel rods housing fuel pellets) with a design capacity of 200 tons of uranium annually will begin production based on a French design for PWR reactors. The launch of the fuel assembly line in Kazakhstan is a success for Kazatomprom, since initially CGNPC insisted on establishing production capacity in China.
- Kazakhstan's participation in an important international initiative to establish a Nuclear Fuel Bank (of low-enriched uranium) on its territory is an important political step to support the concept of non-proliferation of nuclear weapons. In 2017, it is planned to complete the construction of a storage facility on the site of the UMP to accommodate up to 90 tons of low-enriched uranium for the Nuclear Fuel Bank. The placement of the Bank on the territory of the UMP will not be an exceptional event for the plant, as the volumes of fuel storage at the plant earlier significantly exceeded this volume.
- The realization of the concept of achieving a closed nuclear fuel cycle (NFC) may be that nuclear power will become almost renewable; studies toward this goal are being conducted, for example, in Russia's "Proryv" (or "Breakthrough") project. Despite the high hopes placed on the closed-cycle technologies being developed, their significant impact on the uranium market is likely to be felt only beyond the planning horizon of this report. However, in view of the potential prospects of closed nuclear fuel cycle projects and the existence of unique research and test facilities, Kazakhstan is encouraged to explore avenues for greater involvement of its scientists in joint work and research on this and other promising areas of the nuclear industry (expansion of the fuel base, high-temperature reactors, etc.).

[1] The International Atomic Energy Agency (IAEA) recognizes the ISL technology as the most environmentally friendly and safe way of mining deposits.

7.2. URANIUM SECTOR UPDATE

7.2.1. Market structure

Production of uranium in Kazakhstan comes from 19 mine projects, 6 of which owned by the national company Kazatomprom, while the other 13 are joint ventures with foreign companies, including AREVA, Cameco, Uranium One, as well as with Chinese and Japanese investors. On an entitlement basis, Kazatomprom accounted for 54% of the uranium mined in 2015, followed by Uranium One with a share of 20%, AREVA with 9%, and the Energy Asia consortium of Japanese companies with 8%.[2] Because Kazakhstan does not presently possess nuclear power generation capacity (only research reactors and test benches), all of the produced uranium is exported, primarily under long-term contracts. Of all the stages in the nuclear fuel cycle, only uranium mining, reconversion, and fuel pellet fabrication are currently undertaken in Kazakhstan.[3]

Kazakhstan's Government sets the main directions of state policy related to nuclear power generation, and is responsible for certain safety regulations (including for the development of the National Nuclear Emergency Plan). The Energy Ministry is responsible for setting and execution of state policies in the nuclear power sector, as well as for the management of the uranium production sector (including overseeing exports) and the (potential future) nuclear power generation sector. Kazatomprom, which is owned by the Samruk-Kazyna National Welfare Fund—the state corporation managing state assets—has the status of a National Company in the uranium production industry. According to the Subsoil Law, a National Company has the authority to represent the state's interests in subsoil contracts, as well as to monitor and execute such contracts. The National Nuclear Center at Kurchatov, which operates three research reactors, undertakes research and development activities.

7.2.2. Uranium reserves

Kazakhstan's reserves are among the largest in the world: as of January 2015, reasonably assured resources (RARs, roughly corresponding to the A+B+C1 reserves category used in Kazakhstan) that are recoverable at a cost of less than \$260/kg U are estimated at 0.4 MMt (8% of the world's total), below only Australia with 1.2 MMt and Canada with 0.5 MMt.[4] Importantly, as a result of geological exploration, the country significantly increased its low-cost reserves. Kazakhstan's resources recoverable at a cost of up to \$80/kg U increased from 200 Mt as of January 2013 to 230 Mt in January 2015. In absolute terms this increase is second only to South Africa, which expanded its reserve base in this cost category by 55 Mt. For the rest of the world, reserves in this category recorded a net decrease of 73 Mt (driven by Canada, where reserves declined by 79 Mt). In terms of inferred resources—the category corresponding to the C_2 category used in Kazakhstan—the country increased its reserves by 120 Mt (to 438 Mt) in the same period, as more reserves were classified as inferred at the Inkai and Moinkum deposits.

[2] Energy Asia shares are distributed as follows: Marubeni 30%, TEPCO 30%, Toshiba 22.5%, Chubu Electric 10%, Tohoku Electric Power 5%, and Kyushu Electric Power 2.5%.

[3] Specifically, Kazatomprom owns the UMP, which has the capability to produce fuel pellets. During the Soviet period, UMP covered up to 80% of the USSR's nuclear power plants' needs in fuel pellets. After the drop in demand and the subsequent refusal by Russia to place new orders for fuel pellets, UMP reoriented its operations to the production of powdered raw materials from uranium hexafluoride. The production of fuel pellets is now minimal (10 tons in 2014, 0 tons in 2015, 24 tons in 2016), with deliveries directed to consumers in China.

[4] The 2016 NEA/IAEA Report provides a figure of 363,200 tons for RAR (A+B+C1), with another 578,400 tons in the C2 reserve category.

7.2.3. Uranium production

Kazakhstan's total uranium production increased from 22 Mt in 2013 to 25 Mt in 2016 (see Table 7.1). Kazakhstan's leading uranium producer is state-owned Kazatomprom: in 2015 it produced 12.9 Mt of uranium (up from 11.9 Mt in 2013), which constitutes 54% of the country's uranium mine production and 21% of the world's total production. The remaining 46% of U production in Kazakhstan comes largely from mines worked by international joint ventures with companies from other countries (e.g., Canada, France, Japan, and Russia). Globally, other large uranium producers include Cameco (2015 production of 10.9 Mt, or 18%), AREVA (9.4 Mt, 16%), and Rosatom (7.8 Mt, 13%).

Table 7.1. Aggregate uranium production by Kazatomprom's subsidiaries, 2010-2016 (metric tons)

	2010	2011	2012	2013	2014	2015	2016
Total production	17 449	19 096	20 979	22 501	22 829	23 806	24 689

Source: Kazatomprom

Considering individual mines, the biggest addition to output came from the Kharasan-1 and Kharasan-2 mines, which between 2013 and 2015 increased production by 360 and 510 tons, respectively, while the combined output from the Tortkuduk and Moinkum mines increased by 550 tons. At the same time, output at the Vostok and Zvezdnoye minesceased in 2015 due to depletion of reserves.

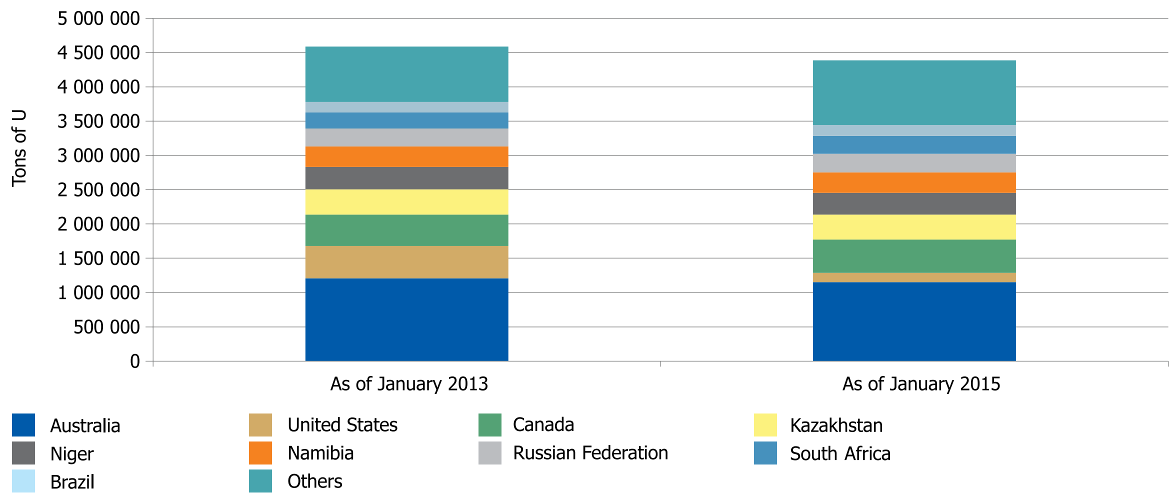
7.2.4. Uranium exports

All uranium produced in Kazakhstan is exported. According to the Kazakhstan Customs Committee, China has remained the largest importer of Kazakhstan's uranium, although its share in total exports decreased from 54% in 2014 to 46% in 2016. Reduction in purchases by China reflects a reduction in the pace of the country's stocks replenishments. Similarly, the share of Russia decreased from 19% to 14% in the same period. In contrast, France increased purchases, as its share went up from 6% to 14%, while India, which previously had not purchased uranium from Kazakhstan, bought 2.5 Mt in 2016, or about 10% of Kazakhstan's total 2016 uranium exports.

7.2.5. Global uranium market

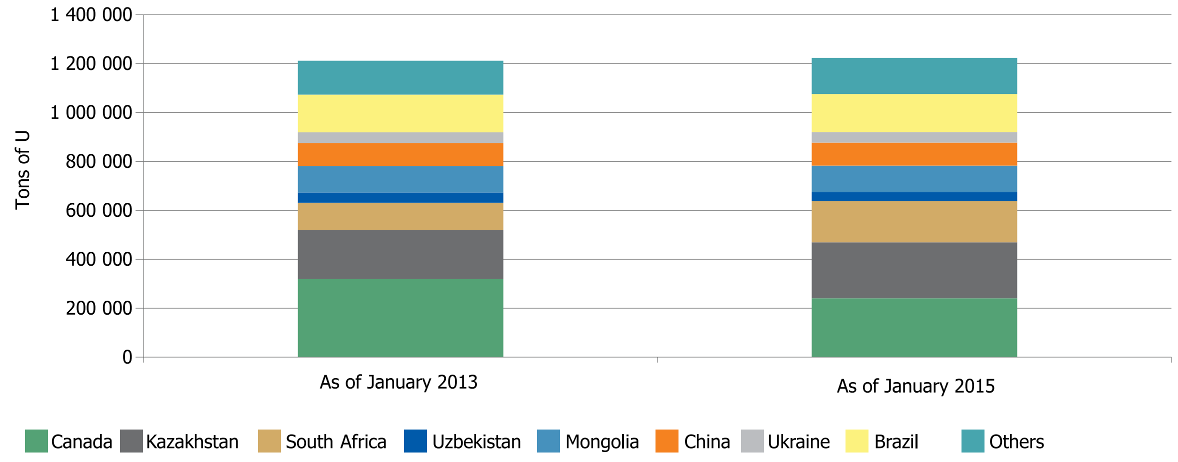
Global RARs of conventional uranium recoverable at a cost of under \$260/kgU decreased from 4.6 MMt as of January 2013 to 4.4 MMt as of January 2015 as the result of the decrease of reserves in the US by 334 Mt due to reappraisal (at the same time, reserves in Greenland increased by 103 Mt during the same period). During the same period, inferred reserves recoverable in the same cost category increased from 3.0 MMt to 3.2 MMt (see Figure 7.1). Global RARs recoverable at costs below \$80/kgU went up by 12 Mt. The largest reserves increases came from Kazakhstan, South Africa, Peru, and Russia, which expanded their reserves by 30, 55, 13, and 12 Mt (respectively), while on the negative side, decreases of reserves by Canada and the US amounted to 79 and 22 Mt (see Figure 7.2). Given the global production level of 62 Mt in 2016, RARs recoverable at costs below \$80/kgU would last for 20 years, while those at costs of up to \$260/kgU—for 73 years.The growth in uranium production in the world over the past 10 years is associated with a reduction in the supply of enriched military uranium to the market. As can be seen from Table 7.2, the production of electricity at nuclear power plants, despite the increase in capacity by 5.4% (20 GW), even decreased by 4.5%. This fact can be explained by a decrease in the output of electricity by nuclear power plants in Germany and the suspension of nuclear power plant operations in Japan after the accident on March 11, 2011 at the Fukushima Daiichi nuclear power plant.

Figure 7.1. World's reasonably assured reserves with cost of production <\$260/kgU



Source: IHS Markit, World Nuclear Association © 2017 IHS Markit

Figure 7.2. World's reasonably assured reserves with cost of production <\$80/kgU



Source: IHS Markit, World Nuclear Association © 2017 IHS Markit

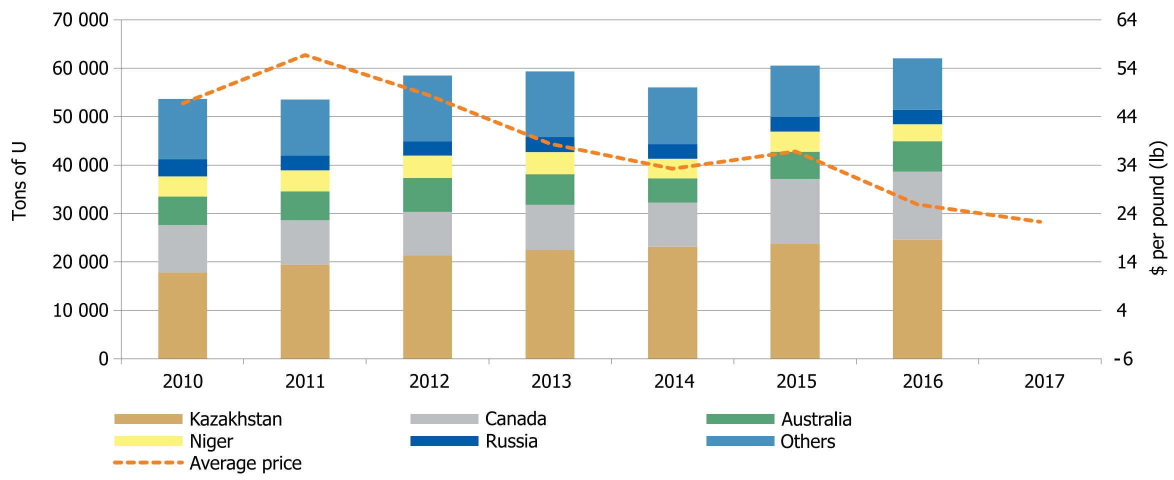
Table 7.2. World's production, consumption of Uranium, nuclear power generation capacity, reactors and power generation from 2007 to 2016 (tons)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Uranium production	41 282	43 764	50 772	53 671	53 493	58 489	59 331	56 041	60 496	62 012
Share of global Uranium demand, met by production	64%	68%	78%	78%	85%	86%	92%	85%	90%	98%
Uranium requirements (end of year)	66 529	64 615	65 405	68 646	62 552	67 990	64 978	65 908	66 883	63 404
Number of operable reactors (end of year)	439	436	436	442	434	435	435	437	439	447
Capacity, GW (end of year)	372	372	373	377	370	374	375	378	383	392
Nuclear power generation, billion kWh	2 608	2 601	2 560	2 630	2 518	2 346	2 359	2 411	2 441	2 490

Source: World Nuclear Association

On the demand side, power generation remains the largest consumer of uranium globally, accounting for 95% of overall demand. Uranium is also used for medical and research purposes and naval propulsion (e.g., powering ice-breaking vessels, submarines).[5]
While global nuclear generation capacity increased, uranium requirements decreased by about 4%, partially reflecting stalled reactors in Japan (see below), as well as higher efficiency in fuel use.[6] Utilities in the US and Europe are specifying lower tails assays at contracts with enrichment facilities, which means that uranium is enriched to a greater degree (for example, from 3.3% of ^{235}U to 5.0% of ^{235}U). Utilities can now burn uranium harder and longer. The World Nuclear Association (WNA) estimates that since the 1970s, fuel burn-up increased from 40 GWd (giga Watt-days) per ton of uranium to more than 60 GWd/t. As a result, utilities tend to leave only 0.5% of ^{235}U in spent fuel, compared to 1.0% in the past. The net effect of the higher efficiency is that less reactor fuel is needed to produce the same amount of electricity.
By the end of 2016, there were 447 reactors with a total capacity of 391 GW around the world. In 2016 they produced 2,490 billion kWh. Total uranium requirements by the end of 2016 were estimated at 63 Mt.[7] China was the main driver behind the growth in global uranium reactor capacity between 2014 and 2017; the number of operable reactors in China increased from 19 in January 2014 to 35 in January 2017, while total generation capacity grew from 16 GW to 32 GW.[8] In 2016 alone, the number of reactors globally increased by 8, adding another 8.8 GW to installed capacity; China added 5 reactors, with a total generating capacity of 4.8 GW. China's ambitious plans for the expansion of nuclear generation are laid out in its 12^{th} (2011–15) and 13^{th} (2016–20) Five-Year Plans (FYP). However, in reality capacity growth lagged far behind the 12^{th} FYP target for nuclear power due to the temporary suspension of new project approvals pending safety reviews and a revision of standards following the Fukushima accident in 2011; new project approvals resumed in early 2015. 13^{th} FYP specifies a 2020 goal for operable nuclear generating capacity of 58 GW, with another 30 GW of capacity under construction. China has ambitions to become a global nuclear industry leader by building up its proprietary Gen III and Gen IV technologies and scaling up supply chains to prepare for future exports.
Other countries that recorded a net increase in nuclear generation capacity during the 2014–15 period included Russia, with a net addition of two reactors (to a total of 35 reactors), adding 1.8 GW of combined capacity, as well as Argentina and South Korea, each adding one reactor with capacities of 0.7 GW and 0.9 GW, respectively. In contrast, the number of operable reactors in Japan decreased by 7 (to a total of 43 reactors), resulting in a net decline of total capacity by 3.9 GW in the aftermath of the Fukushima Daiichi disaster in 2011. These seven reactors have been permanently shut down.
Japan is still one of the major consumers of nuclear energy, with 42 operable reactors and a total generating capacity of 40 GW, as the country gradually starts to bring back online inactive nuclear reactors. Most of the country's reactors are temporarily offline pending safety reviews, but five have been restarted (including Ikata-3, Sendai-1 and Sendai-2, Takahama-3 and Takahama-4), with a total capacity of 4 GW. As of March 2017, 25 reactors (16 power plants) had applied for approval to start operations from the Nuclear Regulation Authority (NRA), which developed new safety requirements in 2013, imposing tougher regulations on the ability to withstand natural disasters and accidents. In 2016, the NRA also granted three Kansai Electric reactors—Mihama-3, Takahama-1, and Takahama-2—lifetime extensions from 40 to 60 years. The three reactors will likely restart operations between 2019 and 2020, after carrying out required modifications to meet the new safety standards. In February 2017, Kansai Electric's Ohi 3 and 4 reactors also received preliminary NRA approval. Before the Fukushima disaster, nuclear accounted for about 30% of Japan's total generation capacity. To meet Prime Minister Shinzo Abe's goal of generating 20% of the country's electricity from nuclear by 2030, about 30 of the operable reactors might need to be restarted. However, the restarts remain politically contentious, with about 60% of Japanese polled in public opinion surveys opposing them; some restarts have been delayed by legal challenges from anti-nuclear groups. If the safety reviews and restarts proceed according to schedule—a big assumption given the uncertainties involved—IHS Markit estimates that annual generation from nuclear in Japan could rise to as much as 143.9 terawatt-hours (TWh) by 2020 (less than half the peak level in 2000).
In addition to Japan, Germany, Sweden, the UK, and the US each decreased the number of operable reactors during the period 2014–15. Each country closed one reactor, decreasing these countries' nuclear generation capacities by a net of 1.3 GW, 0.7 GW, 1.2 GW, and 0.1 GW, respectively.
Although the number of reactors and overall capacity in the United States remained stable during the 2013–15 period (the US leads the world in both metrics), as the industry was able to extend the useful lives of reactors through improvements in maintenance, the bankruptcy of the Westinghouse Electric Company in late March 2017 is a disquieting development for the industry. The filing emerged as Westinghouse's parent company, Toshiba, takes steps to recover from massive losses incurred in the construction by Westinghouse of two nuclear power plants—Units 3 and 4 of the Vogtle Plant in Georgia, and Units 2 and 3 of the Virgil C. Summer station in South Carolina, with each unit's capacity being 1.3 GW—both badly behind schedule and over budget. The problems are attributed to a combination of factors, including the launch of a new reactor design (AP1000), unexpected new safety requirements following the Fukushima Daiichi incident, and (given the dormancy of reactor construction activity in the US) construction delays by US contractors lacking the expertise and equipment needed to make some of the largest reactor components. Not only is the future of the two projects now in doubt, but Toshiba appears either to be seeking a buyer for Westinghouse or to refocus the company on reactor design and maintenance, rather than construction. In either event, Toshiba appears to be considering exiting the nuclear business outside of its home base of operations, Japan.
On the supply side, after decreasing from 59 Mt in 2013 to 56 Mt in 2014 (mainly due to production declines in Australia and Namibia), global conventional uranium output increased to 60 Mt in 2015. As a share of total global production, Kazakhstan accounted for 38% and 39% in 2013 and 2015, respectively, making it the world's leading producer. The increased output in Kazakhstan (2 Mt) was the second largest among producing countries, as Canada expanded production by 4 Mt (to 13 Mt) during the same period, driven by the launch of production from the Cigar Lake mine in Saskatchewan. Thus, Canada remains the world's second largest conventional uranium producer.
The rest of demand (not supplied by world mine production) is met with secondary sources, including civilian stockpiles, re-enriched depleted tails, as well as recycled uranium and plutonium from used fuel and downblended ex-military uranium and plutonium (both in the form of mixed oxide, or MOX, fuel). Although data from the Nuclear Energy Association (NEA) and IAEA suggest a decline in global commercial stocks from 155 Mt at the start of 2013 to 143 Mt at the start of 2015, the availability of secondary resources (and the decline in Japanese and European demand post-Fukushima) has continued to exert downward pressure on prices, despite the suspension in October 2016 of the cooperative US-Russian program on downblending Russia's stocks of weapons-grade plutonium for civilian uses (Megatons to Megawatts).
As demand for uranium has been stagnating (with reactor phase-outs in developed markets, such as Japan and Germany, being balanced with reactor build-ups in emerging markets, such as China and India), production has been rising; as a consequence, prices for uranium plummeted (see Figure 7.3). After briefly increasing from \$28/lb (\$73/kgU) in June 2014 to \$40/lb (\$104/kgU) in November 2014, spot prices averaged \$37/lb (\$96/kgU) throughout 2015 before falling steeply from \$36/lb (\$94/kgU) in November 2015 to below \$19/lb (\$49/kgU) in November 2016, reaching levels last seen in early 2004.

Figure 7.3. Global uranium production by major producer vs. uranium price



Source: IHS Markit, World Nuclear Association

[5] Data on consumption of uranium for nuclear weapons production are not available, but the amount is believed to be negligible relative to quantities consumed during the Cold-War-era nuclear arms race.

[6] The World Nuclear Association estimates that between 1980 and 2008 there was a 3.6-fold increase of electricity generated from nuclear reactors, while the demand for uranium increased only by a factor of 2.5.

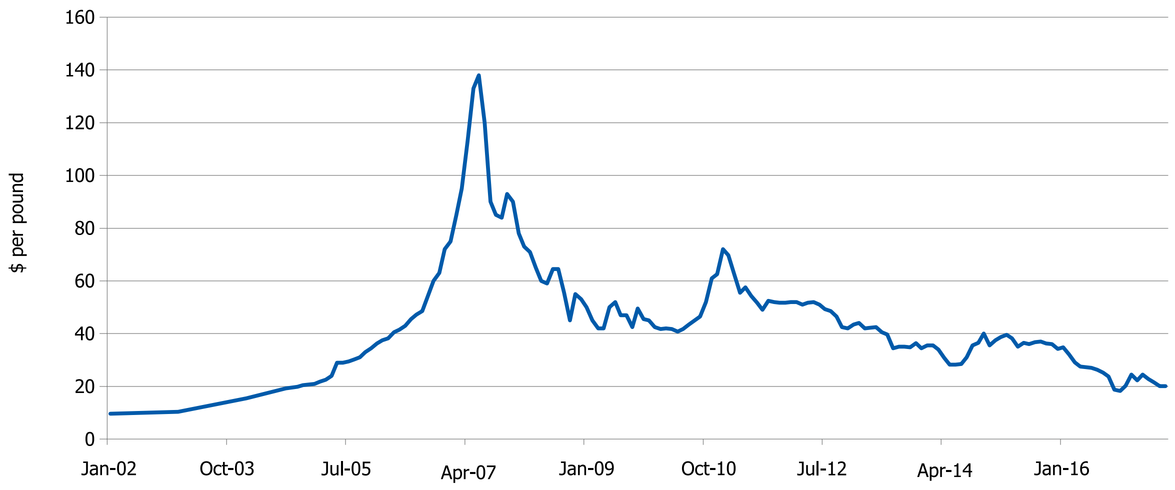
[7] The uranium requirements estimates reflect the annual reactor requirements (specific to each reactor design) that depend on a range of country-specific operating variables, including capacity factor, burnups and enrichment level, as well as first core fuel for new reactors (assumed to be required two years in advance of the reactor's operation).

[8] Operable reactors are the ones that are connected to the grid. A reactor might be operable, but might not be running due to a temporary shutdown.

Producers' reaction to the low price environment included delays in new mine development as well as production cuts from, or shutdowns of, existing mines (including in Malawi, US, Canada, Australia, and Niger). In January 2017 Kazakhstan announced a planned cut in production by "over 2 Mt," or about 3% of global mine out putfor 2017. Since that time, apparently responding in part to news of the production cut, uranium prices rallied to levels above $25/lb ($65/kgU) by mid-March, but averaged $24/lb ($62/kgU) by the end of the month.

As most major producers, Kazakhstan sells uranium predominantly on a long-term contract basis. Spot market prices have been consistently much lower than the long-term contract prices (see Figure7.4). Specifically, the difference between the Nuexco exchange spot price and the arithmetic mean of long-term prices reported by Ux Consulting and TradeTech, averaged $9.5 per pound in 2015 and $12.7 per pound in 2016. This is well above the cost of storage, estimated for certain industry participants at only $0.2 per pound annually.

Figure 7.4. Spot price of U_3O_8



Source: IMF Primary Commodity Prices, IHS Markit

7.2.6. Uranium transportation

Kazakhstan's nuclear materials transportation market is open for participation and requires two licenses: one—from the Nuclear and Energy Control and Oversight Committee, and another—from the Investments and Development Ministry's Transportation Committee. The major transportation modes used are rail, automobiles, and air transportation. Transportation of nuclear radioactive materials also involves participation by security services from the Ministry of Internal Affairs.

7.2.7. Domestic use: nuclear fuel cycle and proposed reactor construction

Kazakhstan is seeking to expand uranium processing to encompass the entire nuclear fuel cycle. As of 2016, Kazatomprom and Canada's Cameco are carrying out a feasibility study on a proposed purification facility in Kazakhstan to produce uranium trioxide (UO_3) from triuraniumoctoxide (U_3O_8), with an annual capacity of 6 Mt, for further conversion into uranium hexafluoride (UF_6) at Cameco's conversion facility in Canada.[9] The two sides are evaluating the economic feasibility of this project. Also, Kazakhstan continues to participate in the uranium enrichment sector through its partnership with the Russian JSC TVEL at the Urals Electrochemical Integrated Plant, Russia's largest enrichment facility. In addition to this project (called the Uranium Enrichment Center [UEC] JSC), Kazakhstan through its national company Kazatomprom has access to enrichment services via the International Uranium Enrichment Center (IUEC) in Angarsk (Russia), 10% of which is owned by Kazatomprom.

In the fuel production segment, Kazatomprom and China's China General Nuclear Power Corporation launched the construction of a fuel assembly production line at the UMP with a capacity of 200 tons annually. The $150 million project will use AREVA-licensed technology and is projected to be completed by 2020.

As to nuclear power generation, Kazakhstan has explicitly stated its interest in constructing a nuclear power plant, and is conducting a study to determine the capacity, location, and timing of a plant. The advantage of developing nuclear energy for Kazakhstan is the fact that there are no greenhouse gas emissions or emissions of other harmful substances. Radioactive waste generated in the process of operation is strictly localized in a relatively small volume. Modern nuclear power plants have an order of magnitude less radiation impact on the population than coal-fired power plants. And nuclear power is a high-tech and knowledge-based industry, the development of which will give additional impetus to Kazakhstan's economic development, including by gradually increasing the share of local content in the design, construction, and operation of nuclear power plants.

[9] The mined ore in the form of U_3O_8 still contains impurities and therefore needs to be purified prior to conversion to UF_6. The most commonly used process is based on the solvent extraction method, which transforms U_3O_8 into UO_3. Cameco's conversion facility in Port Hope (Ontario province) requires UO_3 as a feedstock to produce UF_6.

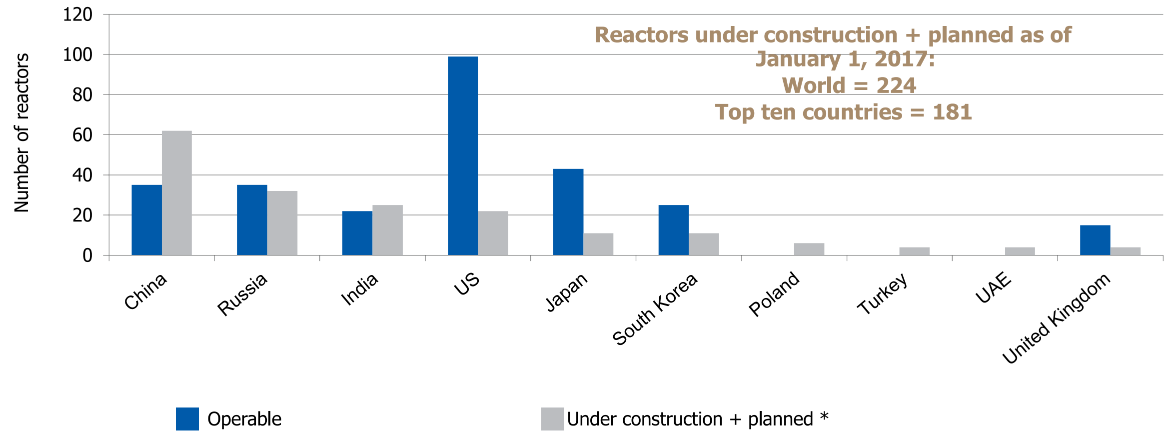
7.2.8. Uranium balance outlook

In the longer term, growth in reactor-related demand will provide support for price growth. As of January 2017, there were 447 reactors in operation and 60 reactors under construction—22 of which are in China, and seven in Russia. To compare, as of January 2015, 437 reactors were in operation and 70 under construction.

- In 2015, construction started on eight reactors (six reactors in China, one in Pakistan, and onein UAE), while ten reactors were connected to the grid (eight reactors in China, one in South Korea, and one in Russia), and seven reactors were permanently shut down (five in Japan, and one each in Germany and the UK).
- In 2016, construction of three reactors commenced (two in China and one in Pakistan), while ten reactors became operational (five reactors in China, one in each of Pakistan, India, Russia, South Korea, US), and three were shut down (one in each of US, Japan, and Russia).

The number of reactors globally that have secured approvals and funding, and are expected to become operational in the next eight to ten years, is estimated at 164, of which 40 planned reactors are in China, 25 in Russia, 20 in India, and 18 in the US (see Figure 7.5). The IHS Markit Rivalry scenario for electric generation capacity by fuel type/technology projects further modest growth in nuclear generation capacity worldwide out to 2030 and beyond—1.6% annually between 2015 and 2040.[10] Although projected nuclear capacity in 2040 (592 GW) exceeds that in 2015 (391 GW) by more than 50%, the share of nuclear in total electrical generation capacity falls to 5% (from 6% in 2015).

Figure 7.5. Top ten countries with the largest additions of reactors



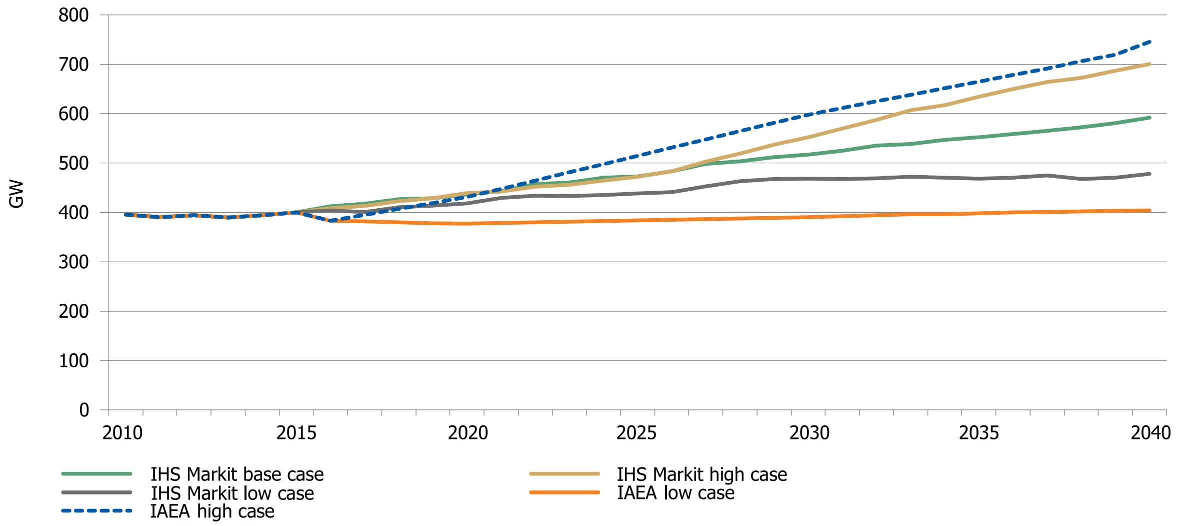
Notes: * Under Construction = First concrete for reactor poured, or major refurbishment underway. Planned = Approvals, funding or commitment in place, mostly expected in operation within 8-10 years.

Source: IHS Markit, World Nuclear Association

The outlook for uranium demand is linked to the nuclear capacity build-out and appears to be positive during the forecast period. IHS Markit Scenarios fall in between the high and low scenarios by NEA/IAEA from 2016 (see Figure 7.6).

[10] The Rivalry scenario is the baseline scenario for IHS Markit projections, and assumes increased competition among energy sources as a result of price differentials, environmental concerns, technology improvements, and energy security considerations. Increased cost competitiveness and more stringent environmental regulation lead to greater powertrain and fuels competition in transportation.

Figure 7.6. Global nuclear generation capacity outlook by scenario



Source: IHS Markit, NEA/IAEA

The low NEA/IAEA case, reflecting a "conservative, but plausible" scenario, assumes a continuation of the current policies and regulations that are cautious about the prospects for nuclear power generation. For example, under the low case scenario, Japan's nuclear generation capacity decreases from 40 GW currently to 25 GW in 2020 and further to 15 GW in 2030. As a result, global annual reactor-related demand is projected to stagnate at levels just over 65 Mt (compared to the present level of about 68 Mt).

The high case, reflecting an "ambitious" scenario, assumes policies favoring climate change mitigation, although this scenario also incorporates the phase-out of nuclear generation capacity in Belgium and Germany by 2025. Under this case, projected annual reactor requirements for uranium will surpass 100 Mt in early 2030s.

The NEA/IAEA estimates that if existing and committed (FID) mines produce at stated capacity, this should be adequate to meet global uranium demand entirely through the early 2030s under the low case, and 60% of the requirement under the high case. When identified planned and prospective mining projects are taken into consideration, however, projected production capacity will exceed requirements.

7.2.9. IAEA Nuclear Fuel Bank in Kazakhstan

Kazakhstan continues progress toward establishing an international low enriched uranium (LEU) fuel bank. The goal of the project is to prevent the spread of uranium enrichment technologies, by providing IAEA member states with access to the reserved volumes of low-enriched uranium used for fabricating nuclear fuel.

A ten-year agreement between Kazakhstan and the International Atomic Energy Agency (IAEA) from 27 August 2015 was approved by Kazakhstan's Parliament in November 2016 and envisions construction of a fuel bank at the UMP. The bank is capable of storing up to 90 tons of low-enriched uranium hexafluoride (UF_6) fuel and is set to be launched in late August 2017.

In accordance with the agreement, any country in case of urgent need and in order to avoid interruptions in deliveries can submit an official application to the IAEA for the supply of nuclear fuel. The organization redirects the application to the fuel bank. Costs associated with the establishment of the fuel bank (which were reduced by placing the bank on the territory of an operating plant) are shared equally by Kazakhstan and IAEA, whereas the cost of acquiring and delivering LEU to the Nuclear Fuel Bank is borne by the IAEA (in part, these costs are financed by donor funds from the US, EU, United Arab Emirates, Kuwait, and Norway).

7.2.10. Conclusions/notable changes since 2015

- Kazakhstan increased its uranium RARs in the price category of $80/kg or below, from 200 Mt in January 2013 to 230 Mt in 2015; this is the second largest increase in this reserve category of any country in the world.
- Kazakhstan plans to voluntarily reduce the country's mine production in response to an oversupplied market and depressed price environment.

As per Kazatomprom's Askar Zhumangaliyev, Kazakhstan's "planned production" will be reduced "by about 10%," or "by over 2 Mt." The effect of this cut on global uranium prices could be limited because: there is no formal agreement among the global producers on coordinated supply cuts; Kazakhstan's planned production cut amounts to only about 3% of global annual demand; and Kazakhstan exportswithin a "buyer's" market, with China accounting for about half of its total exports. For this reason, Kazakhstan is also seeking to address an excessive gap between spot and long-term prices by studying the possibility of storing uranium, which may drive spot market prices higher.

- Reflecting its efforts to expand its presence in the nuclear fuel cycle, Kazakhstan has commenced construction of a fuel fabrication facility in collaboration with Chinese investors.
- An ongoing feasibility study commissioned by President Nazarbayev (to be completed in 2018) will answer questions about future nuclear generation in Kazakhstan: how many reactors will be built in Kazakhstan, and what will be their capacity and locations?
- The IAEA LEU Fuel Bank at the UMP is scheduled to open in 2017.

7.3. INFRASTRUCTURE AND TECHNOLOGIES: KEY CHALLENGES, IDEAS, AND SOLUTIONS

7.3.1. Downstream value added

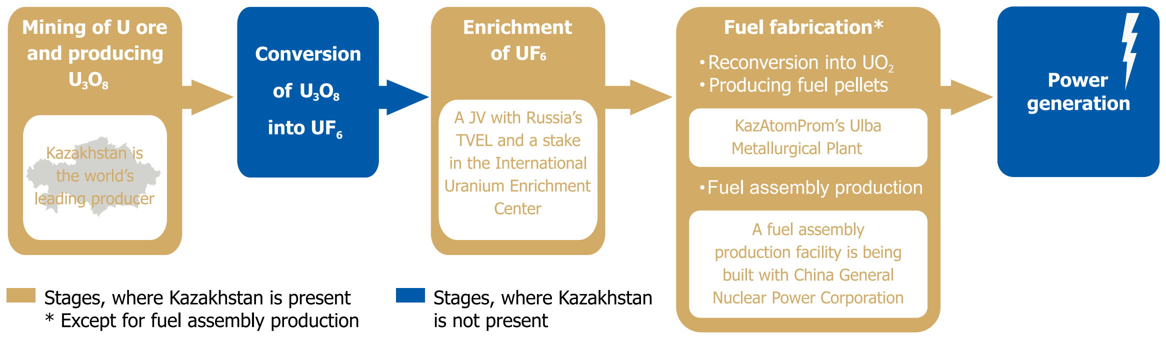
The nuclear fuel cycle has two phases. The "front end" phase of the cycle consists of (see Figure 7.7):

- mining of uranium ore and production of uranium oxide (U_3O_8) concentrate
- conversion of U_3O_8 into uranium hexafluoride (UF_6)
- enrichment of UF_6 (i.e., the increase of the uranium-235 isotope concentration)
- fuel fabrication, which includes three separate steps:
  - reconversion into uranium oxide (UO_2)
  - production of ceramic fuel pellets
  - combination of pellets into fuel rods
  - assemblyof the rodsinto a fuel assembly structure.

The "back end" phase includes the reprocessing, storage, recycling, and disposal of spent nuclear fuel.

Kazakhstan currently is present in the front end phase, specifically in the mining stage, as well as partially at the fuel fabrication stage (namely, in reconversion of enriched UF_6 into UO_2 and pellet fabrication at the UMP). The country is moving towards establishing its position in other stages of the cycle as well.

Figure 7.7. The "front end" of the nuclear fuel cycle



Source: IHS Markit

7.3.2. Mining

Almost 99% of all current mining of uranium ore in Kazakhstan is carried out from sedimentary (sandstone) rocks with the use of in-situ leaching (ISL) technology. This technology was developed in the USSR and the US independently from each other in the mid-1970s. This method generally involves injecting a leaching agent (e.g., 1–2% sulfuric acid solution [H_2SO_4][11]) into the water-saturated and

[11] In the United States, the ISL technology does not use an acid (as in Kazakhstan and Australia), but rather less effective alkali (mainly based on carbonates) because of the large amount of acid-absorbing minerals, including gypsum and limestone, in the water-bearing formations where production is carried out.

permeable ore body through a system of injection wells. Currently, drilling is carried out at depths of no more than 750 meters, but in the future, deeper horizons can be developed. The leaching agent dissolves uranium, and the "productive solution" (usually containing less than 0.1% uranium) is then extracted via a network of production wells and goes through primary treatment (uranium is released using ion exchange resins) before it is ready for conversion and enrichment (see the section on the nuclear fuel cycle below).[12]

The ISL method has pronounced advantages over traditional ore mining methods (mining and quarrying) in terms of costs and environmental impact. Since the reserves are extracted without eliminating the surrounding rock (cap rock), expenditures on ore extraction (excavation) and mining are significantly reduced or even eliminated altogether, while operating costs are also minimal. For the same reason, the level of environmental impact is reduced. Unlike quarrying or mining, the top layer of soil is hardly affected, no waste heaps are formed, radon emissions are minimized, and no toxic dust is produced. However, there is a need to dispose of the productive solution (containing the leaching agent and wastewater) after the initial treatment. In Kazakhstan, the solution (after refortification using an oxidizing agent and a complexing reagent) is pumped back to the injection wells for reuse (i.e., re-injection into the ore body). This makes it possible to significantly reduce the consumption of water and sulfuric acid. That part of the solution that is not pumped into the ore body (a small amount of the solution is poured off to maintain pressure difference at the wellhead) is to be disposed of as waste, since it contains various dissolved components (in particular, chlorides, sulfates, radium, arsenic, and iron). Such wastes are disposed of at special landfills (in particular, in wells for burial of waste in the depleted part of the ore body).

One of the challenges in terms of environmental protection in the application of ISL is the need to prevent contamination of groundwater located at a distance from the ore body. This is facilitated by maintaining a pressure differential at the wellhead, ensuring a uniform flow to the deposit or ore body from the nearby aquifer and preventing drilling fluids from entering the surrounding (undeveloped) area.[13] Here, groundwater quality analysis is performed through control wells. Thus, in the extraction of uranium by the ISL method, pollution of groundwater is minimized. After production is completed using ISL technology, wells are sealed. The quality of the groundwater present in the field is subject to recovery to the level specified by the standard, determined prior to production. After decommissioning, measures are taken to ensure radiation safety, despite the fact that most of the radioactive ore body lies at great depth. It is mandatory to regularly check the condition of the air, soil, and dust content.

Several technological trends are shaping the future of uranium mining. The mining industry has been going through a large-scale adoption of digital technologies in four broad areas:

- digitizing production to generate accurate data about operations
- data analysis to optimize current and future results
- promoting connectivity between workers and equipment
- automationof operations.

Employing digital innovations in uranium mining can yield benefits by providing a better understanding of geological information, optimizing the flows of equipment and materials, reducing maintenance spending, advancing automation, as well as offering real-time performance evaluation. Similar to the Smart Field concept in oil and gas, the Digital Mine concept is a case in point in the mining industry in general.

In September 2016 GE Mining introduced the Digital Mine—a technological suite combining machine sensors, connectivity, and analytics. GE has formed a partnership with the mining equipment manufacturer Komatsu to develop a new generation of mining equipment that would employ the Digital Mine suite, including sensors and connectivity equipment. Kazatomprom launched a pilot Digital Mine project at its SaUran subsidiary in the first quarter of 2016 at a cost of 158 million tenge with the goal of expanding this to other subsidiaries by late 2018. Specific results included reducing the time for equipment diagnostics from 14 days to 2 days as well as cutting energy consumption by 10%.

7.3.3. Conversion

During the conversion stage, uranium oxide concentrate, which leaves the mine as U_3O_8, is stripped of impurities (purified) and then converted into UF_6, which is the feedstock for enrichment—the next phase of the cycle. The "wet" conversion method used in Canada, France, China, and Russia involves dissolving U_3O_8 in nitric acid to produce uranyl nitrate, which is then purified and the uranium stream is evaporated to get UO_3 through thermal decomposition. After reducing UO_3 to UO_2, and a subsequent reaction with HF, the resulting UF_4 is fed into a fluidized bed reactor with fluoride to get UF_6. In the "dry" method used in the US, U_3O_8 is purified through heating before being reduced to UO_2. The resulting UF_6 from the conversion stage has the form of gas under warm temperatures. To transport highly corrosive UF_6, it is turned into a liquid under low temperatures and moderate pressure, which is then shipped in steel cylinders with thick walls.

Currently, the global conversion nameplate capacity is estimated at 52 Mt of uranium (in the form of UF_6). The conversion market is highly concentrated, with five companies owning the entire capacity. Canada and Russia each holds 24% of the total global conversion capacity, France 29%, US 13%, and China 10%. In addition, UF_6 supplies from secondary sources are available in the market. These include commercial and government inventories, recovered depleted uranium tails from depleted uranium hexafluoride storages, as well as residual volumes of UF_6 remaining after enrichment companies meet power stations' requirements by enriching UF_6. The World Nuclear Association estimates secondary sources of UF_6 supplies equivalent to 12 Mt of uranium in 2015 and projected not to exceed 14 Mt a year through 2022. This will lead to oversupply in the conversion market and will continue to exert downward pressure on prices.

There is also demand for deconversion of depleted uranium from the UF_6 form into either U_3O_8 or UF_4. Deconversion allows for the storage of depleted uranium, as well as for recovery of HF as a by-product for further use at conversion facilities.

Kazakhstan plans to enter the conversion segment through a JV with Canada's Cameco. As a part of an upstream asset deal in 2016, Cameco transferred its technology for the purification of uranium to the joint venture on a royalty-free basis. Cameco and Kazatomprom are conducting an economic feasibility study on construction of a 6 Mt uranium purification facility in Kazakhstanthat would also convert U_3O_8 into UO_3. At the early stages of the project, until the construction of Kazakhstan's own plant for production of UF_6, UO_3 is planned to be sent to Cameco's conversion facility in Port Hope, Ontario for production of UF_6. In addition, in 2016 Kazatomprom has obtained a five-year option to license Cameco's conversion technology for the purpose of constructing and operating a UF_6 conversion facility in Kazakhstan on the site of the UMP.

7.3.4. Enrichment

The goal of enrichment is to increase the percentage of ^{235}U to 3-5% required for use in power reactors. UF_6 in gaseous form is the feedstock.In 2015, global enrichment capacity was estimated at 59 million Separative Work Units (SWU),[14] of which Russia's share was 46%, that of France 12%, China 10%, US 8%, with the rest of the capacity located in Germany, Netherlands, and United Kingdom. As a result of enrichment, two products are obtained: enriched uranium in the form of UF_6 and "tails" of depleted uranium with a concentration of ^{235}U at 0.25–0.3%. One ton of UF_6 produces 130 kg of enriched UF_6 and 870 kg of depleted UF_6, containing mainly ^{238}U. Gas diffusion for uranium enrichment is no longer used, and the predominant technology is centrifuge enrichment.

In the centrifuge enrichment process, the UF_6 gas is fed into centrifuges—rotors inside vacuum tubes. As the rotors spin (at high speeds of at least 70,000 rpm), molecules with heavier ^{238}U move towards the rotors' outer edge, while molecules with ^{235}U concentrate near the rotors' center. Subsequently, the enriched product is drawn off the centrifuges. Centrifuges form a cascade, each consisting of 10–20 elements, which continuously operate for about 25 years. Compared to the gaseous diffusion technology, centrifuge enrichment is much less energy intensive, as it requires about 50 kWh per SWU.

In addition to centrifuge enrichment, laser process enrichment is a promising technology that offers low energy consumption, reduced capital costs, and tails assays. In the atomic process, a laser ionizes ^{235}U atoms so that positively charged ^{235}U ions are collected by a negatively charged plate. In the molecular process, a laser breaks the molecular bond binding a fluorine atom to a ^{235}U atom, separating the ionized UF_5 molecules from UF_6 molecules. The WNA estimates that, in 2020, 93% of the entire supply of enriched uranium will come from the centrifuge enrichment process, while 3%—from the laser process.

Kazakhstanhas entered the enrichment segment through a cooperation agreement with Russia. In 2006 Kazatomprom formed the Uranium Enrichment Center JV with TENEX (currently the shareholder representing Russian Federation is TVEL) on a parity basis with the initial goal of constructing a new enrichment facility. However, these plans were changed in 2010 and as a result, the JV acquired a 25% stake in the Ural Electrochemical Integrated Plant in 2013, gaining access to up to 5 million SWU of existing enrichment capacity. Since 2007, Kazatomprom also has owned a 10% share in the International Uranium Enrichment Center on the site of the Angarsk Electrolysis Chemical Plant, which has a total enrichment capacity of 2 million SWU per year.

[12] Analysis of the technology of ISL and its environmental and economic benefits can be found in KAZENERGY "National Energy Report 2013," Astana: KAZENERGY, 2013, p. 95–96, 99, 103.

[13] Control wells are installed above, below, and around the target zone (the developed part of the ore body) to make sure that the flow of drilling fluids does not go beyond the permitted area of development.

[14] SWU is a complex measure of the quantity of separative work performed to enrich a given amount of uranium to a certain level. According to the WNA, 7.9 SWU and 10.4 kg of natural uranium (with uranium tails with a ^{235}U content of 0.25%) are required to enrich one kilogram of uranium to a level of ^{235}U in a volume of 5%. If the content of ^{235}U in uranium tails is 0.20%, 9.4 kg of natural uranium and 8.9 SWU are required.

7.3.5. Fuel assembly

Reactor fuel consists of ceramic UO_2 pellets, organized in columns and sealed in tubes made from zirconium alloy (fuel rods). In this form, reactor fuel can withstand high temperatures and intense radiation for a fuel lifetime of several years. After enrichment is completed, UF_6 is converted to UO_2 powder (a process referred to as "reconversion"), which can be implemented using a "wet" or "dry" technology. For a 1,000 MW water-water reactor, 27t of enriched UO_2 is needed annually. After reconversion, the UO_2 powder may go through conditioning to ensure that uniformity, density, and microstructure standards are met. Then the powder is processed under high temperature and a reducing atmosphere to form pellets (typically 1.5 cm high and 8 cm in diameter). One pellet for a typical reactor allows for production of the same amount of energy as a ton of steam coal. The pellets are inserted into rods made of a noncorrosive material (typically, zirconium alloy). Rods are then arranged in a fuel assembly - a highly precise grid held together by a framework engineered to be resistant to corrosion, high temperatures, vibration, and large static loads. The quality of the fuel assembly is determined by the composition of the grid materials, which are made of a zirconium alloy with the addition of other metals, including nickel, niobium, iron, and chromium. A 1,000 MW pressurized water reactor holds about 47,000 rods, containing over 12 million pellets in total. A fuel assembly weighs about 655 kg, of which the uranium weight is 460 kg.

Kazakhstan entered into the fuel assembly segment in December 2016, when Kazatomprom and China General Nuclear Power Corporation (CGNPC) launched the construction of a facility at the UMP that will produce fuel assemblies for reactors in China. The facility, in which Kazatomprom owns 51% and CGNPC 49%, will use technology supplied by AREVA and will require about $150 million in investments to launch the project by 2020. The agreement with AREVA provides for a license for fuel fabrication technology, engineering documentation, supply of the key production equipment, and personnel training.

7.3.6. Nuclear power generation

Generation of energy at nuclear power plants occurs as a result of the fission reaction of uranium nuclei (or other fissile elements) in the reactor. The central part of the nuclear reactor, including nuclear fuel (located in fuel assemblies), the moderator, and regulating systems (neutron absorber rods), form the core through which the coolant is pumped,[15] transferring heat from the nuclear fission reaction to the turbine (single-circuit reactors) or through the heat exchanger (steam generator) to the second coolant circuit (double-circuit reactors).

According to the neutron spectrum, there are reactors that run on fast neutrons and on thermal neutrons. The deceleration of neutrons in nuclear thermal reactors occurs at special moderators (water, graphite) to increase the probability of absorption of a neutron by the ^{235}U nucleus. The absorption of fast neutrons is more likely to occur on ^{238}U nuclei with the formation of plutonium, which is ^{239}Pu fission.

The pressurized water reactor (PWR/VVER), originally developed for use in nuclear submarines, is presently the most popular reactor type in the world, accounting for 64% of the reactors used for power generation globally. In the primary cooling circuit, water, which also is a moderator for neutrons, flows under high pressure of 150 ATM (to prevent it from boiling inside the core). In the secondary circuit, water boils and moves turbines to generate electricity. The technology of pressure reactors has been most popular due to internal safety features, simplicity and accessibility of the use of the coolant and the moderator—water. The high power density of the core, in comparison to gas-cooled, heavy water, and boiling reactors, made PWR technology the most accessible for export, as PWR reactors have dimensions suitable for transportation by road and rail. Ability to use low-enriched fuel and a comparatively high fuel burn-up make PWR reactors the most economically preferable. In addition, the use of PWR technology results in the accumulation of spent nuclear fuel and radioactive waste in much smaller volumes than in other types of reactors.

The second most prevalent reactor type is a single-loop water-water "boiling" reactor (BWR), which differs from PWR by having only one circuit in which water (coolant and moderator) boils and steam under pressure is directed to turbines. About 18% of the world's power reactors are of the boiling water type, with 34 operable reactors located in the US, 22 in Japan, 7 in Sweden, and 15 in other countries. The simplicity of the design, the circulation system, the equipment used, and the reduced pressure in the reactor vessel create certain advantages for the BWR, including lower capital costs for construction. However, boiling water is characterized by significantly lower critical thermal loads; therefore, the power density of the core is 1.5 to 2 times lower than in PWR, and hence the size of the BWR core significantly exceeds the size of the active PWR zones of the same power. Due to the large size, transportation of the BWR reactor core by rail is impossible; therefore only water transport is used. Disadvantages include more complex analysis of fuel consumption due to the presence of both water and steam in the system, the contamination of the turbine which is in direct contact with the primary coolant, and possible risk of inability to halt the reactor as control rods are inserted from below the core and require an uninterruptable power source.

The third most popular reactor type (11% of the world's reactors, a total of 49 reactors) is the pressurized heavy water reactor (PHWR), in which heavy water is used as moderator. PHWR was first developed in Canada, and is known as CANDU (Canada Deuterium Uranium). It uses natural uranium oxide as fuel, and heavy water (deuterium oxide) as the moderator. CANDU reactors, unlike PWR and BWR, are not vessel-type, but channel-type, where fuel assemblies with nuclear fuel are located in channels (pressure tubes) with a coolant. The supply and removal of coolant from each of the channels is carried out by individual pipelines. One of the advantages of channel-type reactors versus vessel-type reactors is the possibility of replacing spent fuel without stopping the reactor. If heavy water is used as the coolant in this type of reactor, then the reactors operate on unenriched natural uranium, as well as on spent nuclear fuel of other types of reactors. The drawbacks include the high cost of making heavy water, emission of radioactive tritium, and large reactor core size. Heavy water reactors, in comparison with other types, have been less popular primarily because of the high cost of their installed capacity. In addition, an important fact is that the channels (pressure tubes) are located in the core under a constantly strong neutron flux and exposure to hydrogen, which leads to hydride cracking. Therefore, the concept of the CANDU reactor assumes a complete replacement of the duct pipes after 20 years of operation in order to bring the total life of the station to 40 years. This fact has a significant impact on the economics of CANDU reactor operation.

In addition to nuclear thermal reactors (PWR, BWR, and PHWR), fast neutron reactors are operated in limited numbers (three reactors in Russia: BOR-60, BN-600, and BN-800). These reactors lack a neutron moderator in their core, but rather have a breeding zone where fissile elements (^{239}Pu) are produced from uranium ^{238}U. In view of the considerable heat release in fast neutron reactors, molten metal is used as the coolant.

Kazakhstan's only nuclear station operated between 1972 and 1999 in Aktau (also known as the city of Shevchenko). The station used a fast neutron reactor BN-350 that used a sodium coolant; the reactor's thermal power was 1,000 MW, and had a total generating capacity of 350 MW. The generated power was also used to desalinate sea water and for heat supply. The life of the reactor was 20 years, and since 1993, was operated on the basis of an annual license renewal. In 1999, the reactor was shut down and the process of decommissioning began.

In terms of technological advancement, reactors are categorized by generations. Generation 1 reactors were developed in the 1950s and used natural uranium as fuel and graphite as a moderator. Most existing reactors globally today are Generation 2 reactors, as they use enriched uranium as fuel and water as a moderator. Generation 3 reactors are based on Generation 2 units, but with advanced safety characteristics (through greater reliance on passive safety systems, which are independent of the actions of personnel and the supply of electricity), simpler design, higher fuel burn-up, and longer operating life. Generation 4 reactors are expected to enter the market after 2020. In 2002, the intergovernmental Generation IV International Forum (GIF), representing 14 countries that use nuclear power, selected six reactor designs believed to represent future Generation 4 reactors; three of these are fast neutron reactors, two slow neutrons (similar to currently operating reactors), and one epithermal.

The NER 2015 suggested nuclear power generation should have a role in the country's future capacity mix, as it not only would make an important contribution to baseload production, but also would improve the country's carbon credentials by offsetting coal-fired power production.

In his State of the Union address in January 2014, President Nazarbayev instructed the government to develop a plan for building a nuclear power plant. The plan, compiled in May 2014 (and further amended in November 2016), seeks to complete a feasibility study by 2018 on construction of two nuclear power stations in the city of Kurchatov (East Kazakhstan region) and in the town of Ulken (Almaty region). The location and main characteristics of the stations were chosen based on three previous studies: a 1997 feasibility study for a station in Ulken using Russia's VVER-640 PWR-type reactor; a 2006 feasibility study for a station in Aktau (Mangistau region) using Russia's VBER-300 PWR-type reactor; and a 2009 research study on an electricity balance forecast that required nuclear power generating capacities, and which recommended three locations (Ulken, Aktau, and Kurchatov). Most recently, the Energy Ministry has considered using a Russian reactor for the Kurchatov location, while for the Ulken location Generation 3 reactor designs by Westinghouse/Toshiba, AREVA/Mitsubishi, and Hitachi/GE are being considered.

[15] Water as well as heavy water, molten metal (sodium), carbon dioxide, and helium are used as a coolant.

7.3.7. Back end of the fuel cycle

Radioactive wastes are characterized by the amount and type of radioactivity, as well as by the time the wastes remain hazardous. There are three types of radiation: alpha radiation, which is not able to penetrate the skin; beta radiation, which is able to penetrate the body, but does not pass through an obstacle in the form of aluminum foil; and gamma radiation, which requires the use of blocking means of greater thickness (such as concrete). The time the wastes remain radioactive depends on the half-lives of the isotopes they contain, which is the time it takes for the isotope to lose half of its radioactivity. Half-lives can range from milliseconds to billions of years.
There are three types of radioactive waste. Low-level radioactive waste contains small amounts of short-lived radioactivity, and may be present on clothing, tools, and filters. Not dangerous to handle, it is usually buried in landfills. Intermediate-level waste has higher radioactivity and includes contaminated materials from reactors or reactor components. It is disposed by solidification in concrete and deep burial underground. High-level radioactive waste, such as spent nuclear reactor fuel, contains fission products and requires cooling as well as additional protection during handling and transportation. The amount of high-level radioactive waste from a typical large nuclear reactor is estimated at 25–30 tons per year.
In contrast to open pit mining, the volume of radioactive waste from in-situ leaching production (primarily used in Kazakhstan) is negligible, as all materials except for uranium are returned underground. U_3O_8 produced from mines is mildly radioactive. Therefore, most of the waste that requires special handling comes from reactors: a typical 1,000 MW PWR of Russian design produces about 27 tons of used fuel annually, which can be either reprocessed or disposed as waste, after it is stored for several years in cooling ponds at the reactor site.
Reprocessing involves chemical separation into reprocessed uranium (RepU, mostly ^{238}U, but also ^{235}U depleted to less than 1%), Pu, and high-level radioactive residual, with the latter comprising 3% of the recycled output volume. The residual also contains some radioactive actinides (elements with atomic numbers from 89 to 103). Reprocessing fuel used in PWR with a capacity of 1,000 MW generates 230 kg of plutonium and 700 kg of highly active residue annually. Reprocessed uranium also contains ^{232}U and ^{236}U, which are neutron absorbers; thus, reprocessed uranium requires a higher enrichment rate than natural uranium for use as fuel in a PWR. However, RepU can be readily used by PHWRs. Currently the WNA estimates the stock of RepU at 45 Mt globally (equivalent to 50 Mt of natural uranium). Recovered Pu is readily used as MOX fuel. In 2015, 820 tons of enriched RepU and 900 tons of Pu was used, displacing 1720 tons of natural uranium; the projected use in 2025 amounts to 2090 and 1350 tons, for RepU and Pu (respectively), displacing 3440 tons of natural uranium; the prospects for using uranium-plutonium fuel in Russia can further increase this level.
Reprocessing can use three separation technologies: pyrometallurgy—using heat; electrometallurgy—using electric current; and hydrometallurgy—using a chemical solution to dissolve material. Nowadays, the most commonly used process is a hydrometallurgy-type (PUREX) process that uses concentrated nitric acid and solvent extraction. The electrometallurgy process is seen as having the most promise, as it allows for recovery of all actinides.
The high-level radioactive residual is solidified through evaporation, mixed with glass-forming materials (i.e., borosilicate glass) to ensure it is insoluble in ground water, melted, and poured into stainless steel containers to avoid corrosion. For the recycling of this type of waste produced during the operation of a 1,000 MW PWR, 400 kg of glass are required per year. Advanced solidification technology involves turning waste into synthetic rock using naturally stable minerals. Before final disposal, high-level radioactive waste has to spend up to five decades either in sealed concrete structures or under water in ponds to allow for radioactivity to decay. The waste is finally disposed by burial in stable geological formations (using bentonite clay to inhibit ground water movement) for a thousand years, by which time radioactivity will correspond to the naturally occurring background level. Prospective nuclear reactor designs associated with fast neutron reactors change the outlook for waste, as these reactors would source their fuel from used fuel as well as depleted uranium stocks produced by enrichment plants.
On this "back end" of the fuel cycle, Kazakhstan currently has a storage facility for ionizing radiation sources, built in 1993 in Kurchatov. However, as its capacity is insufficient, the government plans to build a center for the processing and long-term storage of nuclear waste. The corresponding feasibility study was carried out in 2006 for the processing of 1.5 Mt, and storage of 9 Mt of waste annually.

7.3.8. Nuclear research and development

The National Nuclear Center was created in 1992 and combines two research reactors (a pulse graphite reactor and a high-temperature gas-cooled reactor) and three test benches. In addition, the Tokamak thermonuclear material research facility was launched in 2017 in the city of Kurchatov. Kazakhstan's Materials science Tokamak (KTM) was launched as part of the international project ITER (International Experimental Thermonuclear Reactor), and is designed for research and testing of materials in the energy loading modes of thermonuclear power reactors. It should be noted that in Kurchatov there is a unique base for nuclear research and nuclear energy, with a great human potential. Research centers including research reactors and test benches were built in Kurchatov as part of the Soviet program for the development of a high-temperature nuclear rocket engine.
In turn, the Institute of Nuclear Physics (INP) of the Republic of Kazakhstan has a VVR-K water-water research reactor, an isochronous cyclotron, and several scientific laboratories. INP is also working on the establishment of a nuclear safety training center in collaboration with the US Department of Energy's Brookhaven National Laboratory to train specialists.
With its experience in operating a nuclear reactor in the past and the extensive personnel base (the INP alone employs 700 people) in its nuclear research institutions, Kazakhstan has definite potential to operate a future nuclear reactor. The domestic capacity to educate nuclear industry personnel is based on the current programs in nuclear physics at Gumilev Eurasian National University and Al Farabi Kazakh National University, which cooperate closely with Russia's leading academic institutions (such as the Moscow Physics Engineering Institute). In April 2017, Kazatomprom signed an agreement with Satpayev Kazakh National Research Technical University to create an international scientific educational center for the nuclear industry.

7.4. REGULATION OF KAZAKHSTAN'S URANIUM SECTOR

7.4.1. Review of Kazakhstan's relevant legislation and national and international goals and targets in the uranium sector

The government reform in August 2014 changed the administration of the nuclear power sector, when the newly formed Ministry of Energy assumed responsibilities over the nuclear power sector as well as uranium production from the former Ministry of Industry and New Technologies. Consequently, the Industry Ministry's Nuclear Energy Committee was reorganized into the Nuclear and Power Control and Oversight Committee under the Ministry of Energy. The committee exercises regulatory and control functions.
A new version of the Law on Nuclear Energy Use was enacted in January 2016 and replaced a similar Law from 1997 that had become obsolete. The new Law expanded safety-related measures by introducing expert evaluation of nuclear safety as well as nuclear safety personnel accreditation. The Law also introduced: rules for physical security of nuclear materials, facilities, and storage; safety rules for handling radionuclides; the Nuclear Emergencies National Plan; rules for transportation of nuclear materials and radioactive substances; and rules for collecting, storing, and disposing of nuclear waste. Most of these regulations were developed and issued by the Ministry of Energy in the beginning of 2016.
Other laws governing aspects of the uranium sector include:

- The Law of the Republic of Kazakhstan from April 23, 1998 No. 219 "On Radiation Safety of the Population", which identifies state policies on, and requirements for, nuclear safety
- The Law of the Republic of Kazakhstan from July 21, 2007 No. 300 "On Export Control", which sets guidelines for control of exports of nuclear and radiation materials
- The Code of the Republic of Kazakhstan from January 9, 2007 No. 212 "Ecological Code of the Republic of Kazakhstan", which identifies environmental standards related to nuclear materials and nuclear power
- The Code of the Republic of Kazakhstan from September 18, 2009 No. 193-IV "On the health of the people and the health care system", which establishes health and sanitary requirements related to nuclear security
- The Law of the Republic of Kazakhstan from May 16, 2014 No. 202-V 3PK "On Permits and Notifications", which identifies licensing requirements related to nuclear energy, nuclear waste, and nuclear security
- The Law of the Republic of Kazakhstan from June 24, 2010 No. 291-IV "On Subsoil and Subsoil Use", which governs all key aspects related to uranium mining.

Kazakhstan's ambition to develop a position encompassing the entire nuclear cycle is reflected in key strategic planning documents.
Published in January 2014, the Concept of Kazakhstan's becoming one of the 30 most developed countries in the world by 2050 (Decree of the President of the Republic of Kazakhstan of January 17, 2014 No. 732) calls for the development of a knowledge-based economy in the country. The Concept envisages that in the future (in 25–30 years) the basic industries, including oil and gas and mining and metallurgy, will be the main driving forces for promoting the economy along the path of further industrialization and the development of related industries. Among other industries, the highest priority

is given to the uranium industry and nuclear power engineering with the task of further developing all phases of the entire value chain.

Strategic Plan for the Development of the Republic of Kazakhstan to 2020 (Decree of the President of the Republic of Kazakhstan from 1 February 2010 No. 922), determines the future directions of the state policy and strategic goals of the country. The development of nuclear power is seen as a way of producing less expensive and more environmentally safe energy. Specific goals set for the energy sector for 2020 include the start-up of a nuclear power plant and creating a vertically integrated company involved in all phases of the nuclear fuel cycle.

The Uranium Industry and Nuclear Energy Development Concept approved in August 2002 (and abolished in April 2010) resulted in the formulation of the Nuclear Development Program for 2011–2014, with the prospect of development until 2020 (Resolution of the Government of the Republic of Kazakhstan from June 29, 2011 No. 728), which establishes specific tasks in four main target areas, including:

- For the nuclear cycle, it called for launching a conversion facility to produce 12 Mt of UF_6 by 2016, starting uranium enrichment in Russia with an entitlement capacity of 2.5 million SWU from 2014, and launching production of fuel assemblies at UMP in 2020.
- For nuclear power generation, it called for completion of a feasibility study on constructing a nuclear power station in Kazakhstan by 2015 (with the station to be built by 2020 in the event of government approval).
- For nuclear science, the Program envisioned modification of the country's three science reactors from highly enriched uranium (HEU) to low enriched uranium (LEU)—by 2018 for a 6 MW basin-type VVR-K reactor and by 2020 for a tank-type research high-temperature gas-cooled reactor IVG-1 with a capacity of 35–60 MW and a pulsed graphite reactor with a capacity of 10 MW. With the help of the Russian corporation Rosatom, the modernization of the VVR-K reactor was completed already in May 2016.
- For nuclear security, the Program sought to develop and implement a nuclear waste storage and recycling plan, including the creation of a Center for the Processing and Long-Term Storage of Radioactive Waste. For environmental protection, the Program planned to open a Center for Complex Dosimetry by 2018 and a Center for Nuclear Medicine by 2015. As of November 2016, the dosimetry center was in the implementation stage, while the medical center project appears to be experiencing delays.

The Concept for the Development of the Fuel and Energy Complex of the Republic of Kazakhstan until 2030 (Resolution of the Government of the Republic of Kazakhstan from June 28, 2014 No. 724) gives the nuclear power sector a nod as a promising sector for future technological development. The Concept indicates that entry into all stages of the nuclear cycle would increase Kazakhstan's competitive advantage and revenues, estimating the profitability (EBITDA) of uranium mining at 40%, enrichment at 45%, and conversion at no more than 15%. In terms of revenues from the initial stage of the nuclear fuel cycle, the concept stipulates that production accounts for 48% (according to the WNA estimates this is 43%), for conversion 8% (according to the WNA 4%), enrichment 32% (according to the WNA 27%), and for the production of fuel assemblies 16% (WNA 22%). The Concept suggested that entry into the various stages of the nuclear cycle could be facilitated by forming strategic partnerships. The main objectives include: further development of the sales network and distribution channels of uranium; expansion of opportunities for uranium enrichment; implementation of uranium conversion and fuel assembly projects; development of nuclear energy; promotion of the development of research centers; and ensuring the availability of skilled personnel.

The goals set by the Concept for the development of the fuel and energy complex were reflected in the Development Strategy of Samruk-Kazyna National Welfare Fund for 2012–2022. This means that the Fund and Kazatomprom will be guided in their work by the state's strategic goals in the field of fuel and energy sector development.

Kazakhstan has been a member of the International Atomic Energy Agency since February 1994. Kazakhstan also has ratified several key conventions that allow the country to pursue international collaboration in the nuclear power industry:

- Agreement between the Republic of Kazakhstan and the IAEA for the Application of Safeguards in Connection with the Treaty on the Non-Proliferation of Nuclear Weapons
- Vienna Convention on Civil Liability for Nuclear Damage
- Convention on Nuclear Safety
- Convention on Early Notification of a Nuclear Accident
- Convention on Assistance in the Case of a Nuclear Accident or Radiological Emergency
- Joint Convention on the Safety of Spent Fuel Management and on the Safety of Radioactive Waste Management
- Convention on Physical Protection of Nuclear Material.

[16] Fuel assemblies with ^{238}U are loaded into the special "breeding zone" of the breeder. The fission reaction (^{238}U) produces ^{239}Pu, which can be used later for the production of new nuclear fuel. The reproduction ratio (the ratio of the speed of formation of fissile isotopes to the speed of their burn-up) of breeder reactors may exceed one, which means that more fissile elements are produced than consumed (burned out) in the core of the reactor.

[17] In the uranium-thorium cycle, ^{235}U can be used as a fissile element, with broadly available ^{232}Th as a raw material; the fission reaction (^{232}Th) produces fissile uranium ^{233}U.

Promising technologies

One of the obstacles to the long-term development of the nuclear energy is that uranium reserves are finite; if uranium consumption increases to 100 Mt a year, known uranium reserves will last for a maximum of 50 years. Closing of the nuclear fuel cycle by using fast neutron reactors that would allow for the production of fissile isotopes (breeder reactors, breeders) will make nuclear power renewable and will allow the use of broadly available isotopes of uranium (^{238}U)[16] and thorium (^{232}Th)[17]. This would resolve not only the problem of the exhaustibility of uranium resources, but also the problem of handling ^{235}U and highly radioactive elements (minor actinides contained in spent nuclear fuel).

Currently, the "Proryv" (or "Breakthrough") project implemented in Russia aims at the practical implementation of a closed nuclear cycle (uranium-plutonium). Within the framework of the project, the construction of a pilot industrial power complex with a BREST-OD-300 reactor and an on-site nuclear fuel cycle are part of a high-density nitride uranium-plutonium fuel production line. In fact, the closure of the fuel cycle occurs within a single nuclear power plant. Another direction that is being pursued under the "Proryv" project is the development of a BN-1200 fast neutron reactor with a reproduction ratio of 1.2.

It is planned that the creation of a nuclear power plant based on BN-1200 reactors will allow for realization of a closed fuel cycle that includes operating nuclear power plants based on thermal neutrons. A closed fuel cycle could be possible if the share of breeder reactors reaches 20% of the total capacity of reactors involved in the cycle; the production of fissile isotopes will provide nuclear fuel not only for the needs of the breeder reactors, but also for the thermal neutron reactors.

Implementation of Russia's strategy to create a closed nuclear fuel cycle is an ambitious project with the potential to significantly impact energy markets over the long term, beyond the planning horizon of this report.

Safety culture

Taking into account the intention of the Republic of Kazakhstan to enter all stages of the nuclear fuel cycle (with the exception of processing imported radioactive waste), including the production of electricity at nuclear power plants, it is important to consider safety culture issues in regulating the production of nuclear energy.

The culture of security is an essential aspect, the importance of which is invariably recognized by the international nuclear community. Thus, according to the definition of the US Nuclear Regulatory Commission (NRC), a safety culture is "the core values and behaviors resulting from a collective commitment by leaders and individuals to emphasize safety over competing goals to ensure protection of people and the environment." In turn, the IAEA defines a strong safety culture as "the assembly of characteristics and attitudes in organizations and individuals which establishes that, as an overriding priority, protection and safety issues receive the attention warranted by their significance." In other words, the safety culture helps to avoid negligence ("counting on luck") and to introduce an active approach to preventing potential problems and, ultimately, accidents. The culture of security is a long-established concept. In particular, the IAEA has developed safety standards based on five characteristics of a safety culture:

- safety is integrated into all activities
- safety is a clearly recognized value
- leadership for safety is clear
- accountability for safety is clear
- safety is learning driven.

A safety culture is an integral part of the guidelines followed by the IAEA. In particular, according to IAEA standards, the concept of a safety culture is included in such documents as the "Governmental, Legal and Regulatory Framework for Safety and Leadership" and "Management for Safety."

7.4.2. Key Recommendations

Given the high priority of the development of nuclear energy in Kazakhstan, it is recommended to:

- based on the projected balances of electricity and capacity, determine the timing of the construction of a nuclear power plant in Kazakhstan
- determine the type of reactor, capacity, and location most suitable for Kazakhstan
- taking into account the goals of the Paris Agreements, determine the share of nuclear in overall power generation and coordinate with the timeframe of electricity market development
- increase targeted funding by the state for research programs on nuclear energy and develop a strategy for the development of nuclear research, taking into account the human resources and research base
- more broadly, implement technologies to improve the efficiency of ISL production methods based on the experience of the oil and gas industry
- given the plans for the development of nuclear energy in Kazakhstan, pay close attention to the safety culture; in particular, IAEA safety standards, and the mechanisms for implementing these norms, should be reflected in the legislation of Kazakhstan.

8. KAZAKHSTAN'S ELECTRIC POWER SECTOR

8. ELECTRIC POWER

8.1. KEY POINTS

With the slump in oil prices over the last few years, Kazakhstan's pace of economic growth also slowed. For Kazakhstan's power sector, this new reality has weighed heavily on annual power consumption, which since 2012 has been drifting within a relatively tight range around 90 TWh (terawatt-hours). And despite year-on-year power demand in 2016 perking up, it will still grow at a considerably slower average annual rate than what was experienced during the last decade. So on the face of it, the economic situation (along with recent increases in grid and available capacity) has removed any immediate impulse to add new power generating capacity. But despite little evidence of a looming energy crisis, Kazakhstan has committed to ambitious green economy goals while ensuring energy security. Considering a significant share of Kazakhstan's generating capacity is relatively old coal-fired and baseload oriented, Kazakhstan has a difficult challenge in justifying and incentivizing investment for improving efficiency and flexibility given current infrastructure availability. Kazakh policymakers need to adopt smarter regulation that support shifts in fundamentals and encourage technology options (on both supply and demand sides) to meet upcoming challenges. Moreover, Kazakhstan's energy strategy needs to better marry its green goals with incentive-based market mechanisms. Consider the following observations:

- **Fundamentals point to changing power consumption trends.** The way electricity is being used and generated in Kazakhstan is changing, and becoming more pronounced. Key factors that will drive this change are greater infiltration of renewables, growing electrification of Kazakhstan's economy (particularly urban demand), and influence of power market mechanisms on power consumption. At that, the grid network will gradually become "active."
- **Investors need incentives to improve power sector infrastructure so as to create flexible power as well as usher in the most efficient technology solutions in grid and generating capacity.** Again brought into sharp focus as renewable production grows, it implies adjusting current regulation and adapting market mechanisms to unlock more of Kazakhstan's gas potential, despite being a relatively more expensive fuel source than coal. Moreover, among many technology solutions, capacity storage technologies can play a growing role stabilizing the grid. Given Kazakhstan's unavoidable use of coal in power production, combustion emission control technologies that destroy or remove sulfur dioxide (SO_2), nitrogen oxides (NOX), mercury, particulate matter (PM), and other air pollutants, which are now a basic obligation globally, should also be the technological norm in Kazakhstan.
- **A more cohesive and logical approach is needed in developing power sector rules and regulations.** The current regulatory situation is disjointed and unpredictable, negatively impacting the investment climate. The current power market mechanisms barely serve the sector's real needs or progress Kazakhstan's stated policy targets. While maintaining current policy goals, Kazakh policymakers might consider moving towards closer harmonization with Russia's market schemes given the strong power infrastructural link, intensifying Eurasian Economic Union integration, and Russia's extensive market experience when trying to adopt Western-styled power market mechanisms.
- **Policymakers need to be guided by realistic outlook assessments while potential investors and analysts need considerably better access to information and data.** While capacity shortfalls are obviously undesirable, the cost of responding to overly optimistic forecasts can place an unnecessary financial burden on the value chain, particularly on consumers. Moreover, power sector transparency and access to data need to be dramatically improved to help spur investment confidence and offer both policymakers and investors better predictability.

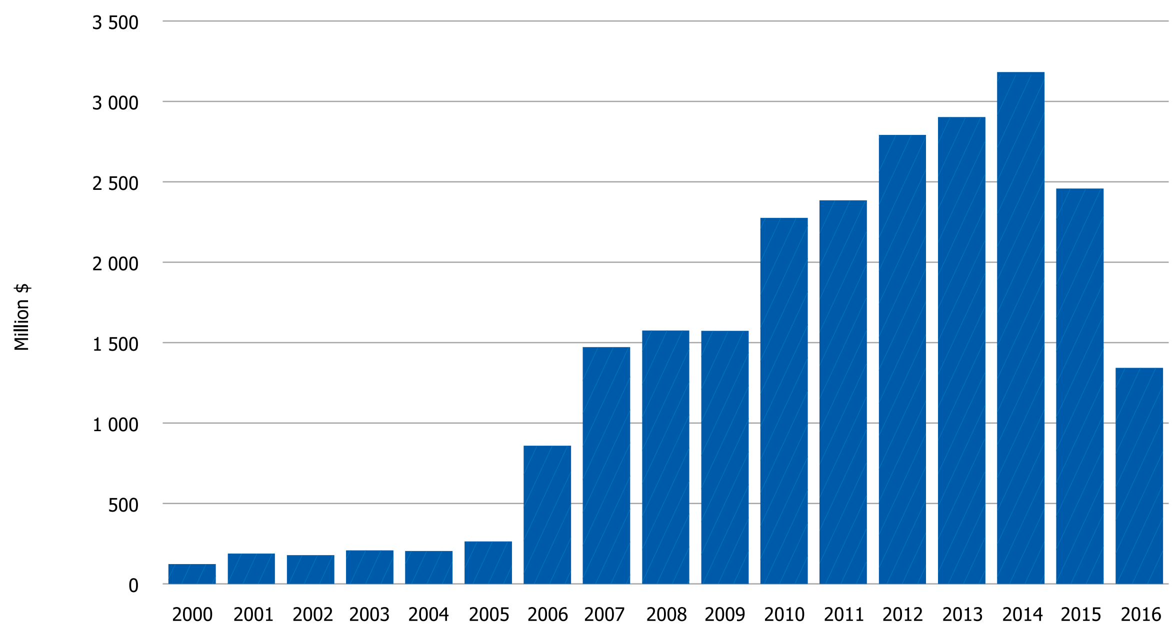
[1] Terawatt hour = thousand gigawatt hours (GWh), a million megawatt hours (MWh), a billion kilowatt hours (kWh)

8.2. INTRODUCTION: PLANNING FOR POWER SECTOR DESTINATION

As noted in the KAZENERGY NER 2015, since independence Kazakhstanhas made significant progress upgrading its power sector. This is particularly noteworthy as Kazakhstan inherited an aging and fragmented Soviet-built power system that by 1991 depended on Russia and Central Asia for meeting up to 15 TWh annually. But the last decade of extensive investment bolstered its generating and transmission capacity, allowing Kazakhstan considerably greater energy security and independence (see Figure 8.1). For instance, since 2000, Kazakhstan's installed capacity has grown 22% while its available capacity has in fact doubled.[2] Essentially, since 2002, overall investment into Kazakhstan's power generation and national grid has dramatically improved flexibility, allowing electricity production to broadly match consumption trends, while even having small amounts of power to export to neighboring countries.

Despite the great investment strides Kazakhstan has made, there are still significant grid limitations; hence Kazakhstan's power sector is analyzed as three zones: North, South, and West (see grid map Figure 8.2). Each zone is fundamentally different from the other, in terms of supply and demand dynamics, generation mix, connectivity, and balance.[3] The grid connection between the North and South zones is limited (two 500 kV lines and a 220 kV line) but constantly improving, while the West Zone is still separated (with several links with Russia). And although Kazakhstan

Figure 8.1. Investments into the Kazakh Power Sector



Source: IHS Markit, Statistical Committee of RK

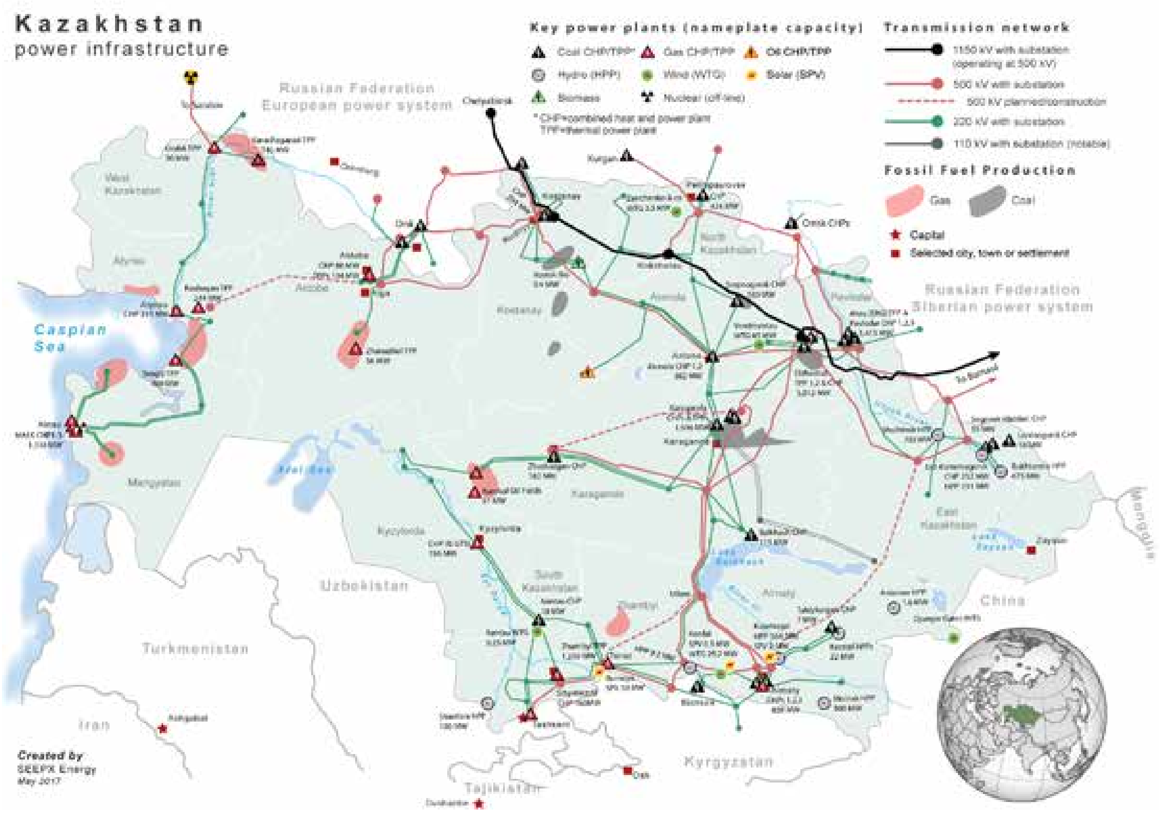
[2] The investment surge in 2009-15 was raised through a "tariff for investment" scheme that targeted generating assets.

[3] See KAZENERGY NER 2015 for detailed review of Kazakhstan's power zones.

has improved its overall power system, it is short of flexible generation—partly owing to a high share of relatively inflexible combined heat-and-power plants (TETs in Russian) emphasizing the importance of neighboring power systems for balancing support.[4]

Notably, Kazakhstan has a large appetite for coal that fuels around 66% of the country's power production (or about 75% of thermal production), and will remain the dominant fuel over the medium to long term owing to the particular geographical layout of the power sector. Some 92% of Kazakhstan's coal-fired production is in the North Zone where 70% of Kazakhstan's power consumption is situated, close to where the coal is sourced, and to date far from any meaningful gas infrastructure.[5] Then there is the relatively lower cost of coal-fired production over gas which means gas-fired production is practically uneconomic without introducing some type of financial support mechanisms.

Figure 8.2. Kazakhstan power infrastructure



Nonetheless, policymakers naturally seek to improve energy system efficiency and the country's overall green credentials while keeping energy security a priority. This means Kazakhstan must undergo a costly modernization program, which suggests promoting more flexible generation and reducing the carbon impact from coal. And this will be brought into sharp focus if Kazakhstan successfully hits, or exceeds its ambitious renewable targets (3% renewable production by 2020 rising to 30% by 2030 [11% solar and wind, 10% small hydro, 9% nuclear]).

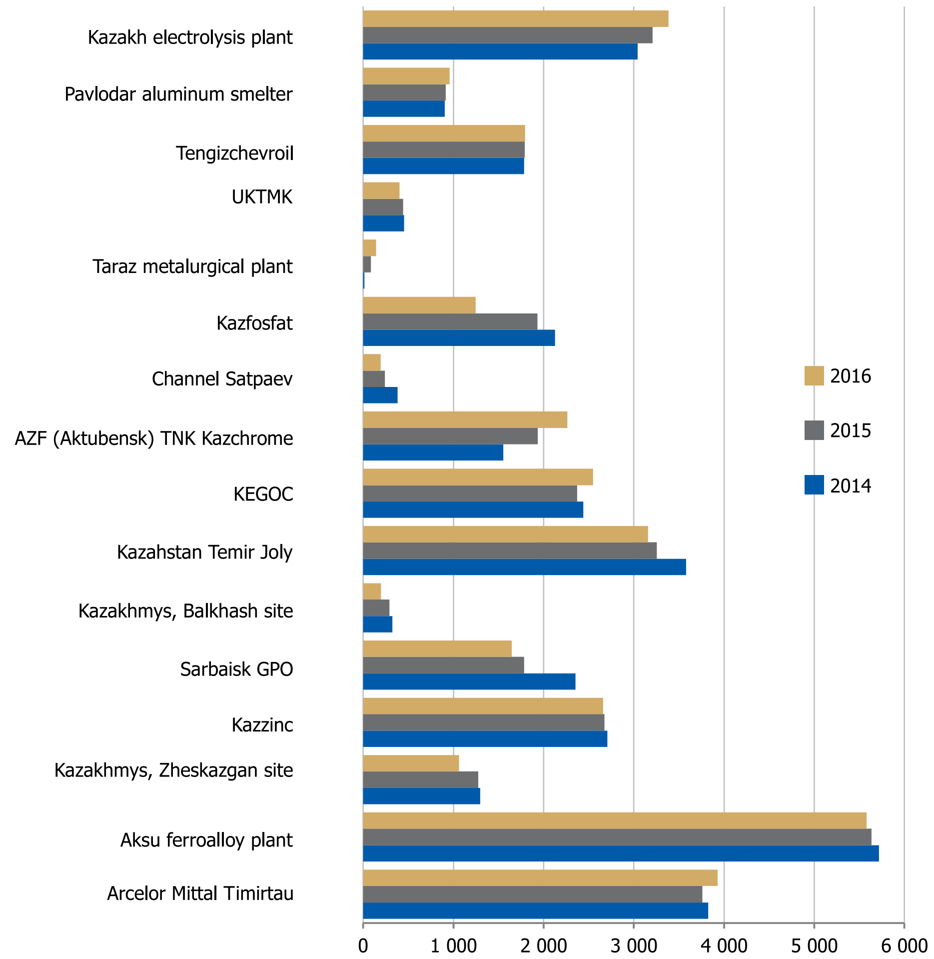
Many influential market participants in Kazakhstan are wary of the potentially undesirable consequences that can spring from untested market ideals, particularly in underinvested power sectors. Several examples can be found from the path that Russia took, which makes it an important benchmark whose experiences and direction should not be dismissed out of hand.

To that end policymakers feel somewhat caught between various power sector participants whose contrary positions appear intractable. Essentially, industrial players—who account for more than a third of overall consumption (see Figure 8.3) are expected to shoulder the lion's share of the cost burden, which is typical for emerging countries. The critical question for Kazakh policymakers now is how to jumpstart the power market reform with this kind of headwind.

[4]TETs in Kazakhstan are designed primarily to provide heat energy with power generally being a by-product. Their power output tends to be relatively restricted while running in heat mode.

[5]The main exception is Aktobe Oblast in the western part of the North Zone. Aktobe is largely gasified and was connected by a 500 kV line to the North Zone at the end of 2009.

Figure 8.3. Power consumption by large consumers in Kazakhstan (GWh)



8.3. FUNDAMENTALS: POWER DATA UPDATE

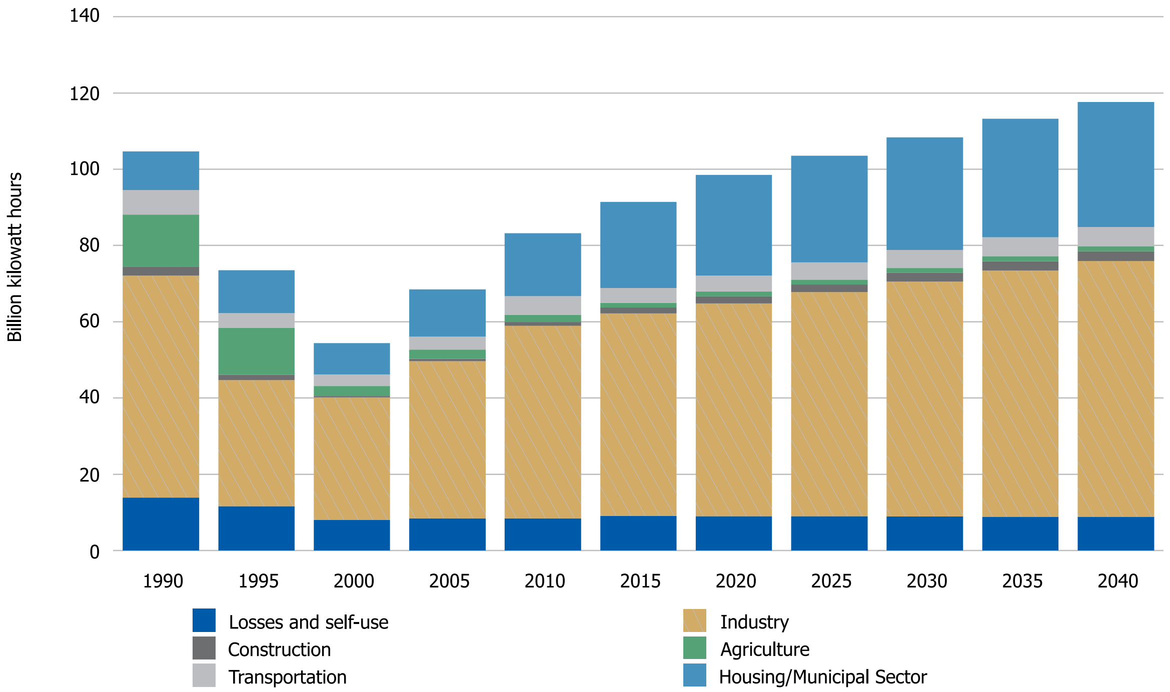
8.3.1. Electricity demand shifting emphasis

Since 2012 Kazakhstan's overall power consumption appears to have entered a new stage of maturity—no longer growing at the relatively rapid pace experienced in 2000–12 (averaging 4.4% annually). Looking forward, we expect power demand to grow more modestly, averaging only around 1.1% annually until 2040 (see Figure 8.4).This is a mild downward adjustment from 1.2% that we expected in the KAZENERGY NER 2015 driven largely by our forecast of a slower pace of economic growth. Nonetheless, demand will gradually become shapelier (transforming the grid into an active network). This will happen for the following reasons:

- **Consumer: increased electrification of Kazakh urban areas.** With the increase of consumer incomes, homes become more power hungry with additional appliances and gadgets. This often spurs growth in the commercial sector as well. For example, the rise of retail (shops and restaurants) and small businesses in urban areas impacts the shape of demand owing to their rapid growth and specific hours of activity.
- **Generation: growth of renewables and the rise of auto producers.** Intermittent sources of power (wind and solar generation) require flexible conventional generation to support their output or capacity storage solutions. In addition, industrial power producers often operate small-scale gas turbines which affect grid supply and demand. Large industrials enter the power market for a variety of reasons, typically for energy security and often to negate the effects of rising power costs. Oil and gas enterprises are classic examples of auto producers, who often have an added incentive to utilize their associated gas.
- **Markets: evolution of power markets.** As power markets evolve with balancing mechanisms, demand response, smart metering etc., these fac-

tors can have a significant impact on the cost of hourly power and this tends to influence power consumption habits through greater efficiencies.
For these reasons, Kazakh policymakers will need to adopt a power market design that can respond intelligently with timely investment, as well as encourage the most suitable technology—this is irrespective of short-term changes in power demand. Importantly, owing to Kazakh realities (similarly to what Russian policymakers experience), Kazakh policymakers should maintain a guiding hand, but not so much as to alarm potential investors.

Figure 8.4. Outlook for electricity consumption in Kazakhstan

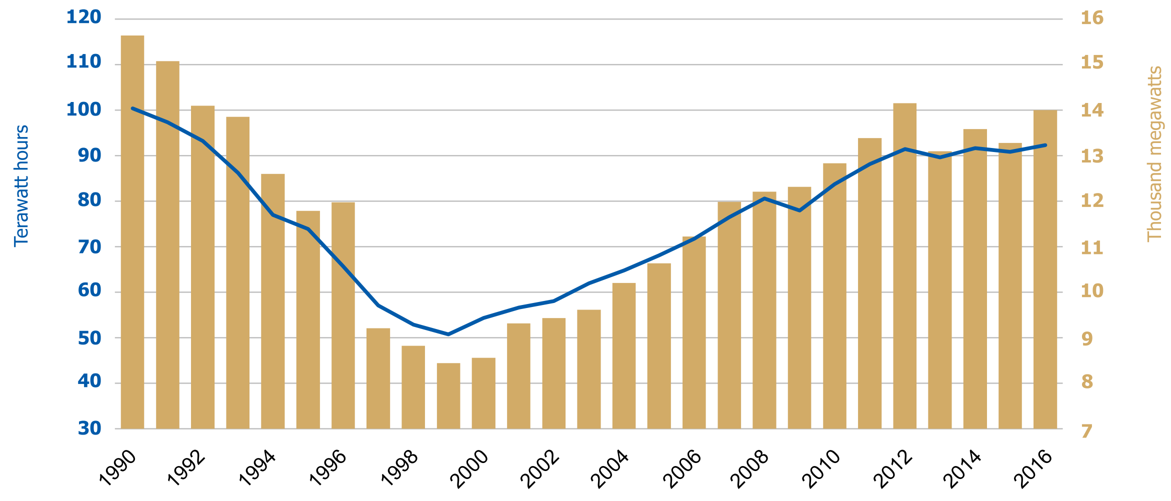


Source: IHS Markit

8.3.1.1. The inevitable maturing of Kazakh power consumption should influence strategy

Sound power demand forecasts are important, as they often direct official investment planning (at the cost of consumers). But recent historical power demand trends may not be a good signpost for setting a long-term trajectory. Naturally, trends in Kazakhstan's power demand are greatly influenced by global economics (and regional stability) because of the direct impact that commodity supply and demand and prices have on overall GDP and industrial activity. This means that while the recent trend in power demand was generally relatively robust, demand also endured several phases when reacting to global shocks, general slowdowns, and economic rebounds.
For instance, throughout the 1990s, after the collapse of the Soviet Union (in conjunction with deeply depressed oil prices) Kazakhstan's power consumption plunged (see Figure 8.5), falling from above 100 TWh in 1990 to 51 TWh in 1999, while the peak demand fell from 15.6 GW in 1990 to 8.4 GW in 1999.
But since 2000, thanks largely to resurgent global oil and commodity prices, Kazakhstan's power consumption experienced vigorous growth with an annual average rate of 3.4%, while peak demand grew an annual average rate of 3.1%. Of course, most recently power demand has slowed considerably and is likely to remain comparatively sluggish for several years at least—owing to general global economic headwinds.
For example, in 2000–12 power consumption grew at an annual average 4.4%—albeit dipping briefly in 2009 (see Figure 8.5). In spite of the economic crisis in 2008–09, by 2012, Kazakh power demand reclaimed much of the lost ground during the 1990s, reaching 90 TWh. But since 2012, power consumption has meandered somewhat, only growing annually by 0.2% while peak demand fell marginally by 0.3% (notably, overall peak demand has been considerably more volatile than consumption). Yet 2016 Kazakh power consumption surged by 1.6% compared to the previous year, with peak demand spiking 5.4%. This means Kazakh power consumption registered a new post-1999 high of 92.3 TWh while peak demand almost reached the 2012 high of 14.2 GW. The behavioral pattern for peak demand reflects a more pronounced (and somewhat mercurial) trend versus consumption. This puts a spotlight on how policymakers should plan for megawatt demand versus megawatt-hour consumption. It also explains why policymakers insist on adding new capacity.
Despite the uplift in power demand in 2016, general confidence in the global economy offers little reason to expect any kind of longer-term consumption take-off similar to 2000–12. The global economy is simply not sufficiently encouraging enough for Kazakhstan's export-oriented industry which accounts for more than a third of domestic power consumption.

Figure 8.5. Kazakhstan's power demand



Source: KEGOC

8.3.1.2. Regional power demand reflects mixed picture

Although regional power demand reflects a mixed picture (see Figure 8.6), a more pronounced peak demand is evident. The North and South (power) zones were clearly influenced by the recent downturn in the economy (although slightly differently), while the West Zone has been more robust (see Table 8.1).

Table 8.1. Electricity consumption in Kazakhstan by zone (GWh)

Electricity Consumption in Kazakhstan by zone (GWh)									% change	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2009-12**	**2012-16**
Kazakhstan Total	**77,960**	**83,767**	**88,136**	**91,444**	**89,641**	**91,661**	**90,847**	**92,312**	17,3	0,9
North Zone	53,917	58,327	60,589	62,554	60,786	60,865	60,399	61,768	16,0	-1,3
West Zone	9,027	9,264	9,582	9,885	10,232	10,940	11,055	11,531	9,5	16,7
South Zone	15,016	16,176	17,966	19,005	18,623	19,856	19,393	19,013	26,6	0,0
Note: In 2009, the Aktobe area was connected with the North Zone, and its consumption is included in that category.										

Source: KEGOC

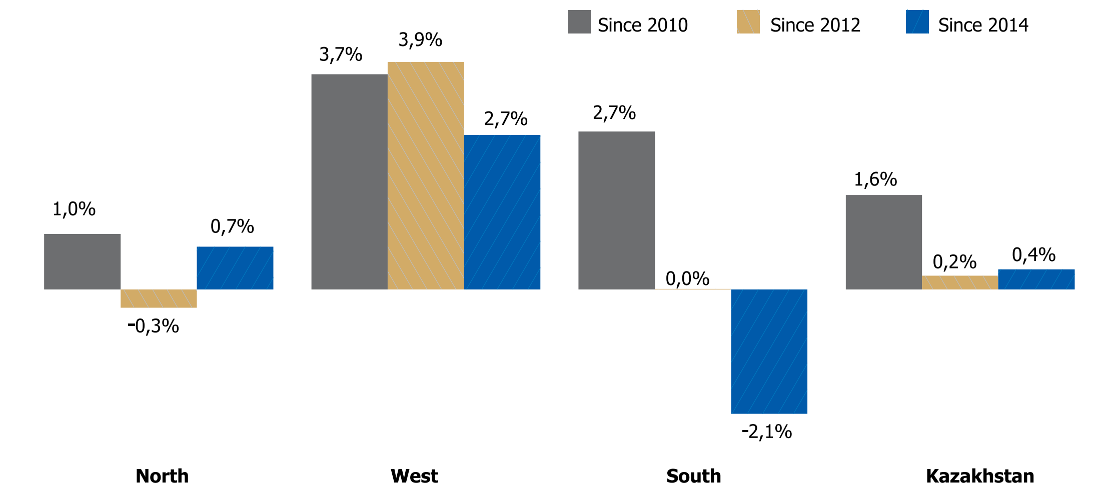
The heavily industrialized North Zone, which accounted for about 67% (61,768 GWh) of overall power consumption in Kazakhstan in 2016, rebounded 2.3%, after being essentially stagnant in 2011–15. Strong growth in Aktobe along with the sheer size of the North Zone masked declines in East Kazakhstan, North Kazakhstan, and Kostanay oblasts. Year-on-year peak demand in the North Zone jumped 6.5%, led by the industrial heavyweight Pavlodar Oblast, which witnessed a 10.6% spike.
The 2% downturn in power consumption (year on year) in the smaller South Zone (19,013 GWh) can be traced to the power-hungry phosphate industry in Zhambyl Oblast which consumed 40% less power in 2016 than in 2014, thus hitting power demand heavily in the region and across the overall zone. Also, much of Almaty's potential demand was hovered up by Astana's growth in the North Zone—with the continual shift of commercial operations to Astana. Since 2010, Astana's power consumption has grown at an average annual rate of 7.7% while Almaty city has only averaged 1.5% per year. Moreover, since 2014, power consumption in Almaty has been essentially flat while the new capital has enjoyed average annual growth of 5.6%.
Irrespective of consumption wobbles in the South

Zone, the region is still short of generating capacity and it will regain a growth trend owing to the growth of population and commercialization. As a result,the South Zone depends on imports from the North Zone and exchanges power flows with Central Asia. As with the North Zone, we observe more pronounced peak demand highs and lows in the South Zone versus megawatt-hour consumption.

Growth in Kazakhstan's West Zone is by far the most robust and consistent: in both megawatt-hour consumption and [megawatt] peak demand. The oil and gas-dominant West Zone (about 12% of overall power consumption) is growing rapidly and exhibited resilience during the recent economic downturn. It is also notable that although year-on-year power consumption in 2016 grew 4.3%, peak demand spiked 11.8%. Similar trends are clear when analyzing consumption and peak demand over longer periods (see Figure 8.6. and Figure 8.7.).

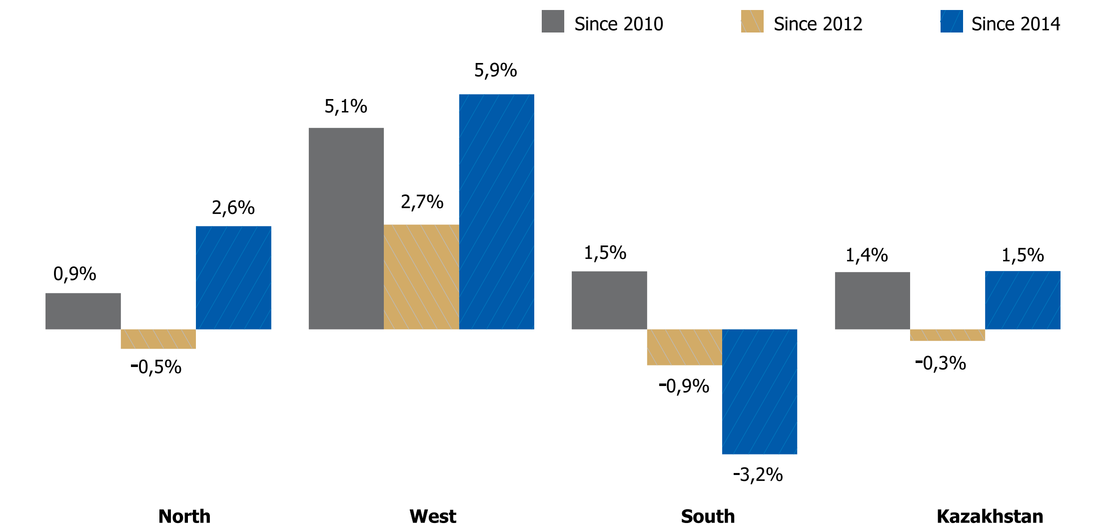
The overall picture evolving in Kazakhstan appears to show a familiar pattern for a maturing economy, i.e., pace of consumption slows in contrast to the pace of peak demand. Essentially this means we can expect demand patterns to continue to become shapelier.

Figure 8.6. Average annual power consumption growth by Kazakh power zone, 2016



Source: IHS Markit, KEGOC

Figure 8.7. Average annual peak power consumption growth by Kazakh power zone, 2016



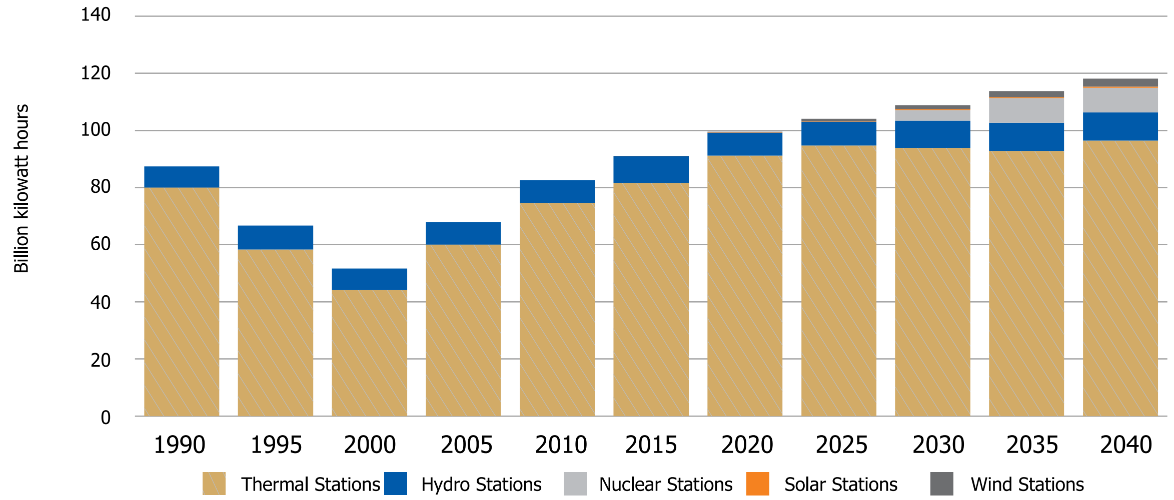
Source: IHS Markit, KEGOC

Note: In the above chart, the average peak demand in each zone was calculated at the exact time when maximum peak was registered in the Unified Energy System (UES) of Kazakhstan, whereas each zone (and region) typically exhibits even higher peaks than registered during the UES maximum.

8.3.2. Power balance: recent investment improves flexibility

Naturally, these consumption trends need to be balanced by supply. Since 2000, power production in Kazakhstan has grown by an average annual rate of 3.8% (which is a little stronger than trends in consumption [3.4%] over the same period). Altogether, since 2000 power production increased 83%, while consumption grew 70%. In our projections, we expect power production to grow in line with consumption, averaging around 1% annually until 2040 (see Figure 8.8). This is hardly surprising given that Kazakhstan has successfully bolstered its overall available capacity by some 40% since 2000 (while installed capacity grew 22%).

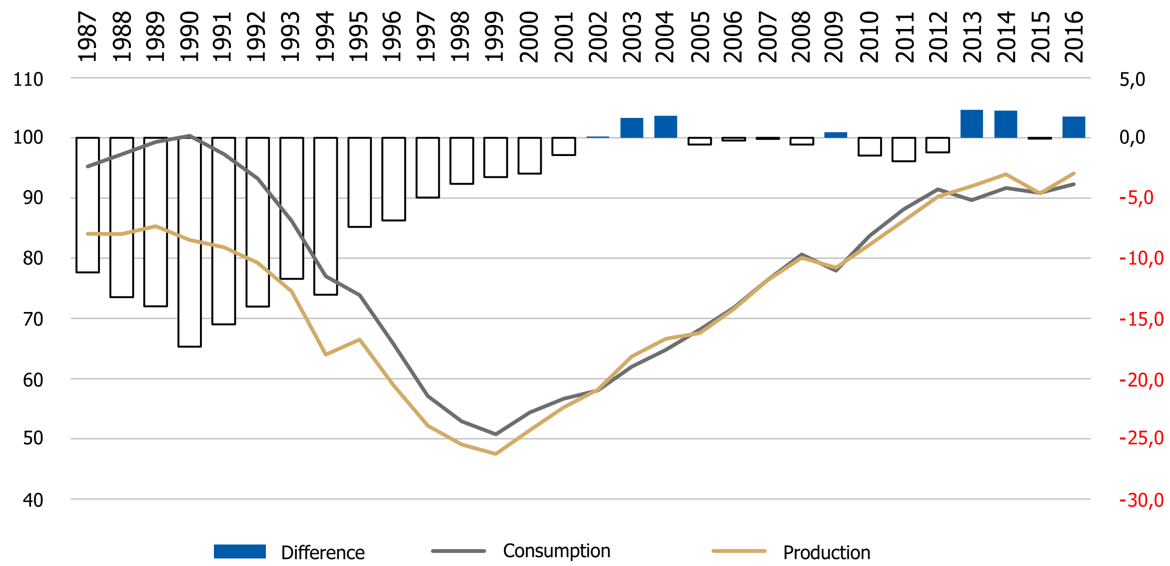
Figure 8.8. Outlook for electricity production in Kazakhstan



Source: IHS Markit

The dramatic increase in Kazakhstan's available capacity in recent years has been an important achievement because until 2002 Kazakhstan's consumption rose faster than production (see Figure 8.9). Although available capacity (illustrated in Figure 8.10) might appear to show that Kazakhstan had sufficient generation for its needs earlier than 2002, several factors restricted power from reaching the consumer. For instance, a segmented transmission network constrained power flows throughout the power system between the capacity-rich North Zone and capacity-deficient South Zone.[6]

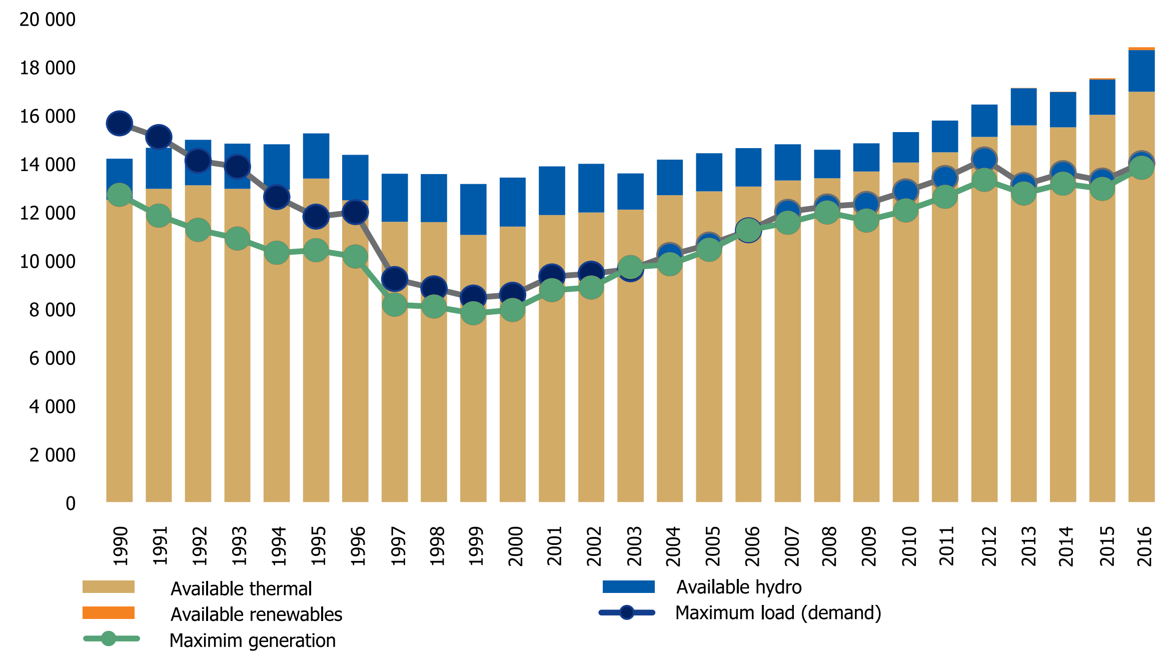
Figure 8.9. Kazakhstan's power consumption and production (TWh)



Source: KEGOC

[6] Selected areas in the north and west parts of Kazakhstan had stronger links with Russia than to Kazakhstan's main grid.

Figure 8.10. Available capacity versus maximim demand and generation, MW



Source: IHS Markit, KEGOC

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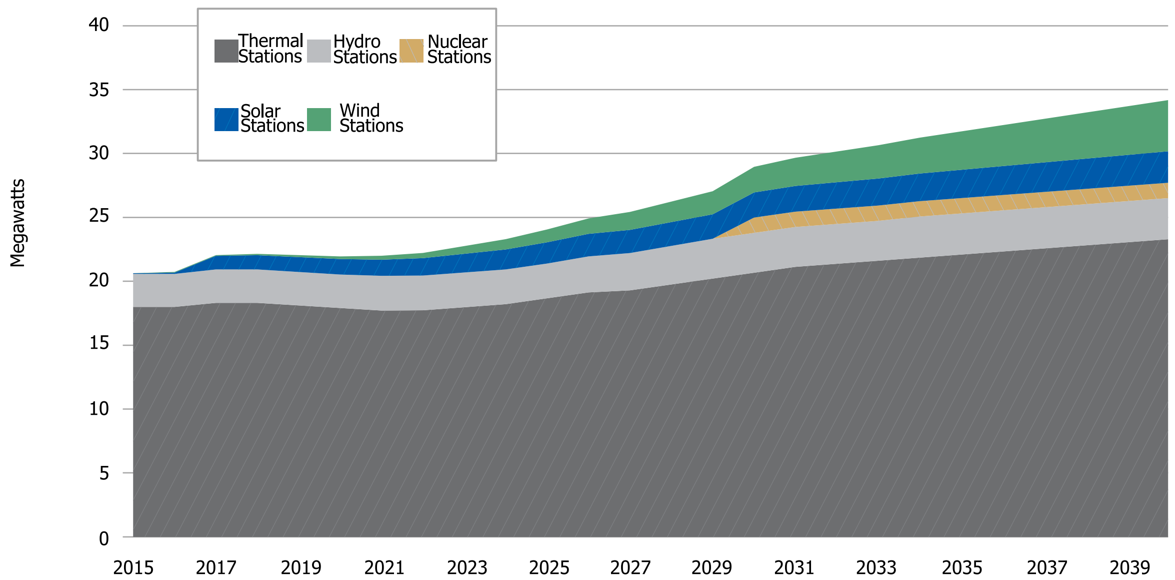
We expect capacity increases to remain robust, particularly from renewables source (which typically have a lower overall utilization), growing on average 2% annually until 2040 (see Figure 8.11).

Figure 8.11. Capacity outlook for Kazakh electric power sector



Source: IHS Markit

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As a measure to improve energy security, the carrying capacity between the North and South zones was doubled (by adding an additional 500 kV line),allowing the South Zone to be weaned from dependence on Central Asian imports. Since 2000 power flows from the North Zone have tripled (from 2.5 TWh in 2000 to 7.5 TWh in 2016) while Central Asian net power flows have practically reversed, where Kazakhstan has become a net power exporter. An additional 500 kV line connecting the North and South zones is nearing completion and is expected to connect the Almaty area with more flexible capacity from Kazakhstan's key hydropower assets (Shulba [702 MW], Bukhtarma [675 MW], and Ust-Kamenogorsk HPP [331 MW]), as well as supporting further capacity from Ekibastuz GRES-1 and -2 (5,000 MW).[7]

Even though significant grid investments have improved nationwide connectivity, the West Zone remains separated from the North and South zones, still relying on several links with Russia for security of supply. But in spite of robust growth exhibited in the West Zone, net imports from Russia have been steadily declining since independence in 1991, when power imports from Russia stood at more than 50% (4,551.4 GWh) of the West Zone's consumption needs, falling to only 1% (154 GWh) in 2016.

8.3.2.1. Role of imports and exports

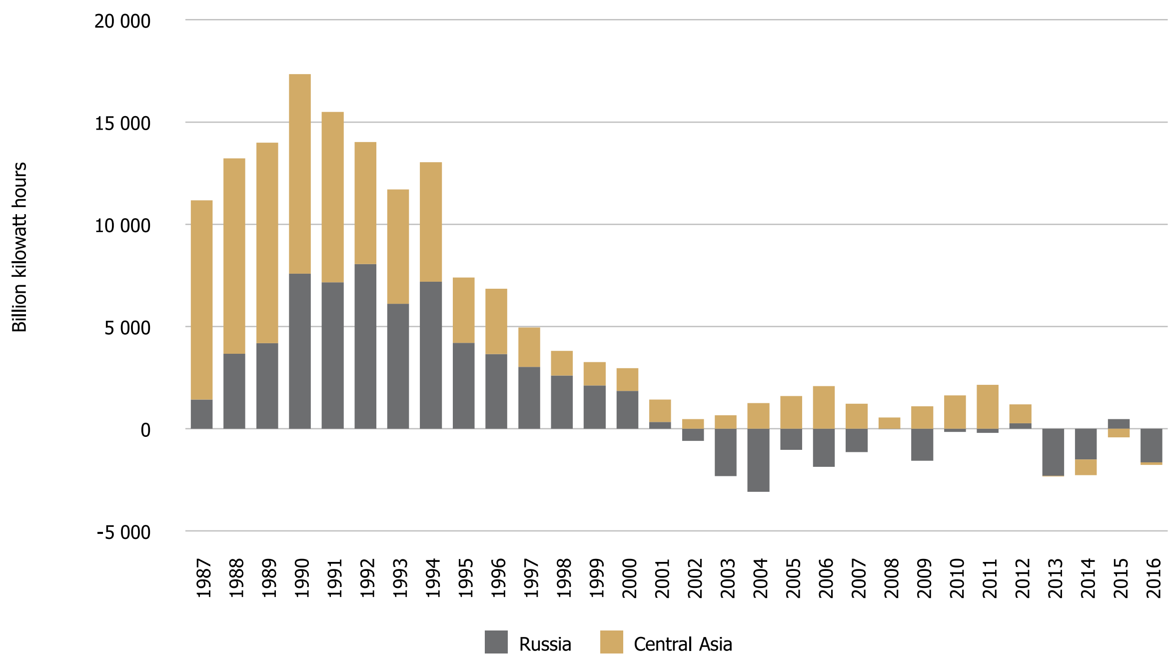
During the 1990s Kazakhstan relied heavily on Russia and Central Asia for power imports (see Figure 8. 12). This mode of operation was quite natural as the respective power systems were originally designed to run in parallel. And power transfers between Russia and Central Asia are still convenient for balancing purposes.

Currently, Russia and Kazakhstan exchange modest power volumes annually; above some trading volume, both countries have a balancing agreement where they play a cross-border system services support role. This symbiotic arrangement is particularly helpful for peak support in Kazakhstan as well as potentially balancing its renewable ambition to an extent. However, this arrangement is at risk because Kazakhstan's power balancing requirements usually occur around peak demand hours for Russia, which are the most expensive hours in Russia's day-ahead market. And Kazakhstan's power market is not yet sensitive to hourly pricing. But it is also important to point out that emergencies can quickly change the power flow dynamics as was the case when the Sayano-Shushenskaya hydropower plant accident occurred in Siberia in 2009 which saw Kazakhstan playing a vital system support role for Russia's Siberian power system for several years.

Central Asian countries, chiefly Kyrgyzstan and Uzbekistan, once played a considerable role in power exchanges but more recently, as noted above, the strengthening of Kazakhstan's national grid has changed this dynamic considerably. Statistical evidence from KEGOC (Kazakh power system operator and national grid operator) shows Kyrgyzstan exchanges relatively small amounts of power with Kazakhstan. This appears to be a balancing arrangement where Kazakhstan takes advantage of Kyrgyzstan's hydropower capacity while Kyrgyzstan benefits from Kazakhstan's thermal output (in particular the gas-fired Zhambyl GRES [1,230 MW]). Any future expansion for power trade with Central Asia is likely to depend on the outcome of the CASA-1000 transmission project and associated trade negotiations.[8] In this event, Kazakhstan's planned new capacity, Balkhash power plant (first stage 1,320 MW, second stage adding another 1,320 MW) could be strategically placed to support power swaps with Kyrgyzstan while playing a designated role in filling the supply gap in the South Zone.

Thus far, Kazakhstan does not trade power with China. This situation is unlikely to change owing to the western regions of China already having an abundance of capacity. For instance, as of 2016 the northwest region of China had an installed capacity of 131.7 GW with a peak load of 76.5 GW (a reserve margin of 72%), and the Chinese southwest region has an installed capacity of 76.9 GW with a maximum peak of 53.5 GW (a reserve margin of 44%). We also do not expect that the economics of building an ultrahigh-voltage power line would stack up given the geography of Kazakhstan's power production and China's consumption.

Figure 8.12. Kazakh power imports and exports (GWh)



Source: IHS Markit, KEGOC

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[7] GRES (state regional electric stations) in Kazakhstan are typically large system power dominant plants with a minimum output of heat. They tend to help balance the power system.

[8] CASA-1000 (Central Asia–South Asia) is a four-party donor-backed international ±500 kV DC line transmission project linking Tajikistan with Pakistan, via Afghanistan, which envisions the export of up to 1300 MW per hour. A further 500 kV link is being made between Kyrgyzstan and Tajikistan.

8.3.2.2. Power production: policymakers' investment choice

In terms of megawatt additions, actually the main-increase in Kazakhstan's power production was from steam turbines (mostly coal-fired), which since 2000 has increased annually 3.6% on average, growing by 32 TWh to 75 TWhin 2016 (see Figure 8.13 and Figure 8.14). Notably, the top five power plants account for about 40% of total power production, of which more than 90% is coal-fired (see Table 8.2).

Table 8.2. Top five Kazakh power plants by production (GWh)

		2014	share	2015	share	2016	share	Growth since 2014
1	EEC (ERG, Aksu GRES)	16,401.0	17%	14,668.0	16%	13,868.9	15%	15.4%
2	Ekibastuz GRES-1	14,096.2	15%	10,728.6	12%	9,037.3	10%	35.9%
3	Ekibastuz GRES 2	4,754.9	5%	3,211.0	4%	4,976.1	5%	4.7%
4	Kazakhmys GRES 2	4,604.5	5%	5,130.2	6%	4,403.4	5%	4.4%
5	Zhambyl GRES	2,520.5	3%	2,872.7	3%	2,466.0	3%	2.2%
	Total	42,377.1	45%	36,610.5	40%	34,751.7	37%	

Source: KOREM, KEGOC.

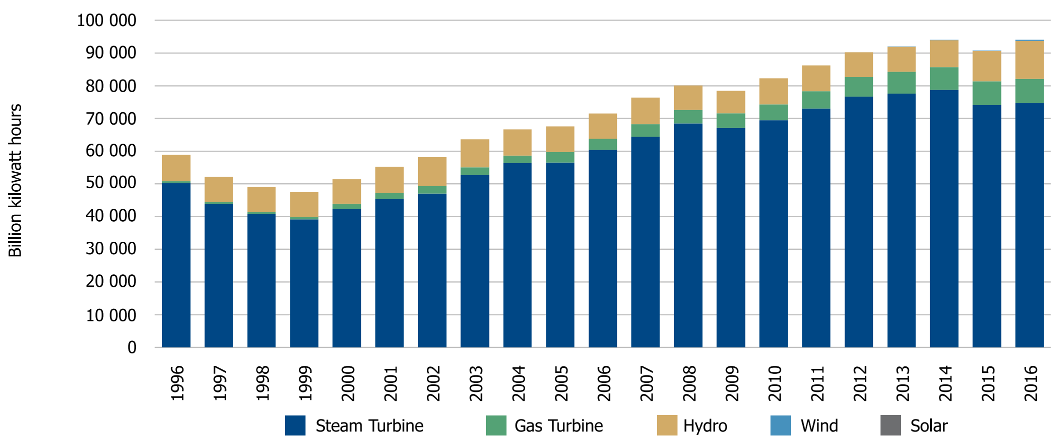
Hydropower is Kazakhstan's second largest power generation source, accounting for around 12% in 2016. Not only does hydropower play a base load role, it is typically used to fill peak demand. Despite that, hydropower can still be constrained by seasonal water flows and thus may not be always available when needed or geographically well positioned. Notably, hydropower production has doubled since 2012, while available capacity grew 30%. The outlook for additional hydropower production appears relatively constrained owing to limited potential sites for major new projects.

Notwithstanding the growth of steam turbines and hydropower in Kazakhstan's generation mix, power production from gas turbines has also increased significantly: output expanded at an annual average rate of 10.1% since 2000, generating almost 6 TWh more power in 2016 than in 2000.

Increased generation from gas turbines and gas-fired steam turbines over the past decade has made a dramatic difference to balancing power demand in the West Zone. In 1996, gas turbines represented just 10% of the West Zone's power production, but in 2016 the share of gas turbine production grew to 37% (4.2 GW). Notably, there is no coal-fired power production in the West Zone. Gas turbine technology is poised to play an increasingly larger role in Kazakhstan's generation mix. The key question is whether Kazakh policymakers will deliberately incentivize more gas use in power through policy, regulation, and market mechanism support.

A leading consideration for creating a bigger role for gas in Kazakhstan's power generation is the shortage of capacity that can be incentivized to respond to sharp changes in demand. There are a number of reasons for this, which include an absence of a proper balancing market and a system services market, but it is mainly reflects Kazakhstan's particularly high share of combined heat-and-power plants known as TETs. A notable design constraint regarding TETs is that power output is governed by heating schedules during winter (heating season), so their availability is much less than it appears.

Figure 8.13. Kazakh power production by type (GWh)



Source: IHS Markit, KEGOC

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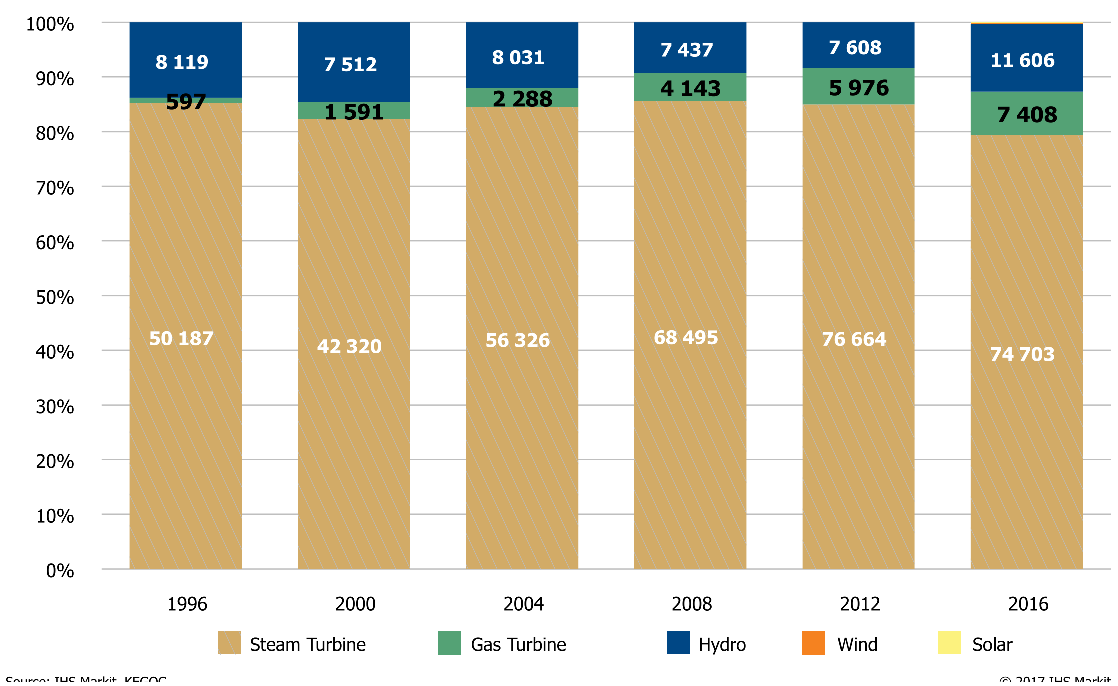
Figure 8.14. Kazakh power production share by type (GWh)

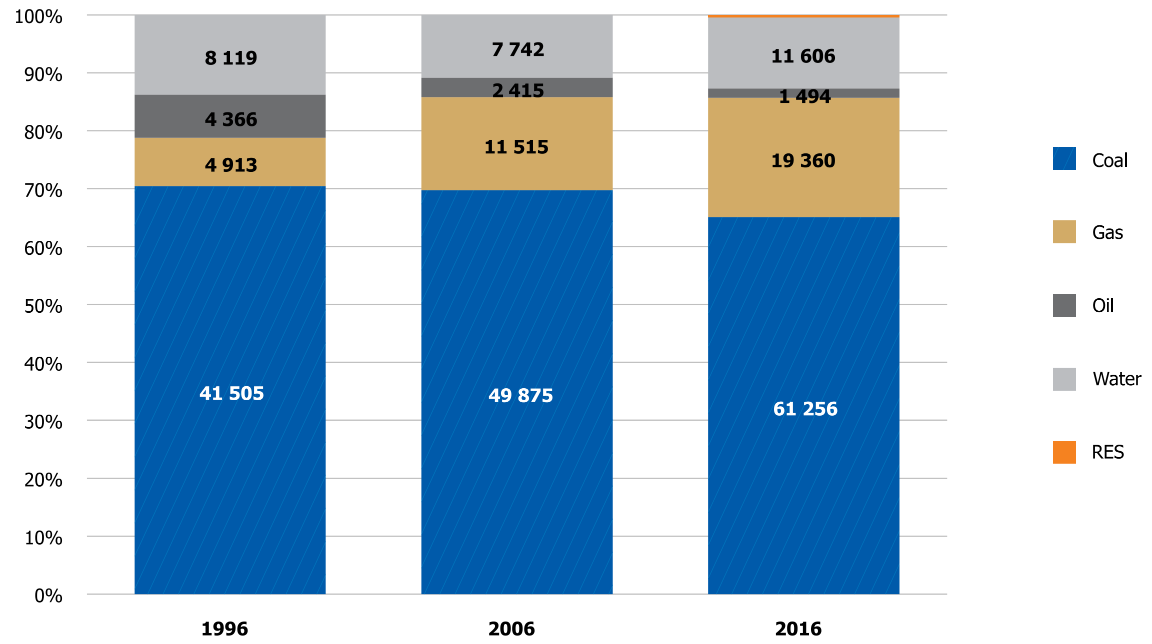


8.3.2.3 Role of fuel

As noted above, Kazakhstan relies heavily on indigenous coal—typically sourced close to the power plant—to fuel 66% of its power production (see Figure 8.15), although the overall share has been yielding to gas. While this mainly results from the rise of gas turbine technologies, it is also evident in steam turbine technology where the share of gas use grew from 8.8% in 1996 to 15.6% in 2016 (see Figure 8.16).

Nonetheless, coal will remain the dominant fuel for generating power because Kazakhstan's gas infrastructure is quite limited. Despite that, the share of gas in Kazakhstan's power production is expected to rise. For instance, to tackle poor air quality, Almaty city—which accounted for around 4.7 TWh in 2016—will likely shift from coal to gas. This would mean replacing at least 650 MW of coal capacity with gas.

Figure 8.15. Share of power production produced by fuel type (MWh)



Source: IHS Markit, KEGOC

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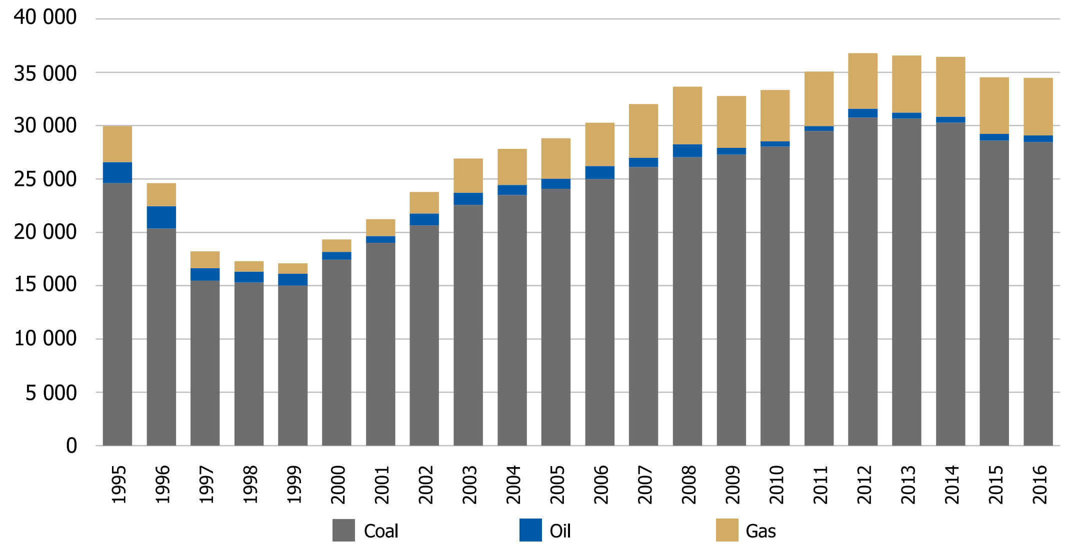
In recent years the gas network has improved significantly, allowing Kazakhstan to shift gas from the hydrocarbon-producing area in the west to the south, via the Beyneu-Bozoy-Shimkent pipeline (see Figure 8.17). Logistically, this allows for more access to gas in Kazakhstan's South Zone, and importantly less dependence on neighboring countries' gas.
There are also future plans to extend a gas pipeline from Karaozek (intersecting the Beyneu-Bozoy-Shimkent pipeline near Kyzylorda) to Astana via Karaganda, as well as a planned pipeline from Kostanay to Astana via Kokshetau. If these projects are realized, gas will play a larger, albeit still modest, role in power generation.
The main drawback for using gas is its relative high cost versus domestic coal. Again, this might mean tailoring power market mechanisms to support gas, while penalizing coal through carbon trading and/or tax mechanisms. But such a move would be relatively expensive for Kazakhstan's power consumers.

Figure 8.16. Fuel consumption by steam turbines (thousand tons of fuel equivalent)



Source: IHS Markit, KEGOC

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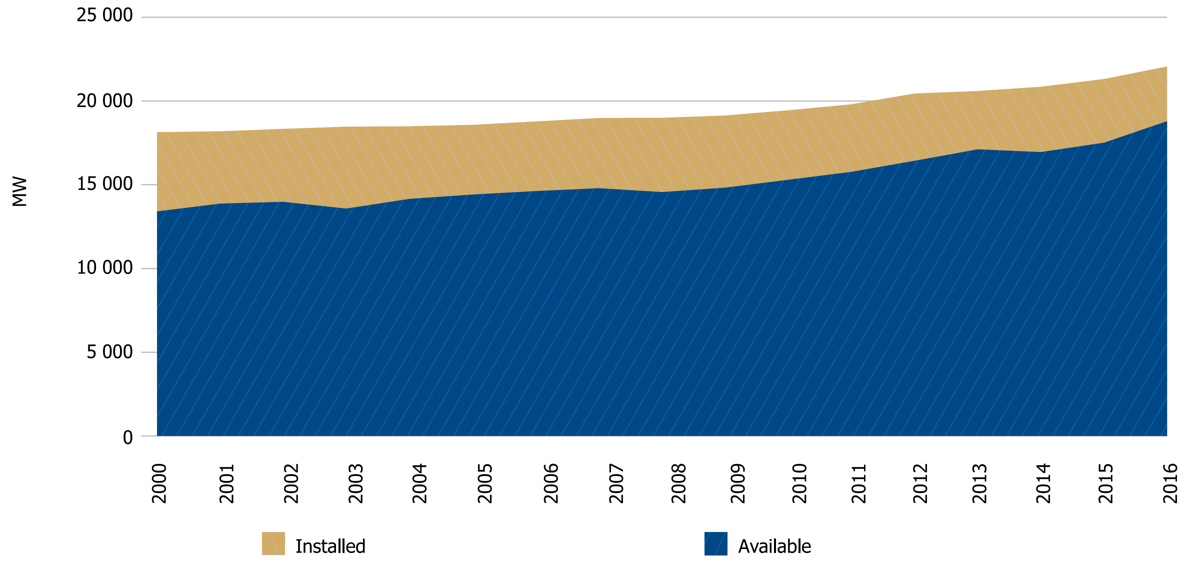
Figure 8.17. Kazakhstan's gas network

8.4. INFRASTRUCTURE AND TECHNOLOGIES: KEY OPTIONS

As noted above, Kazakhstan's installed and available capacity has been rising steadily thanks to coal-fired, hydropower, and gas turbine capacity additions (see Figure 8.18). Despite ongoing capacity renovations, and that some 30% of Kazakhstan's capacity was launched since 2001, much of Kazakhstan's fleet is still based on aged Soviet-era technology (see Figure 8.19). For example, about 39% of Kazakhstan's capacity was installed prior to 1980, and according to KEGOC, in 2016, 42% of Kazakhstan's steam turbines had exceeded their designed operational life.

New coal-fired capacity has been the practical choice in Kazakhstan's North Zone owing to the abundance of cheap local coal (see Figure 8.20).Thus, new steam turbine capacity has been generally added to existing plants or upgrades. In contrast, Aktobe Oblast has gas (joining the North Zone in 2009) and has been adding significant gas capacity since 2004. The south-western part of Karaganda Oblast, also in the North Zone, also witnessed growth in gas turbine technology with expanded oil and gas extraction (Aksai and Akshabula).

Figure 8.18. Installed capacity versus available (MW)



Source: IHS Markit, KEGOC

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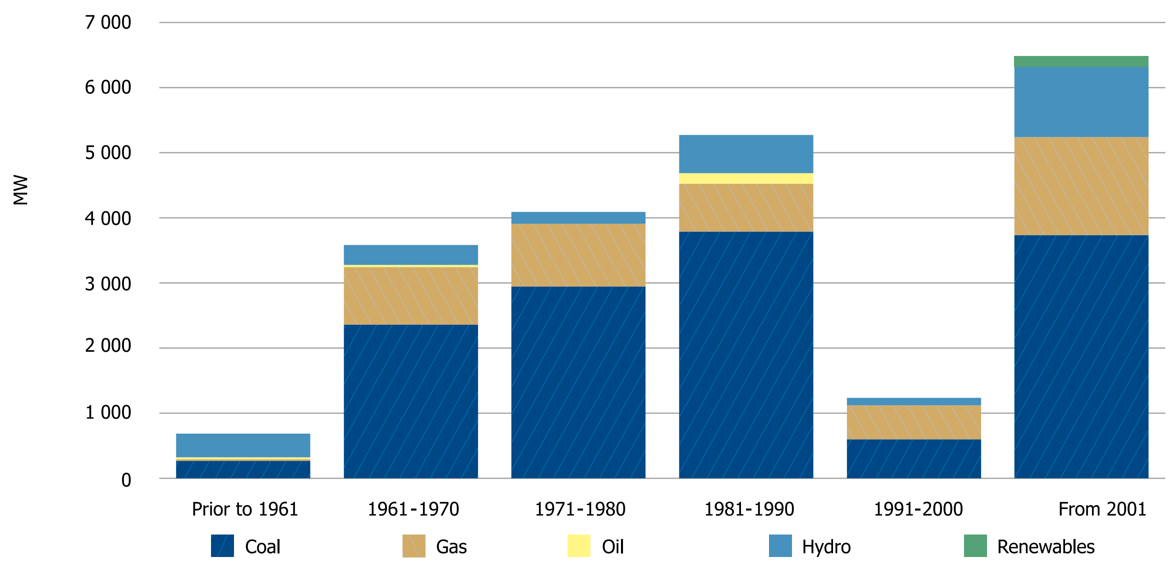
Figure 8.19. Age distribution generating capacity in Kazakhstan (MW)



Source: SEEPX Energy

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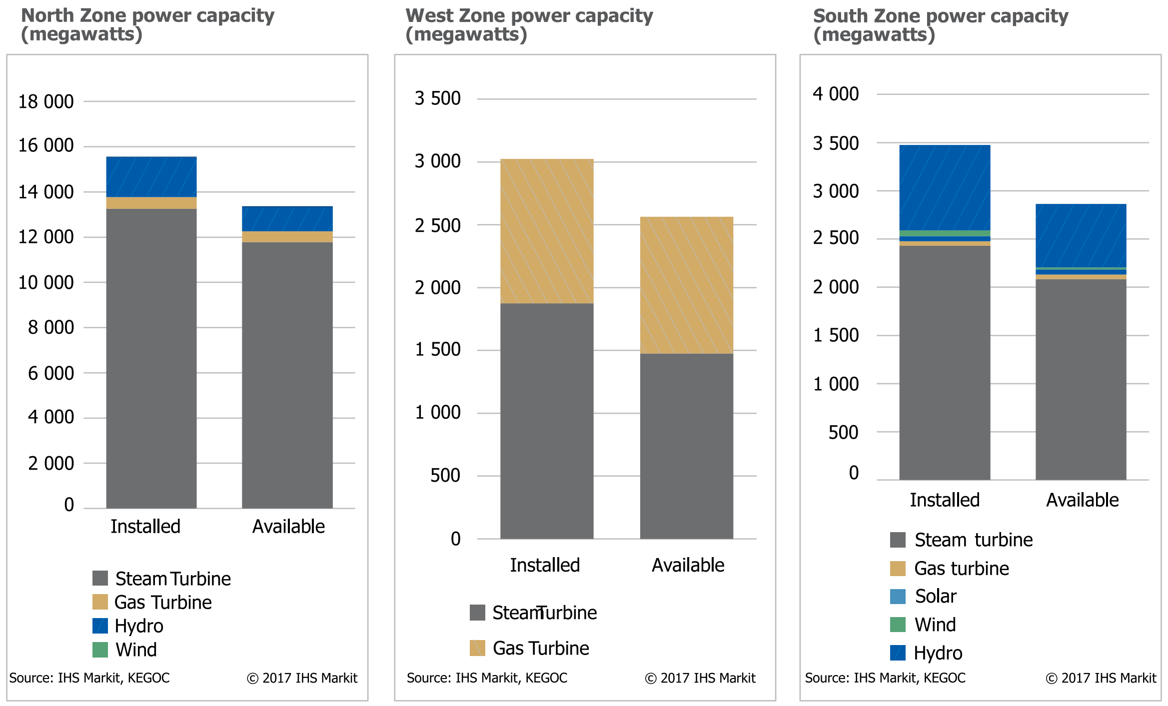
Figure 8.20. Installed and available capacity by zones



The West Zone is entirely gas-fired and has benefited from a steady increase of gas turbine capacity since 1996—driven by the oil and gas industry. While the West Zone still relies on Russia for some of its power supply, KEGOC is exploring several DC line transmission options (using different routes) that connect the West Zone to Kazakhstan's North and South zones (West-North, West-Centre, West-South). [9]

Notably, thermal capacity in Kazakhstan's South Zone has a fairly even mix of gas- and coal-fired capacity. And despite having access to gas the zone has a surprisingly small amount of gas turbine capacity. Depending on market incentives, the South Zone could expect a rise in gas turbine technology. Hydropower capacity in the South Zone plays a growing role too, although future expansion appears limited.

8.4.1. Power (and heat) sector technologies: recent trends and capacity outlook until 2040

As Kazakhstan's energy policies evolve and market mechanisms mature, the following technologies can play an important role in both managing power output as well as reducing Kazakhstan's carbon footprint:

8.4.1.1. Gas Turbines: Advanced CT and CCGT

Combustion turbine (CT) based power generation (single cycle [SC] and combined cycle [CC]) is a mature, ubiquitous technology globally. Certain parts of Kazakhstan already use gas turbines, particularly areas with greater access to gas. Gas turbines will continue to displace coal-fired generation.[10] The equipment manufacturers who dominate the global CT market for power generation applications are General Electric (GE), Siemens, Mitsubishi Heavy Industries (MHI), and Alstom. Although manufactures tout gas turbine efficiencies exceeding 60%, the way these technologies are used in many global power sectors means real efficiency levels tend to be considerably lower.

Applications

- Single Cycle (SC) combustion turbine in a stand-alone configuration, used for peaking and renewables integration; no provision for steam generation; quick start and ramping times; low thermal efficiency
- Combined Cycle (CC) combustion turbine configured in combination with a steam cycle (heat recovery boiler and steam turbine) used for base load and/or intermediate power generation duty (including renewables integration); higher thermal efficiency and longer starting times

Types of combustion turbines

- Industrial (frame)—heavy-duty, low capital cost, longer maintenance intervals; common SC unit size is 175 MW to 200 MW
- Aeroderivatives (aero)—adapted from jet aircraft engines; lightweight, higher capital cost, faster start times; higher SC thermal efficiency than frame units; common SC unit size is 40 MW to 50 MW

Key performance attributes and trends

- Size—trend has been larger megawatt unit sizes, new configurations are over 500 MW for a single 1x1 frame CC unit
- Efficiency—breaking the 60% mark in CC; turbine inlet temperature is a key determinant of thermal efficiency and maximum temperatures are limited by current materials
- Emissions—innovative inner cooling systems solutions (closed-loop steam cooling) allow for high combustion temperatures and low NO_x emissions
- Start-up and ramping—faster times allow for faster response to peaking needs, as well as improvements in part-load thermal efficiency
- Fuel flexibility—ability to burn natural gas, distillate (typically as a backup fuel), and syngas

Levelized cost of electricity ranges from $70/MWh (CC) to $150/MWh (SC)

8.4.1.2. Postcombustion emission control technologies[11]

These are devices that either destroy or remove contaminants from the exhaust stream before they are emitted into the atmosphere. In many countries, there are laws that require power plants to control sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury, particulate matter (PM), and other air pollutants using these devices.

Control technologies organized by pollutant

- Acid gasses (including SO_2)
  - **Wet flue-gas desulfurization (wet FGD)**: Removes SO_2 by reacting flue gas with a sorbent material such as limestone in a dedicated mixing vessel. Wet FGDs use water to increase the contact between the reagent and flue gas.
  - **Dry flue-gas desulfurization (dry FGD)**: Removes acid gases (primarily SO_2) by spraying a basic sorbent material such as lime in a dedicated mixing vessel to produce solid salts. The salts are then removed by an ESP or FF. The lime reagent is generally more expensive than limestone used in wet FGDs.
  - **Dry sorbent injection (DSI)**: Removes acid gases (sodium oxides [SO_x], hydrochloric acid [HCl], sulfuric acid [H_2SO_4], etc.) by reacting flue gas with a basic sorbent material, such as trona, to produce solid salts which are then removed by an ESP or FF.[12]
- NO_x
  - **Selective catalytic reduction (SCR)**: Removes NO_x by reducing NO_x to molecular nitrogen (N_2) (which constitutes 80% of the earth's atmosphere), and water using a reagent in the presence of a catalyst.
  - **Selective noncatalytic reduction (SNCR)**: Removes NOx by reducing NO_x to N_2 and water using a reagent.
- Mercury
  - **Activated carbon injection (ACI)**:Mercury exists in elemental, ionic, and particulate forms. ACI systems inject activated carbon into flue gas, where it adsorbs elemental and ionic mercury emissions, creating particles that can be removed by an ESP or FF. Activated carbon is a porous, highly adsorptive particle made by heat treating carbon. Chemical treatment (i.e., activating) can further increase adsorptive properties for specific applications.
- PM
  - **Electrostatic precipitators (ESP)**: Electrostatically removes PM by attracting charged flue gas particles to the ESP. After a sufficient quantity is collected, a rapper or jet of water knocks the caked-on dust into a hopper for disposal or reuse.
  - **Fabric filters (FF)**: Physically and electrostatically removes PM from the flue gas via a filter bag and accumulated filter cake. Periodic shaking or pulses of air knock the accumulated filter cake in to hoppers for disposal or reuse.
- **Multipollutant:** Multipollutant control technologies integrate controls for at least two of the following emissions: SO_2, NO_x, PM, Hg, and CO_2. The high cost and complexity of integrating multiple control technologies together drives their development.

Coal-fired power plants have a variety of retrofit options requirements. Where possible, coal-fired power plants are installing less capital-intensive, albeit their higher operating cost retrofits to avoid spending large amounts of money on generating facilities that could be made unprofitable by future regulation and/or lower natural gas prices.

DSI, which has had limited applications in the power sector to date and primarily to limit sulfur trioxide (SO_3), is expected to be widely deployed to address a wide range of acid gas emissions in lieu of installing more capital-intensive FGD systems. Furthermore, power plants are optimizing their existing ESPs to improve PM removal performance instead of installing new FFs.

8.4.1.3. Carbon capture and storage (CCS)

There are three key CCS technologies: postcombustion, precombustion, and oxyfuel combustion. These technologies either destroy or remove contaminants from exhaust streams before being emitted into atmosphere.[13]

- In postcombustion carbon capture, flue gas is sent through a scrubber column where it reacts with a solvent (typically a nitrogen compound such as ammonia or an amine). The reacted solvent is then regenerated and reused, and the separated carbon dioxide (CO_2) is cooled and compressed for transport.
- In precombustion carbon capture, the fuel is gasified and then turned into CO_2 and hydrogen through a water-gas shift reaction. A scrubber column using a solvent is then used to separate the hydrogen and CO_2, and the hydrogen is burned as fuel.
- Oxy fuel combustion involves burning a fuel in pure oxygen, which is cryogenically separated from air. The flue gas from an oxy fuel plant is primarily water and CO_2, which can be separated without a scrubber through cooling and condensation.

Typically CCS adds 70–80% to capital costs of new supercritical pulverized coal (SCPC) plants, and 100–110% to capital costs of new combined-cycle gas turbine (CCGT) plants. However, current carbon capture processes are relatively inefficient because of large parasitic power losses: 25–35% for coal, and 15–25% for natural gas.

Large-scale demonstration plants are receiving financial support in Europe, the United States, Canada, and

[9] KEGOC's transmission grid construction projects envisage connecting the West Zone to the broader grid network, the need of long distance power transmission to meet the growing demand in the South Zone, and the trends for international integration of energy systems.

[10] See IHS CERA presentation, Technology Snapshot: Advanced CT and CCGT

[11] See IHS CERA presentation, Postcombustion Emission Control Retrofit Technologies at Coal-fired Power Plants

[12] Trona (trisodiumhydrogendicarbonatedehydrate) is a mined mineral.

[13] See IHS CERA presentation Technology Snapshot: Carbon Capture and Storage

Australia through direct grants, tax credits, and carbon pricing policies. But declines in available funds have contributed to some project cancellations.

Key commercialization hurdles

- More commercial development is needed to reduce upfront costs and parasitic power losses
- Technology development is progressing more slowly than other low-carbon technologies such as solar and wind power
- Low natural gas prices, high capital costs for CCS, and uncertain carbon pricing policies are key obstacles to development
- Regulatory and funding uncertainty has led to numerous project delays and cancellations, slowing development
- Complex value chain through power generation, capture, pipeline, and storage—multiple players and business models at each stage
- Monitoring, measurement, and verification process for carbon storage is needed to allay fears of leakage from underground geological containment reservoirs
- Liability issues for long-term storage also need resolution

At the same time CCS increases the fuel consumption for the heat output (as CCS increases production for own needs significantly). As a result the coal-fired power plants' impact on environment will increase due to escalated coal consumption and ash production. In addition, a risk of CO_2 leakage from an underground geological containment remains.

Given high ash content of Kazakh coal and current level of this technology its application by Kazakhstan's power plants might be premature in the medium term.

8.4.1.4. Grid storage

A growing need for fast-reacting low-carbon solutions to integrate intermittent wind and solar generation, together with ongoing cost reductions for batteries, have triggered rising interest in storage projects (mainly initiated by public funding in Germany, Italy, and United Kingdom).[14]

IHS Markit estimates that by November 2016, 640 MW of non-traditional storage capacity was operating in Europe, equivalent to 940 MWh in energy terms. There is another 190 MW of projects that are under construction or planned, which could come online by the end of 2017, equivalent to 220 MWh of energy storage.

- Li-ion batteries are gaining ground rapidly; they were the preferred technology for the vast majority of projects in 2015 and 2016. Li-ion batteries accounted for three-quarters of project capacity (MW) installed since 2009 and half the energy storage capacity. Sodium-sulfur batteries have a higher duration time and therefore this technology's share is lower on an energy basis than in power terms. It contributed a large addition of energy storage in MWh in 2014 as the technology was chosen by Italy's TSO Terna for its project. A single 290 MW facility installed in Germany in 1978 accounts for all the current compressed air energy storage (CAES) capacity.
- Germany and Italy have the most installed battery capacity. In particular, the large additions of Li-ion batteries by STEAG (90 MW) in 2016 together with the existing CAES facility in Germany, and installation of sodium-sulfur batteries in Italy, put these two countries in the lead. However, the focus has shifted to the United Kingdom, driven by National Grid's Enhanced Frequency Response tender for 200 MW in August 2016, which was almost entirely supplied by energy storage projects, mainly Li-ion. Germany's storage policy is currently concentrating more on residential storage than grid-scale.
- Deployment of grid-scale batteries has mainly been driven by transmission capacity relief (Italy) and frequency regulation (Germany, United Kingdom).

Grid storage capital expenditure (capex) currently ranges from below $1,000/kW to above $4,000/kW, depending on technology and duration.

- Shorter-duration projects are lower cost, because they require much less storage capacity; they almost always use Li-ion or flywheels, which are the best options for frequency regulation.
- Lead-acid remains the least-cost battery technology, but its very low cycle life keeps it from being competitive in most grid applications.
- Two zinc-based batteries on the cusp of commercialization are the next-lowest-cost option, although they must still build up a track record and are challenged by both cycle life and efficiency.
- Li-ion is a higher-cost option today, but costs are falling rapidly, and both cycle life and efficiency are superior to lower-cost options.
- Flow batteries have a much longer cycle life than Li-ion, but efficiency is poor, and costs are not falling as quickly.
- Sodium-sulfur batteries have historically been the least-cost battery option, but they are currently only available with a seven-hour duration, and costs have not changed much in over a decade of deployment.

Flow battery storage (with the storage capacity of 60 kWh) has been installed at Kapchagai solar power plant in testing mode; however plans to balance the output of renewable power plants (solar and wind) with the storage capacity of 100 MWh have not been finalized (likely owing to the technology costs).

Highly efficient battery technologies are capable of improving renewable integration, however at present the cost and efficiency of these technologies are yet to improve several fold to be economically viable in renewable integration.

A battery technology breakthrough could come from quantum electronics, still it is unclear when they will become available for the industrial use.

8.4.1.5. Microgrids

Essentially, microgrids are local power systems that deploy a collection of technologies in the following environments:

- Military installations
- Universities
- Hospitals
- Neighborhoods
- Municipalities
- Office campuses/parks

These technologies enable the centralized control and digital communication necessary to coordinate generation, demand, storage, direct load control, electricity distribution, and imports of electricity from the bulk power system.

A microgrid has the capability to operate as an electric island for reliability, efficiency, economic, or environmental purposes.

Key potential benefits

- Mitigate power outages and protect against cyber attacks
- Integrate renewable and distributed generation resources
- Increase efficiency by reducing fuel dependency, fuel costs, and emissions

8.4.1.6. Small modular reactors (SMRs)[15]

Small nuclear reactors technology (less than 300 MW) offers the advantage of factory production and less complicated equipment delivery, with reactors delivered preassembled. But SMRs need to demonstrate that modular design and factory construction have an economic advantage over competing large-scale, conventional base-load generation options (including conventional nuclear).

Electricity generation

- Reactors can be built in clusters, with additional reactors added over time as demand increases.
- Reactors can power remote communities.

Other process heat applications

- Petrochemical and refining industries
- Oil sands
- Desalination
- Hydrogen production

Economics

- High unit cost, long lead time, and construction complexity of large reactors along with the desire for low-carbon energy sources have renewed interest in SMRs.
- Economic viability of SMRs is uncertain owing to technical and licensing hurdles. SMRs need to demonstrate an economic advantage over conventional base-load generation options through
  - Factory production, simpler construction logistics (including transportation), and shorter construction schedule versus field-erected conventional generation
  - Potential for more competitive supply chain (multiple competing vendors and designs)
- Levelized cost of electricity estimates from vendors range between $90/MWh and $160/MWh.

8.5. REGULATION: LEGISLATION AND POLICY FOR KAZAKHSTAN'S POWER SECTOR

Kazakhstan's electric power sector is subject to extensive federal, regional, and local regulation that defines price- and tariff-setting policies, anti-monopoly regulation, energy efficiency and environmental protection, wholesale and retail market rules, as well as related investment, health, safety, and labor regulation. Kazakhstan's progress on power sector reforms since independence has been generally patchy: the power market design still lacks effectiveness and overall design efficiency on both the wholesale and retail levels. Despite some critical legislative amendments made in 2015, they were not all fully implemented.

The power sector strategy, although now incorporating some modern-day concepts, such as renewable generation and provisions for carbon reduction, still lacks consistency, detail, and long-term predictability. In the last decade Kazakhstan's policymakers have felt compelled to prioritize power sector policy in response to urgent infrastructural needs (e.g., a tariff-for-investment scheme during 2009–15) or to accommodate selected high-visibility initiatives (e.g., support of renewable generation) irrespective of wider policy commitments.[16] The lack of policy consistency meant regulation has not been effective enough to mobilize long-term investment.

8.5.1. Review of the power sector policy documents and commitments

The series of power sector reforms outlined in 2008, in particular with regards to a price-liberalized wholesale power market structure (to incorporate day-ahead, balancing, system services, and capacity markets) as well as performance-based grid tariffs and retail market competition, have either stalled or were substituted by mechanisms introducing tight price control (e.g., a system of price caps, [return to] cost-plus transmission tariff, etc.). Although in 2015 the legislation on many long-awaited power market concepts (capacity market, balancing market, retail market) was introduced, for the most part it disregarded the changing pattern of supply and demand, continued to support (power, capacity, heat energy) price distortions, lacked vital details, and remained inconsistent with the framework programs and commitments that Kazakhstan has undertaken to date; namely:

- External Policy Concept 2014–20[17]
  - Prioritizing Kazakhstan's economic integration within the Eurasian Economic Union.

[14] See IHS Markit analysis European Grid Storage (Part 1 and 2)—Market and technology status / January 2017.

[15] See IHS CERA Technology Snapshot: Small Modular Reactors

[16] See Decree of the President of the Republic of Kazakhstan from August 1, 2014 No. 874 "On approval of the State Program of Industrial and Innovative Development of the Republic of Kazakhstan for 2015-2019 and on amending Presidential Decree No. 957 of the President of the Republic of Kazakhstan from March 19, 2010 "On Approving the List of State Programs".

[17] See Decree of the President of the Republic of Kazakhstan from January 21, 2014 No. 741 "On the Concept of the Foreign Policy of the Republic of Kazakhstan for 2014-2020"

• Expansion of international cooperation to attract investment and latest technologies into strategic sectors of the economy to boost Kazakhstan's industrial and innovative development.

• Prioritizing initiatives on climate and environmental protection, Kazakhstan acts diligently to transit to the "green economy" to increase resources efficiency (water, land, biological and other) and their management, to improve environmental quality and wellbeing of the population. A gradual transition to the "green economy" is on the of the key elements of reaching Kazakhstan's goal in becoming one of 30 leading developed economies in the world.

• Strategy Kazakhstan 2050[18]

• Create investor friendly environment to increase Kazakhstan's economic potential, Profitability and return on investments.

• Develop alternative and renewable energy sources (solar and wind) to reach 50% of power consumption by 2050.

• The Concept of Fuel and Energy Sector Development to 2030[19]

• The ultimate goal of power sector development is to increase the efficiency of Kazakhstan's power resources in support of economic growth and improving living conditions for the country's population.

• Among the strategic priorities, to be achieved by 2030, are

- Energy security.
- Development of the resource base.
- Lessening of the power sector's negative impact on the environment (inclusive of 30% power production by alternative and renewable sources of power by 2030 and 50% by 2050 as per Kazakhstan's transition to the "green economy").

• "Green economy" Concept targets[20]

• Growth of alternative (solar, wind, hydro and nuclear power plants) energy sources' power output: to 3% by 2020 (solar and wind), 30% by 2030 (solar, wind, hydro, nuclear)., and 50% by 2050 (solar, wind, hydro, nuclear).

• Growth of gas-fired generation in total output: to20% by 2020, 25% by 2030, and 30% by 2050.

• CO_2 emissions reduction in the power sector relative to 2013 levels: 2012 level by 2020, to 15% by 2030, and to 40% by 2050.

The concept of Kazakhstan's transition to the "green economy" adopted in 2013 "based on the rational use of natural resources and reduction of Kazakhstan's carbon footprint" has become the most significant commitment for Kazakhstan's energy sector. It would imply that the electric power and capacity markets' policies would have to incorporate this environmental imperative alongside security of supply and value for consumers as overarching goals.

Any change in power market regulation will have to coincide with a new investment cycle in Kazakhstan's power generation. The latter is not only driven by the cost of new technologies (building renewable sources of energy, smart grid, new gas and nuclear capacities, storage solutions, and adapting the existing system to them, etc.), but by the fact that Kazakhstan's power sector is "locked-in" to high carbon production and consumption patterns. Therefore, the new investment is needed to fund a breakaway from them.

The "green economy" initiative also coincides with a change in consumption patterns (peakier and more decentralized), which means Kazakhstan must reevaluate the way it thinks power will be generated, delivered, and consumed by 2050. All these factors require urgent amendments to the power sector capacity balance planning and grid development; electricity production and consumption, heat energy, installed and available capacity, system services, and balancing market regulation. For example, the approved plan of adding several large coal-fired base load power plants contradicts both the "green energy" path and the emerging consumption and production patterns (renewable impact). It would also require potentially constraining certain types of technology that currently contribute to Kazakhstan's higher carbon footprint most, i.e., coal-fired heating power plants (the latter would be a particular challenge in the absence of a broader heat energy market policy, and related social implications), while ensuring system and market readiness to integrate disruptive intermittent generation.

Kazakhstan, like many other countries, is facing the challenge of providing low-cost energy while creating a sustainable power sector and meeting environmental commitments. While state-driven spending is needed to launch the transition to a "green economy," it will be the private sector that will ultimately provide most of the investment. However, embracing the green framework without addressing the power market fundamentals or accounting for the upcoming technological changes is likely to deter private investment or drive capital costs up. The attempt to disregard the "all-in-one" approach (security of supply, environmental commitments, technological advancements [on both supply and demand sides], and value for the consumer) would result in constant need of tweaking of the market framework, and could pile unnecessary financial pressure on certain consumer groups.

8.5.2. Key power sector policy and tariff regulation framework institutions

8.5.2.1. Kazakh Government

The statutory framework for Kazakhstan's power sector is defined by the Electric Power Industry Law, which has established operating principles for the sector and introduced key concepts that are conveyed in all other power sector-related regulation.[21]

According to the Electric Power Industry Law, the Kazakh government is the principal body responsible for setting the overall course for power sector development.

8.5.2.2. Ministry of Energy

The responsibility for executing the government's power sector policy lies with the Ministry of Energy, whose almost 70 duties are listed in the Electric Power Sector Law.

The Ministry of Energy's primary responsibility is to implement the government's vision for the power sector within the context of the overall economy, guided in this endeavor primarily by the strategic plan, "Concept of Fuel and Energy Sector Development to 2030," published in 2014. [22]

8.5.2.3. KREMiZK

The antimonopoly and main price-setting body and de facto regulatory agency for the electricity sector in Kazakhstan is the Committee on Natural Monopolies Regulation and Competition Protection within the Ministry of National Economy (KREMiZK). KREMiZK monitors the wholesale and retail power market participants' compliance with antimonopoly regulations and imposes sanctions with regards to any violations.[23] It also sets tariffs for natural monopolies services, which in terms of the heat energy and electric power sectors include:

• Transmission and/or distribution of electric power
• Production, transmission, distribution, and/or supply of heat energy
• Technical dispatch of electric power into the grid network and consumption of electric power
• Balancing of electric power production and consumption.

The overall price formation of state level (effectively maximum tariffs (price caps) for power producers on the wholesale level) are set by the Ministry of Energy on the government's behalf, while KREMiZK establishes a whole range of operational tariffs at the retail market (sold to end-users) for electric power and heat energy, as well as tariffs for the electric power and heat energy distribution, transmission, and sales.[24]

However, the committee's dependent status and insufficient funding means it merely acts as an intermediary between the government and the market participants, translating the government's view on natural monopolies' pricing, rather than instigating a change in tariff methodologies that might remunerate better performance and quality of service.[25]

In addition, current limited state financing impairs the committee's ability to monitor and check natural monopolies' activity.

8.5.2.4. Market Council (SovetRynka)—Electric Power Association (KEA)

Arepresentative body that would represent and defend the interests of Kazakhstan's wholesale electricity (capacity) market buyers and sellers has failed to materialize fully, although respective legislation creating a market council (familiarly known as SovetRynka in Russian) was introduced in 2015. De facto, the interests of the power producers and large consumers are represented through the Kazakh Energy Association (www.kazenergy.com), the National Chamber of Entrepreneurs (Atameken), the Republican Association of Mining and Metallurgical Enterprises (AGMP) and others. And although SovetRynka (run by the Electric Power Association [KEA], www.kea.kz) monitors the market and acts as a link between the market participants and the Ministry of Energy, it has become yet another platform (out of many) for discussing power sector issues rather than being a consolidated force to lead and implement changes related to the power market structure/design, and/or power, capacity, and emissions trading.

In part, this is due to the restricted authority and functions imposed on KEA by the Electric Power Sector Law, limiting it to power market monitoring and collecting market opinion on legislative changes. Although, in preparation to 2019 capacity market launch KEA reviewed the power plants' investment programs.

8.5.3. Wholesale electricity and capacity markets

Kazakhstan's power market consists of wholesale and retail markets where currently electric power and capacity are treated as a single product. However, from 2019 this will change with the launch of a capacity market. This change would redefine the structure of the wholesale electricity market and power price dynamics by using specific market mechanisms to compensate investors separately for fixed and variable costs. For instance, the purpose of the wholesale electricity price (for the commodity of power) would be to cover generators' variable costs (mainly fuel) while a capacity price should cover generators' fixed costs (such as payroll, maintenance, investment etc.).

8.5.3.1. Wholesale electric power market

The wholesale power market operation is governed by the Electric Power Sector Law and the Wholesale Power Market Rules (Market Rules) approved in 2015.[26] Although the Market Rules define and de-

[18] The Address of the President of the Republic of Kazakhstan from December 14, 2012 "Strategy" Kazakhstan-2050: the new political course of the accomplished state"

[19] See Government Resolution No. 724 of 28 June 2014 on "Approving the Concept of Kazakhstan's fuel and energy complex development to 2030"

[20] See the Presidential order No. 577 dated 30 May 2013, "Kazakhstan transition to the Green Economy"

[21] See the "Electric Power Sector Law No. 588-II of 9 July 2004 with changes made on 28 December 2016."

[22] See Resolution of the Government of the Republic of Kazakhstan from June 28, 2014 No. 724 "On Approval of the Concept for the Development of the Fuel and Energy Complex of the Republic of Kazakhstan until 2030"

[23] See Law of the Republic of Kazakhstan from July 9, 1998 No. 272-I "On Natural Monopolies" which establishes the principles of natural monopolies regulation and defines the rights of consumers and providers of natural monopoly services.

[24] See the Order of the Minister of Energy of the Republic of Kazakhstan from February 27, 2015, No. 160 "On approval of the maximum tariffs for electric power for a group of energy producing organizations" as amended in January 2017

[25] In 2014, the government declared of its intention to introduce European style methodologies to the power sector, gradually increasing their share from 20% in 2014, to 60% in 2016, and to 100% in 2017. It was expected that KREMiZK would lead this process. However, these plans did not materialize, and were swapped for the maximum tariffs (price caps) extension to 2019 for the wholesale power producers, and a cost-plus methodology for the grid.

scribe the four sections of the wholesale power market—centralized and decentralized power trading, balancing market, and the system services market—to date only decentralized and centralized segments have been rolled out.

8.5.3.2. Wholesale market participants

The wholesale electric power market participants include:

- Power producers that generate power in bulk at large power plants
- A national grid company (KEGOC) that transports electric power in bulk over high voltage lines (from 110 kV to 1150 kV)
- A system operator (KEGOC) that is responsible for dispatch and overall system balancing
- Regional electricity network companies (REC) and other energy (electric power and heat energy) distribution companies that transport electricity (heat energy) to power consumers using distribution grid networks (110 kV or less) and heat energy networks.
- Energy supply companies (ESO) that purchase electric power in bulk for resale to retail consumers
- Large consumers (typically industrials) that purchase power for their own consumption
- Financial Settlement Center (FSC), controlled by KEGOC that calculates and distributes the cost of renewable power
- Centralized power market trade system administrator (KOREM)

Buyers and sellers of electric power are qualified to buy/sellin the wholesale market subject to them buying/selling an average daily minimum of 1 MW (base load) capacity (for renewable generation no less than 1 MW of average annual capacity). They must also be equipped with automated commercial power metering systems and have access to the power grid network (transmission and/or distribution).

Wholesale sellers are conventional and renewable power producers, while buyers include large consumers, power transmission and distributions companies (who buy power to compensate losses), and energy supply companies (who buy power for further resale at the retail market). The system operator, KEGOC, provides operational dispatch control services to all wholesale market participants. KEGOC is authorized to give mandatory instructions to the market participants so to balance the system (inclusive of the volume, structure, and distribution of reserve capacity among UES power producers) in real time.

The power producers, in accordance with the Electric Power Industry Law, are obliged to sell generated power to wholesale power consumers, power network companies, and to KEGOC (national grid)—to cover losses in their own distribution grids and for their own needs.

8.5.3.3. Power trading mechanisms

The current wholesale market electricity power trading model uses the following mechanisms:

- Bilateral power purchase agreements (decentralised trade)
- Centralized auction (administered by KOREM): short term (day-ahead, intraday), and medium to long-term (week, month, quarter, and annual)

8.5.3.3.1. Bilateral agreements (decentralised trade)

Almost 90% of Kazakhstan's power is sold via bilateral power purchase agreements (PPAs). PPAs are signed between power producers and large industrial consumers, as well as between power producers and electricity supply companies (ESO), provided they meet the average minimum daily megawatt usage, and have grid access. The market participants can, at their discretion, define PPA counterparties, prices (as long as they do not exceed the price cap for the power plants in question), and volumes. As a rule, PPAs are signed for one year (in line with an annual price cap adjustment).

There are a number of factors that drive the choice of decentralized power trading over that of centralized power trade, namely:

(i) Regulation

a. According to the market rules, participation in the centralized trade is voluntary. Given the slowing rate of demand and availability of spare capacity, power producers are keen to lock consumers into PPAs.

b. Volume, terms, and the price of electric power in bilateral agreements (within the price cap) are set by the parties.

c. The price-capping does not recognize the difference in the cost of power subject to hourly marginal costs (base, half-peak, and peak). This means that power plants cannot sell their peak power at a centralized market at prices higher than the price cap.

(ii) Structure of the market participants' assets

a. Vertically integrated industrial groups own a substantial share of generation. Bilateral agreements for these vertically integrated companies provide price efficiency throughout the value chain.

(iii) Technical aspects

a. Combined heat-and-power plants' [TETs] fuel-to-power cost efficiency deteriorates with a decrease in heat energy output. Power-only production makes TETs uncompetitive at the centralized power market.

b. TETs are not motivated to trade power centrally, as the electric power produced by TETs is a by-product of the heat energy that TETs generate as their primary product.

c. The system operator/regulator does not have the ability to decommission on the basis of technological or economic inefficiency.

(iv) Economic

a. With the exception of hydropower during the spring flood period, consumers do not have access to cheap power at a centralized platform.

Although PPAs contain an hourly schedule, intraday pricing is not sensitive to supply and demand and thus power plants tend to commit to structured agreements. This is one consequence of not having a properly functioning balancing market as well as enforced price-capping.

Agreements between power producers or between energy sales companies are prohibited because the activity is considered speculative trade and causes cost inflation for power consumers.

[26] See Order of the Minister of Energy of the Republic of Kazakhstan from February 20, 2015 No. 106 "On Approval of the Rules for Organization and Operation of the Wholesale Electricity Market".

Notably, in Kazakhstan almost 50% of wholesale power is traded by a handful of power plants, but considering Western experience that does not necessarily mean a market environment cannot be achieved using a centralized marketplace.

8.5.3.3.2. Centralized power trading

Out of a total of 83.5 billion kWh supplied to consumers in 2016 (according to the actual production and consumption balance), about 10.3 billion kWh was sold centrally at an auction administered by Kazakh operator of electric power and capacity market, KOREM. According to KOREM, the share of centralized power trading has increased from 7% in 2014 to 12% in 2016, driven by the availability of spare capacity (capacity that was not contracted bilaterally as a result of declining industrial power demand) (see Table 8.3).

Table 8.3. Change in centrally tradable electric power

	Volume, billion kWh		
	2014	2015	2016
Total volume of electricity supplied to consumers	81,3	82,1	83,5
Total volume of centralized trade	6,02	2,49	10,26
Share of centralized trade in overall power supply to consumers	7%	3%	12%

Source: KOREM, 2016 preliminary annual report

The participants of the centralized market are power producers that sell excesses that were not locked into PPAs, and power consumers (industrial or energy supply companies) that buy the shortage that is either not covered by their own generation or in their PPAs. The power producers are required to cover tradable volumes by their own generation only, as the current legislation prohibits the power producers from buying power from the centralized market (i.e., from other producers) for further resale to consumers, unless in an emergency from a unit outage.[27] In other words, a power producer cannot choose to buy power from a centralized market should it make more economic sense than generating.

Participation in a centralized market is voluntary with the exception of the mandatory sale of hydropower capacity during flood periods. Prior to entering into trading, KOREM ensures power consumers (buyers) are solvent (available funds) by requesting a financial guarantee.

The buyers and sellers of power can trade on the centralized market on a short (day-ahead and intraday market), medium (week, month, quarter), and long-term (year) basis—essentially three marketplaces.

Day-ahead market (DAM)

The day-ahead market (DAM) is an auction of price bids and volumes submitted by the power producers and consumers a day in advance of delivery. According to the day-ahead market price merit order, the buyers' (consumers and KEGOC) bids are ranked from the highest to the lowest and matched to the sellers' offers (power producers) from the lowest to the highest, until the demand is fully met, for every hour. The last accepted seller's price offer that satisfies the demand sets the (clearing) price for all power plants. This marginal price formation rewards power plants' cost efficiency, and therefore appeals mostly to power plants with the lowest marginal costs and price caps (e.g., hydropower). Naturally, the lower the power plant's marginal cost (to produce power) then the higher the profit potential.

The system operator (KEGOC) receives the trade results from KOREM and incorporates them into the day-ahead operating schedule.

To form the day-ahead operating schedule the system operator accounts for both decentralized and centralized trades. Essentially, the power producers inform the system operator of their production plan a day in advance, while the power suppliers (and RECs) submit the demand schedule of their consumers, and how much of this consumption is covered by bilateral agreements. The system operator accounts for potential demand that might not be met, owing to generator malfunction, and estimates the volume of reserve capacity that production (based on standardized reserve capacity ratios per energy zone rather than by the volume and value of lost load) should be increased.

Intraday

Intraday trading allows for adjustments to be made to the daily operating schedule three hours before the physical delivery of electric power (gate closure). Intraday trading is a continuous double auction. The buyer and seller of power have the right to cancel any trading arrangements that have been reached prior to gate closure. KOREM confirms the buyer and seller pairs and the power prices, and submits this information to the system operator for technical assessment and adjustments required to the daily operating schedule.[28]

Nevertheless, the system operator has no influence on meeting the overall demand based on efficiency (with the cheapest power generation available and dispatching more expensive generation only if demand spikes). In other words, the system operator's role in unit commitment (i.e., the determination of

[27] See the Law of the Republic of Kazakhstan from July 9, 2004 No. 588-II "On Electric Power Industry", Article 12, Clause 3-1.

[28] The daily operating schedule represents a document by the system operator that outlines the hourly schedule of electric power production and consumption for every calendar day in accordance with the information from the bilateral agreements and centralized auction.

which resources to start up or shut down driven by security and economic dispatch decisions) is limited to unit dispatch for system stability.

Medium- and long-term trading

Medium- and long-term power trading are forward agreements for the physical delivery of electric power over longer periods, namely a week, a month, a quarter, and a year ahead. They are differentiated further by:

- Baseload power supply, seven days a week
- Peak load power supply, working days

The auction for medium and long-term power trading is held in two unrelated trading sessions:

- The first session is held between 09:30 and 11:30 during weekdays
- The second session is a continuous double auction held between 14:30 and 16:30 during weekdays

The trade participants could participate in either or both trading sessions. The schedule of medium- and long-term trading is approved by KOREM. The pairs of sellers and buyers sign PPAs upon receiving the information on volumes and prices from KOREM.

Long-term trading is of interest to both power consumers and power producers given the current abundance of spare capacity. This is because the consumers hope to enter into long-term PPAs at a more competitive price, while the power producers hope to lock in additional consumers.

8.5.3.4. Wholesale electricity price formation

Since 2009 wholesale power prices are semi-regulated. Essentially this means that the power price is set to a state-set price cap ("maximum tariff") irrespective of the power system or sector indicators. All power plants in Kazakhstan, regardless of their ownership, were divided into 13 groups (from 2016, 17 groups) with each group assigned a price cap according to their cost drivers (marginal cost of fuel for thermal plants and water tax for hydropower plants, as well as distance from fuel source) and set profit margins (to cover investment obligations).

From the point of view of power trading, both centralized and decentralized, power producers are not allowed to sell power at a price exceeding their respective price cap. Even in the day-ahead power market, when a marginal price could settle above some of the power plants' price caps (e.g., for some hydropower plants whose price caps are half that of thermal power plants) the volume of electric power that could be sold above the price cap cannot exceed 10% of total plant's output. Price-capping also means that producers' prices do not fall to marginal cost when there is a surplus of capacity and rise when demand approaches available generation, whether intraday or over longer periods (driven by economic environment). According to the Electric Power Industry Law, the power price can exceed the price cap at the balancing market (once it is finally launched) and for export.[29]

The price cap system was conceived in 2009 as a temporary seven-year measure to boost investment into generation in the face of a looming capacity shortage. In return for higher (maximum) tariffs, each power plant committed to a medium-term investment program between 2009 and 2015 that was subject to an annual increase to accommodate investment plans and inflation. Investment programs were sanctioned to fund upgrades, maintenance, overhaul, and new construction of generating assets.[30]

The price cap (maximum tariff) scheme was billed as "tariff-for-investment", and according to the Ministry of Energy the scheme increased investment into power generation more than fivefold, and attracted over 1 billion tenge of new investment. In 2009–15 Kazakhstan reinstated and launched 2,957 MW of new generating capacity, with a further 350 MW of new generating capacity commissioned in 2016 (see Table 8.4).[31]

Table 8.4. Changes to installed and available capacity

	Installed capacity MW	Available capacity, MW Winter	Summer
2009	19 127,9	14 821,0	12 764,0
2010	19 440,5	15 291,0	13 583,0
2011	19 798,1	15 765,0	14 176,0
2012	20 442,0	16 425,0	14 851,0
2013	20 591,5	17 108,0	15 320,0
2014	20 844,2	16 945,4	16 937,7
2015	21 307,2	17 500,1	16 466,3

Source: Statistical Committee of RK

[29] See "Electric Power Sector Law No. 588-II of 9 July 2004 with changes of 28 December 2016," Article 12, clause 3, point 1.

[30] Should the power plants fail to cover investment needs from the sale of electric power under a maximum tariff (price cap), such power plants were entitled to an individual/specially calculated tariff (subject to receiving the Ministry of Energy's approval of the technical scope of works and investment rationale). Once the capacity market is launched in 2019 the capacity price would replace the individual/specially calculated tariffs. In other words, until 2019 the wholesale power price would be calculated based on the power producers' costs and profit (maximum tariff), or costs, profit, and investment (for individual/specially calculated tariff).

[31] Source: Statistical Committee of RK.

By 2016 the goal of the tariffs-for-investment scheme was successfully accomplished: the power system had built up almost 3,000 MW of excess generating capacity.

Although the capacity market was meant to replace the tariff-for-investment scheme in 2016, the delay in launching the capacity market until 2019 forced the government to extend the price-cap scheme; but now stretching to 17 groups of power producers. However, owing to lackluster demand, policymakers lost the impetus for launching new mandatory investment program, so price caps were set at the 2015 level for three years (2016–18) instead. The need for retaining price caps was driven by the government's plan to accommodate the cost of renewable generation within the conventional power producers' price caps.

8.5.4. Renewable generation in the wholesale market structure

The government remains committed to its renewable targets outlined in the Strategic Plan for the Development of the Republic of Kazakhstan to 2020,""the Concept on the transition of the Republic of Kazakhstan to the "green economy"," and "Strategy Kazakhstan-2050."[32] Similarly to other countries, to boost renewables development, Kazakhstan has opted for preferential treatment of renewable technology; i.e., policy support. Although Kazakhstan had planned that 1% of electric power would come from renewables by 2014, in 2017 only 0.8% of electric power is being generated by renewable energy sources (RES). The key factors slowing renewable project development have been:

(i) Long (12–18 months) process for technical approval of the projects

(ii) Limited RES projects' quota (the list of approved RES projects already exceeds expectations and the set target for 2020, so irrespective of the dormant status of some of the approved projects, new projects cannot be added to the list.

(iii) Unfavorable economic environment, particularly tenge devaluation over 2014-15.

While all RES have been allocated feed-in tariffs almost ten times higher than those of conventional power plants (hydropower plants), the renewable projects' economics suffered due to capex dependence on imported equipment (see Table 8.5). As a result, in April 2016, an amendment was made to the governing law "On Support of the Use of Renewable Energy Sources" (RES Law) for the indexation of the feed-in tariffs to the tenge exchange rate.[33]

Table 8.5. Feed-in tariffs for renewable energy sources (2014)

RES	Tariff (tenge/KWh, without VAT)
Wind	22,68
Solar	34,61
Hydro (up to 35 MW)	16,71
Biogas	32,23

Source: IHS Markit

While this measure could help accelerate construction of renewable capacity, the integration of renewables in the planned quantities by 2030 into Kazakhstan's infrastructure under the current power market design (with regards to the balancing and system services markets, as well as suggested capacity mechanisms) is likely to be a challenge (see KAZENERGY NER 2015, section 10 on technological issues and the economic implications arising from RES integration.[34] In developed power markets, with strict regulation and deep penetration of modern technologies, integration of about 15% of renewable production into an energy system is workable but still challenging for some system operators, given the high levels of intermittency. For Kazakhstan's power sector where the overall rules and regulations are immature, and generating assets and grid infrastructure still require considerable technological upgrade, scaling up renewable production is likely to pose both a technological and economic test.

According to the Law on "On Support of the Use of Renewable Energy Sources", renewable energy sources in Kazakhstan include wind, solar, small hydropower (up to 35 MW), geothermal, and bio fuels. The agreement duration for purchasing renewable power is 15 years. Renewable power producers are allowed to sell their electric power either (i) centrally via a Financial Settle-

[32] By July 2015 the total installed capacity of renewable projects approved for implementation reached 3,756 MW with 2 GW more looking for approval. Of the approved 3,756 MW wind accounts for 1,987 MW, solar for 991 MW, and small hydro for 779 MW. Longer term, and according to the Green Economy Concept, the Kazakh government hopes both renewable and alternative (nuclear) sources of power could grow to 50% of its power output.

[33] See the Law of the Republic of Kazakhstan from 4 July 2009 No. 165-IV "On Support of the Use of Renewable Energy Sources". Regardless of the amendment the profitability of renewable projects remains a challenge irrespective of the global decline in equipment costs due to difference in $ Dollar FIT value between the current FITs and those approved in 2014.

[34] According to Kazakh legislation, RES are obliged to meet the daily operational schedule, follow the system operator's instructions with regards to the unit's operation (for RES with installed capacity over 1 MW), and for hydropower generation to regulate intraday water levels in the reservoirs (subject to water levels). In July 2017 President Nazarbayev announced that 42% of power output will come from renewable sources by 2050.

ment Center (FSC) at fixed feed-in tariffs, or (ii) via bilateral agreements at prices agreed upon between the parties (with no right to switch to power sale via FSC). FSC sells power to the so-called "conditional" consumers, represented by:

(i) Conventional fossil fuel (coal, gas, and oil, nuclear and sulphur) power producers[35]

(ii) Market participants who export electric power from Kazakhstan

(iii) Hydropower plants with installed capacity above 35 MW (launched before 1 January 2016)

Should RES act as a source of heat energy, the heat energy purchase agreement is signed for RES payback period.

Both modernized and new RES are granted preferential right of access to either the power grid network or heat energy network, although RES developers are to assume the costs for construction of the grid from RES to the grid connection point.

8.5.4.1. Renewable electricity price formation

According to the Electric Power Sector Law and the Law on Supporting Renewable Energy Sources (RES Law) the Center of Financial Settlement (CFS) buys all generated renewable power at feed-in tariffs. The choice of having CFS as single buyer of renewable power is driven by the desire to distribute the cost of renewable energy simply and evenly. Interestingly, the buyers of renewable power are not energy supply companies, but conventional power producers who pay for the renewable power in proportion to their output delivered to the grid.[36] This out-of-the market treatment of RES that grants it financial, dispatch, and operational privileges is not uncommon globally, although the payment scheme is unique to Kazakhstan. However, together they have created the highest level of investment stability for developers in renewable generation.[37] For instance:

- The renewable power purchase agreements could be signed three years prior to renewable capacity commissioning.
- Renewable tariffs are fixed for every type of RES (wind, solar, hydropower up to 35 MW, geothermal, and bio fuel) for 15 years, and are subject to annual indexation to inflation, and changes to the tenge exchange rate. Subject to RES type, fixed tariffs are three to ten times higher than those of conventional power producers.
- RES enjoy free of charge connection to the distribution grid and are exempt from existing grid upgrade payments (that might be required for the connection of a RES), as well as power transmission tariff. However, RES developers take on the full cost of building a line to the nearest connection point.
- RES developers also receive tax benefits (corporate tax, property tax, land tax) and investment subsidies (30% of actual costs related to installation and equipment).
- RES developers could be exempt from customs duties and receive state grants (in relation to free use of land, buildings, equipment, and transport).

Conventional power producers reimburse the cost of renewable power by including it into the cost of their power production. In other words, the cost of renewable power is accounted for during the price cap calculation.[38] Essentially, the conventional power plants bear a joint responsibility for the mandatory payment for renewable power.[39] Nevertheless, this scheme distorts the wholesale power price and obscures the true cost of power production.

Although RES are exempt from any costs that arise from any existing power network upgrades that are reflected in transmission fees and do get translated to end-consumers.[40] RES are exempt from transmission tariff payment which also means that these costs (inclusive of transmission losses) are translated to the end consumers.

Similar to electric power, RES are exempt from paying heat energy network tariffs, if RES is a source of heat energy, and the heat energy is supplied to the centralized heat energy network. But for energy supply companies, the cost of acquiring RES heat energy is included into their end-user prices.

[35] In 2013 Sulfate plant in Kazakhstan launched a sulfur power plant (SKZ-U) As part of Its 16 MW steam turbine runs on steam produced by the manufacturing plant.

[36] See the Law of the Republic of Kazakhstan from 4 July 2009 No. 165-IV "On Support of the Use of Renewable Energy Sources. Conventional power plants sign annual agreements for the purchase of renewable power.

[37] According to the RES Law the renewable power producers could choose to sell their electric power directly to power consumers via bilateral agreements at prices agreed upon by the parties, but by doing so such RES would lose their right to sell their electric power centrally via CFS.

[38] See Article 9, clause 4 of the Law of the Republic of Kazakhstan from 4 July 2009 No. 165-IV "On Support of the Use of Renewable Energy Sources"

[39] While this scheme is feasible for stand-alone power producers, the power plants owned by the industry would find it impossible and unpractical to inflate the cost of power at the expense of their own end-product profit margin (which in many cases is export oriented). Industries who own power plants and are willing to build RES for own needs might minimize the cost of renewable power in their portfolio but would also contribute to meeting the overall RES target. Considering this, on 11 July 2017 a retrospective amendment was introduced by Law No. 89-IV "making changes and amendments to some pieces of legislation in the Republic of Kazakhstan. At that, renewable projects by industrial groups should fit within renewable targets which could call for a review of currently approved projects (particularly, should industrial RES happen to be in the right location for system needs).

[40] See Clause 5 of the Law of the Republic of Kazakhstan from 4 July 2009 No. 165-IV "On Support of the Use of Renewable Energy Sources", as amended by the Law of the Republic of Kazakhstan from 28 April 2016 No. 506-V: "In case of expansion and reconstruction of existing electric and heat networks by power transmission organizations to allow for connection of RES facilities, the relevant costs are included in the tariffs of energy transmission organizations in the manner established by the legislation of the Republic of Kazakhstan on natural monopolies and regulated markets."

8.5.5. Wholesale capacity market

According to Kazakhstan's latest Concept for the Development of the Fuel and Energy Complex of the Republic of Kazakhstan until 2030, the government plans to attract 7.5 trillion tenge, or about $51 billion (in 2014 prices) of mostly private investment into power sector. The government recognizes that to achieve this, Kazakhstan will need to create incentives that would attract and secure a return on investment. The launch of a capacity market is seen by the government as a means to achieve this.

The benefits of running a separate capacity mechanism include:

- Creating long-term pricing signals for consumers and investors
- Resolving the chronic "missing money"' problem in semi-liberalized power sectors where revenues from electricity sales alone fail to cover costs fully; adding a supplemental capacity price covers most fixed costs and is designed to keep electricity prices down
- Creates a mechanism for ensuring continued modernization and construction of new generating assets

Capacity remuneration mechanisms (CRMs) are complementary to a well-designed electricity market.[41] But even then, CRMs have to be tailored to reflect the local situation (supply and demand structure, capacity mix and age, consumer price parity) and future commitments (e.g., carbon footprint reduction) to be successful long-term. This means that the CRMs' purpose should be clearly defined prior to their introduction.

According to the Electric Power Industry Law the purpose of a capacity market in Kazakhstan is to attract investment into new generating capacity, as well as to provide a means to maintain existing generating assets, allowing demand to be met according to the system operator's capacity forecast.[42] Essentially, while addressing the "missing money" issue, the goal of a capacity market in Kazakhstan is to ensure the adequacy of supply or security of supply in the future. However, it is essential to estimate how Kazakhstan interprets security of supply: availability of generating capacity for meeting peak demand, fuel capacity, or transmission capacity. In this case the capacity remuneration mechanism (CRM) may not be the primary mechanism to resolve these issues.[43] (e.g., capacity ready to respond to a shapelier demand profile and RES integration.

According to the Ministry of Energy's demand forecast to 2024, even without new capacity launches a shortage of generating capacity is not envisaged until 2024–25,and the immediate security of supply threat. But the Ministry of Energy envisages another 3,712 MW of new capacity, expansion of 1,211 MW of existing capacity, as well as technical upgrade of 2,502 MW. Although by 2024 the Ministry of Energy also plans to decommission 2,373 MW of generating capacity, the system would end up with 1,339 MW of excess capacity. This surplus capacity figure does not include the new coal-fired Balkhash Thermal Power Plant (capacity due for sale at the capacity market has been estimated at 1,221MW) due for commissioning by 2022, which will bring the total amount of excess capacity to around 2,560 MW.[44] Taking all of the above into account, and given existing capacity mix, changing consumption profile for a shapelier one, as well as Kazakhstan's broader decarbonization policy commitments including RES integration, and the fact that the power market reform is incomplete (with regards to the balancing market launch, potential improvements to the existing wholesale market model and the system services market), the proposed capacity market model introduction could be either premature or fail to meet the power sector objectives long term. To that end, Kazakhstan's policymakers may review the CRM objectives and mechanisms to ensure security of supply is met by more flexible and cleaner capacity.

8.5.5.1. Currently proposed capacity market model

Out of all CRM mechanisms available, Kazakhstan has opted for a capacity market. According to the rules of Kazakhstan's proposed capacity market, capacity is treated as a service provided by the power producers in accordance with the agreement on maintaining a certain megawatt capacity in a state of readiness to generate.[45]

According to the regulation the wholesale capacity market participants include:

- Wholesale power producers
- Power transmission companies

[41] Capacity remuneration mechanisms include strategic reserve, capacity payments, tender for the new capacity, centralized auction (single buyer), capacity obligations, and reliability options. Subject to their purpose and urgency they are further divided into targeted and market-wide. The use of terminology "capacity market" therefore would be misleading and too narrow.

[42] See Article 15-3 of the law "Electric Power Sector Law No. 588-II of 9 July 2004 with amendments of 28 December 2016."

[43] The CRM is considered when the security of supply remains a concern after electricity market reforms (with regards to the price formation, risks hedging, improvements to the balancing and system services' markets) and assessment of grid (in case of localized deficit). Nevertheless, the power sector reform in Kazakhstan is incomplete: the balancing market is still due for launch, improvements are possible to the wholesale and system services markets. In addition, reforms are due in the heat energy market.

[44] See Government resolution No 667 of 17 June 2014 "On implementation of Balkhash thermal power plant project" with amendments of January 2016. In addition to the Balkhash project, the government has plans of commissioning unit 3 at Ekibastuz GRES-2 (636 MW) within the same period.

[45] See the "Ministry of Energy order No. 152 of 27 February 2015." On approving the rules of capacity market operation, with changes from 30 November 2015, Article 2, 3.

• Wholesale power consumers (large consumers that buy for their own needs and energy supply companies)
• System operator

The current Kazakh capacity market model is based on a concept of the centralized sale and purchase of power producers' capacity via a single buyer.[46] The capacity market design does not envisage the use of demand side technology, so at a time of high demand the system operator would be forced to increase generation rather than having an option of using demand-side schemes to maintain supply security.

In the current model, the system operator centrally purchases capacity by power zone (North, South, or West), subject to the transmission capacity of the grid and system reliability criteria, in a volume corresponding to the consumers' peak demand and a standardized reserve. The rules omit capacity efficiency, emissions standards, or value to consumers' requirement, and are not determined on a merit order. However, it is understood that the following capacity would have a priority in a selection process:

1) Balkhash Thermal Power Plant (as an intergovernmental agreement) – 1,221 MW (stage 1)
2) New (tender) capacity (subject to capacity shortage forecast)
3) Plants that are going through state approved modernization (currently in receipt of individual tariffs) – 1,000 MW[47]
4) Combined heat-and-power plants [TETs (coal-fired)] (volume corresponding to production in heating mode) – 5,000 MW

All remaining capacity will be selected through an auction.

Out of approximately 15 GW of capacity that needs to be selected (peak demand and reserve), about 7.2 GW would be selected out-of-the-market. Subject to the size of a tender capacity, and Ekibastuz GRES-2 unit 3 approval, it will likely leave less than 50% (or about 6.5 GW) to competitive selection.

The out-of-the-market selection of TETs in particular (with no further plan for their modernization or decommissioning) would mean the capacity market would likely remunerate inefficiency instead of the opposite. With this regard, a separate capacity program incentivizing the overhaul or decommissioning of heating power plants (particularly coal-fired) should be launched simultaneously with the capacity market and supported by the new heat energy market legislation and changes to the heat energy tariff methodology.

The current capacity market design model envisages three sources of capacity:

• **New capacity:** selected through a tender to mitigate the risk of capacity shortages
• **The pool of existing power plants:** selected through a centralized annual auction for maintaining existing capacity in sound condition ready to meet demand
• **Modernized power plants:** generating capacity that has signed investment agreements

A different treatment of old and new capacity in Kazakhstan is not uncommon and is practiced in Europe and Russia. It is mainly driven by the desire to minimize the overall capacity cost to end-consumers (if under the marginal price formation the existing capacity is paid at the same price as a new capacity it creates an inevitable windfall for the former, as the new capacity is more expensive than the costs of running existing capacity).

Both existing and newly commissioned generating capacity are subject to an annual certification by the system operator to certify their technical capability to produce and establish their available capacity. Kazakhstan might consider that an emissions performance standard (EPS) should be applied to both new and existing capacity to moderate carbon-intensive generation's access to the capacity market (or at least to get priority capacity payments).

However, an EPS application is not envisaged in the current model. And with no CRM provision for cleaner technology requirements, even when it comes to new capacity additions, Kazakhstan's shift towards a greener economy seems less likely.[48]

Participation in a centralized wholesale capacity market is obligatory for all power producers irrespective of their plants' ownership and structure. The capacity model does not envisage free bilateral agreements for capacity in addition to the auction, unlike the practice in neighboring Russia.[49] This means that energy-intensive industrial consumers that own generating plants and benefit from vertical integration would be forced to buy capacity from the market and are likely to be at a disadvantage (due to the capacity merit order described above and pricing described below).

Wholesale consumers purchase capacity in accordance with their total peak annual demand, an allocated share of reserved capacity, and the national grid's technological losses and own needs, that is calculated based on an annual peak average monthly power consumption capacity.[50] A downward change of contracted capacity volume is not allowed. This would suggest that all contracted capacity must be paid irrespective of any potential decline in demand. Therefore, the CRM in Kazakhstan values availability rather than capacity output (unlike the neighboring Russia or in the USA).

8.5.5.2. Tender for new generating capacity

The need to attract investment into new generating capacities arises if the capacity shortages exceed 100 MW in the first five years of the system operator's annual seven-year capacity balance forecast. A tender represents a long-term capacity market with the delivery in five years from the year when a deficit is forecasted. For this purpose, the Ministry of Energy will hold a tender, and define the type, fuel, and location of a future generating asset, as well as technical, qualitative, and operational characteristics of the units. According to the generating capacity tender rules, the choice of technology, price and terms are defined by a feasibility study commissioned prior to the tender. Nevertheless, the rules do not provide guidance as to the rationale when commissioning the feasibility study and subsequent decision making (e.g., Kazakhstan's environmental commitments, impact of technology (inclusive of RES integration, energy storage, and demand side resources), shape of demand, and value to consumers).

Apart from meeting the tender administrative requirements, the winner of a capacity tender is anticipated to have at least five years' experience of delivering similar projects, as well as fund 30% of the total capacity construction costs outlay from its own funds. The winner and the system operator sign an agreement for constructing new generating capacity, followed by a services agreement for maintaining the capacity's readiness in the volume and for the period defined by the system operator. The latter also defines the capacity price that is set individually on a project-by-project basis.[51] Although the tender rules do not specify that the capacity payment starts only after the asset is fully commissioned, it is implied in other capacity market–related regulation.[52]

8.5.5.3. Centralized capacity auction

In the proposed capacity market model, power producers will sell capacity at a centralized capacity auction within the volume of available capacity certified by the system operator, less (i) volume of export capacity, (ii) volume of tender commissioned capacity, (iii) volume of capacity consumed by the power plants themselves (iv) priority volume of TETs (in P-min), and (v) capacity of modernized plants. The capacity auctions will be held annually, which is unproductive for a sector that is characterized by long-term investment cycles. Renewable resources (solar and wind) are intermittent and their capacity is not accounted for in firm capacity balance forecasts and capacity markets.

8.5.5.4. Capacity price formation

Under the current version of capacity market regulation, the capacity price for generators will be set either through a tender (for new capacity), or an annual capacity auction (for old capacity). The capacity price for tender-selected capacity will be set on a project-by-project basis, while the capacity price for existing generation will be set by the auction.

The generators at the auction will be paid-as-bid (i.e., each producer is paid its bid price), while the consumers will pay averaged capacity prices. The current legislation suggests that power producers will receive capacity payments for available certified selected capacity irrespective of actual demand (capacity actually supplied) to the wholesale market.

Wholesale consumers purchase capacity centrally (irrespective of ownership) in accordance with their peak consumption at a capacity price calculated as an average cost of new generating capacity commissioned through the tender and the cost of existing capacity selected during the annual centralized capacity auction. Kazakhstan currently does not envisage zonal price formation. In other words, consumers in the isolated West Zone would pay for the new and existing capacity built in the South and North zones. The decision of not making the capacity market design zonal allows the overall capacity (and power) price for the end-consumers nationwide to be minimized.

At present Kazakhstan does not have plans to link capacity price to a reliability requirement or restrict access to capacity based on environmental impact criterion. Together with the out-of-the-market selection of certain capacity and payment for capacity availability and not actual supply there is a risk that:

• End-consumers would ' remunerate generation that would be unable to match the future peakier demand profile and meet decarbonization targets, irrespective of their actual load.
• The cost of acquiring capacity for industrial consumers that already possess their own generation is likely to increase; in fact, there is a high risk that generation owned by industrial consumers would not even be selected (because of the anticipated merit order noted above).
• Investment into generation will remain low due to annual reviews of capacity prices and uncertainty with capacity selection.

[46] The system operator KEGOC will de facto act as a Single Buyer.

[47] Source: The Ministry of Energy.

[48] See the "Government of Kazakhstan Resolution No. 667 of 17 June 2014 (on approving the capacity terms for the construction of coal-fired Balkhash TES in 2018)."

[49] Large industrial consumers in Russia are entitled to sign Free Bilateral Capacity Agreements for the full volume less 1 MW that they are obliged to buy from the market. The risk of 1 MW absorbing financial imbalances makes bilateral agreements between consumers and producers less popular, unlike between producers and supply (sales) companies. The latter avoid capacity auction imbalance payments and could structure capacity payments more beneficially.

[50] In accordance with the capacity market rules the capacity reserve is set at 17 % of total peak power consumption capacity by the power consumers and accounting for the capacity required compensation for the national grid's technological losses and own needs.

[51] See the Minister of Energy of the Republic of Kazakhstan Order No. 110 of 20 February 2015 on the "Tender rules for the construction of new generating units"; see also Article 15-1 of the Republic of Kazakhstan Electric Power Industry Law of 9 July 2004 N588-II with changes of 28 December 2016.

[52] See the Government of Kazakhstan Resolution No. 667 of 17 June 2014.

8.5.6. Balancing market

Participation in the balancing market is obligatory for all market participants.[53] However since 2008 the balancing market in Kazakhstan has been operating in a simulation mode. In 2015 the Ministry of Energy delayed its actual launch yet again further to 2019, citing potential power price volatility, lack of flexible capacity, and insufficient commercial metering as reasons for the delay.[54] The ongoing simulation reflects physical balancing of electric power production and consumption by the system operator. However, it does not imply financial settlement of imbalances when Kazakhstan draws on Russia's power system (for now both countries agreed to adhere to net zero flows).

The anticipated rollout of the balancing market in 2019 presumes Kazakhstan will have dramatically improved system flexibility and full commercial metering. But both areas remain an issue, which is likely to affect the balancing market's operation (in order to accurately calculate imbalance charges, a complete set of metered data is required) and price formation (particularly if Kazakhstan continues to draw on Russia's resources). Price formation requires particular attention, as this should reflect the costs of system balancing in real time.

The overall approach assumes that the imbalances must reflect the cost of flexible power for frequency control for replacing capacity rapidly with reserves at a very short notice. Whether Kazakh policymakers opt for single imbalance pricing (same payments for those who both cause and reduce imbalance) or dual imbalance pricing (penalizing parties who cause imbalances at a different rate to rewarding those who reduce imbalances) are possible options with respective advantages and disadvantages. But the key is that the principles of price formation and system operator's drivers are transparent (and at least-cost for consumers).

8.5.7. System services market

The core principle of the System Services Market is to maintain the national standards of power system reliability and electric power quality, defined in the "Rules on the System Operator's Services and the Operation of the System and Auxiliary Services Market" (System Services Market Rules).[55]

According to the System Services Market Rules, the system operator provides the following services to wholesale market participants on a contractual basis:

(i) Technical maintenance and operational readiness of the national grid for the transmission of electric power

(ii) Technical dispatch services

(iii) Capacity reservation services

(iv) Power production and consumption balancing services

In accordance with the above-listed services the system operator receives compensation in the form of a regulated capped tariff (calculated per kWh), namely: (i) power transmission services, (ii) technical dispatch to the grid and consumption of electric power, and (iii) balancing of power production and consumption.[56] The magnitude of KEGOC's system service needs differ by season (with higher system services in autumn-winter as a result of increased consumption). All of the above services that fall under natural monopoly regulation, are set by KREMiZK, and are the same for all consumers. The System Services Market Rules however, are non-transparent on compensation to the actual providers of services (wholesale power producers and power consumers) to balance the system, or envisage such payment in the future, particularly with the planned growth of variable sources of power production (wind and solar generation). These services are ancillary to those procured through the balancing market and typically cover:

- Reactive power
- Frequency response
- Black start
- Reserve services (operational, supplementary, and demand control)

The system services actions are taken by the system operator for system management, rather than for pure energy balancing. Traditionally the system operator has a number of procedures at its disposal to minimize the price impact of system balancing actions on the power imbalance price calculation. The latter puts a lot of emphasis on the system operator's impartiality and resources, as well as transparency of decision making.

[53] See article 13, clause 6 of the Electric Power Sector Law No. 588-II of 9 July 2004 with amendments made on 28 December 2016; The Minister of Energy of the Republic of Kazakhstan order No 112 of 20 February 2015 "Rules of the balancing power market" Clause 4.

[54] See Minister of Energy and Mineral Resources Order No. 269 of 30 November 2007; see also the Ministry of Energy Order No. 676 of 30 November 2015.

[55] See The Ministry of Energy Order No. 691 of 3 December 2015, "The rules on the system operator's services and the operation of the System and Auxiliary Services Market."

[56] See KREMiZK Order No. 388 of 21 September 2015 "On price caps for regulated services by KEGOC for 2016–20."

[57] See Ministry of Energy Order No. 111 of 20 February 2015 "On Rules of retail market operation and services provision."

8.5.8. Retail market

8.5.8.1. Electric power (and capacity)

The retail market in Kazakhstan is governed by the Electric Power Sector Law and the Retail Market Rules and Services.[57] According to these regulatory documents the retail market participants include:

- Retail power producers.
- Regional energy distribution companies (RECs) that operate regional electric grids and provide electric power distribution services. They are natural monopolies and by law are required to provide non-discriminatory access to their grids.
- Energy distribution companies (EDOs) that operates small distribution networks.
- Energy supply companies (ESOs) that purchase electric power from either energy distribution companies or power producers and sell it on to the end-consumers in accordance with power supply agreements.
- Retail consumers consuming less than 1 MW of average daily (baseload) capacity.

ESOs' service areas typically coincides with the boundaries of a small distribution network where its consumers are connected. An ESO with a high share of household consumers receives the status of a guaranteed supplier. Its service area encompasses the entire REC territory, and it undertakes the responsibility of power sales to all end-consumers that have power distribution agreements with the REC.

The ESO has the right to terminate a power supply agreement with an end-consumer two months in advance by notifying its intention to the guaranteed supplier, energy distribution company, and the anti-monopoly regulator. However, the retail market rules do not have a similar provision for end-consumers, although legally it is not prohibited. In other words, large consumers consuming above 1 MW daily average or (baseload) capacity, and equipped with automated commercial metering systems could opt to buy electricity either from the wholesale market or from an ESO. However, smaller power consumers who consume less than 1 MW (average daily baseload) capacity—and lacking automated commercial metering systems—tend to be locked into power supply agreements with the local ESO and thus would not choose to change the supplier even if they are unhappy with the quality of service or reliability of supply. The latter is a particularly sensitive issue since energy sales companies have no control over the quality and reliability of power distribution by EDOs and RECs, while RECs and EDOs do not sign agreements with end-consumers: ESOs sign power supply agreements with end-consumers, while RECs in particular, are responsible for the quality of distributed power and monitoring of consumption schedule, as they own and control the distribution grid.

The power sales function was singled out from the distribution companies' activities in 2004 to promote competition that was hoped to drive electricity prices down at the retail level. However contrary to the plan, and in the absence of performance-based (incentive tariff) regulation for power sales and distribution business, 25% of all ESOs already enjoy a monopolistic status. This is a result of RECs, large power consumers, and power producers creating their own affiliated ESOs. Power producers support such an arrangement as it secures the retail sale of power, while ESOs' tariff structure does not incentivize them to look for the most competitively priced power. The intention to streamline the structure of the distribution segment, in particular to decrease the number of EDOs was announced in 2015.[58] And although it was not until April 2017 when the Kazakhstan's parliament had the first reading of the changes to the law on RECs consolidation (by absorbing small EDOs) it was finally passed on 29 June 2017. RECs consolidation would enable them to take under control the current cascading growth of end-consumer tariffs.[59]

It is likely that out of the current 160 EDOs, 130 will remain operating by 2020. The reduction of the number of EDOs will put some downward pressure on distribution costs through optimization; nevertheless, the overall tariff reduction is unlikely in view of the investment outlay required for the upgrade of the distribution network and infrastructure, particularly smart (grid and meters) technology integration in the view of the age and general condition of distribution grids.

The penetration of intermittent generation places additional stress on the distribution grid network. The power sector regulation with regards to RES (renewable energy sources) support already envisages free RES connection to the distribution grid as well as a mandatory acceptance of power generated by RES.

Whereas electricity and capacity would be traded separately on the wholesale market from 2019, on the retail market these two products would still be packaged together in the energy supply agreements for end-consumers. The sale and distribution of electricity (and capacity) is executed in accordance with the daily operational schedule that is based on day-ahead data of anticipated power production for the needs of the retail market and ESOs' data on power consumption. The power distribution companies put together their own daily operational schedules based on data from power sales companies and consumers (that have already coordinated their consumption with the power producers), and approves them with the system operator.

[58] See the Presidential address on the "Nation's plan of 100 specific steps to realize five institutional reforms," May 2015 Step 51.

[59] Of the total number of 160 EDOs in Kazakhstan, the regions with the highest numbers include: Karaganda Oblast with 42, Akmola with 10, East Kazakhstan and Kostanay with 13 each, Mangistau with 17, Aktobe with 8, and Almaty with 9.

[60] See rules on Electric power tariffs differentiation by the time of the day and consumption volume for the individual consumers by the energy supply companies and order by the Agency on Natural Monopolies regulation (now KREMiZK) No. 57-OD of 20 February 2009 (last updated on 02 September 2016).

8.5.8.2. Retail tariff policy and price formation

The system of retail tariffs in Kazakhstan is complex: tariffs vary by province, consumer group, and time and consumption volume.[60] Retail consumers are grouped into (i) population, (ii) budget funded, (iii) industrial consumers with connected capacity of 750 kVA and above, and (iv) other legal entities with connected capacity up to 750 kVA. KREMiZK (and its regional affiliates) is the main regulatory body responsible for approving retail tariffs for consumers group. Following the presidential address on the further transition to a market price formation in all sectors of the economy, state price regulation was cancelled in "regulated" markets from 1 January 2017. But to prevent social unrest from higher end-consumers' prices, the government has retained price regulation in "socially significant" segments (which includes retail sales of electricity to 2020).[61]

Tariff differentiation by volume was introduced in 2009, as part of the energy saving initiative to steer households toward more rational power consumption.

Tariff differentiation subject to the time of the day is available to all retail consumers who purchase electric power (capacity) through an ESO, i.e., households (subject to availability of meters) and legal entities (mandatory availability of meters is required).[62]

The simultaneous application of both volume-based and time-sensitive tariffs on the household level is not allowed (for the time being it is one or the other). However recently, due to energy supply companies' losses the tariff differentiation by time of the day for legal entities has been removed.

The structure of the retail consumers' tariff (without VAT) includes a weighted average cost of wholesale power, average weighted cost of power transmission (distribution [REC] and network [EDO] tariffs), transmission tariff (KEGOC), technical dispatch fee (KEGOC), balancing fee (KEGOC), system services fee (KEGOC), administrator of a wholesale centralized trade fee (KOREM), and a supply company sales markup. The retail consumers' tariff growth is adjusted for inflation.

Although the current regulation places some pressure on end-users in terms of power savings through the differentiated payment for consumed volume, consumers have no control over the quality of services they receive. Energy supply companies are not motivated to procure wholesale power at the cheapest price, as they simply pass the full power prices onto the end consumer. Moreover, they are not measured by the quality of service that they deliver to the consumer. The policy designed around the power distribution and supply companies mean consumers in Kazakhstan have little or no choice between power suppliers, while the complexity of the market makes it difficult for them to navigate.

8.5.8.3. Network tariff formation

There is no realistic way of introducing competition in power grid networks (power distribution and transmission fall under the natural monopolies services and are subject to state tariff regulation). Nevertheless, unlike most European countries where the price control is performance based, transmission and distribution tariffs in Kazakhstan are still based on the cost-plus methodology (that aims to compensate operational expenditure and accounts for a profit margin on one hand, but discourages any cost-cutting and meaningful investment on the other).

Transmission tariff

According to KEGOC its key objective as a national grid operator is to ensure reliable operation of the national grid and develop it in the interests of KEGOC own-growth and the needs of the Kazakh economy.[63] And KEGOC as a system operator has set out its mission as namely "ensuring reliable operation and efficient development of UES Kazakhstan in accordance with modern day technical, economic, environmental, and health standards". So KEGOC's objectives as a system operator are similar to those in most other countries which are to achieve the transition to a lower carbon energy system while maintaining security of supply.

KEGOC's activity as an operator of the national grid and a system operator with regards to the dispatch and balancing services is regulated by the Natural Monopolies law.

KEGOC's tariffs are set in accordance with the "cost-plus fixed profit" methodology based on KEGOC's estimation of operational and investment costs as well as a return on investment. The actual tariff is calculated as a ratio of allowed revenues (opex and allowed profit) to the volume of services that KEGOC provides. When calculating the allowed profit, KREMiZK works off KEGOC's asset base (the value of assets used for the provision of services adjusted to the optimization ratio to arrive at the assets actually employed in provision of services multiplied by the rate of return). Since 2013, KEGOC's tariffs are set five years ahead (currently 2016–20) and are known as maximum cap (*predelniye*) tariffs.[64] Although five-year tariffs provide better certainty in terms of costs and investment planning for KEGOC, the methodology does not incentivize KEGOC to optimize costs or beat KREMiZK's expectations. Although KEGOC's long-term strategy envisages improvement of system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) indicators and losses reduction, these parameters are not linked to KEGOC's revenue. The cost-plus methodology does not have inbuilt incentives that would link KEGOC's earnings and tariff to company performance.

In order to support the operational activity of selected industries in 2016, KREMiZK developed a system of reducing ratios applicable to transmission and dispatch tariffs (ranging from 0.71 to 0.99) and differentiated by company. Although developed as a temporary measure, moving forward KEGOC believes its tariffs would continue to be subject to "temporary" reducing ratios.

Since 1 August 2010, KEGOC's transmission tariff is calculated based on the volume transmitted and ignores distance. By applying this methodology KEGOC has granted power consumers non-discriminative access to the national power grid (uniform transmission charges throughout the trading region—also known as a "postage stamp"—is common globally).

Distribution tariff

Although electric power grids and particularly distribution networks are at the core of an ongoing energy transition (emergence of smart meters and smart grids, impact of renewable energy sources, electric vehicles, and decentralized storage), distribution tariffs in Kazakhstan are devoid of adequate incentives to manage the system and invest into it more efficiently. After a trial period of tariff-setting using benchmarking, the regulation for distribution companies reverted to the cost-plus methodology, with the only difference that from 2016, KREMiZK sets maximum tariffs for five years ahead.

- The regulator (KREMiZK) approves economically justified expenses, and adjusts allowed revenues based on operational expenditure.
- Investment for distribution companies is funded by depreciation, reduction of technical losses, and current year's profit.
- In this system distribution companies are forced to artificially inflate tariffs, and are not incentivized to be cost efficient.

Under this approach, operators are not compensated for owning and operating electricity distribution assets, investment is limited to maintenance programs, and long-term borrowing is restricted. Although there is no single approach to distribution methodologies globally, they all tend have fixed capacity and energy components (although they might vary significantly), a concept still not considered in Kazakhstan.

8.5.9. Heat energy market

The heat energy market in Kazakhstan remains intertwined with the power market with 2,207 sources producing heat energy, ranging in output from 3 to over 100 Gcal per hour.[65] Heat energy producers in Kazakhstan primarily include TETs and heat boilers. Thermal power plants account for 64% of total heat energy production.

Largest consumers of heat energy are: commercial-municipal sector; residential (households); and industry.

Heat energy is sold via heat energy supply agreements signed between the heat energy supply (sales) companies and consumers connected either to their heat energy networks or directly to the heat energy producers' heat energy networks.[66]

Heat energy production, transmission, distribution and sales fall under the natural monopoly activity and are regulated by the law on natural monopolies.[67]

Some of the aspects of the heat energy sector's operation are also covered by the Electric Power Sector law. In addition, the relationships between the heat energy producers, heat energy sales companies, heat energy network companies, and consumers are governed broadly by Kazakhstan's civil laws, and the rules on heat energy use (the latter focusing more on the technical aspects of connecting to the heating network, heat energy metering, heat energy estimation in hot water and steam, consumer heat energy payment procedure, etc.).[68]

Although the need for dedicated heat energy market regulation has been discussed actively since 2009, it has not yet been developed.[69] This means that most of the issues that could define the heat energy sector's investment attractiveness, and set the foundation for its rejuvenation, are not spelled out yet, such as:

- The framework of relationships between heat energy producers, heat energy network companies, and consumers
- Principles of heat energy price formation for the heat energy producers, heat energy network companies, heat energy sales, and consumers
- Rules of a centralized heat energy supply
- Heat energy services market (on maintaining reserved heat energy capacity)
- Commercial metering of heat energy
- Maintenance and decommissioning of heat en-

[61] See rules on price formation at socially significant markets, order of the Minister of National Economy No. 36 of 1 February 2017. Socially significant markets include retail sales of electric power by the power supply companies, services on preparing trading system for the centralized power trading, administration of centralized power trading, and centralized trade of renewable energy.

[62] A two-phased tariff (day and night) is applicable to households, while a three-phased tariff (day [day peak and day trough], evening [evening peak], and night [night troughs]) is applicable to the legal entities. The retail consumers daily volume is calculated based on the average daily consumption schedules during the peak days in June and December in the relevant regional power systems.

[63] See management comments to the financial reporting of 31 March 2016, KEGOC.

[64] See KREMiZK order No. 388-OD of 21 September 2015, on approving KEGOC's maximum tariffs for transmission, technical dispatch and balancing services for 2016-20.

[65] See Statistical Committee of RK, 2017.

[66] See the Ministry of Energy order No.211 of 18 December 2014, on the "Rules of the heat energy use."

[67] See "Law on Natural Monopolies No. 272-I of 9 July 1998 with changes of 10 May 2017,"and Government Resolution No. 1360 of 19 December 2014 "On Tariff policy program for natural monopolies in the Republic of Kazakhstan until 2020."

[68] See the Ministry of Energy order No. 211 of 18 December 2014, on the "Rules of the heat energy use."

[69] The law that would unite all aspects of the heat energy segment's operation would define the legal fundamentals of economic relationships between all heat energy market participants and be in line with Kazakhstan's broader power sector and state policy targets.

ergy sources

- Heat energy sources reliability, safety, and efficiency standards
- Heat energy sources and system development principles (in provinces, towns and settlements)
- Heating season readiness procedures
- Connection to the heat-energy network
- Change of ownership and responsibility for the heat energy assets, etc.

Although in 2015 the government declared its intention to "create a new system of legal and economic relations between producers and suppliers of heat energy by 2030," the changes are needed much sooner to support the capacity market rollout, segment rejuvenation, future planning, and phase out the overall power price distortion related to heat energy production.[70]

The government has developed a plan on heating network modernization to 2020.[71] The plan envisages that overall investment would come from tariffs (with some targeted state funding of those networks that require urgent replacement); however the heat energy tariff will not be allowed to grow above a state approved inflation corridor.

It remains unclear if tariffs will be linked to the quality and reliability of supply and incentivize the heat network operators to optimize costs. The latter could be a challenge if standardized business costs continue to be micromanaged by KREMiZK rather than the businesses themselves (inclusive of fuel ratios, cost of materials, number of employees etc.). According to the natural monopolies tariff policy to 2020, the government plans to micromanage 80% of the key heat energy costs (heat energy, fuel, payroll, amortization, raw materials) leaving only 20% of costs to the businesses' discretion.[72]

8.5.9.1. Heat energy producers, consumers, and network companies price formation

The TETs' tariff for the combined production of power and heat energy is set according to a cost allocation methodology. In the KazEnergy National Energy Report 2015, IHS Markit outlined the issue of heat energy costs distortion by thermal power plants through allocating variable costs between heat and power, and legalizing the "cross-subsidization" of heat energy by electric power.[73]

Since January 2017, the government is easing state price regulation of the heat energy sector. Heat energy tariffs will continue to be differentiated by consumer groups (population, budget funded, and other), with further breakdown of the population into those who have or do not have heat energy meters and those who live in buildings where the installation of heat energy meters is technically impossible. Since 2012 heat energy tariffs are 20% lower for those consumers who have a heat energy meter installed. However, the heat energy tariffs for consumers (population) are calculated based on the size of the premises occupied rather than actual heat consumption, so any individual improvement in efficiency by a resident might not result in a reduction of the heat energy bill (although it could help heat energy network companies reduce commercial losses).[74]

The heat energy tariff for legal entities however does not account for the cost of maintaining connected capacity. It has become an issue for the heat energy network companies and heat energy producers when it comes to the large heat energy consumers. A number of large consumers own, operate and consume heat energy from their own heat energy sources while remain connected to the centralized heat energy network for back up. This means that their centralized heat energy consumption is minimum while the heat energy network companies and heat energy sources incur significant expenses related to heat energy losses and keeping heat energy equipment ready to meet demand.

The tariff for the heat energy network companies responsible for the transition and distribution of heat energy is governed by the law on natural monopolies and relevant methodology on heat energy tariffs setting.[75] Similar to electricity transmission and distribution, the heat energy network tariff is set in accordance with the cost plus methodology (economically reasonable costs and allowed profit) and calculated as a ratio of costs and profit to the annual volume of heat energy to be delivered to the consumers. Similarly, to electricity network tariffs, the heat energy network tariff is not performance based, is not split into capacity and service charges, and lacks incentives that would stimulate cost cutting, better quality of service and more efficient investment.

[70] The power price distortion takes place due to the allocation of some of the costs relating to heat energy production into the cost of electric power. The cause is the current tariff regulation that is based on the principle of tariff suppression (discussed in detail in the National Energy Report 2015). As a result, the heat energy tariff does not allow full recovery of the costs of heat energy production and distribution or any meaningful investments.

[71] See KREMiZK Plan on heating network modernization 2014–20.

[72] See Government Resolution No. 1360 of 19 December 2014 "On Tariff policy program for natural monopolies in the Republic of Kazakhstan until 2020"

[73] The consumer tariff is calculated by multiplying the heat energy tariff by the standardized cost of heating one square meter of premises divided by the duration of the heating season. In accordance with construction norms concerning the energy consumption and heat protection of civilian buildings, duration is set at 212 days per year.

8.5.10. Conclusions and recommendations

8.5.10.1. Policy approach: make security of supply, value to consumers, and decarbonization applicable to all power market mechanisms.

8.5.10.1.1. Integrating power sector trilemma into new power sector development plan to 2035, with a view to 2050

Kazakhstan faces a familiar global trilemma in its electric power sector: security of supply, value to consumers (versus cheaper power), and environmental sustainability. Although Kazakhstan's power sector regulation is extensive with a plethora of sound initiatives covering most of these aspects, they tend to operate in isolation from the current policy and not coordinated with the market mechanisms. An integrated approach should be applied to overall power sector planning, market mechanisms, tariff regulation, and use of technology (inclusive of demand and grid). As part of this change, Kazakhstan should accelerate a heat energy market reform and introduce performance-based tariff methodologies for electricity, heat energy, and transmission and distribution. **Considering all of the above, a new concept for power sector development to 2035 with a view to 2050 should be developed.**

8.5.10.1.2. Incorporate recognizable structures and mechanisms with proven track record viable in post-Soviet space

The development of consistent and transparent regulation and recognizable power market mechanisms are likely to impact positively on the investment viability of Kazakhstan's power market. With this in mind, Kazakhstan should continue to pursue its goal in rolling out the capacity, balancing, and improving the system services markets.

However, it will take time to adapt these concepts to Kazakhstan's content. This means the cost of capital will likely remain high (due to the uncertainty around their efficiency in Kazakhstan and overall inconsistency of initiatives within the overall policy). Russia, which has a lot in common with Kazakhstan when it comes to the power sector and social policies, has already successfully adapted foreign power market mechanisms and introduced new heat energy market regulation, as well as performance-based regulation for the grid and sales.

We recommend building on Russia's experience of various historic, structural, and technological changes (formation of price zones, energy systems and energy companies within a single energy system; single-mode economy, transitional and degradation-alphases, reforms,and mixed ownerships) and apply the most viable practices (inclusive of those recognized by international community) to Kazakhstan's reality (technological platform, transparency and clarity of price formation at the wholesale market, system services market, heat energy [while retaining areas of directive regulation], and grid and sales tariff formation). At that we by no means advocate direct copying of Russia's experience.

8.5.10.2. Wholesale electricity and capacity market recommendations

While Kazakhstan will prioritize certain aspects within power market mechanisms and methodologies, driven by its own policies and commitments, the adoption of Russian approaches (where appropriate) will are likely to save time, and cost, the additional benefit of ensuring easier integration into the Eurasian Economic Union space. We recommend that Kazakhstan harmonizes with Russia, and draws on more of the latter's power market experience, particularly when it comes to the following aspects:

- Wholesale power price formation and transparency
- Power market access
- Merit order
- Inefficient capacity treatment.
- Data and information accessibility

8.5.10.2.1. Goal to lift administrative price caps

Administrative power price caps distort the price and remove incentives for accurate power price signals for both dispatch and investment and should be carefully removed.

The wholesale power price should encourage cost-effective decarbonization, and provide certainty for low-carbon investment

8.5.10.2.2. Renewable generation: shift from an out-of-the-market support mechanism for renewable generation towards market-driven carbon price signals

As the penetration of renewable energy sources in Kazakhstan grows, it is anticipated that renewables will have a significant effect on wholesale electricity prices. We recommend that Kazakhstan considers moving away from direct RES support schemes towards market-driven signals (RES would naturally benefit from the market price under marginal price formation).

A shift from feed-in-tariffs (FIT) to feed-in-premiums (FIP) would enable to integrate RES better into power market (as operators receive a premium to the revenue from the power sale at the market). A shift to FIP also mean that RES take on the risk of negative wholesale prices if they generate part of their revenue from the sale of power at the market) and may help to deter renewable asset owner from over supplying the market during certain times..

In the future, we would recommend shifting fully from an administrative tariff setting to descending clock auctions to achieve the most competitive price offer.

The RES payment scheme through conventional generators in Kazakhstan distorts the power price and prevents the price from reflecting the true cost of power production, and as a result transparent competition between the power plants. With this regard, we would recommend shifting to RES payment directly by consumers via energy supply companies. At that, to support energy intensive export oriented industry, we recommend taking on board international experience of lessening or exempting such consumers from RES related costs. The first option would be more acceptable in Kazakhstan given the potential burden on other consumers.

We would recommend assessing the effectiveness of RES support not only from the point of view of reaching the targets, but from its impact on the consumer power price while maintaining the secure operation of the energy system.

Such approach to RES would open electricity and capacity markets to all technologies (including RES) both the supply and demand sides (demand response resources and storage).

8.5.10.2.3. Centralized sale of wholesale electric power

For the purpose of load merit and price transparency, we recommend that Kazakhstan consider mandatory sale of electric power on the wholesale market for power plants with installed capacity above 35 MW that are connected to the central grid.[74] Industrial consumers that own power plants could be exempt from the mandatory sale of electric power on the wholesale market, subject to meeting all of the following requirements:

Group 1

- Industrial consumers whose average monthly power consumption constitutes more than 75% of the average monthly output of a power plant that they own, and to which they are connected via own grid
- Not more than 40% of electric power needs could be supplied by the wholesale market
- The difference between the average calendar month's power production by its own plant a year before did not exceed its own demand by more than 35 MW.[75]

Group 2

- Oil and (associated) gas or (and) its products (the sub-products of main industrial process) are used as a main fuel for the electric power production
- Industrial consumers whose average monthly power consumption constitutes more than 75% of the average monthly output of a power plant that they own, and to which they are connected via own grid
- Such power plants represent a technologically unified process with main industrial production and without such power plants the industrial production long term is either not feasible or problematic
- The difference between the average calendar month's power production by its own plant a year before did not exceed its own demand by more than 35 MW.

System plants, thermal plants (with regards to the volume produced in the heating mode only [until new heat energy regulation is introduced]), RES, and hydropower would have a loading priority followed by all other plants, including heating plants' priority in volume not related to heat energy production. The volume attributed to the free bilateral agreements is accounted for but is not "price setting."

All wholesale power market participants can act both as buyers and sellers of electric power to fulfill their obligations under the purchase agreements the most cost-efficient way.

8.5.10.2.4. Wholesale power prices should be marginal and, locational

We recommend the day-ahead market reflects marginal costs of power production for every hour and is location sensitive (i.e., set per power zone, unless nodal price formation is considered).

We recommend the day-ahead auction is run on pay-as-clear basis, meaning all successful market participants would be paid the same price per unit of MWh in their respective power zone. Priority is given to the lowest producers' offers and highest consumers' bids, with the exception of the price accepting bids by heating power plants at P-min.[76] The highest bid that satisfies the demand (which is likely to be the TETs' volume not attributed to heat mode operation, would set the price for the power zone).

We do not recommend introducing an emissions rice floor (a minimum price for carbon emissions produced in electricity generation) to inflate the price of fossil fueled generation. It would have the effect of distorting the wholesale price while increasing consumer prices. Instead the carbon focus should be applied to the capacity market or emissions trading schemes outside the power market..

The new structure would imply a greater responsibility for the system operator and the commercial operator KOREM, involving both advanced commercial and technical decision-making.

The real-time production and consumption is balanced at a balancing market. The balancing price depends on whether the buyers and/or sellers' fluctuations are driven by their own or external (system operator) initiative. Price formation for fluctuations at their own initiative penalizes inaccurate planning and remunerates precise fulfilment of system operator's orders.

We recommend introducing regulated agreements to match the consumption by residential consumers for the price-cap transition period. They cannot exceed a set percentage of power producers' power sales on the wholesale market, and will be phased out gradually.

8.5.10.2.5. Renewable energy to contribute to the system services market

We recommend that RES bear the costs of intermittency (based on their reliable output, and accounting for meteorological data). In this way RES would not only contribute to system stability but also would be encouraged to invest into storage solutions to limit their exposure. This approach would also minimize the passing of system costs on to consumers via their power bills.

8.5.10.2.6. Reviewing capacity market design to incorporate the power sector trilemma

We recommend Kazakh policymakers not only re-evaluate the capacity market objective and design before it is launched (in its current form), but also state its purpose to address the power market trilemma. Since the capacity market is likely to be a critical element for the economic and commercial environment in which power producers and consumers will operate for decades to come, it is essential it is designed correctly and launched at a time when it is required, as the power market "reforms" failed to remove the threat of security of supply.[77]

Kazakhstan's capacity market should allow all forms of capacity to participate on an equal footing, not just fossil fuels, but renewable and demand-side technology. At that, we recommend capacity at selection (remuneration) should be subject to meeting the emissions standard as a technical requirement, to realize a more flexible, cleaner, and securer generation for the future.

- The emissions performance standard is likely to exclude certain generation from accessing the capacity mechanism (auction). Such power producers might choose to (i) forgo the capacity earnings and rely only on electricity sales, or (ii) initiate retirement. The latter, however, may not be possible immediately due to their obligation to supply heat energy. In such case, the regulator and a system operator could use Russia's experience of isolating such plants into a group of temporary "must-run," and providing a capacity payment for a restricted period of two to three years. This would enable the owner to either mothball or retrofit the plants (particularly with post combustion emission control technologies to control sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury, particulate matter (PM), and other air pollutants. However, the payment of such capacity would be supported only by the consumers of the oblast where the plant in question is located.

The capacity market should replicate the electric power market when it comes to price formation. In other words, if the power price is localized then the capacity price should be too.

To achieve the least cost to the power consumer, the auction mechanism should be designed in such a way that the value of the contracts falls with each round of bidding (descending clock auction). In addition, consumers would benefit from paying for the capacity actually supplied to the market, and not for capacity availability.

Industrial consumers that have their own power generation and would conventionally purchase electric power and capacity internally should be allowed to sign bilateral capacity agreements. As their plants are integral to Kazakhstan's power system balance, they should be obligated to buy 1 MW of capacity from the wholesale capacity market, thus sharing the cost of power system upkeep and development.

We recommend holding capacity auctions four to five years in advance to complement the power sector's long investment cycle.

A change to RES support would imply that renewable sources are included in the capacity market (to their "reliable" contribution), and the forecasted peak demand to be met by thermal generation would not be reduced to accommodate RES' load. In other words, all supply and demand would be explicitly included and priced (without the need to reduce peak demand to be covered by thermal generation).

8.5.10.3. Shifting to performance based regulation for transmission and distribution

We recommend replacing the transmission and distribution cost-plus tariff methodology with a sound, incentive-based tariff system that would allow transmission and distribution companies to earn an appropriate rate of return and thereby boost investment, while also improving overall efficiency (cost and quality). If a company is more efficient than anticipated,

[74] This recommendation is based on Russia's experience, according to the "Electric Power Sector Law No. 35 of 26 March 2003 (with changes of 28 December 2016)," and "Rules of the Wholesale Electricity and Capacity Market No. 1172 of 27 December 2010 (with changes of 07 June 2017)," whereby all power plants with installed capacity over 25 MW sell electric power and capacity on the wholesale market.

[75] According to Russia's "Rules of the Wholesale Electricity and Capacity Market No. 1172 of 27 December 2010 (with amendments made on 07 June 2017)" and subject to meeting all clauses of article 33.

[76] Until a proper heat energy market regulation is introduced TETs' volume with regards to heating-mode operation will receive loading priority, but will not be price setting.

[77] The choice of a capacity market design should be based on the modeling of (i) profitability of the power assets (the impact of revenues from the power sales, auxiliary services, and capacity market as a single interactive process), and (ii) the impact of different designs on the power prices, power plants revenues, capacity retirement, and cross-border flows (Russia and Central Asia).

i.e., spends less money than the allowed revenue, yet delivers the required security and performance standards, then the company retains the benefit for a price control period, thereby incentivizing the company, and vice versa.[78]

We suggest moving towards a "totex" concept (based on the full economic consequences of decision making without differentiating whether expenditure was classified as operational or capex) that would allow for a balanced treatment of expenditures without bias for capex (where investment decisions often favor construction of new assets rather than use alternatives involving opex. This approach would reward companies according to their skill with which they serve the market, and not simply a return on investments that may, or may not, be necessary. This means that the allowed revenue is based on the regulator's forecast of totex. At that, capex needs should be driven by future business needs and not a depreciation formula as is currently practiced (with depreciation being the source of investment for transmission distribution companies).

We recommend establishing a direct link between allowed revenues and service quality to create additional efficiency drivers when it comes to the number and duration of interruptions and guaranteed performance standards. And a further link between the allowed revenues and investment efficiency and innovation (new technologies and operating practices) to keep investment spending under control and assure continued improvement of the grid.

Extended price control periods (from four to eight years) allow companies to plan investments with some (but not complete) certainty as to future revenues: a critical advantage over cost-plus regulation given the capital-intensive nature of the electricity distribution sector, and its long investment cycles.

We recommend reassessing the network tariff structure and shifting to a two-tier network tariff that would enable to recovery of (i) the costs of network upkeep, and (ii) services provision. This approach would provide for the better flexibility in anticipating future changes, rather than being a barrier to new technologies and innovative market solutions.

It is important that KREMiZK ensures that network operators are only at risk for factors within their control, and such aspects as taxes, inflation, and debt financing costs are passed on to power consumers via an annual review rather than absorbed by the distribution and transmission companies. This approach would help lower the cost of capital and will encourage investors seeking long-term investments with stable dividend income and low regulatory risk.

New connections and embedded generation

We recommend the new connections tariff be influenced by the government's policies to encourage certain types of generation or demand-side technology. If embedded generation is to be encouraged, then "shallow" charging is appropriate. This spreads the cost of reinforcements over all users.

However, some connections, particularly to industrial customers, will be very site specific. It may be necessary to take the revenues, costs, and assets associated with these consumers outside the regulated asset base. As such, the connection may be treated as an "excluded service" (e.g., as in the UK) with the costs individually allocated. In some cases, the consumer may make or have made a contribution for all or part of the costs of the connection itself. In these cases, the associated assets are excluded from the network company's asset base and the consumer is only charged for relevant operations and maintenance.

Certain generation may impose additional reinforcement costs on a network – as well as potentially remove the need for reinforcement, depending on the nature of the generation and the supply/demand balance on the network. IHS Markit recommends that RECs and smaller network companies publish statements showing the capabilities of their networks to promote development of solar PV and wind, particularly in light of Kazakhstan's transition to a greener economy.

8.5.10.4. Institutional recommendations

8.5.10.4.1. Changes in system operator's functions triggered by market evolution in the long run might require mechanisms to strengthen the role of UES Kazakhstan system operator.

As the system, technology, power market, and the way power is produced and consumed in Kazakhstan evolve, so will the way the system is managed. The rapid change in global power markets, owing to the rise of new technology, changes to environmental regulation (leading to growth in renewable penetration) have made the task of system balancing significantly more complex.

The growing internal complexity of the energy systems would require a whole system approach: viewing energy system as a single technological complex, rather than a composition of generation, grid, and consumers. Notably, the conventional separation between transmission and distribution will continually be challenged because a lot more of the system balancing will be happening at the distribution level through distributed generation, storage, net-metering, and demand management. This means that with the assistance of operational and dispatch services on distribution level, system operators will be directly involved in the energy system operational management on all levels. With this change the system operator's tasks will include:

- Overseeing a safe, resilient, and cost-effective electricity system taking a whole system view. With a proper roll-out of the balancing market a system operator would be expected to think more broadly about how it can drive greater efficiency in balancing and how its actions in the short term and long term (capacity auctions and tenders) could impact the end-cost of power.
- Driving competition and efficiency across all aspects of the power system and contributing to regulation adaptation to support innovation and competition in the future.
- Promoting innovation, flexibility, and smart/demand-side solutions. New technologies could open up a number of innovative solutions to existing system issues. It is important that such solutions are effective and the decision is impartial.

Considering the increasing importance of the system operator's role in taking price-sensitive decisions, inclusive of long-term planning, and taking into account all available technology, we recommend developing mechanisms that would strengthen the transparency of system operator's functions to eliminate conflict of interests between the market participants.

Moreover, we recommend the system operator reviews its operational/dispatch and national grid management goals medium- to long-term, and consider developing mechanisms that would strengthen specific functions, responsibilities, and accountability when updating its long-term development plan.

With the shift in the system operator's overall activity and responsibility it would be important to assess its efficiency with regards to the energy system management and decision making (inclusive of long-term planning).

Therefore, accounting for international practices in enhancing the system operator's effectiveness we recommend considering placing financial incentives on it with regards to the following activities:

- Demand forecasting
- Wind generation forecasting
- Balancing requirements
- Transmission/balancing charges
- Requirements for ancillary services

In addition, develop non-financial incentives for the following activities:

- Developing UES Kazakhstan long-term development plan accounting for various technologies responsible for system reliability as they become available, updated regularly.
- Regular public reporting on commercial and physical operations of UES Kazakhstan

8.5.10.4.2. Creating an independent KREMiZK

A truly independent and well-funded regulator is essential for effective tariff-setting policies, particularly for natural monopolies such as electric power and heat distribution and sales.[79] KREMiZK must have a budget that allows it to:

- Spend significant resources to extend and improve the skill, and knowledge capacity of existing technical staff.
- Collect, process, and apply information on business costs and develop algorithms for efficient costs and investments.

We propose introducing a KREMiZK license fee levied on the power sector (not on retail consumers) that would secure KREMiZK funding. At the same time, we propose that KREMiZK be subject to rigid price control (which requires it to cut costs each year at a set pace).

8.5.10.4.3. Strengthening the Market Council (SovetRynka) and shifting its duties

Although Kazakhstan has made initial steps in creating a power sector Market Council, it has become one of many platforms for discussing power sector issues. Yet the power sector lacks a strong and legally empowered force to represent the interests of market participants (particularly the wholesale producers and consumers). The changes suggested to the power sector trading as well as successful operation of the Market Council in Russia would suggest that the most logical entity to take on the Market Council's functions is KOREM.

8.5.10.5. Addressing data disclosure and transparency

Although data disclosure and open consultation on the sector's future development among market participants are common practice in developed markets, sharing power market and UES operational data in Kazakhstan is not viewed one of the Ministry's key duties, and in many cases, would be considered a criminal offense. Except for the Ministry of Energy and KEGOC, detailed truepower market and analytical data are not publicly available.

We suggest better, more regularl and fuller data and information disclosure in public sources such as the Statistical Committee and system operator should be acknowledged in the Power Sector Law. The statistical data should be supported by monthly, quarterly, and annual public reporting on commercial and physical operations of the power system by the system operator, KOREM, and Sovet Rynka on electric power market operations, and KREMiZK on aspects of the heat energy market operation

[78] Allowed revenue=costs + depreciation + returnon investment ([real rate of return xregulated asset base] + tax + performance incentives). Regulated asset base = RAB (existing) – capex – depreciation

[79] A genuinely independent and properly resourced regulator is as critical for incentive regulation success as the design of such methodologies. This means that the regulator defines and understands genuine efficient business cost drivers (rather than approves or disapproves itemized lists of fixed and variable costs, some of which are not directly related to the actual delivery of services, as is a common practice in the countries of the former Soviet space). It should have effective mechanisms for standardized and transparent benchmarking of distribution operators on the basis of high-quality data disclosure and collection.

9. GREENHOUSE GAS EMISSIONS, ENERGY EFFICIENCY, AND GREEN ECONOMY GOALS

9. GREENHOUSE GAS EMISSIONS, ENERGY EFFICIENCY, AND GREEN ECONOMY GOALS

9.1. KEY POINTS

• In terms of GDP carbon intensity (1.44 kg of CO_2 emitted per [2010 US dollars] of GDP), Kazakhstan is one of the most carbon-intensive economies in the world. However, this is not unexpected given the heavy natural resource orientation of its economy.

• Kazakhstan's intended nationally determined contribution (INDC), submitted in compliance with the Paris climate agreement concluded in late 2015, includes an unconditional target of reducing greenhouse gas (GHG) emissions economy-wide by 15% below 1990 levels by 2030, and a conditional target of 25% below 1990 levels by 2030. To fulfill its unconditional INDC, Kazakhstan needs to reduce its GHG emissions by 53.4 MMt to 302.8 MMt of CO_2 equivalent by 2030.

• In 2013, Kazakhstan was the first country in Asia to introduce a greenhouse gas (CO_2 only) emissions regulation system, modeled after the European GHG emissions regulation and trading system. The carbon trading market operated for two years (2014–15), but was suspended with restrictions on GHG emissions put on hold until 2018 when a newly revised system is set to go into effect. However, due to continued ambiguity of regulation and seemingly unresolved questions surrounding the new rules of the trading system under a very tight implementation schedule, re-launch of emissions trading is not likely to produce the desired effect without changes in the principles of demand and supply formation in the carbon trading market.

• Given that as much as four-fifths of total GHG emissions come from the electric power sector, mainly from coal-fired plants, over the near term policymakers should focus on measures to curtail emissions based on the existing mix of generating capacity. In order to incentivize energy efficiency improvements and cleaner generation, Kazakhstan needs to take into account its own and the EU experience when its internal carbon trading market resumes in 2018.

• Because of improving energy efficiency, considerable advances have been made by Kazakhstan between 2000 and 2015 in reducing GHG emissions on a per capita basis and as a unit of GDP, despite appreciable economic growth. IHS Markit projections of Kazakhstan's GHG emissions from the energy sector, based on continued energy efficiency improvements and a gradual shift toward natural gas, renewables, and (over the longer term) nuclear power capacity in the electric power sector, show a dramatic reduction in emissions per unit of GDP, down to roughly half the present level by 2040.

• Kazakhstan can attain about half (an almost 8% reduction) of its unconditional Paris-agreement GHG emissions target by following a "business-as-usual" approach—i.e., pursuing policies already in place or planned for implementation. We present an alternative scenario whereby Kazakhstan can not only attain its full 15% emissions reduction under the Paris agreement but even get halfway to its conditional target of 25% through a much greater improvement in aggregate energy efficiency, a more pronounced reduction in coal consumption, and a more rapid build-out of wind and solar.

9.2. GREENHOUSE GAS EMISSIONS, CARBON INTENSITY, AND CLIMATE CHANGE—UPDATE

This section examines environmental impacts resulting from the extraction, processing, and consumption of energy resources that are directly related to the issue of greenhouse gas emissions. It does not focus in any detail on other environmental impacts from energy production and use, such as oil sludge contamination, radioactive contamination associated with oil production as well as uranium mining and processing, ash and slag waste management at coal-fired power plants, and non-GHG air pollution and water pollution at sites of extraction and processing of mineral resources. For a discussion of these topics, please see The National Energy Report 2015, Chapter 13, section 13.2.

9.2.1. Global climate change

The basis for the global effort to control greenhouse gas (GHG) emissions is the 1990 report of the Intergovernmental Panel on Climate Change (IPCC), which confirmed the threat of global climate change due to human activity. For the purposes of the report, global warming is defined as an increase of the average air (atmospheric) temperature of up to 3°C by 2100 (as compared to the 1990 level) and the consequences thereof. According to IPCC experts, the main factor affecting average annual air temperature rise is the increasing concentration of greenhouse gases (mainly carbon dioxide) in the atmosphere as a result of extensive human use of fossil energy resources.

The last 50 years have seen unprecedented (in 200,000 years) growth of carbon dioxide concentrations in the atmosphere. In 2016 the CO_2 concentration in the Earth's atmosphere exceeded 400 parts per million (ppm), or 0.0392%.[1]

The greenhouse effect, which consists of the trapping of a part of the Earth's thermal radiation, is a consequence of the differential permeability of some atmospheric gases to short- and long-wave radiation and is responsible for the formation of a sufficiently warm climate on our planet. The main source of the greenhouse effect in the Earth's atmosphere is water vapor. If there were no greenhouse gases in the Earth's atmosphere, the average surface temperature would be -15°C. However, the greenhouse effect causes the average surface temperature to increase by 30°C, of which 20.6°C, or about 70% is attributed to the presence of water vapor in the air and 7.2°C (or 24%) is due to the presence of carbon dioxide. Therefore, greenhouse gases are very important for the planet's climate formation.

The Earth's climate has been constantly changing throughout human history: periods of cold weather have given way to warmer periods, and vice versa. Research data show that the average atmospheric temperature 10,000 years ago was 2–2.5°C higher than the current value (the Atlantic Climatic Optimum) and in the 8th–12th centuries was 1° higher than the current value (Medieval Climatic Optimum).

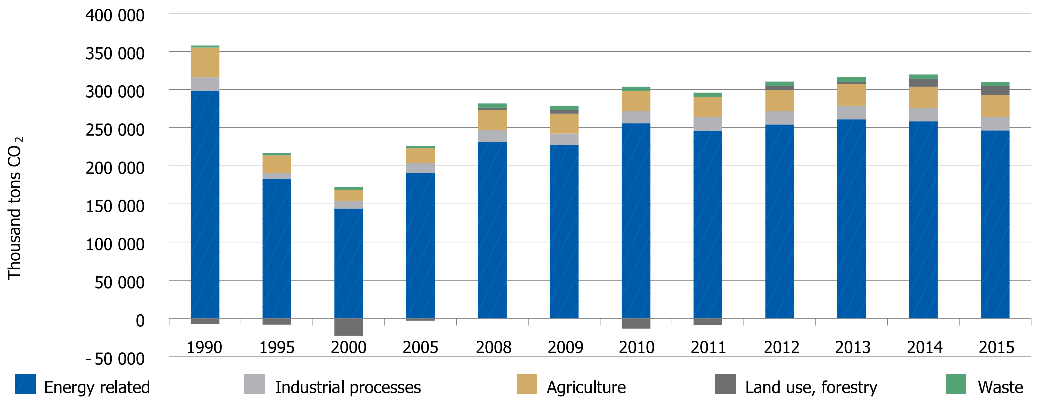
The current physical long-term climate forecast models cannot take into account all the variety of direct and inverse effects related to an increase in greenhouse gas concentrations, and therefore the accuracy of long-term climate forecasts remains quite low. However, at the moment, the theory of carbon dioxide concentration's influence on climate change is accepted as the base theory at the global level (the climate consensus) and environmental and energy policies of most countries are aimed at limiting greenhouse gas emissions.

[1] In the pre-industrial period, the CO_2 concentration was about 280 ppm.

9.2.2. Greenhouse gas emissions in Kazakhstan

According to Zhasyl Damu, Kazakhstan's total GHG emissions plummeted during the 1990s (from 356.2 MMt in 1990 to 161.9 MMt in 2000) (see Figure 9.1). The falling emissions during this period reflected primarily the contraction of Kazakhstan's economy. GHG emissions subsequently rebounded alongside economic growth in the 2000s, reaching about 290.7 MMt in 2010 and peaking in 2014 at 319.8 MMt, but declined in 2015 to 310.2 MMt.Not surprisingly, the energy sector constitutes the largest share of GHG emissions, with a 79% share in 2015, down from a peak of 88% in 2010. Agriculture represents the second largest source of GHG emissions, generating 29.1 MMt or 9% of emissions in 2015, while mining produced 17.6 MMt, or 6% of total emissions. The energy sector is the largest emitter of carbon dioxide, while agriculture primarily emits methane and nitrous oxide (see Figure 9.1).

Figure 9.1. Kazakhstan's GHG emissions by sector



Source: JSC "Zhasyl damu"

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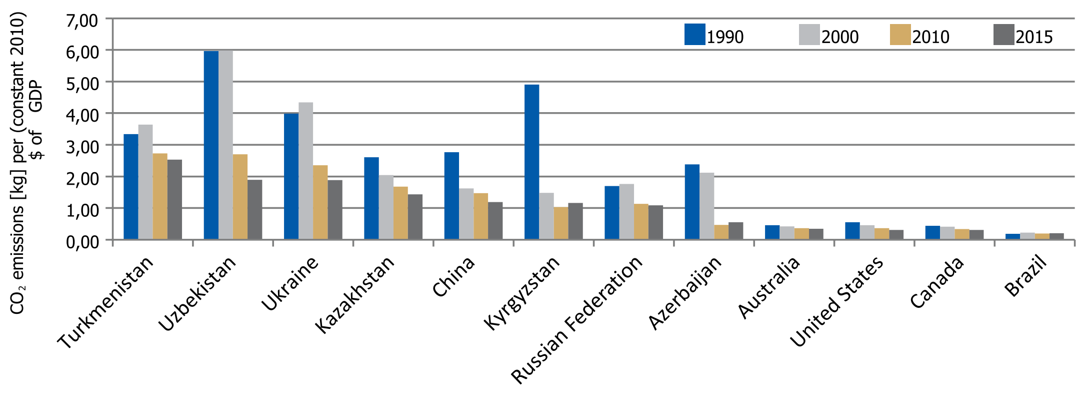
Emissions of carbon dioxide (CO_2), the most abundant greenhouse gasafter water vapor, are used in the calculation of carbon intensity, a widely utilized international measure of the "greenness" of a country's economy. In terms of the most recent data for GDP carbon intensity from the European Commission's Emissions Database for Global Atmospheric Research (EDGAR), in 2015, Kazakhstan along with three other Central Asian Republics (Kyrgyzstan, Uzbekistan and Turkmenistan), ranked among the 10 most carbon intensive economies in the world (see text box: "Carbon Intensity of Economy Measures CO_2 Emissions per Dollar of GDP"), emitting 1.44 kg of CO_2 per 2010 US dollar of GDP (see Figure 9.2). As with energy intensity, individual countries' CO_2 emissions are strongly influenced by the structure of their economies. Coal accounts for roughly 55% of Kazakhstan's primary energy consumption, and the absolute level of its consumption is projected to hold fairly steady out to about 2025. This share is high relative to the world average (29% for 2015 in terms of MMtoe), but again is a reflection of Kazakhstan's natural resource–based economy in which large quantities of energy are expended per unit of GDP. This has important implications for the country's CO_2 emissions, as compared to coal (lignite), complete combustion of the same volume (in energy equivalent terms) of natural gas releases 1.8 times less carbon dioxide, and of fuel oil (mazut) 1.4 times less carbon dioxide (2006 IPCC Guidelines).

Figure 9.2. Declines in carbon intensity in select countries in 1990, 2000, 2010, 2015



Notes: Global CO2 emissions from fossil fuel use and cement production
Source: European Commission's Emissions Database for Global Atmospheric Research (EDGAR), World Bank, IHS Markit

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Carbon Intensity of Economy Measures CO_2 Emissions per Dollar of GDP

The top five emitting countries—China, United States, India, Russia, and Japan—accounted for 59% of total CO_2 emissions globally (estimated at 36.1 billion tons in 2015).[2] Over time, China drove this increase, as its share increased from 14% in 2000 (3.6 billion tons) to 30% in 2015 (10.6 billion tons). At the same time, the United States made progress in decreasing its emissions, reducing its share from 23% (5.9 billion tons, which made the US the largest emitter in the world) in 2000 to 14% (5.2 billion tons) in 2015.

Relating CO_2 emissions to the GDP of a selected country provides an insight into the country's carbon intensity. Kazakhstan, along with three other Central Asian republics (Turkmenistan, Uzbekistan, and Kyrgyzstan), is among the countries with the 10 highest CO_2 emissions per dollar of GDP produced. Specifically, in 2015 Kazakhstan emitted 268 MMt of CO_2, which after applying this to GDP produced in that year results in a carbon intensity of 1.44 kg per dollar of GDP.[3] Among developing economies, Turkmenistan generated 2.53 kg, while China—1.19 kg, Russia—1.09 kg, and India—1.07 kg of CO_2 per dollar of GDP. To compare this to the developed economies, the United States and Canada generated 0.31 kg each, Australia—0.34 kg, Japan and Germany—0.21 kg each, UK—0.15 kg, and Norway—0.09 kg per dollar of GDP.

Kazakhstan decreased its carbon intensity between 2013 and 2015 (by 0.08 kg to 1.44 kg), which represented the fourth consecutive decline on an annual basis since 2011. Different factors (or their combination) might explain the high carbon intensity of a country's economy. On the one hand, it depends on a country's economic structure, as an economy with a higher share of energy-intensive sectors will be more carbon intensive. On the other, the use of less energy efficient technologies or a higher share of "dirty" fuels in the energy balance (e.g., coal) will also drive up a country's carbon intensity. For example, in 2014 57% of Kazakhstan's CO_2 emissions were from solid fuel consumption, reflecting a higher share of coal in the country's energy balance. To compare, 50% of Russia's CO_2 emissions come from gas fuel consumption, reflecting a high share of gas in Russia's fuel mix.

Because coal-fired generation accounts for roughly two-thirds of Kazakhstan's installed capacity, over the next 20 years it will be difficult to significantly change the structure of energy production and consumption. Despite the increasing role of natural gas in electricity generation, at the very least coal will account for over half (~58%) of electric power generation out to 2040. At the same time, when adding new generating capacity in Kazakhstan, a policy of increasing the sector's environmental friendliness will be followed, according priority to energy-efficient coal-fired generation (switching to boilers with ultra-supercritical steam parameters), natural gas, and (to a certain extent) renewables. However, radically altering Kazakhstan's fuel balance in order to substantively change its carbon emissions trajectory can only do so much, as the rate at which power infrastructure is replaced is rather slow, and, among other things, the low cost of the mined coal makes it the fuel of choice for power generation. Longer term, construction of a nuclear power plant (1200 MW) will also contribute to reduction of greenhouse gas emissions. Still, it would seem prudent over the near term to focus on other measures that could be used effectively to curtail emissions based on the existing fuel balance. These are outlined in the next major section of this chapter (see section 9.3 below), which describes a number of pathways that Kazakhstan could follow toward achieving emissions reductions consistent with its commitments under the Paris climate agreement reached in 2015.

9.2.3. Climate change policy: UNFCCC 2015 Paris agreement update

The United Nations Framework Convention on Climate Change (UNFCCC), adopted in 1992, created an international framework for action on climate change, and in 1997 the Kyoto Protocol established a legally binding framework for (signatory) developed countries to reduce their GHG emissions by meeting specific reduction targets, with the ultimate goal of holding the mean global temperature increase to no more than 2°C above the pre-industrial level. Despite the participation of 83 signatory countries, progress toward a coordinated international effort to reduce emissions subsequently slowed, as neither the leading CO_2-emitting country at that time (United States) nor presently (China) ratified the Protocol.

However, on 12 November 2014 the United States and China signed an agreement to jointly reduce their emissions by strengthening adherence to environmen-

[2] The World Bank limits its measurement of emissions to the burning of fossil fuels and the manufacture of cement.

[3] To adjust for inflation, GDP is valued in constant 2010 dollars.

tal policies already in place in the two countries. This created a new agenda for climate change action at the 21st Conference of the UNFCCC, held in Paris in November 2015. The key difference at Paris from preceding climate summits was that mandatory reductions were replaced by less stringent, more achievable policy goals; more specifically, each signatory country (a total of 195) enacted its own emissions reduction goal, known as an intended nationally determined contribution (INDC). The final wording of the agreement was adopted by consensus on 12 December 2015, and the process of ratification (official signature by each participatory member state) was opened on 22 April 2016. By October 2016, a sufficient number of signatures (94, representing two-thirds of total global carbon emissions) had been obtained for the so-called "Paris agreement" to enter into force (on 4 November 2016). Kazakhstan's INDC includes an unconditional target of reducing greenhouse-gas (GHG) emissions economy-wide by 15% below 1990 levels by 2030, and a conditional target of 25% below 1990 levels by 2030.[4]

In the aftermath of the Paris climate summit, two related agreements were concluded for specific activities generating GHG emissions that are not covered by the larger accord. The first, covering international passenger air travel, which accounts for roughly 2% of global GHG emissions, was adopted on 6 October 2016 at a meeting of the International Civil Aviation Organization (ICAO) by more than 190 countries. The agreement (to take effect in 2021) would require airlines to take major steps to improve fuel economy along their international routes. Kazakhstan, although a member of the ICAO, is not listed among the participants in the voluntary pilot and first phases of the Market-Based Mechanism (MBM) of the agreement (2021B26), also known as the Carbon Offsetting and Reduction Scheme for Civil Aviation (CORSIA). This may be because Kazakhstan is designated as a landlocked developing country (LLDC) under CORSIA, and thus is exempted from these phases, although it may later opt for voluntary participation in the second phase (2027B35).

Shortly thereafter, on 15 October 2016, negotiators from more than 170 countries agreed to limit emissions from chemical coolants known as hydrofluorocarbons (HFCs), used in air conditioners and refrigerators. Although HFCs account for only a small percentage of GHGs in terms of their atmospheric concentration, their heat-trapping potency is many magnitudes higher than carbon dioxide or even methane. Under the so-called Kigali agreement (forged in the Rwandan capital), wealthier nations will begin reducing HFC production and consumption more rapidly (starting in 2019) than less affluent ones (2024 or 2028 for hot-climate countries), with mandatory and clearly specified targets, implementation timetables, and trade sanctions for noncompliance. Under the Kigali agreement, Kazakhstan (along with Russia, Tajikistan, Belarus, and Uzbekistan) will begin reducing HFC consumption by 5% (relative to 2011–13 average consumption) by 2020 and 35% by 2035.

Despite progress on these fronts internationally in 2016, the announcement on 1 June 2017 by US President Donald J. Trump that the United States would exit the Paris agreement represented a major setback. The process of unilateral US withdrawal from the accord, which already has the status of international law, will take, at the earliest, more than three years.[5] Washington has announced that in the interim it will stop honoring non-binding elements of the accord, including its INDC (a 26%–28% reduction of emissions from 2005 levels by 2025) as well as its commitment to contribute its share of more than $100 billion in annual financial assistance promised to developing-country signatories to assist them in adapting to climate change.[6]

Although the US departure deals a blow to coordinated global efforts toward global GHG reduction, it is by no means fatal, both in terms of US efforts or to global leadership on the issue (see text box entitled. Potential Impact of Trump Administration in US Environmental Policy). First, in the US, many states (especially California, the most populous) and large cities will resist federal efforts to exit the agreement and can opt to pursue their own fuel efficiency standards and renewable energy targets that are more rigorous than the equivalent federal guidelines.[7] One recent analysis projects that simply the continuation of current economic trends (without any additional commitments resulting from the Paris agreement) would result in a reduction of US GHG emissions by 15–19% from 2005 levels by 2025—i.e., accounting for more than half of the US INDC under Paris.[8] Second, in the absence of clear US leadership in the international arena, new players may step up and play a more assertive role in support of emissions reduction. Among those mentioned are China and India, but could also include European and Latin American nations as well as Kazakhstan, which is hosting the EXPO-2017 international exposition in Astana under the theme of "Future Energy."

[4]The conditional target is contingent upon Kazakhstan receiving additional international investments and green climate funds, technology transfer of low-carbon technologies, and otherwise some flexibility due to its status as an economy in transition.

[5] Signatories to the agreement are not allowed to begin the process of withdrawal within the first three years following the agreement's ratification. The earliest date the US can submit a written notice it is withdrawing is 4 November 2019, with the earliest official withdrawal being possible one year after this date (and coincidentally one day after the 2020 US presidential election). A new administration, should it be so inclined, could apply for re-admission to the agreement in late January 2021, and could be re-admitted following a 30-day waiting period.

[6] The Trump administration specifically announced it would eliminate further US funding for the Paris agreement's Green Climate Fund, to which the previous administration of President Barack Obama had pledged $3 billion ($1 billion of which already has been disbursed). The US Energy Department also closed, as part of an internal reorganization in June 2017, the Office of International Climate and Technology, which provides technical advice to other nations seeking to reduce GHG emissions. The new budget proposed by the Trump administration also eliminates the US Department of State's Global Climate Change Initiative as well as State Department contributions to world development banks that finance green projects.

[7] California has a waiver under the Clean Air Act, and is free to pursue more stringent fuel efficiency standards than those in force at the national level. In late March 2017 the California Air Resources Board voted to continue to follow the higher 2025 automobile fuel efficiency standards regardless of any subsequent federal action, and 12 other states generally coordinate their policies with California's.

Potential Impact of Trump Administration in US Environmental Policy

Despite the rapid momentum gained in 2016 toward a coordinated international strategy to address climate change, the election of Donald J. Trump to the US presidency in November of that year has now put into question further progress in the United States on that front in 2017 and the years immediately following. Trump, after previously concluding (2012) that climate change was a hoax concocted by China to "make US manufacturing non-competitive," on the campaign trail pledged to pull the US out of the Paris agreement. This, plus the overall political shift in the US Congress to a Republican two-house majority, seemed to augur a new era of deregulation in which many of the previous administration's initiatives designed to promote emissions reductions might be overturned. On 1 June 2017 Trump honored one of his many pledges to overturn his predecessor's environmental policies by announcing that the US would exit the Paris agreement.

However, the extent of any rollback of previous environmental commitments during the first term of a Trump presidency ultimately may prove limited. Easiest to roll back would be executive orders signed by President Obama during the waning days of his presidency. Under the terms of the 1996 Congressional Review Act, Congress can scrap new regulations within 60 legislative days of being enacted, by a simple 51-vote majority in the Senate. Regulations already challenged in this way during the early days of the Trump administration include restrictions on methane emissions from oil and gas activity on federal lands and limits on mountaintop-removal coal mining. There is also a clear legal path for overturning a 2011 regulation (issued jointly by the US Environmental Protection Agency (EPA) and the US Department of Transportation) requiring automakers by 2025 to build cars that have an average fuel economy of 54.5 miles per gallon. Indeed, on 15 March 2017 President Trump moved to reopen the review process, which will allow auto industry officials to argue in favor of less stringent fuel economy standards.

Other regulations will prove more difficult to modify. Obama's signature 2015 Clean Power Plan, which curbs emissions from electric utilities in such a way to target coal-fired plants, is currently being challenged by more than two dozen states in federal appeals court, and perhaps eventually in the US Supreme Court. On 28 March 2017, President Trump signed an executive order to start the complex process of withdrawing and rewriting the Clean Power Plan. However, legal scholars believe it could take four to five years before legal challenges involving the Plan are resolved, perhaps not until after the 2020 presidential election. In the meantime, however, proposed cuts to EPA funding (by 31%) in the new administration's budget submission to Congress could severely limit enforcement of the Clean Power Plan, rendering it less effective.

9.2.4. Kazakhstan's future GHG emissions in relation to its Paris commitment (two scenarios)

Kazakhstan's high energy intensity and current energy mix (the highest dependence on coal of any of the former Soviet republics) afford both a challenge to GHG reduction and an opportunity for considerable future improvement. Given that the energy sector contributes the bulk of the total GHG emissions. (~80%), while agriculture, the second largest contributor is responsible for only about 10%, the focus on this report will be on the energy sector and GHG emissions from economic activity using energy. IHS Markit estimates of energy-related GHG emissions by fuel source for selected years for the period 1990–2040 are shown in Table 9.1)[9] between 1990 and the present tracks rather closely that of Kazakhstan's economic output during that period, registering a steady decline during the recessionary 1990s, before climbing sharply as the economic recovery gathered steam after 2000 (see Figure 9.3), and then tapering off after 2012. It is noteworthy that coal accounted for 66% of total GHG emissions in the economy's energy use in 2016 (159 MMt out of a total of 240 MMt).

[8] See Brad Plumer, "The Climate Deal, and What a U.S. Departure Would Mean," New York Times, 1 June 2017.

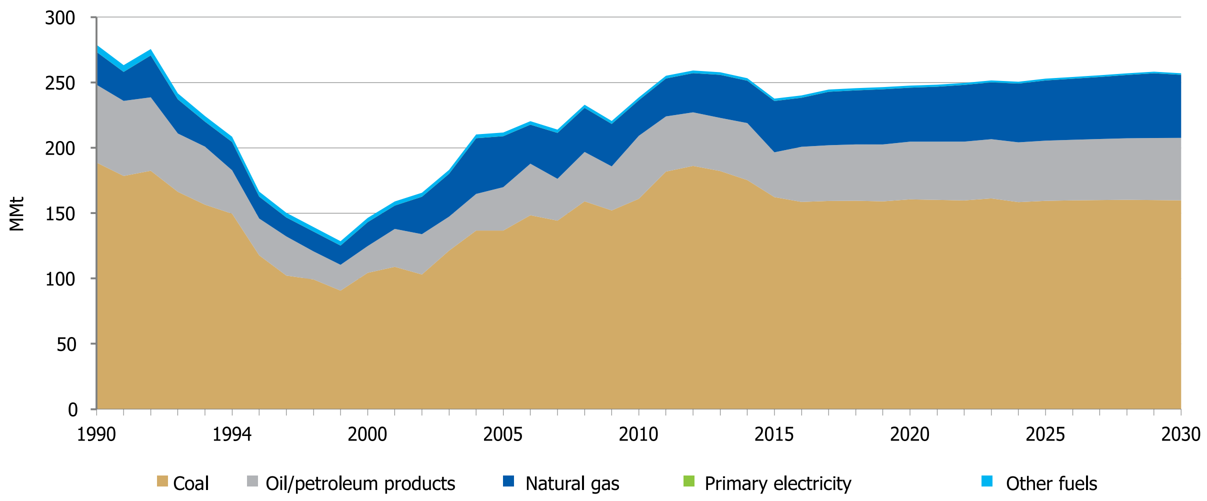
[9] Emissions are calculated for energy consumption only, thus allowing for consistent historical comparison. Total GHG emissions for the country are somewhat larger, as they include emissions from all economic sectors. Greenhouse gas emissions in the energy sector have accounted for about 80-85% of total GHG emissions in the country in recent years.

Table 9.1. Estimated greenhouse gas (GHG) emissions for Kazakhstan for energy-related economic activity, 1990–2040 (million metric tons)

	Emission coefficient, metric tons per thous. TOE consumed	1990	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	Average annual pct. change, 2016-2030	Average annual pct. change, 2015-2040
Total		278,9	208,5	146,4	211,7	238,6	237,7	250,6	255,9	259,9	258,6	263,4	0,5	0,2
Coal	3,81	188,7	149,5	104,3	136,7	161,0	162,3	160,5	159,4	159,8	150,2	146,0	0,1	-0,7
Oil / petroleum products	2,93	59,6	33,3	20,5	33,2	48,2	34,3	47,1	49,0	50,7	52,9	55,7	0,8	0,9
Natural gas	2,12	25,1	21,7	18,3	39,1	27,3	39,3	41,3	46,1	48,3	54,4	60,6	1,8	2,4
Primary electricity	--	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0		
Other (peat, wood, etc.)	6,00	5,5	4,0	3,2	2,8	2,1	1,8	1,6	1,4	1,2	1,1	1,0	-2,9	-2,4
GHG emissions/thousand $ GDP (2005 dollars)		2,4	2,9	1,8	1,6	1,3	1,1	1,0	0,9	0,8	0,7	0,7	-2,9	-2,4

Note: Estimate only for energy-related economic activity (fuel combustion); calculated by IHS Markit.

Figure 9.3. Estimated greenhouse gas emissions for Kazakhstan* (business as usual)



Notes: *Start-up of nuclear station assumed in 2030

Source: IHS Markit, Statistical Committee of RK

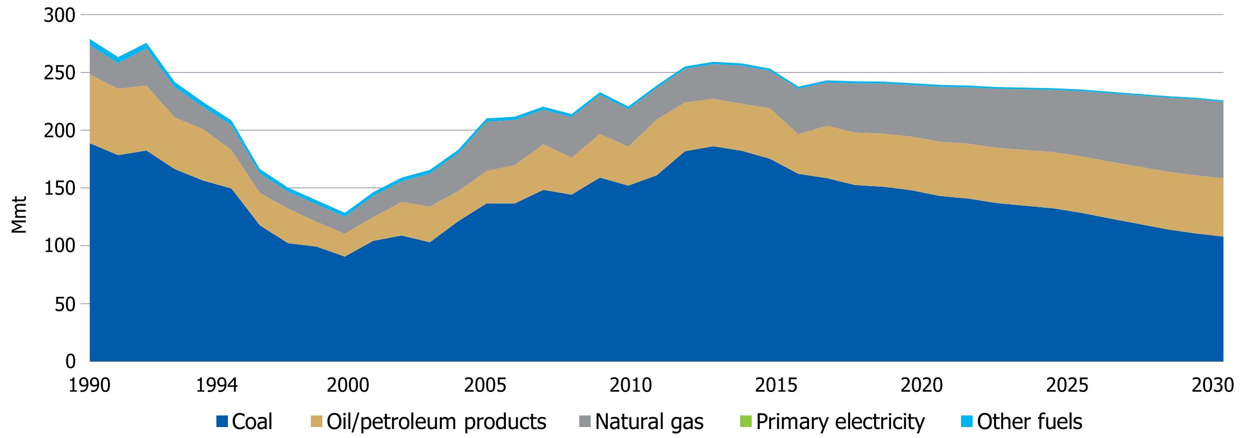
However, the link between emissions and economic growth is weakening, and this trend will continue in the future. Although Kazakhstan's GDP is projected to increase at moderate rates over the remainder of the forecast period (with an average annual GDP growth rate of 2.4% between 2015 and 2040), GHG emissions associated with energy consumption increase more gradually over this period, averaging only 0.2% per year, reaching about 263 MMt by 2040. If the ratio of GHG emissions from energy consumption (to total GHG emissions economy wide) remains in the same general range as at present, then total GHG emissions for Kazakhstan would increase to about 297 MMt by 2020, to about 307 MMt in 2030, and to about 320 MMt by 2040.

An important reason for the decelerating growth in emissions relative to GDP growth is that the energy sources used to satisfy incremental energy demand in the future will become cleaner. Natural gas—whose GHG emissions coefficient (metric tons of GHG emitted per thousand tons of oil equivalent consumed) is only 55% that of coal, 72% of oil, and 35% that of such "other sources" as peat and wood—will accommodate a significant amount of new energy demand in the economy going forward, while supplanting the "other sources." As can be seen in Table 9.1, the growth in natural gas's contribution to Kazakhstan's overall GHG emissions increases far more rapidly (2.4% annual average percentage growth between 2015 and 2040) than any of the other sources. Although at first glance, this "achievement" may seem dubious, it is accompanied by a dramatic reduction in GHG emissions (by about half) per unit of the country's economic output (lowermost row in Table 9.1).

An important takeaway that can be gained by comparing the 1990 GHG emissions from energy consumption with those projected to 2030 is that Kazakhstan can attain about half (a 7.8% reduction) of its unconditional Paris-agreement GHG emissions target for this period (15% reduction) by following a "business-as-usual" approach—i.e., pursuing policies already in place or planned for implementation (for gasification of the economy, improved vehicle fuel standards, normal efficiency gains, and incremental growth in electricity generation from alternative and renewable fuels) (in Table 9.1). This "**baseline scenario**" incorporates the following projections for the period between 2016 and the target date (2030) for emissions reduction according to the Paris accord, which represent more or less an extension of recent trends: (1) an average annual rate GDP growth of 2.6%[10]; (2) average annual growth in primary energy consumption of 0.7%; (3) average annual improvement in aggregate energy efficiency by 1.9%; (4) coal consumption grows only slightly by 0.1% per year; (5) an increase in the share of gas in primary energy from 23% of the total in 2016 to 27% in 2030; and (6) an increase in the share of zero-emission electricity generating sources from 12.7% in 2016 (hydro 12.3%, wind 0.3%, solar 0.1%) to 13.8% in 2030 (hydro 8.8%, nuclear [start-up projected in late 2030] 3.4%, solar 0.3%, and wind 1.3%).

The **alternative scenario** assumes the same general trajectory for GDP growth (2.6% over the period 2016–30).However, the other parameters are changed as follows: (1) primary energy consumption growth (0.3% per year) is less than half that in the baseline scenario; this is due to (2) more rapid improvement of aggregate energy efficiency (increasing to 2.3% per year in 2016–30 from 1.9% in the baseline model); (3) a pronounced decline in coal consumption—by a 2.1% yearly average (vis-à-vis 0.1% growth in the baseline scenario); (4) more rapid growth in natural gas consumption to offset assumed greater coal reductions (an average of 4.1% growth in gas vs. 1.8% in the base case); and (5) an accelerated rate of installation of new solar and wind generation, so that in 2030, the share of zero-emission generation reaches 14.1% of the total (versus 13.8% in the baseline scenario), with solar at 0.5% and wind at 1.4%. Thus in aggregate, the alternative scenario requires much greater improvement in aggregate efficiency, a sharper reduction in coal consumption, and a more rapid build-out of wind and solar (see Figure 9.4).

Figure 9.4. Estimated greenhouse gas emissions for Kazakhstan* (with greater coal reductions and improved energy efficiency)



Notes: *Energy-related GHG emissions only

Source: IHS Markit, Kazakhstan Statistics Committee

[10] This is average annual GDP growth during 2016–30. Average annual GDP growth to 2040 is projected at 2.4%.

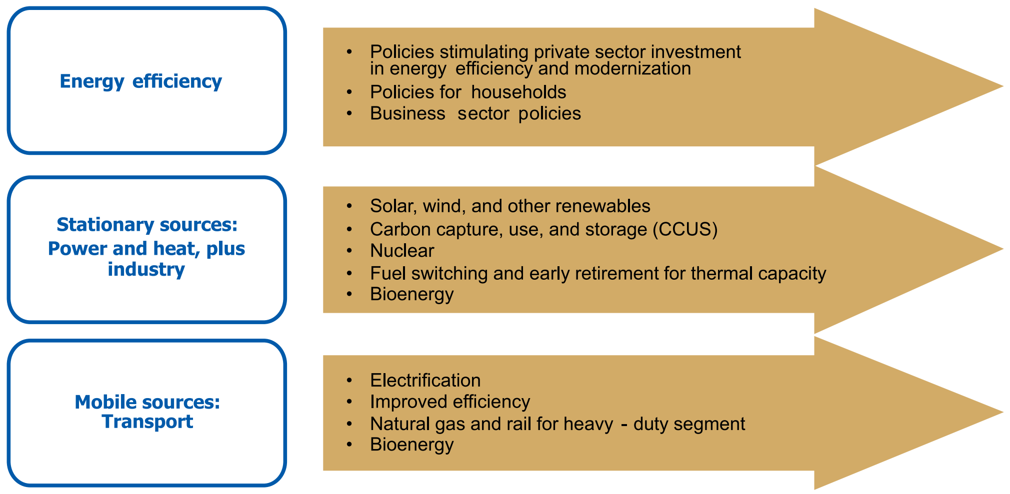
Table 9.2. Estimated greenhouse gas (GHG) emissions for Kazakhstan for energy-related economic activity, 1990–2040 (million metric tons) - alternative scenario

	Emission coefficient, metric tons per thous. TOE consumed	Year											Average annual pct. change, 2016-2030	Average annual pct. change, 2015-2040
		1990	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040		
Total		278,9	208,5	146,4	211,7	238,6	237,7	239,2	235,2	225,8	219,0	215,8	-0,5	-0,6
Coal	3,81	188,7	149,5	104,3	136,7	161,0	162,3	143,1	128,5	108,0	93,8	82,7	-2,7	-2,8
Oil / petroleum products	2,93	59,6	33,3	20,5	33,2	48,2	34,3	47,0	48,9	50,6	52,8	55,6	0,8	0,9
Natural gas	2,12	25,1	21,7	18,3	39,1	27,3	39,3	47,5	56,5	66,0	71,3	76,6	4,1	3,4
Primary electricity	--	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0		
Other (peat, wood, etc.)	6,00	5,5	4,0	3,2	2,8	2,1	1,8	1,6	1,4	1,2	1,1	1,0	-2,9	-2,4
GHG emissions/thousand $ GDP (2005 dollars)		2,4	2,9	1,8	1,6	1,3	1,1	0,9	0,8	0,7	0,6	0,5	-3,1	-2,9

Note: Estimate only for energy-related economic activity (fuel combustion); calculated by IHS Markit.

The following major section of this report outlines measures Kazakhstan might take, in addition to "business as usual," to meet its INDC under the Paris agreement. These "pathways to Paris" involve (a) the adoption of low-carbon, energy efficiency technologies for stationary sources of emissions (power plants and buildings) as well as (b) in transportation; and (c) the strengthening of the policy environment for emissions reductions—both through the creation of incentives and via systems for imposing costs on GHG emissions (carbon tax, emissions trading system) (see Figure 9.5)

Figure 9.5. Key policy "pathways for decarbonization."



Source: IHS Markit

9.2.5. Conclusions, notable changes since 2015

As a signatory to the Paris climate agreement in 2015, Kazakhstan has renewed its commitment to reduction of its GHG emissions—by 15% of 1990 levels (unconditional) to as much as 25% (conditional). This new commitment replaces a previous one (tied to the Kyoto Protocol, ratified in 2009), which called for Kazakhstan to reduce GHG emissions by 5% relative to 1992 levels by 2020 (mandatory), as well as by 15% by 2020 and 25% by 2030 (both voluntary commitments).

• Kazakhstan has undertaken an additional commitment (Kigali agreement) to reduce its consumption of hydrofluorocarbons (not covered in the Paris agreement) by 5% (relative to 2011–2013 average levels) by 2020 and 35% by 2035. Kazakhstan also has the opportunity to voluntarily participate in the second phase of an ICAO agreement covering GHG emissions from international passenger air travel.

• Kazakhstan's GHG emissions regulation system (carbon trading market)—rolled out in 2013 as a pilot project and launched in earnest in 2014—was suspended in February 2016 to allow more time for the system administrator and regulators to develop a new system for emissions reporting and to further improve the market for the trading of greenhouse gas emissions quotas. A new system incorporating improved reporting procedures is scheduled to relaunch in 2018 (described below).

9.3. PATHWAYS TO PARIS: STRATEGIES FOR REALIZING KAZAKHSTAN'S 2030 GHG EMISSIONS REDUCTION GOALS

In a very real sense, the goals of environmental protection and energy efficiency are highly compatible. The less energy that must be consumed to sustain a given level of economic activity, the lower the quantity of energy resources that must be extracted and consumed, and the lower the environmental impact. Kazakhstan has made enormous strides in the overall efficiency of energy consumption per unit of GDP (energy intensity), as seen in the decline of energy related GHG emissions per unit of GDP (see Figure 9.6).[11] Despite its relatively high overall energy intensity (linked in no small measure to the natural resource orientation of its economy, its high-latitude location, and large land area), Kazakhstan's aggregate energy intensity declined spectacularly, by 3.6% on average annually, during 2000–15. This was facilitated, first and foremost, by rapid economic growth, accompanying broad investments, and general modernization (as broad economic improvements often are the most important energy efficiency measures).[12] In addition to these general efficiency improvements, energy intensity also fell as a result of key initiatives undertaken during this period: establishment of a National Energy Register (NER) of major industrial enterprises and public buildings (facilities with energy consumption exceeding 1,500 tons of fuel equivalent per year); the performance of energy audits at these enterprises/facilities and the formulation of energy-savings plans based on these audits; the compilation of a national Energy Efficiency Map;[13] and support for investments in energy efficiency via service contracts from licensed providers of efficiency services.

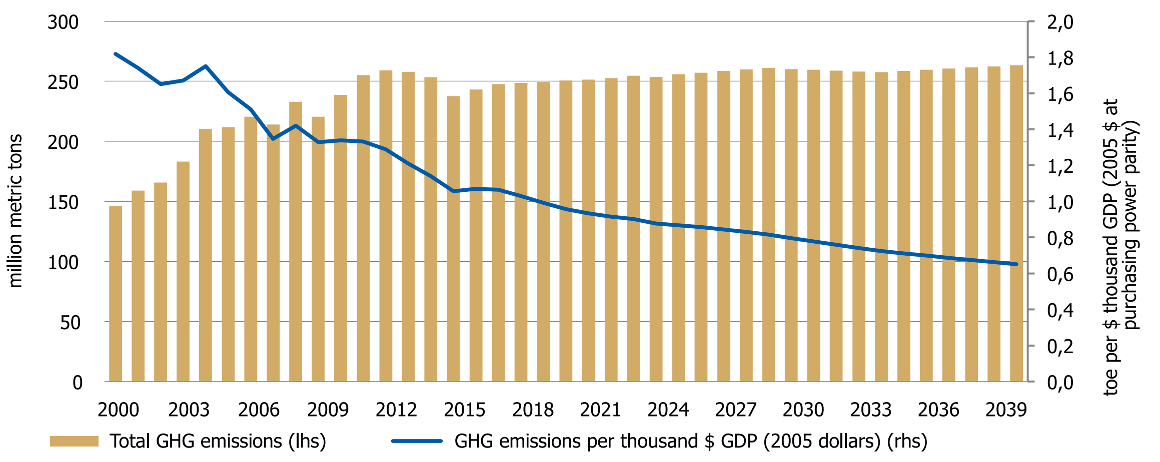
[11] IHS Markit estimates energy efficiency based on all GHGs from the energy sector only, while Figure 9.2 shows "carbon intensity" based on only CO_2 emissions from fossil fuel use and cement production.

[12] It is important to note that in some industries, modernization rather than retrofitting or piecemeal technological fixes is essential to increasing efficiency. In ferrous and nonferrous metallurgy, for example, more than 90% of energy consumption is directly related to process technologies. The main potential for energy saving thus lies in a full upgrade or replacement of the process equipment, which is actually equivalent to construction of a new plant. Similarly, in the mining sector, energy efficiency improvements can be achieved mainly through core equipment replacement and introduction of systems for optimizing fuel consumption during ore extraction, handling, and processing.

[13] The attraction of investments in energy savings through energy service contracts corresponds to the Step 59 of the comprehensive "100 Concrete Steps" modernization plan unveiled by President Nazarbayev shortly after his re-election in 2015. The Energy Efficiency Map was created to aid the implementation of this step. It indicates sources of funding for specific projects for improving energy efficiency and details plans for their implementation.

However, the service contracts have thus far proven challenging to implement, both because of difficulties in determining an accurate monetary value for a given set of services, and because energy metering systems are not adequately equipped to satisfy the requirements of energy contract providers (energy audits before and after the implementation of energy efficiency services are an essential part of the service process).
In February 2015, the signing of the first energy service contract to replace the JSC «Kazpost» lighting system was announced. However, this contract was signed between enterprises (with partial state participation) directly without carrying out a tender. Experience to date demonstrates that the main challenge to attractive investment is the complicated service procurement procedures, which are regulated by legislation for subsoil users, state companies (included in Samruk-Kazyna holding), state enterprises, and natural monopolies.

Figure 9.6. Emission of GHG gases in Kazakhstan related to energy consumption



Source: IHS Markit, Kazakhstan Statistics Committee

9.3.1. Pathway 1: Low-carbon, energy-saving technologies for stationary-source emissions

This section does not undertake a comprehensive review of energy-saving, low-carbon environmental technologies for stationary-source emissions (for such a review, see Chapter 11 in the National Energy Report 2015). It rather briefly outlines major trends in renewable energy development globally before focusing on two of the more prominent technologies that could be relevant given Kazakhstan's current energy mix (where the share of renewable energy remains relatively small at present)—namely carbon capture and storage and efforts to make buildings more energy efficient. The section then summarizes initiatives undertaken in these areas by Kazakhstan since mid-2015.

9.3.1.1. Record additions of renewable capacity globally

An important trend globally in electrical generation in 2016 were the record additions of renewable energy capacity (150 GW), more than for any other form of energy, reflecting falling capital costs and strong policy support for solar photovoltaics and onshore wind. The IHS Markit Global Energy base case (Rivalry) Scenario to 2040 projects global non-hydro renewable energy generation capacity (wind, solar, geothermal, biomass, and tidal energy) to grow at an average annual rate of 6.5% between 2015 and 2040, reaching a total capacity of 3.7 terawatts (or 37% of total electrical generation capacity). However, despite this rapid capacity build, by 2040 renewable sources of energy will account for only 5% of total global primary energy consumption, with the aggregate share of coal, oil, and gas still accounting for over three-fourths.[14]

In a speech on 22 June 2017, Kazakhstan's President Nazarbayev proposed the introduction of a system of auctions for the purchasing of electricity generated by renewable sources, to augment incentives already in place (feed-in tariffs, purchase guarantees) that support the growth of the industry. The president noted (given the long lead times required for the turnover of electrical generation capacity) that the most acceptable strategy over the near term involves "mixed energy production"—continued reliance on energy generation from traditional sources in parallel with the gradual build-out of renewable capacity. IHS Markit projects that by 2040 non–fossil fuel energy sources (hydro, nuclear, wind, solar) will account for 18% of total electricity generation in Kazakhstan.

[14] For a more detailed discussion of investment trends in renewable energy, see Chapter 2.2.

9.3.1.2. Carbon capture and storage

Although global operational carbon capture and storage (CCS) capacity is projected to increase to 58.7 MMt by 2020, the challenges (high development costs, unsupportive national policies, technological uncertainty) have not yet been sufficiently counterbalanced by progress in other areas (industrial waste-gas recycling at the plant level, expansion of a market for CO_2 in enhanced oil recovery via re-injection) to signal a major improvement in prospects for the technology. Only about 15 large-scale projects for carbon capture and storage are in operation worldwide in early 2017, and 2016 was a year of setbacks for the technology, both in terms of project activity and in policy support.[15] Low oil, gas, and coal prices limited the economic rationale and funding available for energy companies to employ the technology (e.g., to recover CO_2 for injection into underground strata during enhanced oil recovery), and as a result only one large-scale project worldwide entered operation in 2016, two were cancelled, two more put on hold, and nine had start dates postponed for a year or more. The total project count (in operation, under construction, under development [FID], and planned) is shrinking rather than growing, from over 70 in 2012 to under 40 in late 2016.

Advocates of the technology (such as the Global CCS Institute) argue, however, that CCS is essential to efforts to combat climate change. More specifically, they argue that given the current structure of primary energy consumption, coal use in the global economy cannot be curtailed rapidly enough to achieve the GHG emissions reductions targets of the Paris climate agreement without further development of CCS and its widespread adoption in industry. As such they are lobbying for CCS to be accorded "policy parity" among the measures governments pursue (e.g., energy efficiency improvements, renewable energy development) to achieve their Intended Nationally Determined Contributions under the Paris accord. Proponents argue that, given the same R&D incentives and subsidies afforded renewable energy, CCS capacity could be built out rather quickly.

As reported in The National Energy Report 2015, the introduction of carbon dioxide capture and geological storage technologies does not seem appropriate for coal-fired power plants in Kazakhstan at the current stage of technological development. Despite the fact that modern technologies enable the capture of 85–95% of carbon dioxide, their use at coal-fired power plants is currently unfeasible from both ecological and economic points of view due to: (a) an increase in specific fuel consumption by 14–40%; (b) increased overall pollutant emissions (due to increased fuel consumption); (c) a rise in electricity generating costs by 43–90%; and (d) growth in plant construction costs by 30–90%.

9.3.1.3. Energy and heat efficiency in buildings: developments in the European Union

As noted in the National Energy Report 2015, a major opportunity for improving overall energy efficiency (and reducing GHG emissions) in Kazakhstan's economy can be found in housing and public buildings. Average residential energy consumption (270 kWh/m²) inKazakhstan exceeds that in Europe (100–120 kWh/m²) aswell as in Russia (210 kWh/m²). The reason, apart from climate, is the need for upgrading of the housing stock. Roughly 70% of the buildings in Kazakhstan were constructed between 1950 and 1980 and do not meet modern requirements for thermal insulation, which results in losses of as much as 30% of delivered heat. Another promising area in the housing and utilities sector that affords considerable potential for energy savings is lighting, which accounts for roughly 39% of total electricity consumption in the residential sector. [16]

The Law on Energy Saving and Energy Efficiency (2012) is an important step forward in efforts to improve energy efficiency in buildings. For new residential construction, it specifies that materials must be used, and automated heating systems and utility metering devices installed. For existing residential structures, the Law requires that such materials, heating systems, and devices be installed during capital repair or reconstruction. However, due to the shortage of funds for repair and reconstruction of buildings and structures, such measures to date have been implemented on a very limited scale.

The need for improved energy efficiency in the residential sector and public buildings is not unique to Kazakhstan, but is a common problem worldwide, as this has been one of the "last frontiers" to be addressed in the campaign to increase energy efficiency. Nowhere in the world has the push been stronger than in Europe, which has taken the lead in the effort to improve energy and heat efficiency in buildings. For this reason, a focus on recent EU policy in this area may prove helpful as Kazakh policymakers consider new ways of meeting their energy efficiency and emissions goals. In the EU, buildings are responsible for 40% of energy consumption and 36% of CO_2 emissions. While occupants of new buildings generally consume fewer than three to five liters of heating oil equivalent per square meter per year, those in older buildings use about 25 liters on average, with some buildings even requiring up to 60 liters (currently, about 35% of the EU's buildings are over 50 years old). By improving the energy efficiency of buildings, EU officials believe they can reduce total EU energy consumption by 5–6% and lower CO_2 emissions by about 5%.[17]

[15] See Steve Phillips, Carbon Capture Snapshot 2016: A Year of Notable Setbacks for an Industry Poised for Growth in 2017, IHS Markit: Climate and Carbon Insight, December 1 2016.

[16] The National Energy Report 2015, p. 26, 329–330.

Responsibility for improvements in energy efficiency in the European Union's building sector is divided between the European Commission and the member states. Several EU directives set the overall framework and define certain minimum standards, but significant flexibility in terms of implementation and compliance remains with the member states. For example, each member state defines its own building codes, which should nonetheless comply with the overall EU framework.

Four main EU directives, evolved from earlier legislation, have an impact on European energy demand in the residential sector and public buildings. These include:

Energy Efficiency Directive (EED). The EED, adopted in 2012 and enacted into national law in June 2014, sets a common framework for all member states to allow the European Union to progress toward its 2020 energy efficiency target (equivalent to a 20% savings versus business-as-usual). It requires member states to achieve specified levels of energy savings during 2014–20 through energy audits, metering and billing, energy efficiency services, and other measures. The single most important element requires member states to achieve a 1.5% savings annually through an Energy Efficiency Obligation Scheme (or equivalent schemes). More specifically, the Energy Efficiency Obligation Scheme requires energy companies in the EU countries to achieve yearly energy savings (power volume reductions) of 1.5% in annual sales to final consumers. In order to reach this target, companies need to carry out measures that assist final consumers in improving building energy efficiency. These may include improving the heating systems in consumers' homes, installing double-paned windows, or better insulating roofs to reduce energy consumption. EU country governments may also implement alternative policy measures that reduce final energy consumption.

Ecodesign Directive. The Ecodesign Directive defines minimum energy efficiency standards for appliances sold in the European Union. It is the directive responsible for the phase-out of incandescent light bulbs across Europe as well as for the tightening of standards regulating standby losses.[19] The original 2005 directive covered 19 categories of appliances, each of which sold more than 200,000 units per year and therefore had a significant environmental impact. The scope of the directive was widened in November 2009 to cover energy-related products as well as energy-using products. This is a significant expansion, as it allows European-wide minimum performance standards to be set for products such as windows and building insulation.

After much debate and significant delay, Ecodesign and labeling regulations for space heaters, heat pumps, and water heaters were adopted in September 2013. In terms of the latter, the new standards increase the efficiency of new natural gas water heating units by 20–30% over the current average. Some major residential gas markets—e.g., the Netherlands and the United Kingdom—had already implemented rules that enforced the purchase of condensing boilers (water heaters fueled by gas or oil) but in others, such as Germany, the share of condensing boilers was still very low. Since 2015, European legislation calls for all new boilers to be condensing.

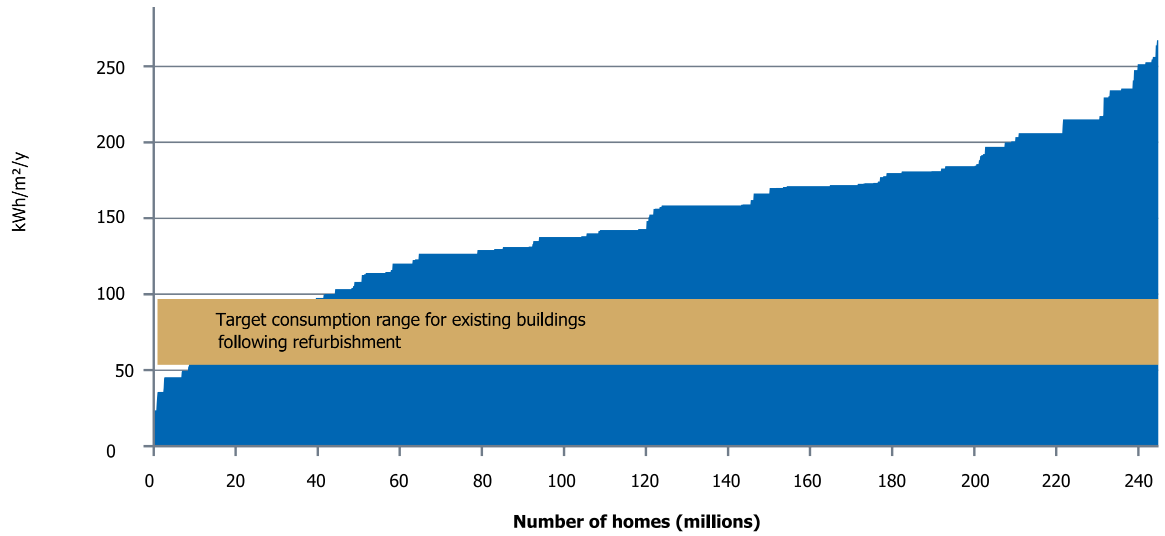
Energy Performance of Buildings Directive (EPBD). The 2010 EPBD sets minimum standards for the heating requirements of all new buildings. From the end of 2020, all new buildings in the European Union should be nearly zero-energy buildings (NZEB), with public buildings required to meet the standard two years earlier. The general concept of a zero-energy building is one with zero net energy consumption, meaning that the total amount of energy used by the building on an annual basis is roughly equal to the amount of renewable energy created on the site (e.g., from solar panels).[20] When existing buildings undergo major renovation, the renovated portion is also required to meet the NZEB requirements.

Additional provisions under the EPBD include: (1) energy performance certificates to be included in all advertisements for the sale or rental of buildings; (2) the establishment of inspection schemes for heating and air conditioning systems or measures with equivalent effect; (3) minimum energy performance requirements for new buildings, for the major renovation of existing buildings, and for the replacement or retrofit of building elements (heating and cooling systems, roofs, walls, etc.); and (4) the compilation of lists of national financial measures to improve the energy efficiency of buildings.

Energy Labeling Directive. The Energy Labeling Directive complements the Ecodesign Directive (discussed above), which sets minimum efficiency standards. The original 1992 directive was restricted to household appliances, but in 2010 the scope was expanded to cover all energy-related products. The Energy Labeling Directive requires that appliances be labeled to show their power consumption in such a manner that it is possible to compare their efficiency with that of other makes and models; similarly, energy-related products that have a significant direct or indirect impact on consumption of energy or other essential resources and that afford adequate scope for increased efficiency should be labeled, when such labeling may stimulate end-users to purchase more efficient products. The intention is that consumers will prefer more energy efficient appliances over those with a higher consumption, resulting in less efficient products eventually being withdrawn or decommissioned.

Proposed New Legislative Package. In December 2016 the European Commission adopted the Clean Energy for All Europeans legislative package. This proposed a binding target for 2030 of a 30% energy savings at the EU level and included proposals for a revision of the EED and the EPBD to bring them up to date with the 2030 energy and climate goals, to check their effectiveness, to simplify and improve the legislation, and to facilitate implementation at the national level. The recast EPBD will strengthen the requirements for long-term strategies for the renovation of existing buildings to de-carbonize the building stock by 2050. This latter provision is important, because although IHS Markit estimates that 40 million new homes will be built in Europe by 2040, there are more than 240 million existing homes, and many have quite poor energy performance (see Figure 9.7).

Figure 9.7. Energy demand by homes in Europe



The leaked Heat Strategy suggests a refurbishment should aim to reduce energy consumption in existing homes to 60–90 Kwh/m². IHS Markit estimates that 200 million homes are above this threshold.

Source: IHS Markit

Measures to improve collection of data on the energy performance of buildings are also included, as is a new Ecodesign Working Plan for 2016–19. The EU Council and Parliament currently are debating the proposals. Reaction from the Council thus far has been that the requirements for decarbonizing the building stock by 2050 are too demanding.

In aggregate, the measures described above represent what can be considered the most advanced set of policies globally that is oriented toward improving energy efficiency in buildings.

9.3.1.4. Recent energy efficiency initiatives and achievements in Kazakhstan

In the period from mid-2015 through mid-2017, the Republic of Kazakhstan initiated a number of energy savings programs in collaboration with international actors focused on stationary (non-transportation) sources of GHG emissions, which appear to have similar objectives to the EU initiatives outlined above. In April 2015 the International Energy Agency (IEA), Kazakhstan's Ministry of Energy, and KazEnergysigned a memorandum of understanding aimed at strengthening mutual co-operation among the parties in the de-

[17] https://ec.europa.eu/energy/en/topics/energy-efficiency/buildings

[18] These measures could include: energy or CO_2 taxes; financial incentives that lead to an increased use of energy-efficient technology; regulations or voluntary agreements that lead to the increased use of energy-efficient technology; energy labeling schemes beyond those that are already mandatory under EU law; and training and educational initiatives, including energy advisory programs.

[19] Standby power losses, also called vampire draw or ghost load, refers to electric power consumption by electronic and electrical appliances while they are switched off or in a standby mode.

[20] For the purposes of EPBD, a "nearly zero-energy building" is one that exhibits "very high energy performance," a standard that is left to member states to define but in practice seems to be equivalent to about 45–50 kWh/m2/year of primary energy consumption.

velopment of sustainable energy. The main objective, in the run-up to EXPO-2017, is for the parties to share expertise in the areas of renewable energy, energy efficiency, carbon capture and storage, energy conservation, and improving the gathering and tracking of energy statistics.

This was followed in September 2015 by the official launch of the four-year Kazakhstan Energy Efficiency Project, designed and overseen by Kazakhstan's Ministry of Investments and Development and the World Bank, to improve energy efficiency in public spaces (schools, kindergartens, hospitals, street lighting) and to create a favorable environment for energy efficiency financing. A total of $US21.76 million was allocated by the Bank, andan initial phase was to focus on energy efficiency improvements at 19 social facilities (8 schools and 11 kindergartens) throughout the country. In late October 2016, it was announced that program implementation had been delayed. Of the 19 originally designated projects, the designs for 6 had been approved but tenders for these projects were canceled by August 2016 due to a lack of bids. A re-tender is expected to be launched soon, and the designs of the remaining 13 projects will be updated and resubmitted for approval. A second stage envisages extension of the program to 25 additional facilities for which preparations are ongoing.

In a more regionally focused initiative, in late March 2016, the governor of East Kazakhstan Oblast, Danial Akhmetov, and EBRD Country Director for Kazakhstan Janet Heckman signed a KZT 7.7 billion ($ 23.9 million) agreement to replace street lighting in Oskemenand Semey with more energy efficient fixtures. The new fixtures are expected to reduce regional lighting expenditures by 60%.

Arguably the most important of these initiatives, however, was launched in 2017. The EBRD announced a loan of KZT 9 billion ($US28 million) to accelerate the installation of heat meters in residential buildings in Kazakhstan. The loan will allow the Housing Services Development Fund to install heat meters in individual residential buildings and later start a pilot phase for installation of wholesale electricity meters. The new meters will not only help save heat and electricity in Kazakhstan, but will also help district heating companies to optimize supply and reduce system losses. The district heating sector is one of the priority areas for EBRD-sponsored action.[21] Currently only about 45% of households reside in buildings equipped with heat meters, varying greatly from region to region. The EBRD-supported project seeks to achieve more than 80% coverage nationwide over the next two to three years.

Kazakhstan's most important recent achievement in energy savings policy has been the reduction in the proportion of incandescent light bulbs from 74% to 18% of the total between 2012 and 2016. This change was also made possible because of the halving of the cost of energy-saving, LED bulbs. Beyond lighting, there are numerous energy-saving technologies that, when installed correctly and in the appropriate context, could potentially improve efficiency in Kazakhstan. However, implementing such technologies is significantly more difficult than lighting upgrades. To this end, creating economic conditions that incentivize investments in equipment modernization should be a major goal of lawmakers in supporting energy-efficiency policy.

According to data from energy audits of industrial enterprises and social facilities carried out by the Electric Power and Energy Saving Development Institute between 2014 and 2016, the energy-saving potential nationwide totals 17.2 million tons of fuel equivalent, while measures currently under development will reduce annual energy consumption by 4.9 million tons of fuel equivalent, assuming an investment of about 363.5 billion tenge (US$1.1 billion). However, the energy audit procedures are not yet fully developed, as there is an underdeveloped methodology and a shortage of specialists. Typically, "energy audits" amount to enterprises completing standard forms. In order for the audits to become more effective, industrial enterprises will need to transfer their reporting systems from manual filing to fully automated metering.

Given that the existence of energy metering systems is a necessary prerequisite for an effective energy-savings program, Kazakhstan in the near term should prioritize the widespread installation of energy meters. While the number of heat metering devices installed inprivate homes has gradually increased in recent years, heat metering in some boiler rooms may still be performed based on approximating calculation methods rather than on the devices' actual data. As a result, the heat energy balance does not provide a comprehensive picture, and data on heat supply system losses is only an approximation.

Natural gas metering in Kazakhstan also faces a range of difficulties, as a considerable number of metering devices lack built- in temperature correction capacities that are necessary for adjusting gas volume in line with standard temperature parameters (20°C, 760 mm Hg). Thus consumption figures are underestimated, especially in colder periods of the year when natural gas consumption peaks. In order to solve this problem, in some regions (Mangystau, Atyrau, and Kostanay oblasts) the national operator KazTransGasAimak has proposed introducing special correction factors that would take into account the average monthly temperature; however, a court blocked the move in February 2017.

[21] The EBRD has committed €80 million ($US87 million) in six modernization projects in the district heating sector in Kazakhstan.

9.3.2. Pathway 2: Low-carbon, energy-saving technologies in transportation

9.3.2.1. Global mobility trends

Consumption of transportation fuels accounts for more than half (56%) of total world liquids demand. On-road transportation, such as cars and trucks, accounted for nearly four-fifths of total transport demand. Therefore ongoing changes in automobile powertrains and in forms of personal mobility are expected to dramatically impact fuel consumption and GHG emissions. In assessing developments in transportation, and on-road transportation more specifically, IHS Markit divides the global vehicle fleet into two broad categories: personal and commercial.[22]

Personal vehiclesor light-duty vehicles (LDVs) are the largest market for liquid hydrocarbon fuels, with gasoline being the dominant fuel option. These vehicles are generally owned by individuals and have low utilization rates and relatively long service lives (typically between 11 years and 20 years). Commercial vehicles, also known as medium-duty vehicles (MDVs), and heavy-duty vehicles (HDVs) are typically owned by municipalities and businesses. In contrast to LDVs, these vehicles have high utilization rates with much shorter effective lives (three to five years). Diesel serves as the main fuel option for these vehicles, such as trucks and buses.

As a market, commercial vehicles account for 30% of on-road transportation fuel demand. The majority of commercial vehicle sales and fuel demand is associated with on-road freight transportation by long-haul tractor-trailers. Commercial vehicle fleet operators make decisions very differently from the personal vehicle market. While both care about costs, personal vehicle consumers often place more value on less-tangible factors such as aesthetics that include vehicle accessories, design, brand, and lifestyle. When a fleet operator is buying a vehicle, its main focus is the vehicle's performance, reliability, and cost.

Up to the present, the attractive attributes of diesel engines (e.g., efficiency, reliability, and power) have challenged the penetration of alternative powertrains and fuels in the commercial vehicle fleet. Today, batteries lack the energy density, range, and life to maintain the high utilization rates desired by most commercial actors. However, more energy-dense forms of natural gas, such as CNG and LNG, are penetrating into return-to-base fleets.[23] These vehicles are used for repetitive tasks on fixed routes—such as garbage trucks, city buses, and delivery vans—which require fewer refueling stations.

In the short term, higher upfront CNG and LNG vehicle purchase costs and limited refueling infrastructure are the primary barriers to natural gas adoption within commercial fleets, particularly long-haul commercial tractor-trailers. Additionally, the current narrow diesel to natural gas price differentials, fewer CNG or LNG vehicle product offerings, limited vehicle maintenance and business infrastructure knowledge, and longer refueling times have heretofore slowed adoption in many countries, with the exception of China. IHS Markit expects oil prices to increase gradually, which should encourage greater CNG and LNG adoption (depending again on other market and policy conditions).[24]

By far, the greater driver in fuel selection (and emissions) in on-road transport (accounting for 70% of demand) is the personal sector (LDVs). Although there are a number of potential constraints to personal vehicle sales overall, such as vehicle cost, sales, and end-use restriction policies, IHS Markit expects automobile sales to continue to increase, from about 90 million vehicles in 2016 to nearly 128 million vehicles by 2040 (see Figure 9.8). This could lead to an expansion of personal vehicles on roads from 1.2 billion vehicles to 1.8 billion vehicles over the next 25 years. We believe more—not less—personal mobility will be needed in the future, although it may be lower than earlier estimates may have anticipated.

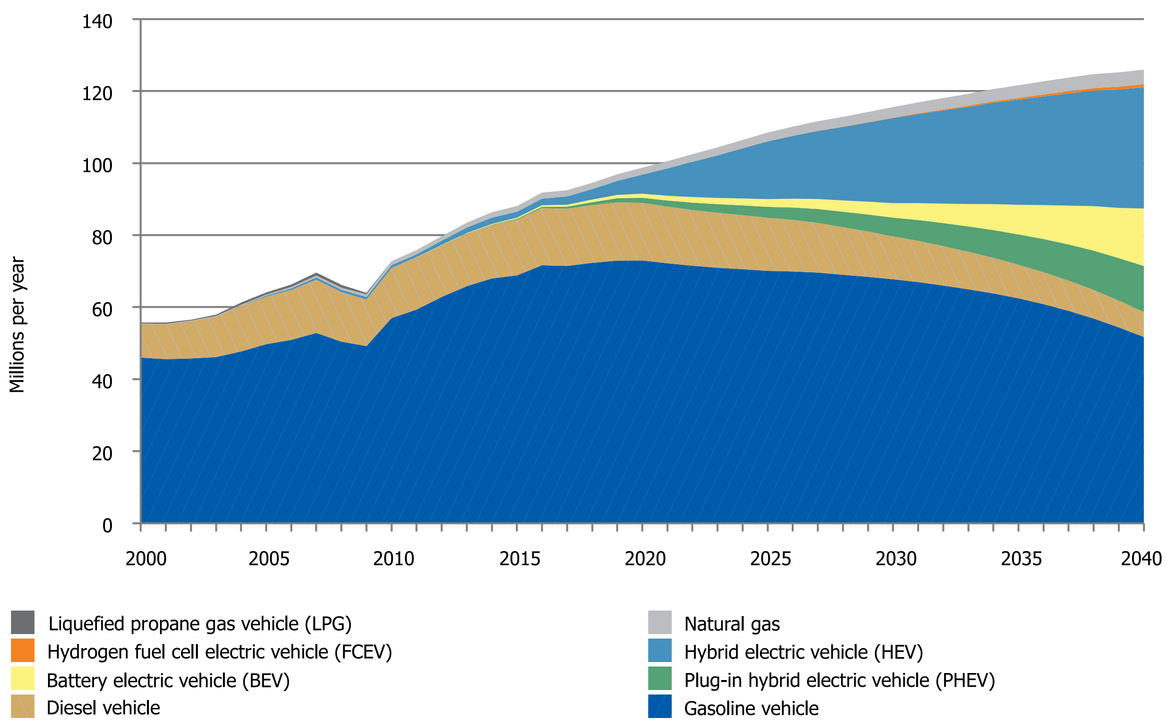
However, the very growth of the LDV fleet, much of it anticipated in urban areas of the developing world where private automobile ownership is not yet universal, ultimately presents its own set of constraints to fleet growth. The very high levels of population density in these cities and the resulting high density of vehicles, coupled with lagging infrastructure, often results in crippling congestion as well as poor air quality. The severity of these city-level issues is influencing municipal decisions in both the public and private sectors. On the public-sector side, there are an increasing number of policies focused on limiting urban vehicle sales. For example, as of 2016 seven cities in China have some form of city-level vehicle sales restrictions or an additional vehicle purchase levy. On the private side, new personal mobility options such as car-sharing and ride-hailing have emerged (discussed below) (see Figure 9.9).

[22] See Kevin Birn, Tiffany Groode, and Hossein Safaei, Where Will Transportation Drive Global Oil (and Oil Sands) Demand?, IHS Markit Strategic Report, December 2016.

[23] The use of natural gas in transport, however, also is not without challenges. Foremost is an 18–20% reduction of power in internal combustion engines due to the lower caloric value of the gas-air mix (as compared to the gasoline-air mix) that reaches the engine. However, in injection engines, the losses of power are less significant.

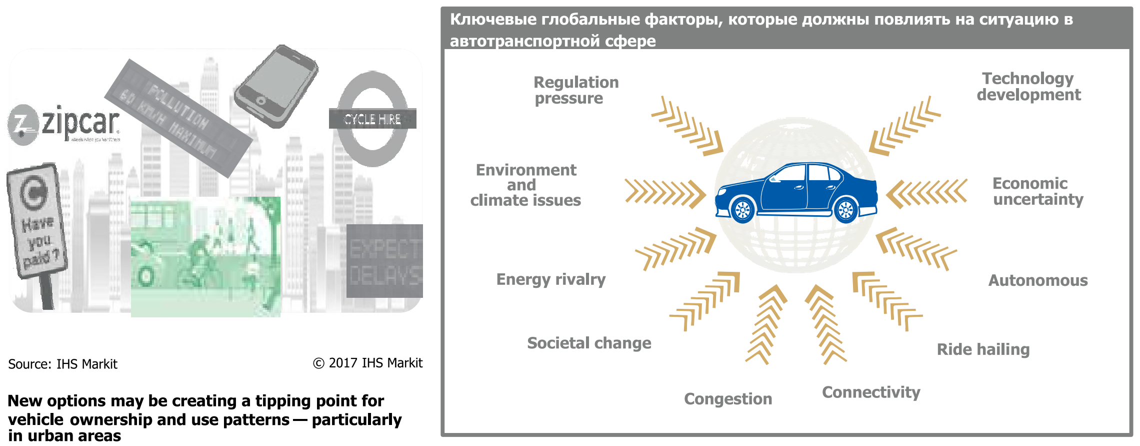
[24] For further details, see Section 5.3.2. of this report on natural gas in transportation.

Figure 9.8. Global LDV sales by powertrain: Rivalry (base case)



Source: IHS Markit

Figure 9.9. Enablers of change in automotive industrial ecosystem).



Source: IHS Markit

Despite the expected increase in the size of the global LDV fleet by as much as 50% globally, the effect on refined products consumption and GHG emissions is not expected to be commensurate; a number of compounding factors are currently expected to act as a drag on refined product demand growth. These include people driving less, increased vehicle fuel efficiency, and the proliferation of alternative powertrains and fuels.

The amount people drive, measured as vehicle-miles traveled (VMT), is by far the most influential factor affecting automotive fuel demand, especially in the short term. For instance, during the Great Recession, global gasoline consumption growth receded from 1.3% in 2007 to 0.4% in 2008. The main reason for the slowing demand growth was that people simply drove less. People who were unemployed stopped driving to work. Households on a budget reduced driving for shopping, entertainment, and holidays. This shift in people's everyday behavior had a quick and pronounced impact on global oil demand, which was 2% lower in 2009 compared with 2007 (5% lower in North America). Conversely, increases in VMT can cause demand to respond quickly. For example, in response to lower US gasoline prices in 2015, demand increased 2.7%, even though economic growth remained sluggish. Compared with 2014, the average person in 2015 drove almost 4% more, leading to higher gasoline demand.

IHS Markit believes driving habits around the world are slowly changing. In developed countries—such as the United States, Japan, and Europe—a mature market is a place where everyone who wants a car—by and large—has one. Consequently vehicle use (and VMT) might not change dramatically in the long run. Conversely, the declining all-in costs resulting from alternative forms of mobility (such as autonomous vehicles and ride-hailing; see below) could lead to more vehicle miles traveled. For developing countries, the conventional wisdom held that increasing personal income would lead to a similar vehicle ownership and use pattern as unfolded in the developed countries, driving automotive sales and refined product demand to new heights. However, this seems increasingly unlikely. One of the key differences is the aforementioned effect of urban congestion, poor air quality, and increasing cost of vehicle ownership in city centers that discourage car ownership and use.

Fuel efficiency is another important factor affecting transportation fuel demand and GHG emissions. The average fuel economy of the automotive fleet is a function of the average efficiency of all the different vehicles and their powertrains on the road. This changes as vehicles enter and exit the market. Concerns over energy security, air quality, and climate change have led legislators to develop and expand fuel-economy standards to reduce fuel consumption and emissions (see the text box on Strategies for GHG Emissions Reductions from Conventional Powertrains in the Transportation Sector). Globally, 80% of new passenger vehicle sales are under some type of fuel-economy regulation. These regulations push automakers both to advance conventional gasoline and diesel engine technology and to develop advanced powertrains and alternatively fueled vehicles such as electric cars.

Strategies for GHG Emissions Reductions from Conventional Powertrains in the Transportation Sector

Kazakhstan's emissions trading system (ETS) that will be re-launched in 2018 (outlined in Section 9.3.3 below) includes 140 enterprises in the oil and gas, electric power, mining-metallurgical, and chemical industries. As in many emissions trading systems worldwide, the transport sector is not included in the plan. Primarily this reflects the difficulty of record-keeping and reporting from many thousands of individual point sources of such pollution as well as in some cases multiple entities involved in service provision. Furthermore, because stationary sources of emissions typically have longer economic lives—many decades for power plants and buildings—actions reducing their carbon emissions tend to lock in greater GHG emission reductions over their operational lifetimes; turnover of mobile emission sources, especially vehicles, tends to be faster, creating the opportunity for continuous efficiency improvements via mechanisms other than an ETS, such as new vehicle fuel efficiency and emissions standards.

However, given the rising levels of private automobile ownership in Kazakhstan (slightly exceeding 4 million units in 2015, but dropping to 3.85 million by May 2017), addressing GHG emissions from the transport sector can play a role in helping Kazakhstan reach its intended nationally defined contribution under the Paris climate agreement. In fact, Kazakhstan has systems in place—in the form of vehicle fuel economy and emissions standards, a vehicle emissions inspection regime, and fuel quality requirements—that can provide an effective framework for reducing transport-sector GHG emissions.

First, proceeding from the concept that reduced fuel consumption equates with reduced emissions, in 2012, Kazakhstan introduced minimum fuel economy standards for all road transport vehicles. The Kazakh standards are based on the calorific values of the fuels burned and specific fuel consumption values. The government also has been proactive in supporting fuel efficiency by establishing higher road taxes on vehicles with large engines and selectively increasing customs duties on imports of older vehicles and those with larger engines. One common shortcoming, however, is that despite these standards and measures, vehicle fuel economy is often hindered by either the low octane levels of available fuels, or substandard fuel quality.

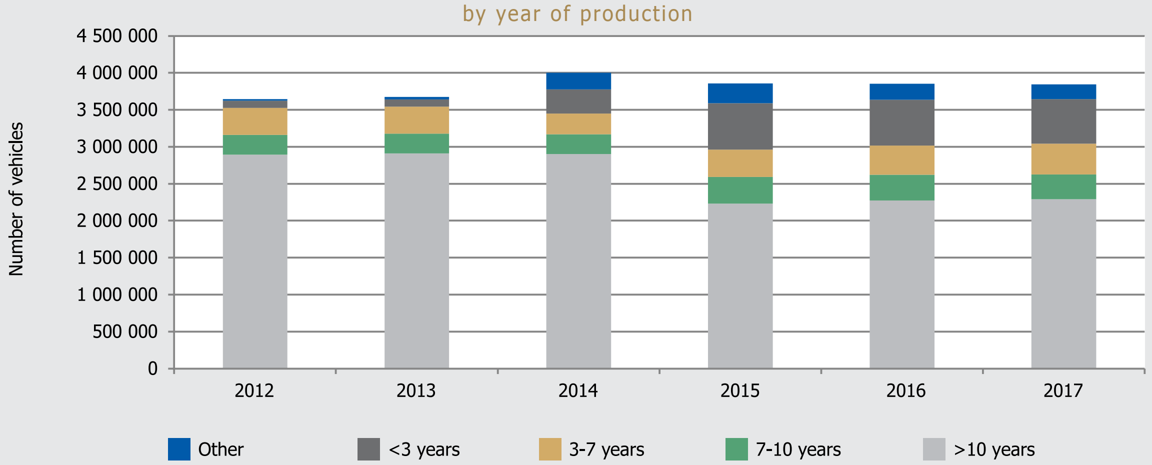
Second, a vehicle exhaust/tailpipe inspection regime was established in Kazakhstan in 2004 for all light-duty vehicles that specifies maximum allowable concentrations of "oxides of carbon" and hydrocarbons (e.g., diesel particulate matter) in vehicle exhaust gases. Vehicle emissions are not allowed to exceed maximum allowable emissions established by Technical Standard 51709-2004, "Motor Vehicles. Technical Standards for Road Safety." As with the case of vehicle fuel economy standards discussed above, the relatively low quality of available vehicle fuels in Kazakhstan has an adverse effect on vehicle performance, and in general elevates the concentrations of carbon monoxide and hydrocarbons in vehicle exhaust gases.

What the two examples above demonstrate is that technical regulations on fuel economy and vehicular emissions have outpaced progress in refinery production of better fuel grades. The timetable for adoption of new road transport fuel standards—the cessation of production of low-octane A-80 gasoline and the increase in production of higher quality gasoline and diesel products (especially Euro-4 and Euro-5 grades)—has been delayed repeatedly due, among other things, to variable levels of preparedness of vehicle producers/importers and refineries to undertake the necessary upgrades to meet them. The challenge, therefore, becomes that of coordinating upgrades in the vehicle fuel mix in the country with improvements in the technological specifications of Kazakhstan's vehicle fleet. A positive development is the expected completion of a modernization program at Kazakhstan's three refineries in the second half of 2018, enabling production of considerably larger volumes of higher octane gasoline and diesel fuel.

Even in the very near term, therefore, the transition from lower to higher grades of gasoline for internal combustion engine (ICE) powertrains can support substantive GHG emissions reductions. Longer term, Kazakhstan's ongoing efforts to support a transition to alternative fuels in transportation (e.g., natural gas) sets the stage for accelerated emissions reduction as vehicles with electric powertrains (either hybrid or fully electric vehicles) find their place in the market.

Although Kazakhstan's private vehicle fleet is fairly outdated, it has been experiencing noticeable changes in the past few years, with important implications for overall fuel consumption. In 2014 just under three quarters of privately owned vehicles were over 10 years old; in 2017 their share declined to around 60% (see Figure 9.10). Gasoline fueled vehicles dominate Kazakhstan's light vehicle fleet, constituting 94% in 2017. However, the share of mixed-fuel vehicles (presumably mainly LPGs) has increased over the last five years from under 1% in 2012 to over 3% 2017.

Figure 9.10. Breakdown of Kazakhstan's light vehicle fleet, by year of production



Notes: 2017 data from end-May 2017.
Source: IHS Markit, Statistic Committee of RK

Another noticeable mobility trend in Kazakhstan is a growing share of kilometers traveled by bus passengers, which has grown by almost 11% per year on average during the past decade. This trend bodes well for municipal governments that are seeking to upgrade their bus fleets and associated infrastructure to cleaner fuels.

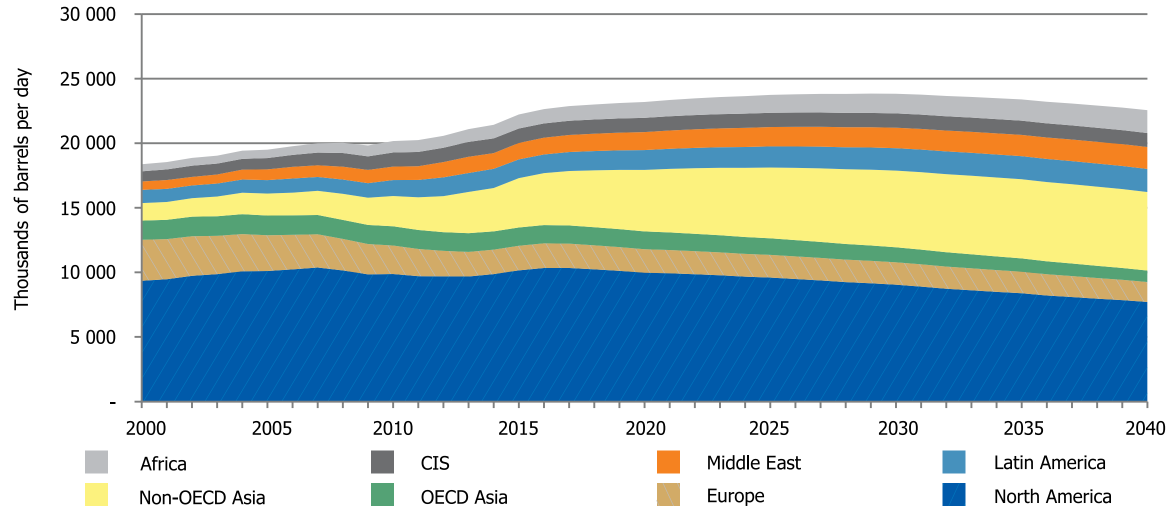
In terms of goods shipments, rail transport remains predominant, with a 46% share of all freight turnover. Kazakhstan Temir Zholy should continue the effort of replacing the older locomotive fleet with more efficient units produced through its joint venture with Alstom. Given the regional interconnectivity of railroads, Kazakhstan should use platforms such as the Eurasian Economic Union to promote improved regional standards for greater energy efficiency among railroad operators and railcar and engine manufacturers.

Despite changes in vehicle miles traveled and fuel efficiency, as well as the gradual penetration of alternative powertrains used in on-road transportation (see the following section), energy forecasters such as the US Energy Information Administration (EIA) and the International Energy Agency (IEA) expect overall crude oil demand will continue to grow in their base cases, albeit at a slowing pace out to 2040.[25] However, impacts of these changes on demand for refined products used primarily as transportation fuels are more salient. Total global gasoline and diesel demand (by all vehicle types in transportation and in all other economic sectors) peaks under the IHS Markit base case (Rivalry) scenario in about 2025, and remains stagnant thereafter; demand for gasoline by LDVs in transportation peaks by 2030 and declines slowly thereafter (see Figure 9.11).[26] Electricity begins to capture a tangible share of road fuel demand from this time forward.

[25] In both the IEA and EIA outlooks, global oil demand increases about 20 MMb/d to exceed 120 MMb/d by 2040.

[26] Global crude demand growth beyond 2030 will be sustained by increasing demand for other refined products.Naphtha is projected to have one of the highest product growth rates between 2016–40, driven by petrochemicals demand. Jet-kero demand also grows substantially over the forecast period as air travel expands in developing markets.

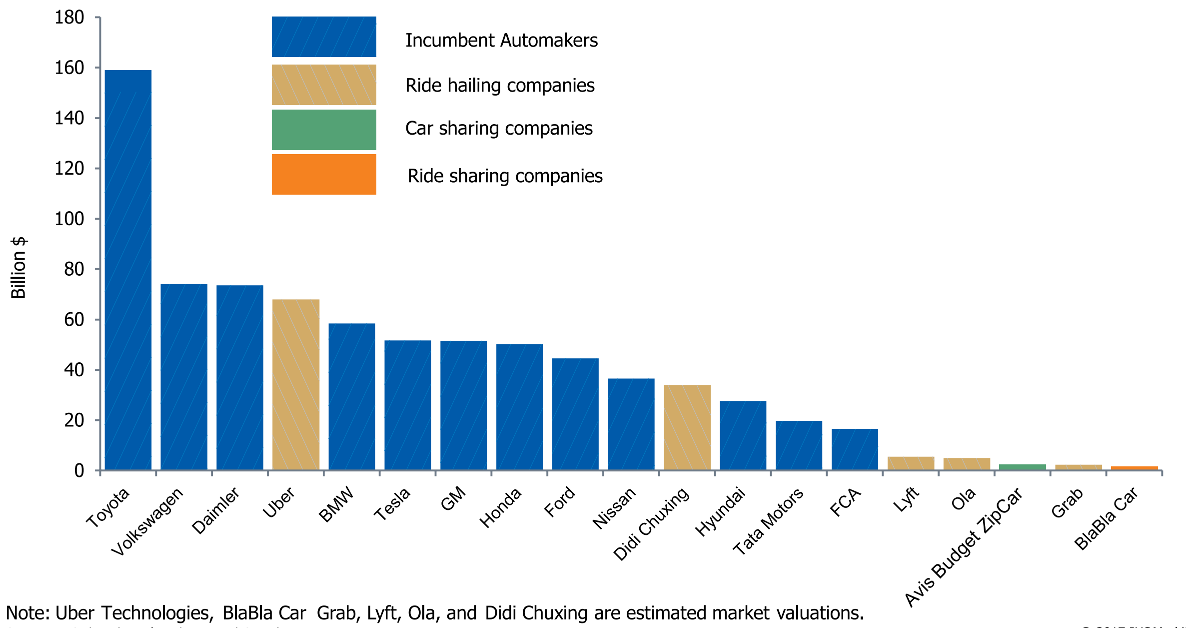
Figure 9.11. Global LDV gasoline demand by region: Rivalry base case



Source: IHS Markit

These projections do not fully take into consideration another transportation-related development that could well have an effect on vehicle fuel demand and emissions—but which cannot at present be precisely predicted. More specifically, this "wild card" involves emerging new forms of mobility in which vehicles move consumers as a service, without travelers needing to own vehicles themselves. The price points of ride-hailing and vehicle sharing are expected to fall below that of private automobile ownership in many areas, especially congested urban areas with high traffic volumes and limited parking availability. During 2016, Uber, the first-mover in ride-hailing, had an estimated valuation of $68 billion—greater than the market capitalization of any of the "big three" US automotive companies (see Figure 9.12). By October of that same year, Uber and other ride-hailing companies such as Lyft, Juno, and Via, were driving 500,000 passengers per day in New York City alone, triple the number of daily passengers driven during the previous year. Didi, the primary ride-hailing company in China, averaged 20 million rides per day during the second half of 2016. With the average ride being around 5 miles, this equates to approximately 100 million miles per day.

Figure 9.12. Market capitalization of top automakers, ride hailing, car sharing, and ride-sharing companies, May 2017



Note: Uber Technologies, BlaBla Car Grab, Lyft, Ola, and Didi Chuxing are estimated market valuations.
Source: NYSE/Nasdaq, Bloomberg, TechCrunch

These new forms of mobility, although often still more expensive than public mass transit, could lower emissions on a per capita basis if they reduce future private automobile ownership. This is particularly applicable in parts of the world where private automobile ownership is not yet universal; for example, ride-hailing is expected to become a dominant mode of vehicular mobility in the urban areas of emerging market countries. However, its global effects on GHG emissions from transportation are not immediately apparent; in New York City one unanticipated consequence attributed directly to ride-hailing has been a decline in public mass transit ridership, increasing both traffic congestion and emissions over the near term.[27]

Driverless or autonomous technology could also help the spread of mobility as a service, but it is not needed as a fundamental enabler of change. Removing the driver from the car would lower the cost of ride-hailing, thereby opening up access to new population segments. Technology companies such as Apple and Google, which hold some of the largest cash reserves globally, are focusing on development of autonomous capabilities, and these investments could lead to new and surprising innovations in autonomy and connectivity.

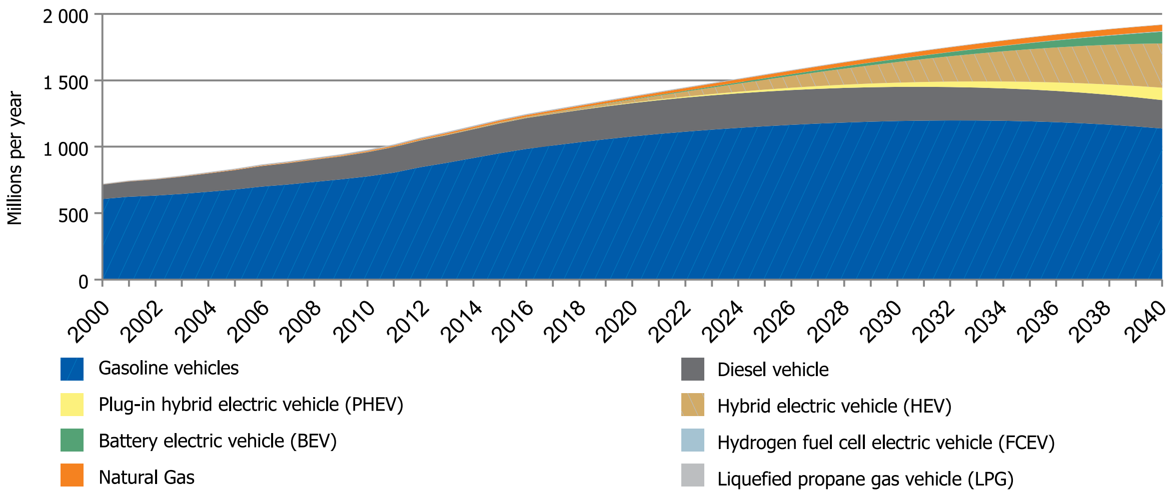
Ultimately, on a global scale, it is not yet clear how these new forms of mobility will affect the number of personal miles traveled, the number of vehicles needed to cover those miles, or how many of those miles will be fueled by gasoline and diesel, as opposed to electricity—or even natural gas or hydrogen. What is clear is that the old equation involving cars, miles, and fuel consumption—relatively stable for about a century—could change, perhaps radically, in the coming decades.

9.3.2.2. Electric/hybrid transport

Helped along by government policy, alterative vehicles, especially electric vehicles, have started to gain traction in the market. Policies intended to bolster energy security, address climate change, and improve urban air quality are working to increase the adoption of electric vehicles around the world. This has encouraged large investments in battery technology by both the public and private sectors. Investments are starting to pay off with the cost of vehicle-based lithium batteries declining almost 30% from 2012 to 2015.

IHS Markit expects sales of both battery electric and hybrid vehicles to increase over time, although their influence on aggregate fuel demand will take time. According to the IHS Markit Global Energy base case (Rivalry) Scenario, by 2040 all alternative powertrains (natural gas, hybrid vehicles of all types, battery electric vehicles, and hydrogen) could capture nearly half (46%) of all world sales of new LDVs, at which time they would account for almost 30%[28] of the entire LDV fleet (see Figure 9.8 and Figure 9.13).

Figure 9.13. Global LDV fleet by powertrain: Rivalry base case



Source: IHS Markit

According to IHS Markit, over the period from 2016 through 2025 world sales of hybrid and electric LDVs are expected to increase tenfold, to 21.2 million units, at which time they will account for just under 20% of all new vehicle sales. However, of these sales, the bulk (16.0 million units) will be hybrid electric vehicles. Sales of plug-in hybrids (PHEV) are projected to rise to 0.8 million units, and fully electric vehicles to about 0.8 million units as well. The latter will register the most rapid market gains, albeit from a very small current sales base. Longer term forecasts vary widely; IHS Markit's base case scenario envisions fully electric vehicle sales rising to 4 million units by 2030 and to almost 16 million units by 2040, at which time they are projected to account for 9% of all cars on the road.

Western Europe, the first region to adopt hybrid and electric vehicles on a large scale, will remain the largest regional market (representing 44% of total world demand), but growth is expected to be faster in the Asia/Pacific region, with China leading the way (70% growth in sales in 2016). Similar to the challenges reported in The National Energy Report 2015 with respect to discussion of LNG use in transportation around the world, a major factor in supporting demand will be the build-out of a battery-charging infrastructure in major cities and along major road transportation arteries. Both in Europe and China, a major factor accelerating the adoption of hybrid and electric vehicles has been high levels of NO_2 and particulate pollution from diesel-powered vehicles. Although the adoption of diesel vehicles in Europe in recent decades has been supported officially for environmental reasons (higher mileage and lower carbon emissions relative to gasoline), planners did not foresee the serious increase in non-carbon pollutants as a result of widespread diesel use in transportation (e.g., half of the UK's private vehicle fleet is diesel powered).[29]

In Kazakhstan, battery electric vehicles currently remain an exotic product limited to the luxury segment of its car market, according to KazAvtoProm, the Union of Kazakhstan's Automotive Industry. In 2016, 35 electric cars were sold in Kazakhstan, 9% more than in 2015. Although purchases are not supported by subsidies as in many other countries, incentives include zero import duties for the period between September 2016 and August 2017, as well as utilization and registration fees that are only half those for traditional vehicles. In addition, electric cars are exempt from transport tax in Kazakhstan. KazAvtoProm noted that the aforementioned incentives have not to date resulted in a noticeable increase in the demand for electric-powered cars. In addition to the high prices (ranging from $23,000 to well over $100,000), demand is limited by the country's harsh climate and lack of charging stations and service. Although most electric vehicles are imported, a small number are produced in Kazakhstan (in Q1 2017 KazAvtoProm estimated that one-third of vehicles [all types] purchased in the country were produced domestically).[30] Kazakhstan's first fast-charging station for electric vehicles opened in Astana in July 2017. The station has 50 kW capacity, and can recharge 24 kW batteries from 30% to 80% in 15 minutes.

Hybrid vehicles also are now entering the country's mass transit fleet. In May 2017 IVECO Bus completed the first delivery (for final assembly in Kostanay) in a contract for the supply of 210 Urbanway and Urbanway Hybrid buses for use in the city of Astana during EXPO-2017 and thereafter. The Urbanway Hybrid buses combine an electric traction system with a Euro-VI internal combustion engine. This increases their fuel efficiency by up to 30% relative to conventional diesel buses, while reducing CO_2 emissions by 33% and nitrogen oxides by 40%.

In addition to imports and assembly of electric vehicles, other recent developments indicate that Kazakhstan could be poised to play a greater role in the production of electric vehicles. In early 2017 Samruk-Kazyna announced that deposits of lithium, used in the production of lithium (Li) ion and Li-ion polymer batteries that power electric vehicles, had been discovered in East Kazakhstan, Almaty, and Kyzylorda oblasts. Although no comprehensive assessment of the country's reserve base has been completed to date, the Akhmetkino field in East Kazakhstan Oblast alone is estimated to hold 26,000 tons of lithium oxide. Experts believe that Kazakhstan has sufficient resources to establish a lithium production chain (from ore extraction to lithium batteries) within the next 10–15 years.

Global demand for lithium is projected to rise from 184,000 tons in 2015 to 534,000 tons by 2025. Electric vehicle batteries are expected to account for about 38% of total Li demand in 2025 (up from 14% in 2015), as the reduced cost of lithium batteries is expected to make electric vehicles fully price competitive with those powered by internal combustion engines by the middle of the next decade. The demand for lithium in production of grid-connected energy storage systems will also increase, from 400 tons in 2015 to 33,800 in 2025, accounting for over 6% of total demand for the metal.

Another potential source of lithium in Kazakhstan and elsewhere is the production water from oil and gas operations. The Canadian company MGX Minerals is currently exploring the commercial feasibility of "petrolithium"—the extraction of lithium from production waters (at concentrations as low as 67 mg/liter) via a complex process of nanoflotation and filtration—at pilot projects in Alberta and Utah. The petrolithium technology requires some pre-treatment of production water (removal of oil, colloid, and metals) prior to the extraction of lithium; this affords some environmental benefits as well as additional costs. However, these costs are expected to be more than offset by the income stream generated from lithium production. If commercial feasibility is attained, MGX is expected to seek partnerships with oil majors and/or major service providers to install the technology near major water collection and reinjection sites. In the meantime, it might be prudent for Kazakh producers to monitor levels of lithium in production waters to identify whether potentially promising sites exist.

[27] See Emma G. Fitzsimmons and Winnie Hu, "The Downside of Ride Hailing: More New York City Gridlock," The New York Times, March 6, 2017.

[28] It is important to note that the share of hybridand plug-in electric vehicles in alternative powertrains is quite substantial and without it the remaining alternative options (natural gas, battery electric vehicles, and hydrogen) account for only 7% of the total LDV fleet in 2040.

[29] See Kimiko de Freytas-Tamuka, "A Push for Diesel Leaves London Gasping Amid Record Air Pollution," The New York Times, February 18, 2016 and Melissa Eddy and Jack Ewing, "As Europe Sours on Diesel Cars, German Groups Fight to Save Them," The New York Times, August 3, 2017.

[30] The first domestically produced electric vehicle was a KIA Soul EV crossover, produced by Asia Auto at the end of 2014. In July 2016, a group of JAC electric cars rolled off the assembly line of SaryarkaAutoprom in Kostanay.

What is the Carbon Footprint of Electric Vehicles Compared to Conventional Ones?

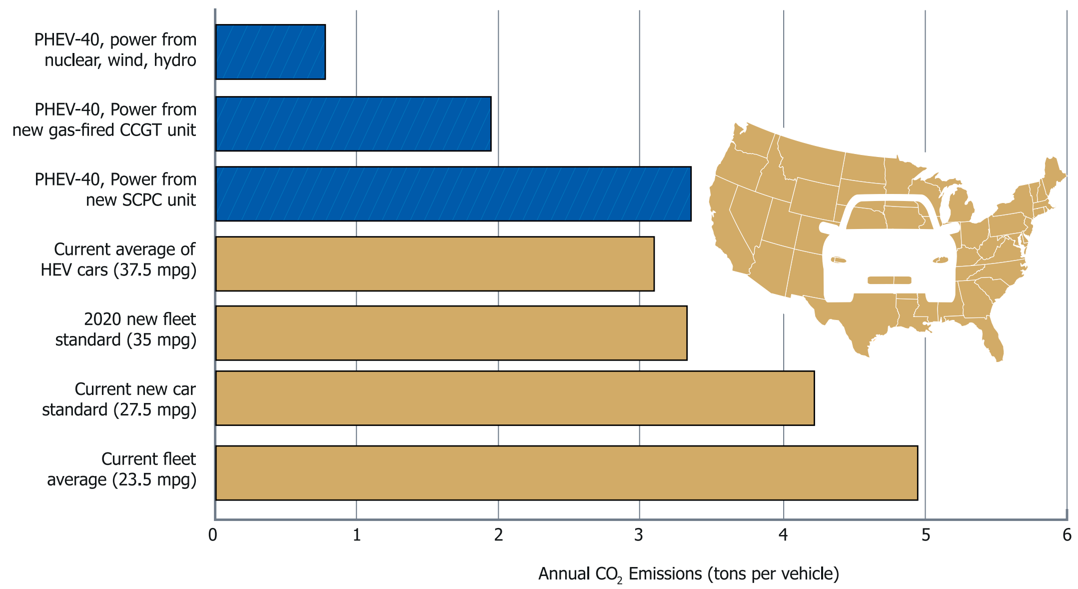
In an early effort to gain insight into the potential impact of the shift to largely or fully electric vehicles on GHG emissions, IHS Markit compared CO_2 emissions of plug-in hybrid electric vehicles (PHEVs) with a number of different powertrains and scenarios.[31] A plug-in hybrid is a good surrogate for today's fully (battery) electric vehicle in terms of its GHG emissions, in that it uses its electric motor, periodically recharged when it is plugged-in to a conventional electric outlet, to power all aspects of propulsion. Only if and when the electric motor battery's state of charge falls below a critical threshold does the vehicle's internal combustion engine kick in to supply power to the electric motor. A plug-in hybrid is therefore an electric vehicle that calls on gasoline only when necessary to extend its range, when the electric motor no longer has an adequate charge. In contrast, a conventional hybrid vehicle (HVE) draws its power at low speeds from an electric motor, but from an internal combustion engine (ICE) at higher speeds; its main fuel source is gasoline.

The potential for PHEVs and battery electric vehicles to reduce GHG emissions depends mainly on two factors: (a) the increased energy efficiency of an electric motor, reducing overall energy consumption; and (b) the type of fuel used to generate the electricity used to charge the vehicle's electric motor battery.

In an exercise designed to highlight the different emissions reduction impacts of electric versus conventional powertrains, the IHS Markit study compared CO_2 emissions for PHEVs in which the vehicles were powered by electricity generated by (a) carbon-free sources (nuclear, wind, solar, hydro); (b) natural gas; or (c) coal; versus emissions from either (a) internal combustion engines; or (b) conventional hybrid vehicles (HVEs). The comparisons involving ICE powertrainsare further subdivided into (a) those in compliance with then-current (2008) vehicle fleet average fuel efficiency of 23.5 miles per gallon for passenger cars and light-duty trucks; (b) the then-current Corporate Average Fuel Economy (CAFE) standard for new light-vehicle emissions (27.5 mpg); or (c) the 2020 new vehicle CAFE of 35 mpg.[32]

The exercise revealed that the emissions reductions yielded by PHEVs depended greatly on the fuel consumed to generate the electricity used to charge the vehicle's battery. Electricity generated in a supercritical pulverized coal-fired power plant actually yielded no improvement in overall CO_2 emissions (~3.5 tons of CO_2 emitted per vehicle annually) compared to internal combustion engines with a fuel efficiency meeting the now-current 2016/2020 CAFE standards (3.4 tons). Emissions reductions only materialized when cleaner fuels were used in the power generation used to recharge the battery: natural gas (from combined cycle gas turbines at ~2 tons emitted per vehicle annually) or nuclear/wind/solar/hydro (at ~0.7 tons).[33] (Figure 9.14). The results of the IHS Markit study thus indicate that achieving a notable reduction in carbon emissions from electric vehicle use is only possible through significant gasification of electricity generation and enhancements to the electricity grid.

Figure 9.14. Carbon "tire tracks" of current and future US passenger cars



Source: IHS Markit

[31] Patricia A. Diorio and Aaron F. Brady, From the Pump to the Plug: What Is the Potential of Plug-in Hybrid Electric Vehicles? CERA Private Report, June 2008.

[32] The 2020 standards were subsequently fast-tracked in 2012 by the Obama administration, and entered force in 2016. They thus represent the fuel economy standards currently in force in the United States.

[33] The exercise assumed that PHEVs would not always be operated in electric mode: rather 67% of annual miles traveled would be in electric mode and 33% in gasoline hybrid mode. Subsequent improvements in battery technology since 2008, increasing intervals between recharging, might be expected to pressure these PHEV emissions estimates to the downside.

9.3.2.3 Hydrogen and fuel cells in transport

Another group of technologies, some already in use and others in the R&D phase, utilizes hydrogen as an energy carrier/medium in the conversion of energy for use in fuel cells. Fuel cell–powered vehicles afford a potentially promising means of reducing vehicle emissions, as they are powered by a chemical reaction in the fuel cells rather than combustion; thus they do not emit GHGs or conventional combustion products into the atmosphere—water and heat are the only byproducts.

Among the hydrogen technologies currently in use, the most widespread at present is known as *steam hydrocarbon reforming* (or steam methane reforming). Natural gas is reacted with steam to form synthesis gas (consisting of H, CO, CO_4), from which pure hydrogen is extracted. A similar "reforming" technology reacts synthesis gas produced by coal combustion at a coal-fired power plant with steam to produce hydrogen as well as electricity, thereby lowering the carbon footprint at the plant. Finally in a process known as *renewable liquid reforming*, a renewable liquid fuel (e.g., ethanol) is reacted with high-temperature steam to produce hydrogen.

Although these reforming technologies all are operational to one degree or another, they are viewed as "interim" rather than long-term solutions for a number of reasons. Hydrogen has a relatively low energy density, requiring twice the energy to produce an equivalent unit of work vis-à-vis many other power sources currently in use (coal, nuclear, and even solar PV), and there can be substantial energy losses during the production-delivery-application chain.[34] In addition to energy losses, steam hydrocarbon reforming is not viewed as a long-term tool in the arsenal of weapons to reduce GHG emissions, as both fossil fuel production and combustion may be involved in the process. Even the fuels used in renewable liquid reforming are not devoid of a carbon footprint.

Another operational hydrogen technology—*electrolysis*, in which an electric current splits water into hydrogen and oxygen—is very power intensive (and costly), but potentially lacks a carbon footprint when the electricity used in the process is generated by wind or solar. A final group of hydrogen technologies currently under development seek to use renewable, zero-carbon energy to more directly obtain hydrogen from a water feedstock. Often referred to as "solar hydrogen," they include three principal technologies: high-temperature water splitting; photobiological water splitting; and photoelectrochemical water splitting. These technologies, although "greenest" from an environmental standpoint, still are experimental as researchers seek to elevate low solar-to-hydrogen energy conversion ratios to potentially commercial levels.

Another important dimension that must be considered in hydrogen energy technology involves developments in end-user demand, and most importantly the market for hydrogen-powered, fuel-celled vehicles. The first commercially produced hydrogen fuel-cell vehicles began to be sold by Toyota and leased by Hyundai in 2015. Vehicles currently produced are expensive ($58,500 for the Toyota Mirai in California), as production has yet to advance to mass levels affording economies of scale. There is also only very limited hydrogen fueling infrastructure in place (e.g., 23 stations accessible to the public in the United States in 2016, 20 of them in California). By mid-February 2017 total cumulative sales worldwide amounted to 2,840 vehicles, concentrated in Japan, the US, Europe, and the United Arab Emirates.

In the end, fuel-cell vehicles at present are poorly equipped to compete with battery electric vehicles. Because of inefficiencies involved in the initial transfer of energy to hydrogen, its storage, and its subsequent conversion to electricity in the fuel cell, only about 30–40% of the original energy is estimated to remain. At least limited transport demand is foreseen in the future, however, for uses that involve numerous rapid start-ups and where zero-emissions are a requirement (e.g., in enclosed spaces such as warehouses).

9.3.3. Pathway 3: Policy environment, carbon pricing, and Kazakhstan's emissions trading system

9.3.3.1 Review of program documents and legislation

The basic legal document governing emissions of greenhouse gases, as well as many other environmental issues, is the Ecology Code of the Republic of Kazakhstan (9 January 2007, with subsequent amendments and additions). Among its 47 chapters are three devoted to state regulation of GHG emissions (including allocation and trade in quotas) and establishing a system for monitoring these emissions.

Kazakhstan's national target for GHG emissions reduction is contained in its INDC, submitted after its affirmation of the Paris agreement in late 2015 (an unconditional target of reducing GHG emissions economy-wide by 15% below 1990 levels by 2030). The INDC additionally states Kazakhstan's support for inclusion of market-based mechanisms in the Paris agreement and notes the possibility of introducing a carbon-trading mechanism recognized by the UNFCCC in its efforts to reach its GHG emissions reduction target. In support of its INDC submission, Kazakhstan will re-launch its emissions trading system for GHG emissions in 2018 after a

[34] For example, it is estimated that 30% of the energy in natural gas in steam hydrocarbon reforming is lost in the transfer to hydrogen

nearly two-year hiatus during which a market model for GHG emissions quotas is being fine-tuned and an electronic emissions reporting system is installed (see below).

A number of other programs and strategies are in place to support emissions reductions in the economy. These include: (a) the Concept for Transition to a Green Economy (May 2013), which set goals for the establishment of the GHG emissions trading system, for energy efficiency in the economy, and for the development of alternative energy in electricity generation;[35] (b) the State Program of Industrial and Innovative Development; and (c) the Law «On Support of the Use of Renewable Energy Sources». Kazakhstan also is playing a leading role in the UN-sponsored Green Bridge Partnership Programme (GBPP), an initiative that supports knowledge-sharing as well as access to technologies and financing to support sustainable economic development in the broader Central Asian region.

One of the major challenges to the development of green technologies in Kazakhstan is access to long-term local-currency financing. To meet this objective the Astana International Financial Center (AIFC, created by presidential decree in December 2015), in collaboration with the EBRD, has undertaken the conceptualization and development of a Green Financial System (GFS) in Kazakhstan.The system, scheduled for launch in September 2017, would seek to mobilize sufficient volumes of domestic and international financing to support necessary investments in energy efficiency, renewable energy development, and low-carbon technologies—i.e., investments in projects that adhere broadly to the goals of the government's 2013 "Green Economy" strategy. More specifically, one of the primary objectives of the GFS is to prepare the infrastructure and establish the administrative functions that would help Kazakh companies to issue "green bonds." These bonds, while not different in character from corporate bonds issued for other purposes, would be focused on green projects—not limited to the energy sector for climate remediation, but also for other environmental protection purposes such as solid waste management, water quality, and biodiversity preservation.

One of the key challenges the AIFC seeks to overcome is the lack of long-term financing in the domestic economy. Currently Kazakhstan's domestic banks are not sufficiently capitalized to support such loans. In the unfavorable external environment accompanying the decline of global oil prices since mid-2014, domestic banks have focused mostly on short-term financing and money market operations. Their incentive to fund long-term projects via local-currency loans has been restrained by limited liquidity and the unpredictability of the exchange rate in recent years. The GFS is intended to provide an alternative source of funding for enterprises seeking to finance green investments.

For the most part the programs and strategies described above set forth the country's long-term vision, rather than providing a regulatory framework. In 2012 and 2013, respectively, some initial pieces of such a framework were instituted for the trading of greenhouse gas emissions quotas (see below), as well as for renewable energy development (via the law On Supporting the Use of Renewable Energy Sources, which establishes technology-specific feed-in tariffs for selected renewable energy technologies—e.g., biomass, solar, wind, geothermal, small hydro). Challenges remain in the fine-tuning of regulatory and legal instruments governing the trading of emissions quotas and grid access and construction permits for renewable energy projects.

9.3.3.2. Carbon pricing globally: coverage and basic forms

Globally, the year 2017 is poised to set a record for the increase in the share of GHG emissions covered by some form of carbon pricing—from 13% to more than 20%—if China launches a national emissions trading scheme as expected later in the year. However, despite a threefold increase in carbon pricing coverage globally since 2005, compliance costs on average have not been high enough to spur dramatic emissions reductions. In part this is because many emissions trading systems in their early years seek to cap growth at some preexisting level before implementing gradual (and then accelerated) lowering of that cap in later years. However, simply a slowing of emissions growth globally represents a major turning point. Provisional estimates of 2016 global fossil fuel CO_2 emissions indicate a minimal rise on 2015 levels, which themselves were relatively stable compared with 2014 values. This has led some observers to suggest that global emissions have now peaked.

The two most common forms of carbon pricing worldwide are an emissions trading system (ETS) and a carbon tax. An ETS sets the quantity of emissions reductions and lets a trading market determine the price, whereas a carbon tax sets the price of emissions reductions and allows the market to determine the quantity of emissions. Because of these differences in approach, each strategy has distinct advantages and disadvantages, leading many countries considering adoption of the two carbon pricing strategies to carefully evaluate their pros and cons. The view generally prevailing globally is that, under conditions of certainty, an emissions tax and an emissions trading system are closely substitutable policy instruments, especially when emissions quotas are auctioned. They have broadly the same environmental and fiscal properties, and the policy choice between the two instruments can be made on the basis of other considerations, such as the administrative cost of the two forms of regulation and the competitiveness of the quota market.[36]

One advantage of a carbon tax (e.g., in dollars per ton of CO_2 or GHGs emitted) is that the carbon price is stable and predictable, so energy producers and industry officials can make investment decisions without fear of fluctuating regulatory costs. It is also more transparent and easier to administer by the government, as the allocation of emissions quotas is not part of such a scheme. And, even during periods of falling or negative emissions growth, it continues to send a price signal (whereas an ETS would not encourage reductions below the emissions cap for a particular year). Finally, although designed not to fluctuate in response to short-term variations, a carbon tax can be adjusted (with sufficient advance notice) if it becomes either too expensive for emitters (threatening their economic livelihood) or too cheap (failing to encourage emissions reductions).

Carbon prices in an ETS, in contrast, are set by the market and thereby (at least in theory) automatically respond to changes in technology, electricity demand, fuel costs, etc., sending (in theory) a real price signal rather than an administratively determined one. An ETS also ensures a pre-determined emissions reduction outcome, albeit one achieved at an unpredictable overall cost.

The disadvantages of the two strategies are in some ways unintended consequences of their strengths. The very transparency of a carbon tax highlights its costs, while the long-term benefits of emissions reductions are often abstract or not easily understood. Thus, if deemed by participants to exert an undue hardship on business operations, the carbon tax may become politically unpopular and lose support. One way of mitigating this possibility would be for the government to redirect some or all carbon tax revenues back to the enterprises for the financing of emissions reductions improvements. Meanwhile, critics of emissions trading systems observe that real-world permit markets ultimately do not function as the perfectly competitive markets they are often assumed to be in theoretical discussions of emissions trading. Typically, these differences between theory and reality involve (a) features of market design, (b) forms of market activity, and (c) market costs and inefficiencies.

9.3.3.3. Kazakhstan's emissions trading system

In November 2010, the law "On Amendments to Certain Legislative Acts of the Republic of Kazakhstan Relating to Environmental Issues" was enacted, opening a path for the establishment of a carbon trading market by specifying general rules for emissions trading, and establishing the liability of enterprises (emitting more than 20,000 tons of CO_2 annually) for GHG emissions exceeding limits outlined in an allowance certificate. This was followed in December 2011 by an amendment to the country's Ecological Code: establishing a market mechanism (emissions trading system) for reducing emissions that allows both domestic and international trade in emissions allowances. The internal emissions trading system rules were developed during 2012, and codified in the government decrees "On Confirmation of Rules for the Allocation of Quotas for Emissions of Greenhouse Gases" (no. 586, 7 May 2012) and "On Confirmation of Rules for Trade in Quotas for Greenhouse Gas Emissions and Carbon Units" (no. 151-e, 11 May 2012).

During 2013 a one-year pilot phase was rolled out that included 178 major enterprises in the power, oil-gas, coal mining, chemicals, and metals mining/metallurgical sectors. In aggregate these enterprises accounted for 77% of the country's CO_2 emissions and 55% of its GHG emissions in 2010. Under a National Allocation Plan a cap (allowance surrender obligation) was placed on the aggregate GHG emissions of these 178 enterprises that corresponded to their 2010 emissions level (147 MMt of CO_2 equivalent).[37] The general concept was that enterprises that failed to reduce their emissions (to the 2010 level) could purchase allowances from those with credits to spare, or would be subject to fines (approximately $75 per ton of CO_2 emitted in excess of the cap). Ultimately, however, no fines were imposed on enterprises during the pilot phase.

Despite the technical and organizational challenges of the pilot phase, the GHG emissions regulation system was launched in earnest in 2014—this time in an operating mode envisaging penalties or the purchase by enterprises exceeding the established emissions limits of additional allocations from enterprises reducing their emissions. According to the National Plan for the allocation of greenhouse gas emissions quotas for 2014–15, allocations were issued to 166 companies using 2013 emissions data as a benchmark (with commitments to maintain the same level of emissions in 2014 and to achieve a 1.5% decrease in 2015). Enterprises exceeding their allowances could purchase additional GHG emissions allowances on Kazakhstan's "Caspy" commodity exchange. A controversial matter at that time involved the issue by the market administrator (the state-owned JSC Zhasyl Damu) of free additional allocations (e.g., based on plans to increase industrial output/introduce new emission sources) to enterprises based on applications received. Concerns were raised about the fairness and transparency of the mechanism for allocating these additional quotas, because not all applicants received additional quotas for new emission sources. Also, many market participants, including the government and private enterprises, did not have a clear understanding of how the carbon trading system fit within a long-term political vision for carbon reduction.

[35] Alternative energy is defined as wind, solar, hydroelectric, and nuclear generation; echoing the prescriptions of Kazakhstan Strategy 2050, the Green Economy concept specifies that the aggregate share of alternative energy should rise from 3% (2020) to 30% (2030), and then to 50% (2050).

[36] See Stephen Smith, Environmentally Related Taxes and Tradable Permit Systems in Practice, Organisation for Economic Co-operation and Development, Environment Directorate, 11 June 2008.

[37] An additional reserve of allowances of 20.6 MMt was set aside for the installation of new capacity at these enterprises in 2013.

The small size of the carbon market also presented a liquidity challenge. Only 1.27 MMt of CO_2 were traded in 2014 at an average price of KZT 301 ($1.62) per ton, followed in 2015 with 1.25 MMt at KZT 765 ($4.13) per ton. Only 15 trades were recorded in the first five months of 2015 (mostly directly between companies rather than openly over an electronic trading system); prices of the allowances were volatile and not transparent, and ended up being much higher for oil and gas producers, ranging between KZT 1000 and 1600 ($5.40–$8.91) and making it hard for participants to establish meaningful benchmarks.[38]

Finally, questions arose concerning the origins of the quotas traded on the market during a period (2014–15) when national coal output was declining, electricity generation fell at certain power stations, and industrial output overall was relatively weak. This led some researchers to suspect that a portion of the quotas was sold by enterprises solely as a result of a reduction of their output (accompanied by falling emissions). Although such sales are clearly prohibited by Point 8, Article 94.2 of the Ecological Code, the mechanism for its enforcement appears to have been inadequate: enterprises registering allowances on the trading platform were not required to report the reason why allowances were granted (i.e., the actual causes for their emissions reductions). The actual extent of such activity became even more difficult to determine following a Ministry of Energy decree of 18 March 2015, which stated that quota allocations for enterprises could be subsequently revised to reflect: (a) changes planned in the basic character and functioning of the enterprise; and (b) the introduction of new production capacity that increases output. The lack of sufficiently precise criteria regarding interpretation of the first provision creates the possibility of its very broad interpretation, which could allow some enterprises to rationalize production cuts as "changes in the character of production." In the lead-up to 2016, the government began work on revising the quota allocation system, and on 30 December 2015 it issued decree no. 1138 "On Confirmation of a National Plan for the Allocation of Quotas for Emissions of Greenhouse Gases for 2016–2020," intended to supplement previous legislation and to go into force almost immediately thereafter on 1 January 2016. However, the problem outlined above had not been adequately addressed.

In February 2016 Kazakhstan's Deputy Energy Minister Asset Magauov announced that the emissions trading system would be suspended until 1 January 2018 "due to system imbalances." The decision was intended to give all parties additional time: for the government to make refinements to the system in response to the aforementioned challenges and for the industrial enterprises to make further adjustments and preparations. Although enforcement efforts would be suspended, the country's Ecological Code required the 140 enterprises (accounting for roughly 50% of total CO_2 emissions) covered by the ETS's third phase to continue to report their emissions. Although to date only CO_2 has been regulated and traded within the system, the participating enterprises also report emissions of methane, nitrous oxide, and perfluorocarbons. Concerns have arisen about the lack of clarity concerning exactly which greenhouse gases are subject to regulation within the ETS. Wording in the two 2012 decrees establishing the rules for the trading of quotas (nos. 586 and 151-e; see above) refer to greenhouse gases more broadly, yet current and previous National Plans set quotas for, and limit trading to, only CO_2. If additional gases are to be traded and regulated in the future, these should be specified clearly and uniformly defined in written law, and be well understood by all government agencies, sub-agencies, and enterprises that participate in carbon trading scheme.

As part of an effort to support the re-launch of a stronger ETS in 2018, in early 2017 Kazakhstan's Ministry of Energy jointly with the World Bank began preparations for the establishment of an electronic system for reporting GHG emissions. This is intended to allow emitters to report online, while third-party verifiers can independently audit the reported data, and JSC Zhasy lDamu and the regulators (the Climate Change Department as well as the Committee on Ecological Regulation and Control, both under the Ministry of Energy) can automatically ensure compliance with corporate reporting obligations. The new reporting system is expected to be introduced by late December 2017, immediately before the system re-launch in January 2018.

The new electronic system for reporting GHG emissions will support the new emissions trading system, which will function through a commodity exchange, which facilitates trading of allowances among participants in the Kaz ETS. The exchange will function through the platform of the newly opened Astana stock exchange operated by the Astana International Financial Center (see above). The exchange will make it possible for enterprises submitting applications to purchase additional quota allocations at auction from the "units of internal emissions reduction" of enterprises reducing their emissions below an established baseline or benchmark.[39] Sales prices at the auctions are to be determined freely by the parties involved in the transactions, reflecting the supply and demand for quotas at the time the auctions are held. In the event of the absence of a market price quote on the day of a transaction, a price will be determined by a quote based on an independent international supplier of information on carbon offset prices.

An additional change to the ETS in 2018 is that enterprises are to be able to choose the mechanism by which their free allocation of emissions quotas are allocated—according to the historical "baseline" method utilized previously or through a benchmarking procedure. The latter, based on a practice in the EU emissions trading system, designates best practice in low-emission production as a benchmark when setting an enterprise's free allocation. The benchmarks are product specific to the extent possible (i.e., would be different for electric power plants, iron and steel mills, and petrochemical facilities). In a general sense, in the EU system the product benchmark is based on the average GHG emission performance of the top 10% (best-performing) installations producing a specific product. Installations that meet these benchmarks in principle will receive all of the allowances they need; enterprises that do not would be required to purchase additional allowances to reach this threshold. The difficulty of this approach lies in the dependence of emissions in specific industries on the load (in the case of thermal power plants or CHP plants) or widely varying geologic and field conditions (in the case of coal mining and oil and gas extraction). When issuing greenhouse gas emission allocations on the basis of benchmarking, the Ministry of Energy may thus face some problems in "creating a level playing field" for comparing enterprises even within narrowly defined economic sectors.

Other outstanding issues in the operation of the new trading system include no special terms or concessions for new installations that are just starting production or for the participation of upstream projects that are legally PSAs. Accounting for new projects is particularly important for the oil and gas companies, as their production is ramping up, and historical benchmarks for operations are lacking. For PSAs, a key issue is that technically, PSAs in Kazakhstan are only allowed to buy and sell the products they extract from the subsoil (such as oil, gas, and sulfur), but not carbon credits.

9.3.3.4. Experience gained in the operation of the EU emissions trading system

The tribulations of the European Union ETS, the first such system of its kind (launched in a trial phase in 2005 and in full operating mode since 2008) and upon which Kazakhstan's current system is modeled in part, offers potentially valuable lessons. The system has struggled for years under an enormous surplus of spare allowances that has depressed prices and, as a consequence, has offered paltry incentives for investment in carbon-reducing technologies. Early projections of future emissions in the EU system used to set emissions caps proved to be inflated, allowing the market to accumulate large quantities of additional reserves, which collapsed prices to almost nothing in 2006–07. Similarly, the unanticipated effects of the Great Recession depressed overall economic activity in Europe to the point where CO_2 emissions in 2009 fell 10% relative to 2008, cutting the price of additional allocations nearly by half (from €29.20 per ton in July 2008 to about €15 in mid-year 2009). The continued downward trajectory of prices since that time (to below €4 per ton in autumn 2016) indicates carbon market traders' continued expectations that the surplus of allocations in the system will remain.[40]

The experience with the EU ETS indicates that, despite all best efforts to replicate a "market environment," emissions trading is an enormously complex process that requires repeated administrative intervention at one time or another. The price currently set by the EU system is not adequate to spur investment in clean energy technologies. This suggests the need for a strong supervisory body that can undertake measures to prevent an excess of surplus allowances in the system or otherwise take steps to control price volatility (either by setting a floor to support prices or a ceiling to prevent them from rising excessively). Despite a faith in the market to set prices, in Europe there is believed to be a "politically acceptable" price range—estimated at €15–€20 per ton at the low end and €40–€50 at the high end—that is high enough to incentivize investment but not so high as to force enterprises to curtail production. Unfortunately, the price set by trading in the EU ETS has not fallen within this range except for brief periods (only during 2006 and again for the first half of 2008).

As a result, member countries are taking or considering steps (both unilaterally and in concert) to reform the system. In 2012 the United Kingdom introduced the concept of a "carbon floor price" for its electricity generation sector. Initially conceived at roughly €30/ton of CO_2, it was to consist of a Carbon Price Support component, paid by the generating enterprises, that would be added to the EU ETS carbon price to reach the national floor. However, later (2014) the government announced that the Carbon Price Support component would be capped at a maximum of £18 (~€20) per ton/CO_2 through 2021 to limit the competitive disadvantage faced by businesses and to reduce energy bills for UK consumers. France considered following suit, proposing in mid-2016 a national carbon price to be paid by generators in its electrical power sector (originally thought to be roughly €30 per ton of CO_2), to which the going ETS price would be added.[41] However, the French initiative was later suspended, due to concerns over the future of five coal-fired coal plants in the country, the competitiveness of its natural gas–fired plants, and the risk of possible state-aid investigations initiated by the European Commission.

Broader, pan-EU action is also underway. In December 2016 the European Parliament's Environment Committee proposed a series of changes to the ETS, most to take effect after 2020, when the system's Phase 3 of operations ends. In an effort to support prices, it proposed measures to accelerate the removal of surplus allocations from the market, and for a more rapid annual reduction

[38] Jacopo Dettoni, "Kazakhstan's Emissions Market Needs Breath of Fresh Air," Nikkei Asian Review, 30 May 2015.

[39] Additional quotas also may be obtained—outside the exchange—from the State Register of Carbon Units, which is designed to accommodate the growth of production at existing enterprises. The National Plan for 2016–20 assigned 746.5 MMt of free emissions allocations to the 140 participating enterprises and set aside an additional 21.9 MMt of reserve quotas.

[40] By 2020, barring any reform to the system, emissions in Europe will be more than 10% below the planned cap, guaranteeing a continuing accumulation of surplus allowances.

[41] See Helene Bonfils and Coralie Laurencin, Another National Carbon Measure: A Carbon Price Floor in France, IHS Markit Insight, 2 June 2016.

of the emissions cap than previously specified. However, the proposals were contentious and were weakened at a subsequent meeting of the Commission in February 2017; they are now subject to consultations between the Committee, the Council of the EU, and the full European Parliament.

9.4. RECOMMENDATIONS ON DEVELOPMENT GOALS AND REGULATORY SYSTEM

9.4.1. New system of regulation of GHG emissions

While we commend Kazakhstan's intention to re-launch a revamped emissions trading system as a sign of its commitment to the goals of the Paris climate agreement, some measure of caution is in order. This reflects both the nature of the problems experienced in the EU ETS as well as concerns among system participants in Kazakhstan. The problem of differentiating between emissions reductions achieved due to compliance measures (e.g., increased energy efficiency, installation of emissions control technologies) and reduced production without compliance (prohibited) must be addressed more rigorously. In addition, some operators in the mineral extraction industry are not confident that the new rules will provide sufficient emission quotas for enterprises that have changing production profiles, potentially frustrating new growth projects. They also point out that the system does not presently provide instruments to manage compliance that are available in emission trading systems in OECD jurisdictions—namely, borrowing and banking, domestic offsets, or additional free allowances for trade-exposed sectors (exporters; see below).

Furthermore, enterprises involved in mineral extraction argue that when a benchmarking method is used for the determination of emissions allocations (one of the two methods that can be selected), the system lacks mechanisms for "creating a level playing field" in such sectors as coal mining and oil and gas extraction, in which differences in geology and field conditions can affect emissions levels greatly (e.g., some deposits are intrinsically more difficult to work than others and thus require greater energy expenditures and hence emissions). A similar challenge exists in power generation. Emissions per unit of power generation vary according to load, and enterprises of widely varying ages and technological levels exist due to the long service lives of the facilities. These differences, as well as the need for some power-sector installations to perform social as well as strictly economic functions (heat provision at TETs) create the same "apples" and "oranges" dilemma as in the mineral extraction sector.

We believe that it is important for the Ministry of Energy to clearly state its long-term emissions reductions goals and provide clear guidance to enterprises seeking to formulate their carbon reduction strategies within the framework of the emissions trading system. The system should be sufficiently advanced and flexible to take into account different geological and operating conditions for mineral extraction enterprises and different load factors and other obligations (heat provision) in power generation. The ETS should be supported by consistent legislation that specifies clearly the gases that should be regulated, and the definitions should be well understood by all government agencies and enterprises that participate in carbon trading scheme.

System administrators and regulators should be granted powers to intervene in the system if imbalances become pronounced or other problems should arise. Although overly frequent interventions threaten the market character of the ETS, the European experience indicates that administrative adjustments may become necessary even under the best of intentions to let "market forces decide."

It also may be advisable to establish back-up plans to be implemented should unforeseen problems compromise system integrity. These might include, but not be limited to: (a) scaling back coverage to particular regions or economic sectors (such as electric power)[42]; or (b) excluding some older enterprises in the register from coverage (e.g., 1960s-era coal-fired plants), whose useful lifetimes in any event may be nearing an end.

Finally, we recommend consideration of the merits of introducing additional compliance mechanisms existing in such systems elsewhere, but not currently in the Kazakh system. First, providing for the "borrowing and banking" of emissions credits would allow participants to adopt a longer term perspective toward financing emissions reductions, reducing their fiscal uncertainty on an annual basis. In other words, in addition to the immediate buying and selling of emissions credits at auction, enterprises might be able to receive "loans" of quotas for payback at a later date, or create "savings accounts" of emissions credits which could be sold at a later date.

Domestic offsets are a second compliance mechanism. These are credits for emissions reductions or for undertaking mitigation strategies that are not explicitly covered in the ETS (e.g., GHG emissions reductions by system participants at smaller plants not listed on an ETS register; reforestation and carbon sequestration initiatives). Such offsets are currently under consideration in Kazakhstan and would add a layer of flexibility for enterprises striving to achieve compliance. Offsets are a feature of a number of emissions trading systems worldwide (EU, Chinese regional pilot systems, US Regional Greenhouse Gas Initiative, California/Quebec system, South Korea, Tokyo region) and typically have been allowed to cover between 3% and 10% of a company's total emissions.

Third, there is the question of granting free additional allowances for enterprises in trade-exposed enterprises in Kazakhstan's export sector. These enterprises otherwise may suffer economic loss through competition with foreign enterprises in countries either lacking an ETS or carbon tax, or having one with a more lenient compliance regime.

From a longer term perspective, much of the theory of environmental policy considers policy instruments (e.g., a carbon tax versus an emissions trading system) as alternatives, rather than complements. However, in practice combinations of instruments possibly could be employed, with new instruments supplementing—rather than replacing—the existing mechanisms of regulation.[43] Some of the reasons reflect real-world complications not present in theory; the multi-dimensional nature of many pollution problems may mean that the availability of multiple instruments can allow more precisely targeted and effective regulation. Perhaps "one size" (or system) indeed does not "fit all," and it may also be less risky to proceed incrementally, adding new instruments within or outside the emissions trading system rather than altering its structure repeatedly.

Given the numerous legal and operational questions surrounding the carbon trading scheme, Kazakhstan should consider delaying implementation until all ambiguities are resolved. Given the numerous, complex questions surrounding the emissions trading scheme, a carbon tax might be better suited for Kazakhstan, especially given its administrative ease of implementation.

9.4.2. Environmentally friendly transport

Because the transport sector is not included in Kazakhstan's emissions trading system, considerable effort should be made to also reduce emissions in transportation. In addition to enforcing existing fuel economy standards and maintaining an emissions inspection regime for existing vehicles, Kazakhstan should accelerate the move toward higher grades of gasoline and diesel fuel, and enhance monitoring and control over fuel quality to ensure compliance. A recent study by ExxonMobil in the United States concluded that improving the fuel economy of conventional vehicles is the single most cost-effective means of carbon abatement in the US economy, a measure that actually has a negative net cost because of reduced fuel expenditures.[44] And, although Kazakhstan's vehicle fleet is not nearly as large as in the US, the low quality of fuels available for existing powertrains in Kazakhstan is a powerful common denominator that impedes efforts to both improve fuel economy and reduce emissions.

Over the longer term, Kazakhstan should continue steps toward expanding the use of alternative fuels such as compressed natural gas and liquefied natural gas as transportation fuels (described in Chapter 5 of this report). It should also further study the potential of recently discovered lithium deposits (and perhaps new petrolithium technologies) as a basis for the development of a lithium production chain that could supporting the production and use of battery electric vehicles. Development of these forms of environmentally friendly transport—as well as a receptiveness to new forms of mobility (ride hailing, car sharing) and continued support for mass transit use in urban areas—should help reduce dependence on imports of refined petroleum products and mitigate the environmental impacts of transportation on air quality.

9.4.3 Other energy efficiency measures

Given the predominance of coal in the country's primary energy consumption and the dominance of coal-fired capacity in the electric power sector (Chapters 6 and 8), improvements in the generation, transmission, and distribution of electricity will make a major contribution toward increasing the efficiency of overall energy use in the economy. Arguably, however, the new frontier for energy savings lies in improvements in energy efficiency in public buildings and in the residential sector. An important initiative in this area was launched in 2017, in the form of an EBRD-supported program to accelerate the installation of heat meters in residential buildings in Kazakhstan. The new meters will not only help save heat and electricity, but will also help district heating companies to optimize supply and reduce system losses.

There is also a need to streamline administrative responsibilities. Many government bodies are

[42] It is important in this context that China, on the eve of the roll-out of its ETS later this year, is now reportedly considering reducing the number of economic sectors covered initially from eight to three sectors (coal-fired power plants, cement, and aluminum) having relatively simple production processes that facilitate collection of accurate emissions data (Chris Buckley, "China's Leader Pushes Ahead with Big Gamble on a Carbon Trading Market," New York Times, 24 June 2017).

[43] For example, a carbon tax, set at a very low level, and possibly applicable to a broader range of sectors in the economy than those in the ETS, might act as a floor price for the emissions trading system. If the carbon tax applies to all firms in the emissions trading system, it would reduce the allowance price by the amount of the tax (Smith, op. cit., 2008, pp. 38–39).

[44] ExxonMobil, 2017 Outlook for Energy: A View to 2040, p. 31.

involved in oversight and regulation of energy efficiency with considerable overlap. These include: (1) the Institute of Electric Power Development and Energy Savings (under the Ministry of Investment and Development), a think tank that administers the energy efficiency audits of industrial enterprises and public buildings under the Law on Energy Efficiency; it also conducts research on ways to make energy service contracts in the residential sector easy to implement with clear guidelines, and enters into partnerships with international organizations to attract educational and financial resources to Kazakhstan to stimulate the development of energy-saving practices domestically; (2) the Kazakhstan Institute of Industrial Development, also under MID; (3) the Ministry of Energy, which undertakes its own energy savings and environmental initiatives; and (4) even Samruk Kazyna, which is implementing its own energy efficiency programs, particularly in the area of sustainable development.[45]

Each of these bodies tends to view energy savings from its own specific perspectives and goals. Thought should be given to whether some of these activities could be consolidated (perhaps within the Ministry of Energy), or at least whether an inter-governmental body might be created through which the various activities of the MID, Ministry of Energy, and Samruk Kazyna might be better coordinated.

This lack of coordination imposes an additional administrative burden on industrial enterprises in Kazakhstan. The typical large heavy industrial enterprise may simultaneously be subject to reporting and inspections relating to the ETS, to energy efficiency audits, as well as inspections from various government agencies relating to emissions, energy intensity, and energy efficiency.[46] Because many of these agencies and contractors employ different metrics in measuring performance or compliance, there is a certain level of redundancy, leading to wasted efforts and resources devoted to reporting and compliance.

While such problems are by no means unique to Kazakhstan, we recommend identifying areas where duplication occurs and taking further steps to streamline industry's efforts to achieve compliance. To the extent possible, government agencies should have a uniform methodology, or where methodological processes differ, there should be a clear understanding throughout agencies and enterprises of where such differences occur and why.

A cogent and uniform system for monitoring various indicators will help to improve quality of data, assist policymakers in policy formation, and help enterprises reduce the administrative burden of tracking emissions reductions and energy efficiency gains. Basically, there needs to be greater harmonization and alignment of conceptual principles and processes, methodologies, and bureaucratic responsibilities. One example of a possible simplification might involve the creation of a single platform by which enterprises could track both efficiency gains and emissions.

[45] Compliance with SamrukKazyna's program of sustainable development is increasingly influential in corporate decision-making, as it is now a factor in assessing overall corporate performance.

[46] In 2016 the Committee for Industrial Development and Industrial Safety increased inspections of industrial enterprises to meet energy efficiency requirements, including compliance with "energy consumption standards." In cases where enterprises were found to exceed "energy consumption standards," the relevant legislation provides for fines calculated as a percentage of the volume of energy consumption exceeding the norm. But as described in the National Energy Report 2015, a single energy consumption standard for all industrial enterprises is not applicable due to the highly diverse operating conditions at industrial enterprises.

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